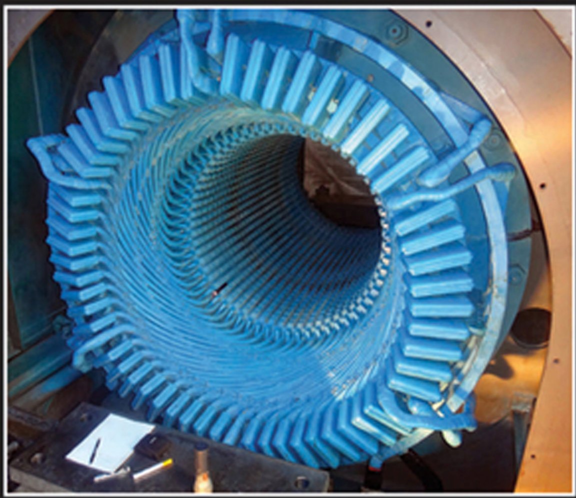
Electrical Insulation for Rotating Machines

Design, Evaluation, Aging, Testing, and Repair

SECOND EDITION



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CONTENTS

PREFACE

This edition was updated by two of us, Greg Stone and Ian Culbert. Given the developments in rotating machine insulation in the past decade, readers will see expanded information on the effect of drives on insulation, the addition of a number of relatively new failure mechanisms, and new diagnostic tests. Many more photos of deteriorated insulation systems have been added in this edition. Many more references have been added, and recent changes in IEEE and IEC standards have been incorporated. We have also added descriptions of the insulation systems used by Chinese and Indian machine manufacturers. The information on Chinese systems came from Mr. Yamin Bai of North China EPRI. Mr. Bai and his colleagues were also responsible for the Chinese version of the first edition of this book. New appendices were added, which give detailed information on the insulation systems used by many manufacturers, as well as insulation material properties. These tables first appeared in a US Electric Power Research Institute (EPRI) document that is long out of print. However, given the number of machines still using these systems and materials, we thought it will be useful to include the information here.

We again would like to thank our spouses, Judy and Anne, and also our employer, Iris Power L.P. We are also grateful to Ms. Resi Zarb for help in organizing and editing the second edition. Finally, we thank the readers of the first edition who took time to point out errors and omissions in the first edition.

Greg Stone and Ian Culbert

CHAPTER 1

ROTATING MACHINE INSULATION SYSTEMS

Since electrical motors and generators were invented, a vast range of electrical machine types have been created. In many cases, different companies called the same type of machine or the same component by completely different names. Therefore, to avoid confusion, before a detailed description of motor and generator insulation systems can be given, it is prudent to identify and describe the types of electrical machines that are discussed in this book. The main components in a machine, as well as the winding subcomponents, are identified and their purposes described.

Although this book concentrates on machines rated at 1 kW or more, much of the information on insulation system design, failure, and testing can be applied to smaller machines, linear motors, servomotors, etc. However, these latter machine types will not be discussed explicitly.

1.1 TYPES OF ROTATING MACHINES

Electrical machines rated at about 1 HP or 1 kW and above are classified into two broad categories: (i) motors, which convert electrical energy into mechanical energy (usually rotating torque) and (ii) generators (also called alternators), which convert mechanical energy into electrical energy. In addition, there is another machine called a synchronous condenser that is a specialized generator/motor generating reactive power. Consult any general book on electrical machines for a more extensive description of machines and how they work [1,2]. An excellent book that focuses on all aspects of turbogenerators has been written by Klempner and Kerszenbaum [3].

Motors or generators can be either AC or DC, that is, they can use/produce alternating current or direct current. In a motor, the DC machine has the advantage that its output rotational speed can be easily changed. Thus, DC motors and generators were widely used in industry in the past. However, with variable-speed motors now easily made by combining an AC motor with an electronic "inverter-fed drive" (IFD), DC motors in the hundreds of kilowatt range and above are becoming less common.

Machines are also classified according to the type of cooling used. They can be directly or indirectly cooled, using air, hydrogen, and/or water as a cooling medium.

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

This book concentrates on AC induction and synchronous motors, as well as synchronous and induction generators. Other types of machines exist; however, these motors and generators constitute the vast majority of electrical machines rated more than 1 kW presently used around the world.

1.1.1 AC Motors

Nearly all AC motors have a single-phase (for motors less than about 1 kW) or three-phase stator winding through which the input current flows. For AC motors, the stator is also called the *armature*. AC motors are usually classified according to the type of rotor winding. The rotor winding is also known as a *field winding* in synchronous machines. A discussion of each type of AC motor follows.

Squirrel Cage Induction (SCI) Motor The SCI motor (Figure 1.1) is by far the most common type of motor made, with millions manufactured each year. The rotor produces a magnetic field by transformer-like AC induction from the stator (armature) winding. The squirrel cage induction motor (Figure 1.1) can range in size from a fraction of a horsepower (<1 kW) to many tens of thousands of horsepower (>60 MW). The predominance of the SCI motor is attributed to the simplicity and ruggedness of the rotor. SCI rotors normally do not use any electrical insulation. In an SCI motor, the speed of the rotor is usually 1% or so slower than the "synchronous" speed of the rotating magnetic field in the air gap created by the stator winding. Thus, the rotor speed "slips" behind the speed of the air gap magnetic flux [1,2]. The SCI motor is used for almost every conceivable application, including fluid pumping, fans, conveyor systems, grinding, mixing, gas compression, and power tool operation.

Wound Rotor Induction Motor The rotor is wound with insulated wire and the leads are brought off the rotor via slip rings. In operation, a current is induced into the rotor from the stator, just as for an SCI motor. However, in the wound rotor machine, it is possible to limit the current in the rotor winding by means of an external resistance or slip-energy recovery system. This permits some control of the rotor speed. Wound rotor induction motors are relatively rare because of the extra maintenance required for the slip rings. IFDs with SCI motors now tend to be preferred for variable-speed applications as they are often a more reliable, cheaper alternative.

Synchronous Motor This motor has a direct current flowing through the rotor (field) winding. The current creates a DC magnetic field, which interacts with the rotating magnetic field from the stator, causing the rotor to spin. The speed of the rotor is exactly related to the frequency of the AC current supplied to the stator winding (50 or 60 Hz). There is no "slip." The speed of the rotor depends on the number of rotor pole pairs (a pole pair contains one north pole and one south pole) times the AC frequency. There are two main ways of obtaining a DC current in the rotor. The oldest method, is to feed current onto the rotor by means of two slip rings (one positive, one negative). Alternatively, the "brushless exciter" method, by most manufacturers, uses a DC winding mounted on the stator to induce a current in an auxiliary three-phase

Figure 1.1 Photograph of an SCI rotor being lowered into the squirrel cage induction motor stator.

winding mounted on the rotor to generate AC current, which is rectified (by "rotating" diodes) to DC. Synchronous motors require a small "pony" motor to run the rotor up to near synchronous speed. Alternatively, an SCI type of winding on the rotor can be used to drive the motor up to speed, before DC current is permitted to flow in the main rotor winding. This winding is referred to as an *amortisseur* or *damper winding*. Because of the more complicated rotor and additional components, synchronous motors tend to be restricted to very large motors today (>10 MW) or very slow speed motors. The advantage of a synchronous motor is that it usually requires less "inrush" current on startup in comparison to an SCI motor, and the speed is more constant. In addition, the operating energy costs are lower as, by adjusting the rotor DC current, one can improve the power factor of the motor, reducing the need for reactive power and the associated AC supply current. Refer to Section 1.1.2 for further subdivision of the types of synchronous motor rotors. Two-pole synchronous motors use round rotors, as described in Section 1.1.2.

1.1.2 Synchronous Generators

Although induction generators do exist (Section 1.1.3), particularly in wind turbine generators, they are relatively rare compared to synchronous generators. Virtually all generators used by electrical utilities are of the synchronous type. In synchronous generators, DC current flows through the rotor (field) winding, which creates a magnetic field from the rotor. At the same time, the rotor is spun by a steam turbine (using fossil or nuclear fuel), gas turbine, diesel engine, or hydroelectric turbine. The spinning DC field from the rotor induces current to flow in the stator (armature) winding. As for motors, the following types of synchronous generators are determined by the design of the rotor, which is primarily a function of the speed of the driving turbine.

Round Rotor Generators Also known as cylindrical rotor machines, round rotors (Figure 1.2) are most common in high speed machines, that is, machines in which the rotor revolves at about 1000 rpm or more. Where the electrical system operates at 60 Hz, the rotor speed is usually either 1800 or 3600 rpm. The relatively smooth surface of the rotor reduces "windage" losses, that is, the energy lost to moving the air (or other gas) around in the air gap between the rotor and the stator—the fan effect. This loss can be substantial at high speeds in the presence of protuberances from the rotor surface, but these losses can be substantially reduced in large generators with pressurized hydrogen cooling. The smooth cylindrical shape also lends itself to a more robust structure under the high centrifugal forces that occur in high speed machines. Round rotor generators, sometimes called "turbogenerators," are usually driven by steam turbines or gas turbines (jet engines). Turbogenerators using round rotors have been made up to 2000 MVA (1000 MW is a typical load for a city of 500,000 people in an industrialized country). Such a machine may be 10 m in length and about 5 m in diameter, with a rotor on the order of 1.5 m in diameter. Such large turbogenerators almost always have a horizontally mounted rotor and are hydrogen-cooled (see Section 1.1.5).

Salient Pole Generators Salient pole generator rotors (Figure 1.3) usually have individual magnetic field pole windings that are mounted on solid or laminated magnetic steel poles that either are an integral part of or are mounted on the rotor shaft.

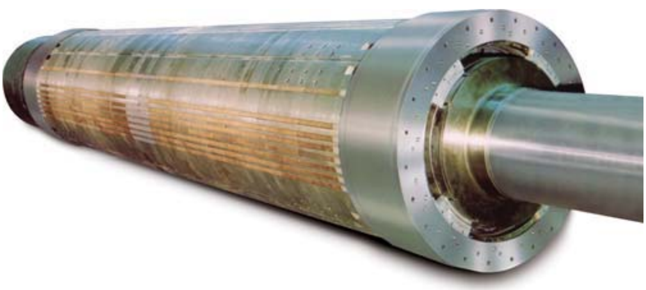


Figure 1.2 Photograph of a round rotor. The retaining rings are at each end of the rotor body.

Figure 1.3 Photograph of a salient pole rotor for a large, low speed motor (Source: Photo courtesy Teco-Westinghouse).

In slower speed generators, the pole/winding assemblies are mounted on a rim that is fastened to the rotor shaft by a “spider”—a set of spokes. As the magnetic field poles protrude from the rim with spaces between the poles, the salient pole rotor creates considerable air turbulence in the air gap between the rotor and the stator as the rotor rotates, resulting in a relatively high windage loss. However, as this type of rotor is much less expensive to manufacture than a round rotor type, ratings can reach 50 MVA with rotational speeds up to 1800 rpm. Salient pole machines typically are used with hydraulic (hydro) turbines, which have a relatively low rpm (the higher is the penstock, i.e., the larger is the fall of the water, the faster will be the speed) and with steam or gas turbines where a speed reducing gearbox is used to match the turbine and generator speeds. To generate 50- or 60-Hz current in the stator, a large number of field poles are needed (recall that the generated AC frequency is the number of pole pairs times the rotor speed in revolutions per second). Fifty pole pairs are not uncommon on a hydrogenerator, compared to one or two pole pairs on a turbogenerator. Such a large number of pole pairs require a large rotor diameter in order to mount all the poles. Hydrogenerators are now being made up to about 1000 MVA in China. The rotor in a large hydrogenerator is almost always vertically mounted, and may be more than 15 m in diameter, but there are some horizontal applications for use with bulb hydraulic turbines for low head high flow application with ratings up to about 10 MVA.

Pump/Storage Motor Generator This is a special type of salient pole machine. It is used to pump water into an upper reservoir during times of low electricity demand. Then, at times of high demand for electricity, the water is allowed to flow from the upper reservoir to the lower reservoir, where the machine operates in reverse as a generator. The reversal of the machine from the pump to generate mode is commonly accomplished by changing the connections on the machine’s stator winding to reverse rotor direction. In a few cases, the pitch of the hydraulic turbine blades is changed. In the pump motor mode, the rotor can come up to speed using an SCI-type winding on the rotor (referred to as an *amortisseur* or *damper winding*), resulting in a large inrush current, or using a “pony” motor. If the former is used, the machine is often energized by an IFD that gradually increases the rotor speed by slowly increasing the AC frequency to the stator. As the speed is typically less than a few hundred rpm, the rotor is usually of the salient pole type. However, high speed pump storage generators may have a round rotor construction [4]. Pump storage units have been made up to 500 MVA.

1.1.3 Induction Generators

The induction generator differs from the synchronous generator in that the excitation is derived from the magnetizing current in the stator winding. Therefore, this type of generator must be connected to an existing power source to determine its operating voltage and frequency and to provide it with magnetizing volt-amperes. As this is an induction machine, it has to be driven at a super-synchronous speed to achieve a generating mode. This type of generator comes in two forms that can have the same type of stator winding, but which differ in rotor winding construction. One of these has a squirrel-cage rotor and the other has a three-phase wound rotor connected to slip rings for control of rotor currents and therefore performance. The squirrel cage type is used in some small hydrogenerator and wind turbine generator applications with ratings up to a few MVA. The wound rotor type has, until recently, been used extensively in wind turbine generator applications. When used with wind turbines, the wound rotor induction generator is configured with rectifier/inverters both in the rotor circuit and at the stator winding terminals as indicated in Figure 1.4. In this configuration, commonly known as the *doubly fed rotor concept* (for use in doubly fed induction generators or DFIGs), the output converter rectifies the generator output power and inverts it to match the connected power system voltage and frequency. The converter in the rotor circuit recovers the slip energy from the rotor to feed it back into the power supply and controls the rotor current. This slip recovery significantly improves the efficiency of the generator. Such generators are connected to the low speed wind turbine via a speed-increasing gearbox and have ratings up to around 3 MVA. The DFIG has also been used in large variable-speed pump storage generators.

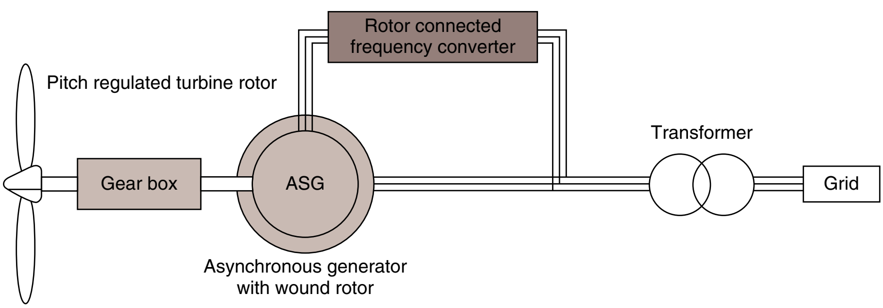


Figure 1.4 Wound rotor induction generator doubly fed configuration [5].

1.1.4 Permanent Magnet (PM) Synchronous Motors and Generators

There has been significant recent development on permanent magnet (PM) machines [6]. The major efforts in this regard were to employ PM materials such as neodymium iron boron (NdFeB) for the rotor field poles that produce much higher flux densities than conventional permanent magnet rotors. Standard induction motors are not particularly well suited for low speed operation, as their efficiency drops with the reduction in speed. They also may be unable to deliver sufficient smooth torque at low speeds. The use of a gearbox is the traditional mechanical solution for this challenge. However, the gearbox is a complicated piece of machinery that takes up space, reduces efficiency, and needs both maintenance and significant quantities of oil. Elimination of the gearbox via the use of these new PM motor/drive configurations saves space and installation costs, energy, and maintenance, and provides more flexibility in production line and facility design. The PM AC motor also delivers high torque at low speed—a benefit traditionally associated with DC motors—and, in doing so, also eliminates the necessity of a DC motor and the associated brush replacement and maintenance. There are many applications for this type of motor in conjunction with inverters, which include electric car, steel rolling mill, and paper machine drives. In addition, larger versions are used in other industrial and marine applications that require precise speed and torque control.

The PM synchronous generator has basically the same advantages and construction as the motor. It is now being widely used in wind turbine generator applications because its construction is much simpler and efficiency much better than a wound rotor induction motor.

1.1.5 Classification by Cooling

Another important means of classifying machines is by the type of cooling medium they use: water, air, and/or hydrogen gas. One of the main heat sources in electrical machines is the DC or AC current flowing through the stator and rotor windings. These are usually called *I^2R losses*, as the heat generated is proportional to the current squared times the resistance of the conductors (almost always copper in stator windings, but sometimes aluminum in SCI rotors). There are other sources of heat: magnetic core losses, windage losses, and eddy current losses. All these losses cause the temperature of the windings to rise. Unless this heat is removed, the winding insulation deteriorates because of the high temperature and the machine fails because of a short circuit. References 7 and 8 are general rotating machine standards that discuss the types of cooling in use.

Indirect Air Cooling Motors and modern generators rated less than about 100 MVA are almost always cooled by air flowing over the rotor and stator. This is called *indirect cooling* as the winding conductors are not directly in contact with the cooling air because of the presence of electrical insulation on the windings. The air itself may be continuously drawn in from the environment, that is, not recirculated. Such machines are termed open-ventilated machines, although there may be some effort to prevent particulates (sand, coal dust, pollution, etc.) and/or moisture from entering the machine using filtering and indirect paths for drawing in the air. These open-ventilated machines are referred to as weather-protected (WP) machines.

A second means of obtaining cool air is to totally enclose the machine and recirculate air via a heat exchanger. This is often needed for motors and generators that are exposed to the elements. The recirculated air is most often cooled by an air-to-water heat exchanger in large machines, or cooled by the outside air via radiating metal fins in small motors or a tube-type cooler in large ones. Either a separate blower motor or a fan mounted on the motor shaft circulates the air.

Although old, small generators may be open-ventilated, the vast majority of hydrogenerators have recirculated air flowing through the machine with the air often cooled by air-to-water heat exchangers. For turbogenerators rated up to a few hundred megawatts, recirculated air is now the most common form of cooling [9,10].

Indirect Hydrogen Cooling Almost all large turbogenerators use recirculated hydrogen as the cooling gas. This is because the smaller and lighter hydrogen molecule results in a lower windage loss, and hydrogen has better heat transfer than air. It is then cost effective to use hydrogen in spite of the extra expense involved, because of the small percentage gain in efficiency. The dividing line for when to use hydrogen cooling is constantly changing. There is now a definite trend to reserve hydrogen cooling for machines rated more than 300 MVA, whereas in the past, hydrogen cooling was sometimes used on steam and gas turbine generators as small as 50 MVA [9,10].

Directly Cooled Windings Generators are referred to as being indirectly or conventionally cooled if the windings are cooled by flowing air or hydrogen over the surface of the windings and through the core, where the heat created within the conductors must first pass through the insulation. Large generator stator and rotor windings are frequently "directly" cooled. In directly cooled windings, water or hydrogen is passed internally through the conductors or through the ducts immediately adjacent to the conductors. Direct water-cooled stator windings pass very pure water through hollow copper conductor strands, or through stainless steel tubes immediately adjacent to the copper conductors. As the cooling medium is directly in contact with the conductors, this very efficiently removes the heat developed by I^2R losses. With indirectly cooled machines, the heat from the I^2R losses must first be transmitted through the electrical insulation covering the conductors, which forms a significant thermal barrier. Although not quite as effective in removing heat, in direct hydrogen-cooled windings, the hydrogen is allowed to flow within hollow copper tubes or stainless steel tubes, just as in the water-cooled design. In both cases, special provisions must be taken to ensure that the direct water or hydrogen cooling does not introduce electrical insulation problems (see Sections 1.4.3 and 8.16). Recently, some Chinese manufacturers have been experimenting with direct cooling of hydrogenerator stators using a Freon type of liquid [11]. The advantage of using this type of coolant instead of water is that if leaks develop, the resulting gas is an excellent insulator, unlike water. Water leaks are an important failure mechanism in direct water-cooled windings (see Section 8.16).

Direct water cooling of hydrogenerator stator windings is applied to machines larger than about 500 MW. There are no direct hydrogen-cooled hydrogenerators. In the 1950s, turbogenerators as small as 100–150 MVA had direct hydrogen or direct water stator cooling. Modern turbogenerators normally only use direct cooling if they are larger than about 200 MVA.

Direct cooling of rotor windings in turbogenerators is common whenever hydrogen is present, or in air-cooled turbogenerators rated more than about 50 MVA. With the exception of machines made by ASEA, only the very largest turbo- and hydrogenerators use direct water cooling of the rotor.

1.2 WINDING COMPONENTS

The stator winding and rotor windings consist of several components, each with its own function. Furthermore, different types of machines have different components. Stator and rotor windings are discussed separately in the following sections.

1.2.1 Stator Winding

The three main components in a stator are the copper conductors (aluminum is rarely used), the stator core, and the insulation. The copper is a conduit for the stator winding current. In a generator, the stator output current is induced to flow in the copper conductors as a reaction to the rotating magnetic field from the rotor. In a motor, a current is introduced into the stator, creating a rotating magnetic field that forces the rotor to move. The copper conductors must have a cross section large enough to carry all the current required without overheating.

Figure 1.5 is the circuit diagram of a typical three-phase motor or generator stator winding. The diagram shows that each phase has one or more parallel paths for current flow. Multiple parallels are often necessary as a copper cross section large enough to carry the entire phase current may result in an uneconomic stator slot size. Each parallel consists of a number of coils connected in series. For most motors and small generators, each coil consists of a number of turns of copper conductors formed into a loop. The rationale for selecting the number of parallels, the number of coils in series, and the number of turns per coil in any particular machine is beyond the scope of this book. The reader is referred to any book on motors and generators, for example, References 1–3.

The stator core in a generator concentrates the magnetic field from the rotor on the copper conductors in the coils. The stator core consists of thin sheets of magnetic steel (referred to as *laminations*). The magnetic steel acts as a low reluctance (low magnetic impedance) path for the magnetic fields from the rotor to the stator, or vice versa for a motor. The steel core also prevents most of the stator winding magnetic field from escaping the ends of the stator core, which would cause currents to flow in adjacent conductive material. Chapter 6 contains more information on cores.

The final major component of a stator winding is the electrical insulation. Unlike copper conductors and magnetic steel, which are active components in making a motor or generator function, the insulation is passive; that is, it does not

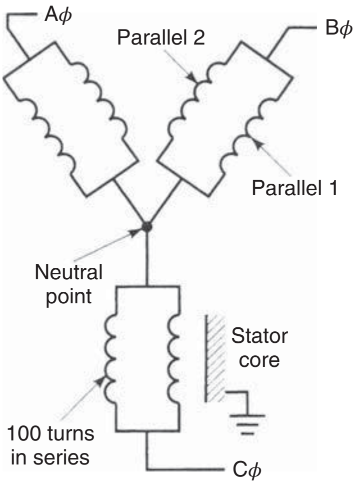


Figure 1.5 Schematic diagram for a three-phase, Y-connected stator winding, with two parallel circuits per phase.

help to produce a magnetic field or guide its path. Generator and motor designers would like nothing better than to eliminate the electrical insulation, as the insulation increases machine size and cost, and reduces efficiency, without helping to create any torque or current [12,13]. Insulation is "overhead," with a primary purpose of preventing short circuits between the conductors or to ground. However, without the insulation, copper conductors would come in contact with one another or with the grounded stator core, causing the current to flow in undesired paths and preventing the proper operation of the machine. In addition, indirectly cooled machines require the insulation to be a thermal conductor, so that the copper conductors do not overheat. The insulation system must also hold the copper conductors tightly in place to prevent movement.

As will be discussed at length in Chapters 3 and 4, the stator winding insulation system contains organic materials as a primary constituent. In general, organic materials soften at a much lower temperature and have a much lower mechanical strength than copper or steel. Thus, the life of a stator winding is limited most often by the electrical insulation rather than by the conductors or the steel core. Furthermore, stator winding maintenance and testing almost always refers to testing and maintenance of the electrical insulation. Section 1.4 describes the different components of the stator winding insulation system and their purposes.

1.2.2 Insulated Rotor Windings

In many ways, the rotor winding has the same components as the stator, but with important changes. In all cases, copper, copper alloy, or aluminum conductors are present to act as a conduit for current flow. However, the steady state current flowing through the rotor winding is usually DC (in synchronous machines), or very low frequency AC (a few hertz) in induction machines. This lower frequency makes the need for a laminated rotor core less critical.

The conductors in rotor windings are often embedded in the laminated steel core or surround laminated magnetic steel. However, round rotors in large turbogenerators and high speed salient pole motors are usually made from forged magnetic steel, as laminated magnetic steel rotors cannot tolerate the high centrifugal forces.

Synchronous machine rotor windings, as well as wound rotor induction motors, contain electrical insulation to prevent short circuits between adjacent conductors or to the rotor body. As will be discussed in Chapters 3 and 5, the insulating materials used in rotor windings are largely composites of organic and inorganic materials, and thus have poor thermal and mechanical properties compared to copper, aluminum, or steel. The insulation then often determines the expected life of a rotor winding.

1.2.3 Squirrel Cage Induction Motor Rotor Windings

SCI rotor windings are unique in that they usually have no explicit electrical insulation on the rotor conductors. Instead, the copper, copper alloy, or aluminum conductors are directly installed in slots in the laminated steel rotor core with their ends being connected to shorting rings by brazed or welded joints. (Smaller SCI rotors may have the aluminum or copper conductors and shorting rings cast in place.) In normal operation, there are only a few volts induced on the rotor conductors, and the conductivity of the conductors is much higher than that of the steel core. Because the current normally flows only in the conductors, electrical insulation is not needed to force the current to flow in the right paths. Reference 14 describes the practical aspects of rotor design and operation in considerable detail.

The only time that significant voltage can appear on the rotor conductors is during motor starting. This is also the time that extremely heavy currents will flow in the rotor windings. Under some conditions during starting, the conductors make and break contact with the rotor core, leading to sparking. This is normally easily tolerated. However, some SCI motors operate in a flammable environment, and this rotor sparking may ignite an explosion. Therefore, some motor manufacturers do insulate the conductors from the rotor core to prevent the sparking [15]. Because such applications are rare, for the purposes of this book, we assume that the SCI rotor is not insulated.

Since SCI rotor windings are generally not insulated they are nominally beyond the scope of this book. However, for completeness, Chapter 12 does discuss such rotors, and Chapters 15 and 16 present some common tests and monitors for SCI rotor winding integrity.

1.3 TYPES OF STATOR WINDING CONSTRUCTION

Three basic types of stator winding structures are employed over the range from 1 kW to 2000 MW:

- Random-wound stators
- Form-wound stators using multi-turn coils
- Form-wound stators using Roebel bars

In general, random-wound stators are typically used for machines less than several hundred kilowatts. Form-wound coil windings are used in most large motors and many generators rated up to from 50 to 100 MVA. Roebel bar windings are generally used for large generators. Although each type of construction is described in the following sections, some machine manufacturers have made hybrids that do not easily fit into any of the above-mentioned categories: these are not discussed in this book.

1.3.1 Random-Wound Stators

Random-wound stators consist of round, insulated copper conductors (magnet wire or winding wire) that are wound continuously (by hand or by a winding machine) through slots in the stator core to form a coil (Figure 1.6). Figure 1.6 shows that most of the turns in the coils can be easily seen. Each turn (loop) of magnet wire could, in principle, be placed randomly against any other turn of magnet wire in the coil, independent of the voltage level of the turn, thus the term "random." As a turn that is connected to the phase terminal can be adjacent to a turn that is operating at low voltage (i.e., at the neutral point), random-wound stators usually operate at voltages less than 1000 V. This effectively limits random-wound stators to machines less than several hundred kilowatts or horsepowers.

1.3.2 Form-Wound Stators — Coil Type

Form-wound stators are usually intended for machines operating at 1000 V and above. Such windings are made from insulated coils that have been preformed before insertion in the slots in the stator core (Figure 1.7). The preformed coil consists of a continuous loop of rectangular magnet wire shaped into a coil (sometimes referred to as a *diamond shape*), with additional insulation applied over the coil loops. Usually, each coil can have from 2 to 12 turns, and several coils are connected in series to

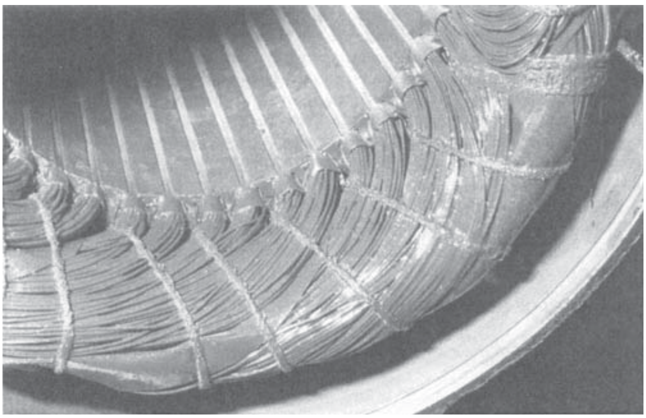


Figure 1.6 Photograph of the end winding and slots of a random-wound stator (Source: TECO-Westinghouse).

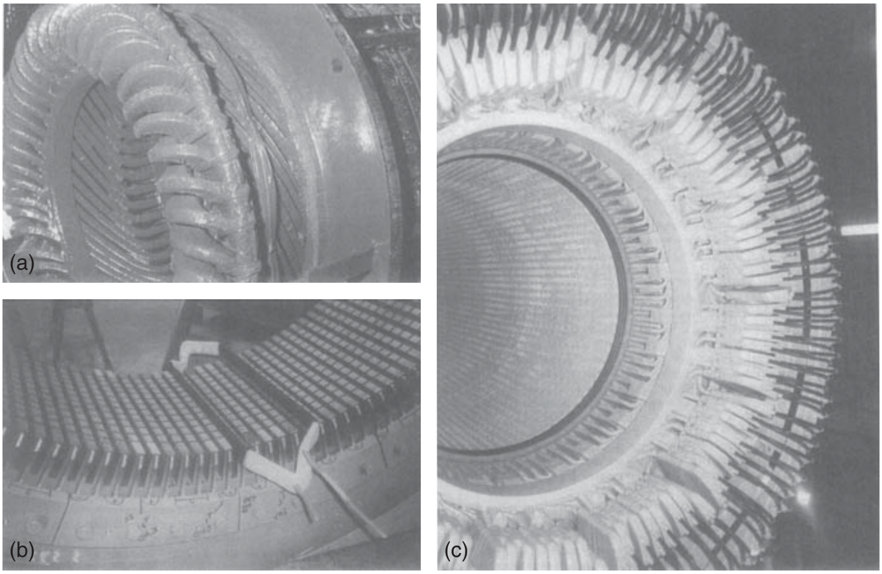


Figure 1.7 (a) Photograph of a form-wound motor stator winding (Source: TECO-Westinghouse). (b) A single form-wound coil being inserted into two slots. (c) Photo of a turbogenerator stator winding using Roebel bars.

create the proper number of poles and turns between the phase terminal and the ground (or neutral); see Figure 1.5. Careful design and manufacture are used to ensure that each turn in a coil is adjacent to another turn with the smallest possible voltage difference. By minimizing the voltage between adjacent turns, thinner insulation can be used to separate the turns. For example, in a 4160-volt stator winding (2400 V line-to-ground), the winding may have 10 coils connected in series, with each coil consisting of 10 turns, yielding 100 turns between the phase terminal and the neutral. The maximum voltage between the adjacent turns is 24 V. In contrast, if the stator were of a random-wound type, there might be up to 2400 V between the adjacent turns, as a phase-end turn may be adjacent to a neutral-end turn. This placement would require an unacceptably large magnet wire insulation thickness.

1.3.3 Form-Wound Stators — Roebel Bar Type

In large generators, the more the power output is, the larger and mechanically stiffer each coil usually is. In stators larger than about 50 MVA, the form-wound coil is large enough that there may be difficulties in inserting both legs of the coil in the narrow slots in the stator core without risking mechanical damage to the coil during the insertion process. Thus, most large generators today are not made from multi-turn coils, but rather from “half-turn” coils, often referred to as Roebel bars. With a Roebel bar construction, only one half of a “coil” is inserted into the slot at a time, which is considerably easier than inserting two sides of a coil in two slots simultaneously.

With the Roebel bar approach, electrical connections to make the “coils” are needed at both ends of the bar (Figure 1.7c).

1.4 FORM-WOUND STATOR WINDING INSULATION SYSTEM FEATURES

The stator winding insulation system contains several different components and features, which together ensure that electrical shorts do not occur, that the heat from the conductor I^2R losses is transmitted to a heat sink, and that the conductors do not vibrate in spite of the magnetic forces. The basic stator insulation system components are:

- Strand (or subconductor) insulation
- Turn insulation
- Groundwall (or ground or earth or mainwall) insulation

Figure 1.8 shows the cross sections of form-wound coils in a stator slot and identifies the above components. Note that the form-wound stator has two coils per slot; this is typical. In large generators, sometimes, the bottom bar may have a smaller copper cross section, to equalize the temperature of the top and bottom bars (there are fewer magnetic losses in a bottom bar). Figure 1.9 shows the cross section of a multi-turn coil. In addition to the main insulation components, the insulation system sometimes has high-voltage stress-relief coatings and endwinding support components (Sections 1.4.5 and 1.4.9).

The following sections describe the purpose of each of these components. The mechanical, thermal, electrical, and environmental stresses that the components are subjected to are also described. As these stresses also affect the insulation components in random-wound windings, occasional reference is made to random windings. Such windings are also discussed in Section 1.5.

1.4.1 Strand Insulation

There are both electrical and mechanical reasons for stranding a conductor in a form-wound coil or bar. From a mechanical point of view, a conductor that is big enough to carry the current needed in the coil or bar for a large machine will have a relatively large cross-sectional area. That is, a large conductor cross section is needed to achieve the desired ampacity. Such a large conductor is difficult to bend and form into the required coil/bar shape. A conductor formed from smaller strands (also called *subconductors*) is easier to bend into the required shape using coil-forming equipment than one large conductor.

From an electrical point of view, there are a few reasons to make strands and insulate them from one another. It is well known from electromagnetic theory that if a copper conductor has a large enough cross-sectional area, AC current will tend to flow on the periphery of the conductor. This is known as the *skin effect*. The skin effect gives rise to a skin depth through which most of the current flows. The skin

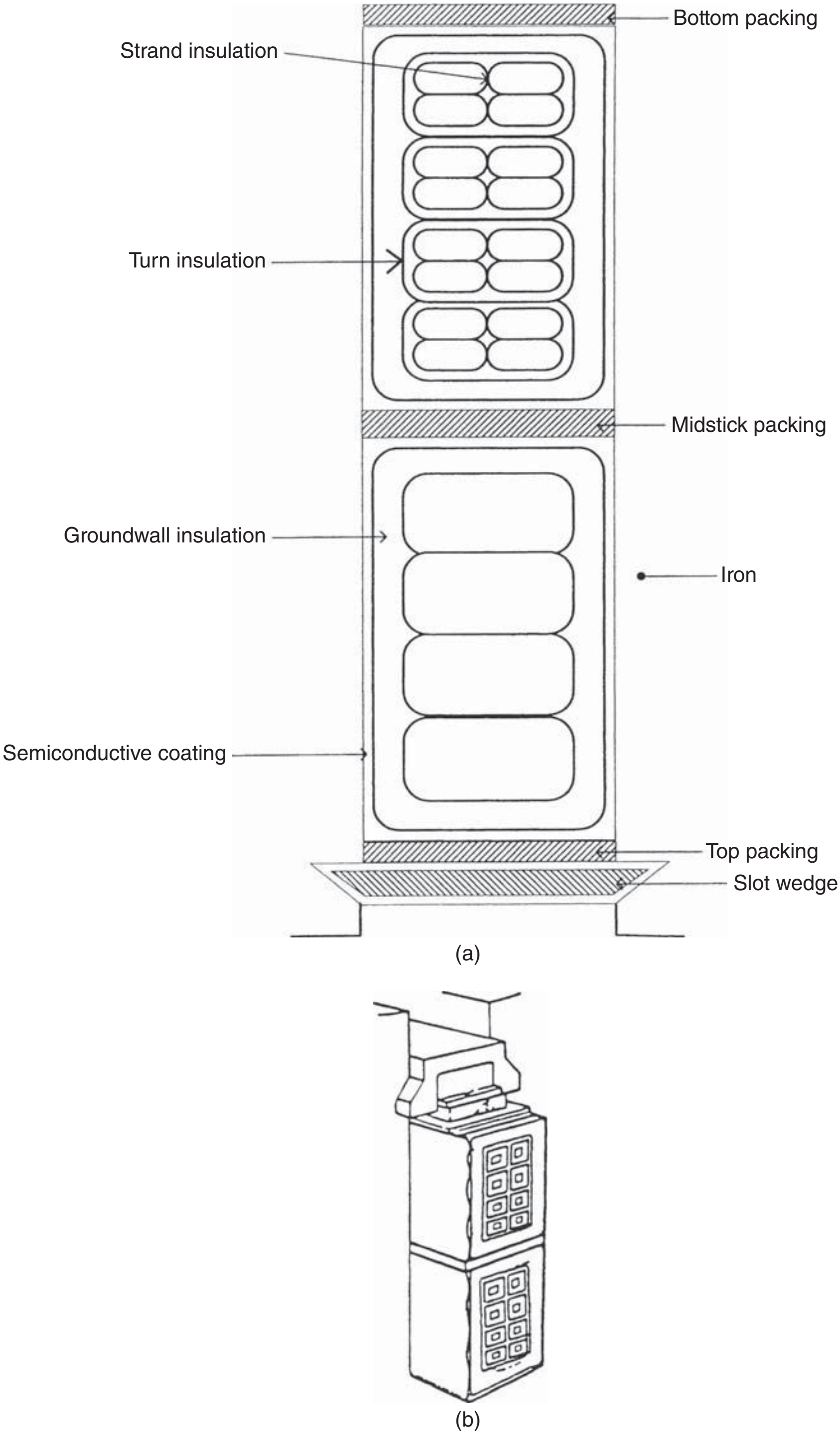


Figure 1.8 Cross sections of slots containing (a) form-wound multi-turn coils and (b) directly cooled Roebel bars.

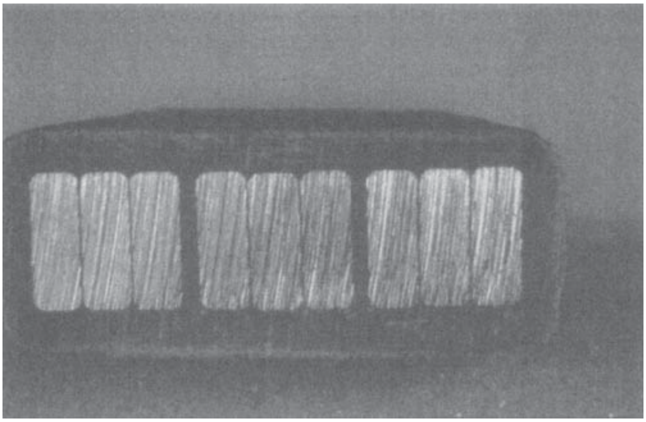


Figure 1.9 Cross section of a multi-turn coil with three turns and three strands per turn.

depth of copper is 8.5 mm at 60 Hz. If the conductor has a cross section such that the thickness is greater than 8.5 mm, there is a tendency for the current *not* to flow through the center of the conductor, which implies that the current is not making use of all the available copper cross sections. This is reflected as an effective AC resistance that is higher than the DC resistance. The higher AC resistance gives rise to a larger I^2R loss than if the same cross section had been made from strands that are insulated from one another to prevent the skin effect from occurring. That is, by making the required cross section from strands that are insulated from one another, all the copper cross sections are used for current flow, the skin effect is negated, and the losses are reduced.

In addition, eddy current losses occur in solid conductors of too large a cross section. In the slots, the main magnetic field is primarily radial, that is, perpendicular to the axial direction. There is also a small circumferential (rotor slot leakage) flux that can induce eddy currents to flow. In the end winding, an axial magnetic field is caused by the abrupt end of the rotor and stator core. This axial magnetic field can be substantial in synchronous machines that are under-excited. By Ampere's law, or the "right hand rule," this axial magnetic field will tend to cause a current to circulate within the cross section of the conductor (Figure 1.10). The larger the cross-sectional area is, the greater will be the magnetic flux that can be encircled by a path on the periphery of the conductor, and the larger will be the induced current. The result is a greater I^2R loss from this circulating current. By reducing the size of the conductors, there is a reduction in stray magnetic field losses, improving efficiency.

The electrical reasons for stranding require the strands to be insulated from one another. The voltage across the strands is less than a few volts; therefore, the strand insulation can be very thin. The strand insulation is subject to damage during the coil-manufacturing process, so it must have good mechanical properties. As the strand insulation is immediately adjacent to the copper conductors that are carrying the main stator current, which produces the I^2R loss, the strand insulation is exposed to the highest temperatures in the stator. Therefore, the strand insulation must have

Figure 1.10 Side view of a generator showing the radial magnetic flux in the air gap and the bulging flux at the core end, which results in an axial flux.

good thermal properties. Section 3.8 describes in detail the strand insulation materials that are in use. Although manufacturers ensure that strand shorts are not present in a new coil, they may occur during service because of thermal or mechanical aging (see Chapter 8). A few strand shorts in form-wound coils/bars will not cause winding failure, but will increase the stator winding losses and cause local temperature increases because of circulating currents.

1.4.2 Turn Insulation

The purpose of the turn insulation in both random- and form-wound stators is to prevent shorts between the turns in a coil. If a turn short occurs, the shorted turn will appear as the secondary winding of an autotransformer. If, for example, the winding has 100 turns between the phase terminal and neutral (the "primary winding"), and if a dead short appears across one turn (the "secondary"), then 100 times normal current will flow in the shorted turn. This follows from the transformer law:

$$n_p I_p = n_s I_s \tag{1.1}$$

where n refers to the number of turns in the primary or secondary and I is the current in the primary or secondary. Consequently, a huge circulating current will flow in the faulted turn, rapidly overheating it. Usually, this high current will be followed quickly by a ground fault because of melted copper burning through any groundwall insulation. Reference 12 suggests that a ground fault will occur in 20–60 s in a low voltage motor, and almost immediately in a medium voltage stator. Clearly, effective turn insulation is needed for long stator winding life.

The power frequency voltage across the turn insulation in a random-wound machine can range up to the rated phase-to-phase voltage of the stator because, by definition, the turns are randomly placed in the slot and thus may be adjacent to a phase-end turn in another phase, although many motor manufacturers may insert extra insulating barriers between coils in the same slot but in different phases and between coils in different phases in the endwindings. As random winding is rarely used on machines rated more than 690 V (phase-to-phase), the turn insulation can be fairly thin. However, if a motor is subject to high voltage pulses, especially from modern

IFDs), interturn voltage stresses that far exceed the normal maximum of 690 Vac can result. These high voltage pulses give rise to failure mechanisms, as discussed in Section 8.10.

The power frequency voltage across adjacent turns in a form-wound multi-turn coil is well defined. Essentially, one can take the number of turns between the phase terminal and the neutral and divide it into the phase-ground voltage to get the voltage across each turn. For example, if a motor is rated 4160 Vrms (phase–phase), the phase–ground voltage is 2400 V. This will result in about 24 Vrms across each turn, if there are 100 turns between the phase end and neutral. This occurs because coil manufacturers take considerable trouble to ensure that the inductance of each coil is the same, and that the inductance of each turn within a coil is the same. As the inductive impedance (X_L) in ohms is:

$$X_L = 2\pi f L \tag{1.2}$$

where f is the frequency of the AC voltage and L the coil or turn inductance, the turns appear as impedances in a voltage divider, where the coil series impedances are equal. In general, the voltage across each turn will be between about 10 Vac (small form-wound motors) and 250 Vac (for large generator multi-turn coils).

The turn insulation in form-wound coils can be exposed to very high transient voltages associated with motor starts, inverter fed drive (IFD) operation, or lightning strikes. Such transient voltages may age or puncture the turn insulation. This is discussed in Sections 8.9 and 8.10. As described below, the turn insulation around the periphery of the copper conductors is also exposed to the rated AC phase–ground stress, as well as the turn–turn AC voltage and the phase coil-to-coil voltage.

Before about 1970, the strand and the turn insulations were separate components in form-wound multi-turn coils. Since that time, many stator manufacturers have combined the strand and turn insulations, although some users oppose this [16].

Figure 1.11 shows the strand insulation that is upgraded (usually with more thickness) to serve as both the strand and turn insulations. This eliminates a manufacturing step (i.e., the turn taping process) and increases the percentage of the slot cross section that can be filled with copper. However, some machine owners have found that in-service failures occur sooner in stators without a separate turn insulation component [16].

Both form-wound coils and random-wound stators are also exposed to mechanical and thermal stresses. The highest mechanical stresses for the turn insulation tend to occur in the coil-forming process, which requires the insulation-covered turns to be bent through large angles, which can stretch and crack the insulation. Steady state, magnetically induced mechanical vibration forces (at twice the power frequency) act on the turns during normal machine operation. In addition, very large transient magnetic forces act on the turns during motor starting or out-of-phase synchronization in generators. These are discussed in detail in Chapter 8. The result is the turn insulation that requires good mechanical strength.

The thermal stresses on the turn insulation are essentially the same as those described earlier for the strand insulation. The turn insulation is adjacent to the copper conductors, which are hot from the I^2R losses in the winding. The higher the melting

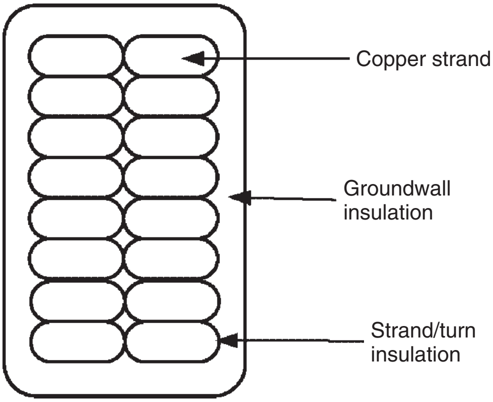


Figure 1.11 Diagram of the cross section of a coil where the turn insulation and the strand insulation are the same.

or decomposition temperature of the turn insulation is, the greater will be the design current that can flow through the stator.

In a Roebel bar winding, no turn insulation is used and there is only strand insulation. Thus, as will be discussed in Chapter 8, some failure mechanisms that can occur with multi-turn coils will not occur with Roebel bar stators.

1.4.3 Groundwall Insulation

Groundwall insulation (also called the *main wall insulation* outside of North America) is the component that separates the copper conductors from the grounded stator core. Its failure usually triggers a ground fault relay, taking the motor or generator off-line*. Thus, the stator groundwall insulation is critical to the proper operation of a motor or generator. For a long service life, the groundwall must meet the rigors of the electrical, thermal, and mechanical stresses that it is subject to.

Electrical Design The groundwall insulation in form-wound multi-turn coils and Roebel bars connected to the phase end of the winding will have the full rated phase–ground voltage across it. For example, a stator rated at 13.8 kV (phase–phase) will have a maximum of 8 kV ($13.8/\sqrt{3}$) between the copper conductors and the grounded stator core. This high voltage requires a substantial groundwall insulation thickness. The high groundwall voltage only occurs in the coils/bars connected to the phase terminals. The coils/bars connected to the neutral (in a wye-connected winding) have essentially no voltage across the groundwall during normal operation. Yet virtually all machines are designed to have the same insulation thickness for both phase- and neutral-end coils. If the coils all had different groundwall thicknesses, then, to take advantage of the smaller width of a neutral end bar or coil, the stator

*If the fault occurs electrically close to the neutral in a wye-connected winding with high impedance between the neutral and ground, some types of relays will not detect the ground fault. This allows a current to flow from the copper to the stator core, which may damage the stator core. Special third-harmonic ground fault relays or relays that inject a current into the stator are available to detect this type of condition [17].

slot would be narrower. All the slots would be of different sizes, and problems would occur when a neutral bar/coil had to be placed on top of a phase-end bar in the same slot. It is simply easier to make the stator core slots all the same size. An advantage to this design approach is that as all coils/bars have the same groundwall thickness, changing connections to reverse the line and neutral ends may extend the life of a winding. That is, the coils formerly at the neutral are now subjected to high voltage, and vice versa. Such a repair may be useful if purely electrical failure mechanisms, such as those described in Sections 8.5, 8.6, and 8.14, are occurring. Other aspects of the electrical design are discussed in Section 1.4.4.

Thermal Design The groundwall insulation in indirectly cooled form-wound machines is the main path for transmitting the heat from the copper conductors (heat source) to the stator core (heat sink). Thus, the groundwall insulation should have as low a thermal resistance as possible, to prevent high temperatures in the copper. Achieving a low thermal resistance requires the groundwall materials to have as high a thermal conductivity as possible, and for the groundwall to be free of voids. Such air voids block the flow of heat, in the same way that two layers of glass separated by a small air space inhibits the flow of heat through a window. Therefore, the insulation must be able to operate at high temperatures (in the copper) and be manufactured in such a way as to minimize the formation of air pockets within the groundwall. Recently, effort has been devoted to develop materials with a higher thermal conductivity than has been available in the past [18,19].

Mechanical Design There are large magnetic forces acting on the copper conductors. These magnetic forces are primarily the result of the two magnetic fields from the current flowing in the top and bottom coils/bars in each slot. These fields interact, exerting a force that makes the individual copper conductors and the entire coil or bar vibrate (primarily) up and down in the slot. The force, F, acting on the top coil at 120 Hz for a 60-Hz current in the radial direction for 1-meter length of coil is given by [20]:

$$F = \frac{cI^2}{d}\,\mathrm{kN/m} \tag{1.3}$$

where I is the rms current through the Roebel bar, or $I = nI_o$ with I_o being the rms coil current times the number of turns in the coil; d the width of the stator slot in meters; and $c = 0.96$. The force is expressed in kilonewton of force acting per meter length of coil/bar in the slot. The highest forces are when both coils/bars in the slot are in the same phase. If the current in a stator bar is:

$$I = A \sin \omega t$$

where ω is $2\pi f$, f the 50- or 60-Hz power frequency, and t time, and then (1.3) becomes

$$F = \frac{cA^2(1 - \cos 2\omega t)}{(2d)}$$

Thus, with two coils/bars in the same phase, there is a net force to the bottom of the slot. Around this “DC” force is an oscillating force at twice the power frequency, that is, 100 or 120 Hz. There is also a 100- or 120-Hz force in the circumferential direction on the top bar/coil caused by the rotor's magnetic field interacting with the current in the stator coil/bar. This circumferential force is only about 10% of the radial force [20].

The groundwall insulation must also help to prevent the copper conductors from vibrating in response to these magnetic forces. If the groundwall were full of air pockets, the copper conductors might be free to vibrate. This would cause the conductors to bang against the remaining groundwall insulation, as well as allowing the copper strands and turns to vibrate against one another, leading to insulation abrasion. If an incompressible insulating mass exists between the copper and the coil surface, then the conductors cannot move.

1.4.4 Groundwall Partial Discharge Suppression

In form-wound bars and coils rated greater than about 4 kV, partial discharges (PDs) can occur within the groundwall insulation or between the surface of the coil or bar and the stator coil. These PDs, which are sometimes colloquially (but incorrectly) called corona†, are the result of the high voltage electrical stress that occurs in the groundwall. If an air pocket (also called a *void* or a *delamination*) exists in the groundwall, the high electric stress may cause electrical breakdown of the air, resulting in a spark. The electrons and ions in the spark will degrade the insulation and, if not corrected, repeated discharges may eventually erode a hole through the groundwall, leading to failure. Therefore, efforts are needed to eliminate voids in the groundwall to prevent stator winding failure. In addition, a PD suppression system is needed to prevent PD in any air gaps between the surface of the coils/bars and the core. The following is a brief discussion of the physics of the PD process within voids in the groundwall. Section 1.4.5 discusses the requirement for a PD suppression system on coil and bar surfaces.

Electric breakdown of insulation is analogous to mechanical failure of a material. For example, the tensile strength of a material depends on the nature of the material (specifically, the strength of the material's chemical bonds) and the cross-sectional area of the material. Mechanical failure occurs when the chemical bonds rupture under the mechanical stress. Tensile stress (kPa) is defined in terms of force (weight) supported (in kilonewton or pounds) per unit cross-sectional area (m^2) or, in British units, pounds per square inch (psi). The larger the cross section is, the more will be the force a material (e.g., a steel wire) can support before it breaks. Different materials have vastly different tensile strengths. The tensile strength of steel exceeds that of copper, which, in turn, is hundreds of times greater than the tensile strength of paper.

Electric breakdown strength is also a property of an insulating material. Electric breakdown is not governed by voltage alone. Rather, it depends on the electric field, just as the tensile stress on a copper wire is not solely determined by the force it is

†According to the IEEE Dictionary (IEEE Standard 100-2000), corona is a form of PD [21]. The term corona is reserved for the visible PDs that can occur on bare metal conductors operating at high voltage, which ionize the surrounding air. As PD within the groundwall is not visible, it should not be termed corona.

supporting but by the force per cross-sectional area. Electric stress, E, in a parallel plate geometry is given by

$$E = \frac{V}{d}(\text{kV/mm}) \tag{1.4}$$

where V is the voltage across the metal plates in kilovolts and d the distance between the plates in millimeter. Note that as for the tensile stress, there is an element of dimensionality. If the voltage is gradually increased across the metal plates, there will be a voltage at which electric breakdown occurs, that is, at which a spark will cross between the plates. Using Equation 1.4, one can then calculate the electric strength of the insulation material. Breakdown involves a process in which the negatively charged electrons orbiting the atoms within the insulation are ripped away from the molecules because they are attracted to the positive metal plate. This is called *ionization*. The electrons accelerate toward the positive metal plate under the electric field, and often collide with other atoms, ionizing these also. A cloud of positive ions is left behind that travels gradually to the negative metal plate. The electrons and ions create a conducting plasma that shorts the voltage difference between the two metal plates. The result is the electric breakdown of the insulation. Two examples of the electric breakdown of air are lightning and the static discharge from a person who has acquired a charge by walking across a carpet in a dry atmosphere and then reaches for a grounded doorknob.

Like mechanical (tensile) strength, each material has its own characteristic electric breakdown strength. For air at room temperature and one atmosphere (100 kPa) pressure, and in low humidity, the electric strength is about 3 kV/mm peak. The electric strength of gas insulation depends on the gas pressure and humidity. For example, the breakdown strength of air at 300 kPa is about 9 kV/mm, that is, for the same distance between the plates, the breakdown voltage is three times higher than at atmospheric pressure (100 kPa). This relationship is known as Paschen's law [22]. The breakdown strength of air and hydrogen is about the same. However, as hydrogen-cooled generators often operate at 300 kPa or more pressure, the breakdown strength of hydrogen under this pressure is 9 kV/mm. As we will see later, this allows hydrogen-cooled generators to operate at higher voltages than air-cooled machines, which operate at atmospheric pressure. The intrinsic breakdown strength of most solid insulating materials such as epoxy and polyester composites is on the order of 200 kV/mm. That is, solid materials used as stator winding insulation are almost 100 times stronger than air. More details on electric breakdown and the physics behind it are in Reference 22.

The presence of air (or hydrogen) pockets within the groundwall can lead to the electric breakdown of the gas filled pockets, a process called a *partial discharge (PD)*. To understand this process, consider the groundwall cross section in Figure 1.12. For electric breakdown to occur in the air pocket, there must be a high electric stress across it. Using a simple capacitive voltage divider circuit (Figure 1.12b), one can calculate, to a first approximation, the voltage across the air pocket.

The capacitance of the air pocket, to a first approximation, can be calculated assuming that it is a parallel plate capacitor, that is,

$$C_a = \frac{\epsilon A}{d_a} \tag{1.5}$$

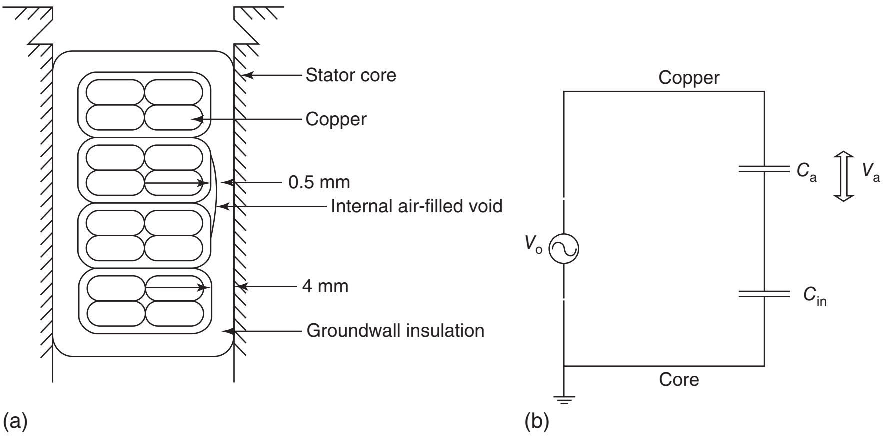


Figure 1.12 (a) Cross section of a coil with an air pocket next to the turn insulation. (b) An electrical equivalent circuit.

where ϵ is the permittivity of the insulating material, A the cross-sectional area of the void, and d_a the thickness of the void (0.5 mm in the example in Figure 1.12a). The permittivity is often represented as:

$$\epsilon = \epsilon_r \epsilon_o \tag{1.6}$$

where ϵ_r is called the *relative dielectric constant* and ϵ_o the permittivity of free space, equal to 8.85×10^{-12} F/m. The dielectric constant for air is 1.0. Thus, assuming a unity cross-sectional area, the capacitance of the air pocket in Figure 1.12a can be calculated.

The air pocket is in series with another capacitor, which represents the capacitance (C_{in}) of the solid insulating material. Using Equation 1.5, assuming a dielectric constant of 4, and assuming that the thickness of the insulation capacitor is 4 mm, the insulation capacitances can be calculated, to a first approximation.

Using simple circuit theory, the voltage across the air pocket can be calculated:

$$V_a = \frac{C_{in}}{C_a + C_{in}} V_o \tag{1.7}$$

where V_o is the applied AC voltage (8 kV rms if the coil is at the phase terminal) and C_{in} the solid insulating material capacitance. Using the above equations, the dimensions in Figure 1.12a, recognizing that A and ϵ_o will cancel out, and assuming the dielectric constants are 1 and 4 for air and the insulation, respectively, one can calculate that the voltage across the air pocket is 33% of the applied voltage. For a V_o of 8 kV rms (rated phase–ground voltage for a phase-end coil in a 13.8-kV stator), the voltage across the air pocket is about 2.6 kV. Note that this is an approximate voltage across the void. A more precise calculation would use finite element electric field computation methods that are now readily available. From Equation 1.4, this voltage implies the electric stress within the air pocket is 5.2 kV/mm rms. This far exceeds the 3 kV/mm peak electric strength of the air, and thus electric breakdown will occur within the air. The resulting spark is called a *partial discharge*. The discharge is referred to as *partial* as the spark is only in the air pocket or void. The rest of the insulation is intact and can support the applied voltage. (A complete discharge is really a phase–ground breakdown, which would trigger the ground fault relay.) The above capacitive model for determining if PD will occur is approximate. In reality, finite element electric field calculations are needed to determine if PD will occur, and account for the nonuniform electric fields within the coil/bar cross section and different void shapes. For a more accurate analysis of the PD phenomena, see References 22 and 23.

As the intrinsic breakdown strength of typical solid groundwall insulation materials is about 200 kV/mm, there is practically no possibility of the solid groundwall insulation itself experiencing electrical breakdown. Rather, PD will occur only when there are gas-filled voids within the groundwall. These discharges are harmful to the groundwall, because repeated PD will eventually degrade the solid insulation by breaking the chemical bonds. The spark contains electrons and ions that bombard the insulation surfaces of the void. This bombardment can rupture the chemical bonds, especially in organic materials such as asphalt, polyester, and epoxy, all common groundwall insulation materials. Over the years, the constant impact from the electrons and ions will erode a hole (called an *electric tree*) through the groundwall, giving rise to a ground fault. The consequence of PD is discussed in greater detail in Chapter 8. The important conclusion is that air pockets within the groundwall of high voltage coils can lead to PD and eventual failure.

1.4.5 Groundwall Stress Relief Coatings for Conventional Stators

The stress relief coatings are important insulation system components in 50/60-Hz stator windings operating at 6 kV or above and IFD motor stators rated 3.3 kV and above (see Section 1.4.6). These coatings are present to prevent PDs from occurring on the surface of the stator bars or coils. They prevent PD from occurring in any air gap that might be present between the coil/bar surface and the stator core, or in the end winding near the end of the stator core.

Slot Semiconductive (Semicon) Coating The reason PD may occur between the coil and the core is similar to the reason PD can occur in air pockets within the groundwall. As coils and bars are fabricated outside of the stator core, they must be thinner in the narrow dimension than the width of the core's steel slots; otherwise, the coils/bars cannot be inserted into the slot. Thus, an air gap between the coil/bar surface and the core is inevitable[‡]. Figure 1.13a shows the gap that can occur in the slot, adjacent to the coil surface, as the coil is undersized. An equivalent circuit, only slightly different from the groundwall case, is shown in Figure 1.12b. As for the

[‡]As discussed in Chapter 3, one stator-manufacturing process called *global VPI* may fill in the gap with epoxy or polyester between the coil surface and the core, thus, in theory, eliminating the need for stress relief coatings. However, because of thermal cycling considerations (Section 8.2), machine manufacturers still use a semiconductive coating with global VPI stators.

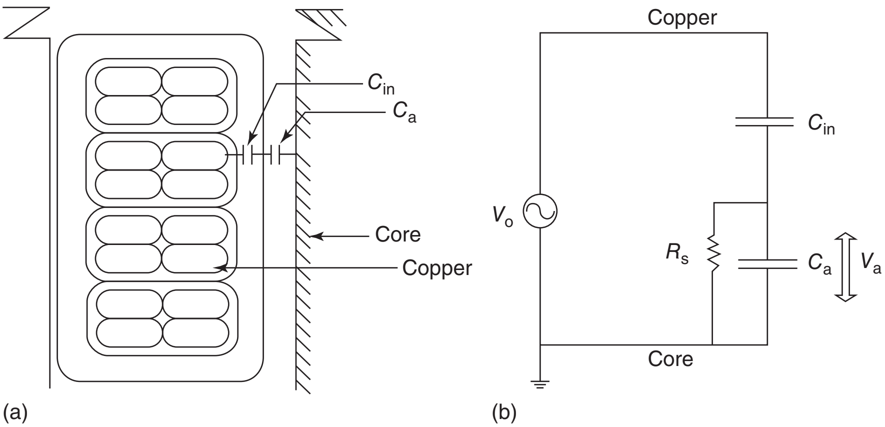


Figure 1.13 (a) Cross section (not to scale) of a coil in a slot where PD can occur at the surface of the coil and (b) the equivalent electrical circuit.

groundwall voids, a significant percentage of the copper voltage will appear across the air gap. If the electric stress in the air gap exceeds 3 kV/mm, PD will occur, at least in an air-cooled machine at atmospheric pressure. This PD will eventually erode a hole through the groundwall causing failure. Discharges on the coil/bar surface are sometimes referred to as *slot discharge*, as they can be seen in the slot. Under practical conditions, most stators rated 6 kV or more will experience this PD on the coil/bar surface. In addition to deteriorating the insulation, surface PD in air-cooled machines creates ozone. The ozone combines with nitrogen and humid air to create nitric acid (HNO_3) that poses a health hazard, and which can chemically attack organic materials and corrode metal; for example, in heat exchangers.

To prevent PD on the coil or bar surfaces, manufacturers have long been coating the coil/bar in the slot area with a partly conductive coating. The coating is usually a graphite-loaded paint or tape. This coating, often called a *semiconductive* or *semicon* coating (although this has nothing to do with semiconductors in the transistor sense), is likely to be in contact with the grounded stator core at many places along the length of the slot. With a sufficiently low resistance (schematically shown as Rs in Figure 1.13b), this coating is essentially at ground potential because of the contact with the core. Thus, the voltage across any air gap is zero. PD cannot occur in the air gap, because the electric stress will never exceed 3 kV/mm. The result is that semiconductive coatings with surface resistance from 0.3 to 10 kΩ per square prevent surface discharges in the slot. Note that the coating cannot be too conductive (i.e., a metalized coating), as this will short out the stator core laminations and/or lead to vibration sparking if the coils/bars are vibrating under the magnetic forces (see Section 8.8).

Semiconductive coatings on coils in the slot are not normally needed for stators rated less than 6 kV. Clearly, this is because it is unlikely that the critical threshold of 3 kV/mm (electric breakdown strength of air) will occur at this low operating voltage, even if a substantial gap occurs between the coil and the core. However, if the winding is to operate at high altitudes (generally higher than 1000 m) where the air pressure is lower, then semiconductive coatings may be needed for 3.3 and 4.1 kV windings as the lower pressure will result in a lower breakdown strength for the air.

Silicon Carbide Coating The low-resistance semiconductive slot coating usually extends only a few centimeters beyond each end of the slot (to the end of the pressure fingers clamping the stator core together)[§]; otherwise, the grounded surface would be brought too close to the connection of one coil/bar to another. Decades of experience shows that even a fully insulated connection between adjacent coils will be a weak spot that may prompt a future insulation failure if ground potential is nearby. In addition, as described in Chapters 3 and 4, it is often difficult to avoid air pockets in the insulation occurring in the end winding during manufacture. If a low-resistance semiconductive coating grounded the endwinding surface, such air pockets are likely to initiate PD as described earlier, eventually leading to failure.

The slot semiconductive coating cannot end abruptly a few centimeters outside the slot as the thin coating would give rise to a high, localized electric field. This field would exceed 3 kV/mm, and PD would occur at the end of the coating. Such PD would eventually destroy the insulation in the vicinity, leading to failure. The thin edge of the coating creates a very nonuniform electric field at the end of the slot coating as the electric stress depends strongly on the inverse of the radius. The smaller the radius is (i.e., the thinner the semiconductive coating is), the larger will be the electric field. For example, a needlepoint at voltage V with a radius r, and a distance d between the needle and a flat ground plane, will create a maximum electric field at the needle tip of approximately [24]:

$$E = \frac{2\,\mathrm{V}}{r \ln\left(\frac{4d}{r}\right)} \tag{1.8}$$

where ln is the natural logarithm. This shows that the radius is critical to the maximum electric field.

Thus, just as for high voltage cables, the end of the semiconductive coating must be “terminated.” In the early days of high voltage rotating machines, the electric field just outside of the slot was made more uniform by embedding concentric floating metal foils of specific lengths within the volume of the groundwall, in the area where the semiconductive coating ends. This is the same principle used in high voltage condenser bushings in transformers [22]. However, when a unique material called *silicon carbide* became available, it superseded the bushing approach.

Silicon carbide is a special material that has an interesting property: as the electric stress increases in this material, its resistance decreases. That is, it is not “ohmic.” In the past, silicon carbide was used in high-voltage surge arrestors to divert high-voltage surges due to lightning strikes to ground (i.e., it has a low resistance

[§]Some manufacturers of very high voltage stator windings may use a high resistance (usually megohms per square) over the entire end winding to control the electrical stress more closely, reducing the probability of flashover during an AC hipot test (Section 15.6). As the coating is high resistance, the further a point is away from the core is, the higher the point will be above ground potential. At the connection to the next coil or bar, the voltage of the coating is assumed to be at the same potential as the voltage of the copper underneath the insulation.

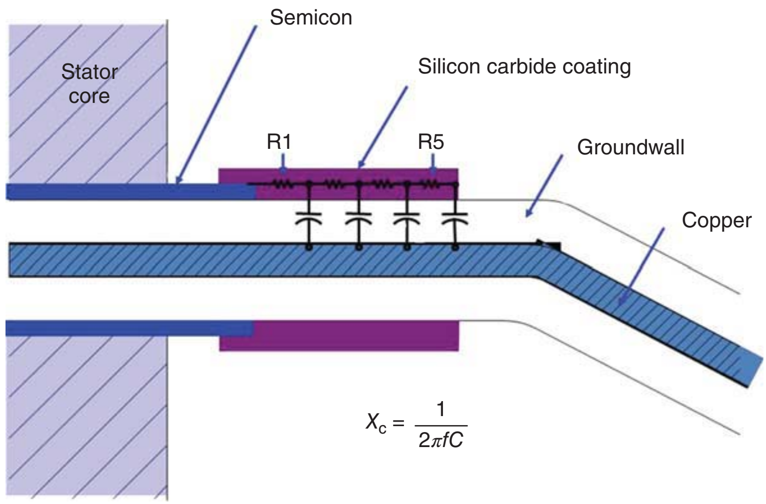
state), whereas being fully insulating during normal operating voltage of a transmission line. When applied to stator coils and bars, the silicon carbide has a very low resistance in the high-stress region at the end of the slot semiconductive coating, and dramatically increases its resistance further along the end winding from the core. This varying resistance makes the electric field at the end of the semiconductive coating more uniform. Figure 1.14a shows an equivalent circuit of the groundwall insulation capacitance and the variable resistance of the silicone carbide coating. R1, closest to the semiconductive coating, has a much lower resistance than say R5, which is farther from the core. The silicon carbide particle density and size are adjusted to make the voltage drop from the groundwall capacitive current across each resistance about the same. Usually, the stress is reduced to below the critical 3 kV/mm (in air) that would initiate PD.

Silicon carbide particles are usually mixed into a paint base, or incorporated into a tape that is applied to the coil/bar surface. The length of the silicon carbide surface coating depends on the voltage rating and the silicone carbide particle size, but 10–20 cm is usual. In Figure 1.7b, the black tape in the middle of the coil is the slot semiconductive coating, whereas the short gray areas at the end of the semiconductive coating are the silicon carbide coatings (not visible owing to a surface paint). The silicon carbide coating is also called the *gradient coating* or the *OCP (outer corona protection coating)*. Further information on stress control coatings can be found in References 25 and 26.

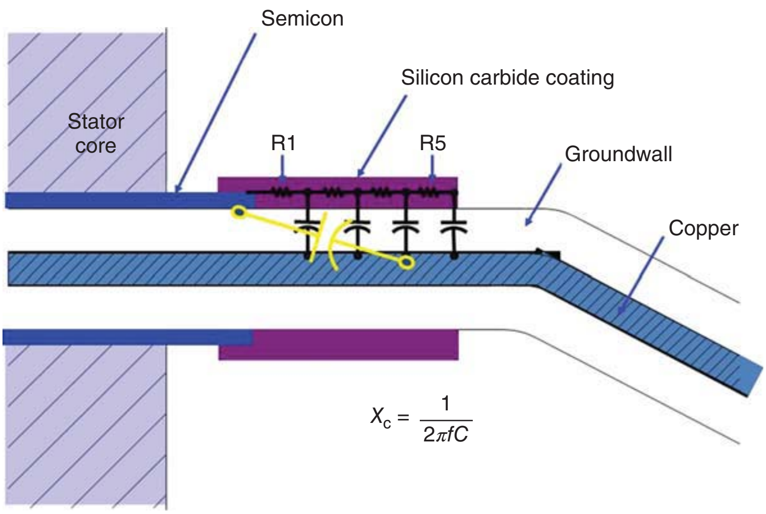
1.4.6 Surface Stress Relief Coatings for Inverter-Fed Stators

SCI motors with form-wound stators rated up to 13.8 kV are now being supplied from inverters for the purpose of speed control. One of the most common types of inverter is called the *voltage source*, *pulse width-modulated (PWM) inverter*. Such invertors use very short risetime electronic switching devices (IGBTs or ICBTs) that are switched on and off at a rate of several kilohertz. As described in more detail in Sections 8.9 and 8.10, the short risetime impulses from the inverter may cause the impulse voltage from the inverter to as much as double because of transmission line effects (reflections) as the impulse travels along the power cable from the inverter to the motor stator winding [27,28]. The result is the peak voltage at the stator winding fed by an inverter will be much higher than the peak voltage in an AC sinusoidal motor, for the same nominal (rms) voltage rating. As electric breakdown and PD are caused by the peak voltage (not the rms or effective voltage), the stress is much more likely to reach the critical 3 kV/mm electric stress in any air gap between the surface of the coil and the stator core, if there is no semiconductive coating on the coil. As a result, most motors rated 3.3 and 4.1 kV intended for inverter duty operation from a voltage source PWM drive should have semiconductive coatings in the slot portion of the coil.

Stator windings fed from a PWM voltage source inverter normally also require some modification of the silicon carbide coatings. The higher frequency current, both from the IFD switching rate and from the short risetimes (which have Fourier frequencies up to 1 MHz), greatly increases the capacitive currents that flow through the groundwall. As a minimum, an inverter switching speed of 2 kHz will result in



(a)



(b)

Figure 1.14 (a) Model of the groundwall capacitance and the silicon carbide coating to create a uniform axial stress at the end of the semiconductive coating in 50/60-Hz applications. (b) Model where the groundwall capacitive impedance is low compared to the semiconductive coating and silicon carbide coating impedances. This is the case for inverter-fed windings.

capacitive currents that are 2000/60 or about 33 times higher than a 60-Hz machine. This higher current flows through the silicon carbide coating (Figure 1.14a) and will greatly increase the I^2R heating in the silicon carbide. Measurements have shown that the I^2R loss can increase the local temperature of the coating by 40°C or more if a conventional silicon carbide coating intended for 50/60-Hz machines is used [27–29].

To reduce the temperature, the silicon carbide coating must be designed to have a significantly lower resistance than the coatings used in 50/60-Hz stators.

Significantly lower resistance is also needed to ensure that the capacitive currents actually flow through the silicon carbide. Sharifi [28] has shown, using analytical techniques and thermography, that with PD suppression coatings designed for 50/60-Hz application, the semiconductive coating and silicon carbide resistances can be so large compared to the capacitive impedance, and that the high capacitive currents are shunted directly to the stator core (Figure 1.14b). Thus, the coatings can rapidly degrade, leading to surface PD (and ozone). Wheeler suggests that the voltage across the silicon carbide coating should be less than 600 V/mm along the length of the coating [29]. Thus, not only must the stator designer use lower resistance silicon carbide materials, it is also advisable that the resistance of the semiconductive coating just outside of the slot also be lower than for a 50/60-Hz machine. Many innovations are being made by machine designers to ensure that the PD suppression coatings are effective, yet do not cause too much of an increase in local temperature. These include the use of much lower resistances of semiconductive coatings outside of the slot, lower resistance silicon carbide coatings, silicon carbide coatings of different properties near and far from the semicon interface, the use of metal-oxide nonlinear materials in place of silicon carbide, and multi-level connections between the semicon coating and the stress relief coating to reduce the resistance of the junction. The optimum design for the PD suppression coatings in PWM voltage source inverter-fed motors is not yet clear.

1.4.7 Conductor Shields

Form-wound coils and bars sometimes use a conductor shield (also called *inner conductor shield* or *inner corona protection (ICP)* coating) applied over the consolidated copper conductor stack in the slot area [30,31]. As with the surface coatings, the purpose of this shield is to reduce the probability of PD occurring, in this case near the copper conductors. During manufacturing of the coils and bars, an insulating material is often wrapped around the copper stack to consolidate the stack and force the copper cross section into a rectangular shape. Experience has shown that it is likely that some small voids will occur next to the rounded edges of the copper strands or at the transposition insulation (Section 1.4.10) in the consolidated stack. Voids tend to be likely here as the conductor stack consolidation process must necessarily be done in air, and thus the high pressures that can be applied in the groundwall impregnation process to reduce void sizes are not possible. In addition, it is possible that the surface of the copper will have imperfections that may cause some of the copper to have a sharp burr that extends from the copper increasing the local electric field. Finally, rapid variations in the stator current may lead to shear stresses between the copper and the groundwall – leading to voids between the copper and the immediately adjacent groundwall insulation (Section 8.2). The voids or copper burrs may lead to PD in the finished coils/bars adjacent to the copper.

To allow for these inevitable imperfections, the insulation system designer may use a lower design electric stress to make sure that such imperfections do not lead to PD in operation. This approach is often used on stator windings rated up to 15 kV or so. Alternatively, such imperfections can be compensated for using a conductive material over the consolidated stack that is close to the same potential as the copper conductors. Any imperfections between the copper and the shield will thus have little or no electric stress across it, thereby preventing PD and its consequent effects on insulation life. The use of conductor shields tends to be more likely on windings rated greater than 15 kV.

Today, conductor shields are usually made from a graphite-loaded tape that is placed as "caps" at the top and bottom of the consolidated stack (i.e., the narrow sides of the copper) or they may be wrapped helically over the entire circumference of the consolidated conductor stack for the length of the slot (and of course underneath the groundwall insulation). In most cases, the graphite layer must be electrically bonded to one of the copper strands, to ensure that the shield is at the same voltage as the copper, and to lower the dissipation factor [30]. Manufacturers sometimes make no intentional galvanic connection between the shield and the copper. Instead, they rely on the very high capacitance between the copper and the shield (as the insulation between these layers is very thin) to ensure that the copper and the shield are close to the same voltage.

A few manufacturers use a very thin metallic foil as the conductor shield on their high voltage coils/bars. If the connection between the foil and the copper is not good, large arcs can occur, which may corrupt PD measurements (Sections 15.12 and 16.4).

1.4.8 Mechanical Support in the Slot

The coils and bars are subject to large magnetically induced forces during normal motor or generator operation, as described in Equation 1.3 and References 2 and 20. These forces are at twice the AC line frequency. Furthermore, if a phase–phase fault occurs near the machine terminals, the transient fault current can be 10 times the rated current [32], which, due to the I^2 component in Equation 1.3, causes a magnetic force as much as 100 times larger than that occurring during normal operation. The coils must be restrained from moving under these steady state and transient mechanical forces. If the coils become loose, then any relative movement that occurs between conductors or coils in the slot or the endwinding will lead to abrasion of the insulation or fatigue cracking of the insulation. Both are obviously undesirable, as they can lead to shorts.

Within the stator slot, the restraint of the coil or bar is accomplished by several means. Often, more than one method is used. As shown in the slot cross sections in Figure 1.8, fundamentally, both random- and form-wound slots are filled as much as possible with conductors and insulation, and then the slot is closed off with a nonconductive and usually nonmagnetic wedge. Filling the slot as much as possible reduces the probability that the coils/bars will become loose. A slot wedge is an essential component to keep the coils and bars in the stator slot. The slot wedge is usually made from an insulating material (nowadays an epoxy glass laminate, usually a NEMA G10 or G11 material) and is critical to restricting movement. Wedges tend to be about 10–20 cm long to make it easier to install them, rather than being a single part that is the length of the slot. Originally, wedges were of a simple "flat" design, held in place

Figure 1.15 Side view of a two-part wedge, where a tapered slider is pushed under the wedge to increase radial pressure on the coils.

by dovetail grooves in the stator slot (Figure 1.8). Some insulation filler strips (also known as *sticks*, *midsticks*, *depth packing*, or *side packing*) are also inserted to take up any extra space in the slot, either under the wedge or on the side of the slots. In machines rated at more than 6 kV, often the filler strips have been filled with graphite to make them semiconductive. This ensures that the semiconductive coating on the coils/bars is grounded to the core via the filler strips, preventing slot discharge.

For large machines, in this context those rated above approximately 20 MW, many manufacturers use a more sophisticated wedge that has two parts (Figures 1.8b and 1.15). The two-part wedge has a tapered slider that is pushed between the main wedge and the coils/bars. This creates a slight spring action in the radial direction that can keep pressure on the coils, even if the slot contents shrink slightly over time.

As an alternative to the two-part wedge (or sometimes as an addition), large machines may use "ripple springs." The ripple spring is a laminated material, sometimes filled with graphite to make it partly conductive (Figure 1.16). The waves in the ripple spring are normally flattened during installation. If the slot contents shrink or creep over time, the ripple spring expands, taking up the new space and holding the coils/bars tight. Ripple springs under a wedge are usually nonconductive. Side ripple springs (between the side of a coil and the core) must be semiconductive.

Other technologies have also been developed to keep coils and bars tight within the slot in large machines. Coils and bars have been manufactured with a compliant semiconductive compound bonded to the surface of the coils/bars, outside of the semiconductive slot coating [33]. As the silicone rubber is compliant, the coils are made to a zero-clearance fit and gradually forced into the slots with hydraulic jacks. If the slot contents shrink over time, the silicone rubber expands to fill the new space. At least some of the silicone rubber must be loaded with graphite to ensure that the semiconductive coating is grounded. Other designs use a U-shaped graphite-loaded hollow tube that is placed in the slot. After wedging (and perhaps after some thermal cycling

Figure 1.16 Photograph of semiconductive ripple spring material lying on top of nonconductive ripple sprint material (Source: Von Roll).

to compact the slot contents), the hollow tube is filled with an insulating material (often silicon rubber) under pressure, to take up any remaining space.

Another way to ensure that the coils/bars do not become loose is to glue the coils/bars into the slot. This is very common for motor stators, and a few manufacturers have used it on high speed generators rated up to about 300 MVA [34,35]. For form-wound machines (and now even some critical random-wound stators and rotors), a process called *global vacuum pressure impregnation (GVPI)* is used. The latter uses epoxy or polyester as the glue. These processes are described in detail in Chapters 3 and 4. The result is coils or bars that do not move in the slot.

Although most stator wedges are made from an insulating material (usually an epoxy-glass laminate), in some applications, designers will use magnetic wedges because of the better coupling of the magnetic field between the rotor and the stator. Magnetic wedges will improve the efficiency of the motor or generator, and thus all other things being equal can result in a smaller stator for the same rating, or a higher rating for the same size of stator without magnetic wedges. The magnetic wedges are made from iron powder or ferrite powder mixed into an organic base material such as epoxy. The wedges may be preformed and slid into the slot dovetail, or may be a thixotropic putty that is molded into the slot and later cured. In the latter, a conventional nonmagnetic wedge may physically secure the coils in the slot [36]. As discussed in Sections 8.4 and 8.11, magnetic wedges on their own are much less robust than insulating wedges, and their disintegration can contaminate the windings or accelerate winding looseness.

1.4.9 Mechanical Support in the End winding

The principle purpose of the endwinding (also called the *end turn*, *endarm*, or *overhang*) is to allow the bars in two slots separated by some distance (or the coil legs that must also be in different slots) to be connected together. In addition, the end winding area facilitates safe electrical connections between coils/bars that are in series and to make safe connections to other parallels. As discussed earlier, for machines rated at 1000 V or more, these connections must be made well away from the grounded stator core, to prevent eventual problems with insulation failure at the insulated connection points. Generally, the higher the voltage rating is, the longer will be the “creepage distance” between the core and the connections. For geometric reasons, high speed machines also tend to have long endwindings. On large two-pole generators, the end-windings can extend up to 2 m beyond the core.

These end windings must be supported to prevent movement. If not suppressed, end winding vibration will occur because the stator winding currents in each coil/bar will create a magnetic field that will interact with the fields produced by adjacent bars/coils. The resulting force vectors can be quite complicated [32,37,38]. However, both radial and circumferential (also called *tangential*) vibrating forces occur at twice AC line frequency (Figure 1.17). As the end winding coils and bars in large machines are essentially cantilevered beams supported by the stator core, once per rotor revolution mechanical forces may also appear on the end windings coupled from the bearings to the machine frame and then to the stator core [38]. These end winding vibration forces can lead to fatigue cracking of the insulation and sometimes even the conductors, at the core end or at the connections. In addition, if the coils/bars are free to vibrate relative to one another, this relative movement can lead to insulation abrasion (fretting) in the end winding. If the machine is expected to see many system disturbances, or a motor is to be frequently started, the high in-rush currents will create even larger transient forces, which must be accommodated. For example, a phase–phase fault in a generator can increase the current by 10 times, resulting in a magnetic force up to 100 times the normal force [32,38]. Motor starting may cause an in-rush current of 5 or 6 times normal, resulting in a 25–36-fold increase in magnetic forces.

End windings can be supported against the vibratory rotational and magnetic forces in many ways. In random-wound machines, the coil endwindings are

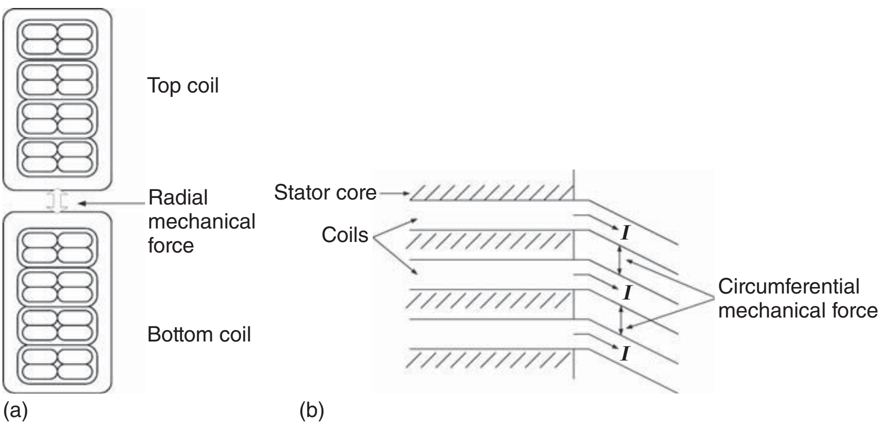


Figure 1.17 Schematics showing the magnetically induced mechanical forces occurring (a) between the top and bottom layers of coils in the end winding (b) between adjacent coils.

essentially right up against the core. With the short extensions and low currents involved, the normal "glues" that impregnate such windings, together with modest insulation tapes or cords (Figure 1.6) around the coil endwindings, are often adequate to support the end winding.

For the form-wound machines, which always have a significant end winding structure, there is almost always one or more "support rings" or "bracing rings" of some sort (Figures 1.7). The ring can be made of steel, which is usually insulated; or polyester or epoxy fiberglass laminate, or fiberglass rope (which is impregnated with stage B epoxy or is dry and then impregnated during a global VPI process). This ring is placed either inside the coil/bar layers (i.e., closer to the rotor than the coils/bars) or radially outside of the coils or bars. Each coil/bar is lashed to the ring. Large machines expecting many starts and stops may have more than one support ring and large generators usually have both inner and outer end winding support rings. The ring tends to prevent coil/bar movement in the radial direction. Insulating blocks a few centimeters in length, placed between adjacent coils, provide circumferential support. One or more rows of such blocking may be present in each endwinding (Figure 1.7a).

Support against the radial magnetic forces comes mainly from insulating blocking that is placed between the bottom (i.e., coils/bars furthest from the rotor) and top layers of coils/bars in the endwinding. The hoop strength of the support ring also helps to ensure that the coils/bars do not move radially.

Most of the endwinding blocking materials, as well as any cords/ropes that may be used to bind coils/bars to one another and to the support rings, are made from insulating material that will bond to other components. For stators that are entirely impregnated, for example, in the global VPI process (Section 3.10.4), the end windings are less likely to suffer from relative movement.

Another consideration in end winding design, especially for large two- and four-pole generators, is the growth of the coils in the slot and the end winding because of high operating temperatures. As a stator goes from no load to full load, the copper conductors heat and, owing to the coefficient of thermal expansion, the bars grow in length. The end winding support system must be able to compensate for this growth; otherwise, the support system and even the bars can become distorted. Accomplishing this tends to be somewhat of an art. See Reference 38 and 39 for more information on methods of allowing for axial expansion in large turbogenerators.

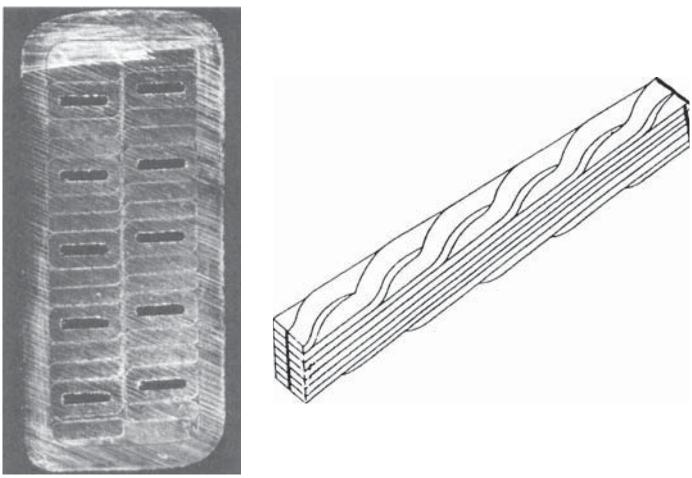
1.4.10 Transposition Insulation

The final stator winding insulation component considered in this chapter is the transposition insulation component. Transpositions occur only in form-wound machines. Multi-turn coils may have what may be called an *internal transposition* of the copper conductors (often called an *inverted* or *twisted turn*). Roebel bars (half-turn coils) always have a transposition. Usually, extra insulation is needed in the vicinity of the transposition to ensure that strand shorts do not occur.

The need for transpositions of the copper strands will be briefly explained first for Roebel bars. The reader is encouraged to refer to Reference 2 for more comprehensive explanations. Magnetic flux leaking across the stator slots is higher near the rotor side of the bar in a generator than at the bottom of the same bar (i.e., furthest from the rotor). Consequently, if the strands in a half-turn coil were always in the same position within the bar, throughout the length of the bar, the strands closer to the rotor would have a greater induced voltage on them than strands furthest from the rotor. In a Roebel bar arrangement, all the strands are normally braised together at each end of the bar. If strands are connected together that have a potential difference induced by the different flux levels, then, by Ohm's law, an axial current will be forced to flow up and down the bar. As the resistance of the copper is low, the circulating current flow will be substantial. This will significantly increase the I^2R loss, which reduces efficiency and increases the temperature of the copper.

In a Roebel transposition, each copper strand is placed into every possible position in the bar as the strand moves along the length of the bar. That is, a strand that is initially in the top left position (Figure 1.18a), after several centimeters along the bar, will be shifted one position lower on the left. The same strand will then be forced another position lower (i.e., two strand positions from the top) a few centimeters further along the bar. About half way along the bar, the strand will be in the bottom position on the left. Then, the strand is shifted from the left side of the conductor stack to the right side, and gradually moves up to the top right position in the other half of the bar. Eventually, it reaches its original position. This is called a 360° transposition. If this 360° transposition is done in the stator core, where the magnetic flux is the highest, then a single strand will have been in each radial position for the same distance along the slot. The total induced voltage on this strand will then be the same as the induced voltage on all the other strands that were transposed. Thus, one can safely connect all the strands together at both ends of the bar and not give rise to axial circulating currents.

There are many different ways to accomplish the movement of the strands into all radial positions. Besides the approach described earlier, another popular way is to



(a) (b)

Figure 1.18 (a) Photo of cross section of a water-cooled Roebel bar with transpositions. (b) Side view showing one way of transposing insulated strands in stator bar.

have the strands move back and forth between the left and right (Figure 1.18b) as it moves from top to bottom. In addition, some manufacturers prefer 540° or even 720° transpositions. Transposing can also occur in the endwinding, as stray magnetic fields are present there. The purpose of the transposition is to improve stator winding efficiency and reduce operating temperature. The mechanical process of shifting strands from one position to another is called *Roebelling*, after the inventor of the original equipment that makes the transpositions.

As discussed earlier, the copper strands have their own insulation layer. As the difference in magnetic flux between the top and bottom positions is not great, the potential difference between the strands is less than a few volts. Thus, normal strand insulation is sufficient to insulate the strands from one another. However, in the vicinity where a copper strand is shifted from one position to another, an air pocket can occur. Extra insulation (often a putty) is needed in these areas to eliminate the air gap and thus any consequent PD. Although all bar manufacturers ensure that strand shorts are not present in new bars, such shorts can occur as a result of in-service aging. A few strand shorts are easily tolerated, especially if they are close to one another.

Most multi-turn coils do not use Roebel transpositions, that is, shifting of strand positions continuously along the slot, because the distance between the top strand in a turn (i.e., the strand closest to the rotor) and the bottom strand in a turn is usually much shorter than occurs in a Roebel bar. Thus, the difference in magnetic flux between the top and bottom strands is much smaller, and the potential difference is much smaller. However, to improve efficiency, many coils have an inverted turn in the knuckle region of the coil (the end that is opposite to the connection end). What effectively happens here is the strand bundle in the turn is rotated through 180°. Thus, the strand that was in the bottom position in one leg of the coil is in the top position of the other leg of the coil. This approximately balances out the induced voltage on each strand in the turn. Alternatively, some manufacturers accomplish a transposition over several coils by more laborious connection arrangements outside of the coil.

1.5 RANDOM-WOUND STATOR WINDING INSULATION SYSTEM FEATURES

Figure 1.19a shows the cross section of a slot in a random-wound stator. Normally, the copper conductors have a circular cross section in smaller stators. The thermal and mechanical stresses in random-wound stators are similar to those in form-wound stators. Random windings have ground and turn insulation. Note that Figure 1.19a could also be the cross section of a wound rotor slot, as used in wound rotor induction motors (Section 1.6.3) and doubly fed generators (Section 1.1.3). The magnet wire insulation serves as both the turn insulation and as one of the components of the ground insulation. The turn insulation is designed to withstand the full phase−phase applied voltage, usually a maximum of 690 Vac.

In most stators rated at more than 250 V, the slots usually also have sheets of insulating material lining the slots, to provide additional ground insulation (Figure 1.19a). They may also have sheets of insulating material separating coils in different phases. Such insulating materials are discussed in Section 3.7. The thermal

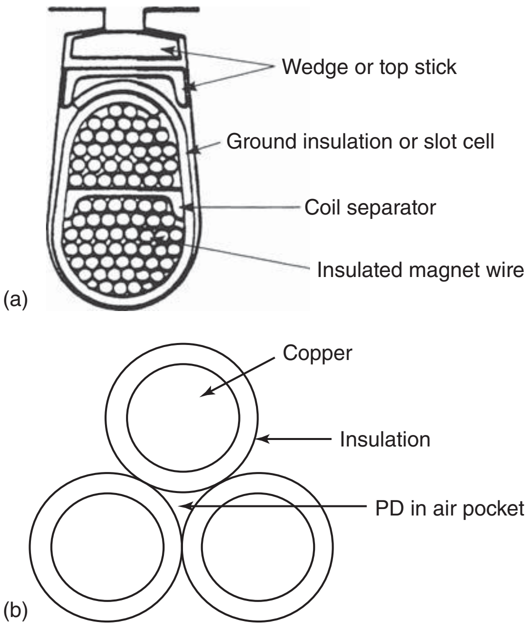


Figure 1.19 (a) The cross section of a random winding in a stator slot and (b) a schematic of (a) where PD can occur between turns in IFD motors.

capability of the liners and separators is less stringent than required of the turn insulation, as the liners are not in immediate contact with the copper conductors. Mechanically, however, the liners must have excellent abrasion resistance to withstand the magnetic forces, which cause the turns to vibrate (Section 1.4.3), and good tear resistance to withstand the manufacturing operation.

The stator winding is usually impregnated with a liquid resin or a varnish (Section 3.4). This is primarily to hold the windings tight within the slot against the twice frequency magnetic forces, so that insulation abrasion will not occur in service. The resin also reduces the amount of air in the slot. This, in turn, will aid in heat transfer from the copper conductors to the stator core. Unlike form-wound coils, with conventional random windings (see Section 1.5.1 for inverter duty motors), the insulation does not have to be void-free to suppress PD, owing to the low voltage on the winding. The most common method for impregnating the resin within the winding is simply to dip the entire stator into a tank full of liquid resin, allow time for impregnation, and then move the stator to an oven for curing (often called the dip-and-bake process). Trickle impregnation and other variations are also sometimes used to introduce the resin into the slots. The best, but most expensive, impregnation method is the GVPI method, as described in Section 3.10.4.

1.5.1 Partial Discharge Suppression in Inverter-Fed Random Windings

With the widespread application of voltage source, PWM variable-speed drives in the late 1980s even low voltage random-wound stator windings started to suffer from PD-related failures. PD has always been an issue with form-wound machines

(Section 1.4.3), but PD causing random-wound stator winding failures (and indeed wound rotor winding failures in DFIGs) was unexpected. The PD was occurring between turns, and sometimes between the turns and the stator slot in voids. Figure 1.19b shows a diagram of a void between turns in the slot, which was not fully impregnated with resin. As described in Sections 8.9 and 8.10, voltage surges from a voltage source PWM inverter will result in a significant portion of the terminal voltage across a pair of turns. Similar to the description in Section 1.4.3, this relatively high voltage will cause breakdown of the air in any void between the turns, which is a PD. The PD will gradually erode the magnet wire insulation and result in a turn-to-turn fault, which rapidly morphs into a ground fault. As the magnet wire insulation has little PD resistance, it has been found prudent to require such inverter-fed motors to be PD free at the operating voltage of the inverter. Effectively, inverter duty random-wound windings need better impregnation by resin than is needed for conventional stators. Thus, such stators often are made with the trickle impregnation or GVPI processes. This is discussed in further detail in Section 8.10 and IEC 60034-18-41.

1.6 ROTOR WINDING INSULATION SYSTEM COMPONENTS

Electrical insulation is present on the salient pole and round rotor types of synchronous motors and generators, as well as wound rotor induction motors and generators (the latter being widely used in wind turbines). Synchronous machine rotor windings have turn-to-turn insulation and slot (ground) insulation. The rotor windings in synchronous motors and generators are subject to relatively low DC voltage, unlike the high AC voltage on the stator. Even in very large turbogenerators, the rotor voltage is usually less than 600 Vdc. This low voltage implies that the turn and ground insulation can be relatively thin. As the voltage is DC, there is no need for strand insulation,¶ because the skin effect is not present under DC voltage. If the DC is provided by static excitation systems, that is, DC created from thyristor operation, some high spike-type voltages may be superimposed on the DC. This is an additional stress that can cause PD [40]. In addition to the steady state DC voltage, voltage transients up to five times operating voltage will occasionally be imposed on the rotor winding when power system events occur such as phase-to-ground faults, energizing a generator with the rotor at standstill, and so on [41].

The other stresses on the rotor insulation include temperature and centrifugal forces. As with the current through the stator winding, the DC current through the rotor winding copper conductors creates considerable I^2R losses, leading to copper heating. The adjacent turn and ground insulation must be able to withstand these high temperatures.

The primary mechanical force on the rotor is not due to magnetic field interaction (although these are present to some degree), but rather due to rotational forces. The centrifugal force is enormous and unidirectional (radially out). The weight of the

¶However, owing to a problem called copper dusting (Section 9.3), some manufacturers now apply strand insulation to prevent copper strands rubbing against adjacent copper strands.

copper conductors will tend to compress and/or distort any insulation. Thus, the rotor winding insulation must have very high compression strength and be supported to prevent distortion. An additional mechanical (or more properly, thermomechanical) stress occurs whenever the machine is turned on and off. When the rotor winding is excited, the current through the conductors causes the copper temperature to rise, and the copper will experience axial growth because of the coefficient of thermal expansion. This growth leads to differential movement of the winding components, and the copper or the insulation can be abraded. Therefore, the rotor insulation components should have good abrasion resistance. This is usually obtained using a slippery coating on the slot insulation.

In a synchronous machine rotor, the winding potential is floating with respect to the rotor body. That is, neither the positive nor the negative DC supply is electrically connected to the rotor body (assumed to be at ground potential). Thus, a single ground fault in the rotor winding usually does not cause extensive damage to the rotor. However, if a second ground fault occurs some distance from the first fault, a large closed loop will be formed in the rotor body through which the rotor DC can flow. This can lead to very high currents flowing in the rotor body, causing localized heating at the fault points and possible melting of the rotor itself. A second ground fault must therefore be avoided at all costs. Most synchronous machine rotors come equipped with a ground fault alarm to warn operators of the first ground fault, or even remove the machine from service if the first ground fault occurs. However, as a rotor winding can often (but not always) operate with a single ground fault, machine owners who are willing to take the risk of rotor damage can install a second rotor ground fault relay, which would only remove the machine from service if a second ground fault occurs [42].

Rotor turn insulation faults in synchronous machines are much less important than similar turn faults in the stator winding. As only DC is flowing in the rotor, there is no equivalent to the "transformer effect," discussed in Section 1.4.2, which will induce a large current to flow around the shorted turn in a stator coil. The main impact of a rotor turn short is to reduce the magnetic field strength from the affected rotor pole. This creates an unsymmetrical magnetic field around the rotor periphery, which tends to increase rotor vibration. Vibration can also occur because of nonuniform heating of the rotor surface, as unfaulted turns in coils will have a higher total current and, consequently, a higher local temperature, than coils containing shorted turns. Thermal expansion of the rotor body will be different around the periphery, bowing the rotor and increasing vibration (Section 16.9). In addition, if too many shorted turns occur, then much more excitation current will be needed to create the magnetic field for the required output. Although shorted rotor turns in themselves may not be hazardous to the machine, if the number of shorts is increasing over time, and then it may be an indicator that there is a greater risk that a rotor ground fault may occur.

Wound induction motor rotors experience much the same thermal and mechanical environments as synchronous machine rotors. However, in motors, instead of a constant DC current, this type of rotor winding sees an initial 50/60 Hz in-rush current during motor starting, followed by a gradual reduction in current and current frequency as the motor comes up to speed. The critical time for the rotor winding then, both in terms of heating and in voltage, is during starting. The open-circuit-induced voltage is normally less than about 1000 V, so the insulation can be very thin. As for synchronous rotors, a single ground fault or multiple turn faults do not necessarily render the motor inoperable.

Wound rotor induction generators are widely used in wind turbines. The rotors in such machines are usually fed by an inverter, whose fundamental frequency is set to add to the changing rotor speed to create a stable stator winding output current of 50 or 60 Hz, for direct connection to the power grid (Figure 1.4). In over-speed conditions that are likely in wind turbine applications, power is also extracted from the rotor winding. These wound rotor generators are called *doubly fed induction generators (DFIGs)*. The inverter supply to the wound rotor is usually of the PWM voltage source type, and hence may result in large voltage impulses being applied to the rotor turn and groundwall insulation systems. As described in Section 8.10, PD caused by these voltage impulses can lead to turn and groundwall insulation failure [43].

The following describes some of the main characteristics of the general physical construction and unique insulation system requirements for each rotor type.

1.6.1 Salient Pole Rotor

Hydrogenerators and four or more pole synchronous motors usually have salient pole rotor windings. Each field pole is constructed separately and the rotor winding made by mounting the completed poles on the rotor rim or directly to an integral solid steel body (Figure 1.20). The poles are then electrically connected to the DC supply in such a way as to create alternating north and south poles around the rim. Each field pole consists of a laminated steel core or solid steel body, which looks rectangular when viewed from the rotor axis. Around the periphery of each pole are the copper windings. Figure 1.20 is a photo of a single field pole from a large motor. There are two basic types of salient pole designs.

The older type of field pole design, and still the design used on motors and generators rated at less than a few megawatts, is called the multilayer wire-wound type. In this design, magnet wire is wrapped around the pole (Figure 1.21). The magnet wire usually has a rectangular or square cross section, and many hundreds of turns

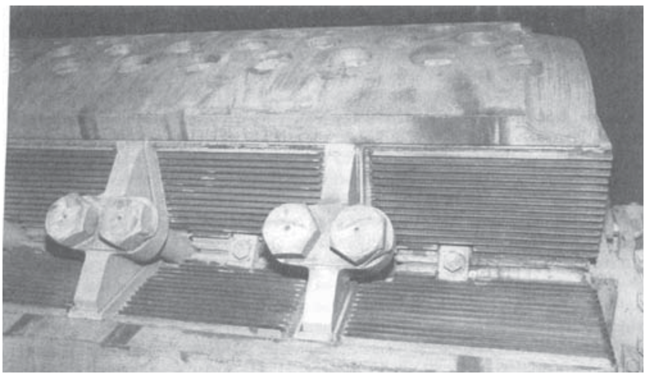


Figure 1.20 Photo of a pole on a salient pole rotor that has a “strip-on-edge” winding. The V block is between two adjacent poles.

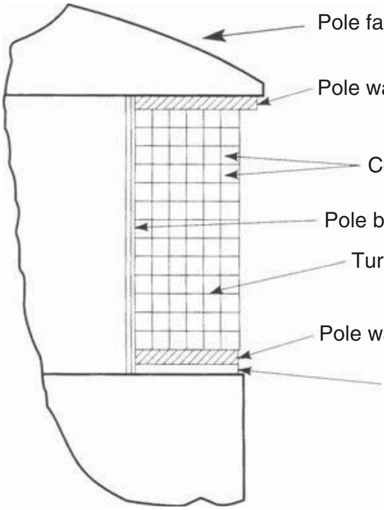


Figure 1.21 Cross section of a multilayer salient pole looking from the top of the pole.

are wound on the pole, several magnet wire layers deep. The turn insulation is the magnet wire insulation. Looking from the axial direction, the laminations are shaped to have a pole tip or pole face (which is the part of the rotor pole closest to the stator) to support the winding against the centrifugal force. Insulating washers and strips are placed between the magnet wire and the laminations to act as the ground insulation.

For larger machines, the “strip-on-edge” design is favored as it can be made to better withstand rotational forces. In this case, a thin copper strip is formed into a “picture frame” shape, so that the “frame” can slide over the pole. Laminated insulating separators act as turn insulation to insulate each copper “frame” from one another. On some copper “frames,” especially those near the pole face, an insulating tape may be applied to the copper to increase the creepage distance. The tape and separators form the turn insulation, and the copper “picture frames” are connected in series to make the coil. An alternative coil construction is to wind a long copper strip helically to form a multi-turn coil. As with the multilayer design, the winding is isolated from the grounded pole body by insulating washers and strips (Figure 1.22). Often, the entire pole may be dipped in an insulating liquid to bond the various components together. For solid pole rotors, the pole tips are usually bolted on (Figure 1.20).

1.6.2 Round Rotors

Round rotors, also called *cylindrical rotors*, are most often found in two- and four-pole turbogenerators as well as in two-pole synchronous motors. The rotor body is usually made from a single steel alloy forging. Axial slots are cut into the forging. The copper turns, made from copper strips up to a few centimeters wide, are placed in these slots. There are usually 5–20 strips (turns) in a slot forming a coil (Figure 1.23). Rather than directly insulating the copper turns with a tape or film insulation, the turns in large rotors are kept separated from each other by insulating strips. Insulating strips or L-shaped channels line the slot, to act as the ground

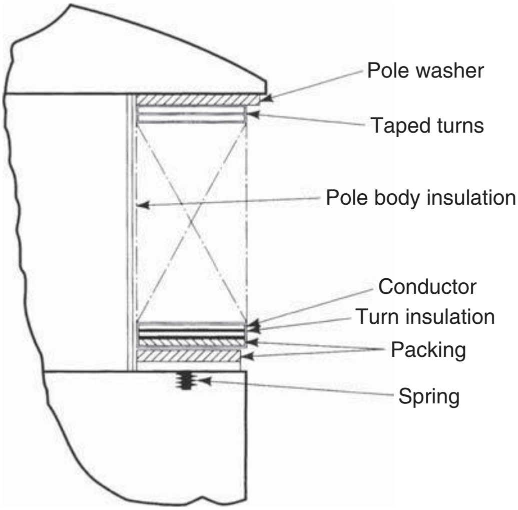


Figure 1.22 Cross section of a "strip-on-edge" salient pole.

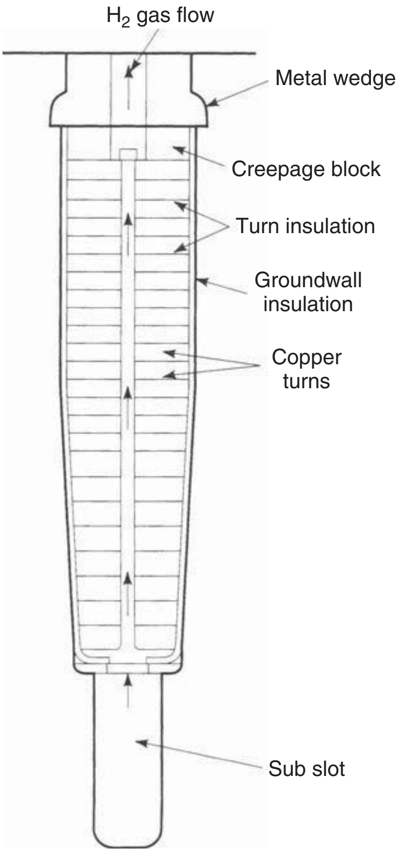


Figure 1.23 Cross section of a round rotor slot. The arrows show the direction of air or hydrogen cooling gas flow.

insulation. As the components are not bonded to one another, the components can slide relative to one another as the current, and thus the temperature, cycles. The copper coils are kept in the slot by means of wedges. As the rotational forces are so enormous (in over-speed conditions, the acceleration can reach in excess of 5000 G), only metal wedges can be used. The wedges are made from copper alloys (in older machines), nonmagnetic steel, magnetic steel, or aluminum alloy. Aluminum is the most common rotor wedge material today. As shown in Figure 1.23, air or hydrogen passages are often cut in the copper turns and wedges, to allow the gas to directly cool the rotor winding. As will be seen in Chapter 9, these passages, together with the use of insulating strips, allow short creepage paths to develop if pollution is present. In addition, these relatively small channels are easily blocked by foreign material or turn insulation migration, causing local hotspots in the rotor.

One of the most challenging design aspects of a round rotor is the end winding. After the copper turns exit from the slot, they go through a 90° bend and are directed around the rotor circumference until they reach the appropriate slot, at which point they go through another 90° bend. This rotor endwinding area must be supported to prevent the centrifugal forces from breaking off the copper conductors. Furthermore, space must be left and slip planes inserted to allow the rotor winding to expand axially as it heats up when current is circulated. In addition, blocking must be installed between coils in the endwinding to prevent distortion from thermal expansion forces. The copper can grow several millimeters along the slot in a large turbogenerator rotor that may be 6 m long.

The end winding is supported against rotational forces by retaining rings at each end of the rotor body (Figure 1.2). In most round rotors for machines larger than about 10 MW, the retaining rings are made from stainless steel. Considerable technology is used to make these rings and shrink them onto the rotor body. An insulating sleeve that allows the components to slip with respect to one another is needed between the copper endwindings and the retaining ring. In open-ventilated air-cooled machines, as well as older machines, the copper turns were often taped in the endwinding region with an insulating tape. However, it is now common to use insulating strips, sheets, and blocks.

1.6.3 Induction Machine Wound Rotors

In motors, these rotors see a 50- or 60-Hz current during motor starting, which gradually reduces to a near DC current once the rotor is up to rated speed. For induction generators especially in wind turbines, the rotor winding is fed by an inverter whose fundamental frequency is determined from the rotor speed, in order to generate 50- or 60-Hz electricity in the stator winding. The rotor consists of a laminated steel core with slots around the periphery. Usually, the slots are partially closed off at the rotor surface by the steel, so that the coils cannot easily be ejected into the air gap. Two basic types of rotor windings have been used.

Random rotor windings are made from magnet wire inserted in the slots (Figure 1.24). The turn insulation is the magnet wire insulation. Once the turns are inserted, an insulating wedge closes off the slot. An insulating slot liner serves as the ground insulation. It is very important to completely fill the slot to ensure

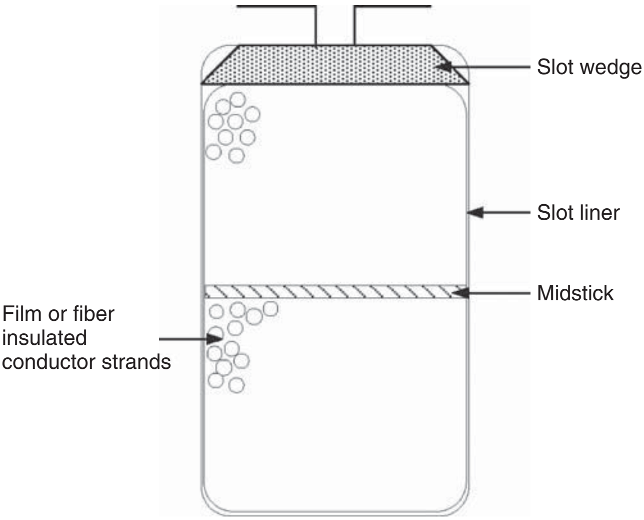


Figure 1.24 Cross section of a small wound-rotor slot.

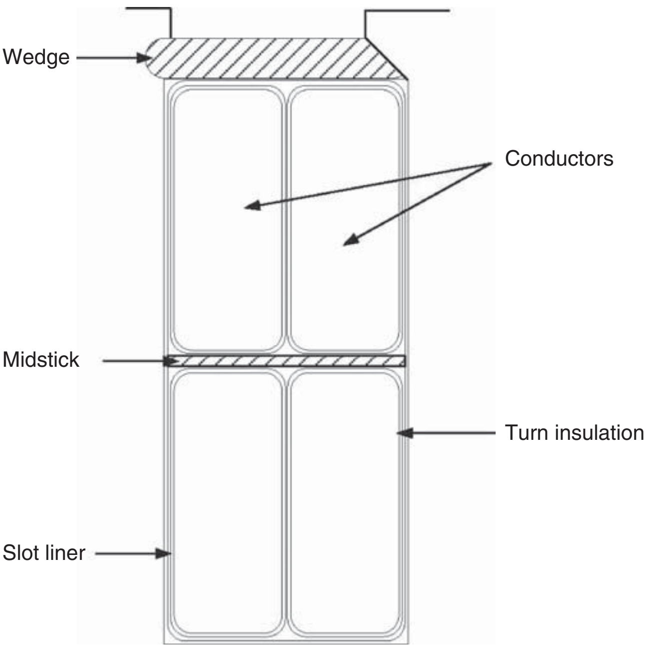


Figure 1.25 Cross section of a large wound rotor slot.

that the turns do not move relative to one another under the rotational forces. All space is filled with insulating strips and the entire rotor is impregnated with a liquid insulation that is cured, using a dipping, trickle impregnation, or GVPI process (Chapter 3). The interturn and ground voltages are low, so the insulation is thin. In the end windings outside of the slot, the end winding region is only several centimeters to 30 cm long, depending on the rotor size and speed, thus end winding movement can be restrained by impregnated cords tying together coils separated by impregnated felt pads. Insulating fiberglass bands are then applied over the end winding area to support it against centrifugal forces.

For larger rotors, copper bars are used for the winding conductors. These bars are rectangular in shape, with the long dimension oriented in the radial direction (Figure 1.25). Usually, either two or four bars are inserted in each slot by dropping through the top, or pushed through the slot from the end of the slot. Before insertion, the bars are preinsulated with a few layers of insulating tape. The ground insulation is a slot liner. As with random-wound rotors, an insulating band restrains the endwindings and the rotor is impregnated to prevent relative movement.

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CHAPTER 2

EVALUATING INSULATION MATERIALS AND SYSTEMS

Owners of motors and generators expect a minimum rotor and stator winding life. For most industrial and utility applications, at least a 20–40-year life is expected before a rewind is needed, whereas in traction applications, a life of 5 years or more may be expected. Decades ago, the insulation system design to accomplish a specified life was largely achieved by trial and error. If an older winding design failed prematurely, then extra insulation was added or other corrective measures were taken in a new design. Generally, to prevent premature failure, "safety margins" were added to the design; that is, the copper may have been given a greater cross section than strictly needed to make sure that the operating temperature was low, the groundwall insulation made thicker to avoid electrical breakdown, etc. The common result was an insulation system that would greatly outperform the specified life. Indeed, many rotor and stator windings made in the first half of the 1900s are still operating today as a result of the conservative design methods used then.

In the past few decades, it has been recognized that the safety margins in the design were excessive and can greatly increase the cost of the rotor and stator. For example, Draper has indicated that a 20% reduction in the groundwall insulation thickness in a large SCI motor stator will allow the width and the depth of the stator slot to be reduced, for the same output power. The stator bore can then be smaller, and the distance from the bore to the back of the stator core can be reduced, while maintaining the same core mechanical stiffness. Depending on the speed of the motor, the weight of the steel needed for the stator is reduced from 13% to 33%, the copper is reduced from 5% to 64%,* and the mass of the insulation is reduced from 12% to 57% [1]. These are significant reductions. As the price of a motor or generator is very dependent on the mass of the steel, copper, and insulation, the stator cost is significantly reduced by increasing the design electric stress level, that is, by reducing the groundwall thickness [1]. Of course, reducing the amount of copper, steel, and insulation used in a motor or generator increases stresses, which may negatively influence life [2].

*This is due to shorter circuit ring busses and less copper cross section in the coil, as the heat from I^2R losses can be transmitted through the thinner groundwall insulation more easily.

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

The recognition that manufacturing costs can be reduced by eliminating unnecessary design conservatism, together with the very competitive global market for motors and generators, has led to more scientific methods in the design of insulation systems in rotor and generator windings. The main tool that manufacturers now use to design the insulation system is called an *accelerated aging test*. The basic concept is to make a model of the insulation system, and then subject the model to higher than normal stresses (temperature, voltage, mechanical force, radiation, etc.); that is, the stress is elevated to increase (accelerate) the rate of deterioration. The model will then fail in a much shorter time than would occur in normal service. Usually, the higher the stress applied is, the shorter will be the life. By testing insulation system models at a variety of stress levels, one can sometimes extrapolate the results from high stress to the expected operating stress, and estimate the service life. Subjecting the different insulation system designs to all the accelerated aging tests will identify the design and material that achieves the desired life with the least cost.

The preceding is very simplistic. As described in Chapters 8–11, the rotor and stator insulation systems may fail from more than two dozen failure processes. Each failure process is driven by one or more stresses such as voltage, temperature, pollution, and mechanical force. That is, one stress alone does not define the life of a winding. The result is that to qualify an insulation system design for service, the system and its constituent parts must be subjected to a wide battery of accelerated aging tests that will establish its probable life over most of the failure processes discussed in Chapters 8–11. Another problem with accelerated aging tests is that the results of the tests tend to have a great deal of scatter. This requires much repeat testing and statistical analysis. In spite of decades of research on aging tests, it is clear that we still cannot estimate with any precision what the expected life of a rotor or stator winding will be, owing to the large number of failure processes, the complexity of aging processes, and the statistical scatter.

This chapter describes the practical aspects and limitations of accelerated aging tests used to determine the capability of winding insulation systems. A large number of accelerated aging tests have been developed to model various failure processes, and many of these have been standardized by international organizations such as IEC and IEEE as well as national standardization organizations. Special attention is paid to these standardized test procedures as users can refer to such standards in an effort to compare the offerings from different manufacturers.

In addition to aging tests, many tests have been developed to evaluate the specific properties or capabilities of insulation materials and systems. For example, tests are needed to determine melting temperature, tensile strength, resistance to heat shock, cut-through resistance, electrical breakdown strength, chemical resistance, etc., in which aging is not a direct factor. Summaries of such tests, which can help ensure that the insulation can withstand known operating conditions, are discussed in Section 2.8. Appendix A lists the main properties determined by these tests on most of the common insulation materials used in rotor and stator windings.

Before proceeding, a distinction needs to be made between insulation materials and insulation systems. An insulation system is composed of insulating materials. The insulation system usually contains conductors and one or more insulating materials of specific thickness and shape. To determine the properties of each insulating material, aging and property tests are often made on a slab of insulation material itself. However, the life of a winding is determined by the capabilities of the system, not its individual constituents. In some cases, the capabilities of an insulation system will exceed the capabilities of the individual materials. Thus, material tests alone are not sufficient to determine the expected life of a complete insulation system.

2.1 AGING STRESSES

There are many different stresses that can affect the rate of insulation deterioration in stator and rotor windings. Some of these were introduced in Chapter 1. Broadly speaking, there are thermal, electrical, ambient, and mechanical stresses, the so-called TEAM stresses [3]. Each of these is described in the following sections.

Before dealing with the individual stresses, it is important to consider that the stresses can be constant, or they can be present for only a brief time, that is, they are transient. Constant stresses include the operating temperature, the 50- or 60-Hz AC voltage, and the 100- or 120-Hz magnetically induced mechanical stresses. In general, if failure is caused by a constant stress, the time to failure is proportional to the number of operating hours for the motor or generator. Transient stresses include those such as motor starting, out-of-phase synchronization of generators, and lightning strikes. If deterioration is primarily due to these transients, then the time to failure is proportional to the number of transients the machine experiences.

2.1.1 Thermal Stress

This is probably the most recognized cause of gradual insulation deterioration and ultimate failure, at least in air-cooled machines. Hence, a winding insulation system must be evaluated for its capability under thermal stress. The operating temperature of a winding causes thermal stress. This temperature results from I^2R, eddy current, and stray load losses in the copper conductors, plus additional heating due to core losses, windage, etc. As will be described in detail in Chapters 8–13, in modern insulations, the high temperature causes a chemical reaction (oxidation in air-cooled machines) when it operates above a threshold temperature. The oxidation process makes all types of insulation brittle and/or tends to cause delamination in form-wound coil groundwall. Delamination is the separation of the groundwall tape layers because of loss of bonding strength and/or impregnating compound.

To a first approximation, the oxidation process is a first-order chemical reaction in which the rate of the reaction is governed by the Arrhenius rate law. As first proposed by Dakin [4], the life of the insulation (L, in hours) is related to the temperature (T, in Kelvin) by

$$L = Ae^{\frac{B}{T}} \tag{2.1}$$

where A and B are assumed to be constants. Saying that the life of the winding will decrease by 50% for every 10°C rise in temperature often approximates this equation. Equation 2.1 is an approximation for two reasons. First, it is only valid at relatively high operating temperatures. Below a threshold, which is different for each insulation material, no thermal aging will occur. For thermosetting insulating materials, the threshold is close to the glass transition temperature. Second, more than one chemical reaction usually occurs at a time. Thus, a simple first-order reaction rate model is not strictly valid. However, because Equation 2.1 is firmly entrenched in standards, there is little desire to make the model more accurate.

Clearly, the higher the temperature is, the shorter is the expected life of the insulation and, thus, the winding. Equation 2.1 is the basis of all accelerated aging tests that are used to estimate the thermal life of a winding, and is also used to define the insulation thermal classes, for example, A, B, F, and H. This will be discussed further in Section 2.3.

A variation of thermal stress is thermomechanical stress. It is primarily applicable to very large machines. As described in Sections 8.2, 9.2, and 10.2, changing machine load will cause the winding temperatures to change. If the winding temperature quickly goes from room temperature to its operating temperature, the copper conductors will expand axially. In contrast, modern insulations have a lower coefficient of thermal expansion than copper and, in a transient situation, are cooler just after a load increase. The result is a shear stress between the conductors and the insulation as the copper grows more quickly than the groundwall insulation. In stator windings, after many thermal (i.e., load) cycles, the bond between the insulation and the copper may break. No simple relationship has been developed to relate the number of cycles to failure as a function of temperature. However, the higher the temperature difference between the insulation and the copper is, the fewer will be the number of cycles to failure.

Temperature has an effect on many other failure processes that are not strictly thermal. For example, in stators with electric stress relief coating problems (Sections 8.5 and 8.6), the higher the temperature is, the faster will be the deterioration rate. In some cases, operating windings at high temperatures can be beneficial. High temperatures tend to prevent moisture from settling on windings, and thus reducing the risk of electrical tracking failures (Section 8.11). In addition, if the groundwall of stator coils/bars is delaminated from either poor manufacturing (Section 8.3) or thermal deterioration (Section 8.1), then operation at high temperature will swell the insulation somewhat, reducing the size of any air pockets in the insulation and decreasing the partial discharge (PD) activity [5]. In addition, some older types of form-wound groundwall insulations swell on heating, reducing the likelihood of abrasion if the coils or bars are loose at low temperatures (Section 8.4).

2.1.2 Electrical Stress

Power frequency electric stress in conventional 50/60-Hz motors and generators has little impact on the aging of the electrical insulation in stator windings rated at less than about 1000 V. The thickness of the insulation in such low voltage stator windings, as well as all rotor windings, is primarily determined by mechanical considerations. That is, the insulation must be thick enough to withstand the rigors of coil winding and the mechanical forces that are impressed on the winding in service.

In conventional 50/60-Hz stator windings rated above about 1000 V, the thickness of the insulation is primarily determined by the electric stress; that is, the rated power frequency voltage divided by the insulation thickness (Equation 1.4). Power frequency voltage can contribute to the aging of the insulation if PDs are present. As discussed in Section 1.4.4, the PDs are small electric sparks that occur within air pockets in the insulation or on the surface of coil insulation. These sparks contain electrons and ions that bombard the solid insulation. Organic materials such as films, polyesters, asphalts, and epoxies degrade under this bombardment because of breaking (scission) of certain chemical bonds such as the carbon–hydrogen bond. With enough time, the PD will erode a hole through the organic parts of the groundwall, leading to failure.

If PDs are present, then the effect of the stress level E (in kilovolt/millimeter) on the life of the insulation (L in hours) is most often represented by the inverse power model [6]:

$$L = cE^{-n} \tag{2.2}$$

where c is a constant and n is called the *power law constant*. This model is based on work done by Eyring, among others [7]. As with thermal aging, below a threshold electrical stress, there is effectively no aging. This threshold is the partial discharge extinction voltage (DEV). Sometimes, E in Equation 2.2 is replaced by $E - E_o$ where E_o is the threshold stress below which aging does not occur. If electric stress versus time to failure is plotted on log–log graph paper, the slope of the line according to Equation (2.2) would be n.

The power law "constant" is usually reported to range from 9 to 12 for machine insulation systems [8–10]. If one assumes n to be 10, then a two-time increase in electric stress will reduce the life by about 1000 times. Thus, the electric stress (voltage) has a very powerful influence on service life if PD is occurring. Although n is referred to as a constant, some have reported that n may change with stress level [11]. Thus, sometimes, an exponential model is used to model the influence of stress on life. For example:

$$L = ae^{bE} \tag{2.3}$$

where a and b are constants. However, this model is rarely used in rotating machine insulation applications.

As with the Arrhenius model for thermal stress, the model in Equation 2.2 in principle enables calculation of the service life based on accelerated aging tests done at high electric stress. As will be seen in Section 2.4, standardized methods have been developed to perform electric stress endurance tests assuming a PD failure process. Such tests are the basis for determining the groundwall thickness of the insulation applied in form-wound stator coils.

Another important way that electric stress can age the insulation occurs when many repetitive voltage surges are impressed across the turn insulation in random-wound stators or synchronous machine rotors. Inverter-fed drives (IFDs) using voltage source invertors with pulse width modulation (PWM) can create many thousands of short-risetime surges per second. As described in Sections 8.9 and 8.10, these surges can impose relatively high voltages across the first few turns in a stator winding or a wind turbine rotor winding. In random-wound machines in which the insulation is thin and air pockets are plentiful, PDs have been detected on machines rated as low as 440 V during IFD operation [12,13]. These discharges gradually erode organic film insulation, leading to failure. Even in the absence of PD, some have suggested that the stress is high enough in some situations that space charge injection occurs, although this seems unlikely in machine windings [14,15]. This process involves the emission of electrons from surface imperfections on the copper into the insulating film with every voltage surge. This repetitive injection on each surge breaks some chemical bonds in the film insulation. Eventually, enough bonds are broken that puncture can occur. On synchronous machine rotor windings in which the DC is obtained from a "static excitation system" that uses thyristors or other electronic switches, the voltage surges created have been reported to cause aging by a PD mechanism [16] (see Sections 9.5, 10.6, and 11.1).

Thus, just as the power frequency AC stress can age the insulation in form-wound stators, the voltage surges caused by electronic switching devices can also age the insulation in stators, wound rotor induction motors, and very large synchronous rotors.

2.1.3 Ambient Stress (Factors)

Ambient stress refers to a collection of factors, which come from the environment surrounding the motor or generator that can lead to failure. Some of these factors are:

- Moisture condensed on the windings
- Oil from the bearings or seal oil system in hydrogen-cooled machines
- High humidity
- Aggressive chemicals
- Abrasive particles in the cooling air or hydrogen
- Particles from brake shoe wear (if fitted) or carbon brush wear (if fitted) within the machine
- Dirt and debris brought into the machine from the environment, such as insects, fly ash, coal dust, and powders that are by-products of associated industrial processes (cement, pulp, chemical residues, etc.)

Each of these can affect the rotor and stator insulation in different ways. In some cases, these "factors of influence" in themselves do not cause aging but, when combined with another stress, can lead to aging. For example, moisture and/or oil, combined with dirt, carbon brush particles, etc. can make a partly conductive film over the insulation, in which the electric stress then causes surface currents and electrical tracking (Sections 8.11, 9.4, and 10.3). Oil/moisture/dirt combinations can collect in the rotor and stator ventilation passages and between coils in the endwinding to block cooling airflow, which increases the risk of thermal deterioration (Sections 8.1, 9.1, and 10.1). Oil can also be a lubricant that facilitates relative movement between coils and the slot in rotor and stator windings, leading to insulation abrasion (Section 8.4). Low humidity in the cooling air or hydrogen reduces the breakdown voltage of the gas, leading to greater PD activity in stator end windings (Section 8.14).

Similarly, chemicals such as acids and ozone can decompose the insulation, reducing its mechanical strength (Section 8.15). With these factors, it is often not possible to relate the level of a factor directly to the rate of deterioration. As will be seen in Section 2.2, these factors are usually either present or not present in an accelerated aging test.

2.1.4 Mechanical Stress

There are three main sources of mechanical stress. On a rotor, the insulation system is exposed to high centrifugal force. This is a nonvibrating force that tends to crush or distort the insulation. For the most part, the insulation either has or has not the capability to endure such forces. Various short-time mechanical material tests can evaluate this. There is little aging involved, although some materials may "cold-flow" or "creep," that is, slowly creep away from the high stress areas, eventually leading to a fault.

The second common mechanical stress is caused by the power frequency current, which gives rise to a magnetic force oscillating at twice the power frequency. Equation 1.3 shows the relationship between the mechanical force and the current flowing in a stator coil/bar. If the coils are loose in the stator slot, the force causes the coils to vibrate, and the groundwall insulation is abraded (Section 8.4). A similar magnetic force occurs in the end winding. If the coils/bars are free to vibrate relative to one another or against blocking or support rings, the insulation may again abrade (Section 8.15).

Unlike thermal and electrical stresses, there are no well-accepted models to describe the relationship between vibration amplitude and life. Although models do describe the amount of abrasion that may occur [17], they are not practical and none have become the basis for standard accelerated aging tests under vibration. Similarly, a form-wound stator coil or bar in the end winding can be modeled as a laminated cantilevered beam and, in principle, a relationship between the number of cycles to failure and the vibration amplitude (referred to as the *SN curve*) can be established [17]. However, none are widely accepted.

Transients cause the third important mechanical stress: switching-on of motors or out-of-phase synchronization of synchronous machines. Both give rise to a large transient power frequency current that may be five times, or more, greater than normal operating current in the stator. The result is that the magnetically induced mechanical force is 25 or more times stronger than normal service. The "DC" component (Equation 1.3) of this transient force tends to bend the coils/bars in the stator end winding. If the force cannot be withstood, the coil/bar insulation cracks. If many transients occur, such as frequent motor starting, then the end winding may gradually loosen over time, allowing relative movement between the end winding components, and insulation abrasion under normal power frequency current, as described earlier. No model exists to relate the transient level to the number of transients that can be withstood. Instead, manufacturers calculate the forces that could occur under various transient current situations, and determine if a single transient can be withstood. Aging is usually not considered.

2.1.5 Radiation Stress

Nuclear radiation due to neutrons, fast electrons, or gamma rays can lead to gradual aging of the insulation by chemical bond scission and, thus, insulation embrittlement. The higher the radiation level is, the faster will be the aging. The process is much like thermal deterioration, with the exception that the surface of the insulation ages more quickly than the interior. This is the reverse of the thermal deterioration situation. As the process is similar to thermal deterioration, the chemical reaction rate law (with radiation intensity replacing temperature) in Equation 2.1 is often used. Modern insulating materials used in motors tend to have a threshold (about 10 Megarads in total gamma dose over their service life) below which radiation aging does not occur, and some insulation systems have been qualified for a total integrated radiation dose of 200 Megarads [18]. Of course, only motors operating in a nuclear plant or a nuclear powered ship are likely to experience radiation-induced aging.

2.1.6 Multiple Stresses

Many of the failure processes to be described in Chapters 8–11 do not, in fact, depend on a single stress causing gradual deterioration of the winding insulation. As pointed out earlier when discussing ambient stresses/factors, two or more stresses/factors often need to interact to result in deterioration. In addition to those described in the previous section, other examples include:

- Thermal deterioration in form-wound stators that creates delamination, allowing PDs that ultimately erode a hole through the insulation.
- Form-wound coil/bar semiconductive coating deterioration caused by poor manufacture and/or high temperature operation, which leads to PD, creating ozone that chemically attacks the insulation.

The key feature is that if two or more of these factors/stresses are present, the failure process is much faster than if only a single stress/factor were present if, indeed, the single stress/factor would ever lead to failure [3,19,20].

Aging models that allow machine manufacturers to predict the capability of an insulation under such multistress situations tend to be very complex and, to date, somewhat impractical. However, Section 2.7 will address this to some extent.

2.2 PRINCIPLES OF ACCELERATED AGING TESTS

The purpose of accelerated aging tests is to increase one or more stresses above normal levels, to speed up a specific failure process that may occur in service. This will accelerate the process and result in a much shorter time to failure. A shorter time to failure is necessary as one cannot realistically wait, say, 20 years to see if a new design or material is acceptable.

Before specific aging tests for each type of stress are described, it is useful to discuss a number of issues that are common to all accelerated aging tests on insulating materials and systems.

2.2.1 Candidate and Reference Materials/Systems

There are two basic possible outcomes from accelerated aging tests. One outcome can be an equation that enables prediction of the life of the insulation under operating stress. For reasons that will be clear later, such predictions are very dubious. No insulation standards are based on this principle.

The second outcome is based on comparing the life measured under an accelerated stress of a "candidate" system (i.e., with a new insulation material or system that is to be evaluated) with a "proven" material or system tested under the same conditions. The proven material or system will be one that has given good service life in actual operation. The proven material/system is often referred to in the accelerated aging test standards as the "reference" material/system. If the candidate system performs as well or better than the reference system in the same aging test, then the candidate system is expected to do as well or better than the reference system in service. The comparison of results from different materials/systems is the usual way aging tests are evaluated in standards.

One of the problems with the comparison approach is finding proven reference material or systems. Either the proven system has too few years in service to be truly "proven" or, more commonly, the "proven" system never operated at stress levels that were high enough to approach what was considered to be the maximum design stress level. For example, the insulation systems rated thermal Class B (Class 130) by the methods in Section 2.3 and widely used from 1950 to 1970, rarely operated near the maximum class operating temperature of 130°C (after allowance for hot spots). Instead, they commonly operated well below 100°C. Yet the comparison method was used to thermally classify new systems as Class F when in fact the "reference" Class B system never operated near the class temperature in operation and thus was not truly proven to be a Class B system. This limitation of aging test comparison methods should be kept in mind when qualifying new materials and systems.

2.2.2 Statistical Variation

If several specimens of an insulation system are subjected to an accelerated aging test using high voltage, there will normally be as much as a ten-to-one difference in the lifetimes of the insulation. That is, if the first failure occurred after 100 h, the tenth sample may survive for 1000 h. This occurs even if the specimens are all identical and the voltage is exactly the same for all tests. This huge variation in outcome is typical of aging tests. Times to failure under thermal and mechanical accelerated aging tests also vary widely. This parallels the situation for human beings: healthy individuals at 20 years of age may live from 20 to 80 or more years.

When outcomes from testing are extremely variable, statistical methods are needed to analyze the results. Statistical analysis helps determine if there are real differences between a candidate and a reference insulation system, or determine whether a result is just due to normal variation. For example, if two insulation models using different materials are tested at high temperature and one model endures twice as long as the other, is the longer surviving model better, or is this just normal statistical variation? Furthermore, if the lifetime is measured on a specimen tested at a moderate temperature, and another specimen is tested at a high temperature, can one predict the life at a third (possibly lower) temperature?

Statistical methods have been developed to help answer such questions. One aspect of statistical methods is to quantify the normal amount of variation in an outcome using statistical distributions, also known as probability distributions. Another aspect is to derive an equation based on aging tests at a few stress levels that can be used to predict the outcome of a test at a different stress level. This is called *regression*, more colloquially known as curve fitting. Both aspects are the subject of many textbooks on statistics. The following will briefly review these two topics and discuss the relevant terminology and methods for insulation testing. The reader is encouraged to refer to any standard textbook on the subject, for example, Reference 21.

Statistical Distributions Most engineers and scientists are familiar with the normal probability distribution, sometimes called the *Gaussian distribution*. This distribution allows the estimation of the mean (μ) and standard deviation (σ) of a collection of test outcomes, as well as confidence intervals. As long as two or more outcomes have been measured, the mean and standard deviation can summarize all the collected data in just two numbers, assuming that the normal distribution fairly represents the distribution of the outcomes. The mean is the most probable outcome. The standard deviation is a measure of the amount of variation possible. For example, there is little variation in the mass of American 25-cent coins, whereas there is tremendous variation in the mass of people, even if they are the same age and of the same sex. The variation is an inherent property of whatever is being measured, just like the mean is.

It is not possible to know the actual mean and standard deviation, as this would require an infinite amount of data to be collected. However, we can estimate what the mean and standard deviation are for a collection of data. For normally distributed data, the mean is estimated by calculating the average ($\bar{x}$):

$$\bar{x} = \frac{\sum x_i}{N} \tag{2.4}$$

where x_i are the individual results and N the number of specimens tested. The standard deviation is estimated by s:

$$s = \left[\frac{\sum (x_i - \bar{x})}{(N-1)}\right]^{\frac{1}{2}} \tag{2.5}$$

where $\bar{x}$ and s are estimates of the true values of the mean and standard deviation. The more specimens tested are, the more closely will $\bar{x}$ and s reflect the actual value of the mean and standard deviation. As $\bar{x}$ and s are not the true values of μ and σ, statisticians have developed methods to calculate confidence intervals, that is, the bounds surrounding $\bar{x}$ and s, within which μ and σ are likely to occur with a set (usually high) probability. For example, the breakdown voltage of an insulation may have an average of 9.2 kV with a 95% confidence interval of 9.0–9.4 kV. This means that the lower and upper confidence limits are 9.0 and 9.4, respectively. The 95% interval indicates that if the same number of specimens (say, 10 insulation specimens) were repeatedly tested, and $\bar{x}$ and s for each group of 10 specimens calculated, s would be within the lower and upper confidence bounds 95% of the time. Thus, the confidence limits indicate the uncertainty in the μ and σ estimates. Methods to calculate the confidence intervals for normal data are described in any statistics text [21]. However, in general, the width of the confidence interval (i.e., the uncertainty) decreases with the square root of N, the number of specimens tested.

Although the normal distribution is widely applicable to a large number of physical properties, this distribution does not seem to fit insulation lifetime data or physical strength data such as electrical breakdown strength or mechanical tensile strength. For lifetime and strength data, the lognormal and Weibull probability distributions are more commonly used [22,23].

Censoring Before discussing the distributions most commonly used in insulation aging tests, there is another important statistical phenomenon relevant to such tests—censoring. In many aging tests, most of the specimens fail in a reasonable time. However, a few of the specimens tend to "live" for what seems to be forever. This can be very frustrating to the testing personnel. The equations described earlier to estimate the mean and standard deviation depend on all the specimens being tested to failure. That is, data must be complete to be applicable. However, methods have been developed to estimate the distribution parameters (such $\bar{x}$ and s) when some of the specimens have still not failed. When an experiment is performed and the parameters are estimated before some of the specimens have failed, this is called a censored experiment. There are different types of censoring depending on when the experiment is stopped—after a fixed number of specimens or after a fixed amount of time (or voltage or tensile strength). More details on censoring are described in most advanced statistical methods books, for example, Reference 22.

For the most popular probability distributions used in aging tests, methods have been developed to estimate parameters using censored data. As seems reasonable, the higher the percentage of specimens that are tested to failure is, the narrower will be the confidence intervals on the parameters.

Lognormal Distribution The lognormal distribution is a simple transformation of the normal distribution where the logarithm of the lifetimes is the variable. This distribution is almost exclusively used to analyze the results of accelerated aging tests in which temperature is the accelerated stress, and is a critical element in the thermal classification of insulation. The lognormal distribution is also sometimes used for breakdown voltage and tensile strength tests. IEEE 930 (also known as *IEC 62539*) [6] gives the general principles for calculating the log mean and log standard deviation for the lognormal distribution, as well as for calculating the parameter confidence intervals. The application of the lognormal distribution to thermal aging tests is described in References 23–25.

Instead of directly using the failure times or voltages, the logarithm of the voltages, times, etc. are first taken. Thus, using the terminology in Equations 2.4 and 2.5:

$$x_i = \log y_i \tag{2.6}$$

where y_i are the individual outcomes (failure times, breakdown voltages, etc.) from an experiment. Either the natural logarithm or the logarithm to base 10 can be used, as long as one is consistent. Once the transformation is done, estimates of the log mean and log standard deviation are calculated using Equations 2.4 and 2.6. The parameter estimates can then be converted to normal engineering units by taking the inverse log. Confidence intervals on the parameter estimates are easily calculated using the Student's t and χ^2 (chi square) tables, found in all statistics texts.

If two types of insulation are subjected to a thermal accelerated aging test, then it is common to ask if the two types of insulation behave the same, or if one insulation type has superior thermal performance, that is, lasts longer at the same temperature, or lasts the same amount of time at a higher temperature. If the confidence intervals on the mean for each type of insulation system overlap, then it cannot be proved that there is a significant difference between the two insulation types. However, if the confidence intervals do not overlap, then one insulation type (the one with the higher mean time to failure) is better. A rigorous analysis of whether the insulations are different can be done using the t test and the F test, which allow one to say if the two insulations are different with a (high) level of confidence, given the natural variation in the test results [21]. IEEE 101 and IEC 60216 [25] give many examples of using statistical methods to determine superior insulating materials under thermal aging tests.

Analysis with the lognormal distribution is difficult if the data is censored. No simple equations or tables have been developed to help one calculate the log mean and log standard deviation if all the specimens under test have not failed. Thus, virtually all thermal aging tests assume that all the specimens will be tested to failure. However, some tables found in [24] can be used in some censoring situations. In addition, some very powerful computer programs can calculate lognormal parameters and confidence intervals of censored data. Although many packages are now available, the SAS Institute SAS/STAT personal computer software has been shown to be effective [26].

Weibull Distribution The Weibull distribution has been widely used for voltage endurance test data, that is, tests in which a constant AC or impulse voltage is applied to insulation specimens and the time to failure is measured. This distribution is also employed in experiments in which the breakdown voltage of insulation is measured. The Weibull distribution is a member of the class of distributions called *extreme value distributions* [22]. In principle, the distribution is most applicable where complete breakdown is caused by the failure of a "weak link." As insulation will puncture at the point where the insulation is the thinnest, or the biggest defect is present, the weak link model seems appropriate.

The cumulative distribution function of the two-parameter Weibull distribution function is given by

$$F(t) = 1 — \exp - \left(\frac{t}{a} \right)^{\beta} \tag{2.7}$$

where $F(t)$ is the probability of failure if the specimen survives time t. The α parameter is called the *scale parameter* and has the same units as t. The bigger α is, the longer is the time to failure, as α corresponds to the time to failure for 63.2% of the specimens under test. β is the "shape" parameter. It is a measure of the spread of the data. The larger β is, the smaller is the range in failure times (or voltages). Thus, it is proportional to the inverse of the standard deviation. In general, β is on the order of 1 to 2 for voltage endurance tests, and tends to be around 10 for tests in which the breakdown voltage is measured.

There is an alternate form of the Weibull distribution called the *three-parameter Weibull distribution* [22]. This form allows for the existence of a minimum possible time to failure or minimum failure voltage. However, this form has rarely been used for rotating machine insulation systems.

Although simple equations are not available to calculate estimates of α and β, a simple computer program exists to calculate the estimates using the method of maximum likelihood [6]. Simple graphs have also been produced to allow the calculation of approximate confidence intervals on the parameter estimates [6]. Many commercial computer programs are also available to calculate the parameters and confidence intervals; for example, the SAS/STAT program described earlier. As discussed earlier, for the lognormal distribution, one can easily tell if two insulation samples are significantly different by determining if the confidence intervals for α overlap. If there is overlap, then one cannot be sure that there is a significant difference, or if the scale parameter for the two different insulations are due to natural variation.

One of the reasons for the popularity of the Weibull distribution is that censored data are easily analyzed. IEEE 930 (also known as *IEC 62539*) [6] gives methods for this. Similarly, most modern statistical programs can easily accommodate censored data, including calculating confidence intervals and performing hypothesis tests to determine if two insulation systems are significantly different.

Regression Analysis In addition to allowing the determination whether two types of insulation are significantly different (a comparison test), statistical methods are also available to enable the prediction of insulation system behavior at a temperature or voltage different from that used in testing. The calculation procedures are called *regression analysis*, also known as *curve fitting*. This subject is a standard part of any fundamental statistics textbook [21], and most of the principles discussed in such texts are applicable to insulation accelerated aging tests.

As an example, tests may be performed on an insulation system at two or more temperatures, usually at temperatures higher than expected in service. For a Class F insulation material, it is expected that the material will survive, on average, for 20,000 h at 155°C (see Section 2.3). This corresponds to about 2.3 years of life. This is too long a time to wait for test results; thus, higher temperatures are used for the testing, perhaps 175, 195, and 205°C. These will give significantly shorter times to failure (recall Equation 2.1 and the strong influence temperature has on life). Using the times to failure for several specimens at each of these three temperatures, regression analysis can be used to define an equation to relate failure time to temperature. Further, the equation can be used to predict the time to failure at a lower temperature, for example, 155°C. Figure 2.1 shows an example plot of life versus temperature for an insulation material, taken from IEEE 1.

The regression procedures are well established for normal distributed data, or data that can be transformed into the normal distribution, such as thermal life data represented by the lognormal distribution. Any statistics textbook outlines the procedures. Examples of the procedure applied to thermal aging data are in References

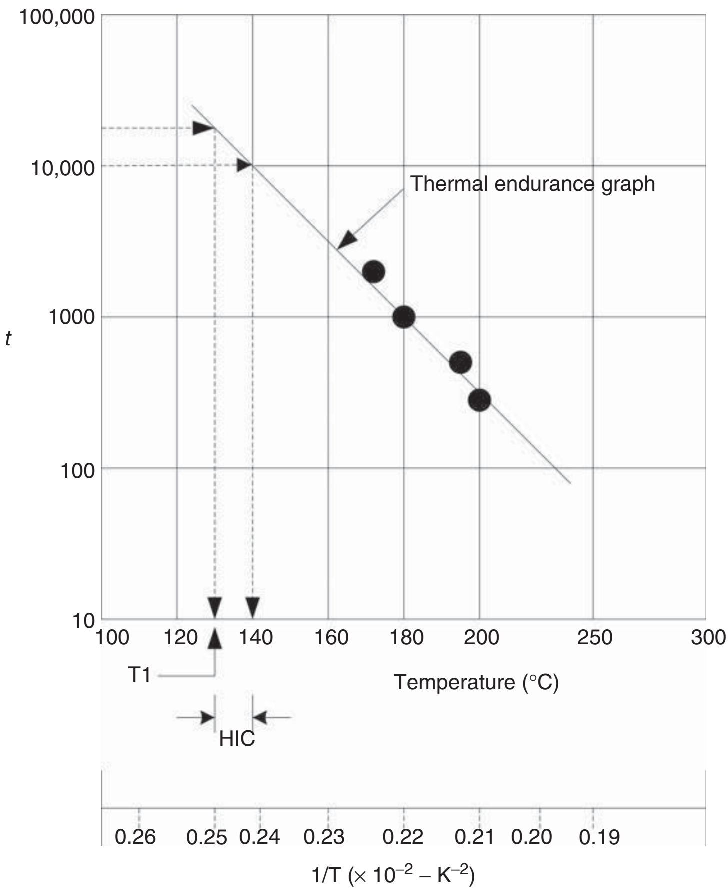

Figure 2.1 Typical thermal endurance plot for a Class B (Class 130) material. Note that the thermal index corresponds to a life of 20,000 h. (Source: Copyright 1989 IEEE. All rights reserved.)

23 and 25. Note that these two standards assume that Equation 2.1 is valid (i.e., there is only one chemical reaction causing the thermal deterioration) and that all specimens are tested to failure. Procedures for other situations have not been generally accepted.

Regression for Weibull distributed data is, in principle, the same as for lognormal. However, there are a number of complications. As the assumption underlying linear regression is that the distribution of times to failure are normal (or can be transformed to normal), then the usual procedures for linear regression should not be directly applied to Weibull data [27]. From a practical point of view, most people ignore this restriction and perform a conventional regression, perhaps assuming that the data fits the lognormal distribution. Alternatively, rigorous regression methods assuming the Weibull distribution are described in [22]. As most engineers find the latter method difficult to implement, various statistical programs, for example, the

SAS/STAT package, can perform the calculations, derive the equation, and calculate confidence limits on the derived equation.

Number of Specimens As the results from aging tests have large statistical variation, the question arises about how many specimens need to be tested to determine if a new insulation material or system is equivalent to or superior to a reference material/system. The more specimens tested the easier it is to detect if a significant difference is present or not. Unfortunately, it takes time and money to produce the test results. Consequently, there is tremendous pressure to test as few specimens as possible.

The variation in times to failure from voltage or thermal aging tests is much larger than from experiments in which tensile strength or breakdown voltage are being measured. The result is that more specimens need to be tested in constant-stress aging tests than in progressive stress tests. On the basis of the normal variance expected in thermal aging tests, many key IEEE and IEC standards (Section 2.3) recommend the number of specimens to be tested at each temperature. Typically, this is five specimens. There is less agreement for voltage endurance tests [28]. To detect an improvement in life of two times between a new and a reference insulation material, 10 specimens of each type should be tested. In reality, usually fewer specimens are tested, leaving the analysis of the results open to question.

2.2.3 Failure Indicators

When the aging stress is voltage, it is obvious how to determine the lifetime of an insulation specimen: measure the aging time it takes to puncture the insulation. Electrical aging deteriorates the insulation such that a hole is eroded through the insulation and the high voltage conductor shorts to ground, which trips out the power supply. Thus, time to failure is directly measured as the time that voltage is applied before the power supply automatically turns off. Similarly, this is often the case for some mechanical properties such as fatigue life. The end of life occurs when the insulation material parts.

For most other aging tests, how to determine the end of life is much less clear. For example, take a thermal endurance test. When an insulation material is subjected to thermal aging, the insulation may lose mechanical strength, become more brittle, lose some mass (i.e., lose weight) and/or have a lower electrical breakdown strength. However, it is unlikely to spontaneously “fail,” unless the insulation catches fire. The question then occurs of how we determine the “life” of the insulation in such a test.

The solution is to use a diagnostic test that is applied after certain intervals of aging. The diagnostic test can be destructive; for example, a tensile strength or electrical breakdown strength test. The diagnostic test can also be nondestructive; for example, insulation resistance, dissipation factor, or PD tests can be used. In both cases, unaged specimens are measured according to the diagnostic test and typical values are established. The specimens are aged at the desired stress for a fixed time interval and removed from the aging test. Then the diagnostic test is applied. If there is a defined change in the diagnostic, then the specimen has “failed,” and is removed from further aging testing.

For thermal aging tests, the most common diagnostic tests are the electrical breakdown strength and the tensile strength. Failure is often deemed to have occurred if either of these strengths is reduced to 50% of the original (unaged) breakdown or tensile strength. An example of a nondestructive diagnostic test is power factor tip-up or PD magnitude, when applied to a thermal cycling test [29]. If the tip-up increases or the PD magnitude increases by, say, two times over the duration of the aging test, then the insulation specimen may be deemed to have failed. The problem with using diagnostic tests is that variability in failure time comes not only from the inherent variability in the aging process, but the diagnostic itself adds some variability. Recall that electrical breakdown strength itself is not fixed, but is a variable. Consequently, all other things being equal, where life is measured by means of a diagnostic test, more specimens will be required to overcome the additional uncertainty in the data.

2.3 THERMAL ENDURANCE TESTS

2.3.1 Basic Principles

In Section 2.1.1, the causes of thermal stresses were introduced and Equation 2.1 was given as a theoretical means of establishing the relationship between the life of insulation and its operating temperature. Organic materials may degrade by several chemical mechanisms when subjected to heating. The most common experience is gradual oxidation of these materials, although depolymerization (chain scission) and cross-linking may also occur. Increasing the temperature generally accelerates these chemical reaction rates, although the presence of other materials and other factors of influence (the TEAM stresses introduced earlier in this chapter) may either accelerate or decelerate the reaction rate.

Organic materials have an activation energy requirement. When the molecular energy of thermal motion is below a level characteristic of each material, little or no chemical change takes place. Increasing the temperature adds to the molecular energy, and when energy is sufficient to overcome the stability of chemical bonds within a material, the reactions start. Initially, near the activation energy, only a few molecules of the material will have sufficient energy to overcome the bonding energy and so only a slow aging of the material will occur. As the temperature is raised, more molecules will attain the necessary energy and the aging rate will increase.

Thermal aging is most straightforward when single insulating materials are evaluated. Combinations with other organic materials, as in some composites, may change the aging rate. Thermal aging tests on insulating materials are well established. Results of these tests are generally available from the suppliers of the materials and are used as a screening test for insulation engineers when selecting the components for an insulation system for a particular application. However, material thermal aging data is not acceptable for establishing the thermal endurance of an insulation system.

When designing an electrical insulation system, the engineer must consider the other material components of the application, including also the inorganic and metallic materials in the rotating machine. They must design for the duty cycle and for the particular stresses of the machine environment. Thus, insulation system tests are generally performed by the equipment builder and are usually done on models or sections of the machine with all of the associated parts. Some of the larger suppliers of materials perform insulation system tests for high volume applications, using their own materials when available and adding materials from other suppliers to complete the insulation system.

Thermal aging tests for materials use endpoints that are arbitrarily chosen and which may not be proper for particular applications. For example, testing may continue until a diagnostic endpoint is reached, such as loss of 5% of initial sample weight or 50% loss of flexural strength. Thermal aging tests for insulation systems usually run until electrical breakdown occurs during periodic exposure to high voltages.

2.3.2 Thermal Identification and Classification

An electrical insulating material is a substance in which the electrical conductivity is very small (approaching zero) and provides electric isolation. An electrical insulation system is an insulating material or a suitable combination of insulating materials specifically designed to perform the functions needed in the rotor or stator winding. A simple combination of insulating materials, perhaps containing a number of them without associated equipment parts, may be tested to evaluate any interaction between them.

There are slight differences between IEEE and IEC definitions for the thermal identification and classification of insulating materials and insulation systems. For this book, the IEC definitions will be used. Historically, the term *thermal classification* has been used in reference to both insulation systems and electric equipment. Thermal classification should be used in combination with the words *system* or *equipment* to clearly denote to which the term applies.

Electrical insulating materials are thermally rated by test to establish a thermal endurance relationship. This is an expression of aging time to the selected failure criterion as a function of test temperature in an aging test. A thermal endurance graph (Figure 2.1) is a graphical expression of the thermal endurance relationship in which time to failure is plotted against the reciprocal of the absolute test temperature. From this work, a material may be assigned a temperature index (TI) or a relative temperature index (RTI). The former is the number that corresponds to the temperature in degree Celsius, derived mathematically or graphically from the thermal endurance relationship at a specified time (often 20,000 hours, about 2.3 years, for utility and industrial machines). The latter is the TI of a new or candidate insulating material, which corresponds to the accepted TI of a reference material for which considerable test and service experience has been obtained. Table 2.1 shows the accepted temperature indices of materials according to IEC 60085. The older classification system was according to a letter designation (e.g., A, B, …). Presently, a numerical designation is preferred (105, 130, …). A Class F or Class 155 material should have an average life of 20,000 h (about 2.3 years) when operating at 155°C.

As noted earlier, in current practice, insulation systems by themselves are not given a temperature class. Technical committees may prepare standards for specific types of rotating machinery in which test procedures are established to enable the

TABLE 2.1 Thermal Classification of Rotating Machine Insulation Materials

Numerical Classification	Letter Classification	Temperature (°C)
105	A	105
130	B	130
155	F	155
180	H	180

Source: From IEC 60085

temperature class of their insulation systems to be established. These tests will usually require a reference insulation system, defined as an electrical insulation system assigned a system temperature rating, based on service experience or testing that is used to qualify a new or modified electrical insulation system.

2.3.3 Insulating Material Thermal Aging Test Standards

In IEEE practice, the basic standard for all insulating materials and insulation systems tests is the latest version of ANSI-IEEE Standard No. 1—Recommended Practice for Temperature Limits in the Rating of Electrical Equipment and for the Evaluation of Electrical Insulations. Subsidiary standards for materials are IEEE No. 98—Standard for the Preparation of Test Procedures for the Thermal Evaluation of Solid Electrical Insulating Materials and IEEE No. 101—Statistical Analysis of Thermal Life Test Data. The comparable International Electrotechnical Commission general standard is IEC publication No. 60085—Thermal Evaluation and Classification of Electrical Insulation. Specifically, for material thermal evaluation, there is an IEC Standard, the IEC 60216 Series—Guide for the Determination of Thermal Endurance Properties of Electrical Insulating Materials:

Part 1: General Procedures for the Determination of Thermal Properties, Temperature Indices, and Thermal Endurance Profiles

Part 2: List of Materials and Available Tests

Part 3: Statistical Methods

Part 4: Instructions for Calculating the Thermal Endurance Profile

Part 5: Determination of Relative Thermal Endurance Index (RTE) of an Insulating Material

There is a lot of commonality between these IEEE and IEC standards and the responsible technical committees contain some members in common who have worked to make them compatible in the areas that both cover.

2.3.4 Insulation System Thermal Aging Test Standards

For insulation systems, there are a number of standards that supplement IEEE Standard No. 1. Some of these are general standards that apply to the thermal evaluation of all insulation systems, whereas a growing number addresses thermal aging for specific types of equipment such as rotor and stator windings. The general standard includes IEEE No. 99—Recommended Practice for the Preparation of Test Procedures for the Thermal Evaluation of Insulation Systems for Electric Equipment. The IEC general standard for insulation systems is Publication No. 60505—Evaluation and Qualification of Electrical Insulation Systems [3]. Several related specific standards are IEC Publications:

- No. 60610—Principal Aspects of Functional Evaluation of Electrical Insulation Systems: Aging Mechanisms and Diagnostic Procedures
- No. 60611—Guide for the Preparation of Test Procedures for Evaluating the Thermal Endurance of Electrical Insulation Systems
- No. 62114—Thermal Classification

For thermal evaluation and classification of rotating machine winding insulation systems, there is a growing list of IEEE and IEC standards. In IEEE, there are:

- No. 117—IEEE Standard Test Procedure for Evaluation of Systems of Insulating Materials for Random-Wound AC Electric Machinery
- No. 304—Standard Test Procedure for Evaluation and Classification of Insulation Systems for Direct-Current Machines
- No. 1107—Recommended Practice for Thermal Evaluation of Sealed Insulation Systems for AC Electric Machinery Employing Random-Wound Stator Coils. (Note that this is expected to be rescinded and the contents to be made an Appendix in IEEE 117.)
- No. 1776—Recommended Practice for Thermal Evaluation of Unsealed or Sealed Insulation Systems for AC Electric Machinery Employing Form-Wound Pre-Insulated Stator Coils for Machines Rated 15,000 V and Below (Note that this is a combined version of the older IEEE 275 and 429 standards.)

A related IEC standard is IEC 61857-2 Procedures for Thermal Evaluation, Part 21: Specific Requirements for General Purpose Model Wire-Wound Applications. IEC 60034-18-31 is the equivalent to IEEE 1776 for the thermal classification of form-wound stator windings. IEC 60034-18-21 is similar to IEEE 117, and classifies random-wound stators.

IEEE 1776 is an example of an accelerated aging test to determine the thermal classification of a form-wound stator coil insulation system [30]. This standard describes the nature of coil specimens (called *formettes*) that are intended to model a coil insulation system. Formettes are specially manufactured coils with turn and ground insulation, which are mounted on a frame simulating a portion of the stator core (Figure 2.2). They are typically only 0.3 m in length but have closely modeled the diamond shape. Instead of the copper turns being connected in series as in a normal coil, each turn in the formette is separately accessible, to facilitate turn-to-turn testing. To evaluate a candidate insulation system, typically, many formettes are manufactured, with two formettes reserved for destructive testing in the unaged condition. Each formette contains three or four coils. Sometimes, six or eight bars are used without being connected to each other. During periodic hipot tests, the test standard

Figure 2.2 Photograph of a formette containing four multi-turn coils after a thermal endurance test (Source: Eltek Laboratories).

recommends that four different test temperatures be used, with the heat being applied in an oven. Thus, one quarter of the formettes are used at each temperature. For a candidate system expected to be identified as Class F, typical test temperatures are 160 C for a 49-day cycle, 180°C for 4−day cycle, 200°C for 2−day cycle, and 220°C for 1-day cycle. After each thermal aging cycle, the formettes are subjected to mechanical stress exposure, followed by moisture exposure, and ending with voltage exposure at a level that is based on the rated line-to-line voltage. Typically, the entire test is designed, so that 10 cycles of heat aging and diagnostic exposures are required before most of the specimens fail during voltage application.

According to IEEE 1776, for a candidate insulation system to be identified as class F, the thermal endurance graph for this system must result in failure times that are the same or longer than a reference insulation system already shown to have satisfactory life in service, and tested in exactly the same manner as the candidate system. As mentioned in Section 2.2.1, the weakness in classifying a candidate system to a reference system is that few reference systems are actually operated at anywhere near the “design” maximum operating temperature in service.

IEEE 117 is a similar standardized thermal aging test for random-wound stator windings, using a “motorette” consisting of model coils installed in a simulated slot. To determine the life of an insulation system, IEEE 117 relies on usually 10 or more thermal aging cycles, with each cycle followed by shaking on a vibration table and then exposure to 100% humidity with condensation in a special chamber. After the prescribed time to allow the insulation to become saturated with moisture, an overvoltage is applied. Coil breakdown ends the test for that particular specimen, whereas those that survive are returned to the several different circulating air ovens, held at several different temperatures, for another thermal aging period. For thermal aging acceleration, it is desirable to have the lowest aging temperature (and the longest thermal exposure) set at 5–15°C above the maximum service temperature for which the insulation system is being qualified. The next two or three aging temperatures should each be at least 20°C above the lowest aging temperature. As with IEEE 1776, the results of this test procedure on a candidate system must be compared to a similar test on a reference system.

Within IEC 60034 Part 18, Sections 1, 21, and 31, there is a comparable set of standards for several of the rotating machinery types. Usually, only the details of the nature of the test models and the diagnostic tests differ among the various standards.

Underwriters Laboratories in the United States has also produced UL-1446 and related documents that are based on IEEE standards. UL-1446 describes thermal testing methods for candidate insulation materials and insulation systems for use in small- and medium-sized random-wound machines and form-wound machines.

2.3.5 Future Trends

Technical committees within IEEE and IEC are continuing to work on both revisions to existing standards and new standards for insulating materials and insulation systems. Both IEEE and IEC have policies requiring the review, reaffirmation, revision, or withdrawal of existing standards on a periodic basis. New standards are written in response to perceived needs in the industry and must complete a thorough review of the need for and content of them in order to make them consensus standards, which will be generally accepted and used.

Recent committee work has focused on such matters as how to evaluate materials and systems when only slight changes have been made in their compositions or where the application of accepted materials and systems have been extended to different duty levels, machine sizes, or applications. There is also a drive to design machines to operate at near their "thermal class," as this will considerably reduce machine cost, because less copper and steel would be required for the same output.

2.4 ELECTRICAL ENDURANCE TESTS

As the main purpose of electrical insulation is to prevent electrical shorts between conductors at different potentials, it is not surprising that there are means to determine the ability of an insulation to withstand voltage. From a basic point of view, each insulation material has a short-term breakdown strength. That is, if the voltage is rapidly increased across an insulating material, at some point, there will be sufficient voltage to puncture the insulation. The breakdown strength is the breakdown voltage divided by the insulation thickness. Each insulating material has its characteristic breakdown strength. Gases typically have a breakdown strength of around 3 kV/mm at atmospheric pressure, whereas most homogeneous solid insulating materials have an intrinsic breakdown strength ranging about 200 kV/mm. Elaborate methods have been developed for measuring the short-term (voltage is applied for less than a few minutes) breakdown strength of insulation. Some of these are discussed in Section 2.8.

No practical rotating machine insulation system is subjected to electrical stresses anywhere near the short-term breakdown strength of the solid electrical insulation. In fact, even high voltage stator windings have an average design electrical stress that is usually less than 3 kV/mm rms (although there are some modem designs that exceed this [1]). This stress is about 100 times less than the intrinsic capability of modern epoxy-mica insulation systems. The reason for the much lower design stress is due to the fact that the insulation will rapidly age at higher stresses, in part owing to PD activity that inevitably will be present because of small pockets of gas in the insulation (Section 1.4.4). Thus, the knowledge of the short-term breakdown strength of the insulation is not sufficient to allow design of an insulation system that will yield long life.

To predict the behavior of an insulation system under voltage stress in stator windings rated at 1000 V or more and determine the best insulation system design with respect to voltage stress, voltage endurance tests have been developed. In a voltage endurance test, a voltage is applied to an insulation system that is higher than that expected in operation, and the time to failure is measured. Sometimes, the insulation system is simultaneously subjected to high temperature. The endurance test voltage is usually an order of magnitude less than the short-term breakdown voltage. Normally, the voltage endurance tests for rotating machines applications are only applied to insulation systems, and not to the materials. Although there are some voltage endurance test methods that have been standardized, the number and pervasiveness of these standards are far less than for thermal endurance testing. Voltage endurance tests using 50- or 60-Hz AC voltage are normally only applied to stator winding insulation systems, as it is usually only the stator winding insulation that may gradually age under voltage stress. However, as discussed in Sections 1.5.1, 2.4.3, and 8.10, voltage surges may sometimes age the stator and rotor winding insulation if the windings are fed from a voltage source PWM drive. In addition, voltage surges from static excitation systems may deteriorate synchronous machine rotor windings (Sections 9.5 and 10.6).

Most voltage endurance tests for stator windings rated at 1000 V or more are proprietary test methods that are unique to each manufacturer of stator coils. These will be discussed first, and then IEEE and IEC test methods will be presented.

2.4.1 Proprietary Tests for Form-Wound Coils

Many machine manufacturers determine the thickness of the groundwall insulation in form-wound stator coils and bars on the basis of voltage endurance test methods developed in-house. Each manufacturer has different approaches. References 9, 10, 31–34 present some of the test methods that have been published. By performing the voltage endurance test on a range of insulation system designs, the manufacturer can establish which design gives a satisfactory result under the accelerated conditions for the least cost.

Most of the test procedures use relatively short specimens that simulate the bar or coil in the slot. Typically, the specimens may be from 0.5 to 1 m in length to simulate the slot section of a coil/bar, although some manufacturers sometimes use full-length coils or bars [31]. The coil/bar specimens may have a thinner insulation thickness than normal, enabling testing at lower voltages. There is always a semiconductive layer applied to give a ground plane. Because the test stress is high, stress relief coatings are needed at each end of the ground plane region (Section 1.4.5).

The 50/60-Hz power frequency voltage is the most common means of energizing the copper conductors of the specimens. However, many manufacturers use 400- to 5000-Hz AC power supplies to energize the specimens [10,34]. Using a frequency higher than the power frequency, the insulation seems to fail faster. This is expressed as:

$$L_2 = L_1 \left(\frac{f_1}{f_2} \right) \tag{2.8}$$

where L_1 and L_2 are the voltage endurance lifetimes at AC frequencies f_1 and f_2, respectively. In part, this "frequency acceleration" effect is probably due to the fact that the number of PDs per second increases proportionally with the number of AC cycles applied. Thus, many researchers believe that the voltage endurance life is inversely proportional to frequency. The frequency acceleration effect remains controversial, as different researchers have found different acceleration factors [10].

Most proprietary voltage endurance tests are done at a temperature that is higher than room temperature. Usually, temperatures in the range 120–180°C are reported. Heating is sometimes accomplished by putting the specimens in a large oven, circulating current through the conductors, circulating hot water or oil in the hollow conductors (where possible), or by applying heated plates to the outside of the specimens.

Clearly, the test procedures are highly variable, and often make comparison of test results between manufacturers very difficult.

2.4.2 Standardized AC Voltage Endurance Test Methods for Form-wound Coils/Bars

The only standard, detailed voltage endurance test procedure for 50/60-Hz AC form-wound bars or coils that is widely applied is IEEE 1043 [35]. The specific test parameters using IEEE 1043, as well as pass-fail criteria, are described in IEEE 1553 [36], although this standard is formerly only intended for hydrogenerator application. The IEEE 1043 method is based on a test developed by Cameron and Kurtz in the 1950s [8]. Key features of the test are:

- Usually, full-length coils or bars are tested.
- The specimens have the normal endwinding, with the usual stress relief coatings, as many problems in service originate from this area.
- Only one method of heat application is permitted: strip heaters applied to the surface of the specimen, in the slot region (Figure 2.3), to develop a thermal gradient across the thickness of the groundwall.
- Only power frequency voltage (50 or 60 Hz) is permitted.

The test procedure does not specify a test voltage or the test temperature. Before the development of IEEE 1553, some utilities had published the temperatures and

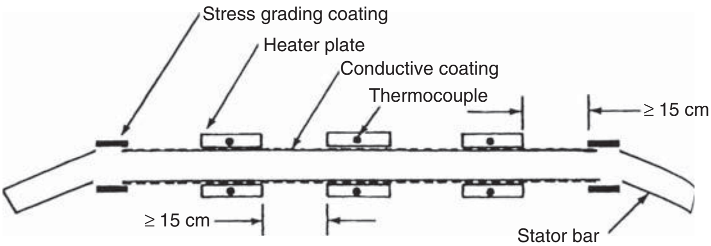

Figure 2.3 Application of heater plates to a stator bar for the IEEE 1043 voltage endurance test.

voltages that they employ [37,38]. IEEE 1553 requires a 13.8-kV rated bar or coil, to be tested at either 30 kV or 35 kV, with a minimum acceptable time to failure of either 400 h or 250 h, respectively. The 35-kV test is considered more onerous. The bars/coils are to be heated to the design operating temperature, typically in the 110–120°C range for Class 155 windings.

The IEEE 1043 test method is now used by many purchasers of windings as one of the vendor selection criteria. The procedure has also been used as a quality control test.

IEC has developed procedures to explain the general principles for voltage endurance testing in IEC 61251 [11]. For rotating machine insulation, IEC 60034-18-32 has been published—but it gives few specifics similar to the IEEE standards [39]. In addition, it is a comparison test, in keeping with the methods in the IEC 60034-18 series, where a candidate insulation system is compared to the voltage endurance test results of a service-proven system. This is unlike the IEEE 1553 standard, where an absolute pass–fail criterion is established. KEMA in the Netherlands has published a specification that uses the basic IEC 60034-18-32 test method, but requires the two bars (or two coil legs) to survive 1000 hours at 2E (twice rated line to line voltage) [40]. This is a lower test voltage than required by IEEE 1553, but a longer time to failure.

The voltage endurance tests are good for establishing the effect of voltage on life for the slot portion of a coil or bar. However, such tests do not enable determination of the voltage endurance capabilities in the endwinding, where electrical tracking and PD between coils may occur (Sections 8.11 and 8.14). The 50/60-Hz test methods discussed earlier also have no relevance to the turn insulation.

2.4.3 Voltage Endurance Tests for Inverter-Fed Windings

The introduction of voltage source PWM invertors for feeding both stator windings (in variable speed motors) and rotor windings (most commonly in wind turbines) has created the need for more specialized voltage endurance tests for such windings. To date, only IEC 60034-18-42 TS addresses this need [41]. This technical specification describes voltage endurance tests for the turn insulation, groundwall insulation, and the PD suppression coatings of what is called “Type II” winding insulation systems. Type II insulation systems are used in windings that are fed by voltage source

PWM invertors, and where the insulation system is expected to experience PD as a result of the voltage impulses from the inverter. (In contrast, IEC 60034-18-41 TS addresses Type I insulation systems that are expected to have a PD inception voltage under impulses that exceeds the expected voltage impulses from the inverter.) Normally, Type II insulation will use mica paper tape for the turn insulation and have a mica-based groundwall insulation system to withstand the PD expected during the voltage impulses. This type of insulation will also need upgraded PD suppression coatings, as discussed in Section 1.4.6. Usually, but not always, the Type II insulation will be a form-wound coil.

The voltage endurance tests for the turn and groundwall insulation in IEC 60034-18-42 TS can be performed with either AC voltage or impulses. The turn insulation specimens are usually two lengths of insulated copper conductors held against one another by a consolidation tape. The groundwall insulation specimens will normally be similar to the short coils used in formettes (as described in IEC 60034-18-32). It seems that most of the endurance tests on the turn and groundwall specimens are performed with AC—either power frequency or high frequency up to a few kilohertz. If power frequency is used, the aging test time needs to be greatly extended (assuming that the same test voltage is used), owing to inverse frequency effect (Equation 2.8). The tests can be completed in a shorter time using higher frequency AC. The IEC voltage endurance test is a comparison test to a service-proven system—although this may be hard to achieve given that such drives have been in use for so short a time. IEC 60034-18-42 does, however, provide for an acceptance test using power frequency at 4.3 times the peak-to-peak voltage that must be withstood for 250 h. This is similar to the IEEE 1553 criterion.

As the PD suppression system has often been found to be the life-limiting component in voltage source PWM motors (Section 8.10), IEC 60034-18-42 requires a separate voltage endurance test for the semiconductive and silicon carbide coatings. The specimens are coils made with the candidate PD suppression coating system. High voltage and high frequency impulse voltages from a special supply (one of which is described in the standard) are then applied to the specimens and the time to failure noted. The voltage is 1.3 times the peak impulse voltage expected in service. The pass–fail criterion is absolute in nature—no visible PD should be seen in a blackout test (Section 15.14) within 20 min, and after 100 h, there should be no visible deterioration (i.e., a white powder or burning).

IEC 60034-18-42 TS is a new document—it should be expected that important changes will be made when it is revised.

2.5 THERMAL CYCLING TESTS

Thermal cycling occurs when a motor or generator rapidly changes load, causing the current and, thus, the conductor temperature, to rapidly change between a low temperature and a high temperature. As the conductor temperature rises and falls, the conductors expand and contract because of the thermal coefficient of expansion; this can gradually fatigue crack the insulation or abrade it away. The specifics of the deterioration processes are in Sections 8.2, 9.2, and 10.2.

Thermal cycling in round rotor windings of large turbine generators is of great concern. However, no standardized thermal cycling endurance procedures for complete rotor insulation systems have been developed. Indeed, not even proprietary methods have been published. Instead, machine manufacturers rely on material property tests such as abrasion resistance or fatigue strength (Section 2.8).

Thermal cycling tests that mimic the associated failure mechanism in form-wound stators have been standardized, by both IEEE and IEC. These tests are normally intended to be used on full-size coils or bars. The tests are most applicable to coils or bars in stators in which the load is rapidly changed, usually hydrogenerators, pump-storage generators, or gas turbine generators. As the winding temperature tends to change slowly in directly cooled windings, thermal cycling test is mainly intended for indirectly air- or hydrogen-cooled stators. As discussed in Section 8.2, motors also experience rapid load changes, but owing to the shorter stator core length in most motors, deterioration caused by thermal cycling is less likely.

2.5.1 IEEE Thermal Cycling Test

IEEE 1310 is a test method developed in the early 1990s and revised in 2010 to allow manufacturers and users to assess the relative capability of stator winding insulation systems to resist the thermal cycling failure process [29]. The test only evaluates the ability to resist failure of the bond between the groundwall insulation and the copper conductors. It does not enable evaluation of the slot mechanical support system (wedges, side packing, ripple springs, etc.), nor is IEEE 1310 relevant for global VPI stators in which the coils/bars are bonded to the stator core. IEEE 1310 is a recommended test procedure, intended to ensure that results from different testing organizations can be compared. It does not specify a pass–fail criterion.

The method uses full-size bars or coils, which are "floating" on supports, allowing free axial movement of the bar/coil. Thermal cycling is achieved by circulating DC or AC current through each bar/coil, sufficient to raise the temperature of the copper to the thermal class temperature for the insulation (155°C for Class F systems). The temperature is raised to this upper limit in about 45 min. When the high temperature limit is reached, the current is shut off and cool air is blown over the coil/bar surface to reduce the copper temperature to 40°C in about 45 min. This temperature swing from low to high to low temperature constitutes one thermal cycle. The test proceeds until 500 thermal cycles are completed. At least four bars (or two coils) are needed to establish a clear trend. While the thermal cycling is occurring, high voltage is *not* applied across the insulation. The coils/bars cannot be installed in a stator after undergoing the test. The test is one of the most expensive of all the aging tests described in this chapter, and is only used if the application warrants it.

Similar to the thermal aging tests in Section 2.3.4, the thermal cycling test does not result in failure by itself. Diagnostic tests are needed to establish when deterioration has occurred. The best diagnostic test is the voltage endurance test. However, this is also the most expensive, as the voltage endurance test requires even more test specimens. With a voltage endurance test (Section 2.4.2) as a diagnostic test, the times to failure of several "virgin" bars, which have not been subjected to thermal cycling, are established. The voltage endurance test is then done on the coils/bars that have been subjected to 500 thermal cycles. If there has been a significant decrease in voltage endurance life compared to uncycled bars/coils, then, clearly, the thermal cycling has deteriorated the insulation. Alternatively, IEEE 1043 on virgin coils/bars can be omitted and IEEE 1553 test can be done on the cycled bars/coils. If they meet the IEEE 1553 criteria, then thermal cycling is not a significant aging factor. As IEEE 1310 provides only a test procedure, the test user must define what constitutes a significant decrease in voltage endurance life due to thermal cycling. In the latest version of IEEE 1310, an AC breakdown voltage test is proposed as an alternative to the voltage endurance test.

Other less expensive diagnostic tests are available that are not destructive. The most useful are the power factor tip-up test and the PD test. These are described in Sections 15.11 and 15.12, respectively. These diagnostic tests are sensitive to the presence of delamination, that is, voids within the groundwall insulation that may occur as a result of the thermal cycling. Test is done either on the bars or on the coils before any thermal cycles. These are the baseline measurements. Then, after 500 thermal cycles, the coils and bars are subjected to repeat PD or tip-up tests. If there is a significant increase in the measurement as compared to the baseline measurement, then deterioration has occurred. The IEEE document does not provide guidance on what constitutes a significant increase, but a doubling of the PD magnitude or a 0.5% increase in tip-up may be considered significant.

Many generator owners are using this test as a vendor qualification test, to decide which manufacturers make windings that are resistant to thermal cycling. In addition, some manufacturers use the test to optimize their insulation system design, especially with respect to the choice of bonding resin formulations.

On the basis of earlier work by Gupta [42], a variation of the IEEE 1310 procedure is being developed to specifically evaluate the turn insulation in multi-turn coils. Thermal cycling may lead to delamination between the groundwall and the turn insulation. A surge voltage test (Section 15.16) is used to determine if the turn insulation has been deteriorated by the cycling. The aim here is to develop a functional test to evaluate turn insulation system designs and materials. An IEEE working group has been created to develop a standardized aging test for the turn insulation.

2.5.2 IEC Thermal Cycling Test

Early in 2000, IEC published two thermal cycling test procedures [43]. One of the procedures is very similar to the IEEE 1310 document; that is, it describes a method for evaluating the bonding between the groundwall and the copper, using floating bars/coils. The only real difference is that the IEC version is less restrictive on the test parameters.

The other IEC procedure is much more comprehensive in that the bars or coils are inserted in simulated slots, with all the normal slot contents, including wedges, fillers, ripple springs, and side packing. In addition, realistic endwinding bracing is applied. Thus, this procedure not only evaluates the ability of the coil/bar itself to withstand thermal cycling but also assesses the entire contents of the slot. As an alternate to circulating AC or DC current to produce the thermal cycles, hot or cold liquid circulated through hollow conductors is also permitted in the procedure.

This method is primarily intended for use by manufacturers who are evaluating the optimum design for wedging, side packing, and/or groundwall insulation. The results of any new insulation material or new wedging approach are compared to a reference system that has seen successful service. The test is very expensive, costing many tens of thousands of dollars to perform.

2.6 NUCLEAR ENVIRONMENTAL QUALIFICATION TESTS

Stator windings in certain motors used in nuclear power plant applications have to be qualified for operation in "harsh or mild radiation environments," which can be either inside or outside a radiation containment area. As the insulation systems must be shown to be able to withstand such conditions, a brief description of what they are is given below. Such tests are sometimes called EQ tests, or environmental qualification tests. The particular environments are as follows.

Loss of Coolant Accident (LOCA) Normally, motors exposed to this type of accident are subjected to mild radiation fields under normal operating conditions, and during a LOCA, they see higher radiation fields together with high pressure and temperature transients. The motor may also be subjected to chemical spraying during the LOCA.

Main Steam Line Break (MSLB) Motors exposed to this type of environment can be either inside or outside containment areas and have to be qualified for operation during or after a high pressure steam line break that may also be associated with a seismic event. Such an event results in the motor being subjected to a high temperature steam environment.

High Energy Line Break (HELB) There are basically two consequences to the postulated HELB:

(1) Dynamic effects in the form of pipe whip, jet impingement on surrounding targets, in-pipe fluid transients (water hammer) caused by the sudden break, and sub-compartment pressurization because of the discharge of hot pressurized fluid inside rooms and compartments.

(2) Environmental effects in the form of flooding and spray wetting from fluid discharge from the break, and harsh ambient temperatures and humidity. Challenged by these effects, plant systems and components must be designed to operate to bring the plant to a safe shutdown.

Harsh Environments An environment resulting from a design basis event, that is, LOCA, MSLB, or HELB.

Radiation-Only Harsh Environment An accident environment where radiation is the only environmental condition substantially different from that normally occurring.

Mild Environment An environment that would at no time be significantly more severe than the environment that would occur during normal plant operation, including anticipated transient operational occurrences.

Environmental qualification must be based on the assumption that the motor will have to be capable of operating after being subjected to a LOCA, MSLB, HELB, seismic event, or a combination of these, at the end of the plant life [18]. At this time, these windings will have been subjected to their maximum normal thermal, mechanical, electrical, chemical, and, if appropriate, radiation aging. Where LOCA, MSLB, or HELB qualification is required and the motor has an open-type enclosure or is totally enclosed but the steam pressure is very high, a sealed winding insulation system per IEEE 1776 [30] is required.

IEEE Standards 323, 334, and 344 [44–46] give some guidance on qualification techniques and the use of complete motors or formettes for qualification testing. The various options for the EQ of a stator winding insulation system are discussed in the following sections.

2.6.1 Environmental Qualification (EQ) by Testing

Test Specimens Complete winding or formette specimens must first be constructed of materials that are considered to be resistant to both normal and accident conditions. Detailed coil- and winding-manufacturing procedures and methods of verifying all of the winding materials used have to be prepared before specimen manufacture. This is required to ensure that if the insulation system is environmentally qualified, it can be exactly replicated. Specimens of all materials used should be kept and insulation resistance (Section 15.1) measured often to provide baseline data for future material verification.

Once constructed, the test specimens must then be subjected to accelerated aging that simulates normal aging plus accident radiation and seismic conditions (if applicable). After such aging, those specimens that represent stator winding insulation systems that have to be qualified to survive a LOCA, MSLB, or HELB are placed in a sealed test chamber and subjected to high pressure steam and temperatures that simulate such conditions. Insulation systems to be qualified for LOCA conditions are also subjected to a chemical or demineralized water spray, if applicable, used to control pressure buildup in the reactor building.

EQ Test Sequence The test sequence that is normally used is as presented in Table 2.2.

EQ Test Report After EQ testing is complete, a report containing details of all the testing performed and the results must be prepared. This is used to justify the use of any insulation system that is qualified for normal plus accident conditions that have been enveloped by the test program.

TABLE 2.2 EQ Test Sequence

	Type of Qualification			
Activity or Test	LOCA	MSLB	Radiation Only	Mild Environment
Test specimen incoming inspection	X	X	X	X
Winding baseline functional testing [normally IR, PI (if form-wound), winding resistance, surge, and hipot tests]	X	X	X	X
Normal radiation aging[a,b]	X		X	
Functional testing [normally IR, PI (if form-wound), winding resistance, and reduced voltage hipot and surge tests]	X		X	
Thermal aging in an oven[b]	X	X	X	X
Repeat functional testing	X	X	X	X
Vibration aging and, if applicable, mechanical cycling[b,c]	X	X	X	X
Repeat functional testing	X	X	X	X
Seismic simulation test[b,d]	X	X	X	X
Repeat functional testing	X	X	X	X
Accident radiation aging[b]	X		X	
Repeat functional testing	X		X	
Simulated LOCA or MSLB[b]	X	X		
Repeat functional testing	X	X		
Visual inspection	X	X	X	X

Notes:

[a] Sometimes, the test specimen is subjected to normal plus accident radiation aging at this time.

[b] For a particular test program, the normal and accident conditions should envelope the worst conditions the insulation system is likely to see. If the motor insulation system is exposed to a chemical spray during an accident, then a test to simulate this must be included in the qualification program.

[c] Sample insulation system specimens must have been thermally aged at different temperatures as described in Section 2.3.4 to establish a thermal life graph, so that appropriate aging temperatures and times can be established to achieve a specific qualified life. From this curve, the insulation system activation energy in electron volt can be established and used to help determine qualified thermal life.

[d] Only performed if the insulation system has to be seismically qualified.

2.6.2 Environmental Qualification by Analysis

This is usually only used for stator winding insulation systems to be used in Radiation-Only and Mild Environment applications and for standby motors that do not see any significant thermal aging. The insulating and bracing materials used are types known to have a radiation damage threshold above the total radiation dose the motor will see in its lifetime. This allows environmental qualification for such applications to be performed by analysis. Examples of insulating materials with high radiation resistance are Nomex™, mica, woven glass, epoxy resin, and polyimide magnet wire insulation. Typical radiation damage threshold total integrated radiation doses for such materials are in Table 2.3 [47]

TABLE 2.3 Radiation Does Thresholds for Common Insulating Materials

Material	Radiation Dose for Threshold Damage (Rads)
Epoxy and polyester resins	5×10^7
Polyimide insulated magnet wire	10^9
Nomex™ paper	2×10^8
Mica paper tapes	$>10^8$
Fiberglass fibers	$>10^9$
EPR/EPDM insulated cables	5×10^6

2.6.3 Environmental Qualification by a Combination of Testing and Analysis

This is best illustrated by the following example. Suppose that an insulation system is to be qualified for use in a motor that is located in a radiation environment, is only operated for testing, and has to operate after a seismic event. By constructing the insulation system with materials having a radiation damage limit above the total integrated radiation dose the motor is subjected to, radiation aging qualification can be performed by analysis. On the other hand, seismic qualification may be most easily obtained by making a formette model of the insulation system and subjecting it to a vibration (shaker) table test that simulates the worst postulated seismic event. Thus, a combination of analysis and testing is to environmentally qualify such a stator winding insulation system.

2.7 MULTIFACTOR STRESS TESTING

Section 2.1.6 discussed the notion that some failure processes in rotor and stator windings do not occur as a result of a single stress or factor but, in fact, depend on two or more stresses/factors. Thus, to reasonably duplicate some failure processes in an accelerated aging test, more than one stress needs to be applied at the same time. In three types of tests described earlier (thermal, thermal cycling, and voltage endurance), there was only one stress that was "accelerated," that is, the stress was applied at a level higher than would occur in normal service. Although another stress or factor may be present (e.g., thermal stress in the voltage endurance test), this additional stress is not an "accelerated" stress. If the applied temperature is above the rated temperature, then it could be considered "accelerated."

A multifactor accelerated aging test is one in which two or more stresses/factors are simultaneously or sequentially applied at higher levels than would occur in service. The aim is both to realistically simulate a real failure process and to have the failure occur in a time much shorter than would be expected in service. As with all aging tests, the purpose is to find the insulation system design that performs satisfactorily in comparison to a reference system, at the lowest cost.

In practice, multifactor aging tests are not used largely to simulate rotor and stator winding failure. No specific test procedures have been standardized with the exception of IEC 60034-18-33 under thermal and electrical aging [20]. What has been standardized, and about which several papers have been presented, are the general procedures that should be employed in a multifactor aging test on insulation systems. Paloniemi introduced the concept of "equalized aging," that is, all the relevant stresses in a failure process should be accelerated to such an extent that the aging rate due to each stress is about the same [48]. This principle has been incorporated in an IEC guide for developing multifactor aging tests for insulation systems [3]. A similar IEEE document was also developed [19]. A general guide to the principles involved in multifactor tests in which both thermal and electrical stresses are accelerated is given in IEC 60034-18-33 [20].

Bartnikas has perhaps gone the furthest in creating a multifactor stress test for rotating machines [49,50]. In his test, bars are inserted in a portion of a stator core. High voltage is applied to the bars at the same time as current is circulated. This creates an environment where thermal, mechanical, and electrical stresses can be applied to the bars at the same time. To date, there has been no effort to standardize this method.

2.8 MATERIAL PROPERTY TESTS

The majority of this chapter has focused on insulation system accelerated aging tests. However, there is a large collection of tests intended to measure specific insulation properties, usually on materials, but sometimes on systems. The idea is that with knowledge of a failure mechanism, it is often possible to identify one or more insulation material properties that can be measured on a candidate insulation material to give an indication of how well the insulation will resist a specific failure mechanism. For example, the slot liner (or ground) insulation in a turbine generator rotor is subject to abrasion during load cycling (Section 9.2). Rather than simulate the entire failure process in an accelerated aging test, the designer knows that a slot liner that is very resistant to abrasion would result in longer winding life. Thus, the designer selects a material that performs well on a material test that is called the "abrasion resistance" test.

Similarly, the endwinding of a high voltage stator winding can suffer from a failure process called electrical tracking (Section 8.11). Rather than try to duplicate and accelerate the entire deterioration process, the designer recognizes that a single property called *tracking resistance* can be measured on slabs of candidate groundwall insulation materials. The material that has the highest tracking resistance will perform the best in a rotating machine that may be subject to a polluted environment.

There are many dozens of tests that have been developed to measure a wide range of insulation properties. Reference 51 describes many of these tests and how many common rotating machine materials behave under them. In addition, standards organizations such as ASTM and IEC have published standard test procedures to measure many of the properties that are relevant to rotating machine insulation systems. Table 2.4 contains a list of common ASTM material tests applicable to rotating machine insulation systems. In addition, many of these tests are described

TABLE 2.4 ASTM Test Standards Relevant to Rotating Machine Insulation Material

D 149	Test Method for Dielectric Breakdown Voltage and Dielectric Strength of Solid Electrical Insulating Materials at Commercial Power Frequencies
D 150	Test Methods for AC Loss Characteristics and Permittivity (Dielectric Constant) of Solid Electrical Insulating Materials
D 257	Test Methods for DC Resistance or Conductance of Insulating Materials
D 495	Test Method for High Voltage, Low Current, Dry Arc Resistance of Solid Electrical Insulation
D 651	Test Method for Tensile Strength of Molded Electrical Insulating Materials
D 1676	Methods for Testing Film-Insulated Magnet Wire
D 1868	Method for Detection and Measurement of Partial Discharge (Corona) Pulses in Evaluation of Insulation Systems
D 2132	Test Method for Dust-and-Fog Tracking and Erosion Resistance of Electrical Insulating Materials
D 2275	Test Method for Voltage Endurance of Solid Electrical Insulating Materials Subjected to Partial Discharges (Corona) on the Surface
D 2303	Test Methods for Liquid-Contaminant, Inclined-Plane Tracking, and Erosion of Insulating Materials
D 2304	Method for Thermal Evaluation of Rigid Electrical Insulating Materials
D 2307	Test Method for Relative Thermal Endurance of Film-Insulated Round Magnet Wire
D 2519	Test Method for Bond Strength of Electrical Insulating Varnishes by the Helical Coil Test
D 3145	Test Method for Thermal Endurance of Electrical Insulating Varnishes by the Helical Coil Method
D 3151	Test Method for Thermal Failure under Electric Stress of Solid Electrical Insulating Materials
D 3251	Test Method for Thermal-Aging Characteristics of Electrical Insulating Varnishes Applied over Film-Insulated Magnet Wire
D 3377	Test Method for Weight Loss of Solventless Varnishes
D 3386	Test Method for Coefficient of Linear Thermal Expansion of Electrical Insulating Materials
D 3426	Test Method for Dielectric Breakdown Voltage and Dielectric Strength of Solid Electrical Insulating Materials Using Impulse Waves
D 3638	Test Method for Comparative Tracking Index of Electrical Insulating Materials
D 3755	Test Method for Dielectric Breakdown Voltage and Dielectric Strength of Solid Electrical Insulating Materials under Direct-Voltage Stress
D 3850	Test Method for Rapid Thermal Degradation of Solid Electrical Insulating Materials by Thermogravimetric Method

in the following chapters and their relevance to materials is described in Chapters 3–6. Appendix A contains a partial list of the insulation properties of many common materials used in rotating machine insulation systems.

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CHAPTER 3

HISTORICAL DEVELOPMENT OF INSULATION MATERIALS AND SYSTEMS

The selection of electrical insulation systems for rotating machines has always been dependent on the materials available, their cost, the technical needs of the motor or generator application, and the relative costs of the several manufacturing processes available at the time. In the early years of the industry, there was a near total reliance on naturally occurring materials and much trial-and-error experimentation to find systems that met minimum design criteria. Thus, operating temperatures, as well as mechanical and electrical stresses, were kept low to accommodate the limitations of these materials.

Service experience with the early machines generally evolved into the widespread use of conservative designs to ensure long life. In an increasingly competitive environment and with growing knowledge of the capabilities and limitations of the existing natural materials, combinations were developed that enabled systems that could be operated at higher TEAM (thermal, electrical, ambient, and mechanical) stresses (Section 2.1).

From the beginning of the industry until the advent of the computer, engineers used slide rules and handbook tables to design rotating machines. This laborious process led to a range of machine ratings within the same frame size and a distribution of insulation stresses from low to fairly high over the rating range. Some machines seemed to never wear out and could be operated at power levels well above their nameplate ratings with safety. In fact, many machines installed in the early part of the 1900s are still in service. Today, with sophisticated finite element mechanical, thermal, and electrical design software as well as manufacturing processes that have narrow process margins and exceptional dimensional control, windings are designed to operate at higher stresses than in the past. The result is that today windings are less expensive (in constant currency) than those of the past, but operation beyond the original design life is much less likely, and operation beyond nameplate ratings is usually not possible.

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair,
Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

This chapter describes the chronological development of insulation materials and systems, together with some of the key innovations in manufacturing. An interesting paper by Hill, which was published in 1928, describes the then new innovations of hydrogen-cooling, asphaltic mica groundwall and PD suppression coatings [1]. More details on the systems in widespread use today are in Chapters 4–6. The reader should also refer to Shugg [2], which has an excellent review of the development of insulating materials for all applications.

The following section describes the historical development of all the main materials used in rotor and stator windings. However, as it tended to drive all the other insulation components, the development of the stator winding insulation systems for form-wound stator bars and coils is first described.

3.1 NATURAL MATERIALS FOR FORM-WOUND STATOR COILS

The first stator winding insulation systems used materials that were then common in industry for other uses. These included natural fibers of cellulose, silk, flax, cotton, wool, and, later, asbestos. The fibers were used both as individual strands for applications such as wire servings, in groups of strands for support ties, and in combined forms as in nonwoven papers and woven cloths. Natural resins derived from trees, plants, and insects, and petroleum deposits, were used in combination with the fiber forms to make insulating materials. These included refined petroleum oils. waxes, asphalts (bitumen), and natural resins such as pitch, shellac, rosin, and linseed oil. Solids such as sand, mica, asbestos, quartz, and other minerals were often used as fillers in ground or powdered form. Among the earliest materials used as stator groundwall insulation was varnished cambric, which is still manufactured and used today in some electrical applications. This material was originally composed of a fine grade of cotton cloth impregnated with a natural resin of the drying oil variety, which oxidizes and changes to a hard, tough, elastic substance when exposed in a thin film to air. Modifications in the choice of oil and blending were used to modify the properties for specific uses.

These resins were applied from solvent solutions and had good shelf life when sealed to prevent oxidation and solvent evaporation. Tower ovens, with good air circulation, were used to speed up evaporation and oxidation to produce continuous rolls of the material that could then be cut to desired shapes for use as insulation pieces or to be built up into thicker sections or wrapped onto conductors as groundwall insulation.

During World War I, thermoplastic asphaltic resins (also called *bitumen*) were combined with mica splittings for the first time to make improved groundwall insulation for turbine generator stator coils [1]. The mica splittings were supported by a fine grade of cellulose paper on both sides. Although practices differed between manufacturers, a common method that was in use until the 1980s was to impregnate the supported mica splitting sheet with a drying-oil-modified asphaltic varnish solution in petroleum-based solvents such as toluene. Tapes, slit from rolls of this sheet, were applied by hand to stator coils and bars and then covered with two layers of cotton tape. The wet coils were then transferred to a large, steam-heated coil tank. After a suitable time period to warm up a batch of many insulated coils, a vacuum was applied to the tank and the remaining solvent and air was evacuated over a period of several hours. This left the insulation in a dry and porous state. While still under vacuum, the entire batch of coils was then flooded with more melted hot asphalt. The tank was then pressurized, usually with dry nitrogen gas, to about 550 kPa (80 psig) and held under pressure for a number of hours, to force the liquid asphalt between the mica layers. Then, the nitrogen pressure was used to push the asphalt back into a heated storage tank to await the next batch of coils. After venting the residual nitrogen gas, the hot coils were removed and allowed to cool to room temperature, which caused the asphalt-impregnated and covered coils to harden. Next, the surface layer of sacrifice cotton tape was stripped off, leaving a smooth, solid, impregnated cotton insulation surface. This vacuum impregnation and pressurizing process was called the *VPI (vacuum pressure impregnation)* process. As discussed later, the VPI process, used with other resins, is still a cornerstone of groundwall insulation manufacturing today.

These mica splittings and asphalt, together with the coil manufacturing process, led to some variations in the uniformity and thickness of the groundwall insulation. To help overcome this limitation, a final hot-press cycle was frequently used for the straight-slot sections of the coils. The pressing led to some redistribution of the impregnating materials and produced a coil with a small enough insulation thickness variation to be inserted into the stator slots.

For lower voltage form-wound stator coils, a varnish made with drying-oil-based paints was applied to the coil surface to give some protection against contaminates in service, such as lubricating oils and cleaning materials. These paints were usually pigmented to give a characteristic color for manufacturer identification. For machines of about 6600 V and higher, it was customary to armor the coils by applying a ferrous asbestos tape to help control destructive slot electrical discharges between the stator core and the coil surface (Section 1.4.5). This material has a natural low conductivity, and when the asbestos in the slot sections of coils was impregnated with a varnish containing added carbon black to obtain the desired range of resistivity, partial discharge (slot discharge) in service was prevented. Some manufacturers carried out the final hot press after the armoring process was completed.

Asphaltic-micafolium-insulated stator coils (as the groundwall was called) varied in their heat resistance properties. The incorporation of drying oils in asphalts, during formulation in large cooking kettles, led to varnishes or resins that would cure to a weakly thermoset condition; that is, they would greatly soften on heating but would not completely melt. Natural asphalts are thermoplastic materials that will repeatedly melt on heating. Natural asphalts, in contact with mica splittings tapes containing drying-oil-modified asphaltic varnishes, will slowly harden during service heating, but will not become true thermoset materials in the modern sense. A thermoset material will not excessively soften and change shape on heating.

All asphaltic mica coil insulations will relax somewhat after winding into a stator core and being subjected to service heating. The resulting puffing or expansion causes a tight fit in the slots, but tends to create small voids (delamination) in the groundwall that would lead to partial discharges in service (Section 1.4.4). To avoid these discharges, the average electric stress (Equation 1.4) was controlled to be less than the partial discharge inception voltage of the voids in the insulation. Thus, the design stress in asphaltic mica groundwall insulation was generally designed to be below 2 kV/mm. In contrast, some designs using modern thermoset insulation systems now employ a stress as high as 5 kV/mm.

The extent of use and types of drying oil formulations varied widely between generator manufacturers, and the resulting coils thus had different thermal properties. At some suppliers, a drying-oil-modified varnish was brushed between each layer of half-lapped tape, whereas other suppliers relied on the tank liquids to complete the impregnating process. Over time, generator ratings grew, so that by about 1940, the slot length of the largest turbogenerators approached or exceeded 2.5 m in length. When such machines were placed in service to meet wartime production power demands and frequently subjected to rated loads or beyond while still relatively new, a new failure phenomenon developed. The insulation relaxation described earlier led to well-bonded tape layers next to the copper strands and to surface tape layers that often were locked into the cooling ducts of the stator core (Section 8.2). As the copper conductors heat up faster and to a higher temperature than the stator core, the insulation is subjected to shear and would fail by differentially migrating with each start and stop or major load cycle. The resulting condition has been called *tape separation* or *girth cracks* and led to many failures of generators during the 1940–1960 period. As will be seen later, this history of both materials and insulation methods led to the many modern variations of stator groundwall insulation systems now in use.

Micafolium insulation systems were being manufactured at the same time as the asphaltic mica systems. Micafolium was first used for sheet wrapping of high voltage coils and the making of shaped insulating parts. A common early construction consisted of clear muscovite mica splittings bonded with natural shellac to a backing of kraft paper. Systems in the 1950s and 1960s used a glass cloth and even a B-stage epoxy varnish (see Section 3.4.2) to make sheet products. Micafoliums are generally supplied in rolls about 1 m wide and are usually not slit into tapes. Such insulation systems had many of the properties and limitations of asphaltic micas systems.

3.2 EARLY SYNTHETICS FOR FORM-WOUND STATOR COILS

The history of synthetic products for insulation started with the work of Baekeland in 1908. This led to the development of a workable and reproducible process for the production of phenol-formaldehyde resins that were used to make many types of electrical products. Although “Bakelite” was formerly a trade name, in contemporary usage, it describes the broad variety of condensation products of phenols and cresols with formaldehydes that grew out of Baekeland’s work (“phenolics”). Other early synthetic materials for insulation use were introduced throughout the 1920s and 1930s. Alkyd resins were used in 1926 for electrical bases and in the same year, aniline formaldehyde formulations were used for terminal boards.

Alkyds, made with saturated long-chain fatty acids and alcohols, are similar to the naturally occurring drying oil resins. During the late 1920s and 1930s, these new alkyds were used to both replace and blend with the natural resins in many applications. New equipment finishes and insulating varnishes in solvent solutions found use in many rotating machines. The varnishes were used for dipping and coating entire windings as well as to make improved versions of insulating materials such as varnished cambric. Most machines made from the late 1920s through the 1950s utilized these improved synthetic versions of the old natural materials, which still have a small place in the insulation industry and in protective paints for equipment. The volatile organic chemicals (VOCs), used to solvate these paints and varnishes for application, became a liability with widespread use because of their contribution to air pollution. When limits were established for VOC emissions, either their removal from the air venting from drying and baking operations or the switch to low VOC materials or modern solventless resins became necessary.

Other pre-World War II materials used in insulation include polyvinyl chloride (introduced in 1927), ureaformaldehyde (1929), acrylic (1936), polystyrene and nylon (1938), and melamine-formaldehyde (1939).

There was a great increase in the types of synthetic polymers and resins introduced during the 1940s and 1950s. Polyesters and polyethylenes date from 1942, fluorocarbons and silicones from 1943, and epoxies from 1947. In the 1950s, polyurethane, polypropylene, and polycarbonate were introduced. Although the early versions of these materials often lacked the sophistication and property enhancements of current offerings, their arrival on the scene led to an explosion of new applications in electrical insulation. Polyesters, derived from experience with alkyd chemistry, which used both saturated and unsaturated polyfunctional carboxylic acids and polyhydric alcohols, became very common after World War II and began to penetrate the electrical insulation market.

An important film insulation is made from polyethylene glycol terephthalate (PET), the reaction product of the saturated aromatic terephthalic acid and ethylene glycol. This linear, thermoplastic polymer has a high degree of crystallization and exhibits a high melting point (265°C) and great stability. Films and fibers of this polymer are manufactured in Russia as Lavasan, in England as Terylene, and in the United States as Mylar and Dacron.

When the dibasic acid or its anhydride is unsaturated (contains double bonds between carbons, or C=C bonds), esterification with polyhydric alcohols gives rise to polyesters that are also unsaturated. With the double bonds present, these polyesters may, in the presence of catalysts, enter into a copolymerization reaction with unsaturated monomeric materials or with more complex compounds containing double bonds. This reaction allows the conversion of liquid starting materials into solid substances with no volatile by-products and without the use of volatile solvents. A typical polyester of this type may be formed from maleic acid or its anhydride and ethylene glycol. When the resulting unsaturated glycol maleate is copolymerized with styrene monomer, in the presence of a small percentage of the initiator benzoyl peroxide, the cured product has very good electrical insulation and mechanical properties. This composition, and similar formulations using other unsaturated organic acids or anhydrides and monomers, has been widely used for impregnating the windings of electric motors. As shown in Section 3.4.1, this chemistry has also been used for high voltage generator insulation.

When natural materials and the early synthetics were the only choices, service experience was the major factor in determining insulation thermal classification. It was recognized as early as 1913 in an AIEE paper by Steinmetz and Lamme on "Temperature and Electrical Insulation" [3] that insulation deteriorates with time when exposed to heat. Materials were placed into three thermal classes on the basis of their generic composition. Class A materials could be used to temperatures of 90°C and included the natural organic fibers such as paper and cotton and the natural oils, resins, and gums described earlier. Class B materials were for use at temperatures to 125°C and included the heat-resistant minerals of mica, asbestos, and silicas, usually used in combination with the natural impregnating and bonding materials. When these inorganic materials were used without dependence on organic binders to maintain their forms, they were classified as Class C (150°C to incandescence). The thermal classifications mentioned earlier do differ from those used today (see Table 2.1).

In 1948, Dakin published an AIEE paper, "Electrical Insulation Deterioration Treated as a Chemical Rate Phenomenon" [4]. In this paper, he showed that the thermal deterioration of organic insulation was the result of internal chemical change during aging. The relationship he described was taken from studies of organic chemical reaction rates experienced in the laboratory and is known as the Arrhenius chemical deterioration rate equation (Equation 2.1). When plotting the log of insulation life as measured at several elevated temperatures, against the reciprocal of the absolute temperature (°K), a straight line will be produced (Figure 2.1), except where second- and higher order chemical reactions are occurring. If the straight portion of the line is extended to lower temperatures, it can be used to predict the insulation system life at the lower temperatures. Thus, after relatively short aging periods at several temperatures above expected service temperature, a life prediction, based on an arbitrarily chosen end-of-life diagnostic test, can be made.

In Section 2.3, the concept of thermal endurance tests was introduced and their use to establish an insulation system thermal classification was discussed. This topic is reviewed here because of its relationship to the history of the development of insulating materials and insulation systems.

The variety of new synthetic materials that became available to the industry after World War II forced the development of new means to quickly evaluate them as a substitute for extended service experience. Instead of the costly building of complete machines and operating them at various service stress levels, a new method of accelerated functional testing was developed. During the 1950s, several organizations developed models of parts of electric motors and small generators that reproduced the essential combinations of insulating materials and associated electrical and supporting parts [5,6]. These inexpensive models evolved into the "motorettes" and "formettes" that we know today, which are the basic models used in IEEE 117 and 1776. Large numbers of these models were built to evaluate many different types and combinations of the new synthetic materials. Section 2.3.4 describes the now-standardized aging test procedure in more detail.

In the course of carrying out motorette tests on many new synthetic materials and on variations of them of the same generic type, it was found that systems of these materials had significantly different test lives and could not be thermally classified by chemical type, as had been common at that time. As a result, today, insulation systems are characterized by their performance in accepted aging life tests, such as IEEE No. 117 and 275 (subsequently replaced by IEEE 1776), as well as IEC 60034, Part 18, Sections 21 and 31, and are thermally classified for specific applications on the basis of such tests. Experience has shown that these comparative functional tests are good indicators of winding life in service. As the new materials and systems accumulate successful service experience, they become the reference systems for comparison with still newer materials and systems.

3.3 PLASTIC FILMS AND NON-WOVENS

In 1950, insulation engineers started to investigate the proliferation of new materials made with synthetic plastic films and later, polymer-fiber-based nonwovens, being offered by suppliers as slot, turn, and phase insulations for random-wound induction motors. Their need for a realistic and economical way to screen these many new materials were the direct cause of the development of the motorette tests described earlier. The new materials offered the potentials of lower costs, better performance, and ease of manufacture. As a result, extruded and calendered films of nylons and polyesters and solution-cast films of other materials were tested. Although some plastic films were used in production motors, a particularly successful insulation product was a thin laminate of an electrical grade PET polyester film sandwiched between layers of calendered, nonwoven polyester mat or paper. These composites have been widely used in the construction of low voltage small and medium motors and, by the IEEE 117 test method, have been accepted as insulation systems for both Class 130°C (B) and Class 155°C (F) when used with the appropriate varnish.

Indeed, the motorette accelerated thermal aging tests were widely used to evaluate insulation systems containing films and nonwovens that are treated with many types of varnishes, both solvent-based and solventless. In addition to modified natural varnishes, the synthetic varnishes using phenolic, polyester, silicone, epoxy, and other chemistries were used for coil treatments on motorettes.

The success of the polyester mat, polyester film, and polyester mat laminates, bonded with thermosetting adhesives, for use in fractional motors up to the largest rotating electrical equipment such as slot, phase, and end winding insulations and such as ground and wrapper insulations in dry-type transformers is well established. Many variations in thickness (4 to 1 ratio) surface treatment and bonding resins are available from a number of suppliers. The polyester film contributes high dielectric, tear, tensile, and burst strengths. The high density polyester mat, laminating adhesive, and surface resin treatments enhance the thermal stability. The polyester mat may be partially or fully saturated with resins from the laminating adhesives and the topcoats.

Many material variations in this type of laminate have been developed to enable them to be economically used for service in machines with insulation systems classes of Class B, Class F, and Class H. To achieve these service temperature levels with the most economical construction for each class, the polyester mat may be replaced with similar structures made with glass fibers, mica paper, cotton paper, wood-pulp kraft paper, vulcanized paper, ceramic paper, liquid crystal polymer paper, or aramid fiber paper. The films can be replaced with ether–imide, amide–imide, or solely imide polymers and biaxial extruded liquid crystal polymer. In addition to heat resistance, some constructions are optimized for use in sealed motors or in coils subjected to high levels of nuclear radiation.

3.4 LIQUID SYNTHETIC RESINS

One of the major developments was the replacement of thermoplastic solvent-borne natural and synthetic resins with solventless synthetic resins. These materials are normally thermosetting under the action of heat, catalysts, hardeners, or radiation. In addition to improved thermal stability and physical properties, the elimination of solvents makes their application more environmentally friendly and less likely to form voids within the groundwall. For groundwall insulation in form-wound stators, there are two families of resins that are very important—the polyesters and the epoxies, both of which are widely used in form-wound stator groundwalls. Other solventless resins that are sometimes used for special applications include silicones, acrylates, imides, and blends of phenolics with other resins.

3.4.1 Polyesters

Polyester resins evolved out of alkyd resins and became available starting in 1942. The first wartime uses were for military needs, including boats and pontoons, where they were combined with glass fibers to make strong laminates. During the decades following the end of the war, extensive development of this resin family took place and now most of their uses are nonelectrical. Their advent was, however, very important in the development of modern coil insulations.

In Section 3.1, the problems of "tape separation" or "girth cracks" developing during service with high voltage asphalt mica flake groundwall insulation were introduced. The softening temperature of the asphaltic resins used by various manufacturers was dependent on the percentage of drying oils used in their preparation. Insulation, containing the most weakly thermoset formulations, could only withstand a small amount of shearing loads from thermal cycling (Section 8.2) before the layers of insulating mica-splitting tape began to separate. Both the generator slot length and the service temperature were important factors in determining the shear loads within the insulation. Other factors included the tightness of fit of the coils in their slots, the duty cycle of the generator, and the degree of cumulative heat exposure in air before cyclic duty was started.

When drying-oil-modified asphaltic resins are heated in air, they will gradually harden by slow oxidation, becoming stronger and with a higher softening temperature. However, the introduction of hydrogen-cooled generators in the 1930s removed the oxygen from contact with the insulation and nearly eliminated the in-service oxidation or drying process that had helped avoid the tape separation phenomenon. Insulation engineers recognized that a new binding and filling resin that cured during coil manufacture to a thermoset, infusible state was needed. The wartime advances in polyester resin chemistry provided the materials to begin the development of a new generation of improved generator insulation.

Not long after the end of the war, Westinghouse Electric Corporation engineers began the laboratory work needed to turn the new polyester chemistry into a workable generator and motor coil high voltage groundwall insulation system. The system they developed was trade named "Thermalastic." Variations of the same basic system have been licensed to several other rotating machine manufacturers and also duplicated by others as patents expired.

Westinghouse chose mixtures of organic, ethylenically unsaturated (containing C=C bonds) dicarboxylic acids, which contain reactive free carboxyl groups (–COOH), to be reacted with polyhydric alcohols having only reactive hydroxyl (–OH) groups. When substantially molar equivalents of these materials are mixed and heated in a closed reaction vessel with an esterification catalyst, which may be mineral acids, the esterification reaction takes place. Removal of the water formed in the reaction, to increase the degree of esterification, may be accomplished by azeotropic distillation when the reaction is carried out in the presence of a volatile organic liquid such as toluene and xylene. The starting materials and the degree of esterification were chosen so that the final product was a solvent-free, syrupy polyester resin at room temperature or when heated.

This resin was typically used to partially impregnate mica splittings that were laid down on a thin, pliable sheet of backing material, such as rice paper or supercalendered rope paper. Many other supporting materials, including plastic films, synthetic resin papers, woven glass cloth, and glass fiber paper, may be substituted on one or both sides of the sheet. Tapes cut from these sheets were wrapped onto coils to build up a few or many layers, depending on the service voltage of the coil design. The tapes were permanently flexible and, with proper storage before use, did not age, harden, or deteriorate significantly at warm or low temperatures for appreciable periods of time.

Westinghouse chose to impregnate the groundwall with polyester using a modified VPI process first used for asphalt mica coils. The wrapped coils where placed into an impregnating tank and subjected to a heat drying and vacuum cycle to remove substantially all moisture, air, and any other undesirable volatile materials from the coils. Then, a low viscosity impregnating material consisting of a liquid, unsaturated, and reactive monomer containing 1–2% of an addition-type polymerization catalyst, usually an organic peroxide, was admitted into the tank until all of the coils were covered. While the coils were submerged, compressed gas such as air, nitrogen, or other relatively inert gas was introduced under pressure into the tank to assist the impregnating monomer in fully penetrating the coil wrappings and to ensure that all of the voids and interstices were filled. The pressurizing time depends on the number of layers of tape that must be penetrated. This can be 10–15 minutes for a low voltage design, to several hours for a high voltage coil with a thicker groundwall.

The impregnating material was selected for storage tank stability, low viscosity, and economic availability. Examples of these unsaturated reactive monomers, containing the group –C=C–, are styrene, vinyl styrene, methyl methacrylate, and a number of other monomers that can be used or mixed with the primary monomer to make up the impregnating composition. These compositions are fluids that will not readily gel or thermoset before coming in intimate contact with the polyester resin in the mica flake tape, even when they are exposed to moderate heating.

After full saturation of the mica splittings insulation, the impregnating monomer was pushed back into storage by the pressurizing gas and the wet, uncured coils were removed from the tank, allowed to drain briefly and then moved to a curing procedure. In the simplest case, the cure may be carried out in an oven, heated above the activation temperature of the catalyst chosen. Temperatures from 80°C up to about 135°C were used to carry out the final polymerization and cure, which converts the resins into a stable thermoset solid. For coils with many layers of insulating mica tape, more uniform dimensions could be obtained by transferring the coil to a heated sizing and curing press. Equipment was developed to apply molding pressure to the endwinding (curved) sections of coils or bars, so that the entire structure could be sized and cured simultaneously. A final armoring and painting step was applied, using materials the same as or similar to those used with asphaltic mica flake insulation, before winding the coils or half coils into the generator or motor stator core.

Many of the process steps previously used with asphaltic mica flake insulation and adaptations of similar equipment were also required with the new polyester thermoset insulation system. The fundamental similarity of the two manufacturing methods was the VPI of a low viscosity liquid into a mica tape containing only part of the material needed to completely fill the voids created in the tape layers by the taping process. Polyester resins are still widely used today, especially in Europe and service shops around the world for low and medium voltage global VPI (GVPI) motor stators (Section 3.10.4).

Versatile polyester chemistry has yielded many other insulating materials that have benefited the rotating machine industry. Polyester films and film/fiber laminates were described in Section 3.3. Treating varnishes, wire enamels and servings, molded insulation pieces, and electrical laminates, based in whole or in part on polyester chemistry, have proliferated and been optimized for many different types of rotating machines and service temperature levels.

3.4.2 Epoxides (Epoxy Resins)

As mentioned earlier, polyesters were first introduced in 1942, whereas epoxides were not commercially available until 1947. Most of the early epoxides were solventless thermoplastic solids at room temperature and were not very suitable for use as low viscosity impregnating resins. The solid epoxy resins could be mixed with low viscosity monofunctional epoxides, such as the glycidyl ethers, to make a viscous liquid at room temperature. However, these cured mixtures did not have the strength, heat distortion temperatures, or hot electrical properties of the high molecular-weight solid epoxides. Epoxy resins did have several advantages over the available polyester resins available during the early and mid-1950s. Epoxides cure to a stronger polymer and tend to have improved thermal stability. Epoxy groups are unstable and react or cross-link readily with compounds that have groups with mobile hydrogen atoms, such as carboxyl, hydroxyl, and amine groups. When these resins and compounds are mixed, a reaction takes place with the polymerization (elongation) of the molecule and the formation of transverse bonds. These cross-linking reactions result in the formation of solid, stable polymers that contract very little on hardening, only 0.05–2%, whereas polyester compounds may shrink by as much as 10%. General Electric (GE), which was the first to introduce the asphalt mica flake insulation system about the year 1915, continued to make changes in the materials and final properties of coils insulated with the asphaltic-mica system into the 1980s. A higher percentage of drying oils were used to make the asphaltic resins employed in both the initial tape construction and in the brushing varnish that was applied between each layer of tape as it was applied. As discussed in Section 3.1, these asphaltic resin variations were weakly thermoset materials when processed through the several shop manufacturing operations. There was, therefore, a 5–7-year delay, as compared to the experience of Westinghouse Electric Corporation with the asphaltic mica flake insulation system, before increasing generator ratings and the associated increased slot lengths led to the frequent occurrence of tape separation in generator stator coils.

When GE began looking for an improved thermosetting resin system in the late 1940s, several new polymer chemistries, including polyesters, were evaluated. To achieve the superior stator coil insulation system desired, epoxy chemistry was chosen. GE wanted to develop an epoxy system that did not depend on impregnating the wrapped coils with a low viscosity resin containing a reactive hardener. Such resins often require refrigerated storage to delay advancement of viscosity. The tapes and brushing varnish for the Micapal I™ system (Section 4.2.2) that evolved from the high molecular-weight, early epoxides contained a solvent mixture to liquefy the resin and hardener or coreactant. Following the lead of the solvent-containing asphalt mica flake system then in current use, the epoxy development also became a so-called resin-rich system in which all of the binding and filling resin was either in the tape, as applied, or in the brushing varnish used between layers as the tape was wrapped on the coils.

Epoxy resins can be cured by several means. The most common curing agents are Lewis bases, such as amines and amides, and Lewis acids, such as boron trifluoride; and other materials including phenols, organic acids, and anhydrides. Alkyds have been developed since 1926 for use in paints and protective coatings and GE had much experience with them. An alkyd is the reaction product of a polyhydroxy alcohol and a polybasic acid or anhydride, the same way that polyesters are formed. In the late 1940s, these materials were widely available from various alcohols and organic acids at reasonable costs. The epoxy curing reaction with organic acids depends on the carboxyl groups on the acids. When equivalent molar ratios of hydroxyl and carboxyl groups are reacted, most of these groups are used up in the esterification reaction, which produces the alkyd or polyester resin, and such materials have little reactivity with epoxy resins. When there is an excess of the acid, there will be unused carboxyl groups left over that may then be used to react with the epoxy group to cure the system with little or no volatile by-products. These alkyds are called high acid number resins. By choosing a medium-length carbon chain organic acid, such as adipic acid with six carbons, to react with glycerol, a three-carbon alcohol with three hydroxyl groups—glycerol adipate resin—is formed. When five moles of adipic acid are reacted with four moles of glycerol, the resulting high acid number polyester will have an average molecular weight of about 800. Using this resin as a hardener or coreactant with an epoxy resin will impart a degree of toughness, without brittleness, to the epoxy formulation. GE used variations of this chemistry in making their Micapal I epoxy-bonded-mica high voltage ground insulation system. GE produced this system into the 1990s.

The former VPI cycle for the asphaltic system now became a hydraulic pressure molding and curing cycle for the new epoxy system, using the same processing equipment still in use for the old system. In the asphalt mica system, there was no harm in having some of the tank asphalt incorporated in the surface layers of the groundwall insulation. However, the tank asphalt would be a contaminant in the top layers of an epoxy mica system. Therefore, a system of shape aids and sacrifice materials were evolved that excluded tank asphalt from the groundwall insulation layers. After a batch of uncured coils or bars were loaded into the empty tank, they were gradually heated, while under vacuum, to remove all of the solvents, moisture, and air present in the raw tapes. When the tank was flooded with hot asphalt and pressurized with compressed gas, usually nitrogen, the gas pressure was hydraulically transferred to the shape aids and the insulation layers underneath, compressing and molding them into a dense, relatively void-free high voltage insulation system. The heat of the pressurized hot liquid asphalt was transferred to the coils, curing the epoxy composition over a period of 8–10 h. After venting the nitrogen and removing the batch of coils to cool down to room temperature, the sacrifice materials and shape aids were removed and the individual coils were given the appropriate semiconducting slot coating, silicon carbide coating at the slot ends, and identifying colored epoxy paints.

Similarly to Westinghouse Electric Corporation's licensing of the Thermalastic VPI manufacturing system and materials to other motor and generator manufacturers, General Electric Company licensed the epoxy mica paper and resin-rich technology to its partners. Over time, as the early patents ran out, other manufacturers developed their own insulation systems, using both the VPI and the resin-rich technologies. One variation was press curing of resin-rich, fully taped coils or bars in special presses, equipped with forms to follow the shape of the coil. It was found that a super-resin-rich tape, on the parts of coils outside of the slot sections, could be compressed and cured with only the use of oriented, heat-shrink tapes made with polyethylene terephthalate (PET) films.

Both generator manufacturers started out with processes derived from those used with asphaltic resins and evolved into the use of quite different resin-rich and VPI processes that still persist. Low viscosity polyester systems became VPI systems, whereas the early high molecular-weight and viscous epoxides were more easily handled by the resin-rich process. Within a few years, epoxy technology evolved to produce a variety of solventless fluid resins and hardener materials that were suitable for both press cure and VPI uses. However, the various motor and generator manufacturers have developed their process equipment and associated insulating materials for one or the other of these basic processes and will not easily change. Today, epoxy resins are widely used in the press cure and VPI and GVPI processes. Virtually all large generator stator windings made today use epoxy in preference to polyester.

3.5 MICA

Mica, for many decades, has been one of the key materials used in stator windings rated above 1000 V, because of its high temperature capability and its excellent resistance to partial discharge. However, human beings have used natural mica since prehistoric times. The earliest uses were in the form of sparkling dust or powder for ornamental purposes, including body paints or cosmetics. Ground mica is still used as a special filler in paints, plastics, and cosmetics, and the largest tonnages of mica today are still in these applications. Because of its transparency and its resistance to fracture and heat, mica, also called *isinglass*, was widely used for lantern globes and for windows in coal, wood, and kerosene stoves. In recent years, there has been a revival of the use of mica for decorative electric-lamp shades and other decorative surfaces. In addition to these ordinary uses, the Russians found mica to be useful as a covering for portholes in warships, as it could stand the shock of cannon fire better than any glass available at that time. The Russian mica became known as *muscovite*, the term still used to describe white or India mica.

Mineralogically, mica is the name given to a group of minerals of related composition and similar physical properties. Micas are characterized chiefly by having a perfect basal cleavage, so that they can be split readily in one direction into a great number of thin, tough, flexible laminae.

Chemically, the micas are complex silicates of aluminum with potassium, magnesium, iron, sodium, lithium, fluorine, and traces of other elements. The principal micas are muscovite, $H_2KA1_3(SiO_4)_3$; phlogopite, $[H,K(Mg,F)_3]Mg_3A1(SiO_4)_3$; and biotite, $(H,K)_2$ $(Mg,Fe)_2(A1,Fe)_2(SiO_4)_3$. Other micas that are not so well known are lepidolite, paragonite, and zinnwaldite.

The micas have a specific gravity of about 3, index of refraction from 1.5 to 1.7, and usable temperature limits of about 550°C (for muscovite) up to about 980°C (for some grades of Phlogopite). Muscovite and biotite occur chiefly in pegmatite dikes associated with feldspar and quartz, although they are abundant also in granites and syenites. They are chiefly obtained in India, Brazil, and the United States, although, for electrical uses, about 70% of the world supply comes from the first two countries. Phlogopite occurs in crystalline limestones, dolomites, and serpentines in Canada and Madagascar. Muscovite is also called *India, white*, or *potassium mica*. Phlogopite is called *Canadian, ruby, amber*, or *magnesium mica*. Biotite is called *black* or *magnesium iron mica*.

3.5.1 Mica Splittings

Mica is mined in chunks or “books” that are rough trimmed to exclude pieces of the associated minerals in which they are found. These books are then given further preparation with a knife, sickle, or shears to remove all edge defects, cracks, etc. before being hand-delaminated or separated into irregular thin sheets. These irregular shapes are then graded to size on the basis of the area of the minimum rectangle that can be cut from each plate. Standard gradings range from 6.5 square centimeters to 650 square centimeters.

The present mining and preparation of mica for electrical use is a very labor-intensive operation with often whole families engaged in the process. This is why most of the mica used in the developed world comes from India, Brazil, and Madagascar. During World War II, when overseas sources either were cut off or were in a state of hazardous supply, muscovite was mined in the State of New Hampshire for the U.S. electrical industry. Mica splittings have been or still are used in many electrical insulation applications. These include microwave windows, capacitors (including those intended for partial discharge measurement), transistor mounting washers, and several rotating machine applications. Except for the latter, most of the other uses are for fabricated individual mica pieces that are cut from selected mica books or individual pieces, leaving a high quality scrap that is preferred as a raw material for conversion into mica paper. Rotating machine use of mica splittings, which normally have a area of a few square centimeters, is generally in the form of built-up sheets or tapes with supporting backers and resinous impregnants or as molded sheets made with bonding resins. The tapes are generally applied by hand as ground insulation for higher voltage motors and generators. Tapes using mica splitting are rarely used today.

3.5.2 Mica Paper

The World War II dependence on overseas supplies of mica splittings led to the development of mica papers. In the United States, a government-supported program in GE's Research Laboratory and at the GE Pittsfield, Massachusetts plant, was started with the help of fine paper manufacturer, Crane & Co. Inc., located in the same geographical area. This mica paper development during the war was to help free the United States from dependence on foreign sources of mica splittings and to assure the availability of mica products to meet military and civilian electrical equipment needs. In Europe, during the German occupation of Paris, an individual Frenchman carried on a parallel program. Both of these efforts succeeded by about the end of the war and lead to patents by both parties. The French work was supported by the Swiss electrical insulation industry, particularly by the Swiss Insulation Works, now part of Von Roll.

In 1947, de Senerclans, representing the Swiss Insulation Works, visited the United States to promote the use of the French-developed mica paper. During his meetings with GE, it was realized that there were some overlaps in the two patents and, to overcome these potential conflicts, a cross-licensing arrangement was later worked out between the two parties.

Mica paper is currently made by several processes and with several sources of raw materials. One approach to prepare natural mica for papermaking, with minimum labor, is to first roast the mica splittings or other micaeous material to partially drive off the natural water of crystallization in the mica. This is carried out in a rotary furnace, a process called *calcining*, followed by quenching in an aqueous medium. After quenching, the mica is wet ground into small platelets before adding it to a liquid suspension or slurry. This slurry is admitted to the head box of a modified Fourdriner papermaking machine, where it is metered out to a porous endless belt. The combination of gravity and vacuum removes most of the water and allows the small mica platelets to bind together into a single structure, without the addition of any adhesive. At this point, the mica is weakly held together by intermolecular Van der Waals forces. The mica paper, still in pulp form, is then transferred to a steam-heated drying drum where the rest of the moisture is removed to produce a continuous dry sheet. Rolls of this pure mica product are then sent to a treater for the application of resins, backing, and facing materials and solvent drying or curing as may be required. These additions enhance the strength and provide mechanical protection of the product for subsequent slitting into tapes for insulating machine windings. Many different combinations of resins, binders, and surfacing materials are used, depending on the ultimate use of the mica paper composite.

An alternate method of preparing small flakelets from natural mica by mechanical delamination was developed after the war. Several different ways of accomplishing this delamination have been developed. One example is described as the water jet process, in which ground flakes are admitted to a water-filled cylindrical tank that has a number of high pressure water jets arranged tangentially on the inner surface of the tank. These jets cause the water in the tank to spin, which, in turn, causes the larger and heavier mica clumps to migrate toward the tank wall and orient them parallel to it. In this position, the water jets impinge edge-on to the mica clumps and begin to delaminate them. Water bearing the finer, most delaminated, and lightest platelets is withdrawn from near the bottom center of the tank. Grains of heavier minerals, found in the raw mica, can be collected for removal from the bottom or can be removed later from the mica slurry by settling. These mechanically delaminated and cleaned platelets are then admitted to the Fourdriner machine to form the mica paper.

Calcined mica paper tends to have smaller platelets than mechanically delaminated mica paper. Both forms of mica paper make good blotters for impregnating resins, as up to 50% of the volume of untreated mica paper consists of small voids. Experience has shown that the mechanically delaminated papers are somewhat easier to impregnate during VPI, although both forms are used interchangeably in this process. It is possible to mix the two forms to make a paper for special applications, although it is not often done.

Mica papers have a consistent uniform thickness, resulting in about a 300% improvement in thickness tolerance compared to flake mica. This means that less total material and less thickness are required to achieve the same insulating value. In preparing laminates of impregnated mica papers, without backer layers, the uniform controlled compressibility and mica thickness result in uniformity in the distribution of binder resin throughout the sheet. Pressed and cured sheets or plates for commutator segment insulation are ideally suited for automatic assembly and punching processes, as the plates do not flake, scale, or delaminate and have a smooth surface.

Mica splittings can be fully impregnated with less binder resin, but this advantage is lost when flake tapes with a greater thickness have to be used to minimize the possibility that thin spots or areas with missing mica pieces do not compromise the insulating value. In resin-rich tape insulation, the use of alternate layers of mica paper tape and mica splittings tape has some advantages. The paper tape layers serve as a reservoir for uncured binder resin, whereas the flake layers minimize the wrinkling that is experienced with all mica paper constructions during compaction and cure, when some of the excess resin is squeezed out. Fully saturated, resin-rich mica paper tapes have been made with one-third less binder resin. This can be achieved by absorbing some of the excess resin from the impregnating step in a sacrifice blotter paper when both materials are passed through warm squeeze rolls. The resulting tape is thinner and, with a fixed insulation thickness, a higher percentage of mica can be obtained in the groundwall insulation. This method gives electrically stronger insulation with a better heat transfer capability.

After 60 years of experience with mica paper tapes and laminates, the use of mica splittings has greatly diminished. What started out as an effort to overcome World War II shortages of mica splittings has now become the engineering and economic material of choice. At first, the preferred starting material for mica paper production was mica scrap generated as a by-product of punching book mica insulation pieces for the electronics industry. This source is now insufficient, owing to changes of materials in the electronics industry as it moved from vacuum tubes to solid-state technology. Now the most common starting material for mica paper is a lower grade of mica, such as mine scrap, which is less expensive. Papers have been made with vermiculites that are derived from large deposits of a number of micaeous minerals that are hydrated silicates and that have been greatly expanded at high temperatures by driving off some of their bound water.

3.5.3 Mica Backing Materials

Mica is applied as a tape (typically 2–3 cm wide) by pulling on the tape to tighten it as it is wrapped by hand or by machine helically around the copper conductors (Section 3.12). Mica splittings and mica paper have insufficient tensile strength to survive this taping operation. Thus, the mica intended for groundwall insulation has to be bonded to a backing material to provide tensile strength. For mica splittings, the backing material was often woven cotton or even tissue paper. The mica splittings were bonded to the cotton tape by a varnish. When mica paper was developed in the 1950s, the backing material was most often either woven Dacron™ and fiberglass, or a mat of Dacron and/or glass. The mica paper was bonded to the backing material by a small amount of epoxy or polyester binder. These materials provided the tensile strength, and would bond well to the impregnating polyester or epoxy resins. Dacron and glass or glass-backed mica paper is still widely used today, especially in large, generator stator windings rated above 14 kV.

In the 1970s, material suppliers and motor manufacturers started investigating other materials that could be used as backing materials, especially in GVPI applications. The desire was for a backing material with a more uniform thickness. This would allow a closer tolerance on the thickness of the mica paper tape, and thus reduced uncertainty on the overall thickness of the groundwall insulation. The result is that the extra tape layers needed to allow for thin points in the tape can be eliminated, resulting in a thinner groundwall overall, all other factors remaining the same. The backing material that is most widely used now is a PET film [7,8]. A DuPont trade name for the backing film is Mylar™. There has been resistance to the use of such backing materials in North America, because early experiences seemed to show that impregnating resins such as polyester and epoxy did not bond well to film-backed mica paper, resulting in voids, and in some cases premature motor failures [9]. Material suppliers have claimed that with surface treatments, problems with poor adhesion are much less likely [7], and some experiments by motor manufacturers support this [8]. In addition, it seems that the impregnating resin tends to enter the groundwall via the endwindings, and then migrates along the coils into the slot region. Thus, coils with long slot sections may be more difficult to impregnate than coils with short slots. This is in contrast to mica paper tapes that have a backing material made from woven materials, where the impregnating materials can penetrate radially though the groundwall tapes. Film-backed mica paper tapes are widely used today throughout the world for GVPI stators in low and medium voltage motors.

3.6 GLASS FIBERS

The creation and production of glass fibers dates from at least 1922. However, their application to rotating machine insulation is more recent. By 1944, the fibers were being used to reinforce polyester resins, which were commercially introduced in 1942, initially as laminates for military uses, such as small boats and pontoons. Following the war, the uses rapidly grew, including the first melamine glass cloth high pressure laminates for arc-resistant electrical applications. By the end of the decade, glass fiber filaments were being used as magnet wire servings (coatings), as individual filament reinforcements for cellulose backing papers in mica tapes, as woven cloth for mica tape backings, and in a variety of resin laminates for electrical insulation. By the first half of the 1950s, glass fiber papers appeared and began to be used as components of insulation. Many resins were used with both woven glass cloths and nonwoven mats in both flat sheets and molded shapes for electrical applications. Glass fiber rovings and polyester resins were used to make very strong support rings for generator endwindings by 1954. The combination of 50% volume fraction each of glass filaments and filaments of PET was introduced as magnet wire servings by 1955. When the served wire is passed through hot ovens, the PET is melted and then coats the glass fibers, fusing them to the wire. The servings may be applied in one or several layers, depending on the desired toughness and insulating qualities needed for the strand insulation. This strand insulation is known by the DuPont trade name of Daglas or by the generic name of polyglass.

Most of the glass fibers used for electrical insulation are made from a lime-alumina borosilicate glass that is relatively soda-free. This glass formulation was developed for electrical applications where good chemical stability and moisture resistance were desired. It is generally called "E" glass because it was initially developed for electrical uses. The raw material for glass is sand and is, of course, widely available. The fibers are drawn from the melt and the special conditions that exist as the fibers are formed modify their properties as compared to bulk glass of the same formulation. The fibers are not brittle and are very strong in tensile strength as compared to bulk glass.

As an inorganic material, glass has a very high electrical breakdown strength and is resistant to attack from partial discharges and electrical tracking. When glass fibers are used to mechanically strengthen electrical insulation, these good electrical properties are not utilized. Glass fibers are round and are generally surrounded by organic polymers, which are subject to damage from partial discharges and tracking. Examination of glass composite insulation after a period of exposure to partial discharges reveals erosion of the polymer materials but no damage to the glass. The electrical breakdown strength and tracking resistance of the composite insulation are only dependent on the polymer. When glass fibers are used to reinforce mica tapes for coil insulation, the mica, with its continuous, overlapping sheet form, provides the most resistance to partial discharges and significantly improves the breakdown strength.

There have been a number of attempts to use E glass in the form of thin flakes as a substitute for mica splittings in high voltage insulation. While some success has been achieved, the glass flakes are more brittle than mica splittings and have proven to be difficult to handle. As noted earlier, most mica splitting applications have been replaced with relatively low cost mica paper and have minimized the need for alternative inorganic materials.

Some work has been done with thin glass ribbons, having a width to thickness ratio similar to the mica splittings, as groundwall insulation. Using special equipment, a number of glass ribbons can be laid up in a brick wall pattern to make a tape. When impregnated with resin and prepared with a supporting and backing layer, such a tape can be applied as coil insulation. However, this construction is more expensive to make and does not provide superior benefits.

Although the chemical inertness of glass is well established, the large ratio of surface area to volume of glass fiber filaments subjects them to the possibility of chemical attack. Freshly formed glass fiber surfaces have a great affinity for water and can abrade each other during gathering, weaving, and other handling operations. To minimize damage, newly formed fibers are usually coated with a lubricating sizing that may be removed after the strands have been fabricated from the individual filaments. A surface treatment known as a *finish* is then applied. A number of sizes and finishes are available and the choice of finish depends on the type of resin or polymer the fiberglass is used with. Finishes have been designed to chemically bond with both the glass fiber surface and many of the resins commonly used. The application of the finish partially replaces the water, which quickly forms from atmospheric humidity on the glass surface.

3.7 LAMINATES

Thermosetting polymers are widely used for the production of laminated electrical insulating materials that are commonly used as wedges, blocking material, filler strips, and slot liners in rotor and stator windings. Laminates are generally prepared by first impregnating paper, nonwoven mats, or fabric from rolls with a solution of a thermosetting resin. The solvent is driven off by continuously passing the treated material through a hot oven with good ventilation. The dried material, usually referred to as in the “B stage” condition and called a *prepreg*, is rerolled and stored until needed. Pieces of the prepreg are laid up in a mold or in a multiple platen flat-plate press. In the process of pressing at increased temperature and pressure, the resin becomes infusible and the fibrous materials are bound into a monolithic system. The IEC and the U.S. National Electrical Manufacturers Association (NEMA) have established many grades of these laminates according to the reinforcements and resins used in their construction and their thermal, electrical, and mechanical properties.

With the use of solventless resins, prepregs do not have to be dried before laminating. The reinforcing layers may even be laid up in the unimpregnated form in a closed mold, followed by injecting liquid resin under pressure, with or without vacuum assist, and cured in place. Complex shapes can thus be molded for use as machine guards, coupling covers, motor and generator end bells, and insulators.

Continuously laminated sheets are made by passing fabric or mat webs through a polyester or epoxy resin dip and combining the layers with surface layers of a suitable release film while passing through pressure rolls. The continuous layup is passed through a heating zone to cure the resin. The laminate thickness and resin content are controlled by the pressure rolls as the several plies are brought together. The release films act as a carrier, keeping out air during cure of the resin and imparting a smooth finish to the continuous laminate. A traveling clamping system can be used to seal the film edges to prevent air from entering the laminate after the combining process. This device is called a *tenter frame*. Laminating speeds as high as 75 cm/min are obtained. The cured stock is edge trimmed by rotary shears and, if flexible, is taken up on windup rolls for shipment to customers. Rigid stock, because of greater thickness and resin choice, is cut off in sheets by metal shearing equipment.

Continuously laminated stock was first developed for liners in self-sealing fuel tanks, aircraft interior liners, transparent tracing cloth, and photo template stock. Sheets from this process have been converted into rotor turn insulation and coil slot filler strips. Another continuously laminated insulation sheet process was described in Section 3.3 for the adhesive bonding of layers of film and woven or nonwoven fabrics for motor phase and slot insulation.

3.8 EVOLUTION OF WIRE AND STRAND INSULATIONS

Motor and generator windings rated less than 1000 V are usually random wound with round wire, whereas larger and medium to high voltage stator windings use rectangular wire or strands and are form wound (Section 1.3). The copper conductor, with associated preapplied insulation, is called *magnet wire* (or winding wire outside of North America). The wire insulation in random-wound machines must be able to withstand the voltage difference between the beginning and the end of each coil, as the random winding process may bring these ends together in the same coil. The natural resins and varnishes first used as magnet wire insulation were not very good. Instead, the natural resins were used to impregnate round and rectangular wire that was first covered (served) using materials such as cotton, silk, and flax for the serving fibers. In comparison with today’s enameled magnet wire, the served and varnished magnet wire insulation was thicker, stiffer, harder to wind, and had much lower thermal capability. The gradual introduction of synthetic resins and varnishes during the late 1920s through the 1940s led to the all-enamel film-based magnet wire in common use today.

These synthetic enamels are applied out of solution by means of multiple dips, with solvent drying and some curing after each dip, in special ovens. The wire enameling horizontal or vertical tower ovens are strung with the wire so that the multiple passes through the wire enamel dries and drying/curing zones can take place continuously. The wire ovens are used for both round and rectangular wires, and for both enameling and applying varnish or adhesives to served wire. The enamels now available can be used for machines rated up to Class 220°C.

Serving materials have also changed. Although asbestos servings were often used in the past for high temperature coils, the carcinogenic property of the material has led to its elimination from all insulation uses. It has been replaced with glass servings and, as discussed in Section 3.6, with the combination of glass and polyester strand servings. The PET polyester strands are fused to the wire and the glass during passage through the wire oven.

In many medium-size motors and generators, form-wound coils are divided into a number of turns, which must be well insulated from each other. In multi-turn coils, the strand insulation may also be the turn insulation, a demand that in the past was usually met by separately wrapping mica-based tape on each turn (Section 1.4.2). This turn-taping step can sometimes be avoided by upgrading the strand insulation through machine taping individual strands with a thin mica paper tape, supported with a PET or imide polymer film. Today, the polymer film may also contain inorganic additives such as alumina that protect it from partial discharges or be made of a special material with natural resistance to these discharges (Section 8.10).

3.9 MANUFACTURE OF RANDOM-WOUND STATOR COILS

Until about the 1960s, most random-wound coils were formed, either by hand or by hand-guided wire, using a winding machine supporting a coil winding form. After removal from the form, coils were usually directly inserted into the stator or rotor slots by hand, usually with the assistance of a padded mallet or hammer. For the very large numbers of random-wound machines now manufactured, typically small motors, high speed winding machines have been developed that directly wind the enameled wire from spools into the correct position in the stator or rotor slot.

Random-wound coils are usually inserted into slots that already contain the ground insulation (Figure 1.19). The ground insulation may be made from folded and cut sheet materials, often a laminate of a nonwoven polymeric fiber and a polymer film. These slot cell insulation pieces are inserted into all of the slots before winding is begun. Similar materials are used as phase insulation in the end regions and as a separator between the top and bottom coils in the slots of two-layer windings. The latter insulation is usually laid into position as the coil insertion progresses.

As discussed in Section 4.4.3, most random-wound stators are dipped in a varnish to bond the magnet wire turns together and aid in heat transfer—this process is sometimes referred to as a *dip* and *bake*. A better impregnation method is trickle impregnation, where the resin is slowly dripped over the rotating stator winding and core while the stator winding is heated by passing an AC current through it, and sometimes exposed to ultraviolet light to cure the resin. The best (but also most expensive) impregnating process is called global vacuum pressure impregnation (GVPI), in which the winding is impregnated with polyester or epoxy to seal the winding against moisture (Section 3.10.4). In such stators, the endwindings and connections are taped and felt seals are inserted on the connections before impregnation to retain the epoxy or polyester resin during processing. Sometimes, felt "dams" are also inserted at the slot ends to retain the resin.

Random-wound coils may be made from wire that is over coated with an adhesive. A baking step after winding will cause the wires to fuse to each other, replacing the varnish treatment usually used. Some consider the use of the adhesive a disadvantage as, with thermal aging, the bonding material may shrink or disappear, allowing the strands to become loose and, ultimately, abrade the insulation.

3.10 MANUFACTURE OF FORM-WOUND COILS AND BARS

3.10.1 Early Systems

In the discussion of natural insulating materials in Section 3.1, the use of varnished cambric was mentioned. This material is a fully processed insulation in that no further impregnation or cure is needed when used for form-wound coil and bar insulation. It can be applied as half-lapped tapes or as a combination of tape and sheet. Slot pressing may be done to squeeze out the air between layers of the material and, if heat is added, to achieve weak bonding in the material as the varnish softens and becomes tacky. When applied as a sheet for high voltage coil insulation, the varnished cambric was often first laid out in sufficient quantity to complete the entire straight section of each coil side. The sheet was cut to a trapezoidal shape, with the shortest edge about equal to the slot length, and then wrapped on the straight section with the longest edge next to the copper strands. Successive wraps thus each covered a little less of the straight section, resulting in a tapering of the buildup of insulation. When the coil insulation was completed, by wrapping half-lapped layers of slit tape around the end sections of each coil, a scarf joint, with good electrical creepage strength, was achieved. The trapezoidal sheet could be applied by hand for small coils. For large coils, it was advantageous to divide the coil into two sections and to insulate the unformed half coil with the help of a machine to rotate the bar and apply tension to the sheet during wrapping. This method, developed in Europe, was named the Haefley process.

3.10.2 Asphaltic Mica Systems

The introduction of asphalt and mica splittings materials for ground insulation was also discussed in Section 3.1. Although the Haefley process was used to some extent for a version of the asphalt mica splitting groundwall (also called *bitumen micafolium*) in Europe, most generator manufacturers applied the new materials by hand, as tapes, and processed the resulting coil through a vacuum and pressure impregnation process. The switch to a Roebel bar construction did not occur until generator sizes grew to the point where coils were too big to handle during winding into the stator (Section 1.3.3). Another factor favoring the bar winding method is the greatly reduced distortion required to assemble the bars into the stator. When winding full coils, insulated with asphaltic binders and mica flakes, preheating coils by circulating high current in the coil or by ovens, softens the thermoplastic insulation and allows some relative movement within the insulation to accommodate coil distortion during winding.

3.10.3 Individual Coil and Bar Thermoset Systems

The post-World War II developments of thermoset ground insulation, to prevent tape separation or girth cracks as discussed in Sections 3.4.1 and 3.4.2, produced rigid insulation and thus rigid fully manufactured bars or coils. Such rigid bars and coils allow limited opportunity for heat forming of coils during winding into the stator core. Although full coil noses or involutes could be left uninsulated during winding to provide some flexibility, there was little advantage over the use of bar windings for fully processed ground insulation.

The first generations of thermoset insulation used synthetic resins that would soften at moderately high temperatures, yet would not melt as some of the asphaltic resins could. The softening temperature of thermoset resins is called the *glass transition temperature* (T_G). It is the temperature at which the resin changes from a rigid, crystalline state to a more rubbery amorphous state. The insulation engineer prefers using resins that have a glass transition temperature above the insulation service temperature. As customer demands grew for insulation systems rated for Class 130°C service to systems rated for Class 155°C service or higher, a selection of resins having higher glass transition temperatures was needed. Such insulation systems are inherently stronger and less flexible at room temperature and do not lend themselves to full coil winding. In the last paragraph of Section 3.4.2, the derivation of the VPI process and the resin-rich process were discussed. Both processes may be used to make fully cured coils or bars for winding into stators.

Although bar-wound machines impose less stress on insulation systems than required on fully insulated coil-wound machines, there is still some bar distortion required to properly nest each half coil with those previously inserted. The ends of each bar are formed in fixtures before the insulation is applied and processed. Often, some slight deviation from the ideal form or shape occurs owing to the factors such as variations in the copper hardness, normal shop handling, and storage while awaiting the winding operation. Within limits that vary according to the characteristics of each insulation system, expert winders can usually do some reforming of fully cured bars. Heating of the bar by circulating current or more local heating, by means of heating tapes and hot air blowers, may be enough to raise the insulation temperature to the glass transition temperature of the insulation composite, allowing some reforming to be accomplished without cracking or delaminating the insulation.

The bar-to-bar copper strand connections required to complete a coil and the insulation of these joints is a slow, labor-intensive operation carried out by highly skilled winders. They also have to make the coil-to-coil and phase connections and the special arrangements for direct water- or gas-cooled bars. The largest conventionally cooled generators and generators with direct-cooled windings are all bar wound with fully processed insulation systems. One advantage of this winding method is that each bar can be given a high potential voltage test as soon as it is placed in its proper position and lashed in place. These windings can also be voltage tested as individual full coils when the bar-to-bar connections are completed and as a full phase group of coils before proceeding with the next phase group. A schedule of voltage levels is used, with the highest level reserved for individual bars before winding, and successively lower test voltages for each additional test, ending with the twice-rated voltage plus 1 kV as the final acceptance value (Section 19.2.3).

3.10.4 Global VPI Systems

The high cost of making form-wound stators with coils or bars that are fully impregnated and cured before insertion in the slots led to the development of techniques in the 1960s for making coils and bars with insulating tapes that are not fully saturated with resin and are not cured before insertion in the stator slots. These soft coils (also called *green coils*) are less expensive to make, are more easily fitted into the stator core, and all of the connections can be made before final impregnation of the windings. This technique is called the global vacuum pressure impregnation (GVPI) or post-VPI method.

In this method, a stator core that has been wound with the green coils is first placed in a large tank where it can be vacuum dried with some heat if necessary. Following the vacuum cycle, the wound stator is entirely flooded with a low viscosity solventless resin that is then pressurized with a nonreactive gas to drive the resin throughout the ground insulation and the coil-to-coil and phase-connection insulations. After the unabsorbed impregnating resin is pushed back to storage, the wet stator can be removed from the tank for drainage of excess resin and placed in an oven to cure the resin. Alternatively, after resin removal and draining of the excess resin, the stator may be baked to cure the impregnated winding within the same VPI tank. This practice reduces the handling operations for the stator and lowers costs.

The tapes for VPI are usually mica paper tapes reinforced with thin glass cloth on one side and sometimes with a nonwoven material on the other side. Alternatively, the mica paper tape may be film backed (Section 3.5.3). They are made with 10–25% of the binder resin needed to fully saturate the insulation, which is sufficient to bond the layers of the tape together for tape application. The binder resin is normally of the same resin family as the final impregnating resin. In some cases, the tape binder resin is used without a curing agent, relying on the subsequent impregnation to supply the reactive material to complete the cure. The product can be used with different impregnating resins, resulting in little or no reactive change or cure in the tape binder resin during later processing. This can be tolerated because the binder resin is such a small percentage of the total impregnate. Another technique is to mix one component of a two-part curing system in the tape resin and the other part in the tank impregnating resin. The porosity of the tape layers allows the impregnating resin to flow through the entire structure, assuring that the proper amounts of curing agent is dispersed throughout the groundwall insulation build.

The resin used for the GVPI process can be either low viscosity epoxy or polyester. In general, polyester is cheaper and requires less stringent manufacturing and environmental controls than does epoxy. Today, most manufacturers usually prefer epoxy for higher voltage stators because of its superior strength and chemical resistance.

Virtually all form-wound motor stators made today employ the GVPI process, using either polyester or epoxy impregnating resins. As discussed in Section 4.3, since the early 1990s, several manufacturers have GVPI tanks large enough to impregnate stators in excess of 300 MVA.

3.11 WIRE TRANSPOSITION INSULATION

Stator bars need to have the individual strands that make up the bar transposed so that each strand will have the same current or voltage induced in it by the magnetic fields from the other bar in the slot, as well as the rotating magnetic field produced by the driven rotor (Section 1.4.10). The most common kind of transposition is the Roebel transposition. The Roebel transposition is made by making each strand follow an elongated spiral through the bar (Figure 1.18b). A strand that starts at the bottom is raised as the next strand is inserted under it and so on with the rest of the strands. When the first strand reaches the top of the bar, it is double bent edgewise so that it crosses over the narrow side of the bar and is in position to follow the spiral down the other side until the bottom of the bar is reached. Most generators are designed with a 360° transition so that each strand makes one full spiral through the slot portion of the bar. Some larger generators are designed with additional transpositions, such as a 540° transition. The additional bending needed for the extra transpositions is usually carried out in the first and last parts of the bar slot section or in the endwinding, to adjust for the varying magnetic field exposure in the end regions of the assembled coils.

Roebel transpositions were first carried out by hand. All of the loose strands for one bar were first laid out on a table. Attached to the table were step-like guide forms that allow each strand to be twice bent in the proper locations by a hand-operated device. After all of the strands were formed, they were laced together in the proper order to create the transposed bar. The entire operation was called bend and lace. Repair and rewind shops still use this technique to make small quantities of new or replacement bars. Original equipment manufacturers have now largely automated the Roebel operation with special robots designed for the purpose.

The copper strands of the bar are insulated from each other by the strand insulation. The Roebel transposition bending and lacing may damage the strand insulation, particularly where the strands cross over from one side of the bar to the other side. To assure insulation integrity, a thin piece or chip of insulation is inserted at each crossover point on the top and bottom of the bar. These pieces may be made of varnished mica splittings, nonwoven pieces such as aramid paper, or specially molded pieces of a composite. At this point in the bar assembly, the strand package is not bonded together. Bonding is achieved by placing a vertical separator (an adhesive material) between the rows of strands for subsequent consolidation in a hot bar press. The final insulation addition to the bare bar is a material that evens out the spaces between the transposition bends. The material may be a series of specially molded pieces placed between the bends or, in more recent practice, strips of molding material laid out on both the top and the bottom narrow sides of the bar. Usually, the loose bar, with all of the component pieces, is wrapped with a plastic film release tape such as PET film with a silicone coating to prevent it from sticking to the bar during pressing (consolidation). The consolidation process compacts the entire assembly by hot pressing, bonding all strands and insulation pieces into a solid mass over the central straight section of the bar. At this point, the end sections of the bar are unbonded and usually held together with an inexpensive tape. After consolidation, the integrity of the strand insulation can be checked with a voltage test between all strands (Section 19.2.5). Any failures are located and repaired before the bar proceeds to the next forming operation.

3.12 METHODS OF TAPING STATOR GROUNDWALL INSULATION

For most stator windings rated >1000 V, the groundwall is composed of 2–3-cm-wide tapes that have been helically applied to the copper conductors, and impregnated with either a thermoplastic or a thermosetting resin. When tapes were first introduced and for many decades thereafter, they were applied by hand by skilled tradespersons.

The advent of modern glass fabric-backed mica paper-based tapes and binder resins made the development of the taping machine possible. Probably the biggest advancements in rotating machine manufacture in the past 25 years have been in the taping operation [10]. The earliest taping machines were designed to tape only the straight or slot portions of bars and coils. The tape tension, along with the rotational and traverse speeds to obtain a half lap or a butt lap, could be preset. For many years, stator bars served as test beds for the development of the rotating taping head components, as well as a production tool to lower the cost and improve the quality of the slot section ground-wall insulation. These early machines would be served by one to three operators, depending on the production rate and slot length. The machine operator could also hand tape the coil/bar endwindings or leave that to separate hand tapers who would then also make the staggered lap joints (also called a *scarf joint*) between the hand- and machine-taped sections. Although some small shops and development facilities still use versions of these straight-bar taping machines, most manufacturers have evolved to much more complicated machines that will tape the entire bar or coil, except the bar-to-bar connection area and coil-side-to-coil-side or knuckle areas.

Tape tension control started out with an adjustable friction brake on the tape supply roll. For resin-rich tapes, from which resin may squeeze out of the supply rolls as they grow in initial diameter, the tension variation between the beginning and the end of the roll became unacceptable. This led to the use of only a small braking action on the supply roll, with most of the tension being supplied by a fixed-diameter braked roll over which the tape would pass. For dry tapes used for VPI coils, tension applied from the supply roll often continues to be used. As taping speeds increased, it was found that the combined inertia of all elements of the tape path led to a variation in actual tape tension four times per revolution of the taping head that often caused tape breakage when taping the usual rectangular coil cross section. The addition of a spring-loaded dancer roll, over which the tape passed before going around the main tension roll, substantially reduced the tension variation when using taping head speeds of up to several hundred revolutions per minute. Even higher taping speeds can be achieved by instantaneously sensing the tape tension with a torque transducer and suitable electronic controls to adjust an electromagnetic brake on the tension roll.

The various designs of mechanical friction brakes have given way to permanent magnet and electromagnetic brakes in modern taping machines. Generally, the permanent magnet brakes are used in small sizes to impart a small tension to the tape supply roll. This tension is needed to keep the roll from spinning with its own inertia when tape demand slows or stops. This input tension is also needed to make the dancer roll and main tension roll perform properly.

Early full-bar taping machines used a pantograph mechanism to control the in-and-out motion of the taping head. The up-and-down and tilt motions in these machines were controlled by the operator, as were the coordinated rotational and transverse speeds of the taping head. The pantograph mechanism settings were established by the machine operator from planning instructions derived from the coil/bar design. Correct and fully productive operation of these machines requires a training period and substantial production practice.

The latest generations of taping machines (or robots) are computer controlled, including all six degrees of motion freedom, if desired (Figure 3.1). Generally, for each coil/bar design, the operator manually steers the taping head at slow speed through all of the positions necessary to properly track the coil/bar during machine

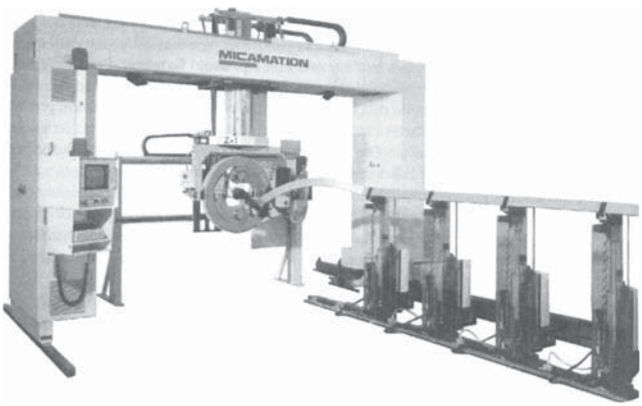

Figure 3.1 A modern six-axis taping machine that applies tape to the slot and end winding portions of the bar (Source: Micamation).

taping. During this mapping process, a measuring device that sends to the computer memory the positional information needed to run the machine automatically is attached to the taping head. This recorded information can be stored on a disk or hard drive for future work on the same design.

Taping heads can be equipped with devices to automatically apply resin, strip out a tape interliner, or soften the tape by preheating just before it reaches the coil/bar surface. The latter device can be used to apply solvent-free, resin-rich tapes, based on improved resins.

The developments in taping technology have been one of the keys to reduce the variation in groundwall insulation quality [10], thus permitting design for higher insulation voltage stresses during service. The insulation improvements show up in less thickness variation and better lap control, with reductions in gaps and extra overlaps within the tape layers.

3.13 INSULATING LINERS, SEPARATORS, AND SLEEVING

3.13.1 Random-Wound Stators

Rotating machines use insulating liners as ground insulation in the slots of random-wound stators, applying materials such as described in Section 3.3. Similar materials, including both nonwovens and thin laminates, are also commonly used as phase separators in the endwindings. Fractional horsepower motors, for light and intermittent duty, may entirely rely on these materials and the magnet wire enamel for strand, turn, and ground insulations.

Low voltage motor connections between coil groups and from the phases to the power supply are usually insulated with extruded plastic sleeving, generally made from polyolefin resins. These materials are a class of crystalline polyallomers prepared from at least two monomers by copolymerization. The resulting polymer chains contain polymerized segments of each of the monomers used. An example of polyolefin widely used for extruded sleeving is thermoplastic propylene ethylene copolymer.

Stators rated up to 1000 V may use varnished sleeving. These are made from woven sleeving of glass or synthetic fibers that are passed through a bath of solvated resin varnish or a solventless liquid resin formulation before heating to remove the solvent and cure the resin. Sometimes, a combination of varnished or extruded sleeving is used directly on the leads and then covered with an unimpregnated woven sleeving designed to be filled with VPI resin or other varnish dip in a subsequent step.

Another technique frequently used with GVPI stators is to place dry felts of polyester fibers in the end windings between coils and between phases, where the felt will be impregnated during VPI and become part of the physical support of the winding as well as part of the insulation system. These felts are also used to help seal connections from moisture ingress. The felt seals are installed between each coil lead and the coil knuckle and around connections. Felts act as a sponge to absorb the resin.

3.13.2 Rotors

The slot and endwinding insulations of large-generator rotors present other problems. Generator rotors have comparatively low DC voltage between the heavy copper strap coils and the rotor steel. During winding of an edge-wound salient pole, the radially inner turns are subjected to severe flexing and distortion to place them in the proper position. Some of the forces applied to the copper are transferred to the slot cell or slot armor insulation during winding. Therefore, the material for rotor winding coil ground insulation must first be able to withstand considerable winding stresses. Synchronous round rotors operate at 1800 rpm for four-pole 60-Hz designs and 3600 rpm for two-pole 60-Hz designs.

When operating at design speed, the ends of the coils beyond the slots are held in place by the retaining ring. Insulation is applied on top of the endwindings to insulate them from the steel retaining rings. In addition, the top of the slot coil insulation is subjected to high compressive loads between the top turn of copper and the alloy steel or aluminum slot wedges. The insulation must also withstand the operating service temperature without significant thermal degradation. Even the sides of the slot insulation are subjected to centrifugal force that must be withstood during operation. Slot cell insulation is often made from hot-press molded composites, containing reinforcing fibers in woven and nonwoven forms and sometimes plastic films, all impregnated and bonded together with thermoset resins. Experience has shown that the glass transition temperature of the cured resin must be above the maximum service temperature of the winding to prevent migration of the resin toward the top of the slots during operation.

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CHAPTER 4

STATOR WINDING INSULATION SYSTEMS IN CURRENT USE

In Chapter 3, the historical development of insulation materials and systems was discussed with emphasis on the stator winding insulation system of form-wound bars and coils. The development of stator insulation systems, from natural materials through asphaltic mica splittings composites and onto modern thermosetting polyester and epoxy mica paper insulation, was reviewed. Although no longer manufactured for coils in new stators, there are many machines still in service, and expected to remain in use for several more decades, that are insulated with asphaltic mica splittings as described in Chapter 3.

The influence of older and established manufacturing processes and facilities on the choice of new materials was also described in Chapter 3. Four major manufacturing processes have been and still are widely used to form and consolidate insulation systems for form-wound stators. They are:

1. Vacuum pressure impregnation (VPI) of individual coils and bars
2. VPI of complete stators, global VPI (GVPI)
3. Hydraulic molding of individual coils and bars using resin-rich (B stage) tapes. The term B stage means that the polyester or epoxy are partially cured in the mica paper tapes
4. Press curing of individual coils and bars, also using resin-rich tapes

There are also some combinations of these methods in use. The binder resins (usually epoxy or polyester) can be categorized as high or low solvent-containing and solventless, as well as by their chemical nature.

There are four principal drivers that govern the selection of the insulation systems currently being manufactured. They are:

1. Good service experience with earlier versions of the same basic system
2. Commercial availability of the materials to be used
3. Relative costs of the raw materials and processes in the competitive machine-sales environment

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

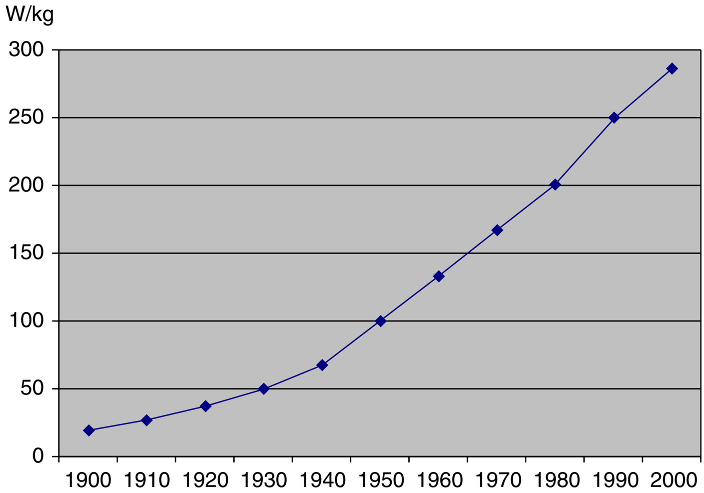

Figure 4.1 Power output per kilogram for rotating machines versus year of manufacture (Source: From Reference [1]).

4. Design advantages or limitations each insulation system and process brings to the final generator or motor for its expected service life and economy of operation.

Figure 4.1 shows a graph created by Glew that shows the increase in machine output per unit mass of the machine [1]. Clearly the mass and size of motors and generators have been decreasing for the same output power over the years. In the middle of the twentieth century, this was driven by rapid advances in polymer materials that could be exploited to obtain improved stator coil insulation systems—and higher temperature operation, in particular. The systems that were developed by extensive laboratory work during this period have become well established worldwide. Since the early 1980s, advances in materials that appear to have significant potential advantages for rotating machine insulation systems have greatly slowed down. Instead, the increase in output per unit mass has been driven by improved manufacturing methods with closer tolerance and optimized stress calculations that permitted smaller "safety factors" in the use of materials.

Present insulation systems generally do not limit the machine designer in thermal rating in the same way as pre-1970s materials did. Increasing the operating temperature beyond the Class 155 (Class F) level for larger machines will have other consequences, as other machine components, such as the bearings and oil seals (in hydrogen-cooled generators), may have difficulty in operating at higher temperatures. In addition, the thermally induced expansion of the rotor, stator core, and frame will be larger if the winding temperatures are hotter, and this expansion becomes harder to accommodate at higher winding temperatures.

The other important parameters of winding design that are now commonly used to increase motor and generator output per unit mass are the electrical stress and the thermal conductivity of the groundwall. Increases in either capability can be used by the designer to increase the rating for the same frame size or mass or to make the same rating in a smaller and less expensive frame size. Thus, electric stress and thermal conductivity are presently the main drivers for the introduction of new materials and processes for stator coil insulation systems (Section 4.3).

A related driver for change is the growth of the gas turbine generator and the steam and gas turbine generator combined-cycle units. Many customers want the simplicity of air-cooled machines and the delivery of plants that can be quickly erected. Satisfaction of these needs has led to power generators in physically large stator frame sizes that have challenged manufacturing and transportation capabilities. While still a very competitive market, the increase in business began to increase the need for insulation system and manufacturing processes improvements.

Another trend that is causing changes in stator motor insulation systems is the expansion of inverter-fed drives (IFDs) to higher voltages and power levels. Motors are now being delivered with ratings up to 15 kV and 65 MW to drive compressors for liquefying natural gas, among other processes. These motors are fed from voltage source PWM inverters that impose much greater impulse voltages on the stator winding. Manufacturers and standards organizations (see Section 2.4.3) are innovating to ensure reliable operation of these motors in spite of the much greater stresses on the insulation.

The big chemical suppliers of polymers and resins moved on from insulation system components to materials for high technology composites for the aerospace industry during the late 1970s, when potential volume and the demand for improved materials at high prices still offered them opportunities for profitable exploitation. From a material supply viewpoint, there is recent desire for "green" insulation systems, that is, systems that produce few if any volatiles during manufacture, as well as materials that can be disposed of with little environmental impact at the end of a machine's life.

Because of these background trends, in recent years, manufacturers have only been making incremental changes in their stator insulation systems, often without describing them as new systems or changing the trade names. Motivations for changes are to reduce material costs, replace a supplier's discontinued or changed product, and, in general, replace solvent-containing resins with very low solvent or solventless resins to minimize air pollution and the costs of abatement, while, at the same time, taking advantage of new technology to assure better electrical performance. Sometimes, a supplier changes raw materials or even the details of the processes used to make what he or she considers to be the same product. These changes can at times produce different resin reactivities that have been known to upset carefully worked out process methods and to introduce variations in the physical and electrical properties of the final insulation.

The success of most major insulation systems presently in service led most rotating machine manufacturers to stop or greatly slow down the development of insulation materials, including major reductions in their laboratory facilities and technical staff [2]. They have come to rely much more on the integrated supplier of insulating materials for the development of new systems. These suppliers can combine the needs of several customers to spread the costs of new materials investigations over a number of machine manufacturers and enhance their own market success in the process.

New insulating materials may require the development of new or significantly modified manufacturing processes to obtain the insulation system improvements inherent in the materials. By 2012, the major insulation material suppliers were offering full insulation systems, including the basic processing know-how, to their customers. For smaller original equipment manufacturers (OEMs) and most repair shops, the insulation supplier's materials, other acceptable materials, and processing specifications are all that is needed to support work. The final insulation system may even use the materials supplier's trade name, for example, Von Roll "Samicatherm." Larger OEMs still work with insulation material suppliers to optimize both the materials and the processes for new or changed insulation systems.

This chapter reviews the state of the art in the manufacturing of random- and form-wound stator coils and presents the known characteristics of the major commercially available form-wound coil and bar insulation systems. Some additional details of stator winding insulation systems are given in Appendix B. A review of some very recent developments is also presented.

4.1 CONSOLIDATION OF MAJOR MANUFACTURERS

One of the interesting trends of the past decade or two has been the merging of many motor and generator manufacturers. As the goal of this chapter is to outline the main characteristics of the stator winding insulation systems for the major manufacturers, these corporate mergers create difficulties in identifying who was the manufacturer. The mergers and acquisitions have often resulted in the same manufacturer having several different insulation systems being made at the same time (albeit from different plants). Therefore, knowing the manufacturer of the machine no longer gives definitive information about the characteristics of the insulation system that was used in the machine. A noncomprehensive list of examples of the mergers includes:

1. Alstom generators today consist of the original Alstom machines made in France, as well as GEC (United Kingdom), Alsthom (the original merger of Alstom and GEC), Asea, and Brown Boveri (which later became ABB). GEC itself was a combination of machines made by English Electric, Metropolitan Vickers, and Thompson
2. Siemens generators today include Kraftwerk Union (KWU), Westinghouse, and Parsons generators
3. Andritz generators today consist of Elin and GE Hydro
4. Voith generators today consist of Westinghouse Hydro and Siemens Hydro
5. Brush now includes HMA (Holec) and Skoda
6. General Electric (GE) motors now consist of Converteam, which in turn was formed from GEC motors (United Kingdom) and Alstom motors (France)
7. ABB now includes Baldor and Reliance electric motors (which for a while was Rockwell Automation)
8. WEG now includes Electric Machinery.

Such mergers and acquisitions are likely to continue. In addition, some major brands routinely use other manufacturers to make certain sizes of machines. For example, GE sometimes brands air-cooled turbine generators from Brush, Andritz, Doosan, and Hitachi as GE. In addition, as alluded to above, an insulation system trade name may stay the same but the actual insulation system it describes over time may change significantly. For example, the Thermalastic trade name from Westinghouse was originally a mica splitting insulation system using polyester resin as a binder. In the 1990s, the same Thermalastic trade name was applied to mica paper construction using epoxy as a binder.

The systems described in the following sections are associated with company names and insulation trade names. However, in view of the above, users should be wary using the information below and in Appendix B!

4.2 DESCRIPTION OF MAJOR TRADEMARKED FORM-WOUND STATOR INSULATION SYSTEMS

There have been many variations over time in the details of the major trademarked insulation systems. As described earlier, minor changes often are not signaled by name changes, whereas major changes may be indicated by the addition of a numeral or letter. The following sections attempt to discuss only the generic details of the various insulation systems, as found in technical papers used to introduce them to the industry and to customers. The exact nature of these systems is generally a trade secret.

The discussion of these trademarked stator insulation systems is limited to the groundwall insulation. It does not include the strand insulation, semiconducting slot section armoring, methods to secure the coils in the slots, measures to allow relative movement between the coils and the stator core, the endwinding grading system, or the endwinding supports. These are all important aspects of the performance of an insulation system and they differ significantly between manufacturers. It is the proper integration of all these components that make a good system.

4.2.1 Westinghouse Electric Co.: Thermalastic™

Chapter 3 discusses a typical 1950s-era Westinghouse “Thermalastic,” the first modern synthetic insulation system. The first Thermalastic insulated generator went into service in 1950, and the insulation system was introduced to industry in an AIEE paper during 1951 [3]. Similar insulation systems, produced under licensing agreements with National Electric Coil (Neccobond™) and KWU (Micalastic™), also contained solventless synthetic polyester resins and mica splittings and were introduced in the 1960s. During this period, minor changes that were made included the introduction of glass cloth as a backing material for the mica, resin modifications to help VPI resin tank stability, and improvements in the partial discharge suppression treatments on generator coil surfaces.

During the 1960s, Westinghouse introduced an all-epoxy Thermalastic insulation for large motors, using the individual-bar/coil impregnation method. The epoxy system was used in this application for 10 years before a hybrid polyester-modified epoxy system went into commercial service on a turbine generator in August 1972. The laboratory work leading up to the use of a hybrid VPI resin was presented to the industry in 1967 [4]. Since 1972, all high voltage rotating machines used different variations of the Thermalastic epoxy system.

Although large turbine generators continued to use the individual-bar impregnation and cure method until Westinghouse was acquired by Siemens, motors and smaller generators shifted to the GVPI method in the early 1970s [5]. The hybrid epoxy VPI resin used for turbine generators was optimized for the previously developed processing equipment and insulation requirements. It is comprised of a modified epoxy resin, prepared in a resin cooker to create polyester linkages, and is compatible with styrene for viscosity control. The final resin cure was achieved by cross-linking through the epoxy or oxirane group. After Siemens acquired Westinghouse in the late 1990s, the Thermalastic system underwent many refinements in materials and processing while maintaining the same resin system.

4.2.2 General Electric: Micapals I and II™, Epoxy Mica Mat™, Micapal HT™, and Hydromat™

The Micapal I™ system is described in Chapter 3. It was introduced to the industry in an IEEE technical paper [6] in 1958, after several years of limited production. Micapal I contained approximately 50% GE Micamat™ (mica paper), made with calcined muscovite, and 50% muscovite splittings. The early solid bisphenol A epoxy resins and the high acid number polyester used with them to cure the system had to be dissolved in a mixed solvent to impregnate the resin-rich mica tapes. The solvents were later removed in a vacuum bake stage during the treatment cycle. This first use of the Micamat was a deliberate attempt to free high voltage insulation from expensive and variable mica splittings, generally imported from India. The system remained in production into the late 1980s for small- and medium-sized steam turbine generators.

Many gas turbine generators made during this period in the same shops had an advanced epoxy system to accommodate the higher operating temperatures found in peaking generator operation [7]. This system was then extended to medium-sized steam turbine generators as service experience with the smaller generators became available. The same needs first led to a closely related all-epoxy mica paper insulation for hydrogenerators, trade named Epoxy MicaMat in 1966 [8]. The gas and steam turbine generator systems have been referred to as Micapal F for its outstanding Class F–H temperature resistance.

Both of these systems use mixtures of epoxy novolacs and the diglycidyl ether of bisphenol A (DGEBA) epoxy, cured with special phenolic resins, and mixed with small amounts of solvents (7–10%) to aid impregnation in making resin-rich tapes containing glass cloth and PET polyester-mat-backed mica paper. The combination cures slowly, allowing time for the vacuum bake solvent removal and the batch cure process of hydraulic molding. The cured resin has a relatively high glass transition temperature and is thermally very stable. The completed tape, slit for machine application, normally has only 2–4% solvent remaining by the time it is ready for application to the stator bars. The individual, fully cured bars are inserted into the stator slots and connected to each other to make complete coils and phases during the winding operation.

After a 12-year development program, GE announced the MICAPAL II™ insulation for large turbine generator stator windings in 1978 [9]. This solventless, resin-rich, second-generation epoxy mica paper insulation system has been used on most GE large steam turbine generators since that time. The all-mica-paper epoxy system, suitable for continuous exposure at 130°C, was developed for the electrical and mechanical conditions found in the largest generators, which are generally made with water-cooled windings that normally operate below 100°C. The special epoxy resin formulation was developed to provide the impact toughness, dimensional stability, and high voltage capability required in the largest machines.

GE has replaced the solvent-containing original Micapal F insulation system with a new solventless epoxy mica paper system, trade named Micapal HT, of similar chemistry, that is used for gas turbine and combined-cycle steam and gas turbine generators. The resin-rich system is made without any solvent and shares the same hydraulic molding production facilities used for Micapal II. The largest output volume in recent years using the new solventless system has been for gas or combined-cycle generators.

GE has used partial-discharge-resistant fillers in epoxy resins or enamels in electric motors for stator strand and turn insulation since 1989 [10]. Adding the patented metal oxide technology to the film backers and resin in the ground insulation to the existing resin-rich epoxy mica mat hydrogenerator system required more than 2 years of engineering and laboratory effort. The program included selected utility users to evaluate individual bars during rigorous testing in their own facilities and installation of 40 bars having a 20% reduced insulation build in a planned generator rewind. This would gain early service experience in an instrumented hydrogenerator stator. With the successful conclusion of this work in 1997, GE began offering the reduced build Hydromat insulation system globally in both the OEM and rewind markets [11,12].

In 1999, GE began to offer a reduced-build strand-and-turn insulation, using similar metal oxide fillers, in the large-motor business [13]. These machines use the GVPI epoxy process to make the glass-fabric-supported Micamat insulation systems for machines at least up to 13.8 kV ratings. Several generations of VPI resins have been used by GE for motor manufacture. Two of these epoxy resin systems have been based on controlled reactivity chemistry. The most recent improvement [14] creates polyether linkages in cured diglycidyl ether bisphenol A epoxy resin and provides high reactivity at curing temperatures with excellent shelf life at room temperature. Since about 2010, GE has moved to using a film-backed mica paper tape in its GVPI motor stators [15].

4.2.3 Alsthom, GEC Alsthom, and Alstom Power: Isotenax™, Resitherm™, Resiflex™, Resivac™, and Duritenax™

During the 1950s, Alsthom licensed the resin technology used in the GE Micapal 1 system to create the first Isotenax™ system. There were several differences in materials and processes between the two systems. Isotenax used only mica paper, not mica splittings. The resin-rich impregnating epoxy contained significant amounts of a solvent mixture that had to be removed after the glass-backed mica paper tape was wrapped around the stator bars. This was accomplished by a controlled vacuum bake that did not cure the resin. Next, the very loose or puffy bars were consolidated in the slot section by a warm-coil sizing and pressing operation that advanced the cure, but did not complete it. Finally, the bars were covered with release and sealing sacrifice tape layers and returned to the hydraulic molding tank. A short vacuum bake stage next removed the air in the insulation and helped in the transfer of molten asphalt into the tank, which was then pressurized with inert gas to compress and complete the resin cure. Isotenax was thus one of the earliest all-mica-paper high voltage hydro- and turbogenerator insulation systems and continued in use until at least the late 1970s.

In 1978, Alsthom Electromecanique SA introduced Isotenax N™ [16], made with low solvent, resin-rich, glass-supported epoxy mica paper. The binding and impregnating resins are epoxy novolacs, selected from various epoxide resins with both short and long molecular chains to give the best mechanical and electrical properties in the finished insulation. Additional solvent is added to the mixed resins to facilitate thorough impregnation of the tape. After partial curing to the B stage, the final tape has a volatile content in the range of 6%, which is still flexible and not sticky. After taping, a batch of bars is processed in similar manner to those made with the original Isotenax. This includes a relatively long vacuum drying followed by final curing under pressurized hot asphalt.

During the 1980s, GEC Alsthom worked with solventless epoxy-resin-rich mica paper tapes that could be processed by either a shortened hydraulic molding process or press curing. The new insulation system is trade named Duritenax™ and is based on selected novolac epoxy resins cured with a Lewis-acid-type hardener. This system has been in production since 1992 [17].

The UK-based operations of GEC, which became GEC Alsthom, and since 2000 part of Alstom Power, used resin-rich epoxy mica paper tapes for Resitherm™, an all-rigid insulation system for solid conductor turbogenerator bars for a number of years. When distortion of bars was necessary to connect hollow conductor bars to coolant hoses, then fully cured slot insulation with permanently flexible endwinding micaeous insulation was used. This is called the Resiflex™ system and has been used for both generators and high voltage motors.

Since the 1980s, the UK operations of Alsthom have also worked with GVPI processing and an insulation system called Resivac™. Recent advances in the VPI system have used bisphenol epoxy resins with a latent Lewis acid catalyst system [18].

4.2.4 Siemens AG, KWU: Micalastic™

As noted earlier, Siemens began using the individual-bar VPI process with polyester resins and mica splittings as early as 1957 for hydro- and steam turbine generators, with initial help from Westinghouse. This system was trade named Micalastic. Production continued with this combination of resins and processes for at least 10 years.

In the mid-1960s, Siemens began investigating epoxy mica paper VPI systems [19], and, in 1965, introduced a VPI process for individual bars and coils. About the same time, they also introduced a similar system for the production of stators up to 80 MVA using the GVPI process. In both cases, Siemens retained the Micalastic trade name. The resins were of the bisphenol epoxy type, cured with an acid anhydride and a catalyst that is often in the mica paper tape. Except for indirect-cooled generators and direct-cooled generators rated at more than 300 MVA or so, which still use the individual-bar epoxy VPI methods, the GVPI process has been standard for all motor and turbogenerator stators since 1986 [20]. For its large GVPI stators, this manufacturer avoids difficulties because of shear stress at the interface of the bar to the stator core (Section 8.2) by employing a slip plane. The slip plane consists of mica splittings sandwiched between two semiconductive tapes.

Fuji Electric and the Indian manufacturer BHEL generally employ stator winding insulation systems using Siemens designs and processes under various licensing arrangements.

4.2.5 Brown Boveri, ASEA, ABB, and Alstom Power: Micadur™, Micadur Compact™, Micapac™, and Micarex™

Brown Boveri AG started changing from resin-rich asphalt mica flake groundwall insulation about 1953, first using modified polyester resins and then switching to epoxy resins to make resin-rich tapes. The ASEA name for bars and coils manufactured from the epoxy-resin-rich system is Micarex™. Initially, these tapes were applied by hand and later by machine taping, followed by hot-press consolidation and curing. New machine production with this system stopped with the end of turbogenerator production in Sweden, although some repair licensees may continue using Micarex for some time. For some applications, such as turn insulation on multiturn windings, the latest epoxy mica paper resin-rich tapes are still in use. The backer layers have evolved over the years to include glass cloth, nonwoven synthetic papers, and plastic films.

The Micadur™ insulation system was introduced in 1955 by Brown Boveri as an individual-bar VPI method. Glass-fiber-backed mica paper tape, now applied to the bars chiefly by machine taping, is dried and then thoroughly impregnated at moderate pressure in a solvent-free modified epoxy resin. Then, the individual bars are pressed in molds and cured in an oven [21,22]. The same process using similar materials still continues for the largest machines. In the early 2000s, Alstom Power introduced a novel form of processing the bars for very large turbine generators called *tube VPI* [23]. The tube VPI process consists of machining a two-part steel mold that precisely accommodates the final shape for two stator bars. The two green bars are placed in the mold and an accelerated VPI process ensues: vacuum, impregnation under pressure, and cure—all in the same mold. Only the resin needed for impregnating the two bars is needed. The claimed benefits are a denser groundwall with more mica, faster processing (about 12 h per two bars), little resin wastage, no release of volatiles to the environment, little risk of contamination of the resin, and reduced energy consumption as only the required resin is needed to be heated. The disadvantage is that a mold must be made for each size of bar (i.e., each rating of generator).

The Micadur Compact™ insulation was introduced in 1965, about the same time that Siemens introduced a similar system. The Compact version uses a GVPI process that was initially for use in high voltage motors [24]. As experience and confidence with the GVPI process were achieved, and some early problems with impregnating elements of the turn insulation were resolved by changes in strand and turn tapes, impregnating tanks for larger and larger machines were employed [25]. In the 1990s and early 2000s, the GVPI process was used for machines rated up to 300 MVA. Since the mid-2000s, Alstom Power has stopped using the GVPI process for large turbine generators favoring instead the tube VPI process for large generators. The Micadur Compact process uses essentially the same groundwall insulating materials as the current individual-bar VPI process. The modified epoxy resins are thought to be of the bisphenol type with an acid anhydride hardener and catalyst.

Before the merger of ASEA with Brown Boveri to form ABB in the mid-1980s, ASEA also developed the technology for individual-bar VPI production, using similar materials [26]. The result was Micapact™, introduced in 1962 for the stator insulation of large rotating machines. It was made with glass-backed mica paper, impregnated with a special mixture of an epoxy resin, curing agent, and additives. Unlike most other VPI tapes, the glass backing and mica paper lack any impregnant or bonding resin. The adhesion between mica paper and glass was accomplished by an extremely thin layer of material, which was melted at a high temperature during the formation of the tape. The tape did not contain any volatile matter, which means that the completed machine taped bar insulation was more easily evacuated and impregnated [27].

4.2.6 Toshiba Corporation: Tosrich™ and Tostight™

The Toshiba Tosrich insulation system for low voltage, small-capacity generators with a relatively small number of insulation layers was based on a resin-rich mica paper tape. The solvent-containing synthetic resin was impregnated into the mica tape, wound onto a coil, and cured in a mold. The residual solvent in the system, when applied to medium-capacity generators having a larger number of mica tape layers, could not be entirely eliminated during press cure in the mold and thus did not show the desired insulation characteristics in these machines. Although used successfully for many years for smaller machines, its replacement with a solventless epoxy, resin-rich mica paper tape during the 1990s allowed the improved Tosrich to be applied to medium-capacity generators [28].

For larger machines, the Tostight™ insulation system was developed. This system used either a conventional, glass-backed, calcined muscovite mica paper tape or a newer mica paper tape made with the addition of a small amount of aramid fibrid. The low-binder tape for the VPI process used an epoxy adhesive to combine the glass cloth backing with the mica paper. A solventless epoxy impregnating resin is used for the VPI process. This system has been used for a number of large-capacity water-cooled turbine generators and medium-capacity hydrogen-cooled and air-cooled generators with a relatively high operating temperature [28]. The use of aramid-fiber-containing mica paper has been deemphasized in recent years.

A new generation of the Tostight™ VPI insulation system was introduced in 1998 [28]. It has been optimized to improve heat resistance and to be environmentally friendly in materials, equipment, production methods, and disposal of waste. The mica paper has been changed to replace the aramid fibrids with short glass fibers. The new impregnating resin is principally a high purity, heat-resistant epoxy resin, employing a complex molecular capsule, latent hardening catalyst that is activated by heat to quickly cure and produce a high heat-resistant, mechanically and electrically strong filling material for the mica. The revised system is manufactured using new production equipment, including a fully automatic taping machine and a new VPI facility and curing oven. The VPI tank is equipped to control vacuum and impregnation as a parameter of the coil capacitance. The new Tostight is intended to be usable for all types of medium and large generators [28].

More recently, Toshiba has introduced a VPI bar manufacturing process that uses a flat glass-backed mica paper to improve thermal conductivity (Section 4.3.1).

4.2.7 Mitsubishi Electric Corporation

The groundwall insulation systems employed by Mitsubishi until the 1990s were largely based on Thermalastic™ licenses obtained from Westinghouse. During the late 1990s, Mitsubishi introduced a new GVPI insulation system for air-cooled generators up to 250 MVA. The new system supplemented an older GVPI system, used for air-cooled generators of up to 50 MVA rating. The new system uses a glass-fabric-backed mica paper tape, bonded with a very small amount of hardener-free epoxy resin as an adhesive. The GVPI resin is an epoxy anhydride [29,30].

4.2.8 Hitachi, Ltd.: Hi-Resin™, Hi-Mold™, and Super Hi-Resin™

At Hitachi, work on synthetic resin impregnated stator insulation started in 1949 and led to the trade name SLS coil, for unsaturated polyester resin vacuum-impregnated coils. They have seen service in large AC generators since 1957. Work continued during the 1950s on the use of epoxy resins for VPI coils, which were introduced into production in 1967 as the Hi-Resin™ coils [31]. Development work continued with epoxy formulations, including combining a number of epoxy resins, such as aromatic, alicyclic, and fatty resins, with various types of hardeners. The objective was to obtain a resin system with low viscosity to permit easy vacuum impregnation and a longer pot life (i.e., a longer time before the liquid resin cures at low temperatures). This culminated with the introduction of the Super Hi-Resin™ coils in the 1970s. The strand insulation for these coils was glass fiber and resin, so that the strand package could be molded together before the groundwall insulation was applied. A new mica paper tape, impregnated with a special mica binder, was used to obtain more flexibility and taping strength. The final surface layer was a woven glass tape. Following vacuum drying, the coils were VPI processed and, after removal from the tank, were heat cured to polymerize the resin.

Hitachi also introduced a pre-impregnated or resin-rich mica paper insulation, called the Hi-Mold^{TM} coil in 1971 [32]. This press-cured system uses an epoxy resin to impregnate glass-cloth-backed mica paper, which is partially cured to the B stage. The high performance resin was selected to obtain superior electric and thermal characteristics for use in machines rated for up to Class F insulation performance. The Hi-Mold system is used for hydro- and gas turbine generators and for heavy duty or other unfavorable environments in synchronous and induction motors.

4.2.9 Dongfang Electric Machinery

Although relatively unknown outside of China, Dongfang has one of the largest hydro- and turbogenerator manufacturing facilities in the world in its plant in south central China, producing over 35 GW of machines each year. Currently, the Dongfang insulation system manufactures two kinds of epoxy-mica insulation systems based on the resin-rich and the VPI processes. The maximum rated voltage using the resin-rich process is 24 kV, and the maximum capacity of electric machinery is up to 778 MVA. The VPI process is used on machines up to 27 kV and 1000 MVA. In 2005, Dongfang developed a single-bar VPI insulation system, which uses an epoxy anhydride. At present, the working electric field strength of the single-bar VPI insulation system can reach 3.2 kV/mm.

4.2.10 Harbin Electric Corporation (HEC)

Like Dongfang, Harbin is also a very large manufacturer of generators, with an annual capacity of about 35 GW. It is located in the north west of China. Currently, it has produced 1000 MVA turbine generators and the largest hydrogenerator in the world—the 777-MVA hydraulic generator at the Three Gorges hydropower station. In the past, HEC had relationships with both GE and Westinghouse. The resin-rich molding process was the normal process used by HEC stator insulation in the early period. Later, HEC moved to a resin-rich hydraulic molding process [33]. Since about 2000, HEC has adopted the VPI process for large hydro- and turbogenerators.

4.2.11 Shanghai Electric Machinery

Shanghai is another very large manufacturer of large turbo- and hydrogenerators based in China. It can make stators using either the resin-rich or the VPI bar manufacturing processes. Currently, Shanghai Electric Machinery makes conventional generators rated up to 600 MVA and 20 kV using the resin-rich process. Since 2000, it has developed a VPI process, in cooperation with Westinghouse (now Siemens). At the end of 2003, it manufactured the first 600-MVA turbine generator adopting VPI insulation technology in China. Since 2006, it started to adopt VPI technology for generators rated up to voltage of 27 kV and 1000 MVA. Currently, generators with the Siemens brand may be made by Shanghai Electric Machinery.

4.2.12 Jinan Power Equipment: Resitherm™, Micadur™, and Micadur Compact™

Jinan Power Equipment in China mainly produces air-cooled turbine generators rated up to 330 MVA. In the early 1980s, it used the resin-rich process with mica paper tapes. In the late 1980s, Jinan licensed the epoxy mica resin-rich insulation system trademarked Resitherm™ from GEC (see Section 4.2.3). In 1989, Jinan Power Equipment then licensed ABB's Micadur Compact™ GVPI technology for generators rated 50–150 MVA (see Section 4.2.5). They also licensed the Micadur™ insulation system to manufacture bars for machines rated more than about 200 MVA.

4.2.13 Summary of Present-Day Insulation Systems

A review of Sections 4.2.1 through 4.2.12 shows that all of the world's larger OEMs are currently using various mixtures and types of epoxy resins and mica paper to make their stator coil groundwall insulation systems for large generators. Motor manufacturers are using either polyester or epoxy for the resin in motors. The compositions are adjusted or tailored to accommodate the exact process used in their manufacture. The impregnation approaches include the resin-rich and VPI processes for large turbine generators and hydrogenerators using epoxy resin. For motors, almost all manufacturers use the GVPI process with either epoxy or polyester resin. Some manufacturers also use the GVPI process for turbine generators up to about 300 MVA. The end results are comparable in terms of inherent insulation quality as related to the machine and insulation design parameters, provided that consistent quality control practices are routinely carried out. This fact is recognized by some large suppliers of rotating machines, who will, in times of extraordinary demand, outsource or purchase generators to their own design from competitors, while allowing the supplier to use their own insulation systems.

4.3 RECENT DEVELOPMENTS FOR FORM-WOUND INSULATION SYSTEMS

In the introduction section of this chapter, the slowdown in polymer insulation materials development was noted. The adoption of solventless, low viscosity, polyester and epoxy VPI resins, the use of very low solvent and solventless epoxy resins for resin-rich tapes for hydraulic or press molding, and the advent and improvements in automated machine taping by the industry have produced economical and excellent bar and coil winding products. These changes have improved the thermal stability of the winding and provided a more dense insulation with far fewer voids. Present stator insulation systems have higher dielectric strength and lower partial discharge levels, when properly made, compared to the systems in general use through the 1980s.

The past decade has seen activity in two areas of insulation materials development: reducing the thermal impedance of the groundwall and increasing the design electric stress by enhancing PD resistance. Both developments have machine up-rating potential and are being actively pursued. The development of practical nanomaterials may have a huge impact increasing both dielectric stress and thermal conductivity, and thus be as revolutionary a development as the introduction of thermoset resins. Finally, environmental concerns with both stator winding manufacture and the disposal of the winding at the end of its life have attracted some attention.

4.3.1 Reducing Groundwall Thermal Impedance

In indirect-cooled stator windings, the heat from the I^2R losses in the copper conductors must penetrate the groundwall insulation to the stator core (which is the heat sink). The higher the thermal impedance of the groundwall is, the higher will be the temperature of the copper (and the adjacent insulation), all other things being equal. Thus, reducing the thermal impedance of the groundwall is a powerful way to reduce the stator winding temperature (or increase the power rating) of the stator. There are three ways to reduce the thermal impedance [23,34]:

1. Reduce the groundwall thickness, increasing the electric stress at the same time, assuming the conventional groundwall materials
2. Use a groundwall with an inherently higher thermal conductivity, while maintaining the same design electric stress
3. Use a thinner groundwall based on what is called a "flat glass" mica paper tape, while increasing mica content.

Reducing groundwall thickness to improve thermal conductivity is discussed in Reference 1 in Chapter 8. Of course, this will increase the electric stress and increase the rate of electric aging, assuming some small voids are present, which will lead to PD (Section 4.3.2).

Two approaches have been investigated to increase the thermal conductivity of the groundwall, without necessarily increasing the electric stress. It is believed that the polymer resin binders in the mica paper have the lowest thermal conductivity in the groundwall insulation system. The addition of high thermally conductive filler particles in the impregnating resin was an early approach to reduce thermal impedance. More recently, Toshiba has introduced a new insulation system in conjunction with Von Roll that uses mica paper tapes containing a boron nitride filler in the binding resin of the glass backing. The resulting increase in thermal conductivity allows Toshiba to increase the MVA of its generators by as much as 15%, for the same slot dimensions and operating temperatures [35].

In contrast, Isovolta has introduced a mica paper tape that uses a flat glass fiber backing material, rather than the more common woven structure used in high voltage stator bars [36]. The resulting backing tape is thinner, allowing for an increased amount of mica for the same overall tape thickness. The claim is that the higher percentage of mica in the tape increases thermal conductivity and PD resistance (i.e., voltage endurance life). Experience with such tapes has been reported by Siemens [37].

4.3.2 Increasing Electric Stress

As shown in Figure 4.1, one of the reasons that the power output per kilogram for motors and generators has increased over the past 100 years has been the reduction in the groundwall insulation thickness, for the same operating voltage. Emery shows that the groundwall insulation thickness has reduced from 15.1 mm in 1911 to only 2.5 mm 100 years later, for the same (unspecified) voltage [37]. Of course, this increases the electric stress across the insulation and increases the risk of deterioration from PD in any voids that result from manufacturing (Section 1.4.4). The reductions in groundwall thickness over the past decade have partly been due to:

- better materials and processing to reduce the size and number of groundwall voids
- more consistent tape thickness, reducing the need to increase the number of layers to allow for thinner tapes in a batch. In addition, better machine taping is available that applies consistent tape tension and consistent overlap of tape layers, reducing the allowance needed for taping variations.
- increasing the percentage of mica within the groundwall, to increase PD resistance
- development of other materials that increase the percentage of PD resistant materials in the groundwall, that is, improve its voltage endurance.

The first two items are dealt with elsewhere in Chapters 3 and 4, and they will be an ongoing effort into the future. One way to increase the amount of mica in the groundwall, other than the use of flat glass as described in Section 4.3.1, is to replace the glass cloth backings in mica paper tapes with thermoplastic films that often are only one quarter of the thickness of the glass cloth used previously—down to about 0.0065 mm. Initially, PET films (polyethylene terephthalate) have been widely used, as there is a long history of successful use of this polymer in rotating machine insulation. Newer polyester films, made with polyethylene naphthalate (PEN), with better thermal stability, became commercially available in the late 1990s and are replacing PET films in some applications. The DuPont product, trade named Kaladex^{TM}, has a glass transition temperature (T_g) that is 42°C higher than PET film. The film has a higher modulus, which gives it a 25% greater stiffness and an average electric strength and also 25% higher than PET film. These properties help make PEN film a better supporting layer for mica paper and it may be further improved by the incorporation of a few percentage of reinforcing fillers in the film. As discussed earlier, the film-backed mica paper tapes yield a higher percentage of mica in the insulation and thus also yields better thermal conductivity in addition to enhanced PD resistance. Films may also be filled with thermally conductive and/or partial-discharge-resistant fillers. Metallic oxides, such as submicron aluminum oxide, have given good results in films and, in combination with epoxy resin and mica paper [38], may lead to improved groundwall insulation. When these fillers are used with enamels, they can be used for partial-discharge-resistant magnet wire and turn insulation [10].

Some North American utilities have restricted the use of films in high voltage generator windings, based on their failure experiences during the 1970s and 1980s. Many of these failures perhaps were caused by poor processing of coils, rather than by the presence of the film alone. Significant improvements in the vacuum and resin filling processes, aided by careful studies of the early failures, and improved instrumentation to measure impregnation may have largely eliminated problems with films.

Another possible approach to increase both the thermal conductivity and the PD resistance is the use of nanomaterials [39]. Potentially this could lead to a revolution as great as the introduction of thermosetting polymers in the 1950s. Nanomaterials are materials (often metal oxides) that have a diameter on the order of tens of nanometers, which are imbedded in a polymer matrix. Ideally these materials would replace mica, and the composite material used in present-day groundwall insulation systems. To date the authors are aware of only one preliminary application of nanomaterials to groundwall wall insulation in form-wound coils. Siemens has developed a VPI epoxy resin filled with treated silicon dioxide nanoparticles that is used to impregnate mica paper tapes. This new VPI resin appears to give much longer life in voltage endurance tests [40]. Practical coils using this new material are expected soon. In general, the use of nanomaterials in high voltage groundwall insulation systems has been difficult to implement, perhaps because obtaining a uniform distribution of the nanoparticles in the correct density has been very difficult to achieve, outside of laboratory investigations.

The highest electrical stress level in the insulation is at the corners of strands and turn packages where they interface with the groundwall insulation. Partial discharges are more likely to occur at these locations as a result of aging or some manufacturing deficiency. Most unfilled films are not resistant to the partial discharges that occur in the minute voids that may be present in new insulation or be produced during thermal aging. During the early 1990s, DuPont introduced a partial-discharge-resistant polyimide film, based on a GE patent [10], trade named Kapton CR$^{\text{TM}}$. When combined with uncalcined mica, the result is improved performance with increased field strength and excellent dielectric and long-term thermal stability [38]. Nanomaterials may also have a practical implementation for such applications.

4.3.3 Environmental Issues

A common theme in Chapter 3 was the desire to reduce the volatile organic compounds during the stator insulation manufacturing process. Not only do such volatiles create voids within the insulation, but also they pose a health hazard to plant employees and are regulated substances in most countries because of adverse environmental impacts. In addition to the concern of byproducts during manufacture [23], some machine manufacturers believe that they will soon see regulations on the environmental impact of the winding that has reached the end of its life [41].

Normally the insulation system is burned off the obsolete windings in an effort to recover the copper conductors. This burning may release organic compounds into the environment. Regulations may impose costs on the manufacturer if some of the released materials are carcinogenic or bad for air quality. As what is released depends on the original materials, this may lead to research on less harmful materials and manufacturing methods that result in less harm at the end of the winding life.

4.4 RANDOM-WOUND STATOR INSULATION SYSTEMS

The insulation systems in current use by most random-wound motor stator suppliers are usually not differentiated by trade names. Instead, most manufacturers use similar materials, although of course manufacturing processes may be different in detail. The following describes the main features of current random-wound stators.

4.4.1 Magnet Wire Insulation

Magnet wire, that is, copper or aluminum conductors with insulating enamels or films bonded to the conductors, is formed into coils, usually by coiling machines. The insulation materials used over the years are discussed in Section 3.8. The most common magnet wire for random-wound stators in use today is a round copper wire insulated with a polyamide–imide insulation (Class 220°C) or polyester with a polyamide–imide overcoat. The insulation thickness is usually from 0.05 mm to about 0.1 mm. The most common standard covering magnet wires is the US NEMA MW 1000. The insulation on the magnet wire serves as the coil turn insulation in random-wound machines.

With the introduction of IFDs, even motors rated as low as 440 V have been observed to have the white powder associated with partial discharge deterioration on the turns connected to the phase terminals (Section 8.10). Thus, new magnet wires have been introduced that contain nano-sized metal oxides to impart PD resistance to the normal organic insulation [10]. The metal oxide bearing enamel is usually applied just to the surface of the magnet wire. These filler materials increase the life of windings subject to voltage surges from IFDs (Section 1.5.1). This certainly seems to be the case with voltage endurance testing of twisted pairs of magnet wire. However, the PD resistance still falls short of mica paper, especially after the machine has been in service where it is exposed to heat shock and thermal cycling that may crack the very thin layer of metal oxide material on the surface of the magnet wire. Once this metal oxide layer in the magnet wire is cracked, the PD resistance property is reduced.

4.4.2 Phase and Ground Insulation

The cross section of a random-wound stator in the stator slot is shown in Figure 1.19. As with form-wound machines, there are typically two coils, often from different phases, in the same slot. Thus, “phase” insulation is often used to separate the two coils. The most common phase insulations are "papers" made from the synthetic material "aramid," DuPont is one supplier, and uses the trade name Nomex™. Nomex has a 220°C thermal classification, is resistant to chemical attack, and has excellent tear resistance. Depending on the voltage class, the paper may be from 0.1 mm to 0.5 min thick. The same aramid material is used as a slot liner, to provide extra ground insulation between the copper in the coils and the stator slot. Similarly, this material is often used between coils in different phases in the endwinding.

Another material that is commonly used for random-wound stator ground and phase insulation, as well as for wedges, is Dacron™/Mylar™/Dacron or DMD, which tends to have better mechanical strength than Nomex.

For sealed random-wound stators, the endwindings are insulated with a Dacron tape to retain the varnish and then the stator is GVPI. Such stators are often required in harsh nuclear station environments (see Section 2.6), or in chemically harsh applications.

4.4.3 Varnish Treatment and Impregnation

Most random-wound stators are coated with a varnish or resin after the coils have been inserted in the slot (Section 1.5). This coating imparts resistance to moisture and contamination (which can lead to electrical tracking), and also improves the electrical breakdown strength of the windings. As NEMA MW1000 specifications for magnet wire do allow a certain number of "pinholes" in the insulation per length of wire, the varnish or resin ensures that partly conductive contamination does not lead to turn-to-turn faults. In addition, the varnish or resin will improve the transmission of heat from the copper to the stator core, as the number of air pockets is reduced. The varnish treatment also holds the conductors tight in the slot, to reduce the tendency for the coils to move under the 100 Hz or 120 Hz magnetic forces (Section 1.4.8). As IFDs permeate the market, the voltage surges they create can lead to destructive PD in any air pockets (Section 8.10). Thus, filling of the air pockets with varnish or epoxy is becoming more critical, as PD can only occur if air pockets exist (Section 1.5.1).

The materials used for varnish or resins follow the same progression over the years as impregnates for form-wound stator coils (Sections 3.1, 3.2, and 3.4). Today, acrylic, polyamide, and polyimide are used as varnishes, and solventless polyesters and epoxies are used as resins. The varnishes are usually applied by dipping the stator in a tank of varnish, and then heat curing the stator. Sometimes, the ultraviolet light can also be used to cure some varnishes. Trickle impregnation is another, more expensive, process that is usually more successful in filling all the air spaces [42]. In trickle impregnation, the resin or varnish is slowly dripped over a very slowly rotating stator, at the same time as current is circulated in the winding to raise the temperature. Again, the curing process may be enhanced by bathing the rotating stator with UV light. The best process to minimize the possibility of air pockets within the winding (to improve heat transfer and eliminate partial discharges) and to seal the winding against moisture is to VPI the stator using a solventless epoxy or polyester.

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CHAPTER 5

ROTOR WINDING INSULATION SYSTEMS

Electrical insulation is required in several types of AC machine rotor windings, including round rotors, salient pole rotors, and wound induction motor rotors (Section 1.6). Usually, there is both turn and ground insulation. The voltages present in rotor windings are much lower than those found in stator windings. Thus, the design of rotor winding insulation systems tends to be limited by their mechanical and thermal capabilities.

This chapter outlines where insulation is needed and the stresses that act on the insulation for the various rotor winding components such as windings, slip rings, retaining rings, end winding banding, etc. The materials used and how the insulation systems are made are also described. Appendix A contains a list of the important physical characteristics of most of the common rotor winding insulation materials. Sections 3.8 and 3.9 discuss the historical development of rotor insulation materials.

Rotor winding insulation is exposed to stresses that are different from those in the stator winding. Rotor stresses can include:

- Thermal stress from the I^2R DC current losses in the field winding.
- Centrifugal force from the high rotational speed of the rotor.
- Relatively low electrical stress, as the synchronous machine field windings and three-phase wound rotor windings rarely operate at more than 1000 VDC. With static excitation systems, voltage surges from thyristor operation may lead to partial discharges in very large generators operating at relatively high DC voltages. Similarly, repetitive voltage surges from voltage source PWM inverters may create PD in doubly-fed induction generator rotors (Section 1.1.3).
- Oil, moisture, and abrasive materials that may be present in the machine can either cause electrical tracking between the winding turns or to ground if the copper is not fully insulated and abrasion of the insulation.
- Expansion and contraction of the copper conductors every time the machine is turned on and off; the copper movement leads to abrasion of the insulation and/or distortion of the copper conductors in the end winding.

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

The most widely used AC motor is the squirrel cage induction (SCI) motor (Section 1.2.3). The rotor consists of heavy copper, brass, or aluminum alloy bars welded or brazed to end rings and embedded in iron laminations. Alternatively, the windings may be cast-in-place aluminum alloy. The winding, without the laminations, resembles a squirrel cage, hence the name squirrel cage motor. The SCI motor operates without sliding electrical contacts of any kind. There is generally no applied insulation between the conductors and the laminations, as the difference in conductivity of copper or aluminum bars versus iron laminations and the low voltage at which the rotor operates obviates the need.

5.1 ROTOR SLOT AND TURN INSULATION

Most types of rotors in motors and generators, except the SCI type, have both ground and turn insulation (Section 1.6). Rotors in smaller machines are usually random-wound, using round enameled (magnet) wire (usually with a varnish dip to bond the conductors together) that serves both as turn and ground insulation. For higher voltage rotors, with either random- or form-wound coils, separate slot and turn insulation is used. This insulation is usually made from formed pieces of materials that are set in place before the windings are installed. Alternatively, some small rotors use an electrostatic coating process to apply polymer powders to the slots for insulation.

Materials selected for slot and turn insulation vary depending on the temperature class of the winding and the voltage and power rating of the machine. Formed sheet materials may be of aramid paper (such as Nomex™ by DuPont) for medium-size generators or laminates of plastic films and nonwoven layers for smaller machines. A very common slot insulation is called *DMD* [for a lamination of Dacron, Mylar, Dacron (DuPont trademarks)], with a suitable adhesive. DMD is made by DuPont and other suppliers from polyethylene terephthalate polyester resin in film and nonwoven fiber form. A series of similar laminates are available for use in machines with different temperature classes. Films in use include polyethylene naphthalate, nylon, and polyimides. The nonwovens include cotton paper, unbleached wood pulp kraft paper, aramid fiber mat, fiberglass mat, and the combination of polyester and fiberglass in mat form. Similar materials are used for turn insulation in the form of pieces cut from sheets or rolls. For round rotor fields with heavy copper coils, thin laminates of fiberglass cloth and polyester or epoxy resin are used.

The slot insulation for two- and four-pole round rotors (Section 1.6.2) has evolved over time from a mica-splittings-based composite with kraft paper, glass, or asbestos cloth and bonding resins to premolded slot cell or slot armor pieces. Several methods are in use to fabricate these insulation pieces. They include individual moldings made in compression presses, step-press compression molding, and hydraulic or autoclave molding of prepreg (B stage) lay-ups in sheet metal molds. The long sections from the latter two methods are cut and trimmed into individual pieces. Polyester resins are used to pre-impregnate glass fabric for individually compression molded pieces, whereas epoxy resin prepregs with glass cloth are used for the step-press process. This process may also add special layers of aramid fleece and high-temperature-resistant imide films to increase the crack resistance and electrical breakdown strength. The hydraulic and autoclave molding process may also use these materials, although continuous-filament nonwoven fiberglass sheets, preimpregnated with epoxy resins by 3M Company under the Scotchply trade name, have been the most successful.

The resins selected for slot cell insulation must be physically tough, resistant to thermal aging, and have a glass transition temperature (T_g) for the cured material that is above the peak operating temperature. The T_g is the temperature at which the cured resin softens or changes from a crystalline to a rubbery or amorphous state. Operating above this temperature allows the resin to creep out of the reinforcement, destroying the insulation pieces.

Most hydrogenerators and 1800 rpm and slower-speed synchronous motors and generators rated up to about 50 MW have salient pole rotor windings. As indicated in Section 1.6.1, the design used on most motors and generators rated less than a few megawatts is called a *multilayer* wire-wound type. In this design, the insulated magnet wire, which usually has a rectangular cross-section, is used. Each pole is constructed with many hundreds of turns of magnet wire several layers deep, wrapped around a laminated steel pole piece. The turn insulation is the magnet wire insulation. Insulating washers and sheet insulation are placed between the magnet wire and the pole laminations to act as the ground insulation. Often, the entire pole may be dipped in or vacuum pressure impregnated with an insulting liquid to glue the various components together.

Salient pole rotors in hydrogenerators larger than about 50 MW, and those operating at 1800 to 1000 rpm, generally have "strip on edge" design as it can better withstand rotational centrifugal forces (Section 1.6.1). The poles for this type of winding can be made from either laminated or solid magnetic steel. In the case of the solid steel pole type, used on larger high-speed machines, the pole tips can be either bolted on or integral. In this case, a thin copper strip is formed into a "picture frame" shape and the coils are usually fully processed, including varnish impregnation, before they are installed on the poles. The only exception is the integral pole type construction for which picture frames have to be connected together to form a coil as they are installed on the pole. Strips of material, which nowadays is usually aramid paper which DuPont calls Nomex™, act as turn insulation to separate the copper frames from one another. On some copper frames, especially near the pole face, an insulating tape may be applied to the copper to increase the creepage distance to the steel pole. The copper picture frames are connected in series to make the coil. As with the multilayer salient pole design, the winding is isolated from the grounded pole by insulating washers and strips.

The bonding varnishes for salient pole designs are selected according to the temperature class of the machine and the hardness and elasticity required for the application. If mica is chosen for the ground insulation, it is clear muscovite mica, bonded with shellac, shellac-epoxy, or vinyl-alkyd. Composites of mica splittings, aramid sheets, glass fabrics, and epoxy resins are also used.

5.2 COLLECTOR INSULATION

Unless the rotor winding is energized from a "brushless" exciter (in which the DC comes from a rectified AC current induced in an auxiliary winding on the rotor), collector rings are needed to bring the positive and negative DC current to synchronous rotor windings. Collector rings are also needed for wound induction rotor motor windings. The collector assembly is generally manufactured as a separate item that is heat-shrunk onto the rotor shaft at assembly. A wide choice of materials is available for the insulation needs. A common choice for ring insulation is molding mica. Molding mica is a B-stage material that is applied by heat softening to the collector shell or hub, along with additional bonding varnish. After wrapping, the mica is subjected to high compressive force by, for example, wrapping with steel wire under tension. The unit is then oven-baked to cure the varnish, stripped of the wire, and machined in a lathe to a closely specified outer diameter. The steel collector rings (copper or copper alloy rings are usually used on wound-rotor machines) are then heat-shrunk onto the mica ground insulation. Modern practice is to apply polyester-resin-impregnated fiberglass rovings, under winding tension, between and beyond each ring. After resin curing, the excess material is machined off and a final coat of sealing varnish is brushed over the fiberglass bands and cured.

The collector brush-rigging insulation is generally made from molding compounds, laminated boards, or tubes made from paper, cotton, or glass fibers suitably bonded and impregnated. The resins chosen for the moisture-resistant surfaces of these pieces are very important for good operation.

5.3 END WINDING INSULATION AND BLOCKING

Round rotors for two- and four-pole designs generally operate in clean environments. Larger generators are usually totally enclosed designs in which the rotor operates in a pressurized hydrogen gas atmosphere to minimize windage losses and improve heat transfer of conductor losses to heat exchangers. Air-cooled machines can also be totally enclosed, air-to-water cooled via a heat exchanger, or have recirculate cooling air through heat exchangers so that only a portion of the air being circulated is outside makeup air. The makeup air is usually cleaned by passing it through filters or centrifugal cleaning units to remove most particulate matter. The clean environment allows the copper edges of the field coils, outside of the slots, to be directly exposed to the cooling gas for maximum cooling efficiency. For larger coils, each turn is separated from the adjoining turns by a strip of sheet insulation. Smaller rotor coils, which are fabricated by edgewise winding, often use taping on every other turn outside the slot section, but can also have strip insulation such as aramid paper. The turn tape is often B-stage-epoxy or other resin-impregnated mica paper or splittings, supported by fiberglass fabric, but can also be aramid paper with a heat-curing epoxy on one side to promote bonding.

Air-cooled rotors that are designed for use in unclean environments, such as mining and chemical manufacturing locations, usually have the entire end winding enclosed in a taped structure made with resin-impregnated fiberglass tape. Some designs have aluminum radiating plates fitted against the end turn insulation and between adjacent coils to help remove heat.

The end windings are not stable under centrifugal load unless they are supported by retaining rings and are securely blocked together. Missing or badly shifted blocks can lead to coil distortion from conductor thermal expansion under load. Blocking materials are generally machined from compression-molded heavy sheet stock. Although asbestos cloth was used in the past, it has been replaced with fiberglass cloth, impregnated with phenolic, polyester, or epoxy thermoset resins. The blocking between the straight portions of the end windings protruding out of the slots consists of wedge-shaped blocks, whereas the end blocks are rectangular pieces with curved outer edges. There are usually strips of laminate fastened to the top of the blocks to help prevent them from shifting. All blocks are individually fitted by sanding and may be bonded in place with layers of B-stage, resin-impregnated glass cloth and with brushed- or sprayed-on thermosetting varnish.

After all of the blocks and ties are assembled, the entire end winding is subjected to radially inward hot pressing. The press completes the cure of resins and varnishes and depresses the outer diameter of the coil package below the diameter of the retaining rings and their insulation, to permit assembly of the rings over them.

5.4 RETAINING RING INSULATION

The end windings of round rotor coils must be restrained from radial movement by the use of heavy steel retaining rings that are heat-shrunk onto the ends of the rotor body containing the winding slots and/or machined sections of the rotor shaft axially outside the coil end windings. Depending on the design, these rings are machined from either magnetic or nonmagnetic forged steel and are the most highly stressed parts of the rotor, as they must carry their own centrifugal load and that of the field coils under them. The retaining ring insulation is inserted between the radial outer (or top) of the field coils and the retaining rings. A number of materials have been used for retaining ring insulation. Early designs used built-up mica sheets, similar to those described above for brush rigging. Recent practice has used several sections of formed sheet materials made with epoxy and fiberglass cloth. Often, a compressible material, such as aramid paper, is placed between the primary insulation and the top of the coils to provide some cushioning. A slip plane consisting of Teflon or other material with a low friction coefficient is required either between the retaining ring and outer insulation layer, or between the outer insulation layer and main insulation to prevent insulation damage that can occur as a result of rotor winding axial thermal expansion.

The assembly of the retaining rings over the insulation requires the steel rings to be heated by gas torches or by electrical induction. The retaining ring insulation must be clamped to the end winding, usually with steel bands, as the rings are forced into position. The bands are removed as the rings advance over the insulation.

5.5 DIRECT-COOLED ROTOR INSULATION

The rotors and their insulation discussed in Sections 5.3 and 5.4 are called *indirect-cooled* round rotor windings. The heat generated in the slot part of the windings has to flow through the ground or slot cell insulation, into the steel teeth between coil slots, and into cooling slots also between coil slots. Cooling gas is forced through the cooling slots and their vent wedges to remove the heat.

Rotor windings can carry significantly more current without overheating, by adopting methods for direct cooling of the copper. This greatly increases the efficiency of the heat removal process, allowing increases in the current density of the field windings. Direct-cooled rotors are of several types. They are all characterized by having most of the heat removed by direct contact of the copper turns with the cooling medium. This arrangement adds some complexity to the rotor insulation. Direct cooling does not necessarily eliminate the presence of the rotor cooling slots. Shallow cooling slots may still be used to carry away heat generated in the rotor steel as well as some of the copper I^2R loss.

The least complicated design uses the simple radial flow of cooling gas from conductor subslots under the coil slots, through the slot cell insulation, up radially through holes in the turn insulation and slot copper and out through the creepage-space blocks and coil-restraining steel or aluminum slot wedges (Figure 1.23). The gas exits into the air gap between the rotor and the inner diameter of the stator core. The holes in the copper turns, subslots, and wedges generally line up perpendicular to the axis of the rotor, thus permitting economical punching of the holes in the copper and turn insulation and machining of holes in the space blocks and wedges.

The insulating components of the simple, radial, direct-cooled round rotors are generally made of the same materials that are used for similar parts in indirect-cooled designs. The most common choices for generators rated above 50 MW are epoxy fiberglass laminates for the ground insulation (often two “L” shaped pieces), the turn insulation, the space blocks, the end winding blocking and the retaining ring insulation. For smaller machines with ratings up to about 50 MW, sheet materials such as aramid paper are used for the ground insulation. The slot section insulating parts are more complicated in cross-sectional shape and thickness, as they contain the gas flow cooling holes. The sub-slots are narrower than the coil slots and are fitted with insulating laminate covers to support the coils and provide creepage distance to the sides of the steel subslots. The creepage space blocks at the top of the coil stack may be placed within the top of the slot cell insulation. They must be thick enough to provide creepage distance to the steel or aluminum wedges and the top of the coil slots. The turn insulation and creepage blocks must have very high compressive strength as they must support the centrifugal load of the coils up through maximum design overspeed conditions.

More complicated designs for direct-cooled rotors for the largest generators utilize hollow sections of copper for the slot sections of the coils and partially for the copper under the retaining rings. These sections may be achieved by machining grooves and holes in two sections of an individual turn, which, when joined during construction of the complete coil, provide the openings to connect adjacent turns and the source of the cooling gas. These designs may employ sub-slots to supply some of the cooling gas or they may rely on scooping gas from the air gap regions where the cooling flow is radially inward through the stator core. The passages through the copper then carry the gas back to the air gap in exit regions where the flow in the stator is in the reverse direction, or radially outward. Although the same insulating materials are used in this design, the detailed machining of the creepage blocks is increased.

The ultimate in direct-cooled rotors is reserved for the largest generators, usually over 1200 megawatts. These massive rotors use cooling water circulating through hollow coil turns to remove the heat. This very efficient heat removal, coupled with direct water-cooled stator coils, makes it possible to build, ship, and install these generators. Since the cooling water never reaches the boiling point, the thermal stability of the insulation in these machines does not need to be as great as in typical indirect air-cooled generators. However, the mechanical properties must remain very high, so the choice of insulation materials often does not change.

5.6 WOUND ROTORS

As indicated in Section 1.6.3, the two most common types of wound rotor designs are random-wound. Coil conductor, ground and phase insulation, together with impregnating resins, are the same as or similar to those for random-wound stators discussed in Section 4.4. Bar-wave or lap type windings are made from rectangular copper and are insulated with 1/2 lap layer(s) of materials such as woven glass tape for smaller machines and mica tape for larger ones. Ground insulation is in the form of slot liners made from sheets of material such as Nomex™ or Dacron-Mylar-Dacron. Mid-sticks, slot wedges and packing are made from the same materials as form-wound stators, discussed in Section 4.2. Once the bars are installed they must be brazed together and insulating tape caps are applied to each inter-bar connection. Rows of insulating blocking, made from materials such as polyester or epoxy reinforced by fiberglass, are inserted between the coils in the end winding region to brace them against circumferential forces present during operation. This blocking is tied in place with a shrinkable tape.

Banding is applied over the rotor end windings to brace them against centrifugal and electromagnetic forces. In more modern windings, this banding consists of a number of layers of resin-loaded fiberglass tape that is heat cured after application to achieve interlayer bonding for mechanical strength. In older machines and some modern motors, soldered steel wire banding is used. This banding is insulated from the rotor end windings with a sheet insulating material such as Nomex™ applied before it is installed.

Jacketed cables or mica tape insulated bus bars are used to connect the winding phases to the slip rings usually routed through holes in the shaft. However, in some designs the slip rings are located on the rotor winding side of the bearing at the slip ring end to alleviate the need for a shaft hole and allow the connecting cables or bus bars to be attached by insulating blocks to the outside of the rotor shaft.

Once the rotor winding is completed, it is impregnated to bond the insulating materials together and seal it by dipping or rolling it through an epoxy or polyester resin or by a global vacuum impregnation process. Once impregnated, the complete winding is baked in an oven to cure the resin.

5.7 SUPERCONDUCTING SYCHRONOUS ROTORS

Although there are few machines in service, superconducting motors, generators, and synchronous condensers have been researched for over 40 years, particularly in the United States, Germany, and Japan [1–3]. Most of the effort has involved developing superconducting rotor windings for synchronous motors and generators. Early rotors were designed using "cold" superconducting wire with coils made with the niobium-tin intermetallic compound Nb·Sn and operating at 4°K. The development of so-called high-temperature superconductors (HTS or high-TC materials) in 1986, which are superconducting at temperatures above liquid nitrogen at 77°K, has energized the goal of developing motors and generators using these materials.

Most of the machines made to date operate with high air gap flux densities, requiring the use of an air gap stator winding, which is not superconducting. The stators of these generators do not contain the usual teeth that create the coil slots but retain the back iron laminated core to control the path of the magnetic flux.

The insulation requirements of the rotor windings are controlled by the very low temperatures in which they operate, as well as the electrical and mechanical stresses of rotating fields. The insulation of these machines has not been standardized since little production has been achieved.

Experience with designing and building a number of demonstration or development motors and generators, high-power superconducting magnets for nuclear physics, and thermonuclear fusion reactor coils has provided knowledge of the stresses imposed on large-coil insulation systems and of the materials that work. Development is underway for variable speed 5000–50,000 horsepower superconducting propulsion motors for military ships and industrial uses [3]. The materials and design challenges are great. The development of high flux permanent magnets using rare earths (Section 1.1.4) has perhaps provided an alternative for some types of superconducting rotors.

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CHAPTER 6

ROTOR AND STATOR LAMINATED CORES

This chapter discusses rotor and stator cores and, in particular, steel lamination and insulation on these laminations, as well as how the laminations are fabricated into cores. The key aspect is steel lamination, which is known as a *ferromagnetic material*. Such materials are very strongly magnetic. For motor and generator applications, there are two ways to obtain a magnetic field with ferromagnetic materials. It can be created either by electric currents, as in electromagnets, or by permanent magnets.

For many years, permanent magnets have been primarily used for small motors, in which they provide simplicity of design, reduced size, low cost, and acceptable efficiency. However, their use has been progressively extended to larger machines with the advent of superior permanent magnet alloys made from the rare earth element neodymium, as they produce stronger magnetic fields. They are being used, for example, in electric drives in ship propulsion and for wind turbine generators up to several megawatts. A detailed discussion of these machines, which are currently in a state of rapid development, is beyond the scope of this book. This chapter is restricted to the materials, processes, and insulation of laminated stator and rotor cores, that is, electromagnet application.

6.1 MAGNETIC MATERIALS

6.1.1 Magnetic Fields

Magnetic fields are characterized by the magnetic flux (in Webers), the magnetic flux density or B (in Tesla or Webers per meter square), and the magnetic field intensity or H (in Ampere-turns). The latter is also called the *magnetomotive force or mmf* when the field is generated by an electromagnet. Any standard textbook on electromagnetics presents the relationship between these three quantities [1].

6.1.2 Ferromagnetism

Ferromagnetism owes its magnetic properties to the electron spin of the material. This may be thought of as an electron spinning about an axis through its own center,

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

in addition to its rotation around the nucleus of the atom. Electron spins and electron charges influence neighboring atoms by trying to keep the spins parallel, while thermal agitation forces try to destroy the lineup. These electron forces result in the formation of small regions, known as *domains*, which are typically 0.01 mm cubes. Ferromagnetic materials are entirely composed of these domains, each magnetized in a definite direction. Thus, the magnetic material is made up of a large number of elementary magnets or dipoles. These domains, each of which is an elementary magnet, will change to line up with each other when a magnetic field is applied. A ferromagnetic substance is unmagnetized when the domains are oriented at random. In this condition, there is no net mmf across a specimen of the material and no magnetic field is produced outside of itself.

6.1.3 Magnetization Saturation Curve

If one makes a toroidal solenoid, wound on a nonmagnetic core, and energizes the coil with an electric current, the space within the solenoid will become magnetized. As the current is increased, the magnetic field intensity (H) and the magnetic flux density (B) increase in a straight line. Reducing the current reduces the flux density along the same line, reaching zero when no current is flowing. With the same solenoid, if the space within the toroid is filled with an unmagnitized ferromagnetic material, increasing the current will produce a magnetization saturation curve. This curve is also called the *B–H curve*, the *virgin curve*, or just the *saturation curve* (Figure 6.1).

As the magnetic field intensity (H) (the mmf) is increased in ferromagnetic material, the current-induced magnetic field acting on the domains begins to orient them in the direction of the field. Thus, the mmf of each domain is aligned with the external field so that the flux from that field is increased. At first, the domains that are nearly aligned with the external field turn easily in that direction, producing a straight line as the external mmf increases. As the magnetizing force continues to rise, the domains whose individual orientations increasingly diverge from the external field are forced to become aligned, producing a rounded part of the magnetization curve that continues until all domains are parallel. At this point, the ferromagnetic material is said to be saturated. Further increases in external mmf causes the flux density (B) to increase at a much lower rate. The difference in flux between the saturation curve and the line produced by an air-filled solenoid at any magnetizing force is caused by the contribution of the magnetic material. The flux obtained up to the saturation point of the ferromagnetic material is known as the *intrinsic flux* and is a better indication of magnetic properties than the total flux that can be obtained at very high mmfs.

6.1.4 Ferromagnetic Materials

Ferromagnetic materials can be roughly divided into groups by noting how rapidly their flux density increases with magnetizing force. The materials in the first group give appreciable flux densities at very low magnetizing forces. The group of nickel-iron alloys, such as Nicaloi, Perrnalloy, and Mumetal, are examples. The next group contains the bulk of industrial magnetic materials and runs from electrolytic iron, the most easily magnetized, to steel and malleable iron castings. The third group contains

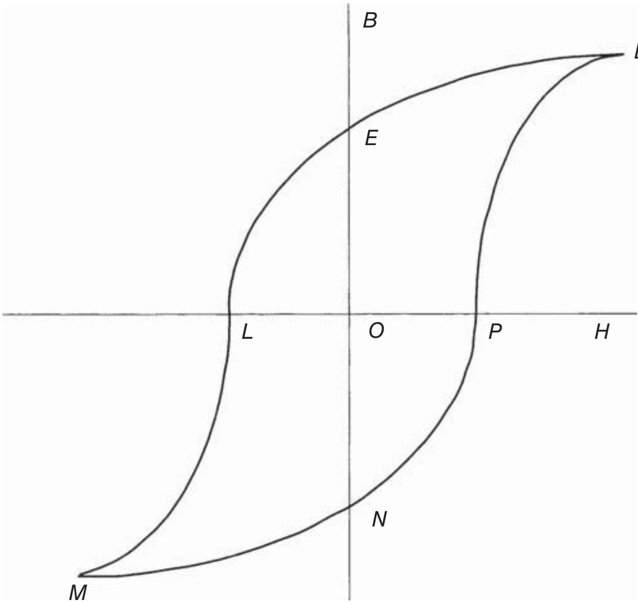

Figure 6.1 The hysteresis loop for a ferromagnetic material. The initial magnetization curve from 0 to D is not shown. The length 0 to E is the residual induction, whereas 0 to L is the coercive force. The width of the loop from L to P is exaggerated compared to materials commonly used in stator cores.

primarily the permanent magnet materials. Among the traditional materials, cobalt alloys have the highest intrinsic saturation values, followed in decreasing order by electrolytic iron, Armco ingot iron, cold-rolled steel, low-silicon steel, high-silicon steel, and iron-nickel alloys.

6.1.5 Permeability

The term permeability refers to the relative ease with which a material can be magnetized. A vacuum or free space has a permeability of unity, a diamagnetic material has a permeability less than unity, a paramagnetic material has a permeability slightly greater than a vacuum and is approximately independent of the magnetizing force, and a ferromagnetic material has a permeability that is considerably greater than unity and varies with the magnetizing force.

6.1.6 Hysteresis Loss

The hysteresis loop is a curve plotted between B (flux density) and H (magnetizing force or magnetic field intensity) for various values of H from a maximum value in the positive direction to a minimum value in the negative direction and back again. When the core of a toroidal solenoid with a ferromagnetic core is first magnetized, the flux density starts at zero and reaches a maximum for the magnetizing force applied, as described in Section 6.1.3. If H is gradually reduced, the flux density does not return to zero, but remains positive even with zero H. The remaining magnetic flux is known as the *residual induction* in circuits in which there are no air gaps. The more general term *remanence* refers to the magnetic induction remaining in the circuit, usually containing an air gap, after the mmf has been removed. The residual flux represents work (i.e., a loss) that was done to overcome friction in rotating and aligning the magnetic domains that is not fully recovered when mmf reaches zero, as some alignment remains. A typical hysteresis loop is shown in Figure 6.1.

When the mmf is reversed, the flux passes zero and reaches a negative maximum for the mmf applied. When the mmf is again returned to zero, there is still a remaining negative flux equal in magnitude to the positive flux of the previous half *cycle.* As the mmf again increases in the positive direction, the flux again passes through zero and increases to the same level obtained in the first application of the mmf. The closed loop, described by the interplay of flux (B) and mmf (H), is a measure of the energy lost during the cycle and shows up as heat (the hysteresis loss) in the material. The demagnetizing mmf required to bring the flux back to zero is the coercive force of the magnet.

When a ferromagnetic material is subjected to an alternating mmf, the first hysteresis loops traced out do not necessarily fall on top of each other. When successive loops do retrace preceding loops, the substance is in a cyclically magnetized condition. For rotor and stator core materials, the hysteresis loop is determined when the materials are cyclically magnetized.

6.1.7 Eddy Current Loss

Whenever the flux in a magnetic material changes its value, voltages are induced that cause eddy currents to circulate in the material. The extent of eddy current loss depends on the resistivity and thickness of the material, as well as the frequency and flux density in the application. Eddy current losses increase with increasing steel grain size up to the point where the grains become as thick as the laminations. Materials such as silicon steel, which have a large grain size, tend to have losses greater than calculated because of this effect.

Eddy current losses increase with the square of the thickness of the material used. To reduce these losses, magnetic structures for use in alternating current applications are usually made with thin sheets or laminations insulated from each other. In practice, it is found that eddy current losses decrease less rapidly than the square law with decreasing thickness. From the losses point of view, there is a limit of lamination thickness below which it is not feasible to go, as each sheet must be insulated from the next. As the thickness of the insulation remains essentially the same for varying thicknesses of core plate, the thinner the core plate used, the smaller will be the proportion of magnetically useful space in the core assembly.

6.1.8 Other Factors Affecting Core Loss

Normal core loss is the sum of the hysteresis and eddy current losses. It is determined in practice by the Epstein test (see ASTM A343), wherein a standardized sample is operated with a standard flux density and frequency, and the power loss in the sample is measured. Other factors relating to design and manufacturing processes occur in apparatus that make total losses considerably higher than indicated by the Epstein test, as discussed below.

Mechanical Clamping Some method must be used to hold the laminations together. It may take the form of rivets, bolts, or edge welding. All of these techniques tend to short-circuit the lamination insulation and, as they may become part of a closed magnetic loop, during AC operation they can cause a serious loss of electrical energy and undesirable heating. Large machines often use steel end plates that are bolted to key bars that are also used to assemble the laminations in segmental stator cores. As these laminations are often insulated after manufacture, they are isolated from electrical contact with clamping bolts.

Pressure A core stack must be tightly held together to provide structural rigidity and to minimize any motion between laminations. Loose cores vibrate and are noisy. *However,* the mechanical strain induced by compression substantially reduces the permeability. Other strains in magnetic materials come about from cold working during the rolling to produce sheet stock, from punching, and from distortions during assembly. These also increase hysteresis and eddy current losses, requiring increased magnetizing current.

Punching and Machining The punching operation to create the steel laminations often produces burrs on the cut edges of laminations. They can be minimized by keeping dies sharp, by using carbide dies to prolong intervals between sharpening, or by using laser cutting. For laminations that are insulated after punching is complete, there are several types of deburring operations that can be carried out, including grinding or sanding and chemical or electrochemical operations to dissolve buns. Those that are not removed can cut through lamination insulation, allowing excessive inter-sheet eddy currents to flow.

Machining operations that are performed on assembled cores. Grinding or broaching frequently smears the edges together, creating undesirable electrical shorts between laminations.

Although it is an electrical insulation, scale is partially magnetic and at high flux levels it carries an appreciable flux. Scale on silicon steel has a very high hysteresis coefficient; so, as it begins to carry flux, the total hysteresis loss rapidly increases. Steel mills normally remove most or all of the oxide scale by acid pickling and either replace it with a mill-applied treatment or rely on the machine producer to apply enamel having an inherently low hysteresis loss.

Aging Coefficient The magnetic properties of ferromagnetic materials change with use and the associated exposure to heat from machine operation. This aging is associated with an increase in core loss and an increase in magnetizing current needed to produce the desired machine performance. A positive value of the aging coefficient indicates a decrease in permeability. Standardized tests have been developed to determine this coefficient, using exposure of a suitable sample to a specified time and temperature. Data is taken before and after the aging period.

6.1.9 Effect of Direction of the Grain

The properties of electrical strip steel vary considerably, depending on the direction of the flux in relation to the direction of rolling. Sheet steel is alternately rolled along the sheet as well as across it, leading to grain development in both directions. Electrical strip steel is rolled in a continuous mill, resulting in the grain being aligned with the direction of rolling. Steels with cross graining show higher hysteresis losses. In making Epstein acceptance tests, it is specified that one-half of the samples be taken with the grain and one-half across the grain.

6.1.10 Effect of Temperature

All ferromagnetic materials will lose their magnetism when heated to a high enough temperature. The temperature at which this occurs is called the *Curie point*. For iron it is 770°C, for nickel it is 358°C, and for cobalt it is 1120°C. As the temperature approaches the Curie point, the relative magnetization, at any specific field intensity, decreases. The magnetic properties of iron and iron-silicon alloys are only slightly affected by small temperature changes. As temperature is increased, permeability usually improves, whereas hysteresis and eddy current losses are decreased. As temperature approaches the Curie point, core losses continue to decrease and, when at this temperature, the permeability reaches unity at medium and high inductions.

6.1.11 Effect of Heat Treatment

The type of heat treatment given to magnetic materials largely determines their magnetic properties. Annealing is used to relieve internal elastic strains brought on by mechanical operations such as punching, bending, and shearing. Usually, annealing is carried out in an inert or reducing atmosphere and tends to remove carbon. The result is to reduce the area of the hysteresis loop and produce changes in the saturation curve. Annealing will not affect strains caused by impurities or magnetization. Freedom from dissolved impurities is important as they disrupt the orderly arrangement of the atoms and produce lattice strains.

6.1.12 Effect of Impurities and Alloying Elements

Impurities in core steel cause an increase in hysteresis loss and a decrease in permeability. Of most concern are the elements carbon, sulfur, phosphorus, oxygen, nitrogen, and manganese. Even a very small percentage of carbon produces a large detrimental effect, resulting in significant permeability loss, an increase in the area of the hysteresis loop, and a lowering of the magnetic saturation point. The next most detrimental element is sulfur, followed by phosphorus and oxygen that, as impurities, have small adverse effects on these magnetic properties. Manganese in very small percentages is only slightly detrimental.

Up to half of one percent of copper is often added to electrical steel to improve its corrosion resistance with little effect on magnetic properties. Silicon and aluminum are alloyed with iron to improve magnetic properties, although with some loss in strength. Both serve as deoxidizers and increase the resistivity of iron, thus substantially reducing eddy current losses. Silicon is more commonly used, as it also reduces hysteresis loss and intrinsic saturation while improving permeability. Recent practice has been to use both elements with the combined alloy content ranging from 0.25% for the least costly grades to about 4% for the high-efficiency grades.

6.1.13 Silicon/Aluminum Steels

The most important magnetic materials for AC applications in motors and generators are the silicon steels. They may be divided into two major types: non-oriented and grain-oriented. There are a number of grades of non-oriented silicon/aluminum steels that have been developed for the cores of electrical machines. The choice of grade depends on the specific application, including the desired magnetic and stamping properties. There is also a choice of lamination thickness or gauge within the AISI or ASTM listed grades or types [2,3].

The cost per kilogram of silicon steel sheet stock increases with the alloy content and decreases with increasing thickness. The non-oriented grades are used for most applications, except where the highest efficiency is desired. The lowest cost grade for cold rolled motor lamination (CRML) is generally not fully annealed (semi processed), with only sufficient post rolling heat treatment to achieve a thermally flattened state. The other grades are available in either the fully annealed (fully processed) state or the semi processed state.

Grain-oriented electrical steel is manufactured to have a well-aligned crystal orientation in the rolling direction and is usually obtained in the fully processed state. In past practice, semi processed grain-oriented steel was often used, followed by an inert gas atmosphere annealing process after punching to relieve the mechanically induced strains and improve the magnetic properties. The silicon used in flat rolled electrical steels has the effect of aiding grain growth during annealing, thereby lowering hysteresis losses.

6.2 MILL-APPLIED INSULATION

Steel laminations must be insulated from one another to prevent axial currents from flowing in the core. These axial currents are driven by the main magnetic field, and if allowed to flow, will cause considerable heating and reduced efficiency.

Generally, the required insulation is applied by the steel manufacturer. There are a number of electrical steel standard insulation coatings specified in ASTM A976-1997 [4]. A partial listing appears in Table 6.1. In summary, small motors use CRML with a C-0 coating, larger or high-efficiency motors use C-3, C-3A, or C-5 lamination coatings, and large generators typically use C-4 or C-5 coatings, often with a varnish overcoat.

TABLE 6.1 Partial List of Standard Electrical Steel Coatings Specified in ASTM A976-1997

C-0	The steel has a natural, ferrous oxide surface
C-2	An inorganic coating of magnesium oxide and silicates that reacts with the surface of the steel during high-temperature annealing. Principally used in distribution transformer cores; not for stamped laminations due to its abrasiveness
C-3	Enamel or varnish coating that enhances punchability and is resistant to normal operating temperatures. Will not withstand stress-relief annealing
C-3A	The same material as C-3, but with a thinner coating thickness to facilitate welding of rotors and stators and minimize welding residue
C-4	An antistick treatment that provides protection against lamination sticking in annealing of semi processed grades
C-5	The insulation is an inorganic coating consisting of aluminum phosphate. C-5 is used when high levels of interlaminar resistance between laminations are required. The coating will withstand stress-relief annealing conditions. C-5 also has a temperature rating in the range of 320–540°C (600–1000°F) which makes it suitable for stator cores used in motors with global VPI stator windings, which usually have to be burned out in an oven to remove the old coils prior to rewinding. This material can withstand steel annealing temperatures up to 815°C (1500°F)
C-5A	The same coating as C-5, but with a thinner coating thickness to facilitate welding of rotors and stators and minimize welding residue
C-6	A combined organic/inorganic coating that can withstand stress-relief annealing

6.3 LAMINATION PUNCHING AND LASER CUTTING

The traditional method of making core laminations has been to punch or stamp them out of electrical steel sheet stock using tool steel dies. However, electrical steels and some coatings can shorten punching die life as compared to nonelectrical grades. The higher alloy content steels are also more brittle and die design must take into account both the punching characteristics and the need for frequent sharpening. Development of improved tool steels for this application has reduced the need for frequent sharpening and allowed the use of the softer fully processed grades that do not require annealing after punching. Tool steel dies are still widely used for limited-volume applications, such as prototype and repair/replacement production, as well as for cases where few machines of a kind are needed. Much improved dies are now available in carbide for high-volume production. Although more costly to make and requiring increased manufacturing time, carbide dies last longer, need less frequent sharpening, and produce tighter punching tolerances.

Original equipment manufacturers (OEMs) have usually maintained an inventory of old dies for discontinued machine designs so that a rapid response to service needs can be realized. During the last decades of the twentieth century, the equipment for computer-controlled laser cutting of laminations became available. The ability to rapidly program the computer for new lamination designs and to quickly start production has led some OEMs to scrap old dies in storage, which are seldom used, and to then rely on laser shops to produce replacement laminations for full or partial cores. Laser cutting is also used for limited new production and prototypes, for modifications of laminations from existing dies or punched stock, and to replace damaged laminations during core repairs.

6.4 ANNEALING AND BURR REMOVAL

Electrical steel is usually formed by the cold rolling process and is annealed to reduce or eliminate the strains in the sheet, as mentioned in Section 6.1.13. The punching operation and any other additional mechanical working of electrical steel will induce strains in laminations that degrade the magnetic properties. When semi-processed steel is used for punching laminations for higher efficiency electrical machines, it is common to anneal stampings, usually after burr grinding. The annealing is carried out in an inert atmosphere to prevent oxidation of the metal surface.

The edges of laminations acquire a metallic burr during stamping that should be eliminated to prevent the burr from causing electrical shorts between laminations and to improve the stacking factor or density of the stack. Burr removal is most often done by a grinding or sanding operation that also leaves some bare metal where the burr was removed. Laser cut laminations generally have less burr than stamped laminations, and laser burrs contain oxidized metal that is not well attached and is more easily removed.

6.5 ENAMELING OR FILM COATINGS

Small- and medium-size motor manufacturers often use pre-insulated core steel to reduce manufacturing costs. For large and higher efficiency machines, most large OEMs do not rely on the mill-applied insulations alone. The anneal-resistant mill finishes provide a suitable base for phenolic resins and may contain finely divided mineral fillers. These enamels are deposited from a solvent solution by passing the laminations through rollers that deposit a controlled amount of insulating material. Immediately after coating, the laminations are passed through a heated oven in which the solvents are removed and the enamel is cured. The evaporated solvents have to be removed from the oven exhaust by incineration.

Since the 1970s, the newer polyester and epoxy resins have been in limited use as enamels. The core plate C-3 contains a high-grade, organic-modified, polyester or other resin that provides die lubrication during stamping. C-5 has a high-resistance insulation formed by a chemical treatment similar to that of C-4, but with the addition of an inorganic filler to enhance its electrical resistance and a small amount of organic material to enhance punchability [5]. It withstands stress-relief annealing if the temperature does not exceed about 815°C and a neutral or slightly reducing atmosphere is used. High resistance makes this insulation advisable for cores of large size with a volts-per-turn ratio in the highest range. It has little effect on lamination factor and is unaffected by oil immersion. This material is widely used for large motor and generator cores.

Solventless epoxy enamels have been developed that cure by ultraviolet light at low temperatures and at high line speed [6]. The speed of the coating line is primarily limited by the tendency of the laminations to sail off the supporting conveyor belt at high speeds and not on the ultraviolet curing time. The compact coating and curing line is very energy-efficient and no solvents have to be removed from the exhaust air stream. The capital and operating costs of such an enameling line are significantly less than the conventional phenolic enameling line.

Note that some core lamination insulation can contain formaldehyde compounds, which may constitute an environmental hazard when a global VPI stator is burned out in anticipation of a rewind.

6.6 STATOR AND ROTOR CORE CONSTRUCTION

6.6.1 Stator Core Construction: General

A large stator core can contain 100,000s of insulated steel laminations and must be held tightly together axially to prevent relative radial movement between adjacent laminations under the influence of 100/120 Hz electromagnetic forces imposed on the core during machine operation. In cores with single-piece laminations, the core can either be:

1. Built into the stator frame and clamped by tooth support fingers and steel rings at each end and then welded to the core support bars, or
2. Built as a separate assembly and then fitted into a stator frame with support bars that have been machined with a profile and dimensions that provide a tight fit between the stator core and frame. Usually the core assembly is keyed to the stator frame to prevent its rotation under the torques from the magnetic forces imposed on it during normal operation and fault conditions.

In either case, usually radial vent ducts are installed during the core building process and the core has to be placed under a high axial pressure before the end support structures, consisting of end fingers and clamping rings, are fixed in place (Figure 6.2).

The end fingers and duct spacer blocks are used to ensure that the tooth pressure is spread evenly towards the centre of the core. The applied pressure during core assembly must be balanced to avoid core damage from overpressure or from lack of sufficient tightness, causing loosening of the core in service. Over-tightening of the stator core can result in damage to the laminations and ventilation duct spacers, which are often “I” beams, resulting in a weakening or even cracking of the beams and thin steel laminations, which in time will result in slackening of the core. If insufficient core pressure is applied, lamination vibration will result, producing a twice-power frequency acoustic hum. This may result in fretting of the lamination insulation followed by potential burning, cracking and breaking of the lamination steel and also a high potential for damage to the stator bar insulation installed in the slots. In addition,

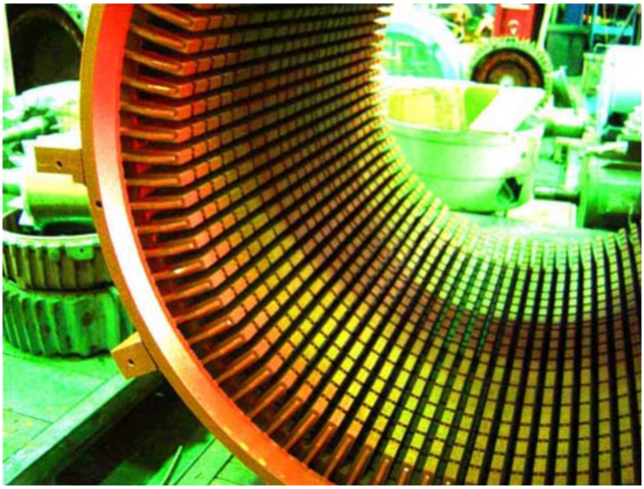

Figure 6.2 Single piece stator core with end fingers, clamping rings, and radial ventilation ducts.

a loose stator core will not be able to withstand the additional forces during fault conditions and may result in premature failure of the stator. Further, a low clamping force will decrease the core capacity to resist the buckling phenomenon.

If the stator core and winding is cooled by axial air flow, then holes are punched in the stator laminations to provide cooling ducts that allow air to travel from one end of the core to the other. The core design and thereby the tightness must be able to accommodate the steady load machine torque as well as the transient torques experienced during fault conditions. Such torques are transmitted through the laminations to the stator frame via the key bars mounted on the stator frame.

When the core outside diameter becomes too large to manufacture the laminations for a single piece of magnetic steel sheet (greater than about 1 m diameter), segmented cores are used. These segments (Figure 6.3) have notches in their outside diameter that facilitate their attachment to key bars in the stator frame or core assembly.

6.6.2 Hydrogenerator and Large Motor Stator Core Assembly and Support

In most cases the core is stacked manually with lamination segments. The core and its end clamping assemblies is held together axially by electrically insulated through bolts that are installed in axial through holes punched in the core laminations, or by tightening bolts located at the back of the core which are attached to the stator frame to avoid vibration and to transmit torque. In the past, some large hydrogenerators had split cores (2, 3 or 4 sections) that facilitate the manufacture of wound core sections in a factory and yet would be small enough to ship to the generating station. The core would then be assembled into a complete stator at site. However, subsequent problems

Figure 6.3 Segmented stator core laminations used in large diameter stator cores.

with the stator cores at the splits have caused many manufacturers of large hydrogenerators to fully stack the cores at the generating station, so that splits do not occur.

6.6.3 Turbogenerator Stator Core Assembly and Support

Most turbogenerator stators are also made from segmented laminations and are usually manually stacked in a vertical orientation. However, a new technique involving robot stacking of core sections has been developed, which may improve production efficiency and allow horizontal assembly of the full stator core [7]. These donut-shaped core sections up to about 15 cm thick are held together under pressure until they are vacuum pressure impregnated with resin to bond the donut laminations together. These donuts are then stacked together in the stator frame to build a core.

Turbogenerators have core clamping requirements that are related to the specific design, dimensions, and fleet history of a given manufacturer's style of machine. These requirements are normally retained and managed by the OEM. The OEM is responsible to assess the suitability of a specific core assembly process needed to manage the complex forces at work in the stator of larger two- and four-pole units. The radial stability of the core is one of the important considerations that demand precise application of proprietary processes for axial and radial clamping. On large two-pole turbogenerators, there is typically a flexible or spring type connection that limits the amount of vibration transmitted to the frame and foundation.

Large turbogenerators have high axial leakage fluxes, generated by the stator and rotor end windings, that enter the stator core ends in the under-excited (leading power factor) mode of operation. These leakage fluxes can induce high eddy current losses in the core end regions and so one or more of the following design

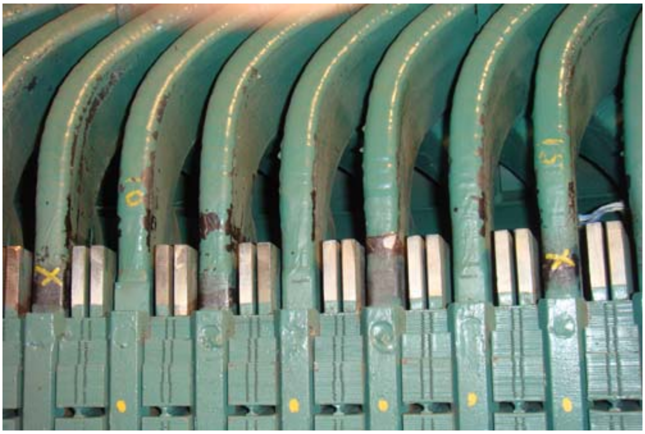

Figure 6.4 Stator core stepped at its end with split tooth support fingers.

features are incorporated to minimize the high localized core temperatures that would result [8]:

- Stepped core ends in the first few centimeter of core at each end (Figure 6.4)
- Teeth and tooth support fingers (Figure 6.4) split into two radial sections in the core stepped region
- Flux shields or shunts at each core end

6.6.4 Smaller Motor and Generator Stator Cores

In this size machine, the core laminations are single piece type, which makes core building and pressure maintenance much simpler. If the core is built into the stator frame, it is mounted vertically, the end plates and tooth support fingers are fitted to one end, the core is built into the frame, with installation of radial vent ducts if fitted, with periodic pressing and then the end fingers and end plates are fitted to the other end. The whole core is then pressed and the upper end plate is held in place with keys attached to the core support bars, which are then welded in place. If the core is assembled outside the frame to facilitate winding the stator before installing it in the frame, the components are the same, but it must be built in a jig that supports it at its bore. Once assembled and pressed, core support bars are welded to the end plates and to the core outside diameter to provide a well-consolidated core assembly.

6.6.5 Rotor Core Construction

The basic components of a rotor core for squirrel cage and wound rotor induction machines, as well as permanent magnet motors and generators, are similar to those of a stator core, but of course the method of support is quite different. As with stator cores, rotor cores with diameters up to about 1 m are made from single piece

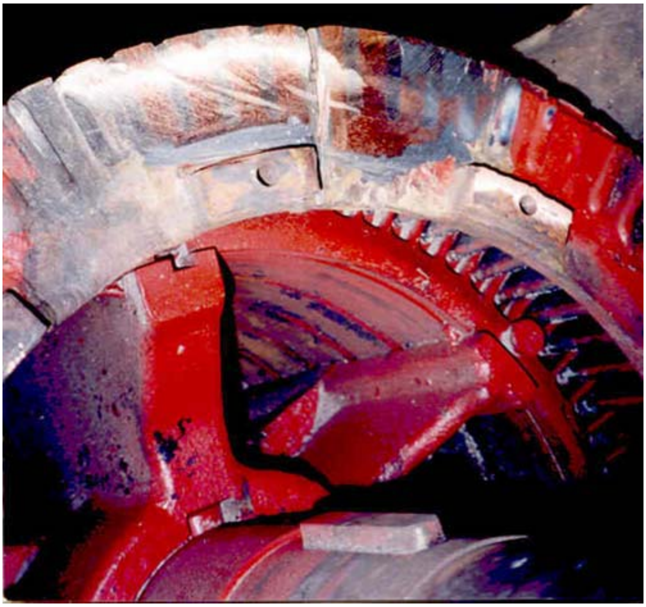

Figure 6.5 Core supported by spider arms mounted on a hub.

laminations and those with diameters greater than this have segmented cores. Rotor cores with single piece laminations are supported by a shaft onto which they are either directly mounted or mounted on spider arms that are integral with and welded to the shaft or are on a hub that is mounted on the shaft (Figure 6.5). Since the rotor core bore expands as a result of centrifugal forces during running, it must be shrunk onto the rotor shaft or spider arms. Also, it must be attached to the shaft assembly by one or more keys, or welding, to prevent it from rotating on the shaft under the influence of the torque transmitted by the rotor during machine operation. Where a heavy core-to-shaft shrink (interference) fit is required in machines such as large two-pole motors, it is best to assemble the rotor core before mounting it on the shaft, then heat the assembly to provide a slide fit on to the rotor. This is because heating bundles of laminations and stacking them on the shaft can lead to core buckling and looseness once they cool and shrink onto the shaft. Segmented rotor cores have two notches in the bore of each segment to allow them to be attached to key bars mounted on a rim attached to the rotor. This rim is usually supported by spider arms welded to the rotor shaft.

The type of rotor core and winding cooling provided depends on the size and design of the machine. In smaller motors and generators, heat is removed by air scrubbing the rotor outside diameter as it passes along the air gap and outwards through vent ducts in the stator core. In larger machines, spider arms or axial ducts in the rotor core facilitate the passage of cooling air into the rotor near the shaft and then radially outwards through vent ducts in the rotor and stator cores. In some designs with only one air fan, cooling both stator and rotor cores and their windings is achieved by having axial ducts in both cores.

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CHAPTER 7

GENERAL PRINCIPLES OF WINDING FAILURE, REPAIR AND REWINDING

Before discussing the specific failure and repair processes for stator and rotor windings, as well as the associated laminated cores, an overview is useful to place this subject in context. As will be apparent in Chapters 8–13, there are about three dozen separate deterioration mechanisms that can operate on the different kinds of rotors and stators. Further, there are numerous repair procedures, in addition to rewinding. This chapter describes why there are so many failure processes and what causes one process to dominate, eventually leading to failure in a particular machine. Also presented is information on how to select an appropriate repair method from all the possible options. Methods are also presented to make a machine operational after an in-service failure. In keeping with the subject of this book, machine failure due to bearing problems, structural problems, and cooling system problems (except where they lead to winding overheating) are not discussed.

7.1 FAILURE PROCESSES

Some machine failures, which are identified by a stator ground fault, rotor ground fault or extremely high vibration, occur as a result of a catastrophic event, regardless of the original condition of the insulation. There is no way to anticipate their occurrence. Such events include:

- Improper electrical winding connections during manufacture or repair, which lead to extremely high circulating currents
- A loose metal object in the machine after manufacture or maintenance, which then cuts through the stator or rotor insulation
- Operating errors such as out-of-phase synchronization on a synchronous motor or generator, or inadvertent shutting down of the cooling system (if present).

Although such failures usually occur soon after the machine has been put into service or returned to service following maintenance, most machine windings do

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

not fail as a result of a catastrophic event. Rather, failure most often is the result of gradual deterioration of the insulation, until it no longer has the electrical or mechanical strength to withstand either normal operating stresses or the electrical/mechanical transients that can occur during normal operation. It is usually the insulation that deteriorates rather than the copper or laminated steel, since the mechanical and thermal capabilities of the predominantly organic insulation systems are far inferior to those of copper, aluminum, or steel.

The failure process, which is a term we will use interchangeably with deterioration process or aging process, is usually slow. Manufacturers have designed most industrial and utility motors and generators to operate for 10–40 years before a rewind is needed. Thus, the failure process should take at least this long. The date on which a machine failure will occur cannot be predicted in the case of age-related failures, because two independent conditions need to occur before failure happens. The first is the reduction in electrical or mechanical capability due to aging. Chapters 8–13 will discuss how each deterioration process causes this aging. However, the common insulation systems in use in stator and rotor windings have an amazing ability to continue to operate even though they may be severely deteriorated. Thus, the second condition that is usually encountered before failure is the occurrence of a mechanical or electrical transient. Such transients include:

- A lightning strike to the power system that causes a short-rise time, high-voltage "spike" that breaks down a weakened stator turn or ground insulation.
- A phase-to-ground fault in the power supply system. Such a fault can give rise to an overvoltage of about twice the normal rated voltage [1], which can break down aged stator insulation, and by induction, the rotor insulation.
- A hipot test done during maintenance (see Sections 15.2, 15.6, and 15.16), which also applies a larger than normal voltage to the stator insulation.
- A power supply (or power system) fault that causes a sudden surge in current to go through the stator (and by induction, the rotor), which in turn gives rise to larger than normal mechanical force acting on the windings (Equation 1.3). This sudden burst in mechanical force can crack aged insulation, especially in the end winding. One cause for a current transient is a phase-to-phase short on the output bus of a motor or generator.
- Motor turn-on (induction motors) or out-of-phase synchronization (synchronous machines only), which cause a very high current to pass through the stator winding and rotor. In the stator and in induction motor rotors, this current will cause a large mechanical force that can crack insulation or conductors. In synchronous rotors, there will be high negative sequence current flowing on the rotor surface, leading to rapid overheating and possible melting. Similarly, if only two of the three phase poles close in a circuit breaker, very high current will flow, with similar consequences.
- Operator errors such as forgetting to close rotor winding circuit breakers, or opening them under load, will cause very high voltages or currents in the machine. Similarly, turning off or failing to turn on cooling water to the

machine, or blocking ventilation circuits, can lead to melting of insulation, especially if it has already aged.

The important point to remember is that a new winding can often withstand the above events because it has sufficient electrical and mechanical strength. Indeed, as discussed in Sections 15.2, 15.6, and 15.16, manufacturers design new windings to be able to withstand the likely voltage transients and most of the likely current transients such as a three-phase short on the machine terminals. However, as the insulation ages, it has less ability to withstand the transient. Eventually, sufficient deterioration will occur that a transient that could be tolerated in the past now causes failure. In consequence, the actual date of a machine failure is not only determined by the condition of the windings, but also depends on when a transient will occur. The day when a transient occurs depends on when the operator makes his/her mistake, or when something goes wrong elsewhere in the power system. Thus, it is not possible to predict the time of failure or remaining life in, say, months, because it is not possible to predict when some other external event will occur [2]. We believe that only the “risk of failure” can be determined, assuming an event occurs. This theme will be repeated in Chapter 14.

7.1.1 Relative Failure Rates of Components

The main components of a motor or generator are the stator winding, rotor winding, and bearings that support the rotor. Some surveys have been undertaken to find which of these components are responsible for the most failures. Although old, by far the most comprehensive survey was a study funded by EPRI on large induction motors in the 1980s [3,4]. The study surveyed 7500 motors, and the authors took care to identify the root causes of failures. (In many cases, plant personnel know only that a ground fault relay tripped and assume that the stator winding failed, or plant personnel see a failed bearing and do not realize that the root cause was a rotor winding problem.) Table 7.1 shows that 37% of the failures were attributed to stator winding problems and 10% of the failures were attributed to induction motor rotor failures [3]. Therefore, windings are a major cause of motor problems. Note that a greater percentage of problems with bearings do tend to occur when a motor is first commissioned, presumably due to balancing, alignment or issues with the driven load. However, once the machine is operating smoothly and the motor has seen some operation, the failure percentages in Table 7.1 seem reasonable.

A similar but less rigorous failure study was carried out on oil platform motors in the North Sea [5]. The stator and induction motor rotor failure rate as a percentage

TABLE 7.1 Motor Component Responsible for Failure

Component	Percent of motor failures
Bearings	41
Stator	37
Rotor	10
Accessories	12

of all failures was found to be 25% and 6%, respectively. The lower winding failure rates in this study are attributed to the fact that other devices, external to the motor, were included as causes of failures, whereas in the EPRI study, they were excluded. In addition, a large number of smaller motors were included in the statistics.

In contrast, a study funded by a European insurance company showed that for medium and high voltage motors, stator windings accounted for 66% of all failures, whereas bearings and rotors each cause 13% of failures [6]. It seems that the larger the machine, the less likely are bearing and related mechanical problems, perhaps due to the more robust bearings used in larger machines.

We are not aware of similar comprehensive studies of generator failure causes. The outage statistics of the North American Electric Reliability Council are not sufficiently detailed to determine the component that is at fault. However, an IEEE working group published data in 1979 for hydrogenerator failures [7]. In that study, stator winding insulation problems caused about 40% of the outages. Rotors caused very few problems. A more recent study by a CIGRE working group found that stator insulation was the cause of 57% of failures [8]. It is interesting that in a large study of hydrogenerator stator winding life, it was found that the time between rewinds was an average of 50 years [9]. This probably means that there are many repairs possible on stator windings that can significantly increase their life.

7.1.2 Factors Affecting Failure Mechanism Predominance

Since there are many failure mechanisms, it is reasonable to ask what determines which mechanism will actually cause failure in a stator or rotor winding. We believe that there are four main factors that determine the process that will occur:

1. Design of the windings
2. Quality of winding manufacture
3. Operating environment of the machine
4. Past maintenance

The first two factors are primarily the domain of the motor and generator manufacturer, whereas the latter two are the domain of the machine user.

Winding Design The manufacturer is responsible for the machine design. For example, in a stator winding, the manufacturer sets the average electrical stress across the insulation by determining the insulation thickness and the operating voltage. The winding temperatures are set by, among other things, the conductor cross-sectional area and the type of cooling system. The mechanical design is determined by the type of end winding bracing system and slot wedging/support system. The manufacturer determines what stress levels they are comfortable with, based on material properties, aging tests (see Chapter 2), and, of course, past successful experience.

However, the designer must make many compromises when taking into consideration the cost of materials and the labor needed to manufacture the winding. Reducing one type of design stress will often cause another stress to increase. For example, in a form-wound stator, end winding temperature can be reduced by limiting the amount of blocking material used between adjacent coils. The consequence is that the end winding will not be as well supported and more likely to suffer from end winding vibration. Similarly, the groundwall insulation thickness can be decreased in an indirectly cooled winding, which means it will be easier to transmit the heat from the copper conductors to the stator core, consequently lowering the stator winding temperature and the risk of failure due to thermal deterioration. However, this same decrease in the insulation thickness will increase the electric stress and, thus, the risk of failure due to partial discharges. Other examples are given in Reference 10. The machine designer must make these design stress trade-offs. Unfortunately, this results in some stresses being higher, and this will favor one failure process over another.

Quality of Manufacture There are many examples of poor quality leading to specific failure mechanisms being more likely than others. In an induction motor rotor, if the rotor bars are made slightly larger than specified, both the bars and the laminations will be damaged as the bars are driven into the slots. If the insulation on a high-voltage motor stator coil is poorly impregnated, partial discharges will occur that may eventually bore through the insulation leading to a ground fault. If the bracing and lashings are misapplied or even missing in a stator end winding, then the magnetic forces during operation or on motor start-up will lead to vibration and gradual insulation abrasion. There are many more examples in [10,11]. The concept is that one or more failure mechanisms may predominate, depending on what quality deficiency occurs.

Operating Environment The plant architect/engineer and/or the user determine the operating circumstances for a motor or generator. The operating environment is partly due to the application and partly due to the physical environment. Obviously, if a motor is driving too large a load for its rating, the stator windings may overheat, causing thermal failure. If a motor or generator is subject to frequent stops and starts, then some mechanisms such as thermal cycling and surge-induced failure may be more likely. If a synchronous machine is required to supply excessive reactive power, then thermal deterioration due to the increased magnetic flux may occur in the stator winding at the ends of the core. In these situations, the application is wrong for the machine. It is interesting to note that the EPRI motor failure survey found that a large percentage of failures resulted from misapplication [3].

The physical environment that can affect winding failure mechanisms include:

- Abrasive particles in the cooling air in open ventilated machines
- Presence of oil, moisture, and/or salty air
- Presence of chemicals in open-ventilated machines
- Altitude in air-cooled, high-voltage machines (see Section 1.4.4, and recall that air pressure changes with altitude and thus PD)
- Ambient temperature
- Ambient humidity

If any of these environmental factors are extreme, then one or more failure mechanisms will become more likely.

Past Maintenance If a user has decided not to clean a winding in an oil-rich environment, then the oil may act as a lubricant and increase the chance of winding-vibration-related failures. Similarly, if the oil traps dirt and allows it to accumulate, then cooling passages may become blocked. Consequently, the rotor and stator may suffer thermal-induced failure, unless the windings and cooling air passageways are cleaned. Many other examples are possible. If timely corrective procedures, such as cleaning, rewedging, dip/bake, are not performed, then some failure mechanisms are more likely to occur.

7.2 FACTORS AFFECTING REPAIR DECISIONS

For any particular failure process, there are usually a number of possible repairs. Each repair method will have an associated:

- Cost in parts and labor
- Time to complete (setting the outage/turnaround time)
- Ability to completely restore the winding or just slow down the failure process
- Probability that the repair will accomplish the desired result (i.e., reverse, stop, or slow down a failure mechanism)

What repair the user will select often depends on complex economic/engineering evaluation that assesses, among other things:

- Criticality of the machine to the plant. If it fails in service, will a process shut down, or will there be no impact in the short term? If there is a large cost impact, then more expensive (and possibly more effective) repairs may be justified.
- Availability of spare machines or spare major components such as rotors or stators. If a spare is available, and temporary stopping of the motor or generator is acceptable, then no repair (i.e., replace on failure) or an inexpensive repair (probably less effective) may be the best option.
- Cost of the machine. Many small motors (say, <50 kW or so) may be so inexpensive in comparison to, say, a stator winding clean/dip and bake, that replacement is cost effective.
- For large machines that are critical to plant production, an extensive cost/benefit analysis may be carried out to determine the best repair method. EPRI has funded the development of software tools to help owners of large turbine generators decide the optimum repair options [12–14].

In addition to repairs to reverse or slow down a deterioration process, there are alternatives to get a stator quickly back into operation after an in-service failure. These include:

- Temporary repair of localized damage
- Cutting out coils
- Bar or coil replacement, or a half coil splice

The following Sections briefly describe these alternatives. Normally any discussion on which path to follow will include the machine manufacturer or a machine service shop.

7.3 RAPID REPAIR OF LOCALIZED STATOR WINDING DAMAGE

Form-wound stator windings that experience localized damage during maintenance, or fail in service, can sometimes be repaired in a short outage/turnaround, and returned to service in a few days. This can be especially important for critical motors or generators where there is no backup, and where significant production is lost as a result of a failure. Generally such a repair is possible where the damage is very localized and the collateral damage is limited. In addition, such repairs are more likely to be successful if the damage is in a bar or coil that is operating at low voltage (as opposed to coils/bars connected to the line end terminals). Typically, such repairs can be done under the following circumstances:

- Localized mechanical damage occurred during a maintenance outage, where the ground insulation was damaged accidently during stator rewedging (e.g., the insulation was crushed by a hammer blow or a router used for wedge removal cut into the groundwall) or end winding maintenance.
- After a phase-to-ground fault in service due to gradual, general aging by any of the mechanisms described in Chapter 8, but where the most severely deteriorated point in the winding eventually failed. In this situation, when the machine is returned to service after a localized repair, failure will eventually occur at another location (since the original deterioration is widespread), but the temporary repair will give the user the time to plan and obtain materials for a rewind or more permanent repair. Phase-to-ground failures usually produce limited damage, as compared to a phase-to-phase fault.
- Sometimes metallic debris, such as a "magnetic termite," left in the machine during manufacture or maintenance will eventually cut a hole through the insulation, causing a localized phase to ground fault. Such damage can often be repaired and the winding restored to almost new condition, without the need for further repairs. Usually metallic debris from a spinning rotor (e.g., a balance weight) will cause widespread damage in many locations, so that a localized repair may not be economic or effective.

A detailed description of the temporary repair process is beyond the scope of this book; however, some procedures are described in References 15 and 16. Most machine manufacturers or large service shops can perform the repairs. Significant expertise is needed by the repair technician. Generally the repair process involves clearing away all the damaged insulation, and tapering back the existing insulation.

Figure 7.1 A coil that is in the process of being repaired after the coil insulation was accidently crushed by a hammer blow just outside of the stator slot (Source: Courtesy Iris Power-Qualitrol).

Replacement of the insulation is done using epoxy or polyester saturated mica paper tapes and/or epoxy loaded with mica dust. Mechanical damage in the end winding that is away from the electric stress relief coatings is most likely to be successfully repaired. Damage to the groundwall in the slot can only be repaired if it is on the narrow side of the coil or bar, immediately underneath the wedge. Figure 7.1 shows a photograph of a coil that has been successfully repaired after an accidental cut in the slot. Damage to stator relief coatings in the slot or underneath the silicon carbide coating will require such coatings to be restored. It is advisable to subject any repaired winding to at least a DC hipot test (Section 15.2), with a voltage equal to the peak line-to-ground voltage (or more). The reason is that if a power system fault occurs, even a neutral end bar or coil will see a transient up to the peak line to ground voltage. If a repair should then fail, the winding may be subject to a phase-to-phase fault. The high currents that then flow may lead to significant collateral damage to the rest of the winding and the stator core. Practical experience shows that even damage repaired in the slot can withstand a DC hipot equal to the peak line-to-ground voltage [16].

7.4 CUTTING OUT STATOR COILS AFTER FAILURE

If an in-service failure occurs, and the damage involves several bars or coils, or the damage is at a location where a localized repair is not likely to be successful, it is sometimes possible for the user to cut out a coil (or bar) from the winding, and/or cut out entire circuit parallels. In either case, the purpose is to de-energize the coil or bar that has had a ground fault. By isolating the grounded coil or bar from the rest of the stator circuit, the machine can often be put back into service without actually fixing the failed coil. Depending on the operating conditions, and how many coils/bars are cut out, the machine can be returned to service in a few days at partial or sometimes even full load. If the coil/bar failed because of a local flaw, then the rest of the winding may run its normal life. If the coil that failed was just the first of many because of a widespread deterioration mechanism, then cutting out a coil may allow the machine to be put back into service long enough to order and install a new winding.

In three-phase motors and generators, cutting out a coil or a parallel may give rise to negative sequence currents or other circulating currents, as well as core hotspots due to nonuniform magnetic flux concentrations, resulting in hot spots in the stator core adjacent to the slots containing coils/bars that have been cut out. Sometimes, to reduce these currents, it is necessary to cut out more than one coil to balance impedances. The total machine derating that may be necessary to prevent overheating will depend on the total number of coils/parallels removed. The procedures for calculating the derating, determining which coils to cut out, and the mechanics involved, are described in detail in two EPRI publications [17,18]. EASA also has published a technical manual describing the process for their member motor and generator repair shops [19]. In general, the procedures described in these three publications are conservative, that is, the derating needed to keep stator winding temperatures within a safe level is often much less than calculated. It is prudent to monitor the area where coils/bars have been removed from the circuit with temperature sensors mounted nearby.

Cutting bars and coils has been successfully applied to motor and hydrogenerator stator windings. In general, cutting out bars in large turbine generators is not feasible, as there are usually relatively few bars in the winding, and removing even one bar will disturb the magnetic flux too much (creating hot spots).

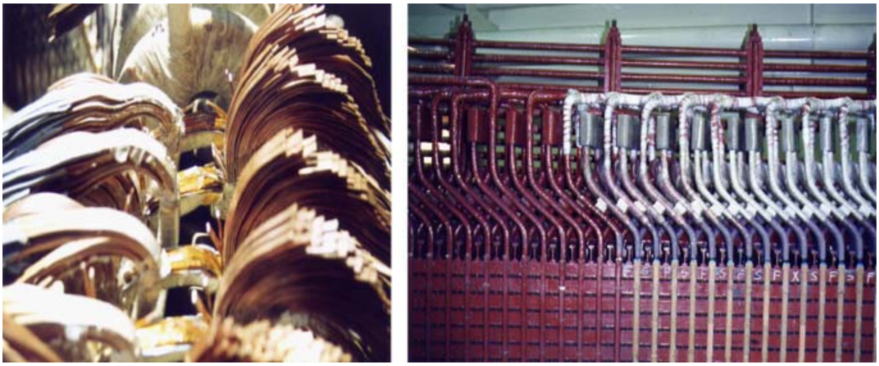
7.5 BAR/COIL REPLACEMENT AND HALF COIL SPLICE

When one or a small number of coils or bars have been damaged as a result of manufacture, maintenance or an in-service fault, it is often not possible to repair the coil/bar as discussed in Section 7.3 if:

- the damage is to a bottom coil/bar
- the damage is on the side of a coil in or just outside of the slot, and/or
- the bar or coil operates at or near high voltage.

A possible repair to quickly return the stator to service is to replace the damaged bar or coil. Such a repair can only be contemplated if the owner ordered some spare bars or coils when the machine was purchased. This procedure is much more difficult to implement if the stator winding is of the global VPI type.

If the stator is a Roebel bar type of winding, and the damaged bar is in the top position (closest to the rotor), then bar replacement is straightforward, with little



(a) (b)

Figure 7.2 Half coil splices on a hydrogenerator (a) during the brazing process and (b) after completion. Many top coils were damaged when a part flew off the rotor. End caps were used to insulate the splice connections (Source: Photo Courtesy Mr. R. Wheeler).

possibility of damage to adjacent bars. However, if the damaged bar is in the bottom position, then to remove the single bottom bar will require the removal of a large number of top bars. Unless a set of spare top bars is available, the removed top bars will have to be reused. Since removal of the top bars can cause considerable damage, it is necessary to AC hipot test all the removed bars that need to be re-used, to ensure that they were not damaged.

A coil replacement always means that a considerable number of coils have to be first removed to access the damaged coil, since the bottom leg of the coil will be "covered" by several other coils in the end winding. Preferably, there should be sufficient spare coils to replace the removed coils; otherwise the coils that must be removed should be given hipot tests to ensure their fitness for reuse.

It is possible that the top leg of a multi-turn coil was damaged, and the bottom leg is undamaged. If there is a spare coil, then a half-coil splice can sometimes be done. In this case, the top leg is cut at each end, and removed. The identical leg from a spare coil is then spliced in its place. This splice will require that each strand be individually brazed and insulated (at each end), and the groundwall restored. A half coil splice should only be attempted by skilled, experienced, and patient craftspeople. It will normally take about a week to accomplish. Figure 7.2 shows several half coil splices on a hydrogenerator.

7.6 REWINDING

If a stator or rotor winding has been destroyed as a result of a failure, or the deterioration is so widespread and advanced that failure is imminent, then a rewind may be the best option. Rewinds are also performed if the machine is to be uprated, because modern insulation systems need less insulation thickness, allowing more copper to be inserted in existing slots. In addition, newer materials may allow the machine to be operated at higher temperatures.

If the rewind is needed because the original winding failed prematurely, then it is important to determine the root cause of the premature failure. With an understanding of the failure mechanism, it is often possible to change the design of the winding to reduce the risk of the same failure process happening again. For example, many older motor stator designs tend to run hotter than needed, because the amount of copper in the slot or the arrangement, number, and size of the strands are not optimal. With a suitable redesign, a new winding can be fit in the same slot and run 10–25°C cooler. This will reduce the risk of thermal failure. Similarly, if the sub-conductors of a round rotor were initially not insulated, "copper dusting" could lead to many turn faults (see Section 9.3). This can be avoided in a rewind by making suitable design changes, for example, insulating the sub-conductors from one another.

Rewinding implies that the core will be reused. Non-global VPI windings can normally be removed without much damage to the core. However, global VPI stators and rotors generally are raised to higher temperatures to make it easier to remove the windings (Section 13.1.2). Clearly, a large "burnout" oven is needed for this. For large turbogenerator stators up to 300 MVA, such ovens do not exist, and even if they did, it would probably result in too much distortion. For such stators, the global VPI windings must be stripped when cold.

A good rewind specification is important if the user is to ensure that a long life is obtained from the rewound rotor or stator. The items to consider for inclusion in a rewind specification for stators and rotors are discussed in Chapter 18. On complete windings, the tests that could be performed are discussed in Chapters 15 and 19. IEEE 1665 also discusses some aspects of what can be included in a rewind specification [20].

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CHAPTER 8

STATOR FAILURE MECHANISMS AND REPAIR

This chapter presents the main aging and failure mechanisms of stator windings, as well as the options associated with each mechanism for repairing the stator or altering its operation to extend winding life. More extensive repairs such as cutting out a coil were discussed briefly in Section 7.4 and rewinds will be discussed in Section 18.4. The only failure mechanisms discussed here are those that are due to gradual aging of the winding. Rapidly occurring catastrophic events such as out-of-phase synchronization, improper manufacturing such as incorrect winding connections, or large objects falling into the machine that cause immediate failure are not presented here.

Some of the failure mechanisms will only occur on form-wound stators, and some only in random-wound stators. However, many of the failure processes can occur in either type of stator. Thus, each section will discuss the relevance of the failure process for both random-and form-wound stators.

The symptoms for each failure mechanism are also described. These symptoms are observed with a visual examination of the winding (but no dissection of coils), and with some of the diagnostic tests described in Chapter 15.

8.1 THERMAL DETERIORATION

Thermal deterioration occurs on both form-wound and random-wound stators. It is probably one of the most common reasons stator windings fail and need to be rewound, especially if the machine is air-cooled. This failure process is not very likely on direct water or hydrogen cooled windings, assuming the cooling channels within the stator bars are not blocked.

8.1.1 General Process

Thermal aging can occur through a variety of processes, depending on the nature of the insulation (thermoset or thermoplastic) and the operating environment (air or hydrogen).

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

In air-cooled machines, where the insulation is a thermoset (epoxy or polyester) material or a film on modern magnet wire, thermal deterioration is essentially an oxidation chemical reaction; that is, at sufficiently high temperatures, the chemical bonds within the organic parts of the insulation occasionally break due to the thermally induced vibration of the chemical bonds. When bond "scission" occurs, oxygen often attaches to the broken bonds. The result is a shorter and weaker polymer chain. Macroscopically, the insulation is more brittle and has lower mechanical strength and less capability to bond the tape layers together.

For magnet wire (winding wire) in random-wound stators, brittle insulation resulting from thermal aging is easily cracked as the copper conductors move under magnetic forces during start-up or normal operation. The aged insulation can also easily peel off the conductor. Both mechanisms can lead to magnet wire insulation failure due to abrasion. In both cases, turn shorts may result, which rapidly lead to local overheating at the site of a short, melting the copper and any other nearby insulation, eventually causing a ground fault (Section 1.4.2).

In addition, for form-wound stators, the reduced bonding strength between strands and ground insulation allows the mica tape layers to start separating, resulting in delamination. Figure 8.1 shows delamination of an epoxy mica groundwall due to long term thermal deterioration. At this point, two processes can lead to failure:

1. The copper conductors are no longer tightly held together. Eventually, the conductors may start vibrating against one another because of magnetically induced forces. Strand shorts or, more seriously, turn faults if it is a multi-turn coil winding, will occur as a result of insulation abrasion. This will create local hot spots, which then decompose the ground insulation, leading to a ground fault. Because a turn fault almost always leads very soon to a ground fault,

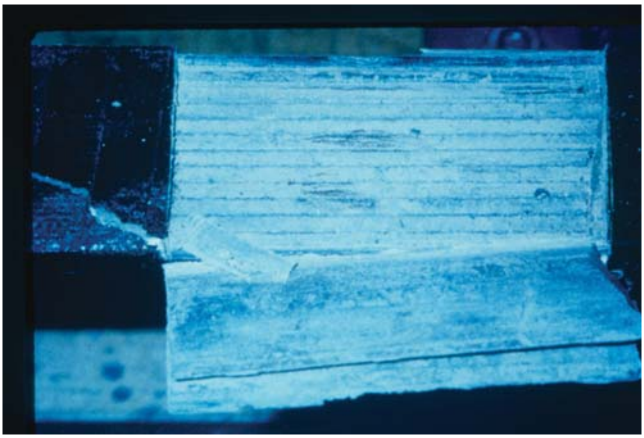

Figure 8.1 A short length of a 4.1 kV motor stator coil that operated for about 20 years at up to 120°C before failing due to thermal aging. The Class 155 (Class F) groundwall insulation has been peeled back to reveal the copper conductors, as well as the complete lack of bonding between the mica paper tape layers.

multiturn coils may experience failure sooner than Roebel bars as only one or two layers of turn insulation need to fail.

2. If the coils are operating at a voltage higher than about 3 kV, partial discharge (PD) may occur in the delaminated insulation. Depending on the PD resistance of the mica tape layers, the PD will eventually erode a hole through the ground insulation or the turn insulation, causing a ground fault.

In older form-wound coils and bars made with thermoplastic bonding materials such as asphalt, there may be an additional failure process. As the asphalt's temperature rises above some critical threshold, usually 70–100°C, the asphalt softens and may actually flow. The result is less asphalt between the tape layers. This delamination leads to conductor vibration and/or PD, as mentioned above.

Rapidity of deterioration depends on the insulation material and the operating temperature of the insulation. As discussed in Section 2.3, each insulation material is rated for its thermal capability. Most windings made before 1970 used Class 130 (Class B) materials, which implies an average life of 20,000 h (about 2.3 years) at an insulation temperature of 130°C. Most modem form-wound insulating materials are rated Class 155 (Class F), that is, will have an average life of 2.3 years at 155°C. Modem random-wound machines typically have Class 155 (F) or 180 (H) insulation systems that can operate at about 155°C and 180°C, respectively, for 2.3 years before becoming brittle. Clearly, the better the thermal capability of the insulation, the longer it will last at a given operating temperature. In general, modern Class 155 stator windings will not experience thermal aging if the stator winding hotspot temperature (measured by a winding resistance-temperature detector, RTD or thermocouple, TC) is below 110°C.

As the process is an oxidation chemical reaction, the higher the temperature, the faster will be the chemical reaction and, thus, the shorter the time to degrade the insulation. As discussed in Sections 2.1 and 2.3, experience shows that for every 10°C rise in operating temperature, the thermal life of the insulation will be reduced by about half. If the insulation is operated at its rated class temperature (say 155°C for Class F windings), then it can be expected that significant deterioration will start occurring after a few years in service. If the insulation is operated at a temperature that is 30°C lower, then about eight times longer life can be expected—about 20–30 years. Therefore, the higher the operating temperature, the faster the deterioration process will be. Thermal deterioration can result in failure after just a few months or may take many decades, depending on the insulation materials and the operating temperature.

Generally, thermal deterioration is not too likely in a directly cooled stator bars, unless there has been a severe operating problem (such as interruption of the stator cooling water or localized stator core overheating). In hydrogen cooled machines, the lack of oxygen slows down the thermal deterioration process. In addition, most manufacturers have designed the machine such that the insulation is usually operating at a much lower temperature than its rated thermal capability.

The maximum insulation temperature is not directly measured in most machines. The standard method used to monitor the temperature in an indirectly cooled form-wound stator is an RTD or TC embedded in the stator slot, between the top and bottom bars/coils. In addition, in direct hydrogen or water cooled stators, bar outlet hose thermocouples are often fitted to measure the temperature of hydrogen or water flowing out of conductor bars. For an indirectly cooled machine (all motors and most generators under a few hundred megawatts), the slot RTD or TC temperature will be 5–20°C cooler than the insulation at the copper conductors (the thicker the insulation the greater the difference in temperature between the copper and the RTD or TC). Thus, deterioration will happen fastest at the copper, and slowest on the coil surface. At the temperatures discussed above, the insulation temperature refers to the insulation temperature at the hottest spot—usually the temperature adjacent to the copper. In random-wound machines, embedded temperature sensors are rare and, thus, the true operating temperature of the stator winding insulation is not accurately known, except when a factory load test is followed by a temperature rise measurement (inferred from the copper resistance).

8.1.2 Root Causes

Thermal deterioration is caused by operation at high temperature. There are a number of reasons why high winding temperatures may occur:

- Overload operation. When the load on the motor or generator is greater than what it was designed for. In general, the temperature will increase with the square of the stator current.
- Poor design. For example, the conductors are too small, there are high circulating currents from inadequate transpositions (in form-wound machines); too large a conductor strand copper cross-section, giving rise to eddy current losses; unbalanced number of turns in each circuit, leading to negative sequence currents (this also occurs if coils are cut out); inadequate cooling system, etc.
- Poor manufacture. For example, due to strand shorts (in form-wound stators), core lamination shorts, and partially blocked ventilation paths, because coils are installed too close together in the end winding.
- For induction motors, insufficient time between motor starts. Each time a motor is started, there is an inrush current about five to six times larger than in normal operation. This inrush current creates an additional I^2R loss. The resulting heat takes time to dissipate. If a motor is restarted shortly after an initial start, the stator (and rotor) winding may still be hot from the first start, and the second start will add to the temperature. This is particularly true for high inertia-drive applications such as fan drives, in which acceleration times are long and, as a result, stator and rotor temperature increases during a start are high.
- High harmonic currents from inverter-fed drives (IFD) increase conductor losses, stator core and groundwall insulation dielectric losses.
- Negative sequence currents from voltage imbalance on the phase leads. A 3.5% voltage imbalance can lead to a 25% increase in temperature. The phase-to-phase supply voltage imbalance comes from the power system supply (utilities permit fairly high imbalances), or where one phase may have more load than the other two phases in a plant.

- Dirty windings that block ventilation ducts in the core and fill the space between coils in the end winding, with the resulting effect of reducing the cooling airflow.
- Dirty, air-locked, or clogged heat exchangers that fail to adequately cool the air (or hydrogen).
- Plugging of a large number of heat exchanger tubes carried out as a temporary solution to leaks that develop in-service or in the presence of significant (>50%) tube wall thinning.
- In direct water-cooled windings, debris or copper oxide in the water channels, obstructing the flow of cooling water.
- Loose coils/bars in the slot, which reduce the conduction of heat from the copper conductors to the core.
- In synchronous machines, operating the machine under-excited. In this case, axial magnetic fluxes are created at the end of the stator core, which induces circulating currents in the stator core ends (and to some extent in the stator conductors), causing local temperature increases at the core ends.
- Too many "dips and bakes" in which the stator is immersed in a liquid resin to tighten up the coils in the slot and repair abraded insulation. This process tends to close up ventilation paths through the core and end windings of form-wound stators, possibly increasing the temperature.

8.1.3 Symptoms

Visual signs of thermal deterioration will depend on the type of insulation and winding. Random-wound machines will show evidence of cracked or peeling magnet wire films, as well as discolored or brittle slot liners and bonding varnish. Thermoplastic form-wound stators will have puffy insulation, which will sound "hollow" when tapped with a hammer. Asphalt may also be oozing out from the groundwall over and above the initial release of excess asphalt that may be present in the form of hardened deposits. Thermoset form-wound stators will also sound hollow when tapped, but this only occurs after severe thermal deterioration. Indirectly cooled form-wound coils and bars will only show surface scorching after severe thermal aging.

In random-wound stators, thermally deteriorated insulation may have a low insulation resistance (Section 15.1) if any part of the magnet wire insulation has cracked or peeled away. Also, there may be a low-surge breakdown voltage (Section 15.16). There may also be a small decrease in capacitance and increase in dissipation factor over time (Sections 15.7 and 15.10).

In form-wound stators, thermal deterioration is accompanied by a decrease in capacitance over time and an increase in power factor and PD over time (Sections 15.10 and 16.4). If thermovision monitoring (Section 16.1.4) has been done over the years, then an increase in machine surface temperature may be evident (under the same operating and ambient conditions). Similarly, if stator winding temperature monitoring is present (Section 16.1.1), as the winding deteriorates, the temperature will increase a few degrees over time under the same operating and ambient conditions. This occurs because thermal deterioration often increases the thermal impedance between the copper and stator core (due to delamination and/or the reduction in bond between the coils and the core).

If the cooling system is becoming blocked, then also the machine temperature will increase. The location (e.g., core, winding) of the temperature increase will depend on the nature of the blockage, such as an air lock in the hydrogen cooler, debris or fouling in the stator cooling water system, or whether the temperature increase is accompanied by an increase in the differential pressure across the affected cooling system.

8.1.4 Remedies

The option selected will depend on the root cause of the overheating. Cleaning a winding to improve airflow will not solve a problem such as shorted strands leading to circulating currents. Thus, before the repair process is selected, the root cause must be established. Note that thermal deterioration of the insulation itself is not reversible (except if one considers a rewind). All that can be done with a suitable repair or change in operation is to slow the rate of thermal deterioration and, thus, extend life. It is important to note that several utilities have developed epoxy injection methods to restore deteriorated groundwall insulation when faced with the high costs of rewinding [1]. Although this novel approach may be suitable in particular circumstances, for example, micafolium windings, the long-term effectiveness of this procedure is not known.

Remedies for overheating include:

- Cleaning the winding and heat exchangers, venting air-locked heat exchangers to improve cooling air (or hydrogen) flow, and more efficiently extracting heat from the core and windings.
- Rewedge, sidepack and/or perform another VPI or dip and bake to improve thermal contact between the stator coils and the core. Note that the latter may increase the winding temperature if the coils are already tight, as the ventilation passages will be slightly more restricted by the addition of the extra insulation film.
- Ensure that the voltages on each phase are within 1% of each other.
- Upgrade heat exchangers (if fitted).
- Install a chiller unit on the cooling air circuit.
- For motors, install protective relaying to prevent frequent restarts.
- Reduce the maximum permissible load.
- Adjust the power factor in synchronous machines to unity to reduce the stator current.

8.2 THERMAL CYCLING

This mechanism, also called load cycling, is most likely to occur in machines with long stator cores (typically more than 2 m), and in form-wound coils/bars in machines experiencing many rapid starts and stops or rapidly changing loads. Large hydrogenerators subject to peaking duty, large air-cooled gas turbine generators, and pump storage machines are most likely to experience this problem. Direct water cooled stator windings are unlikely to experience this problem because the copper temperatures change only very slowly. Random-wound stators are very unlikely to experience thermal cycling-related failure.

8.2.1 General Process

There are three variations of this mechanism; which one occurs depends on the type of groundwall insulation (thermoplastic or thermoset) and whether the stator has been global VPI'd. The thermal cycling tests described in Section 2.5 model these processes. In all cases below, deterioration will be more rapid with faster load changes, longer stator cores, higher operating temperatures, and/or more frequent load changes. Past experience indicates that the process will normally take more than 10 years to cause failure, but some failures have occurred in a shorter time.

Girth Cracking/Tape Separation Girth cracking and tape separation are special variations of thermal cycle deterioration in thermoplastic insulation systems such as asphalt and mica splittings. The mechanisms of girth cracking are complex. When a generator with thermoplastic stator insulation is run up to full load in a few minutes, the I^2R loss in the copper rapidly increases its temperature. The high coefficient of thermal expansion of the copper causes it to quickly expand in the axial direction, whereas the thermal lag in the insulation and its contact with the still cool core restrain the insulation from moving with the copper. Initially, the insulation is bonded to the copper and the part of the groundwall outside of the slots easily moves with the copper. The slot section insulation cannot move as readily, as one of the characteristics of asphaltic and some other thermoplastic insulation systems during service is that the insulation expands into the cooling gas ducts and is, therefore, locked in place. The result is an axial tensile stress within the insulation between the insulation within the slot and the insulation in the end winding, that may be sufficient to cause tape layers to begin to be torn apart in the regions just outside the slots or within the outer sections of the slots. If the tapes part, they will eventually create a crack through the depth of the insulation just outside of the slot (Figure 8.2).

The insulation also expands due to thermal softening outside the slots, sometimes causing a bulge to develop that restricts insulation motion with the copper, and moves back into the slots when generator load levels fall and the copper cools.

In a single thermal cycle, as in base load applications, problems are unlikely. However, with many repeating load changes and the related thermal cycling, the insulation may circumferentially separate, following the path of the tape layers as they are wound around the copper package. Asphaltic insulations were always taped by hand. Normally, right-handed persons apply the tape from the left end of the coil or bar as they face it, taping toward the right end. The tape layers are in the form of spirals around the copper and it is these spirals that are stretched out by the girth crack process on the right end of the bar, as taped. The insulation thickness is reduced a small amount each thermal cycle and may eventually go all the way to the copper.

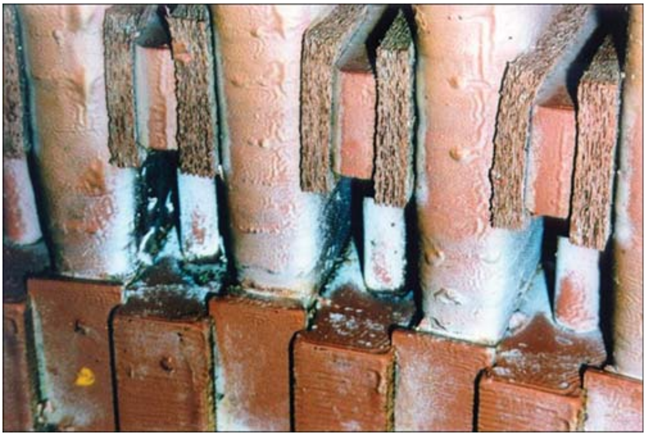

Figure 8.2 Example of girth cracking just outside of the slot on an old asphaltic-mica hydrogenerator winding. In severe cases the crack will completely penetrate through the groundwall to the copper.

Mica splittings contribute to the development of girth cracks because of the ease of delamination within their crystal structure. Mica paper has much smaller and thinner platelets and, generally, a thermoset resin binder. An insulation system based on these materials is much stronger and resistant to delaminating and tape separation. The tape backers for asphaltic systems were generally a kind of tissue paper, which is quite weak in tension. Modern epoxy mica paper tape uses a much stronger glass cloth backer layer. The result is that girth cracks in modem thermoset mica paper groundwall insulation are unknown, although cracks may sometimes occur in them due to their rigidity when exposed to magnetically induced end winding motions that are not properly blocked and braced.

Girth cracking in asphaltic-mica windings tended to occur in new air-cooled machines, or at any time in the life cycle of hydrogen cooled machines. Fresh asphalt and asphalt-modified drying oil varnishes used with this insulation type are either completely thermoplastic or have a low glass transition point, which results in extreme softness and very low physical strength at normal service temperatures when machines first go into service. When asphaltic insulation systems are used in air-cooled generators, service temperature leads to hardening of the asphalt by oxidation to an eventually infusible state, while the drying oil varnishes gradually increase in glass transition temperature and get stronger with time. When this type of generator is used in base load applications, there is very little thermal cycling and service may continue for decades without girth cracks developing.

From the late 1930s through the 1950s, hydrogen-cooled generators insulated with asphaltic mica splitting systems were produced. The hydrogen atmosphere inhibited oxidation and hardening of the insulation. The greater length, associated with increased ratings introduced during that period, led to more tensile stress on the insulation from differences in actual thermal expansion and relative motion between the copper strand package and the groundwall. This led to a number of generator failures due to tape separation during the post-World War II period and was the main cause for the development of thermoset stator insulations. Note that conversion of base load hydrogen-cooled generators to cyclic operation could turn a satisfactory generator into one with girth crack problems.

Conventional Thermoset Deterioration With conventional epoxy-mica insulated bars or coils that are fully cured before insertion in the stator, a different thermal cycling process can occur. As above, if the stator current goes from no load to full load in less than a few minutes, the copper temperature rapidly increases, causing an axial expansion of the copper. At the same time, the epoxy-mica groundwall is at a much lower temperature, since it takes some minutes for the heat from the copper to conduct through the groundwall to the stator core. The consequence is that as the temperature increases, the copper expands, but the groundwall expands less. This creates an axial shear stress between the copper and the groundwall.*

Although a single thermal cycle is not likely to break the bond between the copper and the groundwall, many thermal cycles will fatigue the bond. Eventually, the copper will break away from the groundwall (Figure 8.3). In some cases, the gap thus created between the copper and the groundwall will enable the copper conductors to vibrate relative to one another, abrading the strand or turn insulation. In addition, if the bar or coil is operating above about 3 kV in air, then PD may occur in the air space. The PD may eventually bore a hole through the groundwall, leading to a ground fault.

Large Global VPI Windings Since the early 1990s, some generator manufacturers have built air-cooled turbine generators rated up to about 300 MVA, using much the same global VPI process as has been used for decades in motors. In this manufacturing process, the copper is bonded to the groundwall, and the groundwall is bonded to the stator core. At full power, the bars expand axially beyond the slot. If the load is rapidly reduced, the copper will cool and shrink, as will the groundwall insulation, when the winding cools. However, the stator core retains its dimensions as the difference in stator core temperature between no load and full load is relatively small. Thus, not only is there a shear stress between the copper and the groundwall, but there is also a shear stress between the surface of the groundwall insulation and the stator core. After many fast load cycles, the coil may break away from the core under the shear stress developed. Once this occurs, PDs will occur between the surface of the coil and the core in coils operating at high voltage. In addition, the space that is created between the coil and the core may permit the coil to vibrate, abrading the ground insulation. The latter leads to the slot discharge mechanisms described in Sections 8.4 and 8.5 and a much shorter time to failure. This failure process is known to have caused stator failure in as soon as 4 years.

Some manufacturers have avoided this problem in large global VPI stators by installing a slip plane between the coil and the core. This allows the bar to break away from the core in a controlled manner after thermal cycling. Advanced design is needed to ensure that any air gap created at the slip plane does not have enough

*The greatest shear stress occurs when the windings are cool. When the coils are made, they are cured at a high temperature, and there will be no stress between the groundwall and the copper. As the coil cools, the greater shrinkage of the insulation creates the shear stress.

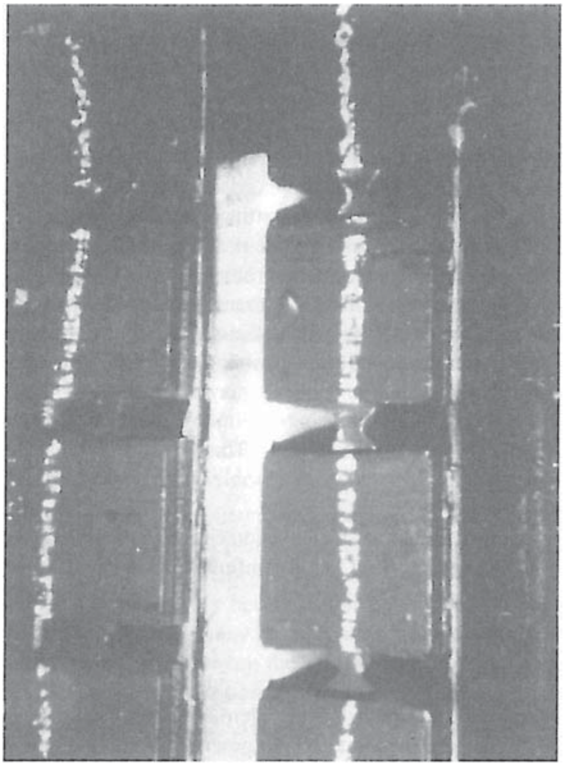

Figure 8.3 Cross-section of a turbogenerator stator bar in which the thermal forces have caused the groundwall to shear away from the copper. The black gap around the copper is where the shear occurred.

electrical stress across it to result in PD by using mica splittings between two layers of semiconductive tape. [2].

8.2.2 Root Causes

If any of the thermal cycling mechanisms occur, the root causes of failure are a combination of:

- Too fast a load change for the design.
- Operation at too high a stator winding temperature, as the higher the temperature, the lower the bonding strength; and the lower the bonding strength of the resins/asphalt, the greater is the chance that the interfaces will shear.
- Inadequate design of the insulation system to withstand cyclic axial shear stresses.

8.2.3 Symptoms

In asphaltic windings, the visual symptoms of failure include puffy insulation at the core ventilation ducts and just outside the slots. If tapped, the insulation will sound hollow. There will also be circumferential cracks in the groundwall just outside the slots.

In modern conventional epoxy-mica windings, there is usually little visual evidence of the problem, although the groundwall may sound hollow when tapped. For global VPI stators, there will be signs of abrasion (powdering/greasing) when looking down the stator ventilation ducts, as well as signs (light-colored powders or other discoloration) of surface PD activity in phase-end coils.

The power factor tip-up and on- or off-line PD tests are the most sensitive tests used to find this problem, as it will be accompanied by intense PD activity. Asphaltic windings may also exhibit low insulation resistance if the girth cracks have penetrated to a significant percentage of the groundwall thickness.

8.2.4 Remedies

The effects of thermal cycling are irreversible; thus, the stator winding cannot be restored to new condition if the process has already caused significant deterioration. However, there are several methods available to slow the process:

- Slow the rate of increase and decrease in power. This will let the temperatures of the core, copper, and insulation remain in as much thermal equilibrium as possible, reducing the differences in the shrinkage or expansion. The time needed to achieve near-thermal equilibrium can be determined by measuring how long it takes the stator temperature, as measured by the embedded RTDs or TCs, to stabilize after a sudden load increase or decrease. Typically, this can range from 10 to 30 min depending on size and cooling method.
- Reduce the maximum operating winding temperature by reducing maximum permissible load. At lower temperatures, the epoxies, polyesters, and asphalts have greater bonding strength to resist the shear stresses.
- Operate generators near unity power factor to reduce the load current and hence the resistive losses.
- For global VPI stators, inject carbon-loaded (i.e., conductive) epoxy or silicon rubber into the slots between the coils and the core. This will prevent the thermal cycling process from developing into the "loose coil/slot discharge" process (Sections 8.4 and 8.5). Note that the injection is not likely to stop the PD; experience shows it is impossible to completely restore the semiconductive layer using post installation injection.
- In thermoplastic systems with girth cracks, some users have been able to fill the cracks with silicon rubber or other compatible resins to improve the electrical strength of the coil insulation.

8.3 INADEQUATE RESIN IMPREGNATION OR DIPPING

Most random-wound stators are dipped in a resin or varnish after being wound, to seal the winding against dirt and moisture, improve heat transfer to the core, and hold the winding coil strands tight in the slot to avoid abrasion from vibration. In addition, for random wound machines fed from a PWM voltage source inverter, the winding must be impregnated to eliminate voids which would lead to PD, even on windings rated as low as 400 V (Sections 1.5.1 and 8.10). For similar reasons, in conventional form-wound coils, the groundwall is impregnated by the resin-rich or VPI processes (Section 3.10). In addition to the benefits described for random-wound machines, the impregnation also prevents PD activity within the groundwall by preventing air pockets from occurring (Section 1.4.4). Similarly, the global VPI process for form-wound stators is intended to eliminate voids within the groundwall to improve heat transfer, prevent conductor movement, and reduce PD.

Inadequate impregnation causing stator failure is more likely to occur in global VPI stators as it is more difficult for quality control procedures to find poor impregnation at the time of manufacture. Failure due to PD in the groundwall voids can occur in as short a time as 2 years in stators rated 6 kV or more. In converter-fed random-wound stators, poor impregnation can lead to failure in just a few months.

8.3.1 General Process

Poorly impregnated conventional random-wound stators are much more likely to fail due to dirt, pollution, oil, and moisture that can be partly conductive. It is not unusual for the magnet wire insulation to have small pinholes or cracks as a result of the rigors of manufacturing. If the impregnation or dipping cycle is poor, these imperfections in the magnet wire insulation, combined with a partly conductive contamination, lead to shorted turns and, thus, failure. Similarly, if the turns are not bonded together and to the core, the twice-power frequency magnetic forces due to motor start-up or normal operating currents cause the turns to vibrate. This vibration leads to abrasion of the magnet wire insulation and to turn shorts. Converter-fed random-wound stators that do not incorporate mica into the insulation system (i.e., a Type I insulation system according to IEC 60034-18-41) should be PD-free when manufactured. If voids are present, the repetitive voltage surges from the drive will cause PD, which will erode the organic magnet wire insulation as well as the ground and phase insulation in a few months to years (Sections 1.5.1 and 8.10). Turn, ground and/or phase-to-phase faults will then result.

Grossly inadequate impregnation of the groundwall in form-wound coils can lead to higher operating temperatures (since the groundwall thermal conductivity is lower), leading to thermal deterioration and/or conductor vibration, resulting in abrasion. However, if the impregnation is poor but not completely missing, the thermal and abrasion processes are less significant. Instead, if the winding is rated at 6 kV or more, PDs can occur in coils connected to the phase terminals. PD will occur in any air pockets resulting from the poor impregnation between the copper and the core, as described in Section 1.4.4. The PD will gradually erode a hole through the insulation. If the winding is made from multiturn coils, and the air pockets are located near the turn insulation (Figure 8.4), then the PD only has to erode the relatively thin turn insulation (taking a few years), leading to a turn fault and, consequently, almost immediately a ground fault due to the high circulating current (Section 1.4.2). For Roebel bars, the PD must erode through the entire groundwall thickness, which may take decades.

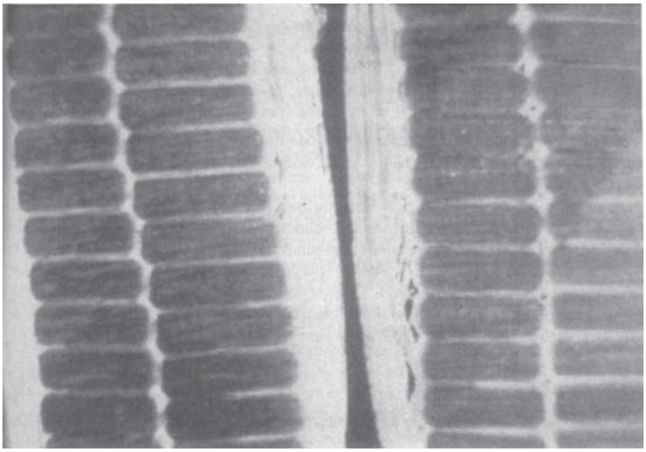

Figure 8.4 Cross-section of a 12-turn coil from a 6.6 kV motor stator made using the global VPI process. The dark voids near the copper resulted from poor impregnation with epoxy, just outside of the slot.

8.3.2 Root Causes

The possible causes of poor impregnation in random-wound stators are:

- A resin/varnish viscosity that is too thin or too thick, or other problems with the resin/varnish chemistry such as contamination and VPI resin gel particles.
- Processing the stator in a manner not in accordance with resin/varnish supplier recommendations, such as not preheating the stator or varnish/resin, inadequate time in the dip tank, and not completely immersing the stator (if appropriate, some impregnation methods such as trickle impregnation that do not require this may be used).
- Use of a magnet wire insulation that is not chemically compatible with the resin/varnish.
- A bake temperature that is too high or too low, or a bake time that is too short.

In form-wound VPI coils or global VPI stators, the root causes may include:

- Poor groundwall insulation taping, which leaves wrinkles in the tape and, consequently, a void too large to be filled by the low viscosity resin.
- Improper resin viscosity or chemical contamination.
- Resin that has been through too many VPI cycles and has not been adjusted to restore the proper chemistry specifications and freedom from suspended particles.
- Incompatible resin and insulation tapes.
- Improper preheat and too short a vacuum cycle, or insufficient vacuum, insufficient time in the heat cure cycle, or using improper curing temperature/pressure.

- Inadequate covering of the stator or coil with resin in impregnation cycle, or not rotating stator during cure so that resin does not drain away from high points.
- Inadequate impregnating pressure and time for the available resin viscosity and insulation thickness.

In resin-rich coils, poor impregnation may result from:

- Old resin-rich tapes that have already started to cure.
- Improperly stored tapes; that is, storage at too high a temperature or at too high a humidity.
- Poor taping, resulting in wrinkles that are too large. Air gaps between the wrinkles will not stay full of resin once the coil or stator is in the cure stage.
- Inadequate pressure or temperature during the cure cycle.
- Taking too long a time to move the coils/bars or stator from the hydraulic impregnation tank to the curing oven, allowing the resin to leak out.
- Poor pressure or pressing. In one type of resin rich process, a heat shrink tape is applied over the end winding to try to compress the tapes to reduce the space between the tapes especially at bends in the coil. This process is more likely to produce large voids in the end winding compared to when pressure is applied by a hydraulic process (asphalt tank) or custom made molds.

8.3.3 Symptoms

Poor impregnation is readily observable in random-wound stators as interstices are not filled with resin and there is no sheen over the coils and the core. The insulation resistance of the stator may also be low.

Poor impregnation is difficult to visually identify in form-wound coils/bars because it is most likely to occur adjacent to the copper conductors, far from the surface of the insulation. In severe cases of poor impregnation, the groundwall will sound hollow when tapped. For machines rated 3 kV or above, the PD test (sometimes an over-voltage is needed to test 3.3 and 4.1 kV windings) is the best way to detect poor impregnation (Section 15.12), although on individually impregnated coils and bars, the dissipation factor tip-up test is also useful (Section 15.11). The surge test may also identify if the turn insulation has been poorly impregnated (Section 15.16). The PD test will only be effective if the location of the poor impregnation is in or just outside of the stator slot; that is not in the end winding. If sacrificial coils are processed with global VPI windings, they can be given a dissipation factor tip-up test or a PD test to determine if voids are present. Alternatively, they can be dissected to determine if the impregnation was adequate.

8.3.4 Remedies

A random-wound stator can often be completely restored by a repeat dip and bake if failure has not yet occurred. However, form-wound coils have almost no chance of being properly impregnated once the initial impregnation is done and the coil/bar is cured. This is because the original impregnation will normally block the resin flow to the points near the copper conductors in the second impregnation. Thus, there is no way to extend life by either repairs or operation changes (unless the operating voltage can be reduced or the phase and neutral ends of the windings can be reversed). The only effective repair is a rewind.

The best way to avoid failures due to poor impregnation is to ensure that it does not occur in the first place. This requires the end-users to specify that the dissipation factor tip-up or off-line PD tests are done on every coil, bar and stator (in the case of GVPI stators). The manufacturer should also implement process controls that continuously monitor temperatures, pressures, times, and resin chemistry. Most manufacturers of GVPI stators also monitor the capacitance of the winding during processing because, as the winding becomes impregnated, the winding capacitance increases to an asymptote. During cure, the capacitance will gradually decrease. Where the VPI process involves separate impregnation and curing tanks, the time to move the coils/bars/stator should be minimized to increase the chance the resin will stay within the groundwall. Some GVPI manufacturers have found it prudent to rotate the stator during the cure process.

8.4 LOOSE COILS IN THE SLOT

This problem, also sometimes called slot discharge, is normally associated with form-wound stators using thermoset-type coils or bars, manufactured in a conventional way, that is, not by the GVPI process. Epoxy-bonded insulation is the most susceptible due to its generally lower coefficient of thermal expansion. Loose-coil-induced failure is one of the most likely failure processes in modern large gas and steam turbine generators, as well as hydrogenerators. It is unlikely to occur in global VPI motor stators or thermoplastic windings. See also the related problems of high intensity slot discharge and vibration sparking (VS), discussed in Sections 8.7 and 8.8. Random-wound machines may suffer from this problem if they were poorly impregnated, as described in Section 8.3.

8.4.1 General Process

As described in Section 1.4.8, coils and bars in stator slots are subject to high magnetically induced mechanical forces at twice the power frequency. As the MVA rating of a machine increases, the forces acting on the bars or coils at full power increase proportionally to the square of the current in the bar or coil.

If the bar or coil is held tightly in the slot at full load, these forces have little impact. However, if the coil is not tightly held, and it starts to vibrate, the coil insulation system moves relative to the stator core, primarily in the radial direction (i.e., up and down in the slot). Since the stator core is composed of steel laminations, the serrated edge of the laminations in the slot makes an effective abrasive surface. The coil movement first abrades the semiconductive coating (if present) and then the groundwall insulation. Experience shows that once about 30% of the groundwall insulation has been rubbed away, a stator ground fault is likely in both air-cooled and hydrogen-cooled machines, usually in the higher voltage coils (line end coils).

There are two basic stages for this loose coil/slot discharge process, also sometimes referred to as slot discharge. In the first stage, the bar or coil is vibrating but most of the semiconductive coating is intact. At this stage, some contact sparking will occur as the coil or bar semiconductive coating moves away from the grounded stator core and picks up some charge due to the capacitance of the air gap (amounting to a few volts of potential) between the coating and the core. When the semiconductive coating comes back in contact with the core, the stored charge is shorted to ground, causing a spark. This is sometimes referred to as Stage I slot discharge.

Stage 2 slot discharge occurs when the semiconductive coating is abraded away and the surface of the coil (at least at the abraded spot) is not grounded, even indirectly. Classic PD will then occur in coils operating at high voltage, as many thousands of volts can build up across the air gap between the core and the exposed groundwall insulation surface. As described in Section 1.4.5, such a high voltage across an air gap leads to electrical breakdown of the air or hydrogen, that is, PD. The intensity of PD is usually large enough to further accelerate the rate of deterioration of the groundwall insulation, at least in air-cooled machines.

Descriptions of the slot discharge process and its variations are found in References 3–5. In large machines with high bar forces, failure has occurred in as short a time as 2 years, making loose coils one of the fastest aging mechanisms. The mechanism can occur equally fast in air- or hydrogen-cooled machines. Although the PD activity is usually less in high pressure hydrogen-cooled machines, the rate of deterioration is similar because the vibration is the principal cause of deterioration, not the PD.

The global VPI process usually keeps the coils and bars tight within the slot, preventing the loose coil failure process. However, if the coils have been poorly impregnated (Section 8.3) and/or are subject to severe load cycling (Section 8.2), coils and bars have been known to become loose enough to lead to bar vibration and a rapid deterioration rate.

8.4.2 Root Causes

The fundamental cause of this deterioration is the magnetic force. However, coils and bars will not vibrate if they are not at least a little loose in the slot to begin with. With the asphaltic mica insulation systems and, to a lesser degree, the older polyester mica splitting insulation systems, when the stator current was increased to full load, the heat from the copper losses raised the insulation temperature sufficiently to expand the insulation in the slot. The result was that even if a coil was loose in the slot at low temperatures, it was tightly held in the slot at full load, greatly reducing the chance that the loose coil problem would ensue. As the coefficient of thermal expansion of epoxy-mica is low compared to asphalt and older polyester resins, if the coil is loose when it is cold, it is likely to still be loose when it is hot, when the bar forces are greatest. Consequently, the loose coil problem is most likely to occur in epoxy-mica insulated windings.

Coils and bars may be loose in the slot when they are manufactured because they were installed too loose. This initial looseness can be prevented by the use of

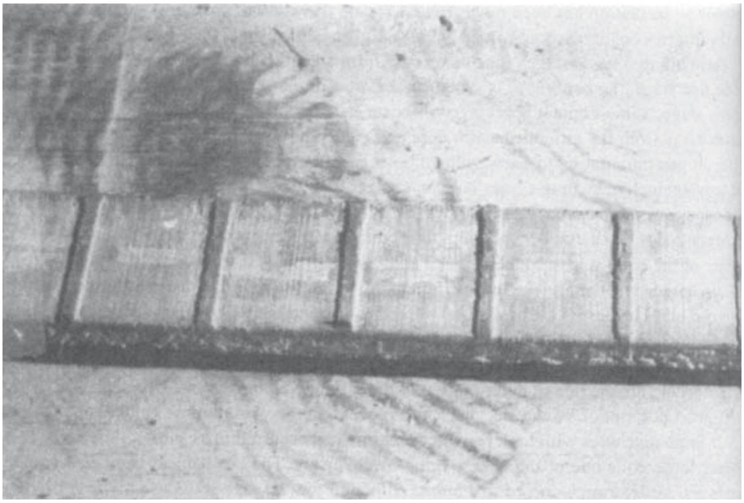

Figure 8.5 Photograph of the side of a coil suffering from insulation abrasion due to loose windings. The abrasion occurred along the length of the coil as the coil was not installed tightly when manufactured. The vertical ridges are where the groundwall has not been abraded as this is where the vent ducts occur in the stator core. The vertical ridge pattern is sometimes called the *ladder effect*.

ripple springs, two-part wedges that can create a follow-up positive force down into the slot, incorporation of compressible materials such as silicon rubbers into the slot contents, and/or the global VPI process (Section 1.4.8). Figure 8.5 is a photograph of a coil (removed from an air-cooled generator) that was loose in the slot due to poor design and installation. About one-third of the groundwall was abraded before it failed to ground.

Loose coils/bars can also exist in the slot as a result of the following processes that occur during operation of the motor or generator.

- Shrinkage of the insulation. Organic materials tend to shrink as they thermally age. Thus, after a few decades, an initially tight winding may become loose enough to cause abrasion as a result of the gradual shrinkage of the groundwall, sidepacking, and wedges. Note also that in the first year of operation, relatively significant shrinkage can occur as the groundwall insulation completes the curing process during operation. Typically, a modern epoxy-mica insulation system has completed about 95% of its cure during the manufacturing stage. If a new stator winding only has flat side-packing and flat wedges for slot support, it is advisable to check for winding looseness after about one year of operation. Some experts recommend that if only a simple slot support system is used, there should be no more than about 0.1 mm clearance between the side of the coil and the stator core [6].
- To combat the problem of gradual shrinkage, many machine manufacturers use ripple springs (warped epoxy-glass composites) under the wedges or as side

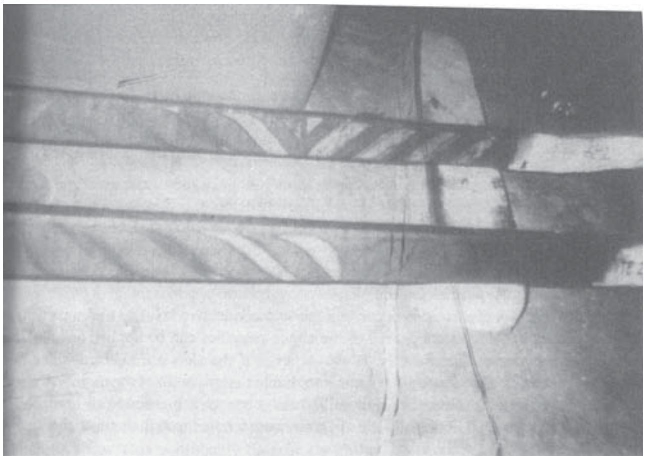

Figure 8.6 Photograph of a stator bar removed from a large hydrogen-cooled stator. The light-colored arcs are where the side ripple springs abraded the groundwall insulation.

packing (See Figure 1.16). The springs expand to take up the space created by shrinkage of the other slot components, holding the coils and bars tight. Ripple springs have become one of the most effective methods to keep windings tight. However, some experience shows that the ripple springs themselves may eventually lose their ability to hold the bars and coils tight after 2 decades or so, and thus need to be replaced. Operation at high temperatures can accelerate the aging process of the ripple springs. Some types of ripple springs lose their "spring" if oil is present for long periods of time. Oil also acts as a lubricant that facilitates relative movement between the coil and the core. Figure 8.6 shows the side of a stator bar from a large hydrogen-cooled generator, where deteriorated side ripple springs (due to the long-term presence of seal oil in the stator) allowed sufficient coil movement that the glass fibers in the ripple springs themselves abraded the groundwall insulation, resulting in a ground fault.

- Wedges can become loose over time, usually due to shrinkage, oil contamination, and/or stator core movement. Unless the coils or bars are forced tightly against the side of the slot, the loose wedges can lead to loose coils or bars in the slot.

Windings using some types of magnetic wedges seem to be particularly prone to coils becoming loose in the slot, even in GVPI stators [7]. Magnetic wedges will shrink with time (they usually have a high organic compound content) and are directly acted upon by the magnetic fields within the stator (unlike conventional wedges). Once a small amount of looseness occurs, the brittle magnetic wedges rapidly degrade to a powder and disperse throughout the machine, becoming a contaminant that accelerates the electrical tracking process (Section 8.11). Of course the stator bars/coils can also then start vibrating, especially in non GVPI stators. The deterioration rate of magnetic wedges can be slowed if non-magnetic materials are also used under the wedges to make sure that the magnetic wedges are not directly exposed to any vibration caused by movement of the coils in the slot [8].

8.4.3 Symptoms

Once the rotor of a motor or generator has been removed, it is usually fairly easy to determine if the coils/bars are loose in the slot. If the stator has not been contaminated by oil, when looking down the ventilation ducts in the core, the powder produced by abrasion of the insulation can be seen. Also, in the coils/bars connected to the phase terminal, there will be signs of pitting/burning caused by the PD. If the stator is contaminated by oil, "greasing," a viscous dark sludge formed from the abrasion products and oil, collects in the ventilation ducts and at the wedges (Figure 8.7). Often the wedges will be loose, yielding a dull thud when tapped with a hammer (Section 15.20). Note, however, that wedges may be loose, yet the winding can still be tight if the bars/coils are tightly sidepacked or use a side ripple spring. If the wedges can be removed, damage to the wedges and sidepacking by the pounding and abrasion is easy to see. A semiconductive coating contact resistance test (Section 15.18) will show a high resistance if the semiconductive coating has been destroyed.

Prior to machine disassembly, an on-line PD test (Section 16.4) can be used to determine if the coils are loose in the slot. If the coils are loose, the PD activity will increase dramatically with load, especially in hydrogen cooled generators. If there is widespread slot discharge, and the machine is air-cooled, then there will be a significant amount of ozone in the cooling air (Section 16.3).

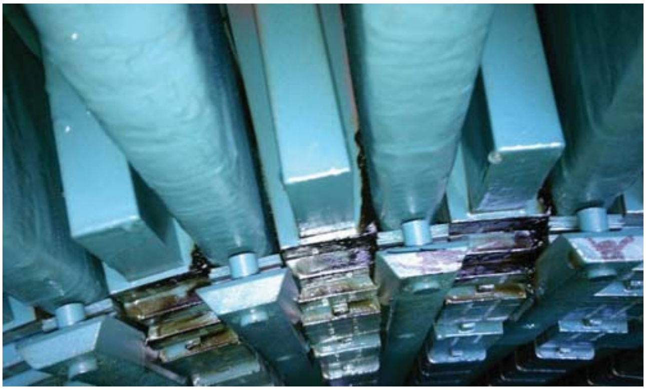

Figure 8.7 "Greasing" at the side of the stator wedges caused by movement of the wedges. (*See color plate section*).

8.4.4 Remedies

If loose coils and bars are detected at an early stage in the process, that is, while it is in the Stage I part of the process, then the stator can be restored to new condition by tightening the coils/bars in the slot. One or more of the following can accomplish this:

- Replacing the wedges and sidepacking
- Preferably, replacing flat side packing and flat wedges with ripple springs (Figure 1.16) and/or two-part wedges (Figure 1.15)
- Replacing top ripple springs if they have flattened out
- Injecting graphite-loaded paint, silicon rubber, or epoxy into the slots

In addition, the process can be slowed by operating the machine at reduced load, as this decreases the magnetic forces.

Once Stage 2 slot discharge occurs, the semiconductive layer has been partially destroyed, at least at some locations. All of the above remedies can be applied and the failure process will be slowed significantly. However, even if the slots are injected with a partly conductive material, experience shows it is impossible to replace all of the destroyed original semiconductive coating. Thus, gaps will still remain between the groundwall insulation and the core, resulting in PD. Eventually, the PD may bore a hole through the insulation.

8.5 SEMICONDUCTIVE COATING FAILURE

This failure process involves the deterioration of the semiconductive coating (also called the *OCP, conductive, stress relief*, and *PD suppression coating*—see Section 1.4.5) on a stator bar or coil in the slot in the absence of coil vibration. This mechanism only occurs on form-wound coils and bars that have graphite-loaded paints or tapes as the semiconductive coating; that is, it normally occurs on stators rated 6 kV or more for conventional machines. This process is more likely to occur on stators supplied by PWM voltage source converters due to the very high voltage impulses from such drives (section 1.4.6). Thus convertor-fed motors rated 3 kV and above (which will almost always have a semiconductive coating) are at risk. As the process involves PDs, this problem is far more likely to occur in air-cooled machines. Motors and generators operating at high altitudes (>1000 m) where the air pressure is lower and consequently the breakdown strength of air is lower, are more likely to experience this problem. Experience indicates that bars or coils with a paint-based semiconductive coating are more likely to experience this deterioration mechanism as compared to those with a tape-based semiconductive coating, although attention to keeping the graphite particles well dispersed in the paint base mitigates this.

8.5.1 General Process

As discussed in Section 1.4.5, the semiconducting coating is placed on the surface of high voltage stator bars and coils to prevent PD. Without the coating, PD would occur in the small gaps that would inevitably be present between the coils and the core, even in GVPI stators. In this failure process, the coating essentially becomes nonconductive by oxidation of the graphite particles and in some localized areas may be nonexistent. In the coils or bars that are operating at high voltage, PD will occur between the bar/coil and the core. This PD will attack the groundwall insulation. A hole may be bored through the groundwall, resulting in a ground fault. Since all mica-based groundwall insulation is very PD resistant, it can take many decades for this process to progress to failure. Note that this process occurs even if the coils are kept tight in the slot. The mechanism is sometimes called *electrical slot discharge*, to differentiate it from the mechanically induced slot discharge described in the previous section.

If the machine is air-cooled, the surface PD will create a gas called *ozone* (O_3). Ozone is a very chemically reactive gas that combines with nitrogen and humidity in air to create nitric acid (NHO_3). This chemical attacks many substances, including epoxy, polyester, rubber compounds, lubricating oil and steel. In particular, the production of the nitric acid facilitates the spread of the semiconductive coating deterioration to adjacent areas. High levels of ozone are thus possible with this process, as experience shows that most coils/bars operating at high voltage will eventually deteriorate due to the nitric acid attack, creating a large number of locations for the PD and thus more ozone to occur. In totally enclosed machines, the ozone concentration can reach over 10 parts per million (ppm). With such high ozone concentrations, it is likely that when a stator rewind is performed, the stator core may also have to be replaced, if the machine has been operating with such high levels of ozone for years.

The chemical attack by nitric acid on the materials in the slot may also cause a winding that is initially tight in the slot to become loose, leading to insulation abrasion due to coil vibration, as described in the previous section. Unless the coils are retightened, the failure process becomes much more rapid, as abrasion is inherently a faster deterioration process than PD attack.

If the coils/bars are kept tight in the slot, the PD itself may take many decades to cause failure. However, stators with this problem have had to be rewound due to water leaks from the air to water heat exchangers or from bearing wear due to lubricating oil degradation, both caused by the nitric acid. In addition, stators have been rewound not out of fear of imminent failure but because health authorities have declared the machine to cause an unsafe working environment. Most countries regulate the amount of ozone concentration that is allowable in the workplace. An open-ventilated machine that has extensive semiconductive coating deterioration can easily lead to "unsafe" ozone levels around the machine (usually around 0.1 ppm).

8.5.2 Root Causes

Invariably, the root cause of semiconductive coating failure is poor manufacturing procedures, both in making the coating and in testing it regularly during manufacture to ensure the appropriate coating resistance. It is believed that the process starts when the coating surface resistance is too high in localized areas. This is probably because the graphite particle density is too low in this area. If a coil with a locally high coating resistance is connected to the phase terminal, then capacitive currents will flow from the copper, through the groundwall insulation, to the stator core via the semiconductive coating. Since the coating is not in direct contact with the core on its top and bottom edges (i.e., the narrow edges in the coil cross-section) and at the ventilation ducts, some of the capacitive current must flow parallel to the bar/coil surface. If the resistance is high, small I^2R losses occur where the current is flowing laterally, heating the coating at these localized spots. This local heating, added to the general winding temperature, can lead to oxidation of the semiconductive coating, which further increases the semiconductive coating resistance, exacerbating the problem. In addition, if the resistance is infinite (i.e., the graphite density is below the threshold for any conduction) even in a small spot less than 1 cm in diameter, then PD may occur as described in Section 1.4.5.

This problem is especially likely to occur if the stator is fed by a PWM voltage source converter [9]. Because the switching frequency in the converter is typically 1 kHz or more, the capacitive currents flowing through the semiconductive coating are 20 times or more higher than with 50/60 Hz sinusoidal voltage (Section 1.4.6). This increased current through the coating increases the heating effect by the I^2, and thus can dramatically increase the rate of deterioration.

A variation of this problem can occur even if the semiconductive coating has a consistent and adequate surface resistance (typically in the range of 500–5000 Ω per square). In some manufacturing processes, small air pockets may occur just below the semiconductive coating, between the groundwall and the coating. In coils connected to the phase terminal, small PDs can occur in these voids. This PD attacks the semiconductive coating, increasing its resistance. Eventually, the problem progresses to the stages described above.

With both processes, the coating gradually becomes nonconductive in a process that tends to spread aggressively over the surface. As the infinite-resistance area spreads, PD occurs, gradually destroying the underlying groundwall.

8.5.3 Symptoms

During a visual inspection of the stator, this problem is easily seen, as the black semiconductive coating turns white, yellow, light gray, or light green (depending on the paint base). These light spots can be seen by looking down the core ventilation ducts (if present) in slots containing coils/bars connected to the phase terminals (i.e., operating at high voltage). Removal of the wedges will expose the top surface of the coil/bar, revealing large patches where the coating has disappeared. Figure 8.8 shows a slot in an air-cooled machine from which the wedges have been removed. The lack of semiconductive coating is apparent in the coil in the slot, which operates at high voltage.

Both off-line and on-line PD testing will detect the problem at an early stage. While relatively small in amplitude, the PD activity tends to be widespread (i.e., there

Figure 8.8 Photograph of a stator slot taken from the axis of an air-cooled machine. The stator wedges have been removed in one slot, exposing the top of a coil. The semiconductive coating on the coil connected to the phase terminal has disappeared (turned white). (*See color plate section*).

are many thousands of PD pulses per second). Measurement of the ozone concentration (Section 16.3) is a less sensitive way of detecting the problem.

8.5.4 Remedies

The best way to ensure that semiconductive deterioration does not occur is to ensure that the coating is manufactured correctly. This means that frequent surface-resistivity measurements must be made before coils are installed in the slot. Alternatively, a uv imaging device can be used to look for surface PD on coils energized to at least rated voltage as per IEEE 1799 (Section 15.14). If the problem occurs in an operating stator, there is no repair that can permanently restore the winding to new condition, unless the coils are removed from the slot and a new coating applied. As removing them from the slot can damage coils and bars, availability of spare bars/coils is critical for this alternative.

In-situ repairs usually involve injecting a graphite-loaded varnish, silicon rubber, or epoxy compound into the slots containing coils operating at high voltage. This remedy works best when the rotor and then the old wedges are removed. Many OEMs and some repair organizations have developed tools that inject the compound under pressure down the sides of the slots and via the ventilation ducts. However, it is impossible to inject the compound into all the locations where the coating has deteriorated. Specifically, the injection process usually misses the bottom edge of the coil/bar.

If the failure process remains a purely PD process, then the failure may take many decades to occur. However, if the process develops into a loose-coil problem, failure can be much faster. Therefore, it is important to replace the side packing and rewedge to keep the coils tight in the slot. The compound injection process also aids in keeping the coils tight.

There is little that can be done to slow the process by changing the operating regime. However, the process is driven by temperature and voltage. Thus, reducing the load can extend winding life. If the machine can be operated at a lower voltage, then the process will be slowed. Even a drop of a few hundred volts can be helpful. There is evidence that the process is faster under high reactive loads.

Reversing the winding, that is, changing the circuit ring bus connections to place the high voltage end coils at the neutral (and the neutral coils at the phase terminal), may also extend the winding life. However, it is important to install a relay that detects any ground fault that may occur near the neutral since the aged coils that were formally at the high voltage end may still fail at the neutral end. Conventional ground fault relays cannot do this.

8.6 SEMICONDUCTIVE/GRADING COATING OVERLAP FAILURE

This problem is closely associated with the semiconductive coating deterioration process described above. The problem occurs only in stators in which there is a semiconductive coating on the coils/bars in the slot and a silicon carbide stress control coating just outside of the slot (Section 1.4.5). The problem is confined to form-wound stators rated at 6 kV and above, energized with 50/60 Hz AC, or IFD motors rated 3 kV and above using both types of stress relief coatings. Overlap failure is most likely to occur in air-cooled machines, as PD is involved. Where the stress control coatings are tape based (rather than paint based), there seems to be less chance of this problem.

8.6.1 General Process

The silicon-carbide coating (confusingly, also called the semiconductive coating by some) extends from the semiconductive coating just outside of the slot, along the coil, into the end winding—typically, 10–20 cm (Figure 8.9). As discussed in Section 1.4.5, the coating resistance is nonlinear. The resistance is very high in regions of low electrical stress and low in regions of high electrical stress (near the overlap region). The silicon carbide coating must be electrically connected to ground by an overlap of the silicon carbide coating and the semiconductive coating. The overlap is typically about 1 cm wide. It is the electrical connection inherent in the overlap that degrades. If the overlap region becomes nonconductive, then the silicon carbide coating is no longer grounded. Instead, the silicon carbide coating “floats,” and tends to rise up to the voltage of the copper within the coil, due to capacitive coupling. For example, on a 13.8 kV winding, the floating silicon carbide coating on the phase-end coil will tend to attain a voltage of about 8 kV. A very high voltage then exists between the semiconductive coating (at 0 kV) and the silicon-carbide coating at 8 kV, separated by a small air gap (the overlap region). Consequently, the air gap breaks down, resulting in discharges over the surface of the coil between the two different coatings. The discharges created by this process tend to be very large compared to PD created by other aging processes.

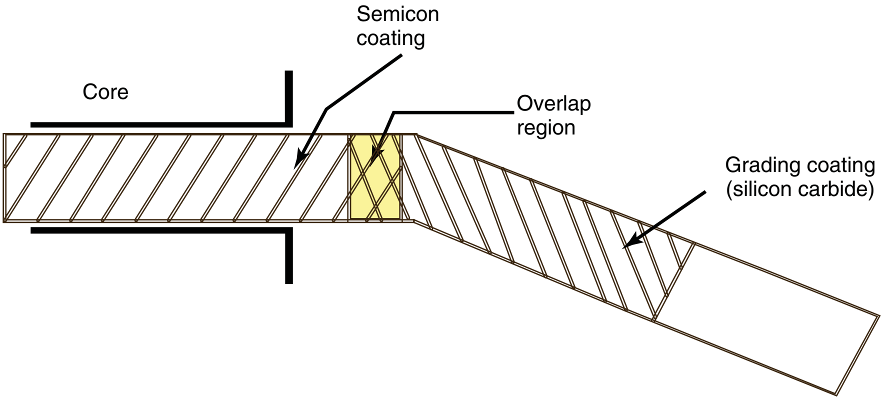

Figure 8.9 Sketch showing the overlap region between the silicon carbide and semiconductive coating that may oxidize and degrade.

A feature of this discharging process, which formally is not a PD process as complete breakdown occurs, is that the discharges are parallel to the insulation surface. That is, the discharges are not perpendicular to the insulation, as is the case for most discharges. Experience indicates that when the discharges are parallel to the insulation surface, the rate of deterioration of the bulk of the insulation is very slow. What groundwall deterioration does occur is usually confined to the surface, where the heat from the discharging vaporizes the organic materials in the surface layers of the groundwall leaving the glass fibers and mica intact. Thus, it is unlikely for this process alone to directly lead to groundwall failure, at least in less than 20 years or so, in spite of the large discharge magnitude.

The overlap deterioration process is not very important; however it can mask more important failure processes, when monitoring the winding condition with PD testing. Finally, if overlap problems are occurring, it is often a sign that the more serious semiconductive coating deterioration process might also be occurring within the slot.

8.6.2 Root Causes

Overlap discharging is caused by poor stress control design and/or poor manufacture. The overlap region is an electrical connection. Currents flow through the overlap. The currents originate from the capacitive current between the silicon carbide coating and the high voltage copper underneath the coating and groundwall insulation (Figure 1.14a). This current flows axially through the silicon carbide coating to the semiconductive coating and then to the grounded stator core. If the resistance of the connection between the coatings is too high, there is an excessive I^2R loss at the overlap. This heating raises the temperature of the overlap region above the winding temperature, creating a local hot region. This increased temperature further increases the resistance through an oxidation process. Once part of the overlap becomes nonconductive, PD will occur due to the high electric stress at the end of the semiconductive coating,

creating ozone in air-cooled machines. The ozone (or rather nitric acid) will attack adjacent coatings. Eventually, the overlap has infinite resistance and the intense discharging begins.
The causes for the initial high resistance of the overlap region are as follows:

- Graphite particle density in the semiconductive coating is too low.
- Improper silicon carbide particle density or particle size distribution in the silicon carbide coating.
- Inadequate amount of overlap surface area for the capacitive currents that are flowing.

Vigilance is especially needed with groundwalls designed at higher electric stress. These "thin wall" designs will have a greater capacitive current flowing through the silicon carbide coating and are thus more prone to age quickly.

Operation with IFDs causes much larger capacitive currents to flow and thus accelerates the process (Section 8.10.3).

8.6.3 Symptoms

This problem is easily identified in a visual examination of the endwinding. A white band around the coil or bar circumference occurs a few centimeters outside of the slot (Figure 8.10). The white band will only occur on coils/bars operating at high voltage. Coils connected to the neutral will not have the band, since there are no capacitive currents flowing to destroy the overlap. The white band is exactly where the overlap occurs between the semiconductive and silicon carbide coatings. PD testing, a blackout test (Section 15.14), and ozone testing (Section 16.3) can also identify the problem.

8.6.4 Remedies

It is not possible to permanently solve this problem once it occurs, unless all affected bars/coils are removed from the slots, and the stress relief coatings are stripped away and replaced. This is usually not practical as removal of the bars/coils may crack them.

If the end winding has not been covered by an insulating varnish, a quasi effective repair may be possible. (Such insulating surface coatings over the end winding are common, as they tend to have better abrasion resistance than epoxy mica insulation.) The repair involves cleaning the overlap region and then applying a partly conductive paint over the existing semiconductive coating to the coil or bar surface just outside of the slot. The new application of semiconductive paint should extend over the overlap region and cover the silicon carbide layer by at least 1 cm. The purpose is to restore the ground connection to the silicon carbide coating. Great care is needed in applying the partly conductive paint, as it should not encroach too far into the silicon carbide coating (say, <2 cm), nor should the paint be spilled over any of the remaining end winding. In practice, it is difficult to apply the partly conductive paint on the bottom coils/bars, or even the bottom edge of the top coil/bar.

Figure 8.10 Photograph of the end winding area from a hydrogenerator. The white band around some of the coils just outside the slot indicates where the coating overlap area has degraded. Note that the entire stator has been painted with an abrasion resistant coating that makes repair of the overlap problem very difficult.

If the end windings have been painted with an insulating varnish, applying the partly conductive paint will not permanently solve the problem. This is because the new partly conductive paint will not be properly grounded with the insulating varnish present. More effective, but much more difficult, is to abrade away the surface varnish to expose the stress relief coatings and then restore them as above. As an alternative, there is a tendency to paint the overlap region (and the complete end winding) with an insulating varnish. This does not affect the deterioration process in any way, and the white band will reappear within a few months. Thus, an insulating overcoat, while esthetically pleasing for a short time, does not prevent the discharging. It must be ensured that the varnish used is compatible with the groundwall insulation and will not reduce tracking resistance (Section 8.11).

8.7 HIGH INTENSITY SLOT DISCHARGE

In Section 8.4, we discussed the failure process caused by windings being loose in the slots that lead to PD (slot discharge). There is a variation of this failure process that does not initially require the bars/coils to be loose. Instead, the slot discharge is caused by the semiconductive coating becoming isolated from the stator core for the entire length of the slot. Since the entire capacitance of the gap between the semiconductive coating and the stator core is discharged when contact is made, a very large discharge results, hence the name “high intensity slot discharge.” This problem is almost always associated with a poor winding design or poor manufacturing. Windings using insulating sidepacking and or made with the GVPI process are most at risk. Failure can happen in months to just a few years. It is rare for this problem to occur on machines made since the 1980s.

8.7.1 General Process

Large sections of the slot conductive coating can sometimes be insulated from the stator core, or at least have a very high resistance contact to the core at only a few points, even in the absence of bar vibration. This may occur as a consequence of the global vacuum pressure impregnation manufacturing process, where a thin epoxy or polyester film isolates the bar/coil surface from the core. In principle, it also could occur on older stator designs where insulating side and/or depth packing is used and bar vibration dynamically isolates the slot conductive coating from the grounded stator core for portions of the AC cycle [3]. One important example occurred on very large hydrogenerators made in the 1970s, where the top bar was only grounded via the bottom bar by means of a semiconductive filler between the top and bottom bars [10].

If a thin film isolates the slot conductive coating from the stator core, then the slot conductive coating is not effectively grounded. On phase-end bars operating at high voltage, a large voltage (determined from the capacitive voltage divider formed by the bar groundwall insulation capacitance and the film capacitance) can occur on the slot conductive coating. At a defect in the film between the slot coating and the core, or when the slot coating makes contact with the core if it is vibrating, the entire capacitive charge stored in the bar insulation is discharged [10]. The energy stored in the equivalent capacitance can be very large, and the resulting discharge has been called *high intensity* because it tends to produce discharges much larger than the PD described in Section 8.4. According to Mulhall [10], the erosion of the groundwall by the high intensity discharge can be rapid, even in epoxy-mica insulation systems, and can lead to groundwall puncture in only a few months, if the entire slot conductive coating is isolated from ground. The discharging (which is probably not formally PD, but rather contact sparking by two surfaces at different potential) is intense enough that it may also damage the stator core laminations.

This failure process is less likely with today's design and manufacturing processes, as manufacturers have developed ways to ensure better contact to the core during the GVPI process. In addition, side packing and depth packing tend to be partly conductive, increasing the probability that large portions of the slot conductive coating are grounded at many places along the slot. Finally, most machine manufacturers ensure that the resistance between the semiconductive coating and the core is less than a few hundred Ohms after manufacturing (Section 15.18).

8.7.2 Root Causes

The root cause is poor design of the slot support system or ineffective grounding of the semiconductive coating during the GVPI process.

8.7.3 Symptoms

With the rotor removed, one can look down the stator core radial vent ducts at the sides of the stator bars or coils. The stator coils operating at high voltage will indicate white power and an absence of graphite paint or tape on the surface of the coils/bars in the slot. If the bars are removed from the slot, there will be a few small areas of extensive pitting and localized burning of the groundwall wall. The associated stator core may also exhibit signs of burning and pitting. In an on-line PD test (Section 16.4), there will be exceptionally high PD activity, perhaps higher than measured in 98% of similar machines.

8.7.4 Repairs

The best repair is a rewind with a new design for grounding the semiconductive coatings. It may be possible to establish better grounding of the semiconductive coating by injecting graphite loaded paint, silicon rubber or epoxy down the sides of the coils (see Section 8.5)

8.8 VIBRATION SPARKING (SPARK EROSION)

Vibration sparking (VS), also called *spark erosion*, is related to the loose coil problem discussed in Section 8.4. It may occur in non-GVPI windings where the bars/coils are loose in the slot while at the same time the semiconductive coating in the slot has too low a resistance. Fortunately, it is a rare problem brought on by poor design. It has occurred sporadically in hydrogen-cooled turbine generators in the 1950s, in motors in the 1970s, in very large nuclear generators in the 1980s, and, in the 2000s, in some air-cooled turbine generators rated about 200 MVA [4].

8.8.1 General Process

In Section 1.4.5 it was mentioned that to prevent PD, the slot semiconductive coating needs to have a maximum resistance limit to ensure there is a negligible voltage build up across any air gap between the coil/bar surface and the stator core. But there is also a minimum permissible resistance. If the surface coating is as conductive as (say) aluminum foil, then the stator core laminations in the slot will be shorted, causing an axial current to flow along the slot conductive coating. This current is driven by the circumferential main magnetic flux within the core (Figure 8.11). The current loop is along the building bars (keybars) at the back of the stator core (which are usually shorted to the steel laminations at that point), radially through the steel laminations, and then through the semiconductive coating on the stator bars/coils in each slot. The resistance of the metallic components and the semiconductive coating and the magnetic flux in the core and the area of the loop that encloses the flux limit the current that flows. Since bars/coils may vibrate to some degree, if the semiconductive coating at some point loses contact with the core, an arc (or spark) will form if the interrupted current is large enough [5]. Note this is a poor electrical contact phenomenon, not electrical breakdown of a gas. Thus it is not a PD mechanism, at least initially.

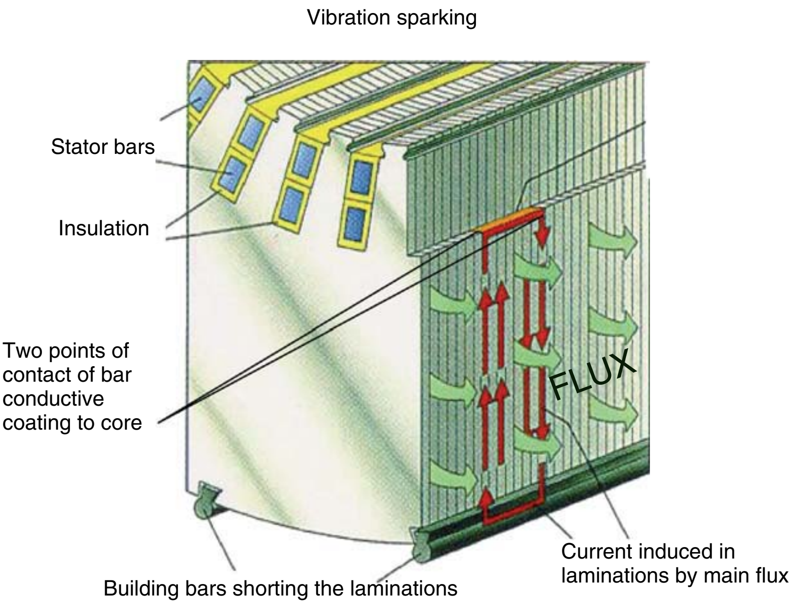

Figure 8.11 Sketch of the current loop formed by the flow of current through the core lamination, the building (or key) bars and the slot conductive coating on a stator bar.

For a particular machine, the interrupted current will depend on the length of the bar along the slot that has become isolated from the core (Figure 8.11). The longer the axial distance for which the semiconductive coating is not in contact with the core, the greater will be the area enclosed by the current loop, and thus the greater will be the induced current by Ampere's Law. This, in turn, roughly depends on how loose the bars are in the slot. Consequently, for a given slot coating conductivity, the looser the bar in the slot, the more likely that a spark will be formed where the slot coating loses contact with the core. Stators that exhibit this problem show that the spark or arc that is created can be intense enough to damage even the mica in the epoxy-mica groundwall. A much more comprehensive description of the physics involved has been presented by Liese [5]. He has also estimated that the surface resistance of the slot conductive coating should be no lower than 5000 Ω per square to prevent the mechanism, although we are aware of many stators with loose bars and a lower surface resistance than this, that apparently do not have VS. The minimum resistivity depends on the axial length of the slot conductive coating that is isolated from the core during vibration, which in turn depends on how loose the bar is in the slot.

Another way to understand the VS mechanism is to recall that along the slot in the stator bore, there is up to about 160 V/m between the laminations in a high flux turbine generator. That is, if the stator bar slot coating is grounded at one end of the slot and if the rest of the bar surface is not grounded, then the potential difference between the surface of the bar and ground is 160 V/m into the slot. If normal 100/120 Hz magnetic forces cause the bar surface to contact the core at this point, a spark will occur when the contact is broken. Note that since there is no discharge of any capacitance with this mechanism (as occurs in the three slot discharge processes described in Sections 8.4, 8.6 and 8.7), it would be inappropriate to refer to VS as a slot discharge or PD phenomenon. As the VS process is driven by the magnetic flux in the stator core, it can occur on any bar/coil, not just line end bars/coils, unlike the slot discharge problem mentioned in Section 8.4

Note that there is still some controversy on the exact details of the VS mechanism.

8.8.2 Root Cause

In the authors' opinion, the cause is poor design of the stator slot contents. First, the stator bars are not firmly secured to resist the magnetic forces, for example, ripple springs are not used. Secondly, the surface resistance of the semiconductive coating in the slot is designed to be below several hundred ohms per square, and quality assurance testing is not sufficient to ensure that the surface resistance is above this limit.

8.8.3 Symptoms

Some signs of VS can be found by removing the rotor and looking at the sides of the bars/coils in the core vent ducts (if present) using a boroscope. However, these images can be misleading as fundamentally the sparking takes place between the bar/coil surface and the stator core laminations [11]. Figure 8.12 shows some damage to the epoxy-mica groundwall insulation caused by VS on a turbogenerator rated about 200 MVA. As for the slot discharge mechanism caused by a stator bar being isolated from the core (Section 8.7), VS seems to involve a high intensity spark that has sufficient power to relatively rapidly fail bars in as short a time as 4 or 5 years.

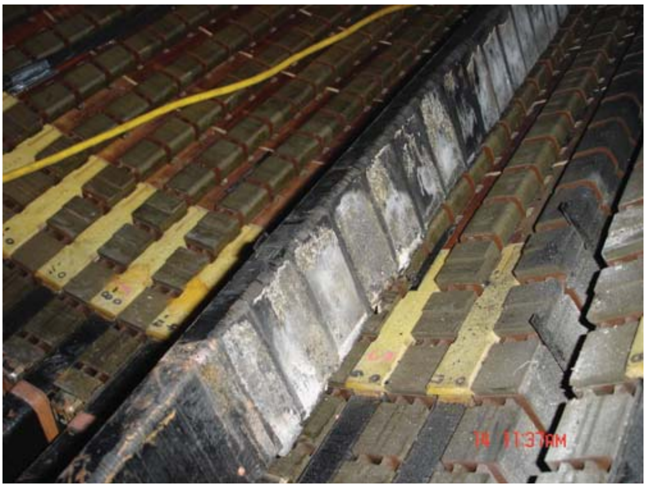

Figure 8.12 A stator bar being removed from an air-cooled turbine generator affected by VS.

The sparking intensity is enough to damage both the stator bar insulation and the steel core laminations. The VS on the air-cooled machine shown in Figure 8.12 was wound without side ripple springs. The appearance of the bar side abrasion in Figure 8.12 is similar to that seen by slot discharge (Section 8.4). However, unlike slot discharge, VS can occur at the neutral, winding midpoint, or phase end bars, as it is driven by the magnetic flux, and not the electric field.

8.8.4 Repair

There does not appear to be a permanent repair, once the problem has manifested itself. In principle, the injection of a graphite loaded resin into the slot should slow the movement of the bar, and thus the opportunity for VS. Alternatively, insertion of conductive side ripple springs or other shimming material should slow down the process.

The best "repair" is to make sure the process does not happen in the first place by ensuring the windings are tight in the slot and the semiconductive coating resistance is high enough.

8.9 TRANSIENT VOLTAGE SURGES

Voltage surges in stator winding insulation systems in motors and generators are transient (nonrecurring) bursts of relatively high voltage that increase the electrical stress beyond that which occurs in normal service. Such voltage transients occur from:

- Lightning
- Ground faults in the power system
- Generator breaker closing under out-of-phase conditions
- Motor circuit breaker closing and opening

It is believed that a voltage surge either causes the insulation to fail immediately or has no lasting effect [12]. That is, transient voltage surges do not gradually deteriorate the insulation. Thus voltage transients will normally immediately cause failure in a new stator winding if the winding was poorly designed or made. This is why all new windings are required to pass an AC hipot test (Section 15.6) and multiturn coils must also pass a surge voltage test (Section 15.16). If the groundwall or turn insulation deteriorates over the years due to any of the aging processes described in this chapter, the electrical insulation will have reduced electric strength. A winding may then fail if a severe voltage transient occurs that exceeds the groundwall or turn insulation strength. Although some may say that a voltage transient produced by lightning or a motor turn-on "caused" the winding failure, in reality the failure was due to other deterioration mechanisms, and the voltage surge was just the "straw that broke the camel's back."

Repetitive voltage surges caused by convertors are discussed in Section 8.10.

8.9.1 General Process

Voltage transients can fail the groundwall insulation in all stators, as well as the turn insulation in multi turn coils. The process for groundwall insulation is straightforward—if the transient AC or impulse voltage exceeds the breakdown strength of the insulation, the insulation punctures and the ground fault relay operates.

Short rise-time voltage surges can be especially hazardous for the turn insulation in multiturn coil stator windings. Rise-times as short as 100 ns or so are created during motor turn-on. By a Fourier transformation, this short rise-time will generate frequencies up to about 3 MHz. In Section 1.4.2, it was discussed that at power frequency the voltages between adjacent turns in a coil are equal. That is, the power frequency voltage is linearly and equally distributed between each adjacent turn from the phase terminal to the neutral point. However, when a very high frequency is applied to a stator winding, the voltage distribution is nonlinear, with a much greater percentage of the applied voltage appearing across the turns in the first coil connected to the phase terminal. This nonuniform voltage distribution occurs because the series inductive impedance of the winding is relatively large compared to the low shunt capacitive impedance to ground (created by the capacitance across the coil groundwall) at this high frequency [13]. Consequently, the effect of applying a fast rise-time surge to a multiturn stator winding is that for less than a microsecond a very high voltage appears across the turn insulation, in the first few turns of the winding. As much as 40% of the applied surge voltage can appear across the first turn in form-wound coils [13].

When a motor is switched on, the motor side of the switch in the first phase to close jumps from zero to (at worst case) the peak line to ground voltage of AC voltage. This sudden jump creates a voltage pulse that travels along the power cable to the stator winding. Since the rise-time is short, and assuming the power cable is longer than about 30 m, a travelling wave effect occurs. That is, the power cable behaves like a surge impedance (in the 30 Ω range) that is terminated by the surge impedance of the motor. If the motor appears as a high surge impedance, then there can be as much as a two times increase in the voltage (for a few hundreds of nanoseconds) due to transmission line effects [13]. Experiments show that there can be an even higher voltage transient on the second circuit breaker pole to close, since some voltage from the first pole to close will transmit through the stator winding and appear on the motor-side of the (still open) circuit breaker pole. This creates an even higher voltage across the contacts in the second pole to close. When the second pole closes, the transmission line behavior repeats itself. The result is that it is theoretically possible for a short rise-time voltage surge of five times normal AC peak line-to-ground voltage to appear at the motor terminals. In practice, the circuit breakers do not always close at the peak of the AC voltage cycle and the surge impedance of the stator is not always much higher than the cable surge impedance. Thus it seems that the voltage transient created by motor turn-on is typically in the range of twice the peak AC voltage (i.e., a 4.1 kV rated motor has a peak line to ground voltage of 3.4 kV, thus it may see a transient of about 6.8 kV). This transient could result in a voltage of 2.7 kV across the first turn in the coil connected to the phase terminal (assuming the 40% factor described above). This is a very substantial voltage compared to the few tens of volts of AC volts that is across the turn insulation during normal operation. If the turn insulation was poorly made, or becomes weak due to, for example, thermal aging (Section 8.1), the turn insulation may puncture and groundwall failure will usually follow within seconds (Section 1.4.2).

Although in the 1980s it was assumed that vacuum and SF_6 circuit breakers and interrupters created more severe voltage surges, this was not actually verified by measurements in plants. The magnitudes and rise-times of voltage surges during motor turn-on are the same for air-magnetic, vacuum, and SF_6 switchgear. However, vacuum and SF_6 can produce many tens of voltage transients for each switching operation, whereas air-magnetic breakers produce just one transient. The extra transients created do not seem to cause aging of the insulation [12].

It is motor turn-on that normally creates short rise-time voltage transients. Turning off a motor normally does not result in any transients, as once the motor breaker is opened, there is no voltage across the breaker contacts because the motor stator winding effectively becomes a generator (due to the back emf within the motor) for several seconds until the breaker contacts are fully open. However, if a motor is turned off before it is up to running speed, the emf from the motor is not the same as the voltage from the power system, and a voltage will appear across the breaker contacts as the contacts are opening. In some cases, usually with vacuum and SF_6 breakers, the circuit breaker contacts “restrike” due to voltage oscillations after the breaker initially opens. This restriking will keep occurring as the breaker contacts open, leading to an escalating repetitive voltage [13]. Surge voltages on opening a circuit breaker can be prevented with properly selected and located surge arrestors, as well as by avoiding opening a circuit breaker while the motor is still coming up to speed [13].

8.9.2 Root Causes

The source of 50/60 Hz AC voltage transients are power system disturbances, such as a phase-to-ground fault. It is unlikely these can ever be eliminated, thus the groundwall insulation system must be designed to withstand such transients over its expected life. This is a key reason why all new machines must withstand an AC voltage hipot test at twice rated voltage plus 1 kV, and that machine manufacturers perform accelerated aging tests as described in Chapter 2 to prove that the AC withstand-strength does not drop below expected AC voltage transients during its design life.

The sources of impulse voltage transients are switching events and lightning. Neither can be eliminated, thus the stator winding must be able to withstand such transient voltages or be protected against them.

8.9.3 Symptoms

Failure due to AC voltage transients will normally lead to a ground fault and is detected by appropriate relays. If the stator has high impedance grounding (as is typical in utility generators) or has a neutral that is not connected to ground (as is typical of form-wound motors in utilities), then the ground fault current is low or just 5 to 10 amps. This low a fault current usually does not produce collateral damage to the machine, and in fact it can often be difficult to locate the faulted coil/bar. If the neutral is solidly grounded, or has low impedance grounding (as is typical in many industrial motors), then the ground fault currents can be 400 A or more. Visually locating the faulted coil is usually much easier as considerable insulation damage is present.

Sometimes a phase-to-ground fault will morph into a phase-to-phase fault, if the voltage transient in the first phase to fault is large enough to breakdown aged insulation in another phase. In addition, some failure processes such as contamination and insufficient spacing in the end-winding (Sections 8.11 and 8.14) directly produce phase-to-phase faults. Such faults tend to have very high fault currents (perhaps 10 times the normal) that can lead to a lot of collateral damage to the winding and extensive destruction (Figure 8.13).

Failure of the turn insulation in motor and generator stator windings using multiturn coils will also cause significant damage. As described in Section 1.4.2, a turn-to-turn insulation failure in any coil in the stator will result in a current flowing through the shorted turn that may be hundreds of times larger than the normal current in the copper turn. This high current in the turn at the fault location creates a very high I^2R loss, quickly raising the temperature to the point at which the copper conductors melt. The melted copper then melts through the groundwall until a ground fault occurs. There is almost always melted copper associated with such faults and

Figure 8.13 View of the stator bore (after rotor removal) of an 800 MVA turbogenerator that experienced a phase-to-phase fault in the stator slot. The white “spaghetti” are the copper conductors that came out of the stator slot under the tremendous magnetic forces that accompany a phase-to-phase fault.

Figure 8.14 A turn-to-turn failure leading to a ground fault on a 6.6 kV, 8 MW motor. A bottom coil experienced the failure, and the top coils were cut away to expose the fault.

considerable burning of the insulation, compared to a ground fault. Figure 8.14 shows a failed motor stator caused by a turn insulation fault just outside of the stator core.

8.9.4 Remedies

The main remedy is to avoid the possibility of failure due to AC and surge failures by designing the groundwall and turn insulation to withstand any likely transients. It is possible to protect the stator against excessive voltage transients by the use of surge arrestors and surge capacitors. Surge arrestors are devices that clamp the maximum voltage that will appear across the groundwall insulation due to AC voltage transients or lightning impulses (which tend to have a relatively long rise-time of about 1 μs). The surge arrestors are often located at the switchgear or the power transformer, and are widely used for motor and generator protection.

Surge capacitors limit the voltage that appears across the turn insulation in multiturn coils due to short rise-time switching transients. Essentially, they short the high frequency components of the voltage surge to ground, before the surge reaches the stator winding. The surge capacitor must always be located immediately adjacent to the stator winding, and connected to ground with very short, noninductive leads. A low pass filter circuit is formed by the surge impedance of the power cable feeding the machine and the surge capacitance. With a typical cable surge impedance (Z) of 30 Ω, a surge capacitance (C) of 0. 2 μF will result in a voltage rise-time of 2.2 ZC or 13.2 μs. With such a long rise-time, the voltage distribution across the turns is evenly divided across all the turns and thus the turn insulation is not exposed to a high voltage. Most utilities do not use surge capacitors on motors; instead they prefer to make sure the turn insulation design is robust enough to resist motor switch-on surges. Industrial users of large motors tend to prefer installing surge capacitors. There is no need for surge capacitors on generators that have Roebel bars, as there is no turn insulation to protect [14].

8.10 REPETITIVE VOLTAGE SURGES DUE TO DRIVES

The introduction of IFDs of the pulse width modulated (PWM) voltage source type has shown that gradual aging occurs if the voltage surges from this type of drive are of a sufficiently high magnitude. Persson was among the first to report that voltage surges from convertors of the PWM voltage source type caused random-wound motors to fail due to gradual aging of the stator turn insulation [15].

The turn insulation in random-wound motors rated between 400 V and 1000 V and driven by convertors of the PWM voltage source type using IGBT switching devices are most likely to suffer from the surge aging problem, as such convertors produce the biggest voltage surges with rise-times as short as 100 ns (Section 1.5.1). Medium and high voltage motors using similar drives may also experience surge-induced deterioration (Section 8.6), but turn insulation failure is less likely due to the presence of mica-based turn insulation. Instead, the semiconductive and grading coatings that are usual for IFD motors rated at 3.3 kV and above can degrade rapidly (Section 1.4.6). Motors fed by drives using SCRs or GTO devices are less likely to induce failure, as the rise-time of the surges is relatively long (about 1 microsecond). These same effects can occur in wind turbine generator stators which typically have rectifiers and invertors on their output to convert the generated AC to 50 or 60 Hz for the power system.

8.10.1 General Process

Repetitive voltage surges can induce gradual deterioration of the (a) turn insulation, (b) groundwall and phase insulation, and (c) the semiconductive and grading coatings, if present. Each is described separately.

Turn Insulation Deterioration PWM voltage source invertors are widely used to supply induction motors to create a variable speed drive. Such invertors turn on and off a high DC voltage, which sends rectangular voltage pulses down the power cable to the stator winding. As discussed in Section 8.9.1, the travelling wave nature of these pulses as they encounter the surge impedance of the stator can result in reflections, and under worst case condition, a voltage doubling of the pulse that was created at the inverter [16]. Figure 8.15 shows the sequence of pulses measured at an inverter and at the stator of a 440 V motor. The voltage pulses clearly are larger at the motor due to the travelling wave effects. Depending on the capacitance of the stator winding, the rise-time can vary from 100 to 500 ns [16]. Drives for medium and high voltage motors tend to have multiple stages, which slows the risetimes of the transients to usually longer than 500 ns.

As discussed in Section 8.9.1, short rise-time voltage surges will apply a very large voltage across the turns in the coils connected to the line end of the stator winding. A high interturn voltage can give rise to a PD if there is an air pocket in the vicinity of the copper turns. In random-wound stators, there are often pockets of air

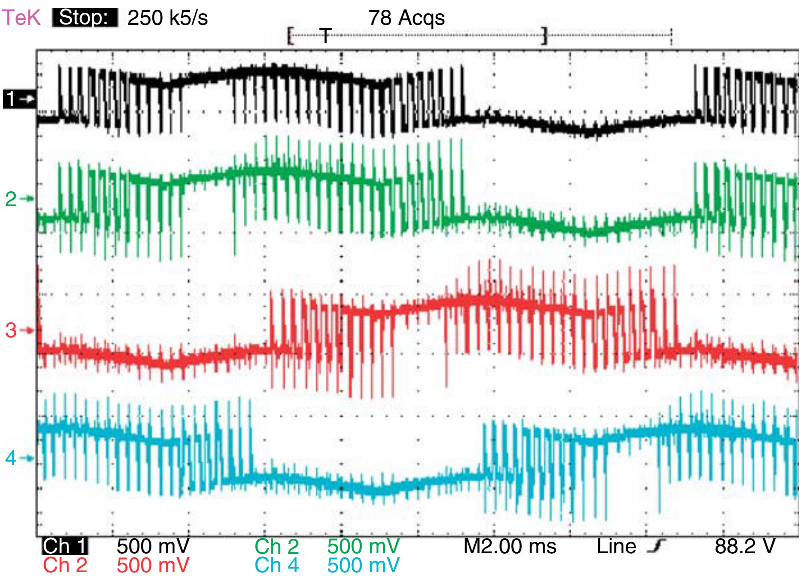

Figure 8.15 Digital oscilloscope image of the voltage waveform measured at Phase A at the inverter (top trace) and the voltage on three phases at the stator winding (lower three traces). The motor was rated 440 V. The horizontal time base is 2 ms/division and the vertical scale 1000 V/division.

adjacent to the turns of round magnet wire. If a PD occurs in the air, then each discharge will slightly degrade the magnet wire insulation. If a sufficient number of surges occur, enough cumulative damage occurs from the discharges that turn-to-turn failure results, rapidly progressing to a ground failure (Section 1.5.1).

Random-wound stators with conventional magnet wire are most susceptible to this process, as the magnet wire insulation is usually organic and not resistant to attack by PD. Unless special measures such as using PD-resistant magnet wire or increasing the distance between components (Section 8.10.4) are employed, failure can occur within weeks or months of an IFD going into service. Form-wound machines can experience the same surges but as the turn insulation often contains inorganic glass fibers, or even mica paper, this insulation is much more resistant to PD and consequently less likely to fail.

Ground and Phase Insulation By definition, in random-wound stators, a phase lead in, say, A-phase may be adjacent to a neutral end turn or a turn connected to the B-phase terminal. If there is inadequate space or insulation between phases or to ground, the small-diameter magnet wire in random-wound stators may create sufficient electrical stress in any air spaces surrounding the magnet wire to create PD. As for the turn insulation, the PD may gradually erode the organic insulation, resulting in a phase–phase or ground fault. For this process, the surge rise-time is somewhat irrelevant. It is the surge magnitude and the repetition rate that are critical.

In form-wound windings, inverters tend to cause a higher phase to ground electrical stress than normal 50/60 Hz power frequency. This is because of the short rise-time switching voltage and the associated transmission line reflections. The result is the peak-voltage to rms-voltage is higher than the 1.4 ratio that is present with sinusoidal voltage. The higher peak voltage will increase the number and magnitude of groundwall insulation PD, and thus accelerate aging.

Stress Relief Coatings Since IFDs generate high frequency voltages, the capacitive currents through the ground insulation are relatively high compared to power frequency. OEMs have found it prudent to employ semiconductive and silicon carbide coatings on IFD motors rated as low as 3.3 kV to control the stress distribution in the end windings, and thus to avoid PD at the slot exits (Section 1.4.6). The high frequency capacitive currents will result in high local I^2R losses in the coatings—far higher than those described in Sections 8.5 and 8.6. The result is that the stress control layers in IFD motors are likely to deteriorate much faster than the layers in 50/60 Hz windings.

8.10.2 Root Cause

The turn insulation deterioration process in random-wound and form-wound stators requires:

- A fast surge rise-time, usually less than 200 ns, since the faster the rise-time, the more voltage appears across the first turn.
- An impedance mismatch between the motor and the cable, which yields a higher than normal voltage due to transmission line effects.
- Air pockets adjacent to the turns connected to the phase terminals, enabling PD to occur.
- A turn insulation (magnet wire insulation in random wound stators) that is not PD resistant.
- Thousands of surges per second. Tests show that a PD occurs very rarely; typically, one PD per several thousand surges [16]. Thus, many surges are needed to create enough cumulative damage to cause failure.

A few fast rise-time surges (as long as they are withstood) seem to cause no harm.

For deterioration of the ground and phase insulation, and the stress relief coatings in form-wound stators, it is just the magnitude of each voltage surge and the repetition rate that determine the aging rate.

8.10.3 Symptoms

On random-wound machines, surge-induced PD attack is visible as a whitish powder on the magnet wire insulation, especially between phase-end turns or where magnet wires from different coils or phases come in contact. If the motor end windings can be exposed for a short time in no-load operation, a blackout test (Section 15.14) may indicate the points of light associated with PD. In form-wound stators, there will be no visible signs of surge aging of the insulation as the groundwall insulation covers the turn insulation. However, if the stress control coatings are deteriorating, they generally turn white, and significant ozone will be present.

Methods are available to measure electrically the PD activity in random-wound windings either off-line or on-line (Section 15.13). However, relatively sophisticated methods are needed, as the surge transients are similar to PD pulses and conventional PD detectors will be destroyed by the high voltage surges. If no PD is detected in the normal surge environment, failure due to voltage surges is unlikely to occur.

For form-wound stators, the only likely visible problem caused by inverters may be the burning of the stress relief coatings just outside of the slot on the phase-end coils, as well as ozone.

8.10.4 Remedies

For random-wound windings, even if PWM voltage source invertors are used, it is not likely that a particular motor will see fast rise-time and high magnitude surges. This is because the magnitude and the rise-time are governed by many factors and most practical situations do not combine to yield severe surges [16]. Thus, prior to commissioning a new IFD motor, or if several stators have failed and surge aging is a possible cause, it is prudent to measure the actual surge environment. This can be done during normal motor operation with a high voltage, 10 MHz bandwidth oscilloscope probe and a 100 MHz digital oscilloscope. Specialized instruments are also available [16]. The measurement must be done at the motor terminals. Tests at the IFD terminals are not useful.

If measurements reveal that the surge environment exceeds specifications (see IEC 60034-18-41), one or more of the following may be tried to reduce the severity of the surges and the risk of this failure mechanism:

- Change the cable length and/or grounding, which will primarily change the surge magnitude.
- Replace the cable with a higher surge impedance cable (thicker insulation), or a cable with a more lossy dielectric (e.g., butyl rubber or oil paper are very lossy).
- Install a low-pass filter between the IFD and the motor to lengthen the rise-time of the surge. For conventional motors, the filter is usually a "surge" capacitor of about 0.2 μF, which lengthens the rise-time of the surge to about 13 μs (See Section 8.10.4). More sophisticated filters are needed for invertors as such a large capacitance on the output of an inverter and the consequent low impedance to the high frequencies can damage the switching devices in the inverter.

The effectiveness of these corrective measures can be ascertained by repeat measurements of the surge environment. In addition, the capability of a replacement winding to withstand the surge environment can be improved by the following methods:

- Using more PD-resistant magnet wire. Metal-oxide-loaded magnet wire has been demonstrated to withstand the PD during surges for much longer than conventional magnet wire [17,18].
- Impregnating the stator to reduce the chance that air pockets will occur at critical locations. Trickle impregnation and the GVPI process have been used in this way. In random-wound VPI'd stators, taping the end windings and fitting "dams" of felt at the ends of the slots, between the slot liner and conductors, has proved effective in significantly reducing the size and number of voids between conductor strands.
- Increasing the distance between adjacent turns in the phase ends and between other coils and phases. In the former case, this can be done by reducing the turns on phase-end coils by one, thus allowing space for more insulation on each conductor, or inserting thicker sheets of ground- and phase-separation material.

For form-wound machines, the stator windings should have been qualified to IEC 60034-18-42 (Section 2.4.3). In the absence of a formal optimization study for inverter drive operation, some form-wound motor manufacturers just increase the voltage class of the insulation by one level if they know a motor is intended for voltage source PWM drive operation. For example, a 6.6 kV winding may use an 11 kV insulation system. This is likely to ensure that neither the groundwall insulation will fail soon due to higher PD nor the stress relief coatings will fail prematurely due to the higher capacitive currents flowing.

8.11 CONTAMINATION (ELECTRICAL TRACKING)

Winding contamination leads to many problems, including faster thermal deterioration (due to blocked ventilation), chemical attack (Section 8.13), and electrical tracking. This section deals only with the last. Electrical tracking enables currents to flow over the surfaces of the insulation, especially in the end windings. These currents degrade and eventually cause the groundwall insulation to fail. This problem has a greater probability of occurring in machines with high operating voltage. However, even 120 V motors can fail due to this process, and machines that are dirty or wet are more likely to be affected.

8.11.1 General Process

Cooling air in open-ventilated motors and generators can be contaminated with dirt, insects, plant by-products (fly ash and coal dust in generating stations, various chemicals produced in petrochemical plants, cement dust in cement plants, etc). This contamination mixes with moisture or oil to produce a partly conductive coating on the stator winding. Oil comes from the seal oil system in hydrogen-cooled generators and from the bearings in all types of machines, whereas moisture comes from the environment, steam leaks, leaking cooling water systems, and/or from the seal oil system. Even totally enclosed machines can be contaminated by oil or moisture combining with foreign material during manufacture or maintenance. Another source of particulates is carbon dust from brushes (where fitted) during operation of the machine or oxides produced from brake operation in a hydrogenerator.

There are two processes that can lead to failure, depending on whether the stator is form-wound or random-wound.

Form-Wound Stators The contamination failure mechanism normally occurs only in the end windings of form-wound stators. If the contamination has some conductivity, say less than a few megohms per square, then currents can flow through the contamination if a potential difference exists. Figure 8.16 shows the cross-section of two adjacent coils in an end winding, together with an equivalent circuit. Assume the coils/bars are in two different phases. The contaminated surface of the A-phase coil will have a tendency to float up to the voltage of the copper within the coil, by capacitive coupling. Similarly, the B-phase coil surface will tend to float up to the B-phase voltage. Insulating blocks used for stiffening the end winding structure and for electrically separating the coils bridge these surfaces. The surface of the block is also contaminated and thus has an "electrical resistance" of the contamination across the block. The equivalent circuit in Figure 8.16 results. If the two coils are phase-end coils in two different phases, then, during normal operation, the full phase-to-phase voltage is applied to the equivalent circuit and a small current will flow.

If the contamination resistance is high compared to the capacitive impedance of the coils in the contaminated area, the surface of the coils is almost at the same voltage as the underlying copper conductors, and nearly full phase voltage is applied across the block. If the contamination has a very uniform resistance across the block, then little deterioration is likely to result, as the current is low (in the nanoamp range) and flowing uniformly across the surface. However, in reality, there are "dry bands" where the resistance is much higher than the general resistance of the contamination. In this case, virtually the entire voltage will then appear across the small dry band, causing electrical breakdown of the adjacent air or hydrogen. The discharge degrades and may carbonize the underlying organic resin and tapes. This small area is eventually left very conductive. The electrical stress then transfers to another region of high resistance, where discharges ensue. The result is an electrical track, which slowly grows across the insulation (Figure 8.17). The track often has many branches and appears as a carbonized, black network of valleys across the blocking. Given time, the discharges will also start boring into the groundwall. If the track is between coils in different phases, a phase-to-phase failure results, which allows extremely large fault currents to flow. Alternatively, tracks can appear between coils in the same phase, if one coil is near the phase end and the other is near neutral. Similarly, tracking can occur along a coil operating a high voltage to the core or a conductive end winding support ring. This is especially likely in coils without semiconducting and grading coatings.

This mechanism is usually very slow, often taking more than 10 years from the time the winding is contaminated to when it fails.

Random-Wound Stators The process is somewhat different in random-wound machines. The electrical tracking process is not the main aging mechanism in such windings, although IFD voltage surges could give rise to tracking. Instead, the process requires pinholes or cracks in the magnet wire before deterioration is likely to occur.

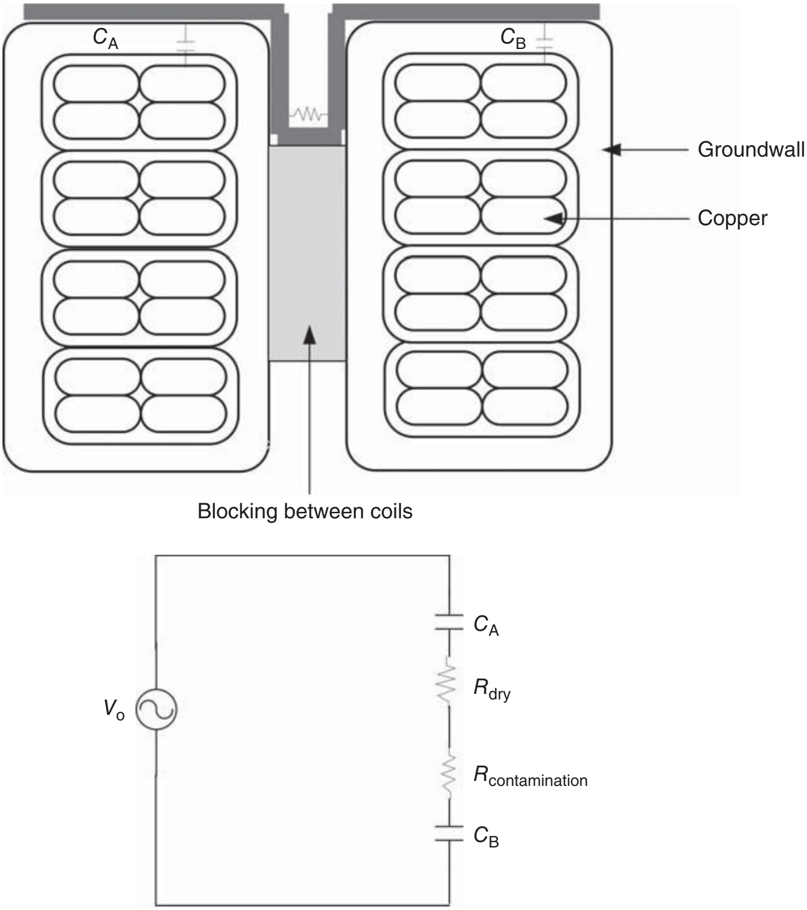

Figure 8.16 Cross-section of two adjacent coils in different phases in the end winding, together with an equivalent circuit, which shows how a small leakage current can flow.

Pinholes in magnet wire, though rare, can occur. The specification for magnet wire does permit a small number of pinholes after manufacturing [19]. In addition, other processes, such as thermal aging, can crack magnet wire insulation, and abrasion of the insulation can expose the copper. When a winding contains such pinholes and cracks, partly conductive contamination allows 50/60 Hz currents to flow between turns at different voltages. Since the distances can be very small, the currents can be relatively large (compared to the currents in the form-wound situation). The current causes the oil/dirt to carbonize, further lowering the resistance. Eventually, the resistance gets so low that very large circulating currents flow between the turns (Section 1.4.2) and a turn short develops, which is followed quickly by a ground fault.

The time to failure depends on preexisting pinholes or the time it takes for cracks to develop, together with the conductivity of the pollution. In some cases, failure may occur within weeks of being put into operation; in other cases, it may take 30 years.

Figure 8.17 A photograph of a carbonized (black) track across a block between two coils in different phases in the end winding.

8.11.2 Root Causes

In form-wound machines, the root cause of failure is the presence of partly conductive contamination. In random-wound machines, failure requires contamination together with either poor manufacture (due to poor magnet wire insulation and poor varnish or resin impregnation) or prior thermal deterioration or winding vibration.

8.11.3 Symptoms

The most obvious symptom during a visual inspection is the presence of contamination. In most situations, this will appear on the winding surface as a dark film that can be wiped away. However, if the winding is clean, occasional moisture can appear on the winding from dripping water or condensation during machine operation at low power. Condensation also forms on the stator winding surfaces after a machine is shut down if it is not fitted with space heaters. Thus, even apparently clean windings can experience contamination failure. In random-wound machines, there may also be evidence of poor dipping, or deteriorated magnet wire insulation from other causes.

The insulation resistance and polarization index tests (Section 15.1) are a very reliable way of detecting this problem, in any type of machine. In form-wound machines, the capacitance, power factor, and PD tests will all detect the presence of contamination, provided comparison values are available from similar uncontaminated windings.

8.11.4 Remedies

This is perhaps one of the simplest problems to solve. Even if the problem is well advanced, the stator can often be restored to as-new condition by a thorough cleaning, together with a dip and bake, paint, or GVPI treatment. Note that it is essential for the dipping varnish or paint to be resistant to tracking. Some varnishes have been found to accelerate the tracking process rather than retard it [20]. If electrical tracking has occurred, it is prudent to remove the tracks with grit cloth.

There is a wide range of cleaning methods. Smaller stators can be put in a special steam-cleaning unit. Larger stators with modern polyester- or epoxy-mica insulation systems can be cleaned with high pressure water or steam. Sometimes, dry ice or broken walnut shells or corncobs driven through a nozzle by high-pressure air can effectively clean encrusted dirt. Note that water and abrasives themselves can degrade the insulation, especially if the insulation was made before 1970. The dry ice cleaning method is particularly effective for high speed motors and generators, in which there is concern that the debris from the particulate cleaning (i.e., walnut shells, etc.) may block small cooling passages, especially in the rotor. Since the dry ice evaporates, blockage is not a problem. However, some users have reported that dry ice cleaning does not appear to remove oil films on the windings. Mixing the dry ice with a detergent or citrus-based cleaner may overcome the inability of dry ice itself to remove oil [21].

Where the dirt layer is relatively thin, solvent, detergent, or other cleaning materials can be poured on lint-free rags and wiped over the coils. This may also be necessary for the removal of heavy buildup of contaminants in large generators where other methods may not be suitable. Solvents such as trichloroethylene are very effective, especially in removing oil. However, the most effective solvents produce vapors that are a health hazard. They can only be safely used with breathing apparatus. A trade-off is often obtained by using less-effective citrus-based cleaning fluids without special equipment but with increased labor cost.

The following are some of the measures that can be taken to eliminate the problem by preventing the source of the contamination:

- Install air-inlet filters and ensure that they are maintained regularly (for open-ventilated machines).
- Specify or upgrade to a totally enclosed cooling circuit, especially if the machine must run in a dirty environment.
- Ensure bearings and hydrogen seal oil systems are properly maintained, so that they do not leak oil on the winding.
- Repair nearby steam leaks or other sources of contamination as soon as they occur.
- Ensure that brakes are applied after a machine, typically a hydrogenerator, has already slowed down considerably, or change airflow patterns so that brake residue cannot find its way into the winding.
- In a totally enclosed machine, change the desiccant frequently.
- In machines with brush gear mounted inside the enclosure, periodically vacuum away any carbon dust that accumulates.

8.12 ABRASIVE PARTICLES

Abrasive particles in the cooling gas stream can grind away stator winding insulation. This problem is most likely to occur on open-ventilated machines operating in environments where sand or other abrasives exist. Both form-wound and random-wound stators are vulnerable.

8.12.1 General Process

Sand, fly ash, glass fibers, or any other small, hard particles, if they are contained in the machine enclosure, will be blown through the stator winding at high velocity as part of the normal cooling air or hydrogen flow. These particles will abrade some of the insulation due to the energy of their motion. With a sufficient number of particles, and a high enough velocity, most types of groundwall insulation (in form-wound stators) and magnet wire (in random-wound stators) are relatively easily abraded because of their lower mechanical strength in directions that are not normal to the surface. Eventually, enough insulation may be abraded so that copper is exposed and a ground fault occurs. Any partly conductive contamination of the winding will accelerate the process, as it will promote the flow of current (Section 8.11).

Abrasion is most likely in the end windings but, in severe cases, the insulation in the stator core ventilation ducts may also abrade.

8.12.2 Root Causes

The fundamental cause of this problem is operation of an open-ventilated machine in an environment that contains abrasives. The problem, therefore, is a poor motor or generator specification. The affect of abrasive particles can be accelerated if the user does not maintain the filters that are intended to block ingress of particulates into the machine.

Abrasive material attack can also occur as part of the stator cleaning process. Materials such as dry ice (frozen carbon dioxide), walnut shells, corncob bits, etc. blown under pressure through a nozzle are sometimes used to clean encrusted dirt from the stator windings. Insulation can be abraded very quickly if the nozzle is held over any one spot too long.

8.12.3 Symptoms and Remedies

In a visual inspection, signs of abrasion in the end winding are usually easy to see. When the problem is in an advanced state, that is, copper has been exposed, then the insulation resistance, polarization index, or hipot tests may detect the problem. (If the end winding is clean, only the hipot test may be effective to find the problems.) In the early stage, no diagnostic test is effective for identifying the problem.

The obvious remedy is to specify or upgrade the machine so that it is not open-ventilated. If a random-wound stator has encountered abrasion, then a dip and bake or VPI treatment will restore the insulation. If only minor surface abrasion has occurred on a form-wound machine, a VPI treatment or varnishing with an abrasion resistant material such as a polyurethane may be sufficient. If more serious abrasion is present, then the groundwall thickness, at least in the end winding, may be partially restored using a spatula to apply a thixotropic (very high viscosity) epoxy prior to a VPI or varnishing treatment. This repair will probably be ineffective if abrasion has occurred adjacent to coils in core vent ducts.

If provisions cannot be made to prevent the introduction of abrasives into the machine, then it may be wise to overcoat the winding with a thin coating of an abrasion-resistant material. Silicon rubber and certain polyurethanes have good abrasion resistance. Note, however, that it is important that the covering does not promote electrical tracking [20] or significantly raise the winding temperature.

8.13 CHEMICAL ATTACK

Chemical attack describes the deterioration of the insulation that can occur if the insulation is exposed to an environment in which chemicals such as acids, paints, and solvents, as well as oil and water, are present. This problem can also occur if inappropriate cleaning methods are used, or if the winding is given a VPI or dip and bake treatment with an incompatible resin. All types of stator windings can suffer from this problem.

8.13.1 General Process

Most types of older insulation systems are prone to chemically induced degradation due to the presence of solvents, oil, water, or other chemicals. For example, magnet wire insulation such as polyester can soften or swell from exposure to certain chemicals [21]. Groundwall insulation using asphalt, varnish, and some early polyesters as bonding agents are prone to softening, swelling, and loss of mechanical and electrical strength. For example, when polyester is in contact with water for long periods of time, hydrolysis and depolymerization result in reduced mechanical and electrical strength [22]. Softening of insulation makes it susceptible to cold flow, that is, the insulation gradually becomes thinner in places where mechanical pressure is applied. Eventually, enough insulation material may migrate so that the insulation can no longer support normal operating or transient voltages. Swelling leads to delamination of the insulation, and even peeling of the insulation in magnet wires. If the mechanical or electrical strength of the insulation decreases significantly due to chemical deterioration, a high voltage surge or the transient mechanical forces during motor turn-on or synchronous machine malsynchronization can puncture or crack the insulation. The result is a turn or ground short.

Modern stator winding insulation systems are more resistant to most kinds of chemical attack. Epoxy is relatively resistant to solvents, moisture, or oil. However, if the epoxy is exposed to oil and water for many years, for example, from a water coolant leak problem (Section 8.16), then it will eventually degrade. Modern magnet wire films such as polyamide-imide or polyester with a polyamide-imide overcoat have excellent resistance to most chemicals.

8.13.2 Root Causes

The root cause of chemical attack is the presence of oil, water, solvents, gases, or other reactive chemicals. Oil is used in all large motors and generators. If the bearing lubrication system is poorly maintained, then excess oil will drip or be blown onto the windings. In hydrogen-cooled machines, a leaky seal oil system is also a likely source of oil. Water can come from cooling water leaks and openings in the machine enclosure that expose outdoor machines to rainstorms. In addition, if an open-ventilated machine operates at low load or is shut down in high humidity areas, moisture can condense on the winding surfaces if space heaters are not fitted or not working. In hydrogen-cooled machines, excessive moisture can enter the machine via the seal oil system, where the oil is in contact with atmospheric air. The problem is made worse if the hydrogen dryer is not functioning.

Materials used to clean a winding are a source of chemicals. It is common to clean stators with steam or high-pressure water (Section 8.11.4). This should not be done with older types of insulation such as asphaltic mica, as the water may be absorbed into the insulation. If water or steam is used for cleaning modern stators, the stator should be dried in an oven or by circulating current through the stator as soon as possible. Cleaning with solvents or caustic compounds can also degrade older insulation systems, although this is rarely a problem with modem stators.

Windings in motors and small generators with grease-lubricated bearings can be contaminated with this lubricant if grease relief plugs are not removed during regreasing. If this is not done, then grease is forced between the bearing cap and machine shaft and enters the stator end winding region.

8.13.3 Symptoms

In a visual inspection, the insulation may be discolored by chemical attack. The insulation may have swollen and, if tapped, may sound hollow. If it is easy to scrape away the insulation with a small knife, then chemical attack may be occurring. Figure 8.18 shows a photo of a motor stator seriously deteriorated by acids from a boiler flue gas.

There are few diagnostic tests that can be done from the machine terminals that will indicate that the problem is occurring. If the problem is in an advanced stage, the insulation resistance and polarization index test results may be low. Chemical analysis from small samples of the insulation and any local debris or dirt will indicate if chemical deterioration is occurring.

Figure 8.18 Photo of a stator winding degraded by acids in chimney flue gas. (*See color plate section*).

8.13.4 Remedies

The most important means of preventing winding failure by this mechanism is to specify a totally enclosed machine with a sealed winding (IEEE 1776, IEEE 1107), ensure that oil leaks or grease ingress is not occurring, and that improper materials are not used for cleaning.

For existing machines, the following actions may delay failure:

- Clean the stator regularly if the machine is operating in an environment where chemicals are likely to be found. Use as benign a cleaning material as possible.
- Ensure that the filters are effective.
- Repair oil or water leaks as soon as possible.
- Ensure effective heater operation (where fitted, or consider retrofitting heaters), to prevent moisture condensation on the windings when the unit is cold.
- Ensure that old grease is expelled through grease relief plugholes when new lubricant is being added.
- Repair or replace an ineffective hydrogen dryer.

8.14 INADEQUATE END WINDING SPACING

In large stators, space is left between adjacent coils in the end windings to ensure that sufficient cooling air flows over them, to aid in limiting the winding temperature. In form-wound stators, particularly windings rated at 6 kV and above, adequate spacing is also needed to prevent PD activity. If the spacing is too small, PD can occur, which may lead to ground and/or phase-to-phase faults. The problem does not happen on random-wound stators, and is unlikely to occur in high-pressure, hydrogen-cooled machines.

The PD problem is most likely to occur in air-cooled machines rated at 11 kV or higher. It may also occur on stators rated at 6 kV and above that are using a thin ground-wall design. Although in a different location, the PD can also occur between circuit ring buses, coil connection insulation, or in the terminal leads if they are too closely spaced, especially if they are in different phases. Machines rated 3 kV and above operating above 1000 m in altitude are especially prone to this problem.

8.14.1 General Process

As discussed in Section 1.4.4, PDs occur when a gas is subject to an excessive electric stress. Figure 8.19 shows a cross-section of two adjacent coils or bars in the end winding of a form-wound stator. The cross-section can be thought of as three capacitors in series between the copper conductors: the capacitance of the A-phase groundwall, the capacitance of the air gap between the coil surfaces, and the capacitance of the B-phase ground-wall. As a simplification, each of these capacitances can be calculated from a parallel plate model of a capacitor, in which the capacitance depends on the insulation thickness (or the distance between the coil surfaces in the case of the air gap) and the dielectric constant of the insulating material (see Equation 1.5). Using normal capacitive divider relationships from basic circuit theory, the percentage of voltage across the air gap can be calculated, knowing the thickness and the dielectric constants. From this, the electric stress between the coil surfaces is calculated (Equation 1.4). If the stress exceeds 3 kV/mm peak in an air-cooled machine at sea level (or a lower stress at high altitudes), the air breaks down, creating a PD. PD most likely occurs when adjacent coils are connected to the phase terminals and in different phases, as the full rated voltage will drive the process.

Given sufficient time, the PD will erode a hole through the groundwall insulation. Since the discharges usually occur in air, ozone is created, which further accelerates the insulation deterioration process because the ozone creates nitric acid that also etches the insulation (Section 8.5.1). The ozone may also corrode heat exchangers and damage rubber gaskets. The time to failure is usually 10 years or more, since mica-based groundwall insulation is resistant to PD attack.

If the space between the coils is too small, typically less than 5–7 mm in a 13.8 kV winding with an average design stress of 2.5 kV rms/mm, PD will result if the full phase-to-phase voltage is across adjacent coils. PD is more likely at high altitudes, since the breakdown stress of air is lower in such locations. In addition, thin groundwall insulation designs increase the capacitance of the groundwall, reducing its capacitive impedance and applying more voltage across the gap. Consequently, such designs are more prone to this problem. High pressure, hydrogen-cooled machines are less likely to have PD, since the breakdown strength of a high pressure gas is many times higher than the strength at one atmosphere.

The problem will occur wherever adjacent coils (side-to-side or between the top and bottom layer of coils) are too close. This problem can also occur if high voltage circuit ring buses are too close. An interesting variation has occurred in some air-cooled generators with Roebel bar windings and “end caps” used to insulate the

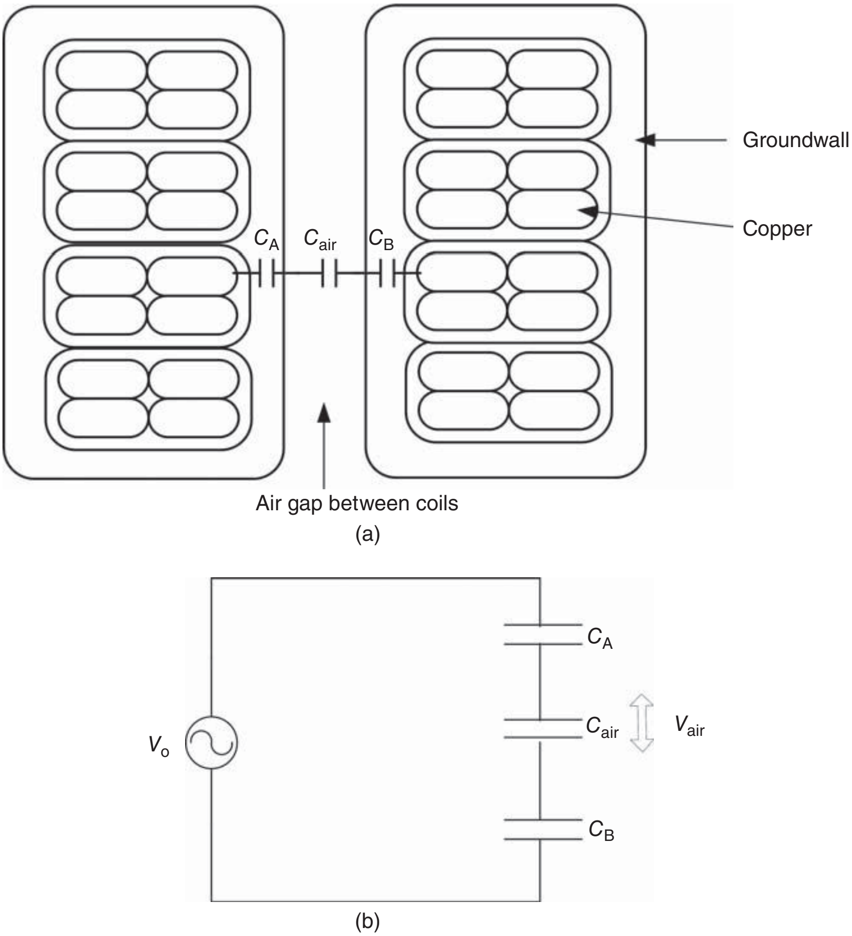

Figure 8.19 (a) Cross-section of two adjacent coils in the end winding where PD will occur if the distance between the coils is too small. (b) Equivalent circuit to calculate the voltage across the air gap.

connection between bars. The end cap insulation is often made by placing a polycarbonate (or similar material) mold over the connection and filling it with a thixotropic epoxy. The epoxy often contains fillers, but these are not especially PD resistant. If two adjacent end caps are insulating high voltage connections in different phases (i.e., at the phase breaks), and the end caps are too close, PD will occur between them and damage the end caps. Since the mold and the epoxy are not resistant to PD, failure occurs in a period ranging from a few months to a few years. If the dielectric constant of the epoxy is too high, the capacitive reactance of the end cap will be low, increasing the stress across the air gap. Sometimes such PD only occurs when the generator is operating at high temperature, since the dielectric constant of the end caps is usually higher at high temperature.

8.14.2 Root Causes

Poor design and/or poor manufacture are the most likely cause of these problems:

- Insufficient space between coils for the altitude at which the machine is expected to operate. The purchaser may also be responsible if the OEM was not made aware of the intended location for the machine.
- Use of a thin groundwall design, without increasing the normal space between coils or making other provisions in the end winding.
- Inconsistent coil/bar shape after manufacturing. If one coil is longer than its adjacent coils, the longer coil must be closer to the adjacent coil than designed for, after the first bend in the end winding.
- Poor installation of the coils in the slot. Even if the coils have identical shapes, if the first bend in a coil occurs farther out of the slot than the other coils, then it will close the space between the coils, after the first bend in the end winding. An inadequate number of space blocks between adjacent coils may also make it harder for winders to keep consistent spacing between coils.
- Insufficient blocking or poor use of conformable packing may enable coils to bend in the end winding, after high fault current or high motor starting current flow through the stator. This may reduce the distance between coils operating at greatly different voltages.
- Poor chemical control of the epoxy (in the coils or the end caps), which allows a high dielectric constant at operating temperature.
- Insufficient space between high voltage top and bottom coil legs in different phases at crossovers in the end windings.

8.14.3 Symptoms

Usually, this mechanism is easy to spot in a visual inspection of the end winding. Intense white powder (the result of ozone attack) will occur between the coils (or end caps or circuit rings) connected to, or close to, the phase terminals (Figure 8.20). The most likely region for the white powder is where there are two adjacent phase-end coils in different phases. However, the powder can occur whenever any two adjacent coils have a sufficiently high potential difference. The white powder will not occur between neutral end coils, or where there is a larger than average space between adjacent coils. The powder may assume shades of gray or brown in the presence of dust, debris, and oil.

On-line PD tests are the most effective diagnostic means of finding the problem. Off-line tests usually do not have sufficient voltage in the end winding to initiate the PD. A blackout test at phase to phase voltage will also identify it (IEEE 1799).

8.14.4 Remedies

To avoid this problem, blackout testing (Section 15.14) and ensuring conformity to the specified distance between coils, circuit rings and leads to the terminals are needed

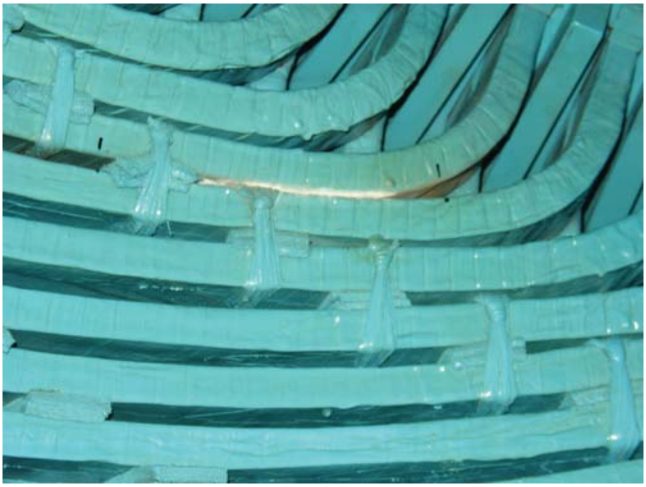

Figure 8.20 PD between adjacent coils in different phases results in white powder on the stator bar surfaces. (*See color plate section*).

at the time of stator manufacture. If the problem is discovered at an early stage of operation, very effective repairs are possible as discussed below.

- A good repair is to inject a conformable insulating material into the affected areas between the coils or circuit ring buses. As a solid insulation has about 100 times more electric strength than air, PD is prevented. Silicon rubber[†] or resin-filled felt pads are the most common materials used. For larger machines, resin-bonded glass fiber blocks wrapped with resin-filled felt are often used. Rigid epoxy-reinforced blocks or even mica flakes are usually not as effective as air spaces often remain, which give rise to very intense PD. Also, rigid materials may break away from the coil after load cycling, again creating an air gap that may discharge. Only gaps showing PD activity should be filled, as such filling impairs the end winding air cooling.
- If the end winding coils are flexible, insert blocks to increase the spacing between adjacent coils with a large potential difference. This procedure needs special care due to the risk of damage to the windings. Similarly, changing the bus supports can increase the spacing between adjacent circuit ring buses.
- For end cap PD, replace the caps and use a low dielectric constant epoxy to fill the new caps. Alternatively, increase the space between the caps. Sometimes it is better to have less insulation in the end cap. Another repair is to hand tape the connection with a resin-rich epoxy-mica paper tape. Although discharges may still occur, the mica paper has a much greater PD resistance.
- Reverse line and neutral ends (and install a neutral ground fault relay).

[†]There is some concern about the use of silicon rubber in a machine that has slip rings. The acetic acid released during cure by some types of silicon rubber can impair the operation of some types of slip rings. However, as a number of OEMs have been using silicon rubber for decades to secure coils in the slot, carbon brushes have been developed that are not affected by the acetic acid.

8.15 END WINDING VIBRATION

Normal 50 or 60 Hz current flowing through the stator coils and bars creates large (100 or 120 Hz) magnetic forces (Section 1.4.9). If the end winding is not adequately supported, the coils vibrate, gradually abrading the insulation. The problem is most likely to occur on form-wound two-and four-pole machines, as such machines have long end windings, which may have natural frequencies close to the frequency of the magnetic forces or rotational speed frequency. End winding vibration is one of the most common failure mechanisms of large gas and steam turbine generators rated a few hundred megawatts and above, and especially those made since about 2000. Two-pole direct hydrogen-cooled stators seem to be the most susceptible type of machine, since all other factors being equal, such stators tend to have longer end windings to achieve sufficient electrical creepage distances. Global VPI stators or random-wound machines are less likely to suffer from high end winding vibration. However, any random-wound or form-wound stator can fail due to this problem if the end windings are not adequately supported and/or have natural frequencies at or up to about 10 Hz above the once per revolution speed and/or twice the frequency of the stator winding current.

8.15.1 General Process

Reference 23 gives a review of the causes of the end winding vibration and mitigation in turbine generators. Section 1.4.9 discusses the need for adequate stator end winding support. If the support is inadequate, the bars or coils will begin to vibrate. In form-wound machines with long end windings, this vibration in the radial and circumferential (tangential) directions will pivot at the stator slot exit, as the coils/bars in the slot are presumably tightly held by the slot support system. Thus, the coil insulation may eventually fatigue-crack just outside of the slot. The fatigue-cracking can occur even if the coils themselves are tightly held together in the end winding, since the entire "end-basket" may be moving. The cracked insulation will enable a phase-to-ground fault.

If the blocking and bracing are loose in the end winding, coils and bars can also vibrate relative to one another. The bars and coils will then rub against each other, the blocks, surge rings, support cone, and/or other end winding support members. The rubbing will abrade through the insulation. Fiberglass roving is especially hard and very effective in cutting through the groundwall insulation. If not corrected, sufficient groundwall insulation can be abraded so that a phase-to-ground failure occurs.

There are additional consequences of end winding vibration in directly cooled stator windings. In water-cooled stators, the 100 or 120 Hz end winding vibration can fatigue-crack the brazed copper connections from one bar to another and/or the water nozzles. This can allow water to leak into the insulation (Section 8.16). Also, some failures have occurred because hydrogen becomes entrained in the stator cooling water. The hydrogen bubbles combined with excessive vibration lead to cavitation of the copper conductors. The thinning copper tubes eventually crack, allowing large amounts of hydrogen into the cooling water.

In direct hydrogen-cooled windings, end winding vibration has led to broken copper strands due to copper fatigue. The strand arcs at the copper ends as the crack makes and breaks contact, causing localized overheating of the insulation. The insulation eventually melts, precipitating a ground fault. Arcing has also occurred at broken resistor connections (due to vibration). The resistors are installed to give a fixed potential to the hollow hydrogen tubes within the bar. Direct hydrogen inner cooled stator windings require a longer end winding than other designs (everything else being equal), as the exposed metallic tubes require longer creepage distances. This makes such windings more susceptible to end winding vibration problems.

Broken copper strands due to end winding vibration can also occur in other types of stators. Once one strand breaks, it increases the current flow in the other strands, making the good strands more prone to cracking. The increased temperature also increases the resistance in the other strands, which further increases the temperature. Eventually more strands break and a runaway condition is reached where the entire conductor bundle melts, and a plasma is created between the parted conductors causing extensive collateral damage to the rest of the end winding (and of course failure). This problem has become a very important failure process for gas turbine generators made since about 2000.

8.15.2 Root Causes

The following are possible reasons for end winding vibration to occur in form-wound windings:

- Inadequate initial design. Many large turbine generators had end winding vibration problems in the 1970s and 1980s, before OEMs developed more effective support systems. Such systems had to allow for load cycling in which the winding tended to expand and shrink axially. Sometimes, the end winding design was such that it had a natural frequency point near twice the power frequency. This was more likely on a machine originally designed for 50 Hz operation but modified for 60 Hz. In some gas turbine generators made since 2000, the end windings had natural frequencies close to either twice the power frequency or the turning speed of the rotor. Note that natural frequencies are normally detected with a bump test done on the stator winding at room temperature (Section 15.23). The natural frequency tends to decrease by 5 to 15 Hz as the winding temperature increases [24]. The higher the operating temperature, the greater is the decrease in natural frequencies. This needs to be taken into account in determining if an endwinding will be resonant at 100 or 120 Hz when operating at a higher temperature (i.e., at full load). Another design flaw is that sometimes the extensions from line end coils/bars to the circuit ring buses can be very long and/or have inadequate support.
- Poor manufacturing procedures. These include blocking and bracing that is not installed uniformly around the end winding circumference or at an inconsistent distance from the stator core. Lashing and roving can be installed nonuniformly or not be properly saturated with polyester or epoxy resin. The coils or bars may have different shapes or be installed with different lengths of the end winding

extending from the slot. This may create very small spaces between the coils in some locations, making it impossible to insert blocks that can brace the coils. There are many other manufacturing-related problems that lead to loose end windings.

- A prior out-of-phase synchronization or excessive motor starting current, which can create sufficient magnetic force to break the lashing and allow blocks to come loose.
- Long-term operation at high temperatures. This results in thermal aging of the insulation and organic end winding support materials (Section 8.1). These materials will shrink, enabling looseness to develop. This process can occur on all types of machines.
- Excessive oil in the end winding. The oil can reduce the effectiveness of some lashing materials, allowing them to slacken. In addition, oil acts as a lubricant that seeps between blocking points, enabling small relative movements that would not normally occur without a lubricant. The low-level vibration very slowly abrades material, increasing the vibration amplitude.

Random-wound machines suffer end winding vibration deterioration usually only if the stator is poorly impregnated or the coils were poorly lashed in manufacture. In addition, if the stator has seen strong thermal deterioration, the organic components will probably shrink enough to allow relative movement to occur.

8.15.3 Symptoms

In a visual inspection of a form-wound stator, insulation vibration is usually manifested as "dusting" or "greasing." If there is little oil present in the machine, a fine, light-colored powder is created by the relative movement between a coil and the blocking or lashing (Figure 8.21). If oil is present, the oil mixes with the powder to create a thick black paste (called greasing) that accumulates at blocking and lashing points. Dusting or greasing can occur at any location in the end winding where two surfaces meet. It may occur at the high voltage or neutral end of the winding. If the coils are covered with a varnish, the varnish may be cracked.

Conventional nondestructive evaluation (NDE) methods can be applied in an off-line test to determine if the end winding is resonant at 50/60 Hz (for a 2-pole machine) or 100/120 Hz, using a "bump" test (Section 15.23). In the bump test, the end winding is struck with a hammer which has an accelerometer attached. Conventional accelerometers are temporarily attached to the end winding and their response is monitored with a frequency spectrum analyzer. If the winding is prone to end winding vibration, it will have a strong response at a natural frequency near twice the power frequency or sometimes the equivalent rotor turning speed frequency. If the end winding is loose, when hit with a hammer, there will be little damping of the response. The bump test can be augmented with a modal analysis to predict which parts of the winding are most likely to vibrate excessively.

Machines that may be prone to end winding vibration can be equipped with end winding vibration monitors (Section 16.6) to detect movement. The vibration sensors must be non-metallic to avoid high voltage problems.

Figure 8.21 The white areas indicate fretting due to end winding vibration where the coils are lashed to a support ring in a motor stator.

In direct water-cooled machines, there will be an increase in the hydrogen content in the water if the problem is so advanced that strands have cracked. Also, in direct-cooled windings, bar outlet temperatures increase a few degrees from normal due to broken strands.

Other than overvoltage (hipot) testing, there are no electrical tests that can detect this problem, unless it is in a very advanced stage. In severe cases where the copper strands may have fatigue-cracked, online PD detection may be effective. Also, if the end winding vibration is severe, it will vibrate into the stator slots and loosen the coils/bars in the slot, leading to slot discharges (Section 8.4).

In random-wound machines, the problem can only be deduced from a visual examination. There may be signs of dusting or greasing at lashing points and the magnet wire insulation may have cracks.

8.15.4 Remedies

For form-wound stators, operating the machine at a reduced load will extend the life, as vibration increases with the square of the load current. As the forces in the end winding are affected by the operating power factor, there may be some reactive power loads that will minimize end winding vibration. Some of the repairs that can be done include the following:

- Complete end winding support system replacement with a superior system. This has been needed on some very large two-pole direct-hydrogen inner-cooled windings [25].
- Removal and reinstalling of blocking and lashing materials.

- Installation of additional blocking and bracing, although higher end winding temperatures may result in air-cooled machines due to reduced coolant flow.
- If the stator was originally GVPI'd, or the form-wound stator did not have a semi-conductive coating in the slot, then a global VPI treatment may slow the process. Note that a global VPI treatment should not be applied to a conventional stator that has a semiconductive coating in the slot. The VPI resin may insulate some coils from the core, giving rise to high intensity slot discharge (Section 8.7).
- For new machines, it must be specified that the end winding will have no mechanical resonance between +10 and −5 Hz of twice the power frequency. The higher upper tolerance is needed because the natural frequency usually decreases as the stator winding temperature increases. Stator end windings expected to operate above 120 C should perhaps be tested at room temperature to ensure a natural frequency does not occur up to 15 Hz above the twice power frequency.

8.16 STATOR COOLANT WATER LEAKS

This problem is only associated with large hydro and steam turbine generators with directly water-cooled stator windings (Section 1.1.5). Such machines are usually larger than 200 MVA. If the water used for cooling leaks onto or into the insulation, either a ground fault immediately occurs, or the insulation degrades over time.

8.16.1 General Process

Since the first direct water cooled stators were built, water leaks have occurred. Most leaks are due to poor workmanship: personnel did not correctly attach the Teflon™ hoses to the nozzles at each end of the stator bars. The stator winding pressure and vacuum decay tests prior to generator startup would help eliminate a majority of such defects in assembly (Section 15.24). Any "plumbing" connections that are marginal can cause water to spray onto the end winding when the machine is in service. This contamination leads to electrical tracking (Section 8.11) or even immediate flashover if there is a large leak. Such gross water leaks are usually easily detected by the presence of hydrogen gas in the coolant alarm, liquid in a generator alarm, an increase in the water make-up rate, and an increase in hydrogen dewpoint.

A more serious problem occurs if a very small leak develops at the end of the bar, but before the nozzle, in the region termed the "water box" or the "clip." Such small leaks are not easily noticed because they may not trigger the alarms mentioned above. Crevice corrosion of the brazed connection between the stator bar copper strands to the waterbox is the primary cause of these small leaks. Porosity in the brazed connections and cracks in strands can also result in leaks.

In spite of the hydrogen pressure being higher than the water pressure, osmotic forces allow a trickle of moisture to be drawn into the groundwall insulation. Although very resistant to moisture, the ground insulation epoxy–mica tape layers tend to delaminate and swell due to the constant ingress of moisture. The water can then migrate along the bar through this delamination or in interstices between copper strands. Dissection of bars removed from affected generators has shown the presence of moisture all the way down to the end of the bar opposite to the leaking end.

The small water leak will have two effects on the groundwall insulation. First, the electric strength of the epoxy-mica insulation is reduced if the insulation has been saturated with water. Thus, the stator will be more prone to fail if an overvoltage event occurs (such as a ground fault in the switchyard) or during an AC or DC hipot test (Sections 15.2 and 15.6). Second, water will reduce the mechanical strength of the insulation. If a current surge occurs due to a fault in the system or if the unit is synchronized out-of-phase, then the groundwall is more likely to rupture.

As this failure mechanism was first recognized around 1990, more than 1000 stators of susceptible designs have been tested and about one-half of them found to be leaking. Consequently, hundreds of stators have either been repaired or rewound.

The deterioration process is very slow, often taking decades before there is a high risk of failure, as each step of the process requires time. The sequential steps are as follows:

1. Corrosion in the brazed connection begins. This may take from years to decades, depending on the water chemistry, the design of the waterbox, the brazing materials used, and the skill with which the brazing is applied.
2. The water must leak from the brazed connection into the slot area. This probably takes years, depending on the stator temperature, the leak rate and the rate of corrosion.
3. Either a hipot test or a system disturbance must occur.

8.16.2 Root Causes

Poor brazing at the connection of the copper strands to the water box during manufacturing or rewinding of the stator has caused the majority of such leaks. Deficiencies in the brazing materials and the brazing procedures gives rise to a process called *crevice corrosion* [26]. Water fills small voids or fissures at the face of the brazed connection to the strands and between the strand and the waterbox. Crevice corrosion then begins when the following conditions are satisfied:

1. Uneven application of the braze results in small pockets at the face of the strand packet and between the strands and the waterbox.
2. The pockets or gaps in the braze allow water to stagnate locally.
3. Phosphorus in the braze combines with water and oxygen to produce phosphoric acid, which corrodes the braze and enlarges the pockets.

Eventually, tiny cracks develop in the braze, allowing water to leak between the adjacent strands or between the strand packet and the waterbox until the water comes in contact with the groundwall insulation.

Generators designed by one major manufacturer (and its licensees) have experienced most of the problems. A new brazing design by this manufacturer on units shipped since 1984 may eliminate this problem. Other designs use stainless steel tubes down the stator bar to carry the water, rather than using hollow copper tubes. Such designs have not developed water leak problems of this type to date. Even stator designs having hollow copper strands have been free of this problem when a different brazing process has been used and the brazed connections have a smooth surface so the water has no place to stagnate.

In an attempt to retard the rate of corrosion, conversion of high-oxygen (>2 ppm) stator cooling water systems to low-oxygen (<50 ppb) operation has been considered [27]. However, whereas aeration may play a role in the initiation of corrosion in the brazed joints, test data does not indicate that deterioration will halt the attack once it is underway [28]. A decision for such a conversion also has to address the risk of copper oxide formation leading to plugging of the strands if the oxygen regime cycles through or drifts into the high corrosive range of 100–400 ppb of dissolved oxygen.

8.16.3 Symptoms

It can be difficult to determine from a visual inspection of the windings if the problem exists, as there is usually no evidence of the problem at the surface of a coil. However, in an advanced stage, the groundwall insulation may sound hollow when it is tapped with a hammer. The closer to the stator core the hollow sound occurs, the greater the risk of failure.

Online and off-line tests are best at detecting the problem at an early stage. If the machine is hydrogen cooled, during operation there will be a high concentration of hydrogen in the stator cooling water. Also, the hydrogen makeup rate will be increased from normal. Proprietary online diagnostic systems are available for monitoring hydrogen leakage into the stator cooling water system (Section 16.10). Off-line tests and repairs can then be planned to avoid a forced outage and to minimize outage time. In off-line testing, vacuum and pressure decay tests are convincing means to determine if the problem exists (Section 15.24). Capacitance mapping (Section 15.7) and helium or SF_6 tracer gas leak tests can help to locate the bars that may have experienced leaks. The use of SF_6 as a tracer gas has come into some disrepute recently, since the gas is considered a greenhouse gas.

8.16.4 Remedies

To prevent the process from occurring or to slow the process once it has started, it is very important for users to follow the manufacturer's instructions for maintaining the cooling system chemistry. In particular, the oxygen content must be monitored and adjusted to keep it within the specified limits. In addition, if the machine is a hydrogen-cooled turbine generator, the hydrogen pressure should be maintained above the water pressure to reduce the water leak rate even if cracks have already developed. If a winding is known to have severely delaminated insulation due to water leaks, it is very important to avoid hipot testing, out-of-phase synchronizations, or (if possible) current or voltage surges from the power system, unless one is prepared to handle the consequences of a ground fault. Even much degraded epoxy-mica insulation can withstand normal operating stresses for years.

Replacing individual bars and coils can help restore normal operating life of the winding. However, before bar replacement or rewinding is needed, implementing the following repairs may extend the life:

- Adding certain chemicals to the cooling water. The chemicals may collect at the cracks and be able to stop the leaks at the braze, without blocking cooling water flow elsewhere [29].
- Using localized epoxy to plug leaks in individual bars. Multistage epoxy compounds are injected in the pores of the braze connection to eliminate pockets where water can stagnate. While it is necessary to cut back insulation to expose the repair site, this method does not require the application of heat to the brazed connection.
- Performing a global epoxy repair. In addition to the known leaky brazed connections, all the brazed connections are repaired with the epoxy injection method as a preventive measure. This major undertaking may not be justified when compared to the additional assurance and possible uprating capability resulting from the rewind option.
- Replacing leaking water boxes and brazing with modern materials using modern methods. In addition to the need to cut back insulation, this method requires the removal of the existing braze and the application of a significant amount of heat, increasing the risk to insulation integrity.

The long-term effectiveness of some of these repairs has not yet been established. A computer program has been developed to evaluate the costs and benefits of each of these repair alternatives [30].

8.17 POOR ELECTRICAL CONNECTIONS

In a typical stator winding, there are hundreds if not thousands of electrical connections. If the resistance of the connections is too high, overheating the joints thermally degrades the insulation, eventually causing failure. Form-wound stators are more likely to encounter such problems, due to the large number of joints that are necessary between coils and bars. However, any poorly made stator can suffer from the problem.

8.17.1 General Process

In form-wound stators, the connections between copper leads in coils and bars are usually brazed or soldered. Motor and generator bus bar connections and leads in the terminal box are usually bolted to the power system cables or bus. If the connections have too much resistance, the leads will become hotter than necessary. The increased copper temperature further increases the resistance and, if the connections are hot for a long period of time, oxidation is accelerated, again further increasing resistance. Eventually, the copper may become so hot it melts, resulting in failure. In addition, the hot connections will thermally deteriorate the insulation over the connections (if present) and the adjacent coil insulation. If a current surge occurs, for example, from motor start-up, the degraded insulation may crack, exposing the copper conductors. The stator then has a high risk of failure from pollution, water, or voltage surges. Since the connections are generally far removed from the grounded stator core, the insulation over the leads can be extremely degraded, yet still not result in immediate failure.

Random-wound motors generally have far fewer connections, but there are still some connections between coils and in the motor terminal box. Since the insulated connections are usually in close proximity to the core or other coils, if the connection overheating has progressed to the state that the insulation is melted or so brittle it has fallen off, a ground fault can follow soon after.

Depending on how high the resistance is, and the proximity of the connection to ground or other conductors, failure may occur from minutes to decades after the machine is put into service.

8.17.2 Root Causes

Usually, poor workmanship is the main cause of connection overheating. Overheating can be caused by poor brazing, poor soldering, or inadequately tightened or designed bolted connections. In some cases, the connection between coils or bars may fatigue-crack over time if there is excessive end winding vibration (Section 8.15). Some manufacturers use clips instead of brazed inter-coil group connections. These clips can come loose, resulting in a high-resistance connection.

8.17.3 Symptoms

In a visual inspection of the winding, connections that pose a risk of failure are usually apparent because the insulation looks discolored (scorched). When touched or rubbed with a knife, the insulation may crack or be easily peeled off.

If one has access to an infrared imaging camera, then it may be observed that parts of the machine enclosure may be hotter than in the past, under the same load and atmospheric conditions. One can sometimes open the terminal box while the machine is in operation, and “shoot” the terminals to see if they are overheated. Also, it is possible to install special infrared windows in a terminal box to allow scanning for bad connections with an infrared camera without opening the terminal box. Unfortunately, except for hydrogenerators, it is impossible to locate bad connections between coils on-line using an infrared camera. Off-line, a welding machine can be used to circulate a high current in the winding (well less than the normal operating current, since there is no cooling air flowing). Any poor connections can then be seen with a thermovision camera (Section 15.5). Although not as good, the trend in winding conductivity (Section 15.4) over time may detect severe bad connections.

8.17.4 Remedies

If overheating connections are suspected, the life of the stator can be extended by reducing load and ensuring maximum cooling air or hydrogen circulation over the affected areas. Otherwise, overheating connections should be separated and rejoined, and new insulation installed, during a suitable outage. Bolted bar–bar connections should be silver plated to reduce the contact resistance and belville washers should be used to ensure adequate contact pressure is maintained.

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CHAPTER 9

ROUND ROTOR WINDING FAILURE MECHANISMS AND REPAIR

The aging processes and failure mechanisms affecting rotor winding insulation and, where appropriate, the winding conductors of round rotors in turbine generators and high speed synchronous motors (Section 1.6.2) are described in this chapter. Root causes of the failures and symptoms characteristic of the failure mechanisms are also discussed, as are the repairs and refurbishment options available for dealing with these conditions. The repairs covered in this chapter tend to be common for all types of deterioration processes. Thus, repairs are described at the end of this chapter. Rewinds for large, round-rotor synchronous machines are discussed in Section 18.5.2.

Experience has shown that visual inspection is an invaluable tool not only for identifying the failure mechanism present but also for determining the optimum repair solution. However, as it is a major task to remove the rotor and disassemble the components in large motors and generators, other symptoms, measurements, and tests that can help with the assessment are also presented.

9.1 THERMAL DETERIORATION

Thermal aging of insulating materials due to high temperatures has been the most studied and is perhaps the best understood because it was the most common underlying reason for winding failure of older types of insulation. Before the 1970s, the slot cell insulation often included composites made with kraft paper, mica splittings, and glass, glass/asbestos, or asbestos cloth, all bonded with natural resins like shellac or solvent-based phenolic material.

The organic components thermally aged in service and allowed the inorganic components to be displaced by cyclic mechanical forces experienced in operation, leading to cracks and gaps in the ground insulation and electrical failure. Similar failures often took place in the turn insulation tapes or strips. Materials such as rubber with mineral fillers, thin cotton phenolic laminates, and tapes with mica splitting and glass backing with early synthetic resin binders were often used. These tapes were

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair,
Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

applied by hand before the coils were wound into slots and not cured until all coils were assembled. Insulation abrasion and displacement were common during winding, often resulting in turn insulation failure. Although a few turn shorts can often be tolerated, they cause imbalanced heating of rotors in service and excess vibration due to thermal bowing of the rotor (Sections 1.6 and 16.9.3).

Starting in the 1950s, modern thermosetting resins and glass fabrics began to replace the older systems. Endwinding blocking was changed from phenolic-bonded asbestos cloth laminates to glass cloth with either polyester or epoxy bonding resins. Similar changes were made in the slot cell insulation. These changes raised the temperature class of the insulation into the Class F (155°C) range and significantly reduced the incidence of thermal aging. Smaller fields are insulated with nonwoven aramid sheets and tapes, whereas larger fields often use nonwoven glass laminates for turn and ground insulation as well as creepage blocks and endwinding blocking.

9.1.1 General Process

Glass laminates bonded with epoxy or polyester resins are commonly used for both the turn and the ground insulation in direct-gas-cooled rotors. Chapter 5 describes these and other types of materials in more detail, including materials used for end winding insulation and blocking. Thermal degradation of these materials may be treated as a chemical rate phenomenon (described by the Arrhenius relationship, Equation 2.1) and includes loss of volatiles, oxidation, depolymerization, shrinkage, surface cracking, and embrittlement (Section 2.3).

Modern glass laminate insulation systems are usually made from Class F (155°C) materials for operation as Class B (130°C) systems. As the average rotor winding operating temperature is in the range of 60–90°C, there would appear to be an adequate temperature margin. However, the margin is reduced at hot spots in the winding, which cannot be measured directly (even the average rotor temperature is an indirect measurement derived from rotor amps and volts; see Section 16.1.2). Depending on the type of the cooling-gas flow system, the estimated hot spot temperature could exceed 130°C. Thus, thermal aging becomes a factor, particularly where Class 130 materials have been used. The thermal degradation is less likely on hydrogen-cooled rotors because of the lack of oxygen, which accelerates chemical aging, and because of the greater operating temperature margin that is usually available.

As described in Chapters 2 and 8, the higher the temperature, the faster will be the chemical reaction, resulting in shortened life of the insulation under thermal degradation.

9.1.2 Root Cause

All organic insulating and bracing materials deteriorate with time due to the heat from the windings, which promotes chemical changes leading to degradation of the material properties. The rate at which component materials deteriorate is a function of their thermal properties and the temperatures to which they are subjected. If the thermal ratings of component materials have been properly selected (see Chapter 5 and Appendix A for the application of various materials in insulation systems), the thermal aging and associated deterioration will occur gradually over an acceptable service life. On the other hand, the following may lead to an unacceptable rate of aging:

- Overload operation or high cooling medium temperatures, leading to operating temperatures well above design values.
- Inadequate cooling, which can be general, for example, insufficient cooling air, hydrogen, or water, local dead spots in the cooling circuit due to poor design or manufacturing procedures, or localized blockages in cooling systems due to debris or movement of slot packing strips, insulation strips, etc.
- The use of materials that have inadequate thermal properties and consequently deteriorate at an unacceptable rate when operated within design temperature limits (unlikely with present day systems as most of these are thermally qualified to some IEEE/ANSI or IEC Standard).
- Overexcitation of rotor windings for long periods of time.
- Stator winding negative sequence currents due to system voltage imbalance, faulty breaker operation, inadequate protection setting, etc. This leads to circulating currents in the rotor pole face and rotor wedges.

9.1.3 Symptoms

In operation, the first indication of thermal aging may occur only at an advanced stage of deterioration when shorted turns are identified by air gap flux monitoring (Section 16.7), if fitted, higher bearing vibration due to a shorted turn (Section 16.9), a ground fault alarm, or a higher shaft current in case of deteriorated ground insulation. When shut down, a low insulation-resistance reading, low impedance reading, or turn short indications are identified from an RSO or surge test (Section 15.26) can signal thermal degradation that has progressed to the stage where the insulation has failed or is about to fail.

Visually, thermal degradation is easy to spot if it has advanced to the point of rupture. The damage will exhibit a characteristic irregular-shaped hole burned through the material and the accompanying discoloration in various shades of brown and gray. In practice, this symptom can be detected quickly if the damage has occurred in the end winding region. However, a significant amount of disassembly may be required if the damage is in the slot region toward the bottom turns.

When the damage has not yet caused puncture, the symptoms will show up as flaky surface, fine cracks, blistering, embrittlement, and discoloration. Gentle tapping with a blunt instrument is likely to result in pieces of insulation falling away from the parent material in the affected area.

9.2 THERMAL CYCLING

Operating temperatures have a direct aging effect on the insulation materials, as seen in the previous section. However, when the operating temperature undergoes variation due to load changes, start-stops, etc., additional stresses are set up that exacerbate the thermal aging process. The temperature changes cause the expansion and contraction of the winding copper relative to the insulation, giving rise to aging due to abrasion. Unless the rotor winding design can accommodate this movement of the copper by, for example, the inclusion of slip plains between components expected to see relative movement, additional built-up stresses can damage not only the insulation but other rotor components as well.

9.2.1 General Process

During operation, copper losses from the winding, and to a lesser extent windage and iron losses from the rotor forging, cause an increase in the temperature of the rotor components. The physical location of the components in the rotor is altered due to the axial thermal expansion caused by the increase in temperature. When the unit is shut down, the rotor cools down and the components contract to their original position, provided the copper has not been stretched beyond its elastic limit and there is no restriction to their movement. Depending on the duty, this expansion–contraction cycle may be repeated hundreds of times during the life of the unit. The axial movement of the copper tends to abrade the ground insulation, especially toward the end of the rotor slots (Figure 9.1a) or the turn insulation (Figure 9.1b). Wear imposed on the winding insulation and other components, due to this repeated back-and-forth movement, results in mechanical aging due to thermal cycling. If there are inadequate slip planes in the slot or under the retaining rings, thermal ratcheting can occur, especially on coil top turns. This results in the coil conductors expanding axially with an increase in field excitation current, but not contracting when the excitation current is reduced. This effect can cause distortion of the field coil end windings.

Peaking units are more susceptible to thermal cycling damage compared to base-loaded units because of the higher number of start-stop cycles. Longer rotors are likely to experience a higher level of damage due to the larger amount of expansion and relative movement. Similarly, air-cooled rotor windings, which generally operate at a higher temperature, will be affected more than hydrogen-cooled ones.

9.2.2 Root Cause

A generator rotor has copper, aluminum, steel, insulation, blocking, and sealing components that are required to maintain their relative positions in the rotor to allow reliable operation within operating limits. Over the years, the spatial relationship between these components is altered due to thermal expansion and contraction and as a result of start-stops and load changes.

The metallic components expand mainly due to the resistive heat from the winding. Expansion causes the components to undergo the following displacement mechanisms:

- The rate and the amount of growth are different for each component due to differences in coefficients of thermal expansion. This results in the first level of displacement between the components.

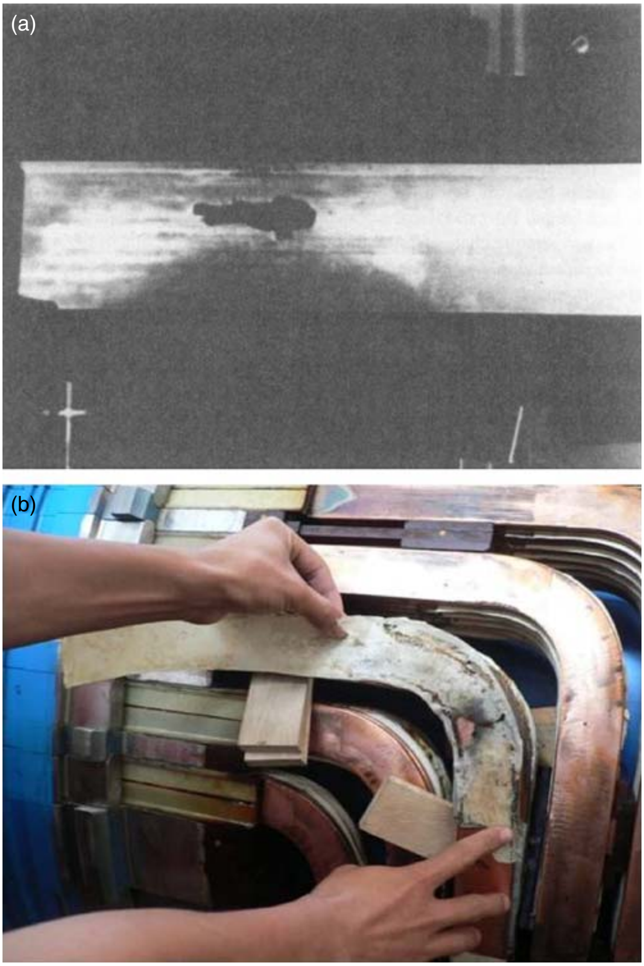

Figure 9.1 (a) Abrasion of ground insulation by conductors at the end of the slot due to thermal cycling. (b) Abrasion of the turn insulation in the end winding (Source: Photo courtesy of Guondong EPRI).

- Although most of the components such as the slot copper and the wedges are axially oriented, critical components such as end winding inter-turn connections and radial leads run in different directions. Components moving in two or more planes produce stress risers at their connections, which represent the second level of displacement between the components. This can lead to end winding distortion and shorting between turns and coils if inter-coil blocking is not adequate (Figure 9.2). In this regard, as indicated in Section 5.4, it is important that there is a slip plane between the retaining rings and end windings to avoid high mechanical stresses being imposed on the end windings and their insulation during thermal cycling.

Figure 9.2 End winding copper distortion from thermal cycling.

- Last, when the rotor cools on shutdown, the components may be prevented from returning to their original locations because of distortion, copper exceeding its elastic limit, other small dimensional variations, inadequate slip planes, and wear. This causes the third level of displacement between the components such as turn insulation and slot packing, leading to blockage of rotor cooling gas passageways through the field winding conductors.

Consequently, instead of the “neutral” as-assembled status of the components, thermal cycling results in progressive displacement, increased mechanical stresses, insulation damage due to wear and mechanical loading, and interference of cooling passages. The faster the load changes, or the faster the excitation current changes, the greater will be the difference in thermal expansion between conductors and the insulation, and, therefore, the more likely that relative movement will occur.

9.2.3 Symptoms

Symptons include:

- *Abrasion.* Rubbing of copper against turn insulation, slot liner (Figure 9.1a), and slot packing will show up as dusting, particularly in the slot exit area. Such damage can lead to looseness of the turns in the slot if not corrected. Once the coils become loose, the insulation may be further damaged by other aging mechanisms.
- *Turn Shorts.* Repeated expansion–contraction of the copper causes pushing and pulling of the turn insulation with which it is in close contact. The insulation strips have a tendency to ratchet or “walk away” under the displacement mechanisms set up by thermal cycling, as described in the previous section. In a new rotor, the bonding glue between the insulation and copper would normally prevent this from happening. However, the bond becomes weak under the action of operating temperatures. Moreover, relative movement due to thermal cycling

can not only shear the bond but can also crack the insulation in areas where the material may be inherently weak or where the movement is restricted. This is most noticeable in the end winding area, where the turn insulation loses alignment with the edge of the coil and begins to creep out from between the turns. Cracking and creeping of the turn insulation eventually lead to turn shorts.

- *Endwinding Distortion.* Changes in the shape of coil end windings leading to shorting between coils (Figure 9.2).
- *Radial Lead Shorts.* Insulation of the radial lead is designed to be sturdy because of the requirements of handling the dual stresses of electrical and mechanical duty. However, the considerable forces of displacement due to thermal cycling can be large enough to wear out the insulation, resulting in chipping and cracking, leading to a short-to-ground.
- *Blocking of Ventilation Holes.* Cooling gas travels through axial and radial ventilation ducts in the rotor to control the operating temperature. In the slot section, the ducts are formed by holes in the copper turns, turn insulation, packing, and wedges to form continuous passageways. The holes are normally elongated to prevent any restrictions due to misalignment from one section to the next. Thermal cycling causes relative movement between the slot contents and pushes the turn insulation out of position. Eventually, the ventilation holes in the copper and insulation become misaligned, restricting the passage of the cooling gas. Although some misalignment is normal and will not affect the cooling, it can cause uneven heating of the rotor in extreme cases. The extent of any such blockage can be determined by shining a flashlight down the ventilation holes to observe if blockage has occurred and recording the results for each winding slot.
- *Failure of pole Jumpers.* If inter-pole jumper connections are not designed to allow flexing during winding thermal expansion and contraction, they will crack and a field winding open circuit will result (Figure 9.3).

9.3 ABRASION DUE TO IMBALANCE OR TURNING GEAR OPERATION (COPPER DUSTING)

Two- and four-pole rotors in large generators can weigh as much as 100 tons. Moreover, they have components such as the windings that can move independently in the axial, radial, and transverse directions. Ensuring that the rotor runs smoothly within acceptable vibration limits under all operating conditions is important to ensure reliable performance over the long term. High vibration can lead to relative movement of the rotor winding components, which, in turn, can lead to insulation and copper abrasion (copper dusting).

Considerable effort is required to ensure a mechanically balanced rotor system, starting with the design stage, to factory assembly and testing, site assembly, and setup, to operating practices and monitoring. Nevertheless, this balance is upset at

Figure 9.3 Failed pole jumper connection.

times due to a number of factors, resulting in an increase in rotor vibration, which can cause further damage and even lead to shutdown of the generator.

9.3.1 General Process

Although rotor vibration is a mechanical phenomenon, its origin can be electrical or thermal in nature. The weight of the rotor is usually supported by a journal bearing at each end. Apart from the requirements for supporting this dead weight, the uniformity of weight distribution is an important mechanical consideration in the design and assembly of rotor components. Because of electrical and thermal stresses that build up during operation, additional forces are superimposed on the distributed weight of the rotor. Initially, these forces may be small; however, the underlying mechanisms being progressive in nature, the forces can become large enough over time to affect the weight distribution of the rotor.

Rotor dynamic performance is sensitive to changes in the weight distribution, particularly for two-pole designs in which the longer and thinner rotor shaft is more susceptible to bending forces. The increased vibration due to rotor imbalance can cause damage to the rotor components, leading to further imbalance. Ultimately, if relative movement occurs between the copper and the insulation, or the insulation and the rotor body, the insulation may abrade, leading to shorts.

Large turbine generator rotors have to be operated on turning gear at very low speeds (a few rpm) to prevent catenary "sets" (bending) in the shaft during unit shutdown. Operation at turning gear speed with low radial centrifugal forces on the windings can cause copper dusting abrasion, particularly when there are two or more conductor sub-strands that are not insulated from one another (Figure 9.4) and the slot side packing is not tight enough to prevent sideways strand movement. The copper particles can lead to turn or ground shorts.

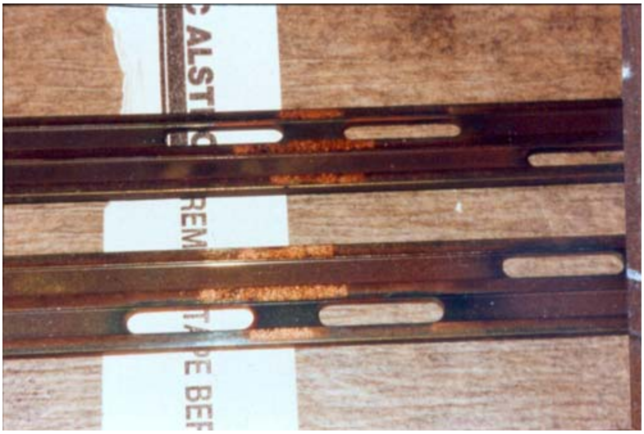

Figure 9.4 Abrasion of adjacent conductor strands and copper dusting due to turning gear operation.

9.3.2 Root Causes

Rotor Vibration Operating machines may exhibit high rotor vibration due to mechanical, thermal, or magnetic imbalances, which are caused by component movement or turn shorts (Section 16.7). This vibration, in turn, may lead to insulation abrasion. The movement and distortion of winding conductors or bracing materials can result in mechanical forces on the rotor. Although some relative displacement of these components is normal during the cycle of operation and shutdown, excessive motion can result in permanent set and distortion. When free movement of components is restricted because of distortion, the weight distribution of the rotor is compromised due to the additional mechanical loads imposed. The balance of the rotor is upset, causing vibrations to increase.

Turning Gear Operation At normal operating speed, centrifugal forces prevent relative movement between conductors or strands. However, during very low speed turning gear operation, these centrifugal forces are negligible. Consequently, relative lateral movement between uninsulated subconductors will take place during rotor rotation if the side packing in the slot is not initially tight enough or is compacted by the side pressure induced by the conductors.

This relative movement between two adjacent copper strand surfaces results in fretting (abrasion), which generates small copper particles that migrate to the top of the slot under centrifugal action at synchronous speed. Much of this copper dust passes out of the slot via ventilation ducts but some gets trapped in areas bounded by the top conductor, the space between the top creepage block, and the sides and top of the slot. If sufficient copper dust accumulates in one of these critical areas, a ground fault can occur as a result of the top turn shorting to the rotor body via the copper dust particles. It is also possible that turn-to-turn shorts could occur as a result of this mechanism.

Failure from this aging mechanism can be prevented by improved designs that eliminate significant sideways movement of subconductors, for example, tapering conductors to fit slot contours, inserting insulation between each subconductor, or operating at turning gear speeds that produce sufficient centrifugal force to prevent relative sideways movement.

9.3.3 Symptoms

Increasing bearing vibration (Section 16.9.3) over time indicates that relative motion may be occurring and, ultimately, shorted turns have occurred. If the abrasion has progressed to shorted turns, then a rotor flux monitor (Section 16.7) will detect the problem.

The operation of the field ground protection indicates that the ground insulation of the rotor has failed. This can be due to a weak or damaged slot liner, failure of the winding lead insulation, bridging of the conductor bars and the rotor forging by foreign material, or by a broken or dislodged rotor component. It can also show that a severe condition of a turn short has deteriorated to the extent that it has established a path to ground.

When the rotor is dismantled, small copper particles may indicate relative motion due to turning-gear operation. Relative movement due to rotor vibration may produce signs of insulation abrasion without overheating.

9.4 POLLUTION (TRACKING)

Insulation is used to electrically separate the copper winding at up to about 500 V from the grounded rotor body. The insulation takes many forms and shapes due to the highly distributed nature of the rotor winding, the need to allow for movement due to expansion, and the geometry of the rotor forging, end rings, balance rings, support rings, slip rings, and connection hardware.

During assembly, care is taken to ensure that the isolation is maintained at these numerous interfaces of live copper and ground that can be potentially bridged to create a short. Normally, the creepage path to ground is more than adequate. However, during service, contamination at these critical interfaces can reduce the creepage path to such an extent that turn-to-turn shorts could develop or the winding could short to ground.

9.4.1 General Process

Hundreds of interfaces exist in a rotor where insulation separates the copper conductors from the grounded components such as the forging, wedges, retaining rings, and balance rings. Intermittent surface discharge between turns or from the winding components to grounded parts occurs when these insulation interfaces are compromised due to surface contamination [1]. The discharge results in a chemical reaction of the components involved, producing carbon and other chemicals. The products of the reaction lodge themselves across the interface, creating a path of reduced resistance along which subsequent discharges occur. Eventually, this path is worn deeper and wider after repeated discharges until their frequency increases to the point of a continuous discharge. This damages the insulation surface further and produces the characteristic "burn-in" impression commonly referred to as tracking.

9.4.2 Root Causes

Ingress of carbon dust from the brushes, dust in the cooling air, coal dust, fly ash, copper dust from abrasion (Section 9.3), iron dust, etc. are the primary sources of the pollution that results in tracking in the rotor insulation. This can combine with moisture from water cooler leaks and oil mist from seals and bearings to produce a partly conductive coating on the surface over time. The rotor speed helps to orient this foreign material along the many discontinuities of the rotor surface, particularly in the end winding region. When sufficient quantities are deposited, currents may flow and contact surface discharges may be initiated between live and grounded parts or between turns, which eventually worsen into surface tracking.

Open-type machines are particularly vulnerable to tracking because of their exposure to the elements and pollutants. Hydrogen-cooled generator rotors are inherently protected from many pollutants that affect open-type generators. Other precautions, such as epoxy painting of the rotor body to obtain a smooth surface, further help to keep any pollutants from lodging themselves on the surface. However, it is very difficult to maintain a pristine environment within the generator at all times. Failure of hydrogen sealing and coolers and variation in the dew point of hydrogen do occur from time to time, and abrasion products are generated within the machine due to the relative movement between parts. Hence, hydrogen-cooled generator rotors can also be affected by tracking.

9.4.3 Common Symptoms

Symptoms of tracking are not apparent during operation until the damage worsens to turn-to-turn or ground faults in the winding. Such faults can be detected by vibration and flux monitoring (Sections 16.7 and 16.9.3). Upon disassembly and inspection, the presence of surface contaminants would indicate failure due to tracking. Other sites may display the characteristic "burn-in" prints on the surface insulation, which are still at an early *stage* of tracking damage. Severe faults to ground will result in a low insulation resistance (Section 15.1) and severe turn-to-turn tracking may be detected by the rotor surge or RSO test (Section 15.26).

9.5 REPETITIVE VOLTAGE SURGES

In generator rotors, the applied voltage of around 500 V DC is rather modest compared to the rating of insulating materials used, particularly in modern designs.

The applied voltage further divides between the turns to result in as little as 10 V between turns, which is a small fraction of the insulation voltage rating. The insulation would last indefinitely under these minor electrical stresses. However, transient overvoltages from the excitation supply can be five times higher, and may lead to insulation degradation.

9.5.1 General Process

Events internal or external to the excitation system can induce large transient voltages in the rotor windings [2]. While the occasional spike may not be harmful, repetitive spikes, for example, from static exciters that are often used to produce DC voltage, can reduce the life of the insulation due to gradual deterioration caused by partial discharges. Thus, this is similar to the stator winding aging process caused by inverter-fed drives (Section 8.10). Insulation that has been already weakened by other aging mechanisms is particularly vulnerable to repetitive voltage surges. As the insulation between turns is the thinnest and is subject to high levels of mechanical stresses, the voltage surges are most likely to cause turn-to-turn faults.

9.5.2 Root Causes

Static excitation systems inherently produce voltage surges due to their wave-chopping circuitry. Typically, six voltage surges are created per AC cycle. The magnitude of the surges can be higher than expected due to voltage reflections and oscillations caused by rotor winding inductance and capacitance. While a correlation between the surges and insulation failure has not been firmly established, the design of any excitation system should be reviewed with respect to the levels of voltage spikes produced and possible effects on the associated generator field winding turn insulation.

For faster response to disturbances on the power system or to sudden load changes, excitation systems are often designed with capability of "field forcing." Higher levels of output are thus available over short periods of time, which can increase the voltage to several times the rated level. As such operation often occurs during periods of disturbances on the power system, it can worsen the impact of the voltage surges striking the rotor winding.

The rotor is also exposed to events affecting the stator because of induced voltage effects across the air gap [2]. Hence, disturbances on the power system such as breaker opening, equipment maloperation, and lightening are transferred to the rotor winding during these transient events, elevating the voltage across the insulation up to five times the rated voltage.

Connecting the generator to the power system is also a potential cause of transient over-voltages on the rotor winding. Missynchronization, motoring, and load shedding can give rise to overvoltage surges that can spike to five times the applied excitation voltage, depending on the phase angle difference between the power system and generator terminal voltage waves involved.

9.5.3 Common Symptoms

Repetitive voltage surges can result in turn-to-turn shorts. The first such short may not be evident during operation unless the generator is fitted with a flux monitor (Section 16.7). Otherwise, several shorted turns may develop before the effect can be felt through higher vibration levels (Section 16.9.3).

An excitation system prone to producing large voltage spikes, transient events on the power system, or synchronizing difficulties experienced at the time of the higher rotor vibration would indicate damage to the insulation due to voltage surges.

When the rotor is examined, the punctured insulation may show no signs of overheating or abrasion.

9.6 CENTRIFUGAL FORCE

At speed, the rotor generates large mechanical stresses in the form of centrifugal forces that can exceed 1,500 tons at the wedges and 15,000 tons at each retaining ring. Significant tangential forces are also present, particularly during startup and shutdown of the generator. Inadequate rotor insulation systems may crack or yield under these forces, leading to turn or ground faults.

9.6.1 General Process

Because of the rotor speed, centrifugal forces are developed that can exceed 8000 times the weight of the component. The self-weight of the insulation materials used will result in significant stresses under these forces, which are generally compressive in nature and well within their compressive strength. However, the contribution of the copper field winding conductors to the total stress on the insulation materials is orders of magnitude larger.

Insulation materials made from quality stock and applied with adequate margins can endure these crushing forces over long-term operation. However, where the materials are weakened due to inadequate quality control or other aging mechanisms such as thermal aging, the insulation can bend, buckle, and crack under the influence of the large centrifugal forces. This can lead to turn-to-turn faults or ground faults. The insulation materials involved include slot liners, turn insulation, slot packing and pads, bracing materials, and connection insulation such as that on the leads between the field winding and sliprings/brushless exciter that pass through the centre of the rotor shaft at the exciter end. The effects of centrifugal forces are a function of the design of winding bracing system, the properties of the materials used, and the frequency of start and stop cycles.

9.6.2 Root Causes

High continuous stresses can cause yielding, distortion, movement, and cracking of winding, insulating, and bracing materials if their design, constraint provisions, or mechanical properties are inadequate. When winding bracing or conductor bonding materials crack, the winding becomes loose and abrasion of insulation due to relative movement occurs. This eventually leads to turn-to-turn or ground faults. The winding conductors or connections may also become distorted and fracture, causing open circuits in the winding, and, in extreme cases, pieces of the conductor may break loose and fly outward into the stator winding, causing faults. Also, slot armors may migrate axially outward, leading to rupture of the insulation or exposure of the conductors.

Cyclic stresses may cause loosening or fatigue failure of winding insulation system components. This will result in the same types of failures as those induced by overstressing. In case of rotor retaining rings, fatigue failure induced by cyclic stressing can lead to fracture, fire, explosion, and severe consequential damage to the generator.

Slot wedges or wedge retaining grooves in large generator rotors may also crack and eventually fracture as a result of cyclic stressing. In rotors with short slot wedges, the damage to the wedge grooves (T-slots) becomes more pronounced at locations that correspond to the wedge ends.

9.6.3 Common Symptoms

Direct evidence of damage due to centrifugal forces may be determined during rotor overhaul. Early stages of such damage can be detected during inspection of various rotor components. Depending on the extent of the disassembly, the following signs may indicate the development of this failure mechanism in various stages:

1. If the retaining ring has been removed, the interface of the ring insulation and the end winding sections of coils underneath can provide an important clue. An imprint of the shape of the end winding on the insulation surface is normally seen as an indentation. The depth of the indentation should be uniform around the circumference and not exceed 25% of the thickness of the insulation at any point. Any variation should be investigated for high localized centrifugal loads. The same action applies in the case of cracks emanating from the edges of the indentations or for pieces missing from the insulation.
2. The top of the slot liners (slot armor) may show fretting, cracking, or chipping due to high centrifugal force pushing the liner against the retaining rings. Cycling stresses may combine to hasten the damage to the liner. This is also symptomatic of inadequate blocking of the slot liner.
3. End winding turn insulation is prone to damage under centrifugal forces, particularly where the insulation from the straight slot section is joined to the curved insulation of the end winding. Lap joints are used in this area to ensure adequate creepage distance to prevent shorts. This weak spot can break down under cyclic centrifugal forces if not properly established. Only the top turn insulation can be inspected for this condition unless the winding conductors are to be removed for further inspection or for other reasons. If the wedges are removed from the slots, the top pad and any packing strips used should be inspected

for damage. Where short wedges are used, the surface of the top pad may show abrasion or cracking in the circumferential direction, corresponding to the ends of the wedges.

4. Chipping or cracking of the outer edges of the end winding blocks may indicate damage due to centrifugal forces.

During operation, the above failure mechanisms may not be evident in their early stages. When the damage has progressed to cause a change in operational behavior, the rotor is likely to exhibit increasing vibration and turn shorts, which can be detected by flux monitoring (Section 16.7).

9.7 OPERATING WITHOUT FIELD CURRENT

If the stator winding is connected to the power system and DC current is not flowing in the rotor, then the rotor winding can be seriously affected. There are two common causes for this type of operation [3]:

- Loss of field during normal operation
- Inadvertent closure of the generator stator winding three phase circuit breaker on to a power system

9.7.1 Loss of Field During Operation

Once the DC field power supply to the rotor winding is lost when the generator is operating, the generator begins to operate as an induction generator and runs at a speed slightly higher than synchronous speed, creating slip frequency currents in the rotor body. This causes severe arcing between rotor components such as slot wedges, retaining rings and the rotor body, and heating in the rotor winding. This can cause damage to these components. Fortunately, most turbine generators have loss of field protection relays that will trip a breaker in the stator winding power circuit to minimize damage.

9.7.2 Inadvertent Closure of Generator Breaker

If the generator is at rest and the main generator three phase breaker is inadvertently closed, a rotating magnetic field will develop in the stator which will induce large currents in the stator winding. When this happens, the generator rotor will begin to rotate as an induction motor. High surface currents are induced in the rotor wedges, forging and retaining rings and as the rotor accelerates, deeper currents will be induced in the rotor field winding. Usually, the most damage occurs at low speed when the skin effect causes the current induced in the rotor to concentrate on components near the surface. This causes large temperature differential and mechanical stresses in these rotor teeth, slot wedges, and retaining rings. The damage from such high temperatures and stresses can result in a rotor having to be replaced.

9.7.3 Root Causes

Field excitation loss during operation can result from inadvertent field breaker opening or failure of a connection in the field circuit such as a pole jumper (see Section 9.2). Inadvertent stator power supply breaker operation while a generator is at standstill usually occurs during a period when the generator is shut down for an outage and the lockout procedure for the breaker is inadequate.

9.7.4 Common Symptoms

- Evidence of overheating of and arcing between slot wedges, rotor body, and retaining rings, as well as rotor field winding overheating.
- Cracked slot wedges, rotor teeth, retaining rings (inadvertent stator breaker closure).

9.8 REMEDIES

Restoring the section of the insulation that is damaged is the basic repair for thermally failed insulation. This can be accomplished in several ways, depending on the resources and materials available. The effort required can range from minimal disassembly to the removal of several turns, depending on the location and severity of the damage. Also, further modification, refurbishment, or changes to maintenance and operating practices may be necessary to address the root cause of the damage and to ensure reliable operation in the future without recurrence of the problem. It is generally advisable to rebalance a rotor that has been subjected to extensive repair. Rebalancing can be used to overcome thermal bowing caused by a few turn shorts without having to repair the shorts.

Actions that may be required to restore the rotor insulation are summarized below.

Section of Turn Insulation Replacement of the damaged section of the insulation. This should only be considered for turn insulation when the damage is in the endwinding region. Continuity of the insulation without gaps must be assured. The same considerations apply to winding lead connections. It is also suitable for insulation under the retaining ring that is normally replaced with new material before the ring is reinstalled.

Full-Length Turn Insulation Replacement of the entire length of the turn insulation is necessary when the damage is in the slot section of the winding. This is to ensure integrity of the insulation under other stresses in operation and to avoid the inadvertent reduction in creepage distances. If turn insulation damage is widespread, all the rotor turns should be removed and the inter turn insulation replaced (Section 18.5.2). In such a situation, the opportunity should be taken to replace the slot liner at the same time. If copper dusting, resulting from relative motion between adjacent un-insulated conductor sub-strands during turning gear operation, has been occurring, insulation should also be installed between these sub-strands. One OEM recommends Teflon for such insulation as it will allow relative sub-strand movement without abrasion.

Repair of the Slot Liner Repair of the slot liner may be possible if the damage is confined to the area outside the slot. In the case of cracks, the end of the crack should first be drilled out to prevent the crack from propagating toward the rotor forging. Pieces of epoxy glass laminates (010 or 011 glass) can then be bonded to the damaged area with epoxy glue to strengthen the liner. Where limited access does not allow drilling a small hole at the apex of the crack, the repair can proceed as above, but the next rotor inspection would have to be scheduled earlier than planned to determine the effectiveness of the repair. The same approach can be taken when the cracks are close to the rotor forging but a decision is made for a local repair rather than a replacement of the liner due to other constraints.

Replacement of the Slot Liner Replacement of the slot liner is the most extreme form of insulation repair as it amounts to a full rotor rewind (Section 18.5.2). If the liner cannot be restored by local repair or in the case of ground faults, all the insulation should be replaced, including turn insulation, retaining ring insulation and winding lead insulation. The end winding blocks may be reused, provided they still fit and are not damaged. Any copper smearing on the blocks or windings due to rubbing against the winding should be cleaned up.

Reuse or Replace the Copper One of the most difficult decisions facing machine-owners in the case of a rotor rewind is whether to reuse or replace the copper. Although some companies would start with new copper, others would tend to reuse the existing copper as the difference in cost can be significant. The following factors may be considered when evaluating options:

- The condition of the copper
- The expected remaining life of the generator
- Operating regime, for example, base-load, peaking, or reserve
- Effort involved in removing existing insulation and residual resin (if bonded)
- Effort involved in restoring existing copper (extent of deformity)
- Number of brazing joints involved
- Opportunity and benefits of uprating
- The cost of the new copper and winding manufacture
- Delivery schedule for the new copper winding.

In addition to the repairs mentioned above, the aging process can be slowed by taking the following action:

- Reduce load
- Slow down the rate of load changes

- Reduce excitation
- Clean rotor to eliminate blockage
- Ensure that negative sequence currents are minimal

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CHAPTER 10

SALIENT POLE ROTOR WINDING FAILURE MECHANISMS AND REPAIR

As discussed in Section 1.6.1, there are two types of windings in salient pole rotors. These are the "strip-on-edge" type used in large machines, especially if they are high speed, and the "multilayer wire wound" type used in large slower speed and small high speed motors and generators. The insulation between the coils and pole body can be the same for both types, while the turn insulation is quite different.

A weakness in some designs is the susceptibility of the series connections between poles to fail from fatigue. Field windings tend to move relative to one another during machine operation. This results in flexing of the connections between them, which can lead to failure from fatigue, even if they have a laminated construction. This will also cause failure of the insulation on these connections. Series connections near the pole tips are most likely to experience this problem as they are at a much larger diameter then those at the inner ends of the poles and consequently see much higher mechanical stresses induced by centrifugal forces. Failure mechanisms for slip ring insulation found on some salient pole rotors is covered in Section 11.5.

10.1 THERMAL DETERIORATION

All insulating and nonmetallic bracing materials deteriorate with time due to the heat from the windings. The rate at which component materials deteriorate is a function of their thermal properties and the temperatures to which they are subjected. If the thermal ratings of component materials have been properly selected, the thermal aging and associated deterioration will occur gradually over an acceptable service life [1].

10.1.1 General Process

Modern salient pole winding designs use aramid paper (Nomex^{TM}) ground and turn insulation in strip-on-edge windings, resin-bonded glass laminate pole washers,

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

Dacron™ and glass (Daglass™)-covered high-temperature enamel turn insulation in wire wound poles, and thermosetting bonding resins. The materials have a thermal rating of at least Class F (155°C). If these materials are operated at Class B (130°C) temperatures, they should have a longer than 30 year thermal life. The materials most susceptible to thermal degradation are organic bonding and backing materials, whereas inorganic components such as mica, glass, and asbestos are unaffected at the normal operating temperatures of electrical machines.

The thermal life of insulation at hot spots in windings is significantly reduced as the margin between operating temperature and thermal rating is much less. This effect is more critical in older Class B insulation systems and the presence of such hot spots is very difficult to detect.

10.1.2 Root Causes

The following are the most common causes of thermal aging in salient pole windings:

- Overloading or high air temperatures leading to operating temperatures well above design values
- Inadequate cooling, which can be general, for example, insufficient cooling air or cooling water, or local dead spots in the cooling circuit due to poor design, manufacturing, or maintenance procedures
- The use of materials that have inadequate thermal properties and consequently deteriorate at an unacceptable rate even when operated within design temperature limits
- Over-excitation of rotor windings for long periods of time
- Negative sequence currents in stator windings due to system voltage imbalance, etc., which leads to circulating currents on the rotor.

10.1.3 Common Symptoms

Severe thermal deterioration can give rise to shorted turns and/or ground faults, which can be detected by bearing vibration monitoring (Sections 16.7 and 16.9.3). Visual symptoms of thermal aging in salient pole rotor windings are dependent on whether it is general or localized.

General Thermal Aging

- Loss of bonding between conductors and brittleness in the bonding varnish or resin leading to turn insulation in strip-on-edge windings (Figure 10.1)
- Shrinkage of pole washers and inter-coil bracing insulating materials
- Brittleness and darkening of the insulation system materials
- Looseness of the windings on the poles due to ground insulation shrinkage (indicated by dusting at the interfaces between components)

Figure 10.1 Strip-on-edge winding turn insulation migration from thermal aging of the bonding resin.

Local Thermal Aging

- Signs of local overheating of insulating materials with the remainder of the materials being in good condition

10.2 THERMAL CYCLING

Insulation aging from thermal cycling occurs mainly in synchronous motors and generators that are started and stopped frequently.

10.2.1 General Process

There are two heat sources within a rotor when a synchronous motor is started. One mainly applies to motors that are started directly-on-line, causing heating due to currents flowing in the pole tips of solid pole rotors or the damper (amortiseur) winding in those with laminated poles. The other, which also applies to generators, is the I^2R heating generated in the windings once excitation is applied.

Frequent starts and stops cause winding expansion and contraction as a result of the presence or loss of these winding heat sources. Relative movement due to the different coefficients of thermal expansion in the various components leads to insulation abrasion.

10.2.2 Root Causes

The thermal cycling resulting from frequent starts and stops leads to the cracking of the resin or varnish bonding the insulation system components together. This causes loosening and relative movement between these components, which leads to increased looseness and abrasion. Also, if the windings are restrained from returning to their cold position, they may become distorted. Poor design or too-rapid or too-frequent load cycles for the design are the root causes.

10.2.3 Common Symptoms

If the following symptoms are found with no evidence of significant winding insulation overheating in a synchronous motor that is frequently started, then thermal cycling is the most likely cause:

- Cracking of the insulation bonding the conductors together (Figure 10.2) and the winding to the pole ground insulation leading to insulation abrasion and turn or ground insulation failure
- Distortion of the windings
- Windings loose on poles which results in higher rotor vibration levels
- Fracture of poorly designed interpole connections (Figure 10.3)

10.3 POLLUTION (TRACKING AND MOISTURE ABSORPTION)

Salient pole rotor windings, especially strip-on-edge types, are generally susceptible to failure from contamination by conducting materials because they rely on adequate creepage distances between bare copper conductors to prevent shorts. Such problems

Figure 10.2 Turn insulation in wire wound coil resulting from cracking of the bonding resin as a consequence of thermal cycling.

Figure 10.3 Failure of inter-pole connection from thermal cycling.

are not confined to machines with open-type enclosures as oil leaking from bearings and moisture from condensation or leaking air coolers can contaminate windings. Such problems can be avoided in wire-wound types by encapsulating the windings to keep contaminants out [1].

10.3.1 General Process

When contaminants such as moisture, rotor brake dust, coal dust, and oil/dust mixtures cover the surfaces of salient pole windings, they can produce conducting paths between coil turns and to ground. This can lead to turn-to-turn failures (especially in strip-on-edge types) and ground faults. Certain chemicals can also attack insulating materials to cause them to degrade.

Earlier insulation systems containing materials such as asbestos, cotton fibers, paper, etc. bonded by organic varnishes are much more susceptible to failure from moisture absorption.

10.3.2 Root Causes

- Ingress of contaminants such as coal dust, fly ash, iron dust, coke dust, etc. into open-type machines, especially in the presence of oil leaking from bearings
- Ingress of moisture from the atmosphere (open enclosures), from condensation (all enclosures), and leaking coolers (TEWAC enclosures)
- Ingress of chemicals that attack the pole winding insulating materials
- Over-zealous application of brakes that are a common source of conductive dust in hydrogenerators

Figure 10.4 Contamination of a strip-on-edge field winding pole.

10.3.3 Common Symptoms

Pollution may cause a low insulation resistance (Section 15.1) or cause a failure in the pole drop test (also called the *voltage drop test*, Section 15.25). The rotor may also appear to be greasy (Figure 10.4), wet, or have a liquid film. If severe, dark carbonized tracks may be present between turns or to ground.

10.4 ABRASIVE PARTICLES

As with stator windings (Section 8.12), rotor windings operated in environments containing abrasive dusts will also experience insulation failures from dust impingement.

10.4.1 General Process

Abrasive dust from the surrounding atmosphere carried into the interior of a motor or generator by cooling air will abrade the rotor winding insulation surfaces. This may eventually expose the conductors in multilayer wire-wound poles, resulting in turn shorts. Also, the ground insulation in both types of salient pole windings and their interconnections may be eroded, causing ground faults.

10.4.2 Root Causes

The use of open-enclosure machines without inlet air filters in locations where there are abrasive materials in the environment. In addition, most hydrogenerators have metal-oxide brakes that can be applied to slow a hydrogenerator on shutdown. Excessive braking can release abrasive particles into the air gap.

10.4.3 Common Symptom

Winding faults in conjunction with erosion of the coil and connection insulation where there is evidence of abrasive materials such as coal dust, iron ore dust, and sand inside the machine enclosure.

10.5 CENTRIFUGAL FORCE

Among the most common causes of failure in salient pole rotor windings are the continuous centrifugal forces imposed on them by rotation and the cyclic centrifugal forces induced by starting and stopping.

10.5.1 General Process

The radial and tangential centrifugal forces imposed on rotor winding insulation system components tend to distort the coil conductors and crack the coil insulation if they are not adequately braced. If the pole winding bracing is inadequate or becomes loose, the resulting coil vibration and movement of the coils on the poles will cause abrasion of the conductor and ground insulation. Inadequate interpole bracing in large, high-speed machines will lead to coil distortion, whereas abrasion from loose windings will occur mainly during starts and stops. Winding looseness can also lead to pole washer and intercoil connection cracking from fatigue. Mechanical winding stresses will become excessive and cause serious winding damage if the rotor is made to run overspeed.

10.5.2 Root Causes

- Inadequate intercoil bracing due to poor design, or shrinkage of materials from thermal aging
- Inadequate radial coil bracing due to poor design, failure of pole washers, or shrinkage of coil insulation/bracing from thermal aging
- Fatigue failures of intercoil connections from relative coil movement
- Frequent starts and stops causing low-cycle fatigue failure of winding components
- Inadvertent overspeed of rotor, causing overstressing of winding conductors and insulating materials

10.5.3 Common Symptoms

Operating symptoms of mechanical aging due to centrifugal forces may be confirmed by a visual examination of the rotor windings and bracing components. If there are signs of abrasion, fracture (Figure 10.5), etc., without indication of thermal or electrical aging, then mechanical aging is the likely cause. A detailed examination of the type of fracture in the winding or bracing materials may also indicate whether it

Figure 10.5 Cracked top pole washer resulting from high stress induced by centrifugal forces.

resulted from overstressing (yielding) or cyclic stressing (fatigue). If a turn short has occurred or pole windings are loose, the bearing vibration (Section 16.9.3) level may increase.

10.6 REPETITIVE VOLTAGE SURGES

The normal DC voltage applied to rotor windings does not cause rotor insulation electrical aging. Also, normal voltage levels in a rotor winding are usually so low that they will not induce insulation aging even in weakened materials. Hence, electrical stress is not an important cause of aging. However, transient over voltages induced by fault conditions on the stator side or faulty synchronization can cause rotor winding insulation puncture [2].

10.6.1 General Process

High transient overvoltages may be induced into rotor windings by phase-to-phase stator winding short circuits, faulty synchronization, asynchronous operation, or static excitation systems. Such transient voltages, in conjunction with weak insulation or insulation that has been degraded by thermal or mechanical aging, can cause failures, which are predominantly turn-to-turn. These overvoltages are most severe in salient pole windings due to their design configuration.

10.6.2 Root Causes

All of the following causes of voltage transients in rotor windings lead to

- Failures of weakened winding insulation, especially those between turns on the winding poles [1].

- Faulty synchronization due to automatic synchronizer defects and manual synchronization errors.
- Asynchronous operation due to loss of excitation while the stator is energized or inadvertent energizing of the stator, with no excitation, while the machine is shut down.

The introduction of static exciters about 30 years ago brought with it some concerns about the possible long-term aging effects of their pulse voltage transients on field winding insulation. These high-frequency voltage spikes, generated by thyristor commutation at a repetition rate of 6 pulses per cycle, can reach magnitudes of 3–4 kV during field forcing (Section 9.5). Operating experience at levels in use to date has not revealed these voltage spikes to be a significant electrical degrading mechanism on healthy turn or ground insulation in salient pole field windings. They may accelerate the failure of weak or degraded insulation, however.

10.6.3 Common Symptoms

Turn faults in synchronous machine field windings induced by voltage transients and static exciter voltage spikes are sometimes indicated by high rotor vibration due to magnetic or thermal imbalance. In addition, if one confirms that rotor winding shorted turns occurred by tests and/or visual inspections, then voltage transients may be the cause if there is knowledge that they have had transient voltages imposed on them.

10.7 SALIENT POLE REPAIR

This section deals with repair methods for salient pole rotor winding coils, ground insulation, bracing materials, and connections. Damper (amortiseur) winding repairs are covered in Chapter 12, which deals with squirrel-cage induction rotors.

Strip-on-Edge Coil Repairs If the coil turn insulation has degraded and the conductors are in good condition, the coils can be dismounted from their poles and the insulation on them incinerated in a burnout oven. The copper conductors are then cleaned before new turn insulation is applied. The new turn insulation, which is usually a Nomex^{TM} type of material (Section 4.4.2), can then be installed and bonded to the conductors with a thermosetting resin, which is often applied to the insulation by its manufacturer. The complete coil is then hot-pressed to consolidate the conductors and the turn insulation.

If the coil conductors have been distorted due to excessive centrifugal forces, it is best to replace them. The new coils would be insulated in the same manner as described above.

The ground insulation between the coils and pole body and the top and bottom pole washers should also be replaced. New pole washers should be made from a single piece of epoxy or polyester-resin-bonded glass fiber sheet material. It is important that, once the new coils are installed, they are tight on the poles and, for high speed machines, the inter-coil bracing, which prevents any coil bulging due to centrifugal forces, must be insulated from the pole winding if it is made from steel or other conducting material.

If the coil top washers crack but the coils themselves are in good condition, and if the poles have bolt-on-tips, then new washers can be installed without disturbing the coils. This is done by removing the pole tips and old top washers, replacing the washers, reinstalling the pole tips, and torquing down their mounting bolts.

Multilayer Wire-Wound Coil Repairs It is not practical to re-insulate the conductors on this type of coil as the magnet wire is purchased with the insulation already applied. For replacement of this type of winding, the poles, with coils installed, must be removed and placed in a burnout oven in which both the turn and ground insulation are incinerated. Once this is done, it is easy to remove the coils from their laminated poles, which can be reused if they were not damaged by the burnout (Section 13.1). The condition of the pole lamination and damper winding must be checked (Section 15.29) and any repairs to these completed before installing the new winding.

Once the poles have been cleaned, new ground insulation and top washers are installed. The new coil can then be wound directly on to the pole, using a pre-insulated magnet (winding) wire, which normally has an enamel covering overlayed with Dacron^{TM} glass blended-type fibers. A thermosetting resin is applied between each coil layer as it is wound and, once complete, the coils are dipped in resin and baked in an oven to cure the bonding resin. Alternatively, after winding, the poles can be vacuum pressure impregnated with resin. If a sealed coil construction is required, a layer of insulation is applied to the outside of the coil and bonded to it with resin. Once this is done, the bottom washers can be installed and the poles remounted on the rotor.

Coil Connection Repairs Damaged coil connections and/or their insulation can be replaced without disturbing the pole windings. Before doing this, it is important to determine why the failure occurred, as an improved connection design may be required to prevent recurrence of such failures, for example, better support against centrifugal forces and omega-shaped connection to allow thermal expansion without inducing high mechanical stresses.

Winding Contamination and Damage from Abrasive Particles Provided the coil conductors and insulation are in good condition, contaminated windings can be refurbished without major expense.

If the contamination is moisture, the winding should be dried out in an oven or by passing current through it. Insulation resistance and polarization index tests, as described in Section 15.1, can then be performed to confirm adequate dryout. Once the windings are dry, they can be coated with a heat-curing or air-drying varnish to seal their surfaces from moisture.

Oil and dust contamination requires more aggressive treatment. If the rotor can be sent to a service shop, it can be steam cleaned, dried out, and varnish treated. Cleaning with dry ice or other abrasives (corn cob, walnut shells) is often effective. As the equipment used to perform this process is portable, it can be done on-site.

However, experience has shown that dry ice cleaning may be less effective if oil is present.

The extent of insulation damage from abrasive particles can vary significantly. Therefore, required repairs can be minor or major in nature. If only minor insulation damage has been inflicted, repairs can be implemented by applying a surface treatment of insulating varnish or resin, using a dip-and-bake process. On the other hand, abrasion that has completely removed the conductor and/or ground insulation will require rewinding or winding insulation replacement.

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CHAPTER 11

WOUND ROTOR WINDING FAILURE MECHANISMS AND REPAIR

The advent of the solid-state variable-speed drives for SCI motors, which can provide high starting torques and low inrush currents, has made the wound rotor induction motor less popular since the 1990s. There are, however, significant numbers of these machines still in service for applications such as crane drives, wood chippers, etc. On the other hand, doubly-fed wound rotor induction generators (see Section 1.1.3) are now used extensively for wind turbine generator applications, where the three-phase wound rotor is fed by an inverter [1,2]. There are tens of thousands of these in service. Slip recovery motors also use a converter in the rotor winding circuit.

As indicated in Section 1.6.3, there are two basic types of construction of wound rotor windings: random-wound and bar-lap/wave-wound. The ground insulation is similar for both types, but the turn insulation is different. In the random-wound type, enamel or enamel overlaid with glass fibers is generally used, whereas the bars in the lap-and wave-wound types are usually insulated with a varnish or resin-bonded tape. In the case of wind turbine induction generators and slip energy recovery motor designs, mica-paper tape is used as the turn insulation as repetitive high magnitude voltage surges from the inverter can produce partial discharges that would attack organic materials. Mica-paper conductor tape is also used in larger induction motors that have higher rotor winding voltages.

Wound rotors have three-phase windings and operate at similar voltages to the random-wound stators described in Section 1.3.1. The failure mechanisms are, therefore, similar to random-wound stator windings. For applications where a converter is not employed in the rotor winding circuit, electrical aging is not a factor. On the other hand for doubly fed induction generators and slip energy recovery motors, electrical aging can be a major factor. This is because the electrical transient voltages induced in these windings can cause them to fail from partial discharge attack (Section 1.5.1) if their insulation has been weakened by thermal degradation and mechanical forces, or they have become contaminated. The high continuous and transient centrifugal forces imposed during operation of this type of rotor can also induce winding failures. In addition, the slip rings used to allow external connections of starting resistors or slip

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

energy recovery solid-state converters to the rotor windings have ground insulation on them that can short.

As thermal aging failure mechanisms are similar to those found in random-wound stator windings (Section 8.1), this is not covered in this section. As failures due to contamination are similar to those found in salient pole rotors (Section 10.3), this mechanism is also not covered. The following are electrical and mechanical failure mechanisms that are specific to wound rotor windings.

11.1 VOLTAGE SURGES

In a wound rotor induction motor or generator, there is a transformer coupling effect between the stator and rotor windings. Consequently, power-system surge voltages imposed on the stator winding will induce overvoltages in the rotor winding. This overvoltage may puncture the turn or ground insulation. In the case of variable speed wound rotor motors and generators with a converter in the rotor winding circuit, the continuously imposed high magnitude, fast-rise time voltage surges imposed on the rotor winding can cause partial discharge activity to occur, which can cause electrical aging, especially if organic insulation is used (Figure 11.1). Since the leads that connect the winding phases to the slip rings are often not insulated with a mica material, this insulation can also fail from the same electrical aging process as a result of interphasal partial discharges (Figure 11.2).

11.1.1 General Process

Provided there is adequate turn and ground insulation on the rotor winding, such voltages should not cause electrical aging; that is, partial discharge is unlikely or if present will not cause rapid failure if mica insulation is used (Section 1.5.1). Voltage

Figure 11.1 Rotor winding turn insulation failure from partial discharges.

Figure 11.2 Rotor winding lead insulation failure from interphasal partial discharges.

transients will, however, accelerate the failure of insulation that is initially weak, or that has been degraded by thermal or mechanical aging.

11.1.2 Root Causes

Turn-to-turn, phase-to-phase, or ground faults can be induced by transient rotor winding over voltages if the insulation dielectric strength has been significantly reduced by aging or is not adequate. The contribution of these voltages to insulation failures is difficult to verify unless their magnitudes and frequency of occurrence can be determined.

11.1.3 Common Symptoms

These are the occurrence of rotor winding turn or ground shorts in motors operating on power systems in which surge voltages are known to be present.

11.2 UNBALANCED STATOR VOLTAGES

Unbalanced stator winding power supply voltages will induce negative sequence voltages and currents in the rotor winding. These can lead to insulation overheating.

11.2.1 General Process

Negative sequence currents induced by unbalanced stator winding voltages increase rotor winding heating in all phases and, therefore, induce accelerated thermal aging of both the turn and ground insulation.

11.2.2 Root Causes

Power distribution system design or unbalanced phase impedances (e.g., due to high resistance connections) cause unbalanced voltages to be applied to the motor stator winding. Due to the transformer effect between the stator and rotor, the negative sequence fluxes generate negative sequence currents in the rotor winding. These significant additional currents cause the rotor winding to operate at a substantially higher temperature, which accelerates insulation thermal aging.

11.2.3 Common Symptoms

Signs of general rotor winding overheating in conjunction with evidence of significant, that is, more than 3%, stator winding supply voltage imbalance and uneven stator winding phase insulation overheating while operating within the nameplate rating of the motor are observed.

11.3 HIGH RESISTANCE CONNECTIONS-BAR LAP AND WAVE WINDINGS

If a joint between two conductors has been poorly soldered/brazed or the compression clip joint poorly made, it will present a high resistance to the current flowing through it under load and this will produce overheating of the joint insulation.

11.3.1 General Process

The excessive amount of heat produced by high resistance bar-to-bar connections induces rapid thermal aging of the insulation around the connection and on adjacent connections until a turn-to-turn, phase-to-phase, or ground fault develops. In many cases, the heat generated is sufficient to melt the solder or brazing material in the joint.

11.3.2 Root Causes

- Poorly brazed or soldered, or poorly made clip joint connections between rotor winding bars that are not found during the manufacturing process
- Failure of the joint between bars due to low-cycle fatigue from frequent starting

Good quality control checks of a completed winding such as surge testing and the use of thermal imaging devices to detect “hot” joints during winding manufacture (Section 15.5) should minimize the possibility of failures of this type.

11.3.3 Common Symptoms

There will be signs of excessive heat and burning in the area of the connections, together with pieces of molten solder or brazing material sprayed around the inside of the motor by centrifugal forces.

11.4 END WINDING BANDING FAILURES

Application of banding over the rotor end windings is required to brace them against the high centrifugal forces imposed on them during operation. Until the early 1950s, end winding banding consisted of a number of turns of round steel wire applied tightly over an insulating layer, which was required to give mechanical and electrical separation from the conductors. The round wires were bonded together with a low-melting-point solder. The development of pre-stressed resin-coated fiber glass material then prompted motor manufacturers to start using this material because of its superior mechanical and thermal capabilities, as well as its elasticity.

11.4.1 General Process

If the steel wire or resin-coated fiber materials fail from overheating, overstressing, or poor manufacture, the end windings fly outward under the influence of centrifugal forces. This results in a rotor winding ground fault and, often, a consequential stator winding failure.

11.4.2 Root Causes

- Excessive winding temperatures, causing wire-banding solder to soften or melt.
- Excessive winding temperatures, causing resin-coated fiber banding to thermally age and the resin bonds between layers to become brittle, crack, and fail (Figure 11.3).
- Poor manufacturing processes that result in inadequate mechanical strength to withstand high imposed centrifugal forces.

11.4.3 Common Symptoms

- If the cause is winding overheating, there will be evidence of thermal degradation in the remaining coil insulation in the slot region.
- If the cause is poor manufacture, there will be no evidence of winding insulation overheating.
- Complete failure of the banding will result in the rotor end windings splaying out (Figure 11.3), or breaking off to cause stator winding insulation damage.

Figure 11.3 Two wound rotors in which the end winding banding has failed.

11.5 SLIP RING INSULATION SHORTING AND GROUNDING

The three slip rings in a wound rotor motor must be separated from the shaft by a layer of insulation applied between the two. The spacing between the rings must be sufficient to provide an adequate electrical creepage distance and in some designs insulating barriers are used to achieve this. Also, the two outer rings are usually connected to the winding leads via studs that pass through the other rings. These studs must be electrically isolated from the rings and this is normally done by fitting insulating tubes over them. The failure mechanisms in this section also apply to salient pole machines with slip ring connections to their field windings.

11.5.1 General Process

If the slip ring enclosure is contaminated with oil, dust from brushes, moisture, or a combination of these, shorting between rings and the shaft and/or between the rings can occur. If this happens, serious damage can occur to the shaft, the rotor windings, and the slip rings due to high fault current flow. Also, if the shaft or stud insulation fails due to thermal aging or mechanical stresses, these types of failures will occur.

11.5.2 Root Causes

- Failure to periodically clean up carbon dust resulting from brush wear.
- Ingress of dust, oil from bearings, and moisture into the slip ring enclosure.
- Failure of slip ring shaft insulation due to thermal or mechanical stresses.

- Mechanical failure of the slip ring connection stud insulation, causing phase-to-phase failures.

11.6 WOUND ROTOR WINDING REPAIR

This section deals with the rewind and repair of the windings, bracing, and slip ring insulation found in this type of winding.

11.6.1 Failed Windings

If the failure is due to the end winding banding coming loose or a serious winding insulation fault, the winding damage is so severe that there is no alternative but replacement. A complete rewind is required if random-wound rotors experience an insulation failure as it is impractical and uneconomical to repair these.

Individual top coil legs in bar-type windings with failed insulation can be rewound if there is a slot opening large enough to remove the old coil. This will necessitate removing the end winding banding and replacing it after the repair. If the insulation on a bottom coil fails, a rewind is necessary as other coils will have to be removed, damaging the insulation in the process.

If the failed winding is in a doubly fed wound rotor induction generator rotor and is deemed to have resulted from partial discharge attack (Section 15.13), all the insulating materials and the winding impregnation process for a new winding need to be evaluated to see if they have high PD resistance or the winding turn, ground and interphasal insulation can be made void free.

11.6.2 Contaminated Windings and Slip Ring Insulation

If the windings are in otherwise good condition, they can be cleaned and refurbished in a similar manner as described in Section 10.7 for salient pole types. If there is any doubt about the condition of the end winding banding, this should be replaced. A similar approach can be taken with slip ring assembly insulation.

11.6.3 Failed Connections in Bar-Type Windings

Provided the failure is caught early enough and it has not caused damage to the insulation on adjacent coils or banding, a joint clip can be removed, the joint cleaned up, and a new clip brazed, soldered, or compressed in place. Once this is done, the joint can be reinsulated. It is important to check for other high-resistance joints during such repairs as they should also be repaired. Such checks can be done by surge comparison testing (Section 15.16) or the passage of current through the winding in conjunction with an infrared thermography scan (Section 15.5).

11.6.4 Damaged End Winding Banding

As indicated above, failure of end winding banding is a catastrophic event as it results in almost complete destruction of the windings. If deterioration in this banding is detected, it should be replaced by prestressed resin-coated fiber glass material, which has very good properties for this application.

11.6.5 Failed or Contaminated Slip Ring Insulation

Failure of the insulation between the slip rings and the rotor shaft should be replaced. Since the slip rings are normally shrunk onto this insulation, they have to be heated to expand them to allow their removal. Nomex^{TM}-type sheet material is a good replacement for this insulation due to its good mechanical, electrical, and thermal properties.

If the insulation on a slip ring connecting studs fails, it has to be replaced. Resin-bonded glass fiber tube material is best for this application as it has excellent mechanical strength and adequate thermal and electrical properties.

Contamination on slip ring insulation can be easily removed by a suitable cleaning agent such as isopropyl alcohol.

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CHAPTER 12

SQUIRREL CAGE INDUCTION ROTOR WINDING FAILURE MECHANISMS AND REPAIR

Although most squirrel-cage rotor windings are not insulated (Section 1.2.3), they can fail due to various aging mechanisms, which can be thermal, electrical, or mechanical in nature. Their susceptibility to failure is dependent on the type of winding construction, the motor application, operating duty, winding geometry, and the materials of construction. Although motors used in centrifugal pump applications very seldom experience winding failures, those used in high-inertia drive systems such as power station induced-draft fans are most susceptible, especially if they are frequently started directly-on-line. References [1–5] give a general review of SCI rotor failure processes.

12.1 THERMAL

Every time a motor is started directly on-line, a significant amount of heat is generated in its rotor windings. The current in the rotor during starting can be five to six times the current once the motor is up to speed. The amount of heat generated and, therefore, the maximum rotor winding temperature is a function of the torque margin between the motor and driven-equipment torque/speed curves and the combined inertia of the driven equipment and motor rotors. The longer the rotor takes to come up to speed, the greater will be the temperature the rotor winding experiences. Much less rotor winding heating occurs once the rotor is at operating speed.

Another factor that determines the maximum rotor bar temperature is "skin effect" that results from leakage fluxes across the rotor slots [1,2]. This creates non-uniform current distribution in the rotor bars during start-up, when the frequency of the current is close to the 50 or 60 Hz frequency. As a result, the current at the top of the bar is much higher than that at the bottom. Hence, the tops of the bars reach much higher temperatures due to I^2R heating than the bottoms during motor

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

starting, and the bars bow outwardly due to non-uniform thermal expansion. This temperature increase is more significant in deep, thin bars and “inverted T” bars, which are much narrower at the top than the bottom.

Repetitive starts (three or more) over a short period of time can produce excessive rotor winding temperatures in motors used in high-inertia drive systems, as not all of the heat created during the first start(s) will have been radiated or conducted from the rotor. Thus, the rotor winding temperature may still be high from the first start when the second start causes a further increase in temperature. Thus if repeated starts are performed, cumulative rotor heating, leading to quite high rotor winding temperatures, will occur.

Motors with speed control devices such as fluid drives, magnetic clutches, and solid-state variable-speed drives do not experience high rotor temperatures during starting. This is because the motor is up to speed before the load is applied, or the starting current is controlled to a much lower value than for a directly-on-line, loaded start.

12.1.1 General Process

The non-uniform heating and high temperatures in the bars of motors with long run-up times or those that are subjected to repetitive starts cause distortion and high mechanical stresses in the bars and end windings due to differential expansion. That is, the tops of the bars expand more than the bottom of the bars, distorting the bars and leading to internal mechanical stresses that may crack the bars as a result of low cycle fatigue, especially after many starts. These effects are much more pronounced in machines with fabricated aluminum or copper alloy bar windings, which have bars that extend beyond the end of the core to connect to the shorting rings (also called *short-circuit rings*) [2]. The type of winding construction and the bar and shorting ring materials are also a factor in determining the effects of this distortion from heating during starts. The mechanical stresses in the end winding region of fabricated rotor windings are further increased by the centrifugal forces (Section 12.2).

Die-cast aluminum windings are least susceptible to distortion since they have no bar extensions. However, such windings can melt due to the heat produced by repetitive starts too close together in time. Fabricated windings made from aluminum alloy are most susceptible to failure from distortion as the mechanical properties of this material deteriorate significantly at temperatures above 100°C. Having said this, copper/copper alloy windings can also fail if the end winding and bar design are poor and allow too much distortion during starting. As already indicated, the tops of “inverted T” shaped bars become very hot if used in motors for high inertia drives. This excessive heat can cause the bar tops to crack and break off.

12.1.2 Root Causes

- Poor rotor winding design and/or winding material selection in conjunction with a high inertia drive application.

- Frequent starting, especially if the motor thermal overload protections are set too high or jumpered out to prevent tripping.
- The use of inverted "T" rotor bar designs in high inertia applications.

12.1.3 Common Symptoms

- Cracked or broken bar-to-short-circuit-ring connections at their interfaces or beyond the end of the core. Core burning may also be present due to the passage of current through it (Section 13.2).
- Cracked or broken short-circuit rings.
- Noise and increased starting times due to cage winding breaks.
- Increasing vibration levels (Section 16.9.2) and power frequency current side-bands (Section 16.8) [4].
- Melting of die-cast aluminum winding bars where frequent starting has been confirmed.

12.2 CYCLIC MECHANICAL STRESSING

There are a number of contributors to cyclically induced stresses in squirrel cage rotor windings and these can cause failures due to "low-cycle fatigue." This failure mechanism occurs mainly in motors driving relatively high inertia loads that are frequently started, such as an induced draft fan in a fossil generating station that is being operated in a "two shifting" mode. The locations of these mechanical forces are illustrated in Figure 12.1. In relation to this figure, the forces are:

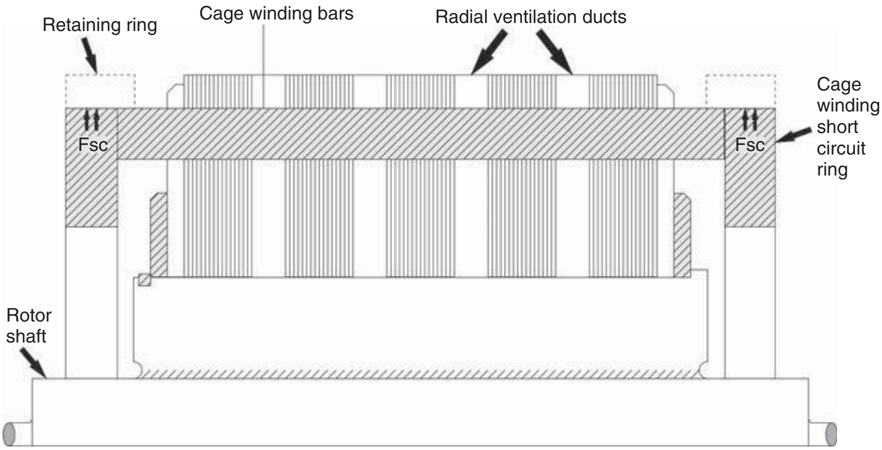

Figure 12.1 Different mechanical forces that occur in an SCI rotor.

F_e = Electromagnetic forces on the bars
F_b = Thermal expansion/centrifugal forces on the bar extensions outside the core
F_{sc} = Thermal expansion/centrifugal forces on the shorting rings
F_r = Force on the retaining rings (if fitted)

12.2.1 General Process

Each time a motor is started, the mechanical forces described above act on its windings to increase the mechanical stresses. Some of these forces are transient and die away once the rotor is up to speed, whereas others remain while the motor is operating. The cause of cyclic fatigue is the change in the rotor winding stresses between stand-still and running conditions. These forces, which mainly affect fabricated rotor windings, are described in more detail as follows.

Electromagnetic Forces on Bars (F_e) Every time a motor is started, electromagnetic forces are imposed on the bars in the slot region. These forces occur at two times rotor current frequency and are proportional to the square of the rotor current. Consequently, they are only significant during starting but they can cause fatigue failures if the bars are loose in their slots. This is most likely to occur in fabricated rather than cast rotor winding designs.

Forces on Bar Extensions Outside Core (F_b) These forces are highest during starting and result from a combination of thermal distortion and centrifugal forces on both the bars and the short-circuit rings to which they are connected. The net result is deformation of the end winding structure, as illustrated by Figure 12.2. The cyclic deformation that occurs due to starts and stops can cause failures in bar extensions, short-circuit rings, and the joints between them due to fatigue. As indicated in Section 12.1, fabricated aluminum alloy windings lose their mechanical properties at higher temperatures and are, therefore, most susceptible to failures from these cyclic stresses.

These stresses become more significant in fabricated rotor windings that are loose in their slots. In this situation, the whole winding moves axially in one direction to change the end winding geometry. Usually, bar or joint failures occur by this process at the end where the bar extensions have been shorted.

Forces on Short Circuit Rings (F_{sc}) Each time a motor is started, the short-circuit rings are stressed by thermal expansion from current heating and centrifugal forces, causing them to expand radially. As well as stressing the rings themselves, this expansion imposes stresses on the bar extensions. Again, changes in stress between stand-still and running can cause failure of the shorting rings from cyclic fatigue.

Forces on Retaining Rings (F_r) In large two- and four-pole motors, F_b and F_{sc} can be controlled by fitting nonmagnetic retaining rings over the bar ends and shorting rings, as illustrated in Figure 12.3. This induces high mechanical hoop stresses in the rings.

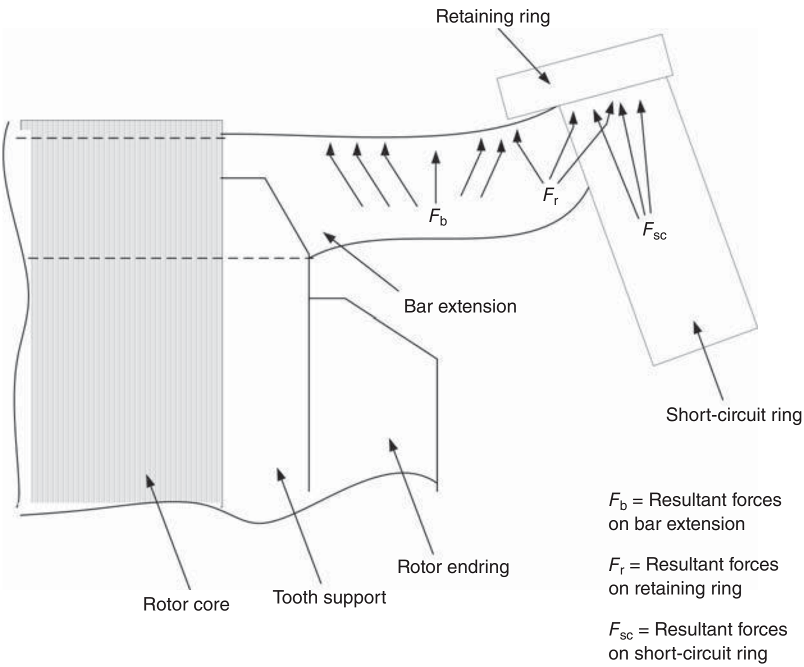

Figure 12.2 Exaggerated distortion of rotor bars outside of a slot by mechanical forces during motor starting.

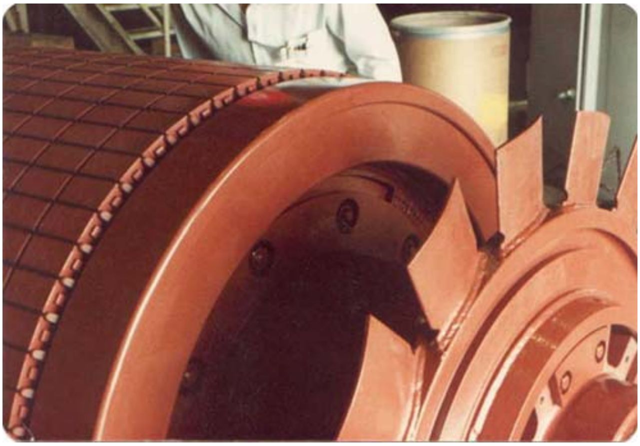

Figure 12.3 Retaining ring over a short-circuit ring.

12.2.2 Root Causes

- Poor winding geometry associated with frequent starts and stops and relatively high load inertia

- Numerous successive directly-on-line starts
- Loose rotor bars in the slot region

12.2.3 Common Symptoms

- Cracked or broken bars, bar-to-shorting ring joints and shorting rings in the end windings. This is usually at the end where the bar extensions are shortest if there has been axial migration of the whole cage winding.
- Cracked or broken shorting rings.
- Cracked or broken bars in the slot region, associated with loose bars or thin bar top sections (Figure 12.4).
- Burning of the core laminations (Figure 12.5).
- Cracked shorting rings (Figure 12.6).
- Increased starting time and noise during starts and while the motor is running.
- Increasing vibration levels and stator winding current harmonics.

12.3 POOR DESIGN/MANUFACTURE

There are a number of design and manufacturing deficiencies that can cause failure on their own, accelerate the failure mechanisms described in Sections 12.1 and 12.2, and/or give unacceptable motor performance. These are:

- Poor end winding geometry and support
- Loose bars in slots due to excessive clearances from poor design or manufacturing practices

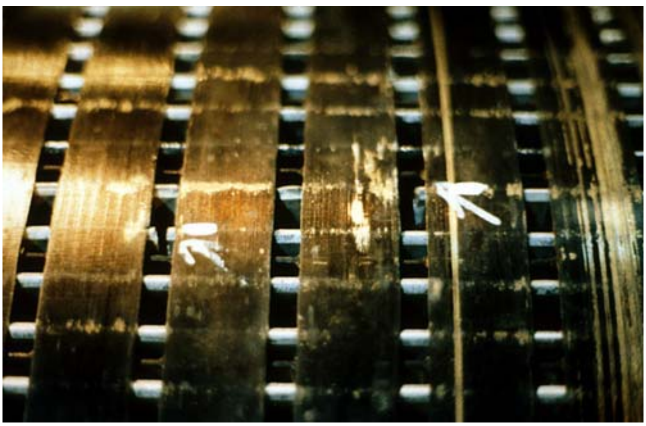

Figure 12.4 Broken bar in slot (Source: Courtesy of EASA).

Figure 12.5 Rotor core burning resulting from broken bars.

Figure 12.6 Cracks in shorting ring of high inertia drive motor due to low cycle fatigue.

- Poor quality bar-to-shorting ring brazed or welded joints in fabricated windings (Figure 12.7)
- Air pockets in die-cast aluminum rotor windings

12.3.1 General Process and Root Causes

Poor End winding Geometry and Support The stresses described in Sections 12.1 and 12.2 can be minimized by good design that takes account of bar extension lengths, shorting ring dimensions, bar-to-shorting ring interface configuration, selection of the brazing or welding technique, and materials to be used. Also, as already

Figure 12.7 Rotor bar-to-shorting ring brazed joint failure due to poor manufacturing.

indicated, retaining rings are used on large two- and four-pole rotors to help control end winding cyclic stresses. Any weakness in the rotor winding design can lead to premature failure that, in some cases, can occur after only a few months of operation.

Loose Bars in Slots Due to Poor Design or Manufacturing Practices Any design deficiencies that lead to the loss of the tight bar fit in the slot or the use of undersize bars will lead to bar looseness and failures from this cause. If only some bars are loose, then non-uniform bar expansion can occur during motor operation and this can create sufficient force to bend the rotor and put it out of balance. Two-pole motors are most susceptible to this problem. Examples of issues leading to loose bars are the use of bars with rounded corners instead of sharp ones, loose slot liners that migrate out of the slots, and omitting the bar swaging operation during manufacture. Small cracks in the tops of the bars can be introduced if the swaging tool used is too sharp. These cracks may grow during motor operation.

There are various methods used to ensure tight bars, including:

- Having an interference fit between bars and slots at the slot corners
- Driving interference-fit steel wedges into keyways in the core laminations below the bars
- Deforming the bars by swaging the tops once they are in the slots
- Using custom-fitted steel liners between the bars and slots and locking them to prevent migration.

Poor Quality Bar-to-Shorting Ring Brazing or Welding The quality of the brazed and welded joints between bars and the short-circuit rings are very dependent on the skill and experience of the person who performs this operation during rotor winding manufacture or repair. In addition, quality assurance practices used to verify the integrity of such joints play a big part in detecting poorly made ones and taking corrective actions. Failure to manufacture high quality joints will result in rapid joint cracking and fracture, resulting from the high stresses imposed on them during motor starts and stops, as well as centrifugal forces during operation.

Poor Shorting Ring Design and Manufacture Some manufacturers roll rectangular copper, copper alloy, or aluminum alloy to form a shorting ring. The two ends must then be brazed or welded together. As these joints sometimes fracture, such a design is not recommended for motors driving high inertia loads.

Air Pockets in Die-cast Aluminum Rotor Windings This defect can be hard to confirm as, in most cases, the air pockets are not on the surface of the winding where they can be seen. This defect causes the following problems.

- If voids create an open circuit in a bar, then the motor will exhibit the symptoms associated with broken bars, leading to high vibration and stator current sidebands (Sections 16.8 and 16.9.2).
- The increased rotor winding heating from non-uniform distribution of current in the rotor winding due to the presence of voids can cause excessive shaft temperatures. These high temperatures can cause the inner rings of rolling element bearings to expand to such an extent that the bearing clearances are reduced and the bearing fails.
- Voids in bars create non-uniform rotor cage winding expansion that produces sufficient force to bend the rotor and put it out of balance.

12.3.2 Common Symptoms

Poor Endwinding Geometry and Support

- Premature breaks in bar extensions between the end of the core and shorting ring
- Lack of retaining rings in large high speed rotors
- Shorting ring cracking

Bars Loose in Slots Due to Poor Design or Manufacturing Practices

- Noise during starting due to effects of high electromagnetic forces
- Bar breaks inside core
- Signs of arcing between bars and core (Figure 12.8). This occurs because there is a voltage between the bars and core when there is a loss of contact between the two at which time there is a current arc across the gap.
- Axial cage winding migration
- Radial movement of bars when pressure is applied

Poor Quality-Bar-to-Shorting Ring Brazing or Welding

- Premature failure of bar-to-shorting-ring joints
- Increased starting time and noise during starting

Figure 12.8 Core bridge burning due to loose bars in slots (Source: Courtesy of EASA).

Figure 12.9 Voids in die-cast aluminum squirrel cage rotor winding (Source: Courtesy of EASA).

- Metallurgical analysis indicating poor quality brazing

Poor Shorting Ring Design or Manufacture

- Broken brazed or welded ring joints
- Cracks in one-piece rings

Air Pockets in Die-cast Aluminum Rotor Windings (Figure 12.9)

- High rotor vibration levels that vary with load
- Premature bearing failures due to loss of clearance from high shaft temperatures

In all cases, the above defects will also cause bearing vibration (Section 16.9.2) and an increase in the stator winding current harmonics at specific frequencies. Incipient cracks may be verified by a dye penetrant (Section 15.28) or ultrasonic test and the rotor rated flux test (Section 15.29).

12.4 REPAIRS

It is important to remember that sometimes a few cracked rotor bars can be tolerated, and perhaps do not need to be immediately repaired. These few cracked bars may have occurred as a result of an unusual operating mode. However, if the vibration, starting noise, stator current signature, or other factors worsen over time, repairs should be made. The other concern with cracks in rotor cage winding is if the damage is severe enough that pieces of the rotor winding break off and are projected into the stator.

Squirrel-cage winding repair techniques are very much dependent on the type of winding. Fabricated windings can sometimes be repaired by replacing only some of the components. On the other hand, die-cast rotors can only be repaired by replacing them with a complete new winding of a similar fabricated type. In many instances, it is more economical to replace the complete rotor if a die-cast winding fails or has a significant air pocket content. Given that in most cases die-cast rotor windings are not repairable, the following repair methods apply to fabricated windings only.

Shorting Ring Cracking or Failure Provided there is no indication of cracked bars, the damaged short-circuit ring can be machined off and replaced by a new one. Weld or braze repairs to shorting ring cracks are not recommended as the high mechanical stresses imposed on these are likely to cause them to fail. If the shorting ring has been formed by rolling a strip of copper or copper alloy into shape and welding or brazing the ends together, consideration should be given to installing new cast or forged single-piece rings, which are much more robust. Before a new shorting ring is installed, the areas of the bars to which it is to be brazed or welded should be machined to provide a clean surface, which helps ensure good bonding.

Cracked or Broken Bars If cracked or broken bars are found, it is advisable to replace all the bars in the rotor as the others are likely to develop similar defects. If all or only some rotor bars are being replaced, it is important to determine the conductivity and chemical composition of the existing ones so that the replacement bars can be specified to have the same characteristics. If possible, the reason for the bar cracking problem should be investigated. If it is design-related, the design or rotor bar material should be changed to reduce the possibility of further failures. If it relates to manufacturing deficiencies, then the manufacturing techniques used for the new winding should be reviewed to ensure that they will not cause similar failures. If broken bars have caused rotor core damage (Figures 12.5 and 12.8) that can only be repaired by lamination replacement, then all bars will have to be replaced. Except in an emergency, cracked bars should not be repaired by welding or brazing as this is only a short-term fix.

Loose Bars If the rotor slots are open at the top, this problem can usually be repaired by swaging the tops of the bars with a round-tip chisel. If the slots are totally enclosed, this technique cannot be used. Dipping the rotor in a polyester or epoxy thermosetting resin is not a recommended repair technique as the resin bonds between the bars and core will eventually crack, especially at the high temperatures occurring during starting. This leads to the presence of both loose and tight bars, which expand differently during motor operation to cause shaft bending and high vibration levels. Two-pole rotors are most sensitive to this problem. Thus, for completely enclosed rotor bars that are loose, a rewind may be needed.

Cracked Retaining Ring If a retaining ring is found to have shallow cracks in it, they can be ground out. On the other hand, if the cracks are deep, the ring should be replaced with one made from the same or an equivalent grade of stainless steel.

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CHAPTER 13

CORE LAMINATION INSULATION FAILURE AND REPAIR

This chapter discusses the most common causes of stator and rotor core failures in both induction and synchronous machines, together with proven repair methods. Core design and manufacture are discussed in Chapter 6. Core lamination insulation shorting and mechanical damage can occur from a variety of aging and failure mechanisms that can be thermal, electrical, mechanical, environmental, design, and/or manufacturing related. Stator cores used in large turbine generators, hydrogenerators, and motors, as well as squirrel-cage motor rotors with fabricated windings are most susceptible to failures from these causes. Some of these failure mechanisms will occur only in specific types of machines, whereas others are applicable to all types. More information on core problems can be found in References 1–6.

Note that some localized lamination insulation failure can be tolerated in machines, particularly in hydrogenerator and motor stators, as well as SCI motor rotors. Such insulation failure will allow currents to flow between laminations to increase the local temperatures. However, if the lamination insulation failures are very local, they may not expand in scope. Stator and rotor core insulation testing is discussed in Chapter 17.

Section 13.5 presents repair options that will arrest the aging process to prevent failures, or at least extend the life of the affected core. However, if aging goes undetected for a long period of time, the resulting degradation may be so advanced that a partial or complete core replacement will be required to give reliable operation for the remaining life of the machine.

The symptoms of each failure mechanism are listed below. Some of these can be detected from a visual inspection, whereas others require tests (Chapter 17) to provide early detection and to assess the severity of degradation in core condition.

13.1 THERMAL DETERIORATION

Degradation of the core condition due to the effects of thermal aging can occur in all rotating machine laminated cores. However, it is most likely to occur in large turbine

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

generator, hydrogenerator, and motor stator cores. The rotor cores in squirrel-cage induction motors with fabricated windings used in high inertia-driven equipment applications are also susceptible to failure from overheating as a result of broken rotor bars (Section 12.2).

13.1.1 General Process

Core overheating will cause accelerated aging of the core insulation if its thermal rating is exceeded [1] for an extended period of time. This is most likely to occur if an organic varnish is used as this will dry out due to loss of solvents by evaporation of low-molecular-weight components. Once this occurs, the varnish becomes brittle, cracks, and eventually breaks down. As a consequence, interlamination shorts will develop axial eddy currents and this will eventually lead to higher temperatures and even core melting. In large hydrogen-cooled turbogenerators, condition monitors may be installed (Section 16.2). These monitors detect the presence of small particles ("smoke") driven off the core by excessive heating.

13.1.2 Root Causes

The root causes of core insulation thermal degradation can be subdivided into the categories general overheating, local overheating, and inappropriate core burnout procedures. These are discussed separately below.

General Stator Core Overheating The most common causes of this are:

- Loss of cooling water for hydrogen or air coolers in totally enclosed machines.
- High ambient air temperatures for open-ventilated air-cooled machines
- Blockage of air inlets in open-ventilated air-cooled machines due to pollution or debris
- Complete or partial blockage of cooling-air passageways due to the accumulation of oil, dirt, etc. (Figure 13.1).
- Turbine generator operation at reduced hydrogen pressure

General overheating of cores in large machines, especially turbine generators, may also cause core slackness that results from thermal expansion of the core steel. When core temperatures exceed design limits, the radial and axial forces exerted on the core support structure may be high enough to cause permanent deformation of these components. As a consequence, the core will loosen when the condition causing the overheating is removed. This core looseness will lead to lamination insulation failure from abrasion. Core looseness has sometimes occurred as a result of extended full-flux core testing (Section 17.2). General thermal aging of core insulation also causes loosening of the core due to shrinkage and weight loss of the organic components in it.

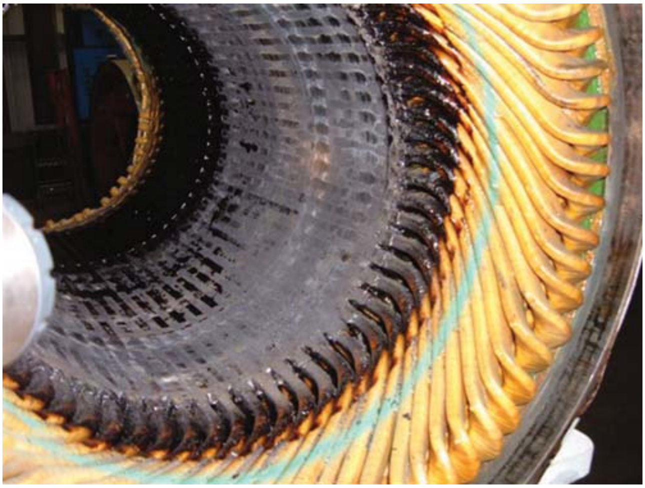


Figure 13.1 Blockage of stator core ventilation ducts with dirt and oil.

Local Core Overheating The most common causes of this are:

- Inadequate cooling of certain areas of the core due to poor design or blockage by debris (e.g., cooling air or hydrogen flow is too low or nonexistent in these areas).
- Manufacturing errors (e.g., some cooling-medium passages have been blocked due to missing holes or cut-outs in the core support structure).
- Broken rotor bars within the core in SCI motor rotors (Chapter 12). The interrupted currents in the bars flow through the adjacent core to healthy bars, overheating the core and its insulation.

It is unlikely that local overheating of the core will cause looseness. However, as with general overheating, it will cause accelerated thermal aging of the lamination insulation and eventual shorting of the core insulation. It should be possible to verify this cause by an analysis of the cooling gas circuit and temperature data from tests or the stator temperature monitoring system if improper design is the cause, or by inspection if cooling-gas passages have been blocked.

Winding Burnout at High Temperatures Stripping an old global VPI stator winding from the core during the rewind of a motor or small-to-medium-size synchronous generator poses a major thermal threat to the core insulation. This stripping is usually accomplished by cutting off the stator end windings and placing the stator in an oven at high temperatures to lessen the force needed to pull the coils from the stator. Weaknesses in the interlaminar insulation could be inadvertently introduced during this "burnout." During subsequent service, these weak spots may overheat due to local

Figure 13.2 Stator core burning that resulted from excessive oven temperatures during stator winding burnout prior to rewind.

or general high interlaminar currents that cause premature core failure (Figure 13.2). To avoid core insulation damage in modern stators, the winding burnout should be performed in a precision temperature-controlled oven with a water spray quenching system. In no case should the maximum oven or component temperature exceed 360°C (680°F) for C-4 organic and 400°C (750°F) for C-5 inorganic core insulation [1]. If the core insulation type is unknown, the burnout temperature should be limited to 360°C (680°F). The core insulation in machines built before about 1970 should be carefully evaluated for the type of core insulation used as it may deteriorate even at 360°C. For example, some machines built in the early 1900s had paper-insulated cores. For such cores, cold stripping of the winding or water lancing are the best options for old winding removal.

The pullout force required to remove an old stator winding decreases significantly with the temperature. For the same "burnout" time in the oven, the pullout force can decrease by an order of magnitude for an increase of about 100°C in burnout temperature. In addition, the time needed in the oven could be reduced to less than 25% by increasing the oven temperature by 100°C. The repair shop and motor owner, therefore, have a good incentive to use high burnout temperatures to remove a stator winding from a core, to shorten turnaround times.

Following a rewind involving a burnout of the original stator winding, the operating losses in the motor or generator are likely to change. Provided that the number of stator turns and the copper cross section per turn are not altered, the change in losses will be mainly in the core and in stray load losses. During repair, the core interlaminar insulation may have been degraded by high temperature, mishandling, burrs, or assembly pressure. This would increase the eddy current losses in the iron due to higher circulating currents induced in the laminations. Overheating of the laminations could lead to local melting of iron and eventual core failure. This increase in losses can be minimized if the tests described in Chapter 17 are performed before and after removal of the original winding and any core insulation damage is repaired before the new winding is installed.

13.1.3 Common Symptoms

General Stator Core Overheating Signs of general deterioration of the core insulation are associated with lamination shorts distributed generally throughout the core (Figure 13.2). From a rated flux core test (Section 17.2), a significant increase in the core losses in watts per kilogram and/or an increase in ambient core temperature are indications of general core insulation degradation. Shorts in visible areas of the core will be indicated by discoloration, broken teeth, and fused metal. Those deeper in the core body may be detected by special tests (Chapter 17), which should be performed to provide early detection of core insulation deterioration that is not visible. Core insulation dusting may indicate a loose core. Core shorts that develop at the edges of slots may increase the temperature enough to cause thermal aging of the winding insulation and resulting ground faults in the stator winding core section.

Local Core Overheating Burn marks or lamination discoloration in isolated areas (Figure 13.3), which are common symptoms of localized core shorts that can be related to inadequate cooling in their vicinity, should be detected early. Overheating can, of course, result from core insulation degradation initiated by electrical or mechanical aging mechanisms, as described in Sections 13.2 and 13.3.

Winding Burnout at High Temperatures Higher full-load and no-load currents associated with significantly higher core and stray losses after a stator rewind (Figure 13.2) could be due to excessive burnout temperatures. It is important to obtain baseline core loss and temperature data before repair so that the effectiveness of a repair can be assessed. The EL-CID test (Section 17.4) or rated flux test

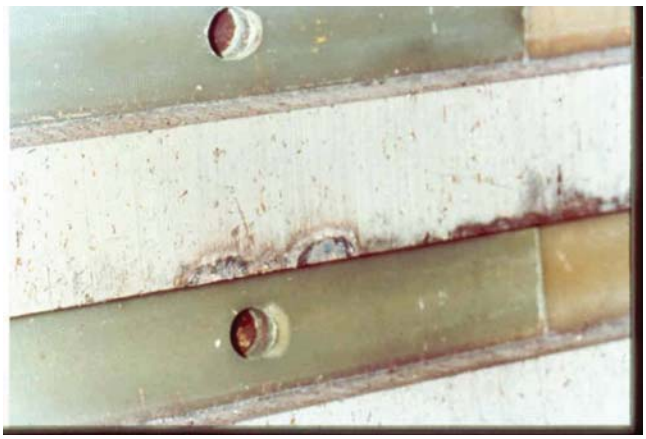


Figure 13.3 Localized core overheating from core insulation thermal aging.

(Section 17.2) can be used to identify shorted laminations and as indicated above, the rated flux test together with evaluation of core loss in watts per kilogram (Section 17.3) and ambient core temperature can give an indication of general core insulation damage from too high a winding burnout temperature.

13.2 ELECTRICAL DEGRADATION

Electrical aging occurs when the voltage across the lamination insulation induced by magnetic fluxes, electromagnetic forces, or high ground-fault currents causes deterioration. Although DC and transient voltages may cause aging, it is normally AC-voltage-induced effects that cause the most severe damage. In addition, broken bars or shorting rings in squirrel-cage induction motor rotors and synchronous machine rotor damper windings cause rapid thermal degradation of their lamination insulation and may be considered an electrical cause of problems. Degradation from electrical aging can occur in all types of stator and rotor laminated cores.

13.2.1 General Process

There are several electrical processes that can lead to deterioration. Excessive fluxes in specific areas of stator cores induce elevated eddy current losses, which can cause lamination overheating. Such overheating is most commonly found in large synchronous machines, especially at the ends of the core. Failure of stator winding insulation in core slot sections leads to the flow of high ground-fault currents that can cause localized core damage (Figure 13.4). High currents that flow through the rotor laminations, between bars, in squirrel-cage induction motor and synchronous machine damper windings, as a result of broken bars or shorting rings, cause rapid thermal aging of the laminations and deterioration in their mechanical strength (Figures 12.5, 12.6 and 13.5). As induction motors have relatively short air gaps, high electromagnetic forces of attraction between the stator and rotor can cause the two to make contact, causing core insulation surface smearing resulting in shorting (Figure 13.6).

Figure 13.4 Damage to stator core from winding ground fault in slot.

13.2.2 Root Causes

The root causes of electrically induced core insulation degradation can be subdivided into the categories of overheating due to over- or under-excitation, winding ground faults, and stator-to-rotor rubs due to unbalanced magnetic pull effects. These are discussed separately below:

Stator Core End Overheating Due to Under-excitation The main air gap flux in synchronous machines is in the radial direction. This flux is responsible for generating the voltage in the stator winding. In addition, synchronous machines have significant leakage fluxes in the end region, especially in round rotor generators when the rotor winding is under-excited. These fringing fields are produced by currents in the stator and rotor end-windings and by the discontinuities at the stator and rotor core surfaces. The axial component of this field generates circulating currents within the segments of the end region stator laminations, generating some electrical losses and, thus, heat. In large turbine generators, flux shields or shunts are used to reduce the heating effects of these axial fluxes (Section 6.6.3).

The eddy currents due to the axial magnetic field cause stray losses in the end regions. The axial magnetic field is sensitive to changes in load and power factor. During leading power factor (under-excitation) operation, this field can be quite high in large machines, especially if they have direct-water-cooled windings. This can degrade the interlaminar insulation as follows:

- Higher temperatures occur, which may reduce the dielectric strength of the interlaminar insulation over time and also give rise to other stresses due to expansion and relative motion between components. Based on tests performed over a limited time, suppliers have claimed that interlaminar insulation with C5 insulation has the capability to withstand temperatures as high as 500°C. However, in some machines, especially if they were built before 1970, this limit is much lower. This compares with the Class B winding insulation temperature limit of 130°C used on a typical large generator of that era. However, the long-term effect of operating near the rated temperature capability of the insulation could reduce its life.
- The circulating currents in the laminations can result in relatively high voltages being developed between adjacent core laminations. Under extreme conditions, this voltage may be an order of magnitude higher than normal. It has been shown that minor defects in the interlaminar insulation may provide a path for circulating currents, causing further, perhaps serious, local deterioration.

The combined effect of the above two mechanisms, in conjunction with other existing stresses, can damage interlaminar insulation in the stator core end regions near the bore. This increases circulating currents between laminations, causing temperature rise, local weakening, and tooth chatter and breakage. Several thermocouples may be installed on generators in the core end areas during manufacture. A rising trend or a sudden increase in temperature recorded by these sensors can provide an early warning of the problem.

Overheating of Back-of-Stator Core Due to Over-excitation In order to keep the physical size of large two- and four-pole synchronous machines within reasonable limits, it is necessary to excite the stator core at a fairly high magnetic flux density. Laminated steel, as well as the lamination insulation, is, therefore, selected to avoid high core losses. The core lamination steel is either grain oriented or specially processed to give low core loss (Section 6.1.9). The lamination insulation is selected for its low dielectric permitivity and good insulation properties under high stress. High temperatures due to increased core loss can result from overexciting the field winding, thus producing higher than normal magnetic flux.

The large volume of core behind the slot is more prone to overheating due to increased flux compared to the tooth area. The core behind the slot has relatively less ventilation than the teeth. Consequently, the core losses can quickly raise the temperature of the back of the core. The temperature increase is particularly steep as the iron begins to saturate.

Once the temperature has been elevated, the chances of breakdown of the lamination insulation are increased. Such a breakdown would give rise to interlaminar faults and increased eddy currents, which can cause even higher temperatures. The higher temperature can also cause mechanical stresses, resulting in distortion and vibration. When combined, these effects can eventually lead to fusing of laminations, melting of iron, and core failure.

Stator Winding Ground Faults in Core Slots The energy and heat produced by stator- or wound-rotor winding ground faults in the slot core region are often sufficient to melt and fuse the core laminations at the core surface (See Figure 13.4). If this core damage is not repaired when the failed coil or bar is replaced, the new coil could also fail to ground as a result of the heat generated by the shorted laminations. It is, therefore, important to perform the tests described in Chapter 17 to check the condition of core insulation in the vicinity of ground fault damage before installing a new bar or coil.

Vibration Sparking A relatively rare stator winding failure process called *vibration sparking* (see Section 8.8) may deteriorate the stator core lamination insulation in the slot area, adjacent to the stator bars or coils. This winding insulation failure process produces high energy sparking between the bar/coil surface and the stator tooth. In addition to eroding the bar/coil insulation leading to a ground fault, the sparking can damage the interlaminar insulation, resulting in shorted laminations. If this happens, shorting and core overheating will occur in areas of the stator core where lamination shorting has occurred due to vibration sparking. If the shorted area extends along the core length to a critical length, then thermal runaway may occur, resulting in extensive core melting.

Stator Core Faults from Through-Bolt Insulation Damage In some medium to large motor and generator designs, the stator core pressure is maintained by bolts that pass through axial holes in the stator core laminations and endplates, and have nuts and washers installed at either end. Core pressure is maintained by keeping these nuts tight. These through bolts have to be insulated from the core with tube insulation or tape on the bolt area and insulating washers at the nuts to prevent core insulation shorting. If the retaining nuts become loose or the bolts stretch, the insulation can fail from core movement and resulting mechanical damage. If this happens, core lamination shorting and core burning may occur.

Broken Rotor Bars or Short-Circuit Rings Bars or short-circuit rings in a squirrel-cage rotor winding or salient pole synchronous machine damper winding may crack or fracture to create an open circuit; then, rotor core insulation damage and shorting will occur. This results from the current flowing through the core laminations, between bars, because this is a lower-resistance path that that through the breaks in rotor bars (Figure 13.5) or shorting rings. The heat generated by this abnormal current flow is sufficient to cause insulation damage, eddy current flow, and core melting.

If a broken short-circuit ring is the cause, the resulting damage will occur at the end of the core nearest the break. Core damage due to broken bars will occur in the vicinity of these breaks. In addition, if bar breaks are outside the core, centrifugal forces may push the end of the broken bar through the weakened bridge at the top of the rotor core slot (Figure 13.5) so that it rubs on the stator winding. If this happens, a stator winding ground fault will occur.

Stator-to-Rotor Rubs Due to Unbalanced Magnet Pull Electromagnetic forces of attraction (unbalanced magnetic pull) between rotor and stator occur in all rotating machines, due to uneven air gaps. The direction of these forces is toward the smallest air gap and their magnitude increases as the air gap gets smaller. If the rotor shaft is not stiff enough, such forces can be high enough to cause the rotor to “pull over” and rub the stator (Figure 13.6). This causes the same type of damage that results from bearing failures. Small to medium size induction motors with relatively small air gaps and single-circuit stator winding connections are most susceptible to this problem as the unbalanced magnetic pull in these machines

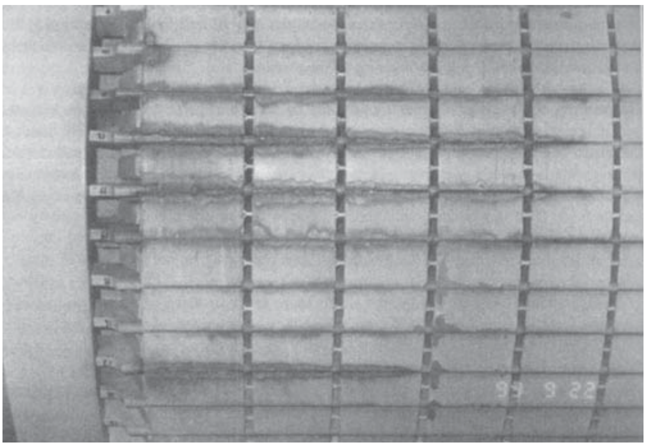


Figure 13.5 Core lamination burning due to broken rotor bars in an SCI rotor.

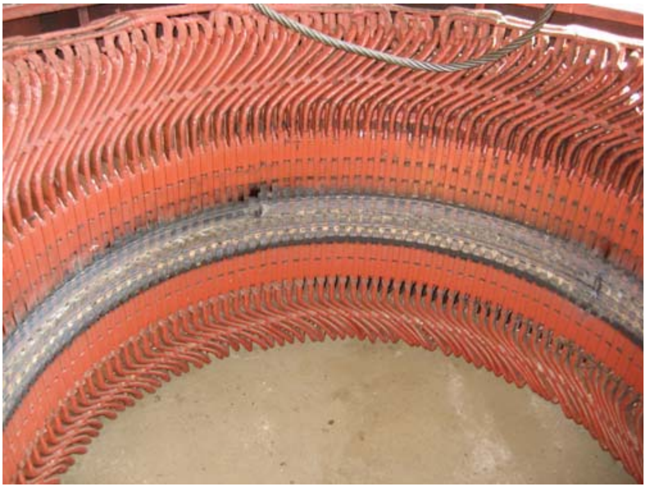


Figure 13.6 Large slow speed motor stator rub from rotor pull over the rub is in the middle of the stator core, at the lighter colored area.

is relatively high. This problem can also result from the rotor not being properly centered in the stator bore during motor assembly, thus creating a much smaller air gap at one location. Salient pole pullover can also occur in hydrogenerators if the air gap becomes uneven due to movement of the stator or rotor. Air gap monitoring in hydrogenerators (Section 16.9) and current signature analysis for SCI motors (Section 16.8) can warn of this condition.

13.2.3 Common Symptoms

Stator Core End Overheating Due to Under-excitation This results in inter-lamination shorts, discoloration, missing ventilation spacers, and, perhaps, broken teeth in the core end regions. If temperature sensors are fitted in the core ends, a gradually rising temperature or a sudden increase in temperature may give an early warning.

Stator-to-Rotor Rubs Due to Unbalanced Magnet Pull This results in smearing of the stator core bore and rotor core outside diameter at or near their centers.

Overheating of Back of the Stator Core Due to Over-excitation Higher vibration and higher stator temperature are often the more common symptoms. However, these may not be immediately evident. It is not practical to install the number of thermocouples required to monitor the complete core of a large turbine generator. Inspection of the core through vent ducts using boroscopes and fiber-optic probes during overhaul is a good precaution. Cracked welds in the inner structure of the generator housing may be an indirect symptom.

Stator Winding Ground Faults in Core Slots These result in shorting and melting of the laminations in the area of a coil ground fault.

Vibration Sparking Core insulation shorting in areas along stator slots where coil/bar vibration sparking has occurred. The surface of the core in the damaged areas will likely be pitted [5].

Stator Core Through-Bolt Insulation Damage Signs of core overheating are seen at core through stud locations.

Broken Rotor Bars or Short-Circuit Rings Core insulation damage and melting may be associated with broken bars, short-circuit rings, or joints between the two. If a bar or short-circuit ring fractures, it may be bent radially outward by centrifugal forces to cause a stator winding fault. The earliest indication of a fractured rotor winding may be arcing, increased noise, and increased vibration. Current signature analysis, as described in Section 16.8, can provide early detection of such problems.

For hydrogen-cooled turbogenerators, condition monitors (Section 16.2) will indicate if any of these conditions is occurring that are appropriate to this type of machine.

13.3 MECHANICAL DEGRADATION

The most common causes of mechanical degradation in cores are inadequate core pressure applied in manufacture, core pressure reduction in service due to relaxation of the core support structure, core vibration, back-of-core looseness, and mechanical damage causing smearing of the core surface at the bore. Degradation due to core looseness is predominantly found in large generators and motors with a segmented core construction [2–4], as described in Chapter 1. Core insulation damage due to vibration is most commonly found in large two-pole turbine generators. Mechanical damage to the core bore due to impact can occur in any type of machine.

13.3.1 General Process

When the laminations in a stator core become loose, they can move relative to one another under the influence of mechanical vibration and/or electromagnetic forces, and the insulation on the laminations degrades due to abrasion. If not detected in time, all of the lamination insulation in the areas of core looseness is removed and lamination shorting occurs. The axial currents that flow as a result of this shorting create excessive heat that can eventually lead to core melting and lamination fracture. Core looseness can also result from vibration caused by the natural frequency of the core and frame being too close to the main twice-power frequency (100 or 120 Hz), the electromagnetic core excitation frequency that occurs in all AC machines.

The stator cores in large machines with segmented laminations are built on axial key bars (two per lamination) welded to the frame. A dovetail fit between each core lamination segment and the key bar provides radial support for the core. If the fit between the core laminations and key bars is, or becomes, loose, then arcing between the two and shorting of the core laminations at the back of the stator core will occur.

If the stator and rotor of a rotating machine make contact during operation or rotor removal, core surface smearing and shorting will likely occur. Also, in any machine, loose components entering the air gap will cause localized shorting of the stator core insulation and that of the rotor if it also has a laminated core or poles.

13.3.2 Root Causes

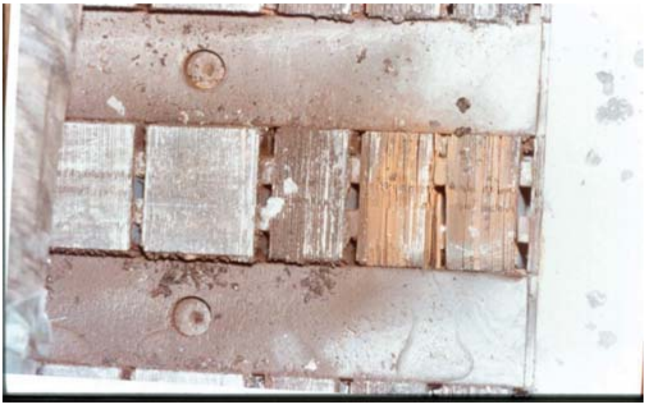
The root causes of mechanically induced core insulation degradation can be subdivided into the categories of core fretting, relaxation, and failure; core vibration; loose fit between back of core and key bars, causing overheating and burning; bearing failures in induction motors; and metallic debris in the air gaps of synchronous machines.

Stator Core Relaxation, Fretting, and Failure—Turbine Generators Core design and manufacturing problems contribute to this type of core deterioration. The following gives some general information, which may not be applicable to particular situations.

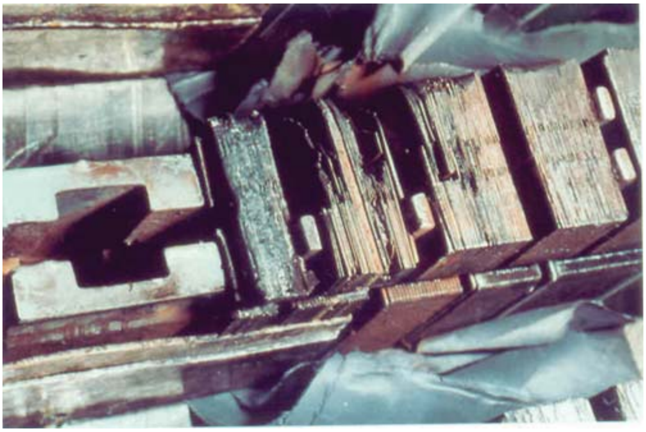
- The excessive use of resilient materials during manufacture may contribute to relaxation during service. Some examples of such materials are varnish in core insulation, rubberized segments for thermocouples, and arimid paper sheets used as electrical separators. Avoiding excessive resilience is particularly important in longer cores associated with higher ratings.
- Core pressure is another important factor to consider during manufacture. The applied and retained core pressure should be sufficiently high to ensure even distribution of the clamping force throughout the core laminations and to avoid slackness and distortion. This becomes more critical as the length of the core increases with the rating. If the core support structure relaxes in service, the core laminations become loose. The most common location of such looseness is at the stator bore as this is farthest from where the core pressure is applied (see Chapters 1 and 6).

If the laminations at the core bore are loose at the end of the core, the following sequence of degradation occurs if this problem is not detected and quickly corrected [3]:

1. The core insulation is abraded due to lamination-relative movement under the influence of axial electromagnetic forces from end leakage fluxes and radial forces from the main flux.
2. Core lamination shorting and overheating start to occur when the core insulation is removed by abrasion (Figure 13.7a).
3. Eventually, pieces of lamination teeth will break off due to fatigue cracking failures (Figure 13.7b) and vent spacers may also break free. As already indicated, such debris can cause core insulation damage in other locations.



(a)



(b)

Figure 13.7 Visual symptoms of loose core. (a) Dusting on tooth tips from loose core and lamination insulation abrasion. (b) Broken tooth laminations from loose core. *See color plate section.*

Stator Core Vibration — Turbine Generators Some of the causes of high stator vibration in service are:

- Inadequate support of the core in the stator frame, creating an assembly resonant frequency close to twice the power supply frequency (100 or 120 Hz)
- Unbalanced phase loading
- Inadequate stator end-winding support (causing vibrations that are reflected back to the core).

Even without these factors, a certain amount of vibration exists due to the 100 or 120 Hz "ovalizing" force caused by the magnetic field. The displacement of a loose core caused by these forces may result in relative motion between laminations and fretting of the lamination insulation to the point of breakdown.

Figure 13.8 Massive core melting with molten steel coming out of the axial vent ducts in a large turbo generator.

When a large number of laminations are shorted, the axial currents can be sufficient to melt the steel laminations. The heat from the melted laminations can further degrade the adjacent core. Eventually, massive core melting can result (Figure 13.8).

Stator Core Fretting, Relaxation, and Failure—Hydrogenerators As a hydro-generator core has a large diameter and short depth behind the winding slot, it is relatively flexible and the frame is the main support. The magnetic forces between the rotor poles and stator core will, therefore, tend to produce displacements in the core.

In general, the displacements and resulting vibration are small in multi-pole generators. The traveling wave produced by the magnetic force has a number of nodes equal to twice the number of poles. This results in smaller displacement. The only exception is in the case of fractional slot windings (i.e., windings having a non-integer number of slots, poles, or phases), where larger displacement is possible due to wavelengths that can be longer than the pole pitch.

The above mechanisms can cause high temperature and melting anywhere in the core. However, the bore section is particularly susceptible. It is physically weaker than the section behind the slot and carries a higher flux density. As these mechanisms weaken the bond between the laminations, the teeth are likely to chatter and break off. Secondary damage to the stator and the rotor can occur if the debris finds its way into the air gap.

Back-of-Stator Core Overheating and Burning Overheating and burning of the back of a stator core can be caused by a loose connection between the core laminations and the stator frame. Axial key bars welded to the frame are used for piling the core laminations. A dovetail fit between each core plate segment and the key bar provides radial support for the core. To allow assembly or stacking on the key bars, a clearance is necessary in the dovetail fit. If excessive, this clearance will permit relative motion, intermittent contact, circulating currents, and overheating during operation.

Leakage flux at the back of the core induces currents in the key bars. These currents flow to ground through the stator frame without causing any harm, provided there is no path for them to flow through the core. This is the case if the punchings are in good contact (positive grounding) with the key bars or if they are completely isolated electrically (insulated key-bars). However, should the clearance become excessive at some point, any core vibration could cause intermittent contact at that point and cracking of key bar insulation, if this is present. This can lead to arcing, overheating, and core melting in the local area. Small amounts of melting are difficult to detect due to inaccessibility and the impracticability of monitoring a large area with thermocouples. An early indication of this problem is an upward trend in frame vibration due to the increase in dovetail clearances.

Should a number of intermittent contacts develop on the key bars, the possibility of current transfer between key bars would increase. The currents would begin to circulate through the low-resistance path offered by the laminations. The resultant overheating could escalate into failure of interlaminar insulation and an increase in circulating currents and temperature, leading to fusing of laminations, melting, and, ultimately, core failure due to widespread melting of the lamination.

This problem can be greatly reduced by interconnecting all the key bars at each end of the core by means of welded copper straps to form a ring for carrying the circulating currents. This is better done during manufacture as retrofitting can be a major task.

Core Buckling Core buckling is not uncommon to some degree in large slow speed vertical/horizontal machines such as hydrogenerators. It is unlikely in turbogenerators. Buckling occurs in a core that has circumferential compressive forces that overcome the axial core clamping forces. The extent of the buckling and the type of core clamping will determine if secondary affects will create looseness in the laminations. Waves can also be created due to installation techniques and very small variations of lamination thickness as manufactured.

The forces on the core laminations from buckling can cause damage to the core insulation [4] leading to overheating in these areas.

Degradation from Mechanical Problems in Split Cores When a hydrogenerator split core is factory assembled (Section 6.6.2), application of a core rated flux ring (Section 17.2) helps consolidation, allows detection of damaged laminations via thermal imaging, and indicates, by noise level, looseness at core joints. In service, the following problems can lead to lamination shorting in split cores.

Figure 13.9 Split core packing movement.

- **a)** If heavy oil contamination has occurred, fretting and core insulation shorting can occur at both at the inner and outer peripheries due to relative movement between core sections.
- **b)** Movement of core split packing. (Figure 13.9)
- **c)** Lamination crushing at joint faces.
- **d)** Clamping fingers cutting through end laminations, due to deterioration in core clamping.
- **e)** Relative radial movement of laminations arising from detachment of the fixing at the outer-periphery.

Stator-to-Rotor Rubs Due to Bearing Failures — Induction Machines These types of failures mostly occur in induction motors, which have relatively small air gaps. Bearing failures can allow the rotor to move toward the stator and rub on its core bore surface (Figure 13.10). If this occurs, smearing of both the stator core at its bore and the rotor core outside diameter will occur. In addition, the rotor-to-stator rubbing may generate sufficient heat to cause rapid thermal aging of the stator winding insulation and a consequent ground fault. Such rubs will cause shorting of the core insulation on both the stator and rotor.

The severity of core insulation shorting from such rubs and the need for repairs can be assessed from the tests described in Chapter 17.

Loose Metal Components Entering the Air gap and Bearing Failures Bolts and other metallic components that break free from machine internal components can enter the air gap. Such objects are "sucked" into the air gap by cooling air or gas flow and magnetic attraction, if they are made from magnetic steel. If this occurs, stator core gouging or smearing and consequent insulation surface shorting will occur. As

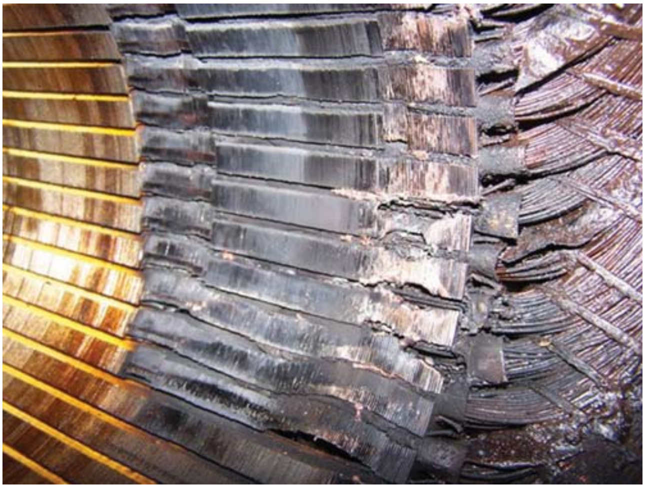


Figure 13.10 Stator rub on bore from bearing failure.

Figure 13.11 Core damage from a loose bolt.

turbine generator synchronous machines have much larger air gaps than induction types, the latter are more susceptible to such damage (Figure 13.11).

13.3.3 Symptoms

Core Relaxation, Fretting, and Failure—Turbine Generators High or increasing core vibration is an early symptom. If no corrective action is taken, a winding fault may result due to abrasion of the stator groundwall insulation. A visual inspection of the core will reveal core dusting and, perhaps, core overheating in areas where the insulation has broken down. If there has been hydrogen seal oil leaking into a turbine generator, this will combine with the dust from core insulation abrasion to produce a greasy substance. Broken teeth, missing ventilation spacers, and loose end-windings may be other indications.

Core Vibration — Turbine Generators High or increasing core vibration is an early symptom. If no corrective action is taken, a winding fault may result due to abrasion of the stator groundwall insulation. A visual inspection of the core will reveal core dusting and perhaps core overheating in areas where the insulation has broken down. If there has been hydrogen seal oil leaking into a turbine generator, this will combine with the dust from core insulation abrasion to produce a greasy substance. Broken teeth, missing ventilation spacers, and loose end-windings may be other indications.

Core Fretting, Relaxation, and Failure — Hydrogenerators High or increasing core vibration, which may vary with generator temperature, is a symptom. If no corrective action is taken, winding faults may result. A visual inspection will reveal dusting of the core insulation and, perhaps, core overheating, melting, broken or cracked teeth, and fretting at segmented core key support bars.

Back-of-Core Overheating and Burning This results in increasing core vibration, with signs of arcing between the core and the key bars that support it (Figure 13.12). A visual inspection may show cracked insulation if key bars are insulated.

Core Buckling The stator core may be considered buckled if it presents a wave exceeding a zone delimited by two parallel straight lines 8 mm apart from each other on a length equal to two spaces between the key bars. These waves are most easily seen by looking at the back of the stator core.

Figure 13.12 Back of core burning at key bar.

Degradation from Mechanical Problems in Split Cores The following are symptoms of such mechanical problems.

- **a)** Red dust, or a black paste at core splits, when the machine is heavily oil contaminated, indicating fretting, both at the inner and outer peripheries.
- **b)** Movement of core split packing.
- **c)** A "chevron" effect of laminations adjacent to the splits, indicative of crushing at joint faces.
- **d)** Excessive penetration by a calibrated knife blade, showing core slackness (Section 17.1).
- **e)** Hot spots, globally, as well as at core splits (located either by sight or such as the EL CID technique discussed in Section 17.3) are evidence of interlaminar insulation deterioration, due to lamination looseness, or distortion of adjacent laminations.
- **f)** Clamping fingers cutting through end laminations, due to deterioration in core clamping.
- **g)** Relative radial movement of laminations arising from detachment of the core segment fixing at the outer-periphery.

Stator-to-Rotor Rubs Due to Bearing Failures — Induction Machines These result in smearing of the stator core bore and rotor outside diameter at the failed bearing end of the motor.

Loose Metal Components Entering the Air gap — Synchronous Machines This can cause localized impact core smearing at the stator bore with evidence of one or more loose metallic components inside the machine.

13.4 FAILURES DUE TO MANUFACTURING DEFECTS

A number of different core insulation defects can be introduced during manufacture and these may not be detected if adequate quality assurance (QA) checks are not performed. Many of these defects can be detected and eliminated if core testing as described in Chapter 17 is performed as part of the QA program during core manufacture or refurbishing.

13.4.1 General Process

Interlaminar shorts can be introduced during core manufacture or refurbishing. The main causes of such shorts are:

- The introduction of defects, such as burrs, during lamination manufacture
- Inadequate cleaning of the lamination surfaces before core insulation application
- Poor quality insulating materials

- Core surface smearing due to stator-to-rotor rubs during factory assembly/disassembly
- Excessive filing of core slots to smooth rough lamination surfaces

As described above, shorts between laminations, especially those in stator cores, result in the flow of high axial currents induced by the main radial magnetic flux, which in turn cause excessive heating. The area affected by these shorts will "grow" as the core insulation in the vicinity also thermally ages and fails. Eventually, if these faults go undetected, portions of the core will melt (Figure 13.8). The heating principle that causes this melting is similar to that of an arc furnace. If this occurs at or near a slot, rapid thermal aging (i.e., burning) of the stator groundwall insulation may occur until, eventually, the winding fails to ground.

13.4.2 Root Causes

The main causes of insulation shorting introduced during core manufacture are as follows:

- Lack of adhesion between the insulation and the steel, causing the insulation to flake off. This results in weak insulation or shorts if adjacent areas of laminations are bare. Such problems generally occur because the lamination surfaces were not adequately cleaned before the insulation was applied.
- Poor edge deburring of the laminations prior to the application of the insulation, or blunt dies used for blanking and punching pre-insulated core steel, will result in shorts being created when the core is built and pressed; that is, the sharp edges on the laminations will cut through the insulation on adjacent laminations creating metal-to-metal contact.
- Hard rubs during rotor installation or removal during manufacturing, repair, or maintenance, cause the lamination surface at the stator bore and rotor outside diameter (in laminated rotors) to be shorted by smearing.
- Poor core building procedures and/or lamination manufacture can create high spots in the slot regions that may damage coil groundwall insulation. Such high spots can be removed by careful filing but, if not controlled, this can cause smearing and shorting of the core laminations in the slot region.

13.4.3 Symptoms

- High core temperatures (which may be difficult to detect in service).
- Melting of the core at the air gap surfaces or around slots having poor edge deburring, or which have been filed.
- Overheating as well as melting of either the core outer surfaces or core body where a poor bond exists between the core insulation and steel.

- If rubs during rotor installation are the cause of failures, they are most likely to be in the 5–7 o'clock location, especially in large turbogenerators where "skid plates" are used for rotor insertion and removal.

13.5 CORE REPAIRS

The need for core repairs can be assessed by applying one or more of the test techniques described in Chapter 17, as well as visual inspection. If core insulation condition tests are not performed after repairs, there is a danger that core and, perhaps, consequent insulated winding failures will occur at some time in the future.

In all repair methods where core un-stacking and/or slot damage is involved, it should be understood that the winding in the core has to be removed and replaced. The only exception to this may be in large generators with Roebel bar windings, in which, if in good condition, the top and bottom bars can be separately removed and reinstalled after the core repair.

13.5.1 Loose Cores

The following repair procedures are based on the premise that the core looseness has been detected before significant insulation damage has occurred.

Core Looseness at the Stator Bore This can be verified by the "knife test" described in Chapter 17 and repaired by a procedure called *stemming*. Stemming or "shimming" involves manufacturing thin (about 1–2 mm thick) sheets of epoxy-glass laminate, which are shaped to the profile of the stator core teeth [2]. Each of these stemming pieces is roughened and grooved on both sides to create a reservoir for penetrating epoxy. In some cases, holes are drilled through the stemming pieces to increase the capacity of the epoxy reservoir. The stemming pieces are then coated with a low-viscosity "weeping" epoxy and driven into a loose area of core to tighten it. Once this epoxy cures, it bonds the stemming pieces in place. It is also a good idea to brush the epoxy onto the stator bore in the area of looseness to help restore the core lamination insulation.

Core Looseness Away from Stator Bore There is no simple remedy for this problem unless the core has through bolts, in which case it should be possible to tighten the nuts at the end of these and, hence, correct the core looseness. Note that over-tightening of the core bolts may make the situation worse if the through bolts stretch. Over-tightening may also cause the core laminations to bend at the I beams in core vent ducts.

For machines that do not have through bolts, core looseness can only be corrected by removing the windings and repressing the core assembly. If the core looseness is due to an inadequate core end support structure, then this structure must be replaced with one having an improved design before repressing. If the looseness is due to resilient materials in the core stack, then the core will have to be un-stacked to remove them before repressing.

Loose Stator Core at Key bar Supports There is no easy repair for this problem, which results from excessive core-to-key bar clearances, established during core design and assembly. The back-of-core damage from arcing between the core and key bars can be greatly reduced by interconnecting all the key bars at each end of the core by means of welded copper straps to form a ring for carrying the circulating currents. This is better done during core manufacture, as retrofitting these straps afterwards may be very difficult because the stator end windings may restrict access to the areas where they are fitted, unless the whole core and winding assembly can be removed. If this does not arrest the problem, then the most economic solution is to unstack the core, replace the key bars with new ones that give a tighter fit, and reassemble the core. Any core insulation damage can be repaired during this process.

If the core looseness resulted from a resonant frequency problem, a more radical approach is required as the root cause is design related. In most cases, a new core and, perhaps, a new frame design will be required to eliminate looseness from this cause.

13.5.2 Core Insulation Shorting

The following repair methods are based on the assumption that insulation shorting has been verified by visual inspection and by one or more of the tests described in Chapter 17. Once repairs have been completed, the core should be retested to verify that the lamination shorting has been eliminated. The repair methods described below have been proved within the rotating electrical machine industry. In all cases, the condition of the core insulation before and after repairs should be evaluated.

Shorting Due to a Loose Core at Stator Bore Shorting of insulation near the core bore is commonly found if core looseness has gone undetected for some time. This is most often found near the core ends and can be corrected by generously applying weeping epoxy and/or inserting pieces of mica splittings between laminations every 2–5 mm of each tooth within the damaged area. This should, of course, be done before any core stemming as described in Section 13.5.1 is performed.

Shorting Due to Surface Smearing If the smearing is very localized, acid etching or high speed grinding can remove it. Acid etching is perhaps the better of the two methods as it removes the thin insulation shorting layer very slowly to reestablish core lamination separation. The procedure for acid etching is described as follows:

- Make a weak solution of 20% phosphoric acid, 20% denatured alcohol, and 60% water
- Make an applicator from Dacron™ felt fitted to a steel rod (with insulated handle) connected to a cable
- Soak the Dacron pad with solution
- Apply a variable voltage AC power source between steel rod and core

- Increase voltage till current of 0.3–0.5 A/cm^2 is obtained via the Dacron pad
- Rub smeared area of core with Dacron pad periodically until individual laminations can be clearly seen.

Core surface smearing over large areas is more difficult to correct. In smaller machines, it may be possible to eliminate stator bore smearing by installing the stator in a boring mill and removing the smearing by machining the surface with a sharp tool. The dangers of this approach are damage to the stator windings and, in the case of induction motors, degradation in performance due to increased air gap size. However, the costs associated with this type of repair are much lower as the stator winding does not have to be removed to allow the core to be un-stacked to restore insulation integrity. In the case of laminated rotors, the smearing can be removed by installing them in a lathe and machining the core outside diameter. Again, there is a limit as to how much material can be removed if an induction motor rotor is involved, as this again increases the air gap and weakens the core bridges at the top of the rotor bar slots.

In some instances, the only way to correct core surface smearing is to unstack the core, remove any remaining burrs, replace damaged core insulation, and rebuild the core.

Shorting Away from the Stator Bore In most cases, the only solution to this problem is to un-stack the core, re-insulate the laminations, replace any with significant damage, and rebuild the core. This is necessary because it is virtually impossible to restore damaged insulation in the body of the core. One technique that sometimes works for small to medium size stators is to VPI the damaged core with thin epoxy or polyester resin that is capable of penetrating the very small spaces between the laminations in the core body. After such treatments, the core must be baked in an oven to cure the resin.

13.5.3 Core Damage Due to Winding Electrical Faults

Ground faults in or at the end of the slot sections of insulated windings and open circuits in un-insulated squirrel-cage windings can cause severe localized core insulation damage and core steel melting. Such damage occurs in or at the end of a core slot.

The method of repair is dependent on the size of the machine and the location of the damage.

Unstacking and Rebuilding Part or All of the Core This repair method is used for:

- Stator and rotor cores with semi-enclosed slots, when the damaged area is away from the end of the slot.
- Cores in small to medium size machines with open slots, when there is damage to the groove that holds winding slot wedge in place
- Squirrel-cage rotor cores that have been damaged by core burning resulting from broken rotor bars

Once the core is unstacked, the damaged laminations can either have their insulation restored or new laminations can be acquired to replace them. If the original laminations are reused, they are re-orientated during the core rebuilding process so that the damaged sections are distributed throughout a large number of slots. This eliminates significant irregularities in the slot or wedge grooves.

High Speed Grinding High speed grinding is effective for removing local core damage in cores with open slots (if away from the wedge groove) [6] and at the ends of cores with semi-enclosed slots. The core surface shorts are ground away to provide separation between the laminations. The ground area should then be treated with weeping epoxy and the depression where the grinding was done filled in with thixotropic (high viscosity) epoxy or other type of filler to restore a smooth surface and prevent future winding mechanical damage.

13.5.4 False Tooth

This method of repair is used for large turbine generator cores in which severe localized tooth lamination damage has occurred to the extent that a significant number of laminations have broken off [2]. All of the tooth sections of the laminations in the damaged area are cut off. Radial securing dowels are epoxied into the root of the removed tooth section. A false tooth, made up of epoxy/glass material, shaped to the same contours as the removed section of tooth and containing holes to allow it to fit over the dowels, is then installed. The new tooth is bonded to the dowels by epoxy. If the false tooth covers more than one core packet, vent ducts are cut into it to allow cooling of the core below it.

13.5.5 Cracked Through-Bolt Insulation

Such damage can be repaired as follows:

1. Removing the bolts, one at a time
2. Removing the damaged insulation
3. Inserting new insulating tubes
4. Reinstalling the bolts
5. Fitting the washers and nuts to either end of the bolt
6. Torquing the nuts to the manufacturer's recommended value.

13.5.6 Split Core Repairs

Significant core deterioration, especially circular distortion, should be referred to an appropriate design authority before an attempt is made to rectify the situation. Remedial work should only be carried out by experienced operators. Renewal of the core, and even the frame, may be appropriate, especially when a rewind is to be made, to ensure equal future reliability of both core and winding.

Rectification measures, apart from the radical action of complete renewal, may embody the following:

1. Packing core looseness, using suitable insulation material and adhesive, after cleaning up rough lamination edges at splits.
2. Retightening core studs.
3. Repositioning distorted core regions, possibly by jacking.
4. Re-securing broken outer core fixings.
5. Retightening the core clamping structure.

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CHAPTER 14

GENERAL PRINCIPLES OF TESTING AND MONITORING

This and the next three chapters describe on-line and off-line tests and monitors that can be used on rotor and stator windings, as well as stator and rotor laminated cores. This chapter discusses several issues that are common to all of the tests and monitors. For consistency, testing shall refer to measurements that are made off-line, that is, during outages of the motor or generator. Monitoring shall refer to measurements taken during normal operation of the motor or generator that shed light on the condition of the rotor and stator windings.

14.1 PURPOSE OF TESTING AND MONITORING

As will be seen in this and the following chapters, there are over 40 different tests and monitors that can be used to diagnose motor and generator winding condition. One could spend a considerable amount of money, not to mention require the machine to be out of service for long periods of time, if one did all of these tests. Therefore, before the individual tests and monitors are discussed, we review the reasons why testing is done and discuss concepts for selecting which tests and monitoring should be done. We believe that there are at least four distinct reasons for testing and monitoring. These are discussed in the following four subsections.

14.1.1 Assessing Winding Condition and Remaining Winding Life

Determining the winding condition or estimating the expected remaining useful life of a winding is a common reason cited for doing tests and monitoring. For example, a plant manager wants to know if a motor that is more than 15-years old can continue to operate for the foreseeable future, or if a new motor or rewind is needed. The manager may also ask how long the existing motor will run before failure occurs. Testing helps answer these questions. Unfortunately, testing and monitoring alone are not likely to give a definitive answer (Reference 1 in Chapter 7). One reason is

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that the end of winding life depends, as discussed in Section 7.1, on when a transient occurs in the power system, or when an operator makes a mistake. This transient may then trigger the failure of weakened insulation in the rotor or stator. In the absence of a voltage or current transient, the insulation may continue to fulfill its function for many years—partly because mica is such a robust insulation. Clearly, tests on the rotor and stator windings will not allow one to predict when a transient may occur from the power system.

In addition, determining remaining life is also difficult because most of the tests measure a symptom, not the root cause of the failure, as we will see in later chapters. A medical analogy is useful here. If one has a cold, a symptom of the cold is that you sneeze. By measuring the sneeze rate (sneezes per hour) one can determine: (i) if you have a cold, and (ii), to some degree, how bad the cold is (more sneezes per hour may be a rough indicator of severity). However, whether you are going to die from the cold (yes, this is unlikely) will depend on the virus that is attacking your body (the root cause), and if the body is able to fend off the attack. As most of the tests in the following chapters measure the symptoms and not the root cause, remaining life cannot be ascertained [1]. Aside from hipot and surge testing, none of the other tests can determine if a rewind or new machine is needed. Some human intervention to correlate results from different tests, to perform a visual inspection and to perform an economic evaluation, is needed to make this determination, as discussed in Section 7.3.

Therefore, assessing winding condition must have a more limited objective. This could be to determine if winding deterioration has occurred. In some cases, the severity of the failure process can be determined and, perhaps, one can then estimate the "risk of failure." Risk of failure means the probability that the motor or generator will fail if a transient or operator error occurs.

14.1.2 Prioritizing Maintenance

Usually, a plant does not have just one motor or generator; it has many. In addition, the plant staff probably have neither the time nor the resources to do maintenance on all of its machines. Thus, testing and monitoring can help maintenance personnel determine which machines are most in need of an outage for maintenance purposes. In other words, testing and monitoring can help maintenance personnel determine on a comparative basis the machines with the greatest risk of failure. This can be combined with the repair cost and the impact of in-service failure on plant production to prioritize which machines must be maintained. This is discussed in greater detail in Chapter 20, where testing is incorporated as part of a company's maintenance strategy.

14.1.3 Commissioning and Warranty Testing

When a motor or generator is purchased, or a rewind performed, the contract between the vendor and the user normally defines that the windings must meet certain minimum test requirements (Chapter 19). These tests are often done by the supplier before the machine leaves the factory or in the first year of operation (or whatever the warranty period is). Examples include hipot tests and power factor tests. Some tests are automatically required by referencing standards (e.g., NEMA MG 1 or IEC 60034-1) as part of the purchase specification, but additional tests need to be specified by the purchaser. The tests are needed to ensure that the windings meet the specifications.

14.1.4 Determining Root Cause of Failure

If a machine fails in service or as a result of a hipot test, it is prudent to discover why the winding failed. The reasons for finding the root cause of a failure include:

- If a repair or a rewind is performed on a machine in which failure occurred before it was expected, the question that arises is: Is the same failure process likely to happen again once the machine is returned to service? If one understands the root cause, it is possible that minor changes to the winding can be made during the repair, or a repair can be made that will extend its operating time. For example, if stator turn insulation failure due to voltage surges has occurred, one can install surge capacitors or other filters to extend the rewind life, or turn insulation can be upgraded.
- If there are multiple machines of the same design, then, by ascertaining the failure mechanism involved in a failure of one of these machines, one can determine if the other motors or generators are subject to the same failure mode.

If an in-service failure occurs, there is often tremendous pressure imposed on the plant and repair shop personnel to return the machine to service as soon as possible, so that rarely can a full battery of tests be done. However, even performing some quick tests and inspections may permit several possible failure processes to be excluded. This can prevent future aggravation and wasted effort in making changes to the insulation system design that may ultimately not be needed.

14.2 OFF-LINE TESTING VERSUS ON-LINE MONITORING

All the rotor and stator tests in Chapters 15 and 17 are performed when the machine is not operating. Many of the tests can be done from the machine terminals, avoiding full or partial disassembly of the machine. However, some of the tests can only be done with the machine at least partly disassembled. Thus, all of the off-line tests, by definition, require at least a short outage (or turnaround, as it is sometimes called in industry).

In contrast, on-line monitoring refers to "tests" that are done during operation of the motor or generator. Therefore, no outage is needed, although, for some monitors, the operating condition of the machine is changed to extract the greatest amount of diagnostic information.

In general on-line monitoring is preferred because:

- No outage is needed to determine winding condition, at least for the failure mechanisms the monitoring can detect.

- Usually, the cost of acquiring the diagnostic data is cheaper than for off-line tests as, generally, one person can collect the data and it usually takes just a few minutes. In modern monitoring, data collection is often automated. In contrast, off-line tests may require a few people to isolate the machine, get the test equipment to the machine, hook it up, and run the test.
- It facilitates predictive maintenance (Chapter 20), as one can determine which machines are in need of off-line testing and repairs without taking the machines out of service.
- The stresses that occur in service (temperature, voltage and mechanical forces) are present. For example, it is difficult for an off-line test to properly simulate the AC stress distribution that occurs in service. An AC voltage applied to simulate the normal phase-to-ground stress in the slot will result in a 60% lower voltage between the line-end coils in different phases in the end winding than occurs in service.

The disadvantages of on-line monitoring are:

- Usually, there is a higher capital cost, as sensors and sometimes monitoring instruments must be installed on each machine, in contrast with off-line testing, in which one instrument can be shared for tests on a number of machines.
- Not all failure processes can be detected with existing on-line monitoring. Thus, unexpected failures can go undetected if all diagnostic information comes only from online monitors.
- As on-line monitors are often connected to plant SCADA systems, and the communications buses and protocols change frequently, continuous effort is needed to keep the system functional.

As discussed further in Chapter 20, a judicious mix of off-line tests and inspections, together with on-line monitoring, is needed to implement predictive maintenance. The mix will change from plant to plant, and even from machine to machine within the same plant, as one considers the importance of the machine to the plant and other economic criteria.

14.3 ROLE OF VISUAL INSPECTIONS

For each of the failure mechanisms in Chapters 8–13, a section was devoted to "symptoms." In addition to diagnostic tests, visual symptoms were often described. Our opinion is that a visual inspection of the winding done by an expert is usually the most powerful tool for assessing the winding condition and determining the root cause of a developing problem. However, there are several problems with visual inspections:

- They require an outage, and at least some (and often major) disassembly of the motor or generator.
- They require expertise. For example, a thin white line at the end of a coil may mean nothing to a casual observer but, to an expert, this may be definitive evidence of the root cause of a problem. This visual evidence enables determining

relative winding condition and the repairs needed. Unfortunately, experts who have many years of experience looking at machine windings are rare, especially among users.

- The disassembly required for a proper inspection may cause another problem when the machine is put back together. For example, a bolt may be left loose in the machine, or a cooling channel may be inadvertently left blocked.

Thus, inspections, wherever possible, should be triggered by an event such as an out-of-phase synchronization or a poor result from a test or monitor. The need for an expert to do the inspection should not be underestimated. Kerszenbaum has written two books to help non-experts inspect motors and generators [2,3]. Maughan has prepared a “text” which has hundreds of photos of various problems in large turbine generators [4]. In addition, EPRI has funded the development of an expert system program to guide non-experts through an inspection process [5], although this software is no longer available. More recently, Hydro Quebec has also assembled software to assess winding condition [6] that is similar to the software in Reference 5. In companies without an in-house expert, users can hire consultants from OEMs and large repair organizations. Also, individual consultants with extensive experience who formerly worked for OEMs or large users are often available.

14.4 EXPERT SYSTEMS TO CONVERT DATA INTO INFORMATION

All of the monitors discussed in Chapter 16, together with the tests in Chapters 15 and 17, produce “data.” That is, temperatures, vibration levels, partial discharge magnitudes, insulation resistance readings, etc. are measured. These measurements in themselves convey little information about the winding condition to casual observers. Unless one has been schooled in interpreting the data, the readings themselves are meaningless. As interpretation expertise is needed for the wide variety of tests and monitoring procedures, few people have the time or inclination to become “experts.”

In the 1990s, new software technologies were developed that enabled the creation of “expert system” programs. Expert system computer programs attempt to recreate the reasoning processes that an expert uses to interpret test results, as well as other relevant information. If successful, an expert system lets non-experts convert data into information, with accuracy approaching that of an expert. Expert systems have a secondary advantage in that they capture and permanently store the knowledge of experts, so that this knowledge is retained for long-term use.

Westinghouse introduced the first on-line expert system that was capable of diagnosing the condition of generator windings [7]. Since then, several American and European manufacturers of large turbine generators have produced their own versions. Recently, an on-line expert system has been introduced for hydro generators [8].

The output of on-line expert systems is intended for both operators and maintenance personnel. If a rapidly developing problem is occurring, these systems identify the most likely cause of the problem, and if a failure may result in a short time, an alarm is raised to alert the operator. Most programs also produce advice for the operator on possible actions that may be taken to avert failure. For longer term problems, for which failure may take weeks to years, the expert system output is usually intended for maintenance personnel.

Most of the input that drives the diagnosis comes from on-line monitors. As turbine generators often have a wide variety of monitors, the diagnosis tends to be more credible on such machines. The more information that is available, the greater is the accuracy. The commercial on-line expert systems use information from:

- Stator slot, core, cooling system, and rotor temperature readings
- Hydrogen and water cooling system pressure differentials
- Output current and voltage readings
- Bearing and frame vibration measurements
- Partial discharge levels
- Rotor flux readings

In general, off-line test results are not available to the expert system. However, most programs have a tremendous amount of customized information embedded within them regarding the design of the generator and the most likely failure processes and symptoms. This high degree of customization tends to make the initial purchase price of the software expensive. In an attempt to overcome this limitation, one program has an auxiliary expert system to make it easier and less costly to customize the software for a particular installation [9]. Unfortunately, the high commercial price for installation and maintenance of the software has greatly limited its application.

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CHAPTER 15

OFF-LINE ROTOR AND STATOR WINDING TESTS

This chapter describes the main tests that are commercially available for assessing the condition of rotor and stator windings. All of the tests require the motor or generator to be removed from service, for at least a short time. Tremendous advancements in testing technology are being made, due to better electronics and computers with sophisticated data analysis software. However, only tests with a demonstrated usefulness at the time of printing this book are included. This does not mean that some newer tests are not useful; it just means that they have been in use for so short a time that independent verification of claims is yet to be made.

The purpose of each test will be described, together with the types of machines and/or windings it is useful for. The theory of the test will also be described where it is not obvious. In addition, each test will be compared to other similar tests. Practical information is given on how to apply the test, including the state the winding must be in to do the test and the normal time it takes to do the test. Finally, a practical guide is given on interpreting the results. This interpretation will reflect the experience of test users rather than test vendors or the very general interpretation guidance that may be published in industry standards.

Although this book is primarily focused on electrical insulation, the last four tests described are concerned with determining the condition of squirrel-cage induction motor rotor windings, which of course do not have any insulation.

To aid in test selection, Tables 15.1 and 15.2 show a summary of the most common off-line tests for stator and rotor windings, respectively. Many of the tests are described in IEEE and IEC standards. In addition IEEE Standards 56 and 62.2 give overviews of the tests used for rotating machine windings.

15.1 INSULATION RESISTANCE AND POLARIZATION INDEX

This is probably the most widely used diagnostic test for motor and generator windings. It can be applied to all machines and windings with the exception of the squirrel-cage induction motor rotor winding, which does not have any insulation

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TABLE 15.1 Common Off-line Stator Tests

Name	Description	Performance Difficulty	Effectiveness	Relevant Standards
Insulation resistance (IR)	Apply DC voltage for 1 min to measure leakage current	Easy	Only finds contamination or serious defects	IEEE 43
Polarization index (PI)	Ratio of 1 min and 10 min IR	Easy	Only finds contamination or serious defects	IEEE 43
DC high potential	Apply high DC voltage for 1 min	Easy	Only finds serious defects	IEEE 95
AC high potential	Apply high AC voltage for 1 min	Moderate, due to large transformer needed	More effective than DC high potential	NEMA MG1 or IEC 60034
Capacitance	Apply low or high voltage to measure winding capacitance to ground	Moderate	Moderately effective to find thermal or water leak problems	
Dissipation (power) factor	Apply low or high voltage to measure insulation loss	Moderate	Moderately effective to find thermal or water leak problems	IEEE 286 or IEC 60034-27-3
Power factor tip-up	Differences in insulation loss from high to low voltage	Moderate	Effective to find widespread thermal or contamination problems in FW[a]	IEEE 286 or IEC 60034-27-3
Off-line partial discharge	Directly detect PD pulse voltages at rated voltage	Difficult	Finds most problems except end winding vibration; for FW only	IEEE 1434
Surge comparison	Apply simulated voltage surge	Difficult to determine if puncture occurred in FW	Effective for finding turn insulation problems in RW[a] and multiturn FW	IEEE 522
Blackout	Apply high AC voltage and look for discharges with lights out	Moderate	Effective for contamination problems in end winding	IEEE 1434
Wedge tightness	“Hammer” wedges to see if loose	Moderate	Effective to find loose windings in FW	
Side clearance	Insert “feeler gauges” down side of slot	Easy, after wedges removed	Effective to find loose windings in FW	

[a]FW is form-wound winding; RW in random-wound winding

TABLE 15.2 Common Off-Line Rotor Winding Tests

Name	Description	Performance Difficulty	Types	Effectiveness
Insulation resistance (IR)	Apply DC voltage for 1 min to measure leakage current	Easy	All	Only finds contamination or serious defects
Polarization index (PI)	Ratio of 10 min to 1 min IR	Easy	All	Only finds contamination or serious defects
DC high potential	Apply high voltage DC for 1 min	Easy	All	Only finds serious defects
AC high potential	Apply high AC voltage for 1. min	Moderate, due to large transformer needed	All	More effective than DC high potential
Open circuit	Measure generator output voltage as a function of field current to find short-circuited turns	Moderate	All	Effective only for generators; needs measurement when rotor OK
Impedance test	Apply 50 (60) Hz current and measure V/I at different speeds to find turn short circuits	Moderate	All rotors with slip rings	Effective
Pole drop	Apply 50 (60) Hz current and measure voltage drop across each pole to find poles with turn short circuits	Easy	SPR[a]	Only finds short circuits that are present when rotor stopped
Surge test	Find turn and ground faults by measuring discontinuities in surge impedance	Difficult	RR[a]	Effective if close to dead short circuit

[a] RR is round rotor; SPR is salient pole rotor.

to test. This test successfully locates pollution and contamination problems in windings. In older insulation systems, the test can also detect thermal deterioration. Insulation resistance (IR) and polarization index (PI) tests have been in use for more than 70 years. Both tests are performed with the same instrument and are usually done at the same time. The test is often referred to as a *Megger™ test*, after the company that developed the first instrument to measure IR and PI many decades ago. The PI test is related to the polarization–depolarization current (PDC) test described in Section 15.3.

15.1.1 Purpose and Theory

The IR test measures the resistance of the electrical insulation between the copper conductors and the core of the stator or the rotor. Ideally, this resistance should be infinite because, after all, the purpose of the insulation is to block current flow between the copper and the stator core. In practice, the IR is not infinitely high. Usually, the lower the IR, the more likely it is that there is a problem with the insulation.

The PI test is a variation of the IR test. PI is the ratio of the IR measured after voltage has been applied for 10 min (R_{10}) to the IR measured after just 1 min (R_1), that is

$$\mathrm{PI} = \frac{R_{10}}{R_1} \tag{15.1}$$

As discussed in Section 15.1.3, a low PI indicates that a winding may be contaminated or soaked with water.

The IEEE 43-2014 version of the standard, as well as ongoing revisions, gives an extensive discussion of the theory of the IR/PI tests as applied to rotating machines [1]. There is no equivalent IEC procedure for the IR/PI test, although one is now under development. In the test, a relatively high DC voltage is applied between the winding copper and the stator or rotor core (usually via the machine frame). The current flowing in the circuit is then measured. The IR at time t is then

$$R_t = \frac{V}{I_t} \tag{15.2}$$

which is just Ohm's law. V is the applied DC voltage from the tester and I_t the total current measured after t minutes. The reference to the time of current measurement is needed as the current is usually not constant.

There are at least four currents that may flow when a DC voltage is applied to the winding. They include

1. *A Capacitive Current*. When a DC voltage is applied to a capacitor, a high charging current first flows, which then decays exponentially. The size of the capacitor and the internal resistance of the voltage supply, typically a few hundred kilohms, set the current decay rate. A form-wound stator coil may have a geometric capacitance of about 1 nF between the copper and the core. A large hydrogenerator may have a capacitance of 1 μF. Thus, this current effectively decays to zero in less than 10 s. As this capacitive current contains little

diagnostic information, the initial IR is measured once the capacitive current has decayed close to zero. This time has been set as 1 min to ensure that this current does not distort the IR.

2. *A Conduction Current*. This current is due to electrons or ions that migrate across the insulation bulk, between the copper and the core. This is a galvanic current through the groundwall. Such a current can flow if the groundwall has absorbed moisture, which can happen in the older thermoplastic insulation systems, or if a modern insulation has been soaked in water for many weeks. This current also flows if there are cracks, cuts, or pinholes in the ground insulation (or magnet wire insulation in random-wound machines), and some contamination is present to allow current to flow. This current is constant with time, and ideally should be zero. With modern insulation, this current usually is zero (as long as there are no cuts, etc.) as electrons and ions cannot penetrate through modern epoxy-mica or film insulation. If this current is significant, the winding insulation has a problem.

3. *A Leakage Surface Current*. This is a constant DC current that flows over the surface of the insulation. It is caused by partly conductive contamination (oil or moisture mixed with dust, dirt, fly ash, salt, chemicals, etc.) on the surface of the windings. Ideally, this leakage current is zero. However, if this current is large, it is likely that contamination-induced deterioration (electrical tracking) can occur (Sections 8.11, 9.4, and 10.3). This current can be large in round rotor windings and strip-on-edge salient pole windings where the copper conductors are bare and the insulation is just slot liners or barriers.

4. *The Absorption Current*. This is a current that is hard to conceptualize. The current is partly due to the reorientation of certain types of polar molecules in the applied DC electric field. Many practical insulating materials contain polar molecules that have an internal electric field due to the distribution of electrons within the molecule. For example, water molecules are very polar. When an electric field is applied across water, the H_2O molecules all align, just as magnetic domains become aligned in a magnetic field. The energy required to align the molecules comes from the current in the DC voltage supply. Once the molecules are all aligned, the current stops. This current is the polarization current, which is one component of the absorption current. There are many polar molecules in asphalt, mica, polyester, and epoxy. In addition to molecular realignment, currents may arise in high voltage-laminated insulation (such as in high voltage stator groundwalls), due to electron trapping at interfaces between layers of tape. Experience shows that after a DC electric field is applied, the absorption current is first relatively high, and decays to zero after about 10 min for modern high voltage groundwall insulation. In contrast, magnet wire insulation has relatively few polar molecules and no effective interfaces, and thus has a low absorption current. In all practical respects, the absorption current behaves like an RC circuit with a long time constant. The absorption current, like the capacitive current, is neither good nor bad. It is merely a property of the insulation materials.

The total current I_t is the sum of all these current components. Unfortunately, we cannot directly measure any of these component currents.

The currents that are of interest, as far as a winding condition assessment is concerned, are the leakage and conduction currents. If just R_1 is measured (after 1 min), the absorption current is still nonzero. However, if the total current is low enough, R_1 may still be considered satisfactory (see Section 15.1.3). Unfortunately, just measuring R_1 has proved to be unreliable, as it is not trendable over time. The reason is that IR is strongly dependant on temperature. A 10°C increase in temperature can reduce R_1 by 5–10 times. Worse, the effect of temperature is different for each insulation material and type of contamination. Although some "temperature correction" graphs and formulae are available to enable users to "correct" R_1 to a common 40°C temperature [1], they are unreliable. The result is that every time R_1 is measured at different temperatures, one gets a completely different R_1 corrected to 40°C. This makes it impossible to define a scientifically acceptable corrected R_1 from measurements over a wide range of temperatures. It also makes trending R_1 almost useless, unless one can be sure the measurement temperature is within a small variation.

The PI was developed to make interpretation less sensitive to temperature. Equation 15.1 shows that the PI is a ratio of the IR at two different times. If we assume that R_{10} and R_1 were measured with the winding at the same temperature, which is usually very reasonable to assume, then the "temperature correction factor" will be the same for both R_1 and R_{10} and will be canceled out. Thus, the PI is relatively insensitive to temperature. Furthermore, the PI effectively allows us to use the absorption current as a "yardstick" to see if the leakage and conduction currents are excessive. If these latter currents are much larger than the absorption current, the ratio in Equation 15.1 will be about 1. Experience shows that if the PI is about 1, the leakage and conduction currents are large enough that electrical tracking will occur. Conversely, if the leakage and conduction currents are low compared to the absorption current after 1 min, the PI will be greater than 2, and experience indicates that electrical tracking problems are unlikely. Thus, if we can see the decay in the total current in the interval between 1 min and 10 min, this decay must be due to the absorption current (as the leakage and conduction currents are constant with time), with the implication that the leakage and conduction currents are minor.

Some users define ratios other than the 1- and 10-min ratio in Equation 15.1. For example, 10 s/1 min or 30 s/5 min are other times that the IR is measured to define a ratio. Such tests can be performed more quickly than the normal PI. The problem with these other ratios is that there is little agreement on what constitutes an acceptable ratio. Thus, unless one has an extensive database, interpretation is more difficult.

15.1.2 Test Method

The IR and PI can be measured with a high voltage DC supply and a sensitive ammeter. The DC supply must have a well-regulated voltage, otherwise a steady-state capacitive charging current will flow ($I = C\mathrm{d}V/\mathrm{d}t$). The ammeter must measure currents smaller than a nanoamp. There are several special-purpose "megohmmeters" available commercially. A megohmmeter incorporates a regulated DC supply and an ammeter that is calibrated in megohms. Modern instruments can apply voltages up to 10 kV DC, and measure resistances higher than 100 GΩ (100,000 MΩ).

For stator windings, the test is best done right at the machine terminals, preferably one phase at a time, with other equipment such as cables and instrument transformers disconnected. This is relatively easy in generators; however, these test conditions can be difficult to achieve in motors. Motor leads in the motor terminal box would have to be untaped and disconnected, which is often tedious. Also, the neutral ends of each phase are usually not accessible in motor stator windings; thus, all three phases are tested at the same time. These difficulties have led many maintenance personnel to test the motor stator winding from the switchgear (motor control center or MCC). In this situation, the IR of the cable insulation (and especially the cable terminations) is in parallel with the stator winding. If failing readings are obtained, the IR/PI test must be repeated at the motor terminal box, with the cables disconnected from the motor. However, if the readings are good, it implies that both the cables and the stator winding have good results.

If the motor or generator is equipped with surge capacitors, they must be disconnected prior to the IR/PI test. This can be done by disconnecting the high voltage leads to the capacitor, or by temporarily isolating the low voltage side of the capacitors from ground. Surge capacitors usually have a 10 MΩ or so discharge resistor within the capacitor case. This resistor will yield a low IR and a PI of 1 if the surge capacitor is not disconnected from the stator terminals.

For direct-water-cooled stator windings, R_1 and the PI will be significantly reduced if the stator is measured with the water in place. Ions in the water will move under the influence of the DC electric field. In addition, electrochemical reactions may occur in the water, releasing hydrogen, with the high DC voltage that is applied. Thus, it is advisable to do the test only after the water has been drained and a vacuum drawn for several days to dry out the cooling water channels. This considerably complicates the test on direct-water-cooled stators; therefore, many users no longer do this test on such machines.

For rotor windings, the test is done at the slip rings. Carbon dust from the brushes tends to accumulate around the slip rings, and so this is the first location to clean if a low IR is encountered on the stator winding. If a brushless type of exciter is tested, the winding must first be disconnected from the rotating diode rectifier to allow this test to be performed.

The IR/PI test will depend strongly on the humidity. If the winding temperature is below the dew point, there is no way that R_1 or PI can be "corrected" for the humidity. If the results are poor, the test must be repeated with the winding temperature above the dew point. It will probably be necessary to heat the winding by circulating hot air or passing current through the winding for hours or days to dry off the moisture that has condensed on it.

Revisions of IEEE 43 since 2000 suggest that the test voltages be higher than recommended in the past, because tests at higher voltages are more likely to find major defects such as cuts through the insulation in stator end windings. Note that the test voltages are still well below the rated peak line-to-ground voltages of the windings. Thus the IR/PI test is not a "hipot" test (see Section 15.2). Table 15.3 shows the test voltages suggested in IEEE 43.

TABLE 15.3 Guidelines for DC Voltages to be Applied During IR/PI Test

Winding Rated Voltage (V)[a]	Insulation Resistance Test Direct Voltage (V)
<100	500
1000–2500	500–1000
2501–5000	1000–2500
5001–12,000	2500–5000
>12,000	5000–10,000

[a]Rated line-to-line voltage for three-phase AC machines, line-to-ground voltage for single-phase AC machines, and rated direct voltage for DC machines or rotor windings (from IEEE 43-2014).

After each IR and PI test, the winding should be grounded for at least four times as long as the voltage was applied, that is, 40 min. Premature removal of the ground will cause a high voltage to reappear, due to the time it takes for the molecules to again become random in orientation, and for the space charge to dissipate. Thus, a shock hazard exists that can last for days. In addition, repeat IR/PI tests will be in error if the winding is not grounded for a sufficiently long time.

15.1.3 Interpretation

What constitutes a "good reading" and a "bad reading" depends on the nature of the insulation system and the component (stator or rotor) being tested. Until 2000, the minimum R_1 and the acceptable range for PI was the same for all types of stator winding insulation. However, it has been recognized that the modern insulation materials in random-wound and form-wound stators have essentially no conduction current (as long as there are no cracks or pinholes). Thus, it is possible for a clean, dry, form-wound stator winding to have an R_1 that is essentially infinite, that is, greater than 100 GΩ. With an R_1 of infinity, calculations of a realistic PI are dubious. Such high R_1's are not likely in asphaltic mica insulation or older polyester-mica insulation. Consequently, the maintenance person needs to establish the type of insulation used in the winding, or at least the approximate age of the winding, before interpreting IR and PI results.

Generally, if the PI is about 1 for form-wound stator windings, the winding is wet or contaminated. If PI is greater than 2, it is clean and dry.

Table 15.4 summarizes how to interpret IR results in rotor and stator windings. The distinction between older and modern insulation systems was set at 1970, although this is somewhat arbitrary. Of note in this table are the following:

- If R_1 is below the indicated minimum, the implication is that the winding should not be subjected to a hipot test, or be returned to service, as failure may occur. Of course, if historical experience indicates that a low R_1 is always obtained

TABLE 15.4 Recommended Minimum Insulation Resistance Values at 40°C (All Values in MΩ)

Minimum Insulation Resistance after 1 min	Test Specimen
kV+ 1	For most windings made before about 1970, all rotor windings, and others not described below
100	For most stator windings built after about 1970 (form-wound coils)
5	For most machines with random-wound stator coils and form-wound coils rated below 1 kV

kV is the rated machine terminal-to-terminal voltage, rms kV.

From IEEE 43-2014.

on a particular winding, the machine can probably be returned to service with little risk of failure.

- The minimum R_1 is the value corrected to 40°C. Unfortunately, that correction is unlikely to be valid.
- The minimum acceptable R_1 is much lower for old stators than new stators, and it depends on voltage class. For modern stators, the minimum acceptable R_1 depends only on whether it is a form-wound or random-wound stator.
- For modern form-wound stators, if a very high R_1 is measured (say >5 GΩ), PI is not likely to indicate anything about the winding, as the resistance is likely inaccurate due to the very small current being measured. Thus, one can save time by aborting the test after the first minute of testing.
- If the R_1 or P1 is below the minimum in a modern stator winding, it is only an indication that the winding is contaminated or soaked with water.
- If a high PI result is obtained on an older stator winding (say >6), there is a possibility that the insulation has suffered thermal deterioration. This occurs because thermal deterioration fundamentally changes the nature of the insulation and, thus, the absorption currents that flow. The insulation has changed in an asphaltic mica winding if the asphalt has been heated enough to flow out of the groundwall.
- Rotor windings generally have a lower PI and R_1 than stator windings, because the insulation is thinner and there is much more surface area. In round rotor and salient pole strip-on-edge windings, there is often exposed copper, making leakage currents much higher.

In general, the IR/PI test is an excellent means of finding windings that are contaminated or soaked with moisture. Of course, the test is also good at detecting major flaws where the insulation is cracked or has been cut through. In form-wound stators with thermoplastic insulation systems, the test can also detect thermal deterioration. Unfortunately, there is no evidence that thermal deterioration or problems such as loose coils in the slot can be found in modern windings [1].

15.2 DC HIPOT TEST

The DC hipot test is an over-potential test that is applied to stator windings of all types. Hipot is a short form for high potential. In this test, a DC voltage that is substantially higher than that of the peak AC voltage that occurs in normal operation is applied to the winding. The basic idea is that if the winding does not fail as a result of the high voltage, the winding is not likely to fail anytime soon due to insulation aging when it is placed in or returned to service. If a winding fails the DC hipot test, repairs or a rewind are mandatory, as the groundwall insulation has been punctured. Stator windings are required to pass a hipot test after manufacture (often called a *commissioning* or *acceptance hipot*). Many end users also perform a reduced voltage hipot test on stators that have been in operation (often called a *maintenance hipot*). Synchronous rotor windings are required to pass an AC hipot after manufacture. However, virtually no end user appears to do a DC or AC hipot on a rotor winding once it has been placed into service unless it has been rewound or a major overhaul has occurred.

An alternative to the DC hipot test is the AC hipot test, discussed in Section 15.6.

15.2.1 Purpose and Theory

The purpose of this test is to determine if there are any major flaws in the groundwall insulation before a winding enters service or during service. The principle is that if there is a major flaw in the insulation, a high enough voltage applied to the winding will cause insulation breakdown at the flaw. By IEC 60034-1, IEEE/ANSI C50.12, IEEE/ANSI C50.13, and NEMA MG1 standards, all new windings (original or rewound) must pass a hipot test prior to being accepted by the customer.

Of course the main problem with hipot testing (both DC and AC, see Section 15.6) is that the winding may fail. If failure does occur, either the insulation that punctured must be replaced, the coil with the puncture is removed from the circuit, or the coil or even the complete winding is replaced. These are all expensive alternatives and all involve a delay in placing the machine in service.

As a hipot test can be destructive and delay a return to service, many plants do not perform a maintenance DC hipot (i.e., a hipot on a winding that has seen service). The rationale for this is that the hipot test may cause a failure that would not occur for a long time in service, resulting in rewinding or significant repairs before they are really needed. This is true. However, the proponents of hipot testing argue that for many critical machines, an in-service failure (that could have been prevented if a hipot test had been done) can result in a greater disruption to plant output than a hipot failure. For example, the in-service failure of a critical pump motor in a petroleum refinery can stop production for days or weeks, and cost as much as a million dollars per day. Also, an in-service fault can sometimes cause collateral damage such as stator core damage, a fire, or coils being ejected from the slot, resulting in much higher repair costs. Thus, whether a DC hipot is performed as a maintenance test depends on how critical the machine is to the plant, the availability of spares, and the philosophy of plant management to avoid unexpected plant shutdowns. A recent survey of North American motor operators indicated that between 50% and 75% of them perform maintenance hipots, and the DC hipot is more common than the AC maintenance hipot [2].

There are important differences between a DC and an AC hipot test. These are discussed in Section 15.6.

15.2.2 Test Method

There are several methods for performing a DC hipot test. Most are reviewed in IEEE Standard 95 [3]. Some of the variations reduce the risk of a failure during the test, and some also give information of a diagnostic nature. IEC does not have a guide for winding DC hipot testing.

For all types of DC maintenance hipot test methods, the critical decision to be made concerns the maximum test voltage. For form-wound stator windings, IEEE 95 gives guidance. It suggests that the maintenance hipot should be as high as 75% of the acceptance hipot level. NEMA MG1 and IEC 60034-1 stipulate that the DC acceptance hipot should be 1.7 times the AC hipot acceptance level of $(2E + 1)$ kV, where E is the rated rms phase-to-phase voltage in kilovolts of the stator winding. The original rationale for the 1.7 factor was that DC breakdown tests in the 1950s on stator groundwall insulation seemed to be about 1.7 times higher than the AC breakdown voltage. More recent testing has not confirmed that the 1.7 ratio is always valid for epoxy-mica stator windings [4]. However, the IEEE 95 working group has decided to leave the factor at 1.7, as no other ratio seems to have a better experimental basis.

Many users have adopted a DC maintenance hipot level of about $2E$ [2,5]; that is, a 4.1 kV winding would be tested at about 8 kV DC. This level was originally suggested as it approximates the highest likely overvoltage that can occur in the stator if a phase-to-ground fault occurs in the power system. Consequently, a maintenance hipot test just reproduces, in a controlled, off-line manner, the overvoltage a stator can see in service. The idea here is that if the winding can survive this hipot test, it is unlikely to fail in service due to a voltage surge created by a power system fault.

In general, it is better to isolate the phases from one another in a stator winding hipot test. The hipot is applied to each phase in turn, with the other two phases grounded. Energizing each phase separately ensures that there is at least some electrical stress between coils in the end winding, so flaws in the end winding are more likely to be detected. In 3.3 and 4.1 kV motor stators, it is usually not possible to isolate the phases: therefore, the DC hipot test energizes all three phases at the same time. Because there is no potential difference between coils in the end winding, end winding problems that are distant from the core are not detected in the three-phase test.

All winding-temperature detectors should be grounded before this test is performed, especially on windings rated less than 6 kV, which are unlikely to have a semiconductive coating in the slot.

If the DC hipot test is performed on a direct water-cooled winding, the water should be drained from the stator. The high voltage DC may cause hydrogen to be created from any water left in the Teflon™ hoses at the end of each bar. The Teflon hoses will also be prone to tracking.

It is prudent to always perform an IR/PI test prior to a DC hipot test (Section 15.1). If the winding is wet or contaminated, which will be discovered by the IR/PI test, one should not perform the DC hipot test until the winding is dried and/or cleaned. Performing a hipot test on a wet or contaminated winding may unnecessarily puncture the insulation, greatly increasing the amount of effort needed to repair the winding.

In contrast with an AC hipot test (Section 15.6), the DC hipot test does not age the winding insulation, as partial discharges occur very infrequently under DC voltage. Thus, if the winding passes the DC hipot test, the insulation has not been deteriorated in any way by the test [5]. However, one should be aware that if the DC hipot test is done from the switchgear, and if the power cables have been soaked in water for years, the DC hipot might age and even cause the power cables to fail. This occurs because power cables rated 2300 V and above often fail by a mechanism called *water treeing*. A DC potential accelerates water treeing. If the cables have always been kept dry, DC hipot testing should pose no risk to the cables.

Hipot testing poses a risk of electric shock to the test personnel. Even after the winding has been grounded for many hours after a DC hipot test, if the ground is removed, residual polarization can cause the copper conductors to jump up to a high DC voltage. Appropriate safety procedures are needed [3].

There are several alternative DC hipot test methods, as described in the following.

Conventional DC Hipot Test In the conventional maintenance DC hipot test, a suitable high voltage DC power supply (available from many suppliers) is connected to the winding, either at the switchgear or at the machine terminals. The DC supply is compact, usually weighs less than 10 kg, and can be plugged into any 120/220 V AC output. The DC voltage is quickly raised to the test voltage and held for either 1 min or 5 min. After this time, the voltage is quickly lowered and the winding is grounded. If the insulation is sound, there will be no high current surge, and the power supply circuit breakers will not trip. If the power supply breaker trips, it is likely a puncture or flashover has occurred, as the IR will have instantaneously dropped to zero, which causes an "infinite" current to flow (by Ohm's law), and the power supply cannot deliver this "infinite" current. Circuit breaker tripping is an indication that the winding has failed and winding repairs or replacement are required. The conventional test has little diagnostic value, although one can measure the DC current after the 1- or 5-min application of the test voltage. If one trends the leakage current over the years, an increasing trend is an indication that winding contamination is occurring.

Step-Stress Hipot Test This is also called the *progressive stress test*. A variation is to use the same power supply as described previously and gradually increase the voltage in either equal or unequal steps. For example, the DC voltage can be increased in 1 kV steps, with each voltage level being held for 1 min before it is increased again. One then measures the DC current after the end of each step (as by this time the capacitive current will have dropped to zero), and plots it on a graph of current versus DC voltage. Ideally, the plot will be a line with a gentle upward curve. However, sometimes the current increases abruptly above a certain voltage. This may be a warning that the insulation is close to puncturing. If the tester acts rapidly, the test can be aborted (voltage turned off) before a complete puncture occurs. Experience shows that warning is likely if the flaw is in the end winding, but little or no warning is given if the flaw is within the slot. By carefully applying this test, a hipot failure may be avoided. However, if the voltage at which the current instability was detected is below the peak operating voltage, there is a high risk in returning the winding to service without repairs.

In the 1950s, a variation of the step-stress test was developed that replaced the equal time steps with steps of variable duration. This test is often called the *Schleif test*, after its developer [6]. The intention is to make the plot of DC current versus applied DC voltage a straight line by using time durations at each voltage step that linearize the absorption currents discussed in Section 15.1.1. This makes any abrupt increase in current easier to identify, further increasing the probability of detecting a flaw before puncture occurs. In addition, the test usually takes a shorter time to complete than the stepped-stress test discussed previously. More details on applying this test are in Reference 3. The Schleif test was developed at the time when asphaltic mica groundwall insulation was present in most machines.

DC Ramp Hipot Test A third variation of the DC hipot is called the *ramp test*. In this case, the DC voltage is smoothly and linearly increased at a constant rate, usually 1 or 2 kV/min. Thus, there are no discrete steps in voltage or current. The current versus voltage plot is automatically graphed and displayed. By increasing the voltage as a constant ramp, the capacitive current is a constant current ($I = C\mathrm{d}V/\mathrm{d}t$, with $V = rt$; r being a constant, and t being the time), which can be easily ignored, unlike in the stepped-stress test. The primary advantage of the ramp test is that it is by far the most sensitive way to detect that a current instability due to an incipient fault is occurring, as the capacitive charging current is not changing with time. Consequently, the ramp test is the method most likely to enable the user to avoid a puncture [7,8]. As described in Reference 8, the test may also enable the detection of such conditions as groundwall delamination. Figure 15.1 shows an example of a ramp test output with an instability that may indicate an imminent groundwall insulation failure.

15.2.3 Interpretation

Fundamentally, the DC hipot test is not a diagnostic test that gives a relative indication of the insulation condition. Rather it is a go-no go test; the winding is in good condition if it passes, and in severely deteriorated condition if it fails. However, the DC current measured at the time of the test can give some qualitative indication of condition, much as the IR test does. Specifically, if the current at any particular voltage increases monotonically over the years, it is an indication that the IR is decreasing and the winding is gradually getting wetter or becoming more contaminated. However, caution is needed when trending the current over time. The current is very dependent on winding temperature and atmospheric humidity. Thus, in most cases the trend is erratic and impossible to interpret. When a hipot failure has occurred, and the location of the puncture is not obvious, if the DC source can supply a fault up to about 1 mA, an infrared thermal imaging camera can sometimes be used to pinpoint the fault.

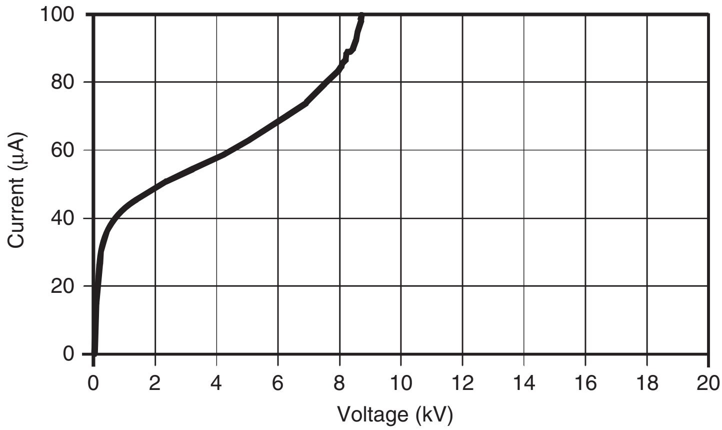

Figure 15.1 Example of a ramp test output. Once the DC voltage exceeds about 5 kV, there is a departure from linearity. This can indicate that the groundwall has a risk of imminent puncture, especially at about 9 kV. (Source: Plot courtesy Iris Power-Qualitrol).

15.3 POLARIZATION/DEPOLARIZATION CURRENT (PDC)

The PDC test is a relatively new off-line DC test primarily intended for stator windings. A DC voltage is applied for 10–20 min while measuring the DC current. Then the winding is grounded via the PDC instrument and the discharge (or more correctly the depolarization) current is measured. In addition to detecting contamination problems, proponents claim the PDC test can also detect problems such as delamination of the thickness of the groundwall insulation [9–11]. At present, there is no IEEE or other test standard that gives guidance on the PDC test, although one is in development.

15.3.1 Purpose and Theory

As discussed in Section 15.1, the IR/PI test is not sensitive to the condition of the bulk of modern stator winding groundwall insulation. The PDC test is a DC test which does seem to have sensitivity to bulk insulation degradation, for example, delamination caused by thermal deterioration (Section 8.1). This may be a considerable advantage, because, as discussed in Sections 15.6–15.12, normally only AC tests can detect bulk insulation deterioration.

In the PDC test, a DC voltage of up to 10 kV is applied for 10 or more minutes between the winding and a stator core, while simultaneously measuring the "polarization" current. The winding is then discharged through the PDC instrument, and the "depolarization" current is measured. During the voltage application, the insulation is said to be polarizing, that is, charge is moving to the interfaces between insulation tape layers and polar molecules in the groundwall are reorienting in the applied electric field. This is the same as discussed for the PI test (Section 15.1). During the discharge cycle, a reverse current flows and the molecules gradually become disoriented and the space charge dissipates. This is referred to as the *depolarization cycle*. The relatively long time while both the voltage is applied and the winding is discharged allows the current to "probe" the molecular condition of the insulation system. Ideally, the polarization and the depolarization currents should be identical (after accounting for the reversal in polarity).

Although PDC measurements have been researched for many years, in the past decade there has been considerable attention to its application in rotating machine insulation diagnosis. Researchers have indicated that different failure processes have different characteristic PDC plots [9–11]. For example, end winding contamination is easily detected by PDC, as one would expect considering the ability of the IR and PI tests to find this problem. As surface leakage currents will not flow during the depolarization cycle (because no voltage is applied), any difference between the polarization and depolarization plots versus time implies that the difference between the plots is due to contamination of the stator end winding. Of greater interest, damaged stress relief coatings or thermal deterioration leading to insulation delamination can also apparently be identified by the nature of their PDC plots.

15.3.2 Test Method

In the PDC test, a stable, high voltage DC voltage (up to 10 kV) is applied to the isolated stator winding (the complete winding or a single phase). The voltage is applied for 1000–2000 s—while recording the current. Then, the stator winding is shorted to ground via the PDC test device, and again the current is measured. The test can be performed with a very stable DC power supplied and a sensitive DC current meter or electrometer. Otherwise a PDC instrument is available. PDC instruments will automatically invert the discharge current and plot both the charge and discharge current on the same plot to facilitate comparisons between the two currents.

15.3.3 Interpretation

As an example, see the PDC plot in Figure 15.2. It shows the charging and discharging current as two different plots on a graph of current versus time. The time is the number of seconds since the voltage was applied for the polarizing cycle, and the time since a short was applied for the depolarizing cycle. Typically the depolarizing current is assigned a positive current, even though it is really the opposite polarity to the polarizing current. This facilitates the comparison of the polarizing and depolarizing current.

Clear guidance on interpretation has not been standardized. With regard to interpretation, a difference in the polarization and depolarization plots indicates there is an insulation problem.

15.4 DC CONDUCTIVITY

The DC conductivity test is a means of finding if the copper strands in the stator winding coils or associated circuit ring buses are broken or cracked; if the conductors in insulated rotor windings are cracked or broken; or if the brazed or soldered connections in either type of winding are deteriorating. In addition, if the test is done from the

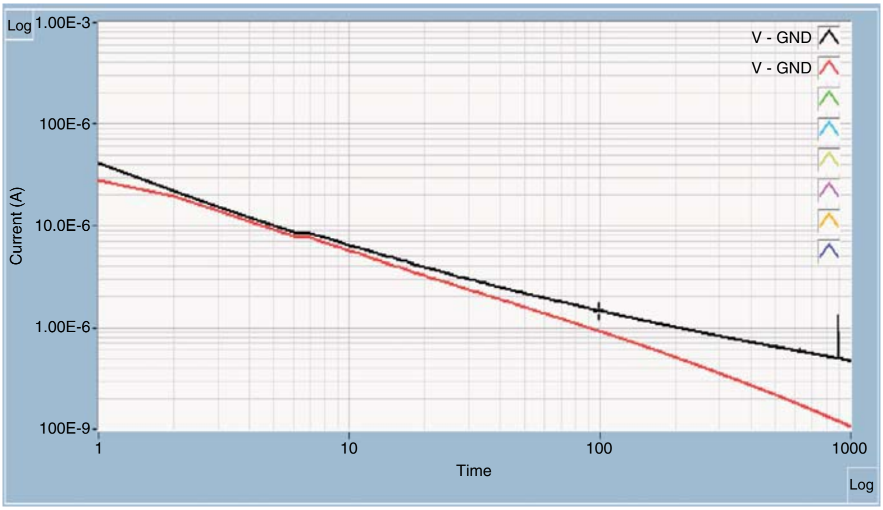

Figure 15.2 Example PDC plots where the upper (black) line is the polarization current and the lower (red) line is the depolarization current. The difference in the plots is attributed to insulation deterioration. (Source: Iris Power-Qualitrol).

switchgear, one can sometimes detect loose bolted cable connections in the machine terminal box. An alternative or complementary test to detect poor connections is to circulate a high current and look for hot spots, as discussed in Section 15.5.

15.4.1 Purpose and Theory

If the copper conductors in the rotor or stator winding crack or break, the DC resistance between the terminals of the winding will increase, due to the reduced copper cross section that must pass the current. There are several reasons for the resistance to increase:

- Stator winding end winding vibration (Section 8.15) can fatigue crack copper strands.
- Operating events such as an out-of-phase synchronization can put such a high magnetic force on coils that the copper cracks or breaks at connection points.
- Stator or rotor winding connections between coils or to buses may be poorly brazed, soldered or connecterized (Section 8.17). This gives rise to local heating that oxidizes the connection, further increasing the temperature and increasing connection resistance.
- Stator winding leads may be poorly bolted or brazed to the power system bus or cables.
- High centrifugal forces may crack copper conductors on the rotor.
- There may be shorted turns in insulated rotor windings.

Cracked strands or high resistance connections ultimately lead to failure due to thermal deterioration of the insulation (Sections 8.1, 9.1, and 10.1).

It is best to use DC rather than AC current to measure the resistance, except for detecting shorted turns in insulated rotor windings (Section 15.25). An AC measurement will be sensitive both to the resistance and the inductive reactance of the winding. The reactance can be modified by changes in the magnetic permeability near the machine and, thus, by rotor position; the amount of enclosure disassembly (if any); or even if the machine is adjacent to large objects made of magnetic steel. Consequently, unless one can guarantee the magnetic environment from test to test, AC measurements make it hard to trend the conductor resistance.

15.4.2 Test Method

The DC resistance (or conductance) is measured by passing a DC current through a winding and measuring the voltage across the winding. The resistance is the voltage divided by the current. The resistances of a stator or rotor winding are very low, ranging from just less than 1 Ω for small machines to less than a milliohm for a large machine. To accurately measure the resistance at such low values requires either a four terminal measurement, a bridge type of measurement, for example, a Kelvin bridge or a digital low resistance ohmmeter (DLRO) instrument. There are many commercial instruments in the market to measure such low resistances. The measuring instrument should have an accuracy of at least 1% to detect winding problems.

For a stator winding, it is best to measure each phase individually between the phase terminal and the neutral terminal in the same phase. If a motor stator winding is measured, it is often not possible to isolate the three phases. Instead, a measurement is made between the phase terminals, that is, three measurements: A-B, B-C, and C-A. If resistance between phases is measured on motor stators from the switchgear (MCC), the resistance of the connections of the power cables to the stator is also measured. As the connections between the power cables and the motor leads are often troublesome, this is very desirable. However, if the power cable length is long, there will be less sensitivity to incipient conductor cracks in the stator winding itself. Rotor winding resistance can be measured between the slip rings.

The DC resistance is strongly affected by the temperature of the stator winding; that is, as the winding temperature increases, so does the resistance. Thus, to trend the resistance in a winding over the years, temperature correction is needed. To correct a copper resistance R_T measured at temperature T to the resistance R_{20} at 20°C:

$$R_{20} = \frac{R_T}{1 + (T - 20)/234.5} \tag{15.3}$$

Humidity has no effect on the winding DC resistance.

15.4.3 Interpretation

Resistance measurements are easiest to interpret by comparisons between phases, comparisons to other identical machines, or by trending the measurement (corrected for winding temperature) on the same winding over time.

For a stator winding, the resistance of each phase (or resistance of the phase-to-phase winding in a motor) should be compared. All three resistances should be within 1% (for form windings) and 3% (for random windings) of each other (or the accuracy of the measurement instrument). If one of the phase resistances is high, it may be an indication that a strand is broken or that there is a bad connection on that phase, etc.

If there are several identical machines with identical rotor and stator windings, all windings should have a resistance that is within about ±5% of one another. If a winding has higher resistance than the others, perhaps it has a winding problem. Note that a rewound winding is not likely to have exactly the same resistance as the original winding, but resistance balance between phases should meet the criteria indicated earlier.

Trending the resistance of a winding over the years is perhaps the most useful way to find a developing problem such as cracking conductors or deteriorating joints. To make the trend meaningful, the resistances must be corrected to the same temperature, using Equation 15.3. If the corrected resistance increases by more than 1%, problems may be occurring. It is prudent to use the same measurement instrument over the years to achieve the best sensitivity. Frequent calibration of the instrument is also needed.

As could be expected, it can be difficult to find cracked strands or one bad joint if a stator or rotor winding has many parallel circuits. Also, high resistance joints or cracks may appear very quickly. Therefore, a test every year or so is unlikely to catch rapidly developing problems. To locate the high resistance joints, the test in Section 15.5 using an infrared camera at the same time current is flowing through the winding can be effective, and in fact it may be more sensitive than the DC resistance test.

15.5 POOR CONNECTION HOT SPOT (HIGH CURRENT-INFRARED CAMERA)

As many plants have access to infrared thermal imaging cameras, an alternative method to that in Section 15.4 to identify if there are poor electrical connections or cracked copper conductors in rotor and stator windings is to circulate a high current and look for hot spots using a thermal imaging camera. This method is often more sensitive to poor connections than the DC conductivity test, especially if there are many parallel circuits in the winding. In addition, the hot spots can be located, which is not possible with the DC conductance test unless the winding is sectionalized. A disadvantage of this test is that the winding must be visible, thus significant disassembly of the machine is needed, as compared to the DC conductivity test.

15.5.1 Purpose and Theory

If a high DC or AC current flows through copper, any areas of high resistance will generate extra I^2R losses, which in turn raise the temperature at the location of high resistance. If the copper conductors are bare and visible (for example, in a strip-on-edge salient pole rotor winding or a squirrel-cage induction motor rotor bar), this rise in temperature will be immediately visible using an infrared thermal imaging camera. If the conductors are insulated as in most stator windings, it will take from 15 to 60 min for the higher temperature to manifest itself on the insulation surface. Modern infrared imaging devices can indicate the hotspot temperature and the ambient temperature of the winding.

15.5.2 Test Method

Prior to the test, the windings must be exposed, requiring some disassembly. Rotors should be removed from the machine. For stators, the end windings and all series connections should be visible. A suitable current source is required. It can be either AC or DC. One of the more common supplies used for larger motors and generators is a welding machine. Alternatively, a core loss tester can supply an AC current. For smaller machines, a large variac (variable AC autotransformer) supplied from 120/220 V AC can be used. One must be careful to circulate a current that is no more than about 50% of full load current for the rotor or stator winding being measured, as there is no forced cooling air flow over the winding as occurs in service. The current should circulate for no more than 1 h, again to minimize the risk of overheating the insulation.

A modern thermal imaging camera is swept over the winding immediately after the current is applied.

15.5.3 Interpretation

Most modern thermal imaging cameras can detect temperature differentials as small as 1°C. Any winding component 5°C or more warmer than another component may have a high resistance connection. If such a location is at or near a series connection or connection point, it is possible that the hot spot is caused by a poor connection or a cracked copper strand.

15.6 AC HIPOT

The AC hipot test is similar to the DC hipot test (Section 15.2), with the exception that power-frequency (50 or 60 Hz) voltage is used. Sometimes 0.1 Hz AC (also called *very low frequency* or *VLF*) is also employed. Both commissioning (acceptance) and maintenance (after the machine has seen service) AC hipot versions of the test are in use. This test is most commonly applied to form-wound stator windings. A variation on the commissioning test is a reduced AC voltage hipot test that is performed when a stator winding is submerged under water or soaked by water. This “sealed” winding hipot test is to ensure that the stator winding is sealed against moisture ingress (see the 2011 version of NEMA MG1). The maintenance AC hipot is rarely used in North America, but does find more widespread application in Asia and Europe.

15.6.1 Purpose and Theory

Most of the description given for the DC hipot test (Section 15.2) is relevant to the AC hipot test. Specifically, it is a go-no go test that ensures that major insulation flaws that are likely to cause an in-service fault in the near future can be detected in an off-line test.

The major differences between the DC and AC tests are the test voltage applied and the voltage distribution across the groundwall insulation. With DC voltage, the voltage dropped across insulation components within the groundwall and in the end winding depends on the resistances (resistivity) of the components. Components with a lower resistance will have less voltage dropped across them. In contrast, the AC voltage dropped across each component in the groundwall or in the end winding depends on the capacitance (dielectric constant) of each component. Thus, there tends to be a completely different electric stress distribution across the groundwall thickness between AC and DC tests. In older insulation systems, particularly asphaltic mica systems, the differences between the AC and DC stress distributions were less pronounced due to the absorption of moisture and thus the lower resistivity of the asphalt-mica. However, with modern epoxy-mica insulations, the DC resistivity of the bulk insulation is essentially infinite; thus, the DC voltage may all be dropped across a very thin layer of insulation. Consequently, significant flaws within the groundwall insulation that might cause puncture under AC stress may escape detection with a DC test because of the more uniform voltage distribution across the insulation thickness with AC stress.

For modern windings, the AC hipot test yields an electric stress distribution that is the same as that which occurs during normal operation. Consequently, the AC hipot test is more likely to find flaws that could result in an in-service stator failure if a phase-to-ground fault occurs in the power system, causing an overvoltage in the unfaulted phases. For this reason, the AC hipot is considered superior to the DC hipot, especially with modern thermoset insulation systems.

In the 1950s, there was considerable research on the relationship between AC and DC hipot tests, specifically, the ratio of the DC to AC hipot voltages [12,13]. Eventually, a consensus was reached that, under most conditions, the DC breakdown voltage is about 1.7 times higher than the AC rms breakdown voltage. This relationship has been standardized in IEEE 95 for DC testing. This research was based on older insulation systems and, unfortunately, is largely irrelevant in modern insulation systems, because, as described earlier, the voltage distribution is completely different under AC and DC. There have, however, been a few studies of the relationship between AC and DC breakdown in modern groundwall insulation systems. One of the largest of these studies pointed out that the ratio of DC to AC breakdown voltage on average was 4.3 in epoxy-mica insulation [14]. Other experiments confirmed the unpredictability of the breakdown ratio between AC and DC [5]. The 1.7 factor, then, no longer seems to be valid, but as the variability is so large, no replacement ratio has been proposed. Thus, we are left with 1.7.

NEMA MG1, IEEE/ANSI C50.12, and IEEE/ANSI C50.13, as well as IEC 60034-1, define the AC acceptance hipot level as $(2E + 1)$ kV, where E is the rated rms phase-to-phase voltage of the stator. IEEE 56 recommends the AC maintenance hipot for stator windings should be 1.25 to 1.5*E* [15]. The AC hipot for a 4.1 kV rated motor that has seen service is about 6 kV rms, applied between the copper conductor and the stator core.

The sealed stator winding AC hipot test is described in NEMA MG1-2011, Part 20. End users may specify this test be done on a new or rewound stator that has a high probability of being exposed to moisture and/or partly conductive contamination. As the stator is immersed in or sprayed with water, a lower hipot voltage of 1.15*E* is used. The test is particularly good at detecting poorly impregnated groundwall insulation, and taping issues where the leads leave the body of the coil in multiturn coils. Well-impregnated global vacuum-pressure-impregnated (VPI) stator windings should have no problem passing this hipot test. This test should not be done with DC voltage, as it may generate hydrogen gas and lead to rapid surface tracking of the stator insulation.

NEMA MG1 and IEC 60034-1 also define the acceptance AC hipot for synchronous rotor windings. For rotor windings rated less than 500 V_{dc}, the AC hipot is 10 times the rated DC voltage. Thus a 300 V_{dc} rotor is hipot tested to 3 kV AC, rms for the acceptance test. For rotors rated >500 V, the AC hipot is two times the rated voltage plus 4000 V_{rms}. The relatively high AC hipot levels for a new rotor winding reflect what transient voltages the rotor insulation may experience in service, plus a safety factor [16]. There is no equivalent DC hipot for new rotors as the overvoltages in service are most likely to be AC coupled from the stator winding. There is no standard that suggests either a DC or AC maintenance hipot test for rotors, and based on informal surveys, it seems at least utility users have little interest in such a maintenance rotor winding hipot test. The reasons are unclear, but it may be due to the high level of contamination a rotor might see once it is in service, and/or the fact that a single ground fault of a rotor winding does not necessarily mean the motor or generator must be immediately removed from service (unlike a ground fault in a stator winding).

There normally is no diagnostic information obtained from the AC hipot test. A winding usually either passes the test or it fails because of a puncture. Although the current needed to energize the winding can be measured, this current contains little practical information, unless the winding is saturated with moisture or the insulation has not been cured.

The AC hipot will age the insulation. In most cases, the hipot voltage is sufficiently high that significant partial discharge activity will occur. These partial discharges will tend to degrade the organic components in the groundwall, thus reducing the remaining life. However, if one uses Equation 2.2 in Section 2.1.2, it is apparent that a 1-min AC hipot test at 1.5*E* is equivalent to about 235 h or 10 days at normal operating voltage. Therefore, the life is not significantly reduced by a hipot test if the expected life is about 30 years [5].

15.6.2 Test Method

The key element in an AC hipot test is the AC transformer needed to energize the capacitance of the winding. A 13.8 kV generator stator winding with a capacitance of 1 μF requires a charging current of 8 A at 60 Hz for a 1.5*E* maintenance hipot test.

A minimum transformer rating is 21 kV at 8 A or about 170 kVA. This is a substantial transformer and is definitely not very portable as compared to a DC hipot set. The AC hipot set is also much more expensive than the DC supply. It is because of the size and expense of the AC hipot supply that an AC hipot is rarely performed as a maintenance test in some countries such as the United States.

An alternative to the power-frequency transformer is a “VLF” supply. VLF refers to very low frequency (LF). Such supplies operate at 0.1 Hz. With this low a frequency, the capacitive charging current is 1/500 or 1/600 of the current needed at power frequencies. The current for the winding above would then be only about 13 mA. The VLF supply is then rated at only 275 VA, which is considerably smaller and more practical to move about in a plant. Modern VLF supplies are relatively cost-effective. Research indicates that the voltage distribution across the groundwall insulation is essentially the same as at power frequency, that is, the capacitances govern the voltage distribution [17]. Thus, the VLF AC hipot has all the advantages of the power-frequency AC hipot described earlier. According to the VLF test standard IEEE 433, a higher voltage is used for the VLF hipot than for the power frequency version [18]. The factor stipulated in IEEE 433 is 1.63 (slightly smaller than the 1.7 factor used for DC testing). As with the DC factor, there is little that substantiates the 1.63 factor. Although the VLF test using modern test sets (for example by Baur or High Voltage Inc.) produce a good sinusoidal waveform, which have found wide acceptance for power cable hipot testing, there has been little acceptance of its use with rotating machines. Perhaps this will change in the future.

As with the DC hipot, it is best to AC hipot test each phase separately, rather than all three phases at the same time, as this will allow more effective detection of any significant flaws in the end winding. The test can be performed at the stator winding terminals or from the switchgear. AC or VLF testing does not age cables that are in good condition. As with the DC hipot test, considerable caution is needed when performing the test, as there is a personnel hazard.

If the stator winding is direct-water-cooled, the water should be drained from the winding. If this is not feasible, the water in the winding should be circulated to ensure the dielectric heating of the water in the Teflon hoses does not cause excessive heating.

The procedure for performing the sealed stator winding hipot test is described in NEMA MG1 Part 20. The stator is either completely submerged in water or thoroughly soaked with water by continuously spraying the entire stator for 30 min. The latter method is used when the stator is too large to be submerged in an available tank. To ensure the water coats the surface, a wetting agent must be added to the water. An IR/PI test is then performed (Section 15.1) and if it is passed, an AC voltage of $1.15E$ applied to the stator (while the stator is still submerged or soaked with water). If the stator winding passes this hipot test, its IR must be $\geq$five times the machine kV plus 5 in megohms after the hipot.

15.6.3 Interpretation

A winding either passes or fails the AC or VLF hipot tests. There is no other diagnostic information provided. If the winding fails, as determined by the power supply circuit breaker tripping or an observed insulation puncture, repairs or coil/bar or winding replacement are required. The maintenance hipot test is often performed at the same times as the tests in Section 15.7–15.12.

15.7 CAPACITANCE

Measurement of the winding capacitance can sometimes indicate problems such as thermal deterioration or saturation of the insulation by moisture within the bulk of the insulation. This test is most useful on smaller random- and form-wound motor stators, or very large direct-water-cooled generator stators that may have water leaks (Section 8.16). When performed, this test is mainly used on stator windings.

Capacitance measurements are also made during manufacturing to determine (i) when the resin has impregnated a coil, bar, or global VPI stator; and (ii) when the resin has cured.

15.7.1 Purpose and Theory

Some deterioration processes involve changes to the winding that fundamentally alter the nature of the insulation. For example, if a form-wound stator deteriorates due to long-term overheating, the groundwall insulation layers delaminate (Section 8.1). Some of the epoxy, polyester, or asphalt has either vaporized (giving the "burned insulation" smell) or, in the case of asphalt, it has flowed out of the groundwall. The result is that the groundwall now contains some gas, usually air. The dielectric constant of air is lower than the dielectric constant of all solid insulation materials. Specifically, the dielectric constant of gas is 1, whereas the dielectric constant of epoxy-mica is about 4. As the percentage of gas within the groundwall increases as a result of thermal deterioration, the average dielectric constant decreases. If the coil in a slot is approximated by a parallel plate capacitor, then, from Equation 1.5 in Section 1.4.4, the capacitance will decrease, as the dielectric constant has decreased.

Similarly, if the insulation bulk has been saturated with water, the capacitance will increase over time. The water may have soaked the insulation because the machine was flooded. In direct-water-cooled windings, the water can come from cracks in the water-filled copper tubes within the stator bar (Section 8.16). As water has a dielectric constant of 80, the presence of water increases the average dielectric constant of the groundwall, increasing the capacitance.

If the end winding of a stator is polluted with a partly conductive contaminant, the ground potential of the stator core partly extends over the end winding. This effectively increases the surface area, A, of the capacitor "plate" (Equation 1.5). Thus, winding contamination will also increase the capacitance.

By trending the change in winding capacitance over time, one can infer if thermal deterioration or problems with moisture or contamination are occurring or not. If the capacitance is unchanged over the years, little deterioration is occurring. If the capacitance is decreasing, the winding is likely to have experienced thermal deterioration. If the capacitance is increasing, perhaps the winding has absorbed moisture from the environment, a water leak has occurred in the winding, or electrical tracking is present. A single measurement of the capacitance has no diagnostic value.

15.7.2 Test Method

The capacitance tests discussed in this section are generally performed at low voltage with commercial capacitance bridges. (Section 15.8 discusses capacitance tests performed at high voltage.) As the amount of gas or moisture within the groundwall is usually a small percentage of the normal insulation mass, the change in capacitance over the years is also very small, even for very significant deterioration. Thus, the measurement device should have a precision of better than 0.1%. Capacitance bridges can easily achieve this precision.

Unfortunately, inexpensive "capacitance meters" are not suited for this application. In general, such meters have a true precision of only about 1%, which is inadequate to detect small changes in capacitance due to thermal deterioration. More importantly, most of these meters work on the principle of applying a voltage pulse through a known resistance to the load capacitance, and measuring the decay time of the capacitive charging current. The capacitance can then be inferred from the charging current time constant. As discussed in Section 15.1.1, stator winding insulation not only has a capacitive charging time constant, but the absorption current also has an apparent charging time constant. The absorption current confuses the capacitance meter, producing a capacitance reading that is much larger than it actually is.

The capacitance of the entire phase or winding can be measured in a "global" measurement. This version of the test determines overall insulation condition. In addition, for the specific problem of stator winding water leaks, the "local" capacitance of a portion of a stator bar is measured. With measurements on all bars, a "capacitance map" is created.

Winding Capacitance Test This test is best performed at the stator winding terminals. If the test is done from the switchgear, the cable capacitance between the switchgear and the stator may dominate the stator winding capacitance. This will make any change in the stator winding capacitance harder to discern. The longer the power cable, the less sensitive the test becomes. With small motors, if the power cables are longer than about 100 m, it is likely that the test results will not be meaningful. Similarly, any surge capacitors connected to the machine must be disconnected to achieve meaningful measurements.

On a generator, the capacitance of each phase can be measured as each phase can be isolated from the others by disconnecting the neutral connections. For most motors, the stator winding phases are connected at the neutral, and this can only be broken with great difficulty. Thus, no matter what phase is measured, the capacitance of all three phases is measured.

It is important to use a calibrated capacitance bridge for these measurements as the results are usually trended over many years, and small changes in capacitance are important. Any drift in the bridge may be mistaken for a problem in the winding. Also, it is prudent to use the same instrument over the years for the measurements.

Capacitance Map When it became apparent that the water leak problem in direct-cooled stators was an important cause of failure (Section 8.16), utilities developed the capacitance mapping technique [19]. In this method, the stator winding is grounded. A small metal plate is then placed over an accessible portion of the end winding, usually near the connections as this is where the water is first likely to collect. The capacitance is then measured between the plate and the (grounded) copper conductor within the stator bar, using a capacitance bridge. The plate is then moved to another bar, and the capacitance to the plate in this bar is then measured. Similarly, the capacitance of the plate at every bar, at both ends of the bar and, possibly, at different axial positions of the bar in the end winding is measured. The result is a map of capacitance versus slot number and axial position. The test is more useful if the dissipation factor (DF) (Section 15.10) is measured at the same time as the capacitance [19]. This is easily done as capacitance bridges measure the capacitance and the DF at the same time.

A statistical analysis of the capacitances is then performed. Specifically, the mean and standard deviation of all the capacitances of all stator bars in a given axial location are calculated. Recent improvements in the method have been aimed at making the measurements more repeatable. These include using a guard electrode to reduce the effect of stray capacitance. Also, a ratioing technique has been developed in an effort to reduce the effect of variable groundwall insulation thickness from bar to bar [20].

15.7.3 Interpretation

For the capacitance measurement on complete phases or windings, the key for interpretation is the trend. A significant amount of thermal deterioration will result in only a 1% drop in capacitance over the years. If the winding has been soaked with water, a significant amount of deterioration may result in about a 5% increase in capacitance. If thermal deterioration or water leak failure processes are occurring at only a few locations, the test is probably not sensitive enough. If the entire winding is affected, the capacitance test is more likely to detect it. This form of the capacitance test assesses the average condition of the insulation.

The trend is less important with the capacitance map version of the test to find bars with water leaks. Instead, one compares the capacitance measured on all the bars in the winding. The bars, that have a capacitance (and DF) higher than the mean plus three standard deviations, are likely to have water in the insulation. Small variations are to be expected because of the variable thickness of the insulation (refer to Equation 1.5).

Coil manufacturers often use the capacitance test to monitor the impregnation and curing process during coil, bar, and global VPI stator manufacturing. Epoxy- and polyester-impregnating resins have a very high dielectric constant when in the liquid state. As they cure, the dielectric constant asymptotically reaches its low value (about 4) as it cures to a solid. When a coil is first impregnated with the liquid resin, its capacitance increases as the resin replaces the air between the mica-paper tape layers. It reaches a high steady-state value when complete impregnation is achieved. During the cure cycle, the capacitance starts to decrease as it cures. With experience, manufacturers can be assured of better impregnation and can determine the optimum cure time by monitoring the initial increase and then decrease of the capacitance.

15.8 STATOR CAPACITANCE TIP-UP

The capacitance tip-up test is a variation of the capacitance measurement on complete stator windings described in the previous section. This test is an indirect partial discharge test, and is closely related to the power factor tip-up test in Section 15.11. This test is only relevant for form-wound stator windings rated 2300 V and above. The test is not widely used in the Americas or Asia, but has been applied in Africa and Europe.

15.8.1 Purpose and Theory

Thermal deterioration, load cycling, and poor impregnation methods can result in air pockets or voids within the groundwall insulation of form-wound stators. If the winding is energized at a sufficiently high voltage, a partial discharge will occur within these voids, ionizing the gas for several milliseconds (Section 1.4.4). The ionized gas has sufficiently high conductivity that the void is "shorted out," that is, it is much like a metal sphere within the void. As part of the distance between the copper and the core is "shorted out" by the PD, the effective thickness of the insulation is reduced, which, by Equation 1.5, increases the capacitance. One void "shorted out" by the PD will have no measurable effect on the capacitance of the entire winding; however, if there are thousands of voids, all undergoing PD, there will be a noticeable increase in the capacitance.

PD only occurs if there are voids and the electric stress within the voids exceeds 3 kV/mm (at 100 kPa). Thus, PD only occurs at high voltage. Measurement of the capacitance at high voltage is not sufficient to detect the voids. Instead, by measuring the capacitance at high voltage and subtracting from this the capacitance at low voltage, the result is the increase in capacitance due to PD activity [21]. Stated differently, the capacitance at low voltage is the normal capacitance of the insulation (voids plus solid insulation). The capacitance at high voltage is the capacitance of the solid insulation alone, as the voids have been "shorted out" by the PD. By taking the difference, one can estimate the capacitance of the voids. The larger this void capacitance, the more deterioration within the groundwall and, presumably, the closer the winding is to failure.

In summary, the capacitance tip-up test measures the total void content within the groundwall.

15.8.2 Test Method

There are no standardized procedures for performing this test. An AC voltage supply is needed that can energize the capacitance of the winding to rated voltage. This can be a conventional transformer, a resonant supply or even a VLF supply (Section 15.6.2). For a large stator at power frequency, 20–30 kVA may be needed. An instrument is also needed that is capable of measuring the capacitance at least at the rated line-to-ground operating voltage of the stator winding. To cover all the machines, the capacitance instrument should be able to operate up to about 25 kV. In addition, the device needs an accuracy of better than 0.1%. There are several types of devices that can meet these requirements. The Schering bridge and the transformer ratio bridge are the most common [22].

The test is best done with the phases isolated from each other, with all terminal equipment such as cables disconnected, as this will increase sensitivity. One phase at a time is tested, with the other two phases grounded. The low voltage capacitance (C_{lv}) is first measured, usually at about $0.2E$, where E is the rated phase-to-phase voltage of the stator. Then the applied voltage is raised to about the rated line-to-ground voltage (about $0.6E$) and the high voltage capacitance (C_{hv}) measured. The capacitance tip-up is

$$\Delta C = \frac{C_{\text{hv}} - C_{\text{lv}}}{C_{\text{lv}}} \tag{15.4}$$

It is usually expressed in percent rather than in Farads. Sometimes the capacitance is also measured at rated phase-to-phase voltage (E) applied between the copper and the core.

15.8.3 Interpretation

The higher the ΔC is, the more voids there are within the insulation. Modern epoxy-mica groundwalls should have a ΔC less than about 1%. Older asphaltic mica windings should have ΔC of less than 3% or 4%. If ΔC is higher than these values, it is an indication that thermal or load cycling deterioration, or poor manufacturing problems are present.

There are some limitations to this method that affect interpretation. The first is that ΔC is a measure of the total void content. There is no indication from the measurement whether there are many thousand tiny voids or whether there are just a few big voids. Of course, the winding is more likely to fail from the few large voids than from many little defects. Thus, the test is more sensitive to the average condition of the winding than to the condition of the worst coil.

The second limitation comes from the effect of the silicon carbide stress layers (Section 1.4.5) on the capacitance measurements. Silicon carbide has a resistance that depends on the applied voltage—at low voltage the layer is fully insulating, whereas at high voltage it is much like a grounded metal plate. When the capacitance is measured at high voltage, the conducting silicon carbide effectively increases the area of the capacitor plates (Equation 1.5), increasing the capacitance. Thus, it is possible for the increase in capacitance at high voltage to be caused by both the PD in the voids as well as by the increase in capacitance due to the silicon carbide coatings. The influence of the silicon carbide coatings can be reduced in tests on individual coils, as the layer's effect on the measurement can be neutralized with a suitable guarding circuit (see Section 15.11). The net effect is that the silicon carbide coating creates a "noise floor," which tends to diminish the effect of voids on the capacitance. For tests on individual coils/bars, the silicon carbide coatings can be guarded out (see Section 15.11).

The best means of overcoming these limitations is to trend ΔC over the years. The initial tip-up test on a complete phase has little meaning, due to the silicon carbide coating effect. However, if ΔC increases monotonically from year to year, perhaps doubling in magnitude, it is an indication of progressive delamination, possibly due to overheating or load cycling.

15.9 CAPACITIVE IMPEDANCE TEST FOR MOTOR STATORS

This is another variation of the capacitance test described in Section 15.7. In reality, the capacitive impedance test is just another way of measuring winding capacitance. We include it as a separate section here because a number of specialized instruments have been introduced for measuring motor stator winding condition. The capacitive impedance is one of the measurements made by some of these specialized motor test instruments.

The relevance of measuring the trend in capacitance of a motor stator winding is discussed in Section 15.7. In that section, the measurement was done with an AC capacitance bridge. The capacitance can also be calculated by an accurate measurement of the current and voltage across a winding, enabling the calculation of the capacitive impedance $X_c = V/I$. Specifically, the capacitance C of a winding is

$$C = \frac{1}{2\,\pi f X_c} = \frac{I}{2\pi f V} \tag{15.5}$$

where f is the frequency in Hertz, and V and I are the measured voltage and current across the winding. Note that all the copper is energized with respect to the core (the other phase leads are open circuit). The frequency can be 50 or 60 Hz, as in some brands of power-factor-measuring equipment, or it can be 10–100 kHz as in some of the modern specialized motor testing instruments. At the higher frequencies, higher currents are measured and the measurement will suffer less from interference due to power-frequency currents. As discussed in Section 15.7, the voltage and current measurements must have accuracy better than 0.1% to produce results that can be successfully interpreted.

In addition to the capacitive impedance, the specialized motor testing instruments may also measure one or more of the following:

- IR and PI (Section 15.1)
- Conductivity (Section 15.4)
- Inductive impedance (Section 15.17)

All these measurements are usually made at relatively low voltage, which can impair effectiveness, especially in the IR/PI test. However, a computer usually automates the measurements, and a summary is made of many important quantities that can be easily trended over time.

15.10 DISSIPATION (OR POWER) FACTOR

DF provides a measure of the dielectric losses within an insulation. Certain deterioration processes, such as thermal aging (Section 8.1) or moisture absorption, will increase these losses. Thus, trending of the dielectric loss over time is an indication of certain types of insulation problems. There are two main ways to measure the dielectric loss: (i) DF ($\tan \delta$) and (ii) insulation power factor. These tests are relevant for stator windings only and are usually applied only to form-wound stators. The test is also employed by some original equipment manufacturers (OEMs) to determine when the resin in newly manufactured coils, bars, or global VPI stators is cured.

15.10.1 Purpose and Theory

Dielectric loss is a property of any insulating material. Ideally, the winding insulation will act as a pure capacitor, that is, it will only store energy, not dissipate it. In practice, the materials used for groundwall insulation will heat up a little when excited by AC voltage, that is, they will dissipate some energy. The cause of the dissipation is primarily the movement of polar molecules under the AC electric stress. As discussed in Section 15.1.1 in connection with the absorption current, common rotating machine insulation materials contain polar molecules that tend to rotate when a DC electric field is applied, giving rise to the absorption current. With power-frequency AC applied, the polar molecules oscillate back and forth as the applied voltage changes from positive to negative and vice versa 50 or 60 times a second. Because the polar molecules are oscillating in a solid medium, the friction created with adjacent molecules (or parts of molecules) gives rise to heat. The energy to cause this molecular heating comes from the applied electric field, that is, from the power supply. The dielectric loss is a property of any particular insulation material and its chemical composition. It is not an indicator of insulation quality.

When the organic parts of an insulation system are exposed to a sufficiently high temperature, some of the chemical bonds within the polymer vibrate with such intensity that they break. If an oxygen molecule is near the broken ends of the polymer chain, a new chemical reaction occurs, with the oxygen forming a bond with the broken ends. This process is called *oxidation* and gradually makes the insulation brittle (Section 8.1). The uptake of oxygen into the polymer tends to create additional polar groups within the insulation. The result is that, as there are more polar molecules, more molecules are available that will oscillate when excited by an AC electric field, thus increasing the dielectric loss. An increase in dielectric loss in a winding over the years may indicate insulation aging due to overheating, or radiation which can similarly break chemical bonds.

In addition, if a winding has been soaked with water, the dielectric loss will increase. This occurs because the H_2O molecules are polar.

15.10.2 Test Method

There are three different ways to measure the dielectric loss. All involve recognizing that the winding is essentially a capacitor with a small dielectric loss.

1. *DF*. The DF is measured with a balanced bridge-type instrument, where a resistive–capacitive network is varied to give the same voltage and loss angle

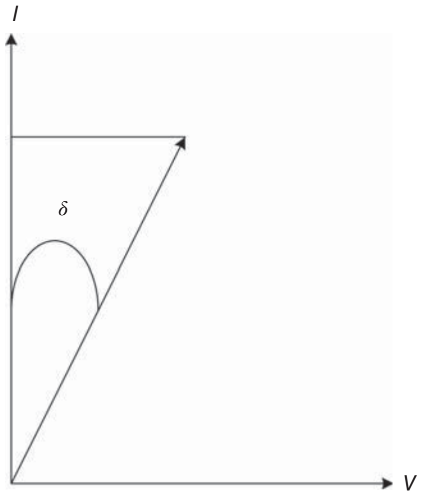

Figure 15.3 Calculation of loss angle for tan δ measurement.

(tan δ) as measured across the stator winding (Figure 15.3). The DF is then calculated from the R and C elements in the bridge that give the null voltage. This method can easily achieve a 0.01% accuracy.

2. *Tan δ*. Another method digitally measures the phase angle between the voltage and the current through the stator winding. In an ideal capacitor, the phase angle should be 90°. However, as indicated in Figure 15.3, dielectric loss creates a component of the current which is in phase with the voltage. The tangent of the angle δ shown in Figure 15.3 is an indicator of the dielectric loss.
3. *Power Factor*. The power factor is measured by accurately measuring the voltage (V) applied between the copper and the core of a winding, and detecting the resulting current (I). At the same time, the power (W) to the winding is measured with an accurate wattmeter. The power factor PF is

$$\mathrm{PF} = \frac{W}{VI}$$

As with DF, PF is usually expressed in percent in North America, and sometimes per one thousand in Europe. The PF test is often less accurate in measuring the dielectric loss than the DF or phase angle methods.

All methods can be performed by applying low voltage AC between the winding copper and the stator core. However, as discussed in Section 15.11, there are advantages to measuring the dielectric loss at high voltage also. In most cases, all methods are accomplished by using power-frequency AC voltage to energize the winding. However, if low voltage power-frequency AC is used, there may be some induced power-frequency currents in the winding due to inductive or capacitive pickup from other energized equipment. These induced signals can lead to false results. Thus, a frequency different from 50 or 60 Hz is often used. Alternatively, the measurements could be done at a high power-frequency voltage to minimize any interference from other energized equipment.

The specific technology used by each method is given in detail in References 22–25. The DF is usually measured on a capacitance bridge (Section 15.7). The DF can be converted to PF using

$$PF = \frac{DF}{(1 + DF^2)^{0.5}}$$

However, the numbers produced by all methods are essentially the same for most rotating machine insulation systems.

As with the capacitance test, the dielectric loss is most sensitively measured at the stator terminals. Power cable can distort the readings. However, if less than 100 m of polyethylene cable, cross-linked polyethylene cable, or isolated phase bus (with air insulation) are connected to the terminals, reasonably accurate measurements of dielectric loss can be measured. This is because these three materials have very low (<0.01%) loss. Oil-paper cable and most rubber-insulated cables have too high an inherent loss and will mask the loss readings from the stator winding.

It is best to measure each phase separately, as this increases sensitivity. However, in motors, this is usually not possible due to the stator winding neutral connection.

15.10.3 Interpretation

For maintenance tests on complete windings, the initial DF measured is irrelevant. Typical DFs are about 0.5% or less for modern epoxy and polyester-impregnated insulation. The DF can be 3% to 5% for asphaltic mica windings. If the DF is measured on a regular basis, say every few years, and if it remains constant over time, it is an indication that there is no thermal aging or gross contamination of the winding. If there is an increase over time, it is an indication that insulation overheating is occurring or the winding is becoming more contaminated by moisture or partly conductive contaminants. A significant amount of deterioration has occurred if the DF has increased by 1% or more from the initial value.

If the capacitance and DF are measured at the same time, and if the trend in C decreases while DF is increasing, this is strongly indicative of general thermal deterioration. If both C and DF increase over time, this is a powerful indicator that the winding is contaminated or has absorbed moisture.

DF trend is indicative of the average condition of the insulation, as it measures the total dielectric loss in a winding. The additional loss for a single seriously overheated coil in a winding, when the rest of the coils are in good condition, will be small. Thus, this test cannot detect a few deteriorated coils.

Coil manufacturers sometimes use the DF test as a process monitor for the impregnation process. As the groundwall is impregnated, the DF will increase, as liquid resin has a higher DF than the air the resin is replacing. As the coil cures, the DF will decrease to its steady final level, as the DF of liquid resin is higher than the DF of cured epoxy or polyester.

15.11 POWER (DISSIPATION) FACTOR TIP-UP

The power factor tip-up test, sometimes called the *DF tip-up test*, is an indirect way of determining if partial discharges are occurring in a high voltage stator winding. As PD is a symptom of many high voltage winding insulation deterioration mechanisms, the tip-up test can indicate if any failure processes are occurring. The power factor tip-up is a complement to the capacitance tip-up (Section 15.8). This test is only relevant to form-wound stator coils rated at 2300 V and above.

In addition to its use as an off-line maintenance test, the tip-up test is widely used by stator coil and bar manufacturers as a quality control test to ensure proper impregnation by epoxy and polyester during coil/bar manufacture.

15.11.1 Purpose and Theory

As discussed in the previous section, all practical insulating materials have a dielectric loss, which can be measured with a power factor, tan δ or DF test. At low voltages, the PF and DF are not dependent on voltage. However, as the AC voltage is increased across the insulation in a form-wound coil, and if voids are present within the groundwall, partial discharges will occur at some voltage. These discharges produce heat, light, and sound, all of which consume energy. This energy must be provided from the power supply. Consequently, in a delaminated coil, as the voltage increases and PD starts to occur, the DF and PF will increase above the normal level due to dielectric loss, as the PD constitutes an additional loss component in the insulation. The greater the increase in PF or DF, the greater is the energy that is being consumed by the partial discharge.

In the tip-up test, the PF or DF is measured at a minimum of two voltage levels. The low voltage PF, PF_{lv}, is an indicator of the normal dielectric losses in the insulation. This is usually measured at about 25% of the rated line-to-ground voltage of the stator. The voltage is then raised to the rated line-to-ground voltage (about $0.6E$) and $\mathrm{PF_{hv}}$, is measured. The tip-up is then

$$\text{Tip-up} = \mathrm{PF_{hv}} - \mathrm{PF_{lv}} \tag{15.6}$$

The higher the tip-up, the greater is the energy consumed by PD. Some organizations will record the PF or DF at several different voltage levels up to rated phase-to-phase voltage (applied phase to ground) and calculate several different tip-ups between different levels. For example, IEC 60034-27-3 (still under development) suggests measuring the DF from $0.2E$ to $1.0E$, in $0.2E$ increments. E is the rated phase-to-phase voltage of the stator winding. By plotting the tip-up as a function of voltage, the voltage at which PD starts is sometimes measurable. If the PF or DF is measured in percent, the tip-up is in percent. As the tip-up on windings rated greater than 6 kV is usually significant, both DF and PF measurement methods yield about the same result. That is, the greater accuracy possible with a DF measurement will usually not yield superior tip-up results.

15.11.2 Test Method

Detailed test methods are described in References 23 and 24. Historically, the test was first applied to high voltage stator bars and coils, to ensure that the insulation was completely impregnated or the layers of resin-rich tape were fully bonded and air eliminated by the compaction process. However, since the late 1950s, some generator operators have applied the test to complete windings to detect various aging mechanisms that produce PD. In tests on machines, it is important to test as few coils as possible at a time, as this will increase sensitivity (see Section 15.11.3). Thus, as a minimum, each phase should be tested separately while the other two phases are grounded. Preferably, the winding should be partitioned into parallels or coil groups to gain maximum sensitivity.

Measurement of the tip-up is complicated by the presence of silicon carbide stress control coatings (Section 1.4.5) on coils rated at 6 kV or above. At low voltage, the silicon carbide is essentially a very high resistance coating, and no current flows through it. Thus, there is no power loss in the coating. However, when tested at rated voltage, by design the silicon carbide coating will have a relativity low resistance. Capacitive charging currents flow through the insulation and then through the coating (Figure 1.14a). The charging currents flowing through the resistance of the coating produce an I^2R loss in the coating. The DF or PF measuring device measures this loss. As the loss is zero at low voltage and nonzero at operating voltage, the coating yields its own contribution to tip-up. It is not uncommon for the tip-up due to the stress relief coating to be 2% or 3%. This coating tip-up creates a noise floor. Very significant PD must be occurring in most windings for the PD loss to be seen above the silicon carbide tip-up.

When manufactures test individual coils and bars in the factory as a QA test, the tip-up contribution due to the stress relief coating can be negated. The most common way is to “guard” out the currents due to the silicon carbide by overlapping the coatings with grounded aluminum foil, or even isolating the silicon carbide coating from the semicon coating, and grounding it separately. Other methods are also possible [23–26]. Unfortunately, it is not practical to guard out the coating tip-up in complete windings, which makes tip-up testing of complete windings less sensitive to defects in the insulation, especially for hydrogenerators and motors, which typically have shorter slot lengths than large turbine generators.

If the tip-up test is made on direct-water-cooled stator windings, and the water is present during the test (in fact the water should be circulating, see Section 15.6.2), the water may cause an additional tip-up. References 23 and 54 describe how this effect can be compensated for.

As discussed in Section 1.4.7, some manufacturers of high voltage stator coils insert a partly conductive or metallic shield adjacent to the copper conductors in the straight portion of the coil. The purpose is to reduce the effect of voids in the copper stack consolidation, as well as high electric fields caused by sharp points on the copper or any misaligned strands. Such shields have been known to cause a negative tip-up [25,26]. The reasons why conductor shields cause a negative tip-up are not clear. However, it may be because the connection of the conductor shield to the copper conductors is insulating at low voltage and thus dielectric losses in the insulation between the copper and conductor shield are a component of the total loss. When the insulating barrier breaks down at higher voltages, the shield is in good electrical contact to the copper and the insulation between the copper strands and the shield is no longer under electric stress and its contribution to the overall dielectric loss reduces to zero. A negative tip-up obviously will subtract from the tip-up due to PD, giving an overall lower tip-up. This may make the unwary believe that the winding insulation has a lower void content than it actually does.

15.11.3 Interpretation

As a maintenance tool for complete windings, the tip-up test is used for trending. The initial value of the tip-up on a phase is of little significance, because it will be dominated by the stress relief coating and/or conductor shield contributions to tip-up. However, if the tip-up is measured every few years and the tip-up starts increasing from the normal level, it is likely that the winding has significant PD activity. To increase the tip-up above the normal level requires widespread PD. The most likely causes of this PD are thermal deterioration, load cycling, and semiconductive coating deterioration. The tip-up test is not likely to be sensitive to loose coils in the slot, insufficient distance between end winding coils, or end winding electrical tracking. In all these cases, the PD is at a relativity low repetition rate or the damage is confined to the relatively small portion of the winding, and, thus, the PD contribution to tip-up is relatively minor. Details on each of these mechanisms are found in Chapter 8.

For tests on newly manufactured stator bars or coils, IEC is developing a new standard which gives some suitable limits on tip-up [24]. The IEC limits are usually easily met. KEMA has also suggested limits for many years, which are lower [27]. Generally, with modern insulation systems, the tip-up should be less than about 0.3% between 25% and 100% of rated line-to-ground voltage. Alternatively, KEMA recommends that the tip-up be less than 0.15% in any step in voltage of $0.2E$ between $0.2E$ and $1.0E$. Many users will allow a small percentage of coils to exceed these limits; however, these bars or coils should be used near the neutral end of the stator winding so they do not see electric stress in operation.

15.12 OFF-LINE PARTIAL DISCHARGE FOR CONVENTIONAL WINDINGS

The off-line partial discharge test directly measures the pulse currents resulting from PD within a winding energized at rated line-to-ground voltage. Thus, any failure process that creates PD as a symptom of insulation aging can be detected with this method. The off-line PD test is mainly relevant for form-wound stator windings rated at 2300 V and above. However, it is also commonly applied to the 690 V rotor windings of doubly fed induction generators (Section 1.1.3), typically used in wind turbines. Methods to locate the PD sites are discussed in Sections 15.14 and 15.15.

Detection of PD during normal operation of the motor or generator (i.e., online PD monitoring) is discussed in Section 16.4. However, a variation of the test is also relevant for random-wound stators intended for use on PWM-type inverter-fed drives. This is discussed further in Section 15.13.

15.12.1 Purpose and Theory

Many of the stator winding failure processes described in Chapter 8 had PD as a direct cause or a symptom of the process. When a partial discharge pulse occurs, there is a very fast flow of electrons from one side of the gas-filled void to the other side. As the electrons are moving close to the speed of light across a small distance, the pulse has a very short duration, typically a few nanoseconds [28]. The higher the pressure of the gas in the voids, the shorter is the pulse duration. As the electrons carry a charge q, each individual discharge creates a current pulse ($i = \mathrm{d}q/\mathrm{d}t$). In addition to the electron current flow, there will be a flow of positive ions (created when the electrons are separated from the gas molecules) in the opposite direction. However, the ions are much more massive than the electrons and, consequently, move much slower. As the transition time of the ions across the gas gap is relatively long, the magnitude of the current pulse due to ions is very small and usually neglected.

Each PD pulse current originates in a specific part of a winding. The current will capacitively couple from the void to the copper, travel along the coil conductors, and as the surge (or characteristic) impedance of a coil in a slot is approximately 30 Ω, a voltage pulse will also be created, according to Ohm's law. The current/voltage pulse travels away from the PD site, and some portion of the pulse current and voltage will travel to the stator winding terminals. A Fourier transform of a current pulse generates frequencies up to several hundred megahertz [28]. In high pressure hydrogen machines the pulse duration is even shorter, and thus creates frequencies up to about 1000 MHz.

Any device sensitive to high frequencies can detect the PD pulse currents. In the off-line PD test, the most common means of detecting the PD currents is to use a high voltage capacitor connected to the stator terminal. Typical capacitances are 80–1000 pF. The capacitor is a very high impedance to the high AC voltage (needed to energize the winding to create the PD in any voids that may be present), while being a very low impedance to the high frequency PD pulse currents. The output of the high voltage capacitor drives a pure resistance or a resistive-inductive-capacitive (RLC) load (Figure 15.4). The PD pulse current that passes through the capacitor will create a voltage pulse across the resistor or RLC network, which can be displayed on an oscilloscope, frequency spectrum analyzer, or other display device. Older analog oscilloscopes had trouble displaying the very short duration PD pulses on the screen. Thus, older detectors use an RLC load as the PD current will then create an oscillating pulse at lower frequency, which can be easily viewed on analog oscilloscopes. The RLC network also facilitates integration of the current pulse to yield the apparent charge of the PD (see later). In modern PD detectors, the load is normally a simple resistor, and the pulse is integrated digitally or uses a digital filter in combination with a digital oscilloscope display. The bandwidth of the detector is the frequency range of the high voltage-detection capacitor in combination with the RLC network or digital

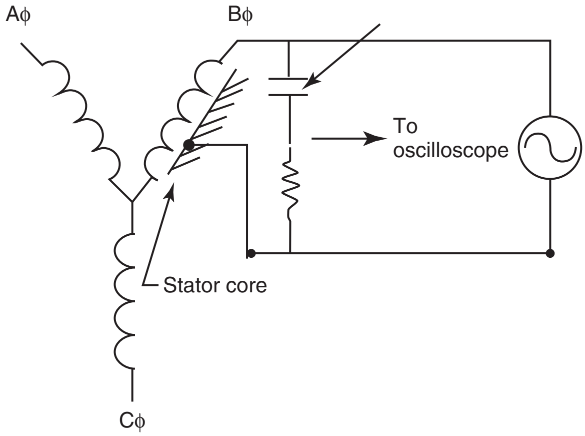

Figure 15.4 Measurement of PD pulse currents from a stator winding.

filter. For off-line PD detection, the most common bandwidth is in the 50 kHz to 3 MHz range, which is now called the *LF range*.

Every PD will create its own pulse. Some PD pulses are larger than others. As described in Reference 29, in general, the magnitude of a particular PD pulse is proportional to the volume of the void in which the PD occurred. Consequently, the bigger the detected PD pulse, the larger is the defect that causes the discharge. In contrast, smaller defects tend to produce smaller PD pulses. The attraction of the PD test is that one concentrates on the larger pulses and ignores the smaller pulses. In comparison to the capacitance or power factor tip-up tests, which are a measure of the total PD activity (or the total void content), the PD test enables the measurement of the biggest defects. Because failure is likely to originate at the biggest defects and not at the smaller defects, the PD test can indicate the condition of the winding at its most deteriorated portion.

15.12.2 Test Method

Like the tip-up tests in Sections 15.8 and 15.11, the off-line PD test requires a 50/60 Hz power supply to energize the winding to at least rated phase-to-ground voltage. Thus, for large-generator stators, a conventional or resonant transformer rated at 20−40 kVA may be needed. In addition, a low noise 0.1 Hz (VLF) sinusoidal output power supply could also be used (see Section 15.6.2). The AC voltage supply must be PD and noise free to the desired test voltage (the rated line-to-ground voltage, and sometimes the rated phase-to-phase voltage of the winding). If the PD testing is performed on individual coils or bars, a much smaller AC power supply can be used, as coils and bars typically have a capacitance of only 1 nF or so.

The relevant PD test methods for stator windings are in IEEE 1434 and IEC 60034-27-1 [30,31]. Off-line PD tests should be performed in what is now referred to as the *LF* range, that is, 50 kHz to 3 MHz. As all coils/bars in a winding will be subject to high voltage in an off-line PD test, PD can occur in any of the coils. Thus the PD pulse currents may often have to “travel” through many coils to reach the PD detection capacitor at the phase terminals. If the PD is measured in the LF range, the attenuation of the pulse as it travels through the winding will be minimized.

It is best to perform the PD test at the machine terminals, energizing one phase at a time, with the other two phases grounded. PD tests can be measured from the switchgear, but the test frequency must be in the LF range. As discussed in Section 16.4, power cables tend to strongly attenuate the higher frequency components of the PD pulses as they travel from the stator winding to the detector at the switchgear. Thus, unrealistically low PD signals will be measured at the switchgear if the detector primarily operates at frequencies greater than 1 MHz.

In the off-line PD test, it is common to gradually raise the applied voltage while monitoring the PD pulses on an oscilloscope screen. The voltage at which the PD is first detected is called the *discharge inception voltage* (DIV). The voltage then is raised to selected test voltage (line-to-ground or line-to-line voltage, applied phase to ground). The winding should remain energized for 10 to 15 min at this voltage, and then the peak magnitudes (Q_m) recorded (Figure 15.5). The "soak" or "conditioning" time is needed as the PD tends to be higher in the first few minutes after the voltage is applied. Space charge effects cause this, together with the build-up of gas pressure in the void due to deterioration caused by the PD. The voltage is then gradually lowered and the voltage at which the PD is no longer discernible is measured. This is the discharge extinction voltage (DEV). The DEV is usually lower than the DIV, and it is desirable to have the DIV and DEV as high as possible.

The test is normally performed one phase at a time, with the other two phases grounded. As there is still some attenuation through the winding, to be sensitive to PD at the neutral end, some users do a series of measurements with the PD detection capacitor at the neutral end of the winding, in addition to measuring PD at the phase terminals. Of course this will double the time it takes to complete all the testing. If the power supply does have noise or its own PD, some users will energize one phase from the neutral end, while the PD detection capacitor is at the phase terminal. The noise from the power supply may then be suppressed enough by the natural attenuation through the winding to permit useful measurements.

In tests on individual coils or bars, the semiconductive slot coating on the coil must be grounded. There is no need to isolate the silicon carbide stress relief coating from the semicon, as is required for the tip-up tests (Sections 15.8 and 15.11). If the

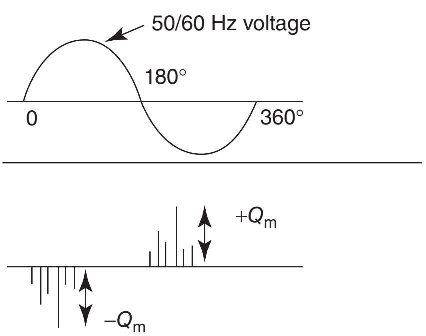

Figure 15.5 Oscilloscope-type display of PD pulses (lower trace) versus the power-frequency voltage waveform.

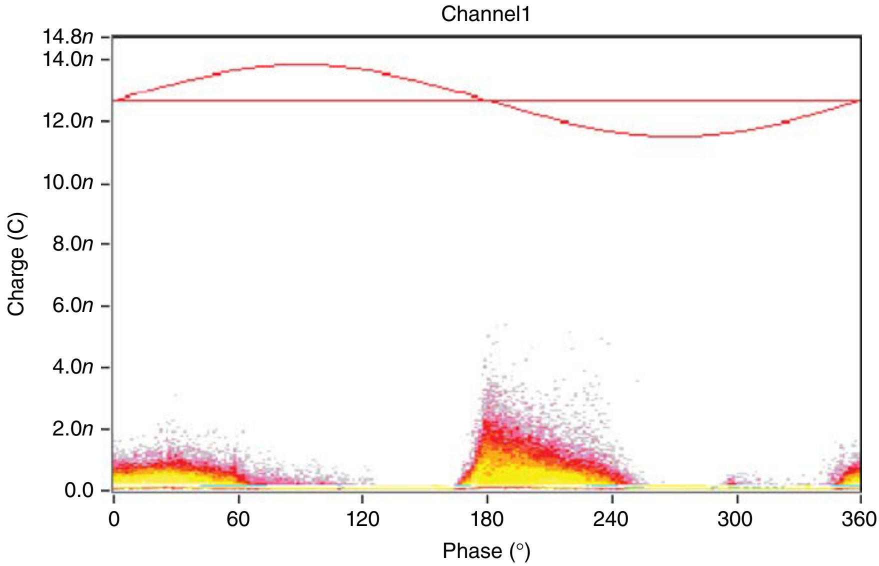

Figure 15.6 PD display with respect to the AC cycle. The color of the dots indicates the number of PD pulses per second. Note in the plot, all the PD pulses are shown as positive pulses due to the characteristics of the PD detector. (Source: PDTech-Qualitrol). *See color plate section.*

bars/coils are energized at phase-to-phase voltage, which is a 70% overvoltage, some PD from the silicon carbide coating may be measured.

In the past, the main recording device for PD pulses was an oscilloscope. Today, most PD is recorded with what is now called a *phase-resolved pulse magnitude analyzer*. This device is also often referred to as a *pulse phase analyzer* or *phase-resolved PD (PRPD)* analyzer. These give an image much like what would occur on an oscilloscope, but the analyzer records the number, magnitude, and phase position (with respect to the 50/60 Hz AC cycle) of the PD. Figure 15.6 shows the most widely used plot, as popularized by Fruth [32]. As discussed in the next section, PD patterns with respect to the AC cycle can sometimes be used to identify which of the failure processes in Chapter 8 are responsible for the PD. Note that in Figure 15.5, the pulses have the same polarity as they are measured with the PD detector in Figure 15.4. German manufacturers of PD equipment tend to display the pulses with the reverse polarity to those shown in Figure 15.5, as they take the polarity designation from the polarity of the AC voltage, rather than the polarity of the measured pulses.

15.12.3 Interpretation

The quantities involved in interpreting the PD activity are the DIV and DEV, Q_m and sometimes the pattern of PD with respect to the AC cycle.

Inception and Extinction Voltages Generally, the higher the DIV and DEV, the better. However, unlike all other types of high voltage equipment which require the

DIV and DEV to be well above the operating voltage, normally the DIV and DEV are below the rated line-to-ground operating voltage in stator windings rated 6 kV and above (the mica in the groundwall means that the groundwall can resist low level PD for an exceptionally long time). Although the relevant IEEE and IEC standards do not propose a minimum value for the DIV and DEV for new machines, most users consider it prudent to have the DEV above about 75% of the rated line-to-ground voltage.

With a motor or generator that is tested periodically over the years, if the DIV and DEV are constant over time, it indicates there is little aging. However, if the DEV and DIV decrease over time, it implies that the windings are deteriorating due to one or more of the many mechanisms identified in Chapter 8. The DIV and DEV should be measured over the years with the same type of PD detector and in the same frequency range, to ensure that the sensitivity of the test is consistent.

Peak PD Magnitude The peak magnitude of the PD at either rated line-to-ground or rated line-to-line voltage can also be helpful in interpretation. The key measure is the peak PD magnitude Q_m, that is, the magnitude of the highest PD pulse. When using a pulse magnitude analyzer (PMA), this is the magnitude corresponding to a PD pulse repetition rate of 10 pulses per second (pps) [30,31]. The Q_m can be measured in several units:

- picoCoulombs (pC) if a laboratory PD measurement device is used. pC is a measure of the apparent number of electrons that were involved in each discharge.
- millivolts (mV), where the PD magnitude is measured with an oscilloscope or electronic PMA. A PMA also counts the number of PD pulses of each magnitude range.
- milliamperes (mA) if the PD pulses are measured with a high frequency (ferrite core) current transformer and displayed on an oscilloscope.
- decibels (dB) if a frequency spectrum analyzer records the pulses.

For tests on coils and bars in the LF range, pC should be the measurement unit. Many modern PD detectors directly read the Q_m in picoCoulombs. If the PD is measured in millivolts, milliamperes, decibels, etc. a calibration to convert these units to pC can be done, using ASTM D1868 or IEC 60270 [33,34]. Unlike virtually all other types of high voltage equipment, there is no maximum permissible Q_m specified in the IEEE or IEC standards [30,31]. However, at least one user has required that Q_m on coils or bars be below 100 pC at rated line-to-ground voltage [35].

Measurement of the PD magnitude for complete windings is more complicated. The calibration procedures in ASTM D1868 and IEC 60270 are intended for capacitive test objects only. Windings constitute a capacitive-inductive test object, with many resonant frequencies. IEEE 1434, IEC 60034-27-1, and Reference 36 discuss this issue at length. In general, users in North America tend to measure winding Q_m in millivolts, whereas in Europe and Asia, picoCoulomb is more common. In fact neither millivolt nor picoCoulomb is an absolute quantity when applied to windings, and thus should only be used in comparison tests or trending.

In addition to the calibration difficulty, the detected PD magnitude of a PD pulse within the winding, but measured at the stator terminals, also depends on other factors:

- *The Size of the Defect*. In general, physics indicates that the larger the volume of the defect, the larger will be the detected pulse [29].
- *The Capacitance of the Winding*. If the winding has a large capacitance, the impedance to ground at high frequencies will be very low. Thus, most of the PD pulse current is immediately shorted to ground, leaving little to be detected at the stator terminals.
- The inductive impedance between the PD site and the PD detector. The pulse will be attenuated as it propagates through the winding to the terminal. In general, the further the PD site is from the PD detector, the lower will be the magnitude detected at the machine terminal.

This again illustrates that the PD magnitudes are only useful if they are compared to other measurements. Thus it is not possible to define a "high" PD magnitude that indicates that a winding has seriously deteriorated [30,31]. Therefore, off-line PD results are interpreted in comparison to other tests, for example:

- Compare one phase against another to determine the phase with the highest Q_m
- Compare one machine against other similar (in ratings and design) machines
- Trending the Q_m on the same phase over time.

Generally, if the Q_m of one winding is more than 25% higher than a Q_m from another phase or from another machine, the winding with the higher Q_m is more deteriorated. Similarly, if the Q_m on a machine is doubling every year or so, there is a rapid rate of winding deterioration.

For new machines, absolute limits on the PD magnitudes are not possible for the reasons given earlier. However the winding manufacturer can compare a new winding's Q_m with other similar windings that they have made in the past (and tested in the same manner). If the mean and standard deviation of these other similar windings have been calculated, it is reasonable for an end user to request that a new machine have a Q_m not higher than the mean plus two standard deviations.

PD Pattern Analysis If the PD equipment is digital and has the ability to produce PRPD plots similar to that shown in Figure 15.6, sometimes it is possible to determine which of the failure processes described in Chapter 8 is responsible for the PD. As shown in Figure 15.5, both positive and negative PD pulses are created. If the positive PD pulses (which, by definition, occur in approximately the negative half of the AC cycle) are larger and more numerous than negative PD pulses, it is likely that the PD is occurring on the surface of the coil (due to loose coils or defective semiconductive coatings). If the negative PD is predominant, the PD is most likely occurring at the copper. If there is no polarity predominance, the PD is likely to be between the groundwall insulation layers (due to delamination). Recall from Section 15.12.2 that in some brands of PD detectors, a negative PD pulse occurs on the negative portion of the AC cycle.

Belec and colleagues [37] have simulated many of the important failure processes in Chapter 8 to determine if there are different PD patterns with respect to the AC cycle. They suggest if there is a dominant failure process, indeed there may be patterns that are characteristic of the dominant failure process. However, as discussed in Section 16.4.2, sometimes the pattern can be an unreliable indicator of the failure process.

15.13 OFF-LINE PARTIAL DISCHARGE FOR INVERTER-FED WINDINGS

Inverter-fed variable speed motor stator windings or doubly fed induction generator rotor windings are subject to short rise-time voltage surges. As discussed in Sections 1.5.1 and 8.10, these voltage surges apply a high voltage stress between turns, and may cause PD even in 400 V random-wound windings in stators and rotors, leading to premature failure.

Off-line PD testing as discussed in Section 15.12 cannot be used to measure the PD caused by short rise-time surges. Such voltage surges have risetimes as short as 100 ns. The Fourier transform of such a short risetime indicates that there will be frequency components up to about 3 MHz. At this frequency, the PD detection capacitor in Figure 15.4 will have a much smaller capacitive impedance, and a considerable fraction of the voltage surge will be applied to the PD measuring system electronics, often destroying it. Thus, an alternative measurement system is needed to assure the quality of turn insulation of rotor and stator windings that will experience voltage surges from invertors.

15.13.1 Purpose and Theory

IEC Standard IEC 61934 describes the requirements of a PD measuring system where the applied voltage comes from invertors or surge testers (Section 15.16), which produce short risetime surges in the range of 100–500 ns [38]. The standard also discusses several possible implementations. The idea is to strongly suppress the voltage surge that may be hundreds or thousands of volts, while minimally affecting the PD pulse which has a frequency content that is only one or two orders of magnitude higher. In principle, a fourth or higher order filter will suppress the voltage surge. But such filters are hard to realize with practical components.

Two methods have been applied in practice to suppress the voltage surge while preserving the PD pulses. One uses a directional electromagnetic coupler (normally used in microwave instrumentation) [39,40]. The other method uses a "patch" antenna-fixed to the power cable feeding the winding to detect the PD signals [41,42]. Both techniques involve ultrahigh frequency (UHF) detection that is sensitive to signals several hundreds of megahertz and above.

In the first method, the surge voltage from a surge tester or an inverter must be directed through the instrument, where the PD from the winding is detected with a fixed coupling efficiency, while surges from the other direction are drastically suppressed. In the patch antenna method, a centimeter long antenna is simply attached to the power cable feeding the winding. Although very simple to implement, the patch antenna has an undefined coupling efficiency for PD, as it will depend on the thickness of the insulation on the power cable and the true length of the antenna.

15.13.2 Test Method and Interpretation

As with the conventional off-line PD test in Section 15.12, one can measure the discharge inception and extinction voltages, as well as the PD magnitude at some fixed surge voltage. To date, most users have focused on measuring the DIV and the DEV. There is no analogy for the measurement of the PD pattern (Figure 15.6) as there is no AC voltage. Instead, one measures the PD with respect to the applied surge voltage (Figure 15.7).

To measure the DIV, one applies the surge voltage, often from a surge tester such as made by SKF-Baker Instruments or Schleich. The output voltage from the surge tester is gradually raised until fast transients similar to Figure 15.7 appear. Normally the PD pulses should appear on about 50% of the applied surges to define what is known as the *repetitive partial discharge inception voltage (RPDIV)*. Similarly, the surge voltage is then lowered until PD occurs less frequently than on 50% of the surges (this is the RPDEV).

For windings that do not have an insulation system that is designed to resist PD, that is, windings that do not incorporate mica into the turn insulation, the RPDEV and the RPDIV are required to be above the surge voltages that may occur from the inverter in service. To this end, IEC 60034-18-41 defines the minimum RPDEV and

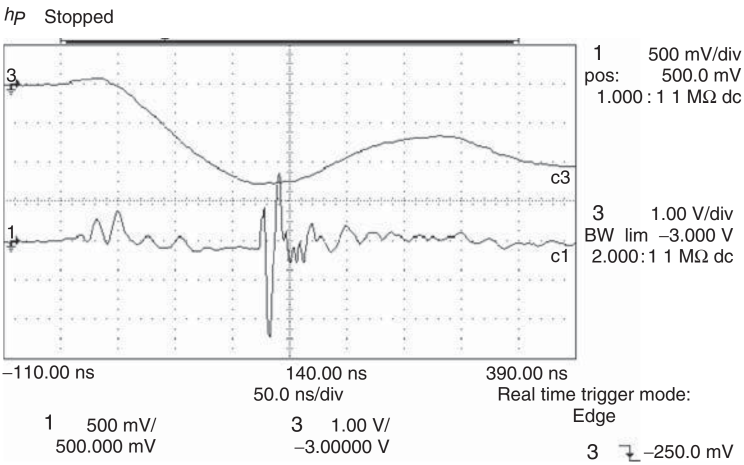

Figure 15.7 PD (lower trace) recorded during a single surge (upper trace) from a surge tester applied to a small stator. The time base is 50 ns.div. The surge voltage is 1000 V/div while the PD is 500 mV/div. The low frequency transient at the beginning of the PD waveform is the residual from the surge. The high frequency oscillation in the middle of the lower trace is the PD. (Source: Iris Power-Qualitrol).

RPDIV that windings should have. This standard was first published in 2006, and is evolving rapidly.

To date, the off-line PD test with surge testers has only been applied to help machine manufacturers design windings that will not experience turn insulation PD in service. It has only been rarely used as a diagnostic test on windings that have seen service.

15.14 STATOR BLACKOUT AND ULTRAVIOLET IMAGING

15.14.1 Purpose and Theory

End winding partial discharge is a symptom or cause of several problems such as stress grading-coating failure, pollution, and inadequate end winding spacing (Sections 8.6, 8.11, and 8.14). In addition to electrical and acoustic signals, partial discharge also creates an optical output. Some of the light output is in the visible frequency range, but most is in the ultraviolet frequency range. If a stator winding is energized one phase at a time, there will be some electrical stress in the end winding. If any of the above-mentioned deterioration mechanisms are occurring, surface PD may occur, which can be observed by the light emission. As the visible light is very faint, the room containing the stator under test must be darkened ("blacked out") for a short time before the PD light will be visible to the human eye.

Alternatively, ultraviolet light imaging devices (UV cameras) can be used to locate the PD without having to darken the lights. Such cameras are insensitive to visible light, so there is no need to turn the lights out in the room where the motor or generator is. Clearly this makes the test safer to perform than the blackout test. There are two types of camera:

- A camera that displays only the UV image. As there is little UV light in a room with normal artificial lighting, this can make it difficult to see exactly where any PD is occurring. This is the type of camera most commonly used for stator winding PD detection, due to its low cost.
- A camera that superimposes a visible light image on top of the UV image, so that the exact locations of any PD activity can be precisely identified (and recorded). These cameras also tend to have photon counting circuitry to record the UV light intensity, and can be used outdoors in sunlight. Such cameras tend to be 5–10 times more expensive than the basic UV imaging devices.

The test is most commonly used on new stator bars/coils rated 6 kV and above. Some manufacturers perform this test on new stators, to ensure they have been manufactured properly. It has also sometimes been used on windings that have seen service to locate PD sites in the end winding at an early stage, that is, before the characteristic signs of white powder have been produced. It complements the PD probe tests described in Section 15.15.

15.14.2 Test Method

IEEE 1799 describes the test procedure both for the blackout and the UV light imaging variations of the test [43]. This test is often done at the same time as the off-line PD test (Section 15.12), with the same AC supply. Each phase of the stator is energized to rated line-to-ground voltage, with the other two phases grounded. At this voltage, problems with the stress grading can be assessed (Section 8.6). Sometimes the voltage is then increased to the line-to-line voltage (applied phase to ground), to detect phase-to-phase PD caused by insufficient spacing between coils and bars (Section 8.14). At this higher-than-operating voltage there may be significant PD coming from the stress grading coating, which some users may choose to ignore as the coating is operating well above the rated voltage.

The voltage is applied for about 15 min to stabilize the PD activity (see Section 15.12.2). The blackout test is best performed at night with all the lights turned out near the machine under test. If this is not possible, a temporary shroud is constructed around the machine to block the ambient light. One or more people then stand near the machine (or within the shroud) and the voltage is applied. While the PD is stabilizing for 15 min, the observer's eyes will become accustomed to the dark. The number of points of light, if any, is then counted. Using a red flashlight that is briefly turned on, the points of light are located on the end winding. Note that extreme care is needed when performing this test, as personnel are close to an energized winding. As personnel are in the dark, they may not see the high voltage power supply or details of the stator.

To reduce the danger of this test to personnel, ultraviolet imaging cameras can be used, which do not require the lights to be turned out to make the eyes sensitive to the faint light from the PD [43]. The camera amplifies the intensity of the ultraviolet light emitted by the PD, while strongly attenuating the visible light. The output is displayed on an imaging screen or directly on a video screen. With appropriate lenses, the camera can be used from a position well away from the energized stator winding.

As there are several UV imaging devices commercially available, and they all operate in slightly different frequency ranges and have different sensitivities, some way of ensuring their effectiveness for PD detection is required. Hudon and his colleagues [44] discovered that most people have about the same sensitivity to PD light in a blackout test, if they have been acclimatized in the dark for 15 or more minutes, and that even the best UV cameras are not as sensitive as the human eye when acclimatized to the dark. Thus they propose that any UV imaging device be compared against the human eye in a blackout test. Specifically, the voltage on the stator winding is raised gradually while human observers and the UV camera are observing the winding. A UV camera is suitable for PD detection if it detects the light from PD at the same sites and at the same or a slightly higher voltage than the human eye can detect the light in a blackout test. This has been embodied in IEEE 1799.

15.14.3 Interpretation

When either test procedure is performed at rated line-to-ground stress, ideally there should be no light emitted by surface PD. Windings that have operated in service will usually have a few surface PD sites. In each test, the approximate number of points of light should be estimated. The test can be repeated every few years. The winding is deteriorating if the number of points emitting light increase by more than five times between tests.

If the voltage is then raised to the rated phase-to-phase voltage (applied phase to ground), realistic stress is applied between the coils/bars in the end winding area away from the stress grading coatings (assuming only one phase is energized at a time with the other two phases grounded). Interphasal PD can then be observed, if it is occurring. Note that many more areas will see phase-to-phase stress in this off-line test than would occur in operation. Thus, if excessive PD is located between coils/bars in what would be low voltage regions in operation, these PD locations can be ignored. Instead, one should concentrate on whether light is coming from the area of the "phase breaks," that is, where two adjacent coils/bars are in different phases and connected to the phase terminals. Some users ignore any light from the stress relief coatings during this higher voltage test, as the stress relief coatings will not operate at this high a voltage in service.

When the test is used on new coils/bars or windings, some users may require the test voltages to be a little higher than the rated voltage. In new coil/bar tests, problems with the semiconducting coating may be found, as well as with the silicon carbide coating.

15.15 STATOR PARTIAL DISCHARGE PROBE

The direct or indirect partial discharge tests in Sections 15.8, 15.11, and 15.12 indicate that partial discharges are occurring somewhere in the winding and therefore, some stator winding insulation deterioration has occurred. However, these tests do not give any indication of where in the winding the problem is occurring. PD probe tests can answer this question. The probe test is useful for stator windings rated at 2.4 kV and above. This test is an alternative or is a complement to the "blackout" test described in Section 15.14.

15.15.1 Purpose and Theory

If high PD has been detected using any of the direct or indirect PD tests, it is sometimes prudent to locate where the PD is occurring in the stator, so that the visual inspection of the winding can concentrate on the most deteriorated regions. Two special probes have been developed to help locate the PD sites. One probe detects the RF energy emitted by PD. The other detects the acoustic energy emitted.

The RF probe was first developed by Dakin in the late 1940s, and subsequently improved by the utility Tennessee Valley Authority (TVA) [45]. The probe is called either the *corona probe* or the *TVA probe*. In addition, another very similar device called the *EMI Sniffer* works in much the same way. The RF probe is essentially a modified AM radio, usually tuned to about 5 MHz. The loop stick antenna is at the end of a rod. A radio detector, with no automatic gain control, is connected to the antenna. As the antenna comes close to a coil with high PD, the PD generates radio waves that the antenna detects. The bigger the PD, the stronger the signal, thus yielding a louder demodulated signal and a higher meter indication. The TVA probe is calibrated in "quasipeak" milliampere, which means that it tends to register the highest PD pulse detected. Iris Power and Doble make various RF probes.

The ultrasonic probe is a directional microphone that is pointed at the winding. When a partial discharge occurs on the winding surface, high velocity ions move through the air to create a pressure wave, a tiny version of thunder from a lightning strike. This pressure wave creates an acoustic pulse that has its greatest intensity around 40 kHz. A directional microphone and associated frequency downscaler tuned to 40 kHz can make the ultrasonic noise audible to the human ear. As the microphone points to the PD sites, a louder indication will be heard from the device. UE Systems is one manufacturer of the ultrasonic probe.

15.15.2 Test Method

For best access to the stator winding, the rotor is usually removed. The winding is then energized to the rated line-to-ground voltage using a conventional or resonant 50/60 Hz transformer. This is usually the same power supply as used for the direct or indirect partial discharge tests. Most users of the probe tests energize one phase at a time and ground the other two phases. However, as will become apparent, this will increase threefold the time it takes to perform the test. The windings are usually energized for at least 10–15 min (some "soak" the winding for 1 h) to allow the PD activity to stabilize. Extreme caution is needed when performing this test, as by its nature, one has to get close to an energized winding.

With the winding energized, the RF probe antenna is placed over the slot near the end of the core and a helper records a reading. The antenna is usually in contact with the core and bridges the stator slot. The probe antenna is then moved to the next slot and the reading recorded. This is continued until the RF activity in all slots is measured. It is then common to measure the RF activity at the other end of the stator core. Sometimes, the activity in each slot in the middle of the core is also recorded. Some users also "wave" the probe antenna over the end winding region, being careful to have the antenna no closer to the winding than about 2–3 cm. This can sometimes detect PD in the end winding area. After one phase has been completed, the other phases are energized in turn, and the entire RF map repeated. On a large hydrogenerator, it may take 10–20 h for two people to complete the test, because there may be several hundred slots in the stator. Note that these RF probes can also be used to identify sources of PD or arcing in other energized equipment.

In general, the ultrasonic probe test is performed just after the RF probe test is completed on each phase. This test usually is much quicker, as the directional ultrasonic microphone is relatively quickly scanned over the end windings and the slots. Slots or endwinding locations showing the greatest noise activity are noted.

15.15.3 Interpretation

Usually, slots having the highest RF probe or highest ultrasonic microphone readings will have the greatest PD and, hence, are more likely to be more deteriorated. IEEE

1434 gives a consensus indication of what constitutes a high reading for the TVA version of the RF probe test [30]. If the indication in any slot is above about 20 mA for a modern epoxy-mica insulation, significant PD is occurring in that area. There are no agreed-upon limits for what constitutes a high ultrasonic reading; thus, one just notes that the loudest noise is probably from the most deteriorated location.

If both the RF and ultrasonic probes point to the same site as having high PD, this is solid evidence that there is significant PD occurring on the surface of the coils/bars. This PD activity should be visible. If the RF activity is high and the ultrasonic probe gives little indication, the PD may be occurring within the groundwall insulation and, thus, may not be visible.

There should be no region in which the ultrasonic probe gives a high indication and the RF probe gives little or no reading. If this occurs, the acoustic indication is probably spurious. The high acoustic reading probably is just detecting acoustic reflections. Cross coupling and resonance can also result in spurious high readings from the RF probe. If one phase is energized at a time, it is not uncommon for the RF probe to show high PD occurring in a slot that contains no energized coils!

Thus, though the RF and ultrasonic probe tests are simple in theory, considerable skill is needed to ensure that slots with coils in good condition are not misidentified as being bad.

15.16 STATOR SURGE VOLTAGE

The surge voltage test directly measures the integrity of the turn insulation in form-wound or random-wound stator windings, and sometimes wound induction rotor windings. As envisioned in IEEE 522 and then IEC 60034-15, the test is primarily intended for ensuring the integrity of the turn insulation in individual coils [46,47]. However, it has seen some application for testing the turn insulation in both new and in-service complete windings. The stator voltage surge test does this by applying a relatively high voltage surge between the turns. This test is a hipot test for the turn insulation and may fail the insulation, requiring a repair, coil replacement, or rewind. The test is not relevant for half-turn Roebel bar windings, as there is no separate turn insulation (or more correctly, the turn insulation is the same as the ground insulation, and no realistic surge voltage is likely to puncture the groundwall). In the past, this test was called a *surge comparison test* as the results from two phases had to be compared to one another to determine if one phase had a turn fault. Present-day surge test sets do not require two phases to be tested at a time. The test can be done in conjunction with the special off-line PD test described in Section 15.13.

15.16.1 Purpose and Theory

Section 8.9 indicated motor turn-on is accompanied by a fast (i.e., short) rise-time voltage surge caused by breaker or switch contactors coming together. Similar voltage surges occur from IFDs (Section 8.10) and faults in the power system. These short rise-time surges result in a nonuniform voltage distribution across the turns in the stator winding. If the rise-time is short enough, the surge voltage high enough, and the turn insulation weak enough, the turn insulation punctures, rapidly leading to a stator ground fault for an operating machine (Section 1.4.2).

The surge test duplicates the action of an external surge. As such, this test is analogous to the AC and DC hipot tests for ground insulation: apply a high voltage to the turn insulation and see if it fails. The surge test is a destructive, go-no go test. If the turn insulation fails, the assumption is that the stator would fail in service due to motor switch-on, IFD surges, or transients caused by power system faults. If the winding does not puncture, the assumption is that the turn insulation will survive any likely surge occurring in service over the next few years. Thus, the main question is whether a maintenance surge test is to be performed or not, and this is a philosophical question identical to that posed for the DC hipot (Section 15.2).

The main difficulty with the surge test is determining when turn insulation puncture has occurred while testing a complete winding (detection of shorted turns is trivial when an individual coil is tested). In the DC or AC hipot test, groundwall puncture results in the insulation resistance plummeting to 0 Ω. This causes the power supply current to increase dramatically, opening the power supply circuit breaker. There is no question that puncture has occurred. A turn-to-turn puncture in a winding does not cause a huge increase in current from the power supply. In fact, if there are 50 turns between the phase terminal and neutral, the failure of one turn will only slightly reduce the inductive impedance of the winding, as the impedance of only one turn has been eliminated. Thus the other 49 turns can continue to impede current flow, and the surge tester circuit breaker does not trip.

In the surge test on complete windings, turn failure is detected by means of the change in resonant frequency caused by shorting out one turn. The schematic of a simplified surge tester is shown in Figure 15.8. The inductor is the inductance of one phase of a stator winding, or in a motor stator where the neutral ends cannot be isolated, the inductance of (say) the A phase and B phase windings in series. A high voltage capacitor within the surge tester is charged from a high voltage DC supply via the winding inductance. Once the capacitor is charged to the desired voltage, the switch (usually a thyratron or IGBT solid state device) seen in Figure 15.8 is closed.

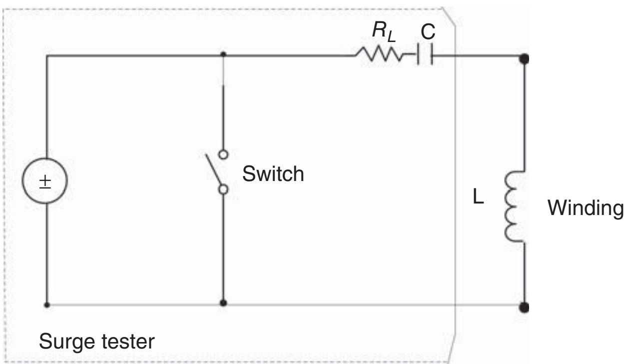

Figure 15.8 Schematic of a surge comparison tester applied to one phase of a stator winding.

The energy stored in the capacitor then oscillates back and forth with the winding inductance. The resonant frequency (f) of either the voltage or current waveform is approximately

$$f = \frac{1}{2\pi\sqrt{LC}} \tag{15.7}$$

If there is no turn fault, there will be a fixed frequency of oscillation. If a turn fault occurs as a result of the short rise-time surge imposed on the line end turns, together with weak turn insulation, the inductance of the winding will decrease and, thus, the resonant frequency will increase, according to Equation 15.7. Thus, one looks for the increase in frequency of the voltage surge on an oscilloscope screen as the voltage is gradually increased and as the winding moves from no turn shorts to having a turn short.

The increase in frequency is small, typically only a few percent. Such a small increase is difficult to detect. To aid in detecting the frequency shift, most surge testers made since the early 1990s digitally capture the resonant waveform at low voltage, where the turn insulation is still intact. The surge voltage is gradually increased by raising the voltage that the capacitor charges to, and triggering the switch after the capacitor has charged up (usually the switch is automatically triggered once per second or once per 50 or 60 Hz cycle). If a change in the waveform is noted above a certain voltage, which can be detected by scaling the low voltage stored waveform up to the current applied voltage, turn insulation puncture has occurred.

Older surge test sets were called *surge comparison testers*. They consisted of two energy storage capacitors, which were connected to two phases. The waveform from each phase was monitored on an analog oscilloscope. The assumption was that the waveform was identical for the two phases. As the voltage increased, if one of the waveforms changed (increases in frequency), turn puncture has occurred in the phase that changed. This approach has lost favor as it is possible for two phases to have slightly different inductances due to different circuit ring bus lengths, mid-winding equalizer connections, or even due to rotor position (as it affects the permeability).

It is easy to detect turn insulation failure on individual coils, as the shorting of one turn will have a much larger impact on the total inductance of a coil, thus drastically changing the waveform. Machine manufacturers and rewind companies use individual coil surge testing to check the quality of the turn insulation. Such testing is best done after the coils are wound, wedged, and braced, as by then they have been exposed to all the mechanical handling and stresses associated with the winding process. However, as a quality check, most coil manufacturers do the surge test prior to inserting coils into the slot. Ground faults are easily detected by a surge test, as the waveform collapses. Surge testing is also useful to identify wrong connections in new windings.

15.16.2 Test Method

IEEE standard 522 provides the best description of both an acceptance and maintenance surge test [46] for form-wound stator windings, as well as quality assurance testing of coils. As an acceptance test for coils, the surge is recommended to have a rise-time of 100–200 ns and a maximum magnitude of 3.5 per unit, where 1 per unit is the peak line-to-ground rated voltage. For a maintenance test performed after the winding has seen service, the surge should have the same rise-time, but reaches only 2.6 per unit. As for the DC and AC hipot test voltages, these limits were set because they represent the worst surge that is most likely to occur in normal service. Voltages higher than these maximums should not be applied to the stator winding; otherwise there is a significant risk that good turn insulation will fail unnecessarily.

NEMA MG1 and IEC 60034 Part 15 set generally lower acceptance surge test requirements and do not specify maintenance surge tests for complete windings. NEMA requires that IFD motors should withstand 100 ns rise-time surges at 3.7 per unit. IEC 60034-15 was recently revised with a narrower allowed range of rise-times (100–300 ns), but this is still a larger range than in IEEE 522. As discussed in Section 8.9, the longer the surge rise-time, the lower is the voltage applied across the turn insulation. Thus, longer rise-time surges are not as severe as short rise-time surges.

The test should be applied at the machine terminals. If the test is performed from the switchgear, the long cable or bus will lengthen the surge rise-time, decreasing the effectiveness of the test, as there will be less interturn voltage.

As discussed earlier, for complete windings the surge voltage is gradually increased to the maximum recommended test voltage. If the waveform changes on the oscilloscope, the turn insulation has likely been punctured. If the winding is form wound, the failed coil will have to be located and isolated. This is likely to be a phase end coil. If the lights are dimmed around the stator, it is sometimes possible to find the faulted coil by reapplying the surges and looking for a glow through the ground insulation from the puncture site. Otherwise, the coils must be separated from one another and tested separately until the faulted coil is found. This can be tedious. In a form-wound stator, the faulted coil must be replaced or the coil must be cut out of the circuit (Section 7.4). If the turn insulation fails in a random-wound stator, it is often possible to locate visually the faulted turn by dimming the lights and reapplying the surge. Sometimes, the turn insulation in a random-wound stator can be restored by cleaning and dipping the stator in varnish (dip/bake).

If a turn puncture has occurred, it is not acceptable to ignore it and return the stator to service. Once the first significant surge occurs in service, the punctured turn insulation will break down again, allowing power-frequency currents to flow, rapidly leading to groundwall failure and possible collateral damage.

15.16.3 Interpretation

The surge test is a go-no go test, and the stator either passes or fails. There is no real diagnostic information obtained, unless one measures the PD at the same time. If one combines the surge test with a partial discharge test (Section 15.13), it may be possible to detect significant voids between the turns, before actual puncture occurs.

Although the surge test was stated earlier to be the only test that directly determines the condition of the turn insulation, there are some caveats. In random-wound stators, the turn insulation and the ground insulation are, to a large extent, the same. That is, the insulation film on the magnet wire serves as both turn and part of the ground insulation. Thus the IR/PI, capacitance, and DF tests discussed earlier will also indicate the condition of some of the turn insulation.

For form-wound stators, the turn insulation is again part of the groundwall insulation where the turn insulation is around the outside of the copper conductors (Figure 1.9). Thus, the diagnostic tests described earlier (particularly the capacitance tip-up, DF tip-up, and 50/60 Hz PD tests) also indirectly evaluate the condition of the turn insulation. However, the turn insulation between two adjacent turns is not tested with groundwall tests. The surge test specifically tests this “between-turn” insulation.

15.17 INDUCTIVE IMPEDANCE

This test is a low voltage version of the stator surge test and can be applied to any three-phase stator winding. This test is often included in the motor winding test instruments discussed in Section 15.9, to complement the IR/PI, conductance, and capacitance tests. The test set applies a high frequency f (typically in the range of 1 kHz) at a voltage V (usually a few volts) to a pair of phase terminals and measures the AC current, I that flows between the terminals. The inductive impedance X is

$$X = \frac{V}{I}$$

As $X = 2\pi fL$, the higher the inductive impedance, the greater is the inductance of the winding. The inductance is measured three times, between A and B, between A and C, and between B and C phases. The inductance will depend on the number of turns between the two-phase terminals and the permeability of any surrounding steel.

Ideally, the three inductances should be equal, within about 1%. If the three inductances are not equal, this could be for several reasons:

- One of the phases has a shorted turn. For example, if B phase has a shorted turn, the A-B and B-C inductances should be lower than the A-C inductance. If there are 50 turns between phase and neutral, then there are 100 turns between the two phases. Thus, a single turn short will result in 1% less inductance between the two phases.
- The rotor is in a slightly different position with respect to the coils in each phase. As the rotor is made of magnetic material, it will affect the inductance via the permeability. As the rotor is not a completely homogeneous magnetic material (if nothing else, there are slots cut into the surface for the nonmagnetic rotor bars), moving the rotor makes small differences in the inductances of different coils in the stator.
- Presence of steel end shields and other steel around the motor. Unless the motor is completely enclosed in steel, structural steel beams, other motors, or other close-by magnetic objects affect the inductance of the coils, as this affects the permeability.

Unfortunately, the last two effects can completely overwhelm the very small change in inductive impedance due to a shorted turn. This makes the test very difficult to interpret.

There is another limitation with this test. The purpose of the test is to detect the presence or absence of a turn short. As only a few volts are applied to the winding, the volts per turn are only millivolts. Unless the short already exists, this low voltage is not likely to cause a puncture in the turn insulation. As discussed in Section 1.4.2, if a turn insulation failure occurs in service, it is very likely that the high circulating current that results from the short will rapidly melt the copper turn. This melted copper then burns a hole through the ground insulation, rapidly leading to a ground fault. In form-wound machines, the time between the onset of a turn fault and the ground fault is understood to be seconds or minutes (Reference 12 in Chapter 1). For a random-wound stator, the time may be longer due to the higher resistance that may occur between the shorted turns (although if the resistance of the short is high, the inductance measurement will not be affected either). Thus, the inductive impedance test can only be useful if it can detect a turn fault before it progresses to a ground fault. As this time is usually extremely short, it will be virtually impossible for this test to give any more than a few minutes warning of failure. Reference 48 discusses the problems with the inductive impedance test in greater detail.

The stator surge test (Section 15.16) is much more effective for determining the condition of the turn insulation, as it develops hundreds or thousands of volts across the turn insulation. If the insulation is weak, it will be punctured, changing the resonant frequency of the winding. The voltage from the inductive impedance test is below that of the normal in-service voltage. If the in-service voltage was not able to puncture the turn insulation, it is impossible for an even lower voltage to do this.

15.18 SEMICONDUCTIVE COATING CONTACT RESISTANCE

The measurement of the resistance between the semiconductive coating (also called the *outer corona protection* or OCP coating, the partly conductive coating, or the semicon coating) and the grounded stator core can indicate if coils are loose in the slot or if the coating has deteriorated. This test is only useful in form-wound stator windings that have a semiconductive coating. Thus, the test is usually only applied to stators rated at 6 kV and above.

15.18.1 Purpose and Theory

Section 1.4.5 discussed the need for a partly conductive coating on the surface of high voltage coils and bars, in the slot region. Specifically, this "semiconductive" coating prevents partial discharge (also known as *slot discharge*) between the coil surface and the stator core. Poorly manufactured or applied coatings (Section 8.5), abrasion of the coating due to coils and bars being loose in the slot (Section 8.4), isolation of the coating from the core (Section 8.7), and/or severe vibration sparking (Section 8.8) will reduce the effectiveness of the coating and promote the onset of the slot discharges.

As the semiconductive coating deteriorates, its resistance increases. Also, if the coils are loose in the slot, there may be only a few points of contact between the semiconductive coating and the core, rather than many. In both these situations, the contact resistance between the coil surface coating and the core will increase. In this test, the electrical resistance between the coil surface and the core is directly measured.

15.18.2 Test Method

The test requires access to the stator winding coils/bars, just outside of the slot or in the stator vent ducts. This is easiest to achieve if the rotor has been removed. An electrical contact must be established to the semiconductive coating that extends 2 or 3 cm beyond the slot at each end of the core. If this area has been painted with an insulating varnish, the varnish needs to be carefully abraded away on the coil surface closest to the bore. Contact is then made to the semiconductive coating with a short length of braided wire, making sure the wire does not contact the core. The resistance is then measured with a standard digital volt-ohmmeter between the braid and a solid ground point on the stator core. The resistance is preferably measured at both ends of the core on each top coil in the stator (it is virtually impossible to make electrical contact to the bottom coil in a slot). If this is too time consuming, then as many coils as possible that are connected to the phase terminals should be measured.

If the rotor is out and some stator wedges can be removed, the resistance from the exposed semiconductive coating on the air gap edge of the coil can also be measured in several locations.

15.18.3 Interpretation

The lower the resistance, the better the contact between the coating and the core, and thus the coils are tighter in the slot. Coils showing high resistance should be visually examined to determine if the semiconductive coating is becoming lighter in color or if dusting is occurring due to coil looseness.

In general, all the coils should have a resistance less than about 2000 Ω. If the resistance is higher than about 5 kΩ in phase end coils, it is likely that slot discharges will occur. If the resistance is very low, say less than 100 Ω, and the coils/bars are loose in the slot, vibration sparking may be occurring.

15.19 CONDUCTOR COOLANT TUBE RESISTANCE

Section 1.1.5 mentioned that large turbine generator stators are sometimes directly cooled with hydrogen. The hydrogen flows from one end of the stator bar to the other in stainless steel tubes that are adjacent to the high voltage copper conductors. Resistors are connected between the tubes and the copper. The resistance of these resistors is tested occasionally to ensure that they have not open-circuited.

15.19.1 Purpose and Test Method

As the stainless steel tubes are conductive, they will pick up some voltage by capacitance coupling from the copper conductors in the stator bar. To ensure that high potential differences do not occur between the copper conductors and the tubes, resistors are connected between the coolant tubes and the copper conductors. If the end winding starts to vibrate (Section 8.15), these resistors sometimes crack. If these resistors fail, sparking can occur, causing local overheating and possibly damaging the insulation. A resistance test can determine if the resistors are open or not.

With the generator off-line and the end windings exposed, the resistors are located near the end of the bars. The resistance of each resistor is measured with an ohmmeter. If there is an open circuit (infinite resistance), the resistor is defective and must be replaced. If several resistors are open-circuited, it is likely that severe end winding vibration is occurring.

15.20 STATOR WEDGE TAP

This test determines if the stator wedges are loose and, thus, if the windings are likely to be vibrating in the slot (Section 8.4). The test is relevant for conventional form-wound stators, that is, nonglobal VPI stators. Global VPI stators are presumed to always have tight wedges, as they have been glued into place.

15.20.1 Purpose and Theory

The loose coil/bar problem has been described in Section 8.4. One of the root causes of this failure process is stator wedging that was never installed tightly, or became loose over the years. If the wedges are tight, it is less likely that the coils will be loose. The most direct means of assessing if the wedges are tight is to tap each individual wedge.

15.20.2 Test Method

The original way of measuring wedge looseness is to tap each end of each wedge sharply with the ball end of a ball peen hammer or similar tool. This version of the test can only be performed if the rotor has been removed.* If the wedge is loose, the hammer will make a "thud" sound as it contacts the wedge and vibration will be felt if a finger is placed alongside the point of hammer impact. If the wedge is tight, it will "ping." Often, there is an uncertain state between loose and tight. This is clearly a subjective judgment, but someone with experience can easily grade the three levels of looseness. The looseness of every wedge in every slot is measured. A two-dimensional "wedge map" is created before the test. This has a row for every stator slot and a column for each wedge in a slot (or vice versa). The degree of looseness of each end of each wedge is marked on the map.

Instruments that measure the wedge looseness are also available. Usually a calibrated "hammer" strikes the wedge and an accelerometer placed against the wedge

*In large hydrogenerators with salient pole rotors, the removal of the rotor can sometimes be avoided if one or two poles are removed instead, so that a person (or robotic vehicle) can be lowered into the space where the poles were. They can then perform the tap test on several slots. The rotor is then manually rotated so that the wedges in other slots can be tapped.

measures the vibration of the wedge in response to the impact. If the vibration is highly damped, the wedge is tight. If the output is undamped (i.e., takes longer to decay to zero), the wedge is loose. With suitable signal processing, the wedge can be easily graded into three levels of looseness. The device is moved from wedge to wedge and slot to slot to create the wedge map (Figure 15.9). The result is a more objective, repeatable wedge map, although a very experienced person can probably be more accurate in defining the relative looseness of the wedges, especially if top ripple springs are present. Some caution is needed with automatic wedge looseness detectors as they can be "calibrated" to indicate that all wedges are tight or all wedges are loose, when a manual test indicates a mix of looseness.

The wedge tap test can be automated using a tractor or robot to carry the instrument along the slot. The tractor moves the instrument over each wedge, stops for the impact test, transmits the results to a computer, and then moves to the next wedge (Figure 15.10). This innovation certainly reduces the laboriousness of the test. In addition, as large steam turbine generators often have a space between the stator bore and the rotor surface of 5 cm or more, the robot can sometimes complete the wedge map with the rotor in place, as long as the robot can be inserted around the rotor retaining ring. This same tractor or robot can also carry a tiny video camera for looking down the core ventilation ducts, to see if abrasion is occurring, and a stator core insulation tester such as the ElCid type described in Section 17.4. If the only reason to remove a rotor is to perform the wedge tap test, the robot alternative can sometimes result in considerable savings. One deficiency of this type of robotic tester is that it

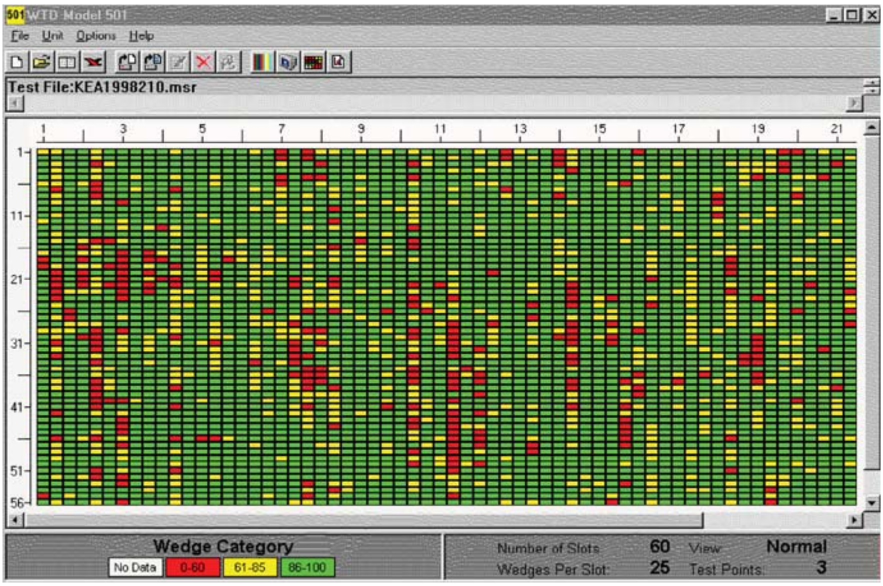

Figure 15.9 Map of wedge tightness versus slot number (vertical scale) and axial wedge number (horizontal scale). Green is tight, red is loose, and yellow is indeterminate. (Source: Iris Power-Qualitrol). *See color plate section.*

Figure 15.10 Photo of a wedge looseness detector mounted on a robotic vehicle to find loose wedges automatically in the stator. The detector is mounted in the middle, immediately over the wedges. (Source: Iris Power-Qualitrol).

does not reliably check the tightness of end wedges, especially if the core is stepped at the ends. This is because the device cannot be adequately supported at this location. Most large-generator OEMs and a few large service organizations can provide a robotic test service.

15.20.3 Interpretation

When viewing the wedge map, a few loose wedges are of little concern. However, some consideration for general or local rewedging is warranted for modern epoxy-mica or polyester-mica insulation systems if

- two or three adjacent wedges in the same slot are loose;
- any wedges at the end of the slots are loose;
- more than 25% of the wedges in the core are loose;
- 10% or more wedges are looser than on the previous test;
- none of the wedges should be cracked.

Asphaltic windings often have many loose wedges, and generally this is not a problem. Asphaltic windings tend to expand in the slot at operating temperature, which tends to prevent the bars/coils from vibrating in service. Rewedging of asphaltic windings should only be considered if there is obvious coil/bar abrasion and/or the wedges are ratcheting out of the slots. If rewedging of asphaltic windings is contemplated, ensure the work is done by someone who has had successful experience in rewedging such machines, as conventional wedging practices may actually damage an asphaltic winding.

Note that loose wedges in themselves are not a problem (unless they are so loose they are migrating out of the slot). However, loose conventional wedges tend to lead to loose coils or bars, especially if there are no side ripple springs or other conformable materials in the slot (Section 1.4.8). Also of importance is that if wedges are loose when the unit is out of service, they will also be loose at full load if the windings are made with modern epoxy-mica or polyester-mica insulation.

Loose magnetic wedges should always be replaced, as any looseness will destroy the wedge, and contaminate the machine.

15.21 SLOT SIDE CLEARANCE

This is another test to complement the tests in Sections 15.18 and 15.20 that can indicate how loose a coil is in a stator slot. The test is only valid for nonglobal VPI form-wound stators.

15.21.1 Purpose and Theory

This is a simple test to measure the gap that exists between the surface of a coil and the stator core. If there is too large a gap, the coil or bar is likely to be free to vibrate in the slot and rub against the stator core, reducing the groundwall insulation thickness (Section 8.4). The test is most applicable to stators that have a flat side packing system, and which do not use a conformable coating on the side of the coils/bars (Section 1.4.8).

15.21.2 Test Method

The rotor must first be pulled from the machine and then wedges are removed in some slots. Usually the slots containing phase end coils in the top position in the slot should be examined. "Feeler gauges" (thin metal fingers with known thickness) are then slid down the side of the coil/bars between the coil and the core. The purpose is to find the thickest feeler gauge that can be easily slid between the coil and the core and moved back and forth in the axial direction for at least a few centimeters. The gauge should be inserted at both ends of the core, as well as at random positions along the slot.

15.21.3 Interpretation

If the winding is insulated with modern epoxy-mica or polyester-mica groundwall insulation and uses flat side packing, the largest feeler gauge that should be able to fit between the coils and the core is 0.125 mm [49]. If larger gauges can be inserted in many spots and slots, the winding is loose enough to warrant corrective action. For asphaltic mica windings and the early polyester (pre-1970) windings, it is not uncommon to have larger gaps and still not have the winding at risk. This is because the older materials expand when operating at full load and high temperature, thus reducing the size of the gap that may exist when the winding is cold. However, even with older groundwall insulation systems, the gap should be no larger than 0.5 mm.

15.22 STATOR SLOT RADIAL CLEARANCE

The importance of a tight fit for stator conductor bars in the slot is underscored by yet another test to complement the stator wedge tap and the slot side clearance tests (Sections 15.20 and 15.21). Applicable to large form-wound stators, this test, also referred to as the *bar jacking test*, determines the amount of radial clearance in the stator winding slot.

15.22.1 Purpose and Theory

Stator bar support systems in large generators are designed to restrain the motion of the stator winding due to twice-per-cycle magnetic forces of several tons acting on each conductor bar. Use of conforming materials, two-part wedging systems, and ripple springs, as well as curing of conforming materials under pressure and elevated temperature are the principal methods used to eliminate radial clearance in the slots (Section 1.4.8). Nevertheless, bars become loose in the slot due to aging, as described in Section 8.4. This test directly measures whether stator bars are free to move up and down (radially) in the slot.

Radial clearance may not be identified by the stator wedge tap test. The end wedges may still be tight with radial clearance present between the conductor bars or between the bottom bar and the bottom of the slot. It is, therefore, useful to conduct the radial clearance test to determine the risk of bar abrasion, particularly in the presence of oil.

15.22.2 Test Method

The test method involves the application of a known amount of radial force in the 2200 N (500 lb) range and measuring the deflection of the stator bar in the same direction. The potential for damage to nearby generator components is significant when performing the clearance test. Special tooling and considerable expertise are required to safely conduct the test with the rotor in. It is, therefore, recommended that the OEM or a large, experienced service organization should perform this test.

The test can be performed with the rotor removed. However, *in situ* inspection systems offered by most OEMs have been adapted to allow the performance of this test without removing the rotor. Extra care is required with rotor-in inspection because of the potential for surface damage to the rotor retaining ring, which is used for supporting the jacking equipment, and because of the confined space involved.

15.22.3 Interpretation

Generally, “zero clearance” is the requirement for slot content design. Rewedging, including changes to the slot support system, may be required if the clearance does not meet this criterion. A minor amount of clearance may be permissible until the next outage if there is no oil contamination, the stator was recently rewedged, and the clearance is not widespread. However, the impact of all contributing factors has to be assessed, together with the results from visual inspection, wedge tap, and clearance tests, to determine the course of action.

15.23 STATOR END WINDING BUMP

This test, known as a *bump* or impact test, objectively determines how loose the stator end winding is, and if it is susceptible to high levels of end winding vibration. The test is most useful for large two-pole or four-pole generators and motors. Such machines are most likely to suffer from the end winding vibration deterioration process (Section 8.15).

15.23.1 Purpose and Theory

Magnetic forces tend to make the stator bars/coils vibrate at twice the power frequency (100 or 120 Hz) as well as at twice the frequency of any other strong harmonics in the stator current. Furthermore, any bearing vibration (at the rotational frequency) can be transmitted from the frame to the core and then to the stator end windings. If the length and mass of the end windings are such that they have a mechanical natural frequency near twice the power frequency, it is very likely that the end windings will vibrate, no matter how well they are braced. As discussed in Section 8.15, this will eventually lead to groundwall insulation failure due to fatigue cracking of the copper conductors or abrasion of the groundwall insulation in the end winding. One of the purposes of this test is to ensure that the end windings do not have a natural vibration frequency at 100 Hz or 120 Hz, for 50 or 60 Hz AC, respectively. As the end windings may also see some once per rotor revolution vibration from the stator frame, resonance at 50/60 Hz (for a two-pole machine) may also be of concern.

Similar to the wedge tightness test, if the end windings are hit with a hammer, the tightness of the end winding bracing system can be established by how much displacement occurs and how quickly the vibrations of the end winding damp out. If the coils/bars just “ping,” they are tight. If they respond with a dull thud, the blocking and bracing may be loosening.

Areas with the largest response should be considered as locations for fiber optic vibration sensors, if online end winding vibration monitoring is contemplated (Section 16.6).

15.23.2 Test Method

The best tool for this test is the standard vibration analysis instrumentation used by NDE (nondestructive evaluation) specialists. This equipment includes

- A “calibrated hammer” massing about 1 kg that can impact the end winding and measure the magnitude of the impact force with an accelerometer mounted on the hammer.

- Detection accelerometers that are temporarily bonded to the coils/bars (usually with bee's wax). At least two accelerometers are needed to measure the vibration in the circumferential and radial directions. A three-axis accelerometer would be even better.
- A fast Fourier transform (FFT) type of spectrum analyzer that can respond to frequencies up to about 10 kHz to simultaneously capture the three accelerometer responses and produce the frequency spectrum analysis. Figure 15.11 shows a plot of the normalized acceleration as a function frequency.
- For advanced structural analysis, software to compute the vibration mode shapes and amplitudes.

Specialized personnel are needed for this testing. Most OEMs and some large service organizations can provide the equipment and specialists.

The testing should be done at several locations at both ends of the stator. Performing the tests on coils/bars connected to the circuit ring buses is important, as the vibration pattern may differ from the rest of the coils/bars.

15.23.3 Interpretation

If the test reveals that there is a natural frequency within about −5 Hz and +10 Hz of twice the power frequency, and ±5% of running speed frequency, it is likely that severe end winding vibration may eventually occur. The upper limit is high as it allows for the decrease in resonant frequency that will occur as the stator winding temperature in the end winding increases [50]. If the end winding is expected to operate above

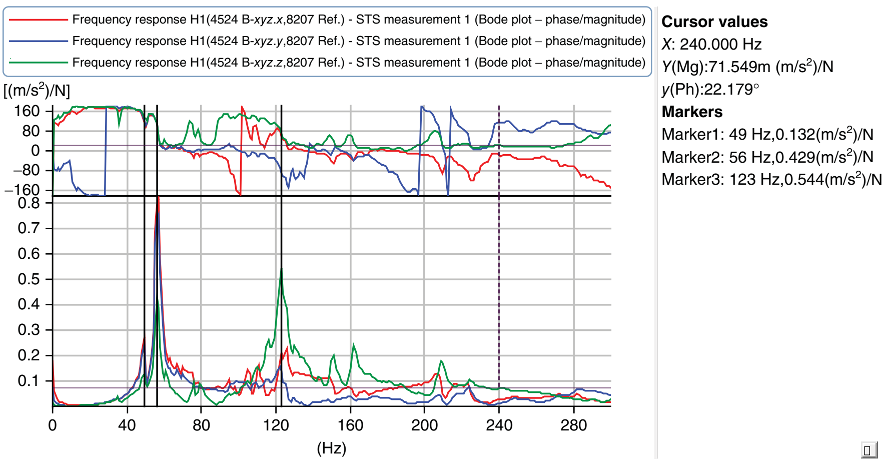

Figure 15.11 Bump test result from the endwinding of a 60 Hz two-pole turbine generator. The upper plot is the phase angle of the response while the lower plot is the normalized amplitude of the response in terms of acceleration per Newton of impact force. Unfortunately, there are significant resonant peaks at 60 and 120 Hz on this machine, which implies that the endwinding is likely to vibrate. The three lines represent vibration in the radial, circumferential, and axial directions. (Source: Iris Power-Qualitrol). *See color plate section.*

100°C, an even higher upper limit may be needed. Also, if the vibration response (accelerance) is greater than 0.44 m/s^2 per Newton of applied force, and near a forcing frequency (50/60 Hz for a two-pole machine, and 100/120 Hz), the end winding may already be loose. The OEM or a large service organization should be contacted for possible remedies [51].

It is difficult to set an acceptable level for vibration damping. Instead, a fingerprint of the vibration spectra should be obtained when the stator is new and is presumed to have a tight blocking and bracing system. The test is then repeated in the same locations every 5 years or so. If there is any change in the resonant frequencies or the damping over the years, this will be an indication that the end winding support system is becoming less effective.

15.24 STATOR PRESSURE AND VACUUM DECAY

This is a pair of tests that are performed on direct-water-cooled stator windings (Section 1.1.5). The tests detect if there are any small leaks in the water tubes (copper or stainless steel) that are within the stator bar (Section 8.16). The test can be performed on individual bars, or complete windings. Gross water leaks are usually immediately discovered online by hydrogen in water monitoring.

15.24.1 Purpose and Theory

End winding vibration and poor brazing methods can lead to small cracks in the water-filled tubes that run the length of stator bars for cooling or at the connections at either end of large-generator stator windings (Sections 8.15 and 8.16). Slow water leaks can degrade the groundwall insulation, leading to failure. Two tests are available to detect if small cracks in the coolant tubes have occurred. One is the pressure decay test and the other is the vacuum decay test. The basic idea is that if the coolant system cannot maintain a vacuum after the air has been evacuated, or if a static pressure is applied and the pressure gradually reduces, there is probably a leak in the coolant system. If a leak is detected, there are methods using tracer gases that are sometimes helpful in locating the leak. If leaks are confirmed, a capacitance map test (Section 15.7) may confirm if the water leak has degraded the insulation.

15.24.2 Test Methods and Interpretation

Pressure Decay Test This is a standard test to detect leaks from enclosed systems, and it is usual to perform this test after any dismantling of the generator. The stator winding coolant system is completely dried out internally by blowing air, and then by using a vacuum pump. Then the system is pressurized with dry air, nitrogen, or helium to the level of the design hydrogen operating pressure. The generator enclosure itself is at normal atmospheric air pressure. As the pressure is highest within the cooling channels, the pressure is in the same direction that would cause the water to leak. Any drop in pressure indicates that there is a leak in the system somewhere. The location of the leak(s) can sometimes be identified if a suitable "bubble" solution is applied at the potential leak sites.

The test is relatively insensitive to small leaks and is much affected by the changes in the environment temperature and barometric pressure. The pressure will drive the water in the leak direction and may aggravate the insulation damage. In a typical test at 300 kPa, a volume of 0.03 m^3 (1 cubic foot) must leak out of the generator to produce a change of 10 kPa (1.5 psi). Therefore, the test has to be done over about 24 h and very accurate pressure gauges are needed to obtain sensitive results. Ideally, there should be no drop in the pressure, after correction for winding temperature and atmospheric pressure. A 10 kPa drop in pressure over 24 h is significant.

Vacuum Decay In this test, a high vacuum is applied to the stator water coolant vacuum system fitted with a vacuum gauge and measurements of the decay in the vacuum are made at about 0.0002 kPa. Prior to the test, the coolant system must be thoroughly dried by first blowing dry air through the system and then by pulling a rough vacuum for 2 or 3 days. The test is very sensitive and can be applied without any access to the winding itself. Accurate results can be obtained in 1 to 2 h as compared to 24 h required for a pressure decay test [52]. The test is relatively insensitive to changes in ambient temperature and atmospheric pressure. Tests on individual bars may be done to find which bars are leaking.

The test may have to be repeated several times, because any water vapor will raise the vacuum pressure, indicating a test failure. The pressure differential is from the insulation into the coolant system and, thus, will not drive any water into the insulation. This test usually precedes the pressure decay test.

If there is no increase in pressure in 2 h, there are no leaks.

Leak Location If the bubble test does not locate the bar(s) with the leaks and the axial locations of the leaks, tracer gases can often be used. The winding is pressurized with a tracer gas, usually helium, and the potential leak sites are carefully inspected with hand-held detectors that are sensitive to the tracer gas. The test may take over a day to perform, as the helium detector must be within about 2 cm of the leak.

Rotor removal is needed to measure the entire length of the stator winding. Sometimes, the location of the leak at the stator bar surface can be a significant distance from the crack in the copper.

15.25 ROTOR POLE DROP (VOLTAGE DROP)

This test is used to determine if there are shorted turns in a synchronous machine rotor. The "pole drop" name alludes to its use on salient pole rotors, while "voltage drop" is used on round rotors. It is quite effective for all rotor sizes and speeds and does not require any special test equipment. However, this test is not completely reliable as some turn shorts can disappear when the centrifugal forces due to rotor rotation are not present. Similarly shorts may occur when the rotor is not spinning that clear when the machine is operating. As a result, the online method to detect shorted turns described in Section 16.7 may be more reliable.

There are two variations of the pole drop test. One simply measures the voltage across each pole. In the other method, the inductive impedance of each pole is calculated. For round rotors, usually the voltage drop across the turns in a coil is measured.

15.25.1 Purpose and Theory

For salient pole and round rotor windings, this test is designed to verify the presence of shorted turns. It takes advantage of the fact that if an AC power supply is applied to a mainly inductive circuit, shorted turns will create a significant reduction in inductive impedance. Thus, if an AC voltage is applied between the terminals of a salient pole winding and the voltage across each pole in it is measured, poles with shorted turns will have a lower voltage drop, due to their reduced impedance, than those with no turn shorts.

15.25.2 Test Method — Salient Pole Rotor

For small synchronous machines, it is often more convenient to remove the rotor for this test. On the other hand, it is usually possible to perform this test with the rotor in place if access to the individual pole connections can be obtained. This test also requires access to both ends of the rotor winding. This is readily available if the winding is connected to slip rings. If the machine has a brushless exciter with a rotating diode rectifier, the ends of the winding have to be disconnected from the rectifier to allow the test to be performed.

Voltage Drop Method The test equipment is simple, comprised of only a 120/240 V variac (variable auto transformer) plus common meters. The AC voltage is applied across all the series-connected poles via the variac, which is adjusted to a convenient voltage (say 100 V) that does not exceed the rated current of the winding. The voltage is then measured across the terminals of each pole. Poles with a lower voltage may have shorts.

Inductive Impedance Method A variation of the pole drop test is to measure the inductive impedance of each pole, which makes this method more sensitive as the resistive component is suppressed. It requires a wattmeter, ammeter and voltmeter, and is a little more difficult to implement. Voltage is directly applied to each pole from a variac. Even with the connections to other poles, the other poles will not cause a problem as long as the slip rings are not shorted. The voltage is increased until about 10 A flows through the pole. The resistance of the pole winding can be calculated from

$$R = \frac{W}{I^2}$$

where W is the wattmeter reading and I is the current. The AC impedance of each pole is given by Ohm's law ($Z = V/I$). Then the inductive impedance (X_L) for each pole can be calculated from

$$X_L = \sqrt{Z^2 - R^2}$$

The inductive impedance of each pole is measured in turn. The poles with a lower than average inductive impedance may have shorted turns. This test is more complicated than the normal pole drop test so it is less frequently used.

15.25.3 Test Method — Round Rotors

The rotor must be removed from the stator. If there are axial vent ducts through the wedges, and the copper turns in each coil are bare, it is sometimes possible to insert a voltage probe down the vent duct to contact each turn. Alternatively, if the retaining rings have been removed, each turn of each coil can be contacted in the end winding.

A 120/240 V variac or DC supply is used to create a voltage between the slip rings (if present). The voltage across each coil and each turn is measured.

15.25.4 Interpretation

For salient pole rotors, if the minimum voltages (or inductive impedances) measured across any of the pole winding coils is 10% or less than the average of the voltage drops (impedances) across all the poles, it is unlikely that there are any shorted turns in the winding. The only caution is that, in some cases, turn shorts are only present under the influence of the centrifugal forces from rotation, and at standstill these shorts are not present. If the minimum voltage measured across a coil is greater than 10% of the average value (that is, <0.9 of the average pole voltage drop) shorted turns are likely. Such turn shorts at standstill may “disappear” when the rotor is at speed. If there is no increase in bearing vibration (Section 16.9) and no increase in excitation current needed for the same load, it is likely the short is not present when running.

For round rotor windings, if the voltage drop between adjacent turns in a coil is 0, that turn is shorted.

The pole drop and voltage drop tests have a significant risk of giving both false positive and false negative indications.

15.26 ROTOR RSO AND SURGE

Both of these off-line tests can be used for detecting shorted turns, ground faults, and high resistance connections in synchronous machine rotors. The data obtained from the recurrent surge oscillography (RSO) test can also be used to identify the location of the fault. These test procedures are primarily for round rotors in synchronous turbine generators and motors, but can also be applied to salient pole rotors.

15.26.1 Purpose and Theory

Both tests rely on the fact that a healthy rotor winding, when viewed from the positive and negative terminals, is electrically symmetrical with respect to the rotor body, and a winding with a turn fault, ground fault, or high resistance connection is not.

RSO Test This test assumes that the coils in a rotor slot are essentially a transmission line with a specific characteristic (or surge) impedance. If low voltage (<100 V peak), identical high frequency electrical pulses are injected at both ends of a healthy winding, their travel time through the winding surge impedance will be identical when they reach the other end. If a turn short or ground fault exists in a rotor winding, the impedance seen by each set of pulses will be different and some of the pulse energy will be reflected back to the end of the winding, thus changing the input pulse waveforms in a way that is dependent on the distance to the fault. Thus the fault will produce different waveforms at each end of the winding unless the fault is exactly halfway through it. This technique is a variant of time domain reflectometry. A high resistance connection also creates different winding impedances to produce a similar effect.

This technique can also be applied to rotors with slip rings (with the DC field current disconnected) while the rotor rotates. Thus, it can detect turn shorts or ground faults that disappear when the rotor is at standstill.

An experienced operator is required to perform this test as interpretation of the results can be difficult.

Surge Test This is based on the same principles as the stator winding surge test described in Section 15.16. If a turn short, ground fault, or high resistance connection exists in a rotor winding, a voltage surge applied to the winding will cause oscillations at a frequency that depends on the presence of shorted turns. If high frequency surges are injected at one end of the winding and then at the other end of the winding, the resulting waveforms will be seen to be different. The peak voltages used for such tests are much lower than that for stator windings as round rotor and salient pole rotor windings have much lower operating voltages, typically well below 500 V DC.

15.26.2 Test Method

RSO Test A special instrument, sometimes called a *reflectometer*, can be used to perform the RSO test. Alternatively, a digital oscilloscope and a high voltage pulse generator can be used. If the machine has a brushless exciter, its field winding must be disconnected from the rotating diode rectifier to allow the test instrument to be directly connected to the winding.

The test instrument alternately or simultaneously injects identical, fast-rising, high frequency, voltage pulses with maximum peak magnitude of less than 100 V at each end of the winding. The potential at each injection point is then recorded as a function of time, using an oscilloscope. In the absence of a fault, identical records should be obtained for the two injection points due to the symmetry of the winding. Features found on one trace and not on the other are, therefore, indicative of a winding fault. The time at which the irregularity occurs can be used to locate the fault.

Surge Test The same test equipment that is used for stator winding surge testing can normally be used for round rotor and salient pole rotor windings. As for the RSO test, the rotor windings with brushless excitation must first be disconnected from the rotating diode rectifier. The rotor body must then be grounded for this test and it is advisable to perform a 1-min, 500 V IR test first (Section 15.1), to ensure that there are no dead shorts between the winding and ground. Providing the IR test results give a value of at least 1 MΩ, the winding can be surge tested. A peak voltage in the region of 500–1000 V is normally used and the voltage surges are applied to one end of the winding. The resulting waveform is stored electronically. The test is then repeated from the other end of the winding and the two stored waveforms are overlaid and compared for differences.

15.26.3 Interpretation

As already indicated, some experience is required to interpret the results of both of these tests, especially when a turn fault is indicated. It should be noted that for the standstill RSO and surge tests, some faults might not be detected. This is because the removal of the centrifugal forces present during operation may significantly increase the resistance of the fault to the extent that it may not be detected. For both tests, it is advisable to have a set of reference baseline test results taken when the rotor winding was known to have no faults in it. This aids in the interpretation of the results.

RSO Test The RSO test will detect ground faults having a fault resistance of less than about 500 Ω. As standard generator protection systems can usually detect such faults, the value of the RSO is mainly as a confirmatory test for ground faults.

The RSO test will detect interturn faults if the fault has a resistance of less than about 1 Ω. Faults that are significant during operation but are less severe when the rotor is at standstill may not be detected as they are likely to have a resistance of more than 10 Ω.

Surge Test If the two recorded traces are identical, no fault is present. On the other hand, if there are significant differences in their frequency, the type of fault present can be determined, by an experienced operator, from the nature of these differences.

15.27 ROTOR GROWLER

This is a simple test that has been used for many years to detect open-circuited bars in squirrel-cage rotors [53]. It can be particularly useful for diecast aluminum rotor windings in which none of the bars is visible. There are two types of growlers. One consists of a U-shaped laminated core with a multiturn 120 V AC coil wound on to it. This device is placed across the teeth on either side of a bar and moved axially from one end of the rotor to the other. This process is repeated for each suspect bar in the rotor. The other type also has a multiturn 120 V AC coil wound onto an open V-shaped laminated core into which the rotor outside diameter will fit. In this type, each bar is scanned by turning the rotor while it is in the core "V." There is a limit to the size of rotor that can be tested by this latter type.

15.27.1 Purpose and Theory

Growlers are used to detect rotor bars that are open-circuited inside the core and therefore not visible. The growler induces a current in healthy bars by creating a flux, which encircles them; that is, the flux generated by the winding in the growler passes around a circuit consisting of its own and the motor rotor laminated cores. For the U-shaped growler, a magnetic strip, such as a hacksaw blade, or a metal plate integral with the growler is placed on top of the bar. This metal strip will rattle under the influence of the magnetic force from the induced core flux if there is a break in the bar. Also, if the bar is loose in the slot, it will be heard to rattle. The open V-type of growler usually has an ammeter and resistor in series with its excitation coil to limit the current from the power supply. The ammeter reading will drop significantly when an open bar passes through the growler "V."

15.27.2 Test Method

For this test, the rotor must be removed from its stator and be supported at either end. The supports used must be such that the rotor can be rotated by hand. For the simple U-shaped growler, each bar is traversed axially with the growler and those that produce vibration in the metal strip will have open circuits in them. With the open V-type growler, the rotor is placed in it and rotated slowly. Any bars that indicate a significantly lower ammeter reading as they pass through the center of the "V" will have open circuits in them.

15.27.3 Interpretation

The growler will reliably detect completely open-circuited bars as indicated earlier. It will not, however, detect open circuits that close up with the rotor at standstill and are cold.

15.28 ROTOR FLUORESCENT DYE PENETRANT

This test is used to detect the presence of hairline cracks in squirrel-cage rotor windings.

15.28.1 Purpose and Theory

Hairline cracks in fabricated winding rotor bars, shorting rings, and the brazed or welded joints are often difficult to detect with the naked eye. This is also true for diecast winding shorting rings and their integral fan blades. If a fluorescent penetrant dye is sprayed onto areas with suspected cracks and an ultraviolet light beam is aimed at the dye-treated surfaces, cracks will glow in the presence of this light.

15.28.2 Test Method and Interpretation

Spray a fluorescent penetrant dye from an aerosol can on to the parts of the rotor winding suspected to have cracks in them. Then shine an ultraviolet light on the area. If cracks are present, the entire length of the crack will glow under the light.

15.29 ROTOR RATED FLUX

This test can be used to check for cracks or breaks in squirrel-cage rotor windings, to indicate the severity of rotor lamination surface smearing due to stator rubs, and to detect loose rotor cores.

15.29.1 Purpose and Theory

If an AC current is passed through the shaft of a squirrel-cage rotor, it will induce a flux in its core which, in turn, will generate currents in its winding. If the rotor core is mounted on shaft spider arms, the induced flux and current can be generated by a winding made from a number of turns of cable that is passed through the spider and connected to an AC power source. If the excitation flux is selected to produce enough ampere-turns to induce rated core flux, the rotor outside diameter surface will become hot in areas where the lamination insulation is shorted and the currents induced in the winding will create core hotspots at rotor bar cracks and open circuits. These can be seen with an infrared thermal imaging camera. If the rotor core is loose, it will vibrate under the influence of the magnetic flux induced in it. Also, if iron shavings or magnetic paper are placed over the rotor surface, a clear representation of each bar covered by these should be seen. If any discontinuity or misalignment appears, there is a broken bar present.

15.29.2 Test Method

AC flux is induced in the rotor core and currents in the rotor squirrel-cage winding by applying a low voltage across the ends of the rotor, or by a stator core loop test similar to that described in Section 17.2. Safety precautions are very important during this test. Iron shavings or magnetic paper is placed over the rotor and a clear representation of the bar should be seen. If any discontinuity or misalignment appears, there is a broken bar present. If there is evidence of broken bars, warm the rotor winding by increasing the applied voltage. This will produce hot spots at the location of a cracked rotor bar, which should be detected and recorded with an infrared scanning device. If the rotor core is loose, it will vibrate during this test.

15.29.3 Interpretation

If hot spots on the rotor surface are greater than 10°C above the ambient core temperature, significant surface lamination insulation shorting is present and/or there are broken rotor bars. The majority of cracked or broken bars occur at or near the connections between the bars and short-circuit rings. Sometimes, the fault area may spark due to the voltage differential across the crack. This test can also to be used to determine the effectiveness of rotor core and winding repairs.

15.30 ROTOR SINGLE-PHASE ROTATION

This is an often-used test for broken rotor bars, short-circuit rings, and the joints between them in squirrel-cage induction rotors. The test can be performed without motor disassembly.

15.30.1 Purpose and Theory

If a single-phase 50/60 Hz power supply is connected across two of the three stator winding leads of a squirrel-cage induction motor, the resulting current flow will create a non-rotating sinusoidal flux in the air gap. Breaks in the rotor cage winding will create a nonuniform impedance in the rotor winding. If the rotor with cage winding breaks is rotated through the air gap flux created by a single-phase power supply, the current drawn will fluctuate significantly due to the variation in rotor impedance.

15.30.2 Test Method

This test is done with the rotor within the stator bore and able to rotate. An instrumented, single-phase AC power supply is connected to two stator winding leads to apply a voltage of 10–25% of the rated line-to-line value. The rotor is slowly turned while monitoring the stator winding current. It is important to note that this test will produce rapid heating in both the stator and rotor windings; therefore, the test time should be kept to a minimum.

15.30.3 Interpretation

If current fluctuations exceed 5%, this indicates broken rotor bars and/or short-circuit rings. It should, however, be noted that this test may not detect cracks or breaks that close up when the rotor is not at normal operating speed and temperature.

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CHAPTER 16

IN-SERVICE MONITORING OF STATOR AND ROTOR WINDINGS

Chapter 15 discussed 30 different tests that can be performed on rotor and stator windings to assess insulation condition and squirrel-cage rotor winding integrity. All these tests are done with the motor or generator shutdown and sometimes disassembled. This chapter describes a number of different monitors that determine winding condition during normal operation. The advantages and disadvantages of in-service monitoring versus off-line testing were reviewed in Section 14.2.

The monitors in this chapter measure thermal, chemical, mechanical, and electrical phenomena, and together they can detect most of the important stator and rotor winding failure processes that are likely to occur. For the first time in history, it is now possible to have a very high likelihood of detecting most (but not all) of the likely problems that can lead to winding failure, without ever having to remove the machine from service. Thus, if the capital resources are available to implement all the appropriate monitors on a machine, times between shutdowns for visual inspections can be greatly increased (Chapter 20). All the monitors identified in this chapter are commercially available. Other works that review this subject are books by Tavner et al. [1] and Gonzalez [2]. Extensive bibliographies on motor testing and monitoring are in References 3, 4.

Section 14.4 discusses the software to convert the data produced from online monitors into practical information that can be used by machine operators and maintenance personnel. In general, except for alarms presented to operators indicating that exceptionally high temperatures or very small air gaps have been detected in a machine, the output from these monitors is intended for use by maintenance personnel. Most of the monitors detect problems years before failure (i.e., a ground fault) will occur. As plant operators tend to only focus on the very short term, it is best not to provide monitoring output data for them to analyze. In fact, most operators, if given access to many of the monitors described in the following sections, will tend to say that they do not work. They tend to feel that if a monitor output changes, and immediate failure does not occur, then the monitor is defective.

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

16.1 THERMAL MONITORING

Insulation failure caused by gradual deterioration of the insulation by long-term operation at high temperatures was extensively discussed in Chapters 8–13. Thermal deterioration is one of the leading causes of failure in air-cooled machines, especially hydrogenerators, gas turbine generators, and motors of all sizes. The deterioration rate depends on the operating temperature of the insulation and the duration at that temperature. The higher the temperature and/or the longer the operation at that temperature are, the more deteriorated the insulation will be. Thus, it is not surprising that virtually all stator windings, above a few hundred kilowatts or horsepower, are equipped with embedded temperature sensors. In most cases, these sensors are used during initial machine acceptance testing and, once in operation, are connected to alarms to warn of very high temperature excursions. However, maintenance personnel can sometimes diagnose that certain failure processes are occurring by monitoring and trending winding temperature information.

This section reviews how to make better use of the existing temperature monitors in motors and generators, to extract diagnostic information. Other online temperature monitoring such as infrared thermography is also discussed. Temperature monitoring, especially where temperature sensors are already in place, is probably the most cost-effective and easiest monitoring to perform.

16.1.1 Stator Winding Point Sensors

Small-machine stator windings rarely have temperature sensors within the winding. The most they may have is a thermal cutout switch, which turns off the machine if the winding operates above a specified temperature. Some small motor and generator stator windings may be fitted with a thermistor to give an alarm if a specific temperature is reached. However, modern stator windings in larger motors and generators normally have at least a few temperature sensors, which can be continuously monitored. These sensors measure the temperature at specific points. They can be at a variety of locations:

- *Embedded within the Stator Winding*. In random-wound machines, these are inserted between coils. In form-wound machines, they are between the top and bottom coils in a stator slot (Figure 16.1). In these locations, the sensor is most sensitive to the copper temperature, rather than the stator core temperature or the cooling air temperature. The sensors will be 5–20°C cooler than the copper in an indirectly cooled machine. The thicker the groundwall insulation is, the greater will be the temperature difference. Consequently, older windings and stators operating at higher voltages have the greatest temperature difference between the copper and the sensor. In most air-cooled motors and generators, 3–12 stator slots may contain sensors. These slots are randomly selected, except in 2.3–4.1-kV stators, in which the sensors are installed in slots containing coils operating at a low voltage. (Recall that such stators usually do not have semiconductive coatings on the coils and, thus, an effort is made to not expose the sensors to high voltages.) The axial position of the sensor depends

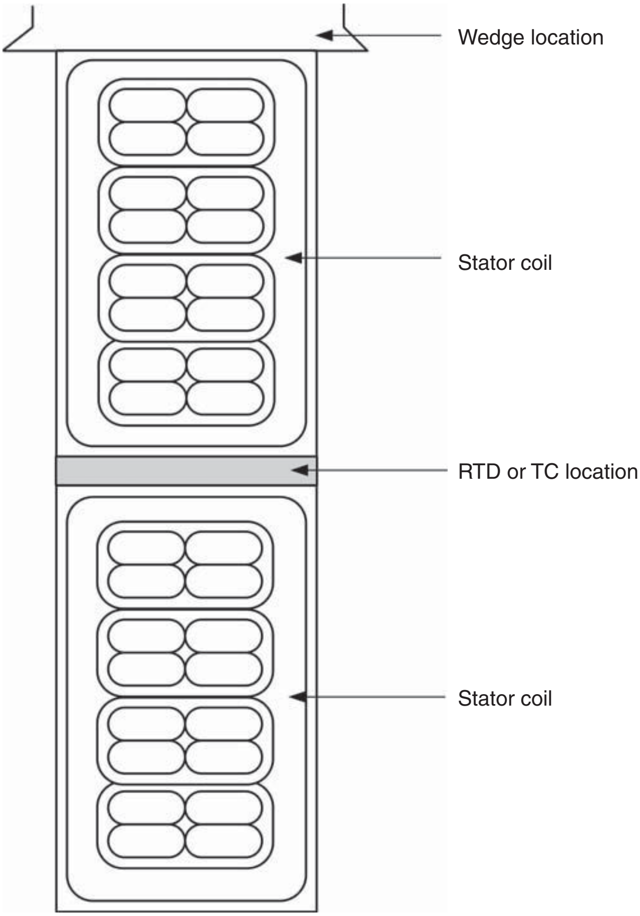

Figure 16.1 Placement of an RTD or TC between the coils/bars in a stator slot.

on the cooling system. The sensors should be installed at the end (or middle) of the slot, where the temperature should be the hottest.

- *Cooling Water or Gas Channels*. In direct water-cooled stator windings, temperature sensors are installed in the ground side of the water coolant hoses, on the end of the stator where the water has passed through the stator bar. Similarly, sensors are placed near the hydrogen gas outlet duct at the end of the direct hydrogen-cooled stator bars. Usually, there is a sensor for each bar in a water-cooled winding. On direct hydrogen-cooled stator bars, one sensor per parallel is usually used.
- Stator core, to measure the core temperature.
- Stator frame, although this is only loosely correlated to the winding temperature.

- At the air or hydrogen gas inlets and outlets of water coolers in totally enclosed machines to measure the temperature of the coolant leaving and going back into the machine.

There are many types of temperature sensors employed in machines. The most common is the resistance temperature detector (RTD). This sensor takes advantage of the fact that the electrical resistance of a conductor is directly proportional to the temperature. RTDs contain a thin strip of metal, many centimeters long, with a nominal resistance of 10 or 100 ohms. A fixed current is passed though the metal strip, and the voltage across the strip is measured. This allows calculation of the resistance. As the temperature dependence of the resistance is known, the temperature can be calculated. RTDs used in stators usually have three leads. A modified Wheatstone bridge measures the resistance, from which the temperature can be calculated. To reduce interference and thus obtain better readings, the leads from superior RTDs should be shielded. RTDs tend to be installed between the top and bottom coils in slots.

The thermocouple (TC) makes use of the property that when two dissimilar metals are welded together at a single point, and the metal leads are brought away from the heat source, a voltage will be induced that is proportional to the temperature at the weld. The output of the TC is two wires composed of the two different metals (copper and constantan are the metals often used for machine TCs). As with RTDs, noise immunity is better if the two leads are shielded. TCs tend to be used for measuring water- and hydrogen-cooling channels and core temperatures in large turbine generators.

16.1.2 Rotor Winding Sensors

The rotor winding temperature sensor is usually the winding itself. For synchronous machine rotor windings that employ slip rings, the voltage and current applied to the slip rings can be accurately measured. This allows the calculation of the rotor winding resistance from Ohm's law. As discussed in Section 15.4.2 and Equation 15.3, the resistance of the rotor winding will vary with temperature. With an initial calibration, the average rotor winding temperature can be inferred from the rotor current and voltage measurement. Most manufacturers can then provide a rotor temperature indication for synchronous machines with slip rings. This average temperature will not be indicative of the temperature of hot spots; for example, where there are local blockages of cooling gas channels. The indication is most useful in detecting rotor winding overloading or general malfunctions in the machine cooling system. As discussed in Section 16.7, an apparent but false reduction in rotor temperature will be detected if shorted rotor turns occur. Such shorted turns reduce the DC resistance of the rotor winding, which is interpreted as a phantom temperature reduction.

Temperature sensing of rotors with brushless excitation systems or induction motor rotors is not easily achieved. The problem is bringing the temperature signal off the rotor, in the absence of any slip rings. In addition, the very high rotational forces imply that the temperature sensors must be very mechanically robust.

Point temperature sensors for rotor windings have been developed for research or special commercial applications. These sensors tend to use a TC, from which the output voltage is converted into a digital signal and broadcast off the rotor using a radio frequency transmitter [5]. These sensors are point temperature sensors. Careful thought is needed for their placement. They are rarely employed in normal motor or generator applications.

Monitors are also available from VibroSystM for monitoring the temperature of rotor poles using sensors mounted on the stator, in hydrogenerators [6].

16.1.3 Data Acquisition and Interpretation

In the past, a machine equipped with temperature sensors may have had one or two of them connected to an alarm, to warn operators when very high temperatures were occurring in the machine. Although operators may have manually recorded temperatures on a periodic basis, rarely was this information used for diagnostic purposes.

The introduction of computer-based SCADA, computer-based protective relaying, and computer-based machine data acquisition systems facilitated the direct and continuous monitoring of all the temperature (as well as vibration, coolant flow, etc.) sensors in a machine. More importantly, this data can be continuously archived in a computer database and stored with the ambient temperatures, voltage, current, and other relevant operating data taken at the same time.

Once the data is stored in a computer file, relatively simple programs can enable dynamic temperature alarming. That is, instead of the high temperature alarm being set based on the maximum measured temperature rise for the hottest day of the year with the machine at full load, the alarm temperature is determined from minute to minute, based on the ambient temperatures and the present stator/rotor current. With an initial calibration, and knowing that the winding temperatures are approximately proportional to the current squared, a temperature alarm can be raised even if the machine is operating at 10% load. This allows problems such as coolant channels that were inadvertently blocked during maintenance to be found at low load, and before major winding damage may result.

In addition, from a maintenance planning point of view, the database can be explored to determine the trend in winding temperatures over the years under constant operating load and ambient conditions. If there is a consistent increase in temperature under identical operating and ambient conditions over the years, then it may indicate one of the following problems:

- Gradual blockage of the heat exchangers or coolant ducts in the rotor or stator. If the winding temperature and coolant temperatures increase under constant operating conditions by more than a few degrees, then it may be wise to plan an inspection and cleaning. The use of the temperature monitoring in this way is a classic example of enabling the planning of maintenance, in this case cleaning, based on need, rather than an assumed time interval for the machine to become fouled.
- Another cause for a gradual temperature increase from sensors embedded in stator slots, especially if the coolant temperatures are relatively constant,

is delamination of the groundwall insulation and/or strand shorts. As the insulation delaminates, the thermal impedance between the indirectly cooled stator conductors and the core will increase (see Section 1.4.3). Consequently, the copper temperature will rise, increasing the measured slot temperature.

- If there is an erratic variation in temperature of more than a few degrees over the years (under constant operating conditions), then one possible cause is voltage imbalances between the phases, which tend to vary as plant load requirements shift or the energy supplier has power quality problems (Section 8.1).

The key requirement for monitoring is the economic archiving of all the temperature and operating data. Most machine original equipment manufacturers (OEMs) and protective relay manufacturers can easily provide the data to be off-loaded to a computer. Data acquisition systems (sometimes called *scanners*), both general purpose and specific to machines [7], are also widely available.

16.1.4 Thermography

Infrared thermal imaging cameras are widely used in plants to find overheated electrical joints and cables, hot spots in boilers and process fluid pipes, and hundreds of other applications. Such cameras are sensitive to the infrared portion of the electromagnetic spectrum. As hot objects give off infrared energy in proportion to its temperature, the normal temperature of the surface of apparatus can be easily assessed, and the location of any abnormally hot areas is determined. Modern thermal imaging cameras contain computers to directly indicate the temperature of the surfaces, as well as to provide the ability to compare past images with the present image, enabling changes in the thermal image to be easily detected.

As applied to motors and generators, thermography has limited use, because key areas cannot be observed when the machine is in operation. However, gross problems such as severe cooling system blockages can be detected.

If only the machine surface can be observed, then comparison of the present image with past stored images with the machine operating under the same load and much the same ambient temperature will give a general indication if the machine is getting hotter. This is particularly true for totally enclosed fan-cooled (TEFC) enclosures for which all the heating losses in the stator and rotor are dissipated on the outer surface of the frame. The first image is not likely to be informative, and any temperature differences over the surface are probably a natural result of how the cooling system operates. However, if the images are stored over the years, and if more recent images show most of the machine surface and outlet cooling air to be getting warmer, then this is most likely due to general blockage of the cooling system. This can occur if the machine is open-ventilated and the stator and rotor core ventilation ducts and/or filters have become clogged with dirt. In machines with heat exchangers, the cooling channels may have become obstructed. Because of natural changes in the machine surface, which can affect the measurement, temperature differences should be consistently about 5°C higher than in the past (under the same load and ambient conditions) to be considered significant. If uncorrected, thermal deterioration of the insulation will occur.

In comparison with past stored images of the entire machine, if one particular area is showing a greater temperature difference to the rest of the machine than it has in the past, there may be several causes:

- Local blocked cooling passages in the stator, or perhaps only one heat exchanger is becoming clogged
- A phase-to-phase voltage imbalance, resulting in one phase running hotter than the others.

Thermography can also be used to ensure that the connections from the power system to the machine are well made. If a general increase in termination box temperature is occurring over the years (or after a maintenance outage), then the connections may not be properly torqued, or they may be oxidizing. However, the greatest sensitivity is obtained if the termination box can be opened and the thermal imaging camera can directly see the connections. Alternatively, the termination box can have infrared windows installed. If one connection is hotter than the other two or if there is a significant temperature increase (more than 5°C under the same load and ambient conditions) from past readings, then the connections may be degrading. An offline conductance test or thermal imaging test (Sections 15.4 and 15.5) would confirm this.

16.2 CONDITION MONITORS AND TAGGING COMPOUNDS

Condition monitors, sometimes also called *core monitors*, are essentially smoke detectors. As they are applied to large hydrogen-cooled generators, they are called *generator condition monitors* (GCMs). These devices were first developed to detect stator core problems. GCMs are applied to hydrogen-cooled machines to detect severely overheated insulation within the generator. Sometimes, condition monitors are used with "tagging compounds," which are special paints that emit characteristic chemicals when exposed to specified high temperatures. The compounds, when released, can trigger the condition monitor and provide a much better indication of the temperature and location of a hot spot.

16.2.1 Monitoring Principles

GCMs The first condition monitors were developed in the 1960s specifically to detect burning of the stator core lamination insulation in large hydrogen-cooled turbine generators (Section 13.1). When overheating occurs inside the generator, any organic material affected, such as epoxy insulation, will thermally decompose to produce a great number of particulates ("smoke") with the size of condensation nuclei of 1–100 nm. These are readily detected by the GCM because, under normal operation, particulates of this size should not be present in the hydrogen gas [8]. The condition monitor is able to detect burning organic material, whether on the rotor, the stator winding, or in the stator core.

The condition monitor is installed in the recirculating hydrogen gas stream as close to the generator as possible to keep piping lengths short. This is essential because the rotor fan differential pressure, which is not substantial, is used to produce the flow of hydrogen through the GCM. Because GCMs are fully integrated with the hydrogen cooling system, with the consequent safety concerns, GCMs tend to be very expensive.

In the GCM, the hydrogen gas flows through an "ion chamber" where it is bombarded by a weak nuclear radiation source. This produces a large number of hydrogen ion pairs, in which the negative ions are attracted to a collector electrode. The current produced is amplified and displayed as a percentage on the GCM front panel meter. Changes in gas flow, pressure, and temperature also affect the detected current flow so these must be maintained constant.

When particulates are introduced in the ion chamber with the hydrogen gas, the current will decrease. This is because some of the ions become attached to the particulates, greatly increasing the mass-to-charge ratio. As the mobility of the particulates is less than the ionized hydrogen, fewer ions are collected per second, resulting in reduced current. Therefore, the reduction in current is proportional to the number of particulates produced and, hence, the extent of overheating. The output of the GCM is in percentage of current flow. If the output is 100%, no particles are present, and the organic insulation material in the machine is presumed to be healthy. If the current falls to 50%, some particles are present and possible burning of the insulation somewhere in the machine is indicated. The GCM output is usually continuously plotted on a graph of percentage of current versus time, or transmitted to the plant computer for archiving.

Most modern GCMs have a preheated ion chamber to vaporize any oil mist, which can be present in the hydrogen atmosphere. This is done to eliminate nuisance alarms because of oil mist rather than particulate emission from overheating. The theory is that if the ion chamber is heated only sufficiently to gasify the oil, the temperature required (roughly 160°C) is not enough to gasify any particulates from actual overheating, and only true alarms will be received. Some manufacturers of GCMs claim that hot ion chambers desensitize the GCM by gasifying real particulates from overheating. It seems that desensitization may take place with hot ion chambers, but this can be compensated for by changes in the alarm levels [9].

Tagging Compounds Most insulation will not produce particulates (smoke) until it is at a very high temperature. In rotor and stator windings, if the groundwall insulation is at such a high temperature, it is likely that a ground fault will follow within minutes or hours. This is in contrast to stator cores, where the core lamination insulation can burn locally but this does not imply that the machine will fail even within the next few years, if at all (a few shorted laminations are not hazardous to the machine). Consequently, GCMs are usually not able to give much warning of overheating problems in the rotor and stator windings.

To overcome this limitation, tagging compounds were developed in the 1970s to be used in conjunction with GCMs. Tagging compounds are applied as a paint to any desired surface in a hydrogen-cooled or totally enclosed air-cooled machine. Usually, several different types of tagging compounds will be used in the same machine. When the surface heats up to a specified temperature, particles with unique chemical signatures are released into the cooling air or hydrogen [9]. These particles will normally trigger the GCM alarm, because they have the same particle size as smoke. Some types of GCMs have the ability to divert the hydrogen or air stream containing these particles through a filter, which can trap the particles for later analysis. When a GCM alarm is raised, the filters are removed from the GCM and the particles subjected to chemical analysis, with either a gas chromatograph (GC) or a mass spectrometer (MS). The chemicals in the tagging compounds are easy to identify in the GC or MS. The idea is that if these chemicals are detected on the filter, the surface that was painted with them reached the temperature at which the chemicals are released. Thus, not only can the temperature of the winding be measured, but the location of the hot spot can be determined, as long as one knows where each type of tagging compound was painted.

The tagging compounds are usually chlorine compounds encapsulated within microspheres. When the microsphere exceeds a specified temperature, it bursts, releasing the chemicals. The critical bursting temperature is higher than normal for the winding, but much lower than the melting or ignition temperature of the insulation. Usually, there are many slightly different chemical compounds, each with its own unique chemical signature. Thus, if compound A is painted on the stator core, compound B on the rotor wedges, compound C on the rotor copper, and compound D on the stator endwinding, and compound C is detected in the GCM filter, then we know that the copper conductors (and the adjacent insulation) reached a specified temperature.

Although effective, because a GCM is required and the compounds usually have to be analyzed by the vendor at their lab, this temperature measurement approach is reasonably expensive and, thus, normally used only in very large generators where there is already some belief that overheating problems are possible. Many tagging compounds have a fixed life. As the chemicals can eventually diffuse out of the microsphere, if a high temperature occurs many years after compound installation, there may be insufficient compound left to trigger the GCM or allow analysis. How long the compound will be useful depends on the temperature of the surface the compound is painted on. If the surface is consistently near the "trigger" temperature, then the life will be shorter. The compounds should be replaced every 5 years or so. Unfortunately, the compounds can only be replaced during an outage, when the rotor is pulled.

Environment One makes GCMs and tagging compounds.

16.2.2 Interpretation

Interpreting GCM readings, in some sense, is very straightforward. However, as the typical output is an alarm to the operators, there have been many misunderstandings of GCM readings. Traditionally GCMs have produced an alarm when the current dropped below about 40% of normal. If an alarm occurred and the cause of the alarm was in the stator core, often the alarm would apparently clear itself after a few hours. Many operators believed that this was an indication of a "false alarm," that is, the GCM was not working properly. In reality, the GCM behaved as specified and detected the burning of the insulation. The operator was in error in not understanding that an alarm can naturally clear itself, and that a GCM alarm will often not result in a generator failure in the near future. Similar "false positive alarms" sometimes can occur if a surface within the machine is very hot and oil drops on the surface. The oil may “mist,” that is, create many small droplets that can trigger a GCM alarm. This alarm also does not indicate that failure is imminent, but does indicate that there are hot surfaces within the machine.

The plant operator should only be concerned with the GCM output if there is a sustained, very severe drop in current (say, to <20%), which indicates that a sizeable amount of insulation is creating smoke. In all other situations, maintenance personnel should be responsible for collecting and analyzing GCM data.

Without the aid of tagging compounds, the GCM is most useful for finding hot spots in the stator core. If the lamination insulation degrades by any of the mechanisms described in Chapter 13, then shorted laminations will occur. These shorted laminations will allow circulating currents to flow. If sufficient laminations are shorted, the current flow is such that the steel laminations may weld together and become hot enough to burn the insulation in the local area, triggering the GCM. After a few hours, the insulation in the affected area will be all burned away, and the GCM returns to a normal reading. As the insulation in other areas of the core degrades, leading to shorts, other burning will occur. The result is that the GCM yields bursts of activity over days, months, and even years. Eventually, enough lamination insulation will be compromised that a failure occurs because of very high local core temperatures. Thus, repetitive bursts of GCM activity over a sustained period are an indication of core lamination insulation burning. For many core lamination problems, a burst can sometimes follow a situation, in which the machine is overexcited.

If tagging compounds have been installed, then the particulate samples should be analyzed once a GCM alarm occurs. As discussed earlier, the chemical analysis, together with information on where each compound was installed, will indicate the location and the temperature.

16.3 OZONE

Ozone, or O_3, is a gas that is a by-product of partial discharge (PD) in air. PD in the air, that is, on the surface of the stator coils or bars, occurs as a result of loose windings, semiconductive or grading coating deterioration, and/or insufficient coil spacing in the endwinding (Sections 8.4–8.6, and 8.14). Devices have been developed that can measure the ozone concentration and, thus, detect these problems during normal operation of the machine. Ozone monitoring is only relevant to air-cooled machines rated at 6 kV and above.

16.3.1 Monitoring Principles

Two main methods are available to measure the ozone concentration. The cheapest method uses inexpensive gas analysis tubes, which are sensitive to ozone. These tubes, available from chemical supply houses, contain a chemical that reacts with the ozone. When the tube is broken open, a chemical inside the tube changes color and the approximate ozone concentration in the surrounding air can be read. The tubes come in different ranges of ozone concentration. To do a test, the tube is broken open by an operator in the stream of the air exhaust from an open-ventilated motor or generator. The test should be repeated about once every 6 months.

Ozone tubes cannot be used with totally enclosed machines. Persons using these tubes should be reminded that ozone is a health hazard, and many jurisdictions insist that personnel not be continuously exposed to ozone with concentrations higher than 0.1 parts per million (ppm).

A second technique uses an electronic instrument that can measure the ozone concentration continuously [10]. Many such ozone monitors are commercially available, as they are commonly used for pollution monitoring. A sensor is placed within the machine enclosure or in the exhaust air stream of an open-ventilated machine. The measuring instrument can be located remotely from the machine; thus, this method can be employed in both open-ventilated machines and totally enclosed machines. The instrument continuously measures the ozone concentration.

The ozone produced by a stator winding is affected by many factors, such as

- operating voltage
- air humidity
- power factor in synchronous machines. As discussed in Section 16.4, slot discharges can be affected by the ratio of reactive to real power, as it affects the forces acting on the coils/bars.

Thus, the trend in ozone concentration is only meaningful if the readings are taken with the above-mentioned factors held constant.

16.3.2 Interpretation

As with the electrical techniques to measure the PD activity on stator windings (Section 16.4), it is best to monitor the ozone in a machine over time. If there is a persistent increase in the ozone concentration, then other tests or a visual inspection should be planned. The ozone level depends on the magnitude of the surface PD, as well as the how many PD sites there are. Thus, similar to the tip-up tests (Sections 15.8 and 15.11), ozone measures the average surface PD activity. The monitor is not sensitive to a single severe PD site where failure is most likely to occur.

In open-ventilated machines, the concentration is high if it is near or exceeds 1 ppm. Concentrations of 0.1 ppm are immediately identifiable by ozone's characteristic odor. Some open-ventilated machines have had ozone concentrations in excess of 4 ppm [11]. With such a high level, there is usually widespread PD activity on all the coils/bars operating at high voltage in the stator winding. If a high level of ozone is measured, the operator should ensure that it is not due to a high concentration in the general environment by repeating the test remote from the machine. The normal ozone background of up to 0.1 ppm or so sets a lower limit for detecting winding problems. Ozone occurs naturally after lightning storms. In addition, copying and fax machines can increase the ozone background in a plant.

Ozone measurements within a totally enclosed machine will yield substantially higher levels of ozone. The ozone concentration not only depends on the rate of generation by the surface PD but also depends on the rate of ozone consumption. The latter depends on the surface area of materials that react with the ozone, such as uncoated steel and rubbers. This is highly variable from machine to machine. Thus, it is virtually impossible to state the level of ozone below which the winding is not suffering from excessive PD. The method for interpreting results is to note that if there is an increasing trend in ozone concentration over time (under the same machine operating conditions), then the rate of insulation aging is increasing. In totally enclosed machines, the rate can easily increase dramatically (10–100 times) in the first few years, but tends to saturate as equilibrium is achieved between creation and consumption of the ozone.

Semiconductive coating deterioration (Section 8.5) tends to produce the most ozone, even though this is a relatively slow failure process. Loose coils in the slot (Section 8.4) and inadequate endwinding spacing (Section 8.14) can produce moderate levels of ozone. Silicon carbide coating deterioration (Section 8.6), although creating very large PD, produces relatively little ozone, as the number of pulses and the number of PD sites are few. Consequently, higher levels of ozone do not imply a shorter time to failure.

Internal PD within the groundwall insulation does not produce measurable ozone. Thus, ozone monitoring is better for epoxy-mica windings than for the older asphaltic, shellac, or polyester-mica splitting types of winding.

16.4 ONLINE PARTIAL DISCHARGE MONITOR

This monitor directly detects stator winding PD electrical pulses during normal operation of the motor or generator. In most respects, it is very similar to the off-line PD test discussed in Section 15.12. Online PD monitoring can be done on a periodic basis, typically every 6 months. In addition, continuous online PD monitoring can also be performed. As PDs are a symptom, or cause, of about half the stator failure processes discussed in Chapter 8, online PD monitoring is a powerful tool for assessing the insulation condition in form-wound stators.

In off-line PD testing, the test system normally works in the low frequency (LF) range of 30 kHz to 3 MHz. In contrast, by far the most common frequency range for online monitoring is 30–300 MHz, known as the *very high frequency (VHF) range*.

16.4.1 Monitoring Principles

As discussed in Section 15.12, every PD creates a small current pulse that will propagate throughout the stator winding. As the pulses are typically only a few nanoseconds in duration, using a Fourier transform, each pulse creates frequencies from DC to several hundred megahertz [12]. These electrical pulses are detected and processed in several different ways by the various PD monitoring systems. Online PD monitoring systems are presented in IEEE 1434 and IEC 60034-27-2 [13,14].

In virtually all systems, the following elements are found:

1. Sensors, such as antennae, high voltage capacitors on the machine terminals, and/or high frequency current transformers (HCFTs) at the machine neutral

or on surge capacitor grounds are needed to detect the PD. These sensors are sensitive to the high frequency currents from the PD, yet are insensitive to the power frequency voltage and its harmonics. Most sensors have an inherent wide range of frequency sensitivity, usually from a few kilohertz, and sometimes ranging up to 1 GHz. The sensors are normally permanently installed on the motor or generator.

2. Electronics convert the pulse signals from analog to digital form. By far the most common approach is to use pulse magnitude analyzers that record the number of PD pulses per second versus PD magnitude. More recently, pulse phase analyzers (sometimes also called *phase resolved PD* (PRPD) analyzers) also digitally record where the PD pulses occur with respect to the power frequency AC cycle. In older systems, the signals were directly displayed on an oscilloscope or spectrum analyzer.
3. Signal processing techniques are used to reduce the information to manageable quantities and/or help discriminate PD signals in the winding from electrical noise to ensure more reliable interpretation. In addition, signal processing can perhaps be used to determine which type of insulation failure mechanism is occurring.

All of the existing PD measurement technologies available today rely on enhancing one or more of the above-mentioned elements to implement online PD monitoring. There are perhaps 20 vendors of online PD systems for machines. The following first describes the sensors employed, and then describes the monitoring systems.

PD Sensors Historically, the first sensor used for online PD measurement was a HFCT, sometimes called *radio frequency CT* (RFCT) [15]. The HFCT usually has a ferrite core, around which 10 to 100 turns are placed. The bandwidth of most commercial HFCTs that have a large enough opening is from about 100 kHz to 100 MHz, into a 50-ohm load. The HFCT, as originally used, was placed around the cable connecting the generator neutral point to the neutral grounding transformer or impedance. Each PD, which originates in the coils/bars operating at high voltage, propagates through the winding and generates a small current pulse in the neutral grounding circuit, which is detected by the HFCT [15,16]. On motors equipped with surge capacitors (Section 1.4.2), the HFCT can also be placed on the ground lead from the surge capacitor to machine ground (Figure 16.2). As the HFCT on surge capacitors is adjacent to the coils likely to have PD, much larger PD signals are detected in this location compared to the HFCT located at the neutral. HFCTs cannot be placed around power cables to the stator except in the smallest of machines because HFCTs do not have a large enough opening and the ferrite core of the HFCT will tend to saturate. Air core HFCTs (Rogowski coils) can be placed around the power cables but suffer from very low sensitivity because there is no ferrite core to concentrate the magnetic field from the PD current pulse.

The most popular sensors used in online PD monitoring are high voltage capacitors installed on each phase terminal. Perhaps 90% of the tens of thousands of

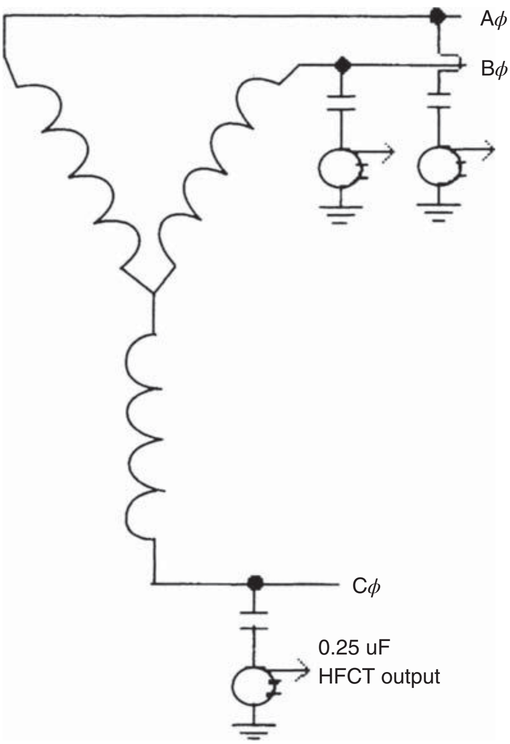

Figure 16.2 Placement of HFCT sensors on a surge capacitor to measure PD.

machines equipped for online monitoring use capacitive couplers. As in the off-line PD test, the capacitor blocks the 50 or 60 Hz high voltage while serving as a low impedance path for the high frequency PD pulses. The most common capacitor rating is 80 pF. However, earlier users employed capacitors from 375 to 1000 pF, as these were the most common capacitors used with laboratory PD detectors. In general, the capacitors feed a 50-ohm load. Thus, the basic bandwidth of the detection system is formed from the high pass filter of a capacitor in series with a resistor. An 80-pF capacitor detects PD pulse frequency content above 40 MHz. A 1000-pF capacitor detects signals above 3 MHz. In the absence of electrical noise, and assuming that the capacitors are located near the coils/bars most likely to experience PD, either capacitor size can detect the PD. If noise is present, communication theory shows that the signal-to-noise ratio is larger with the 80-pF capacitor [12]. In addition, the smaller capacitance implies that a much thicker dielectric can be employed in the same volume of sensor, greatly reducing the risk of capacitor failure.

Unlike the HFCT, the capacitor is connected to the high voltage terminal, and it will cause a ground fault if it fails. Thus, capacitor reliability is crucial, which is why the relevant IEC and IEEE standards outline the requirements for PD sensors [13,14].

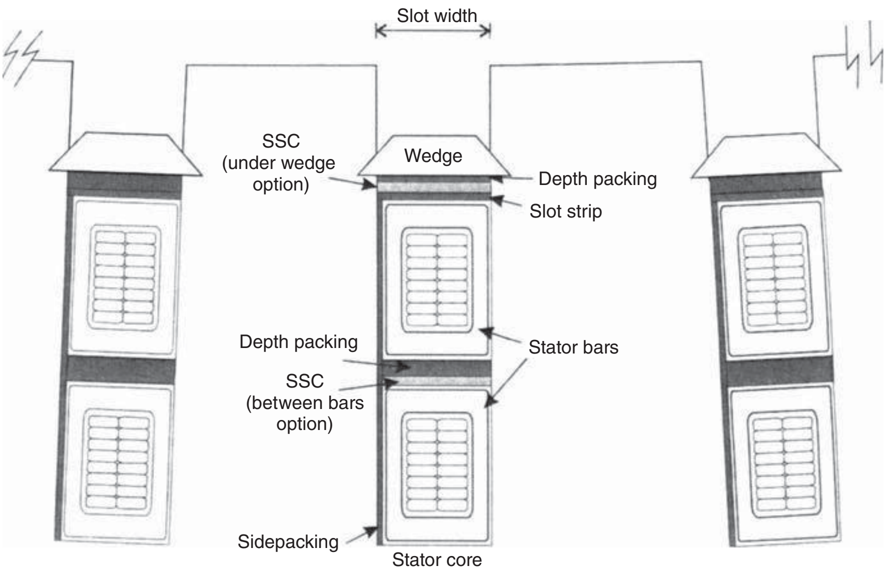

Figure 16.3 SSC location either under a wedge or between the top and bottom coils/bars.

Various forms of antennae installed within the motor or generator enclosure are also employed to detect PD online.* The most popular "antenna" is called the *stator slot coupler* (SSC). It is a strip-line directional coupling antenna that is usually installed under the wedge (Figure 16.3) in a stator slot containing coils or bars operating at high voltage [17]. The SSC directly detects the electromagnetic wave from PD that travels along the slot. The SSC has two outputs, so that it can directly distinguish between PD originating in the endwinding and PD originating in the slot, based on the direction the pulse is traveling. This type of sensor is primarily used in large, hydrogen-cooled turbine generators. SSCs have a bandwidth from 10 to 1000 MHz [17].

In addition, ultrahigh frequency (UHF) antennae, sometimes called *microwave antennae*, have been installed near stator endwindings to detect PD [18]. Such antenna may not be sensitive to PD occurring within stator slots.

Over the past decades, RTD and TC temperature sensors have occasionally been used as PD sensors [19,20]. The PD is usually detected not by the temperature sensor but, rather, by the cable from the sensor, through antenna-like coupling. Unlike all the PD sensors discussed earlier, these sensors do not need to be installed in machines, as they are already in the stator slot in large machines. This is a major advantage. However, the sensitivity to PD depends entirely on the proximity and length of the RTD cable to the PD sources, thus interpretation of results is highly subjective. Thus, the main proponents of using RTDs as PD detectors have stated

*Antennae installed outside of the machine enclosure will not detect PD, unless there are large openings in the enclosure. Faraday's law prevents the radiation of RF signals outside of a metallic enclosure.

that they should only be used when the machine is also equipped with conventional sensors such as capacitors or HFCTs [20].

Online PD measurements of motors driven by IFDs requires modified PD sensors. As the frequency content of the IFD surges and the PD are similar, the PD is easily submerged in “noise” from drive switching electronics. Variations of the methods discussed in Section 15.13 are sometimes used online.

Electrical Interference The main difficulty with online PD monitoring is coping with the electrical interference (noise) that is inevitably present. In the off-line PD test (Section 15.12), there is little interference so, usually, no measures are needed to separate the noise from the stator winding PD. Online monitoring is performed with the machine connected to the power system. There are many signals that originate in the power system that have the pulse-like nature of PD, including

- corona from overhead transmission lines;
- poor electrical contacts on buses, which tend to spark;
- corona from electrostatic precipitators;
- sparking from slip rings in machines and power tools;
- shaft ground brush sparking;
- fast risetime transients from IFDs and computer power supplies.

All the early online PD monitors used an oscilloscope or radiofrequency (RF) spectrum analyzer for displaying the signals from the PD sensors. With experience, a skilled test operator could subjectively separate the stator PD from the electrical interference based on frequency content, pulse shape, repetition rate, and/or phase position in the 50 or 60 Hz AC voltage cycle. With a suitably experienced person, this “subjective” PD monitor produced good results and is still the preferred method of many online PD monitoring service providers. When this test is done with an HFCT and a spectrum analyzer/specialized radio receiver for display, it is called *RFM* (radio frequency monitoring) or EMI (electromagnetic interference) monitoring.

For those desiring continuous PD monitoring, a subjective approach to separate noise from PD is not cost-effective and would likely lead to many false indications of stator winding problems. Furthermore, many machine users desire more objective data from even periodic monitoring, as expensive decisions are based on the data, and plant managers prefer something more substantial than a result that is hard to independently verify.

Two predominate methods have been developed to separate the PD from the interference. One requires the installation of at least two sensors per phase and measuring the relative time of arrival. The other is to look at each pulse and determine if the pulse shape is characteristic of PD or noise. The following presents information on how each method is implemented for different types of machines.

Hydrogenerator PDA Monitor The partial discharge analyzer (PDA) monitor system was developed in the late 1970s and was one of the first monitors that enabled nonspecialists to perform and interpret online PD tests [21]. The PDA monitor is intended specifically for salient pole machines (usually hydrogenerators) with a stator

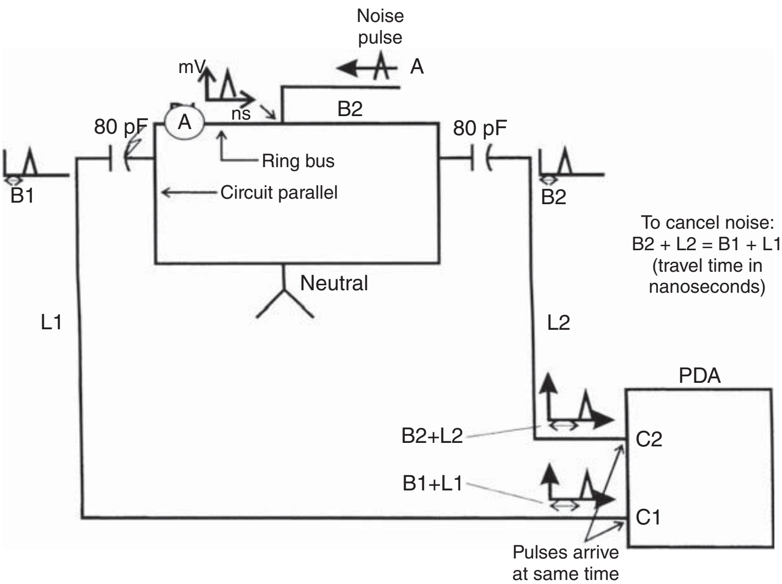

Figure 16.4 Location of capacitive couplers on the circuit ring bus of a hydrogenerator stator winding.

bore diameter exceeding about 3 m. At least two 80-pF capacitors are permanently installed per phase, at the ends of the circuit ring buses where the connections are made to the coils/bars (Figure 16.4). External noise is separated from stator PD on the basis of comparing the pulse arrival times from a pair of sensors at the PDA instrument, which in turn depends on the fact that pulses travel along the circuit ring bus at close to the speed of light: 3×10^8 m/s, or 0.3 m/ns.

A noise pulse from the power system in Figure 16.4 will travel in both directions along the circuit ring bus. If the busses are the same length, which is rarely the case, the pulse will arrive at the two capacitors at the same time. With a bus length of 5 m, the pulse will arrive at the capacitors about 17 ns after it entered the stator. The coaxial cable on the low voltage side of the capacitor will transmit the pulse to the PDA instrument. If the coaxial cables from both capacitors are the same length, the pulses will arrive at the pair of instrument inputs at the same time. Digital electronics will note the near simultaneous arrival of the pair of pulses, and digital logic will define the detected pulse as noise. (As noise can sometimes indicate problems in the power system such as deteriorating electrical connections, modern PDAs separately display the noise.)

If a PD occurs on a phase-end coil/bar at the end of the B1 ring bus (Figure 16.4), the signal will be almost immediately detected by the capacitor at the end of B1. Some signal also propagates around the circuit ring bus to the other sensor. The result is that the PDA detects the arrival of the PD pulse at the C1 input many nanoseconds (34 ns in the example) before it detects the pulse at the other coupler. As the pulse was detected by the C1 input of the PDA well before the pulse at C2, the PDA digital logic determines that the pulse must be due to PD near B1.

Similarly, a stator PD pulse occurring near the other sensor will be detected first by that sensor, and the PDA can determine that PD occurred in that portion of the winding. Thus, by measuring the relative time of arrival of pulses at the pair of sensors in a phase, the pulse can be identified as external noise or PD near each of the sensors. As sequential PD pulses are usually many tens of microseconds apart and the two detected pulses arrive at most 40 or 50 ns apart, two different PD pulses are unlikely to confuse the instrument.

The time-of-arrival method separates stator PD from external noise, but it is still susceptible to "internal noise" from within the machine. The most likely source of this is slip ring sparking occurring on the rotor. Although such sparking initially has a fast pulse risetime at the slip rings, by the time the pulse is coupled across the air gap into the stator, its risetime has degraded. Thus, by measuring the risetime, "internal noise" can also be separated.

Motor and Turbine Generator Monitoring Most motors, most small turbine generators, and some hydrogenerators with "wave" windings have circuit ring buses that are too short to ensure reliable separation of noise and PD on the basis of pulse arrival times. In such cases, it has been found effective to permanently install a pair of 80-pF capacitors per phase on the bus connecting the machine to the power system (Figure 16.5). One capacitor is normally installed per phase as close as possible to the stator winding terminals, usually in the termination enclosure. The other capacitor in the pair is installed at the potential transformer cubicle (if present), the circuit breaker or somewhere along the bus between the generator terminals and the breaker or transformer.

A variation of the time-of-flight principle is used to distinguish PD from external electrical interference. A similar instrument to the PDA, called the turbine generator analyzer (*TGA-B*), records the pulses from a pair of sensors [17,22]. A PD pulse from the stator will arrive at the M input of the instrument before it is detected by the capacitor further from the machine. Similarly, an external noise pulse will trigger the

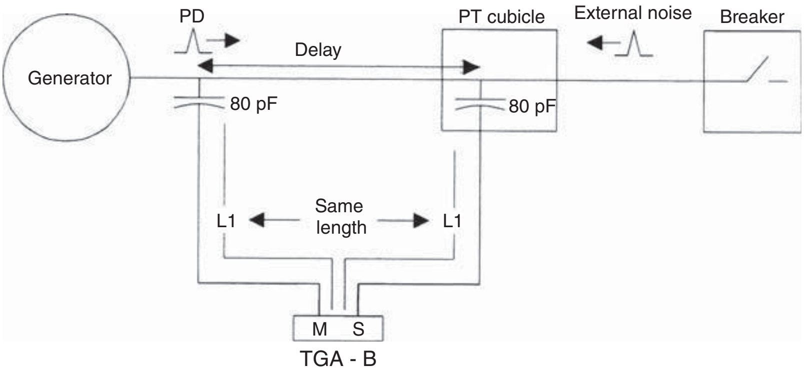

Figure 16.5 Installation of two capacitors per phase to separate turbine generator PD from power system noise.

S input of the instrument before it is detected at the M input. Thus, digital logic can determine which pulse arrives at what input first if the pulse is external noise or from stator winding PD. In fact, it is also possible to determine if PD or noise is occurring on the bus between the capacitors.

Research with this system showed that it is often unnecessary to install the set of sensors at the switchgear if the connection between the machine and the switchgear is a power cable longer than about 30 m. It seems that short risetime noise pulses will be both attenuated and distorted as they travel along the power cable to the machine sensor [22]. The distortion involves the slowing of the pulse risetime: stator PD pulses will have a short risetime, whereas noise that comes through the power cable will have a longer risetime. Thus, circuitry can separate the noise from the stator PD on the basis of risetime alone. Consequently, most motors, which often have power cable lengths in excess of 30 m, usually require only one sensor per phase. Generators usually have only short lengths of air-insulated bus in the connection to the power system, and will not see sufficient pulse distortion along a short bus. Thus, two sensors per phase are needed for most generators.

The pair of capacitive couplers mounted on the output bus has yielded false indications of stator winding problems in turbine generators rated at more than about 200 MVA. The problem was high levels of relatively fast risetime pulses that were not associated with stator PD, but rather seemed to be associated with stator core lamination sparking or relatively harmless sparking at the output bushings. The solution was the development of the SSC sensor [17]. Core and generator terminal sparking was found to yield longer risetime, highly oscillatory pulses from the SSC, as compared to the few nanosecond, unipolar PD pulses that are caused by PD in the slot or immediate endwinding. The SSC sensor only reliably detects PD in the slot it was installed in. A version of the TGA determines the pulse characteristics of each pulse to digitally discriminate between PD and all types of noise.

Data Acquisition The PD sensors are permanently installed in the machine during a convenient machine shutdown. In most online PD monitoring systems, portable instrumentation is used to record the signals periodically. The measurements typically take about 1 h. With the monitoring methods that use specialized instruments or modern digital oscilloscopes and spectrum analyzers, permanent records can be made of the signals. Experts, at the time of the measurement or at a later time, use their knowledge to determine what the true PD activity is, as opposed to the noise. Usually, these types of measurements are performed by specialized staff from test service organizations or machine manufacturers. Similarly, portable PDA and TGA instruments can also be used to regularly measure the PD activity from appropriate sensors. In this case, as noise is separated from PD on a pulse-by-pulse basis, plant technicians can perform the testing.

For machines rated at 6 kV or more, experience indicates that the monitoring should be done at least every 6 months. With this measurement interval, PD signals can be detected 2 years or more before serious insulation deterioration with a consequent high risk of failure has occurred. For lower voltages, the warning time may be less—as short as a few weeks with the thermal deterioration process in 3–4-kV stators. In this situation, continuous PD monitoring is more cost-effective.

The PD activity in a machine strongly depends on several factors other than the condition of the stator insulation condition [13,14,23]. These include

- stator voltage (increasing voltage strongly increases PD);
- gas pressure (increasing hydrogen pressure strongly decreases PD);
- humidity (usually increasing humidity will decrease any PD caused by electrical tracking or other endwinding PD);
- winding temperature (if the groundwall is delaminated, then as the temperature increases and the PD decreases as the internal voids shrink in size because of the components expanding);
- machine load (if the coils/bars are loose in the slot, increasing load will increase magnetic forces on the coils/bars, increasing PD).

Thus, to obtain trendable results, all the above-mentioned factors should be duplicated from test to test. Voltage and hydrogen pressure are the most important factors to keep constant from test to test.

Continuous PD monitoring systems are now widely installed to ensure that PD is detected with the maximum amount of warning time. With suitable software, such continuous monitoring systems also ensure that the PD data is collected under the same machine operating conditions [24,25]. Such systems also enable the remote reading of PD results, with appropriate communications from the plant. This can significantly reduce monitoring costs in plants in remote areas.

Online PD monitoring tends to produce higher PD activity on newly installed windings, for two reasons. The epoxy or polyester in new windings is usually not fully cured when the stator is first operated, but gradually completely cures in its first few months of operation. As partly uncured resin has a higher dielectric constant than cured resin, this will impose a higher stress on any small voids within the groundwall, resulting in greater PD activity until the resin is fully cured (Section 1.4.4). For nonglobal vacuum pressure impregnation (VPI) stators with coils/bars having a semiconductive coating (Section 1.4.5), the coating may be isolated from the core in some locations along the slot. The isolation may be due to oxide on the core or insulating varnish on the surface of the semiconductive coating. The result is that the coating is not fully grounded along the slot and, under normal magnetic forces, may cause sparking as the coating makes and breaks contact with the core. Eventually, the coil/bar vibration will abrade any oxide or varnish coating, fully grounding the coating and preventing the sparking. Experience indicates that results from online PD monitoring taken within the first 6 months or so after installation of a new winding should not be immediately taken to imply that there are winding problems.

16.4.2 Interpretation

The PD monitoring instrumentation will record all the PD pulses that are detected. The earliest online monitors usually displayed the PD pulses on an oscilloscope with respect to the 50- or 60-Hz AC cycle (Figure 15.5). More recently, pulse magnitude

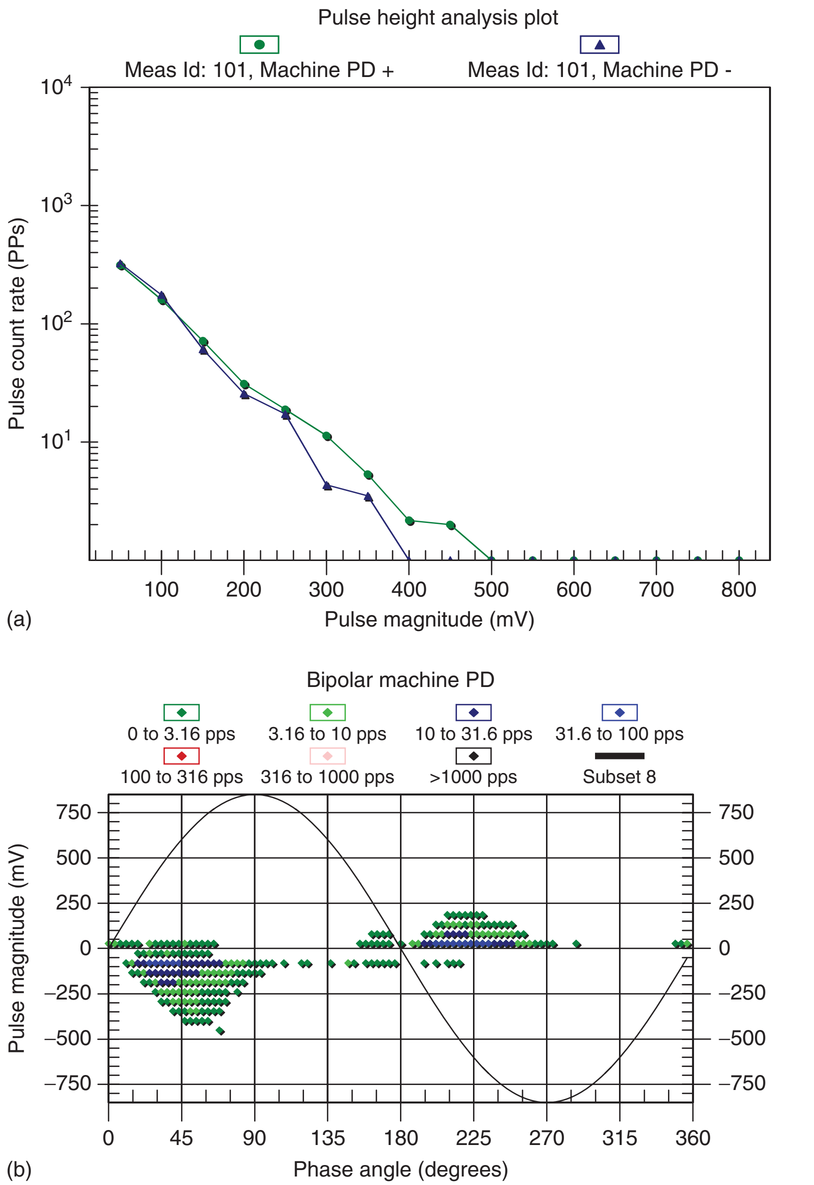

Figure 16.6 (a) Pulse magnitude and (b) pulse phase analysis plots from online PD detection. (Source: Iris Power-Qualitrol.)

analyzers enable the PD to be digitally recorded as a plot of the number of pulses versus the pulse magnitude (Figure 16.6a). Depending on the PD sensor and the recording apparatus, the magnitude can be measured in picocoulombs, millivolts, microvolts, milliamps, or decibels. The two-dimensional graph in Figure 16.6a shows the number of PD pulses recorded per second at each magnitude interval. Modern PD monitors also display the pulse magnitude analysis as a function of the AC phase position (Figure 16.6b). Because both positive and negative PD pulses are produced (Figure 15.5), the electronic pulse counters tend to record and display the two polarities separately (Figure 16.6a).

The fundamentals of online PD interpretation are given in IEEE Standard 1434 and IEC 60034-27-2 [13,14]. As mentioned in the section on off-line PD testing, the key result to interpret from any online PD monitor is the peak PD magnitude. The highest PD magnitude recorded, referred to as Q_m, is important because the PD site associated with the peak PD will generally have the greatest volume of deterioration. That is, Q_m occurs at the most deteriorated site of the winding. It is most likely that if failure is to occur, it will occur at this site. As PDs are somewhat erratic, IEEE 1434 and IEC 60034-27-2 have defined Q_m to be the magnitude associated with a PD pulse repetition rate of 10 pulses per second (pps), as recorded by a pulse magnitude analyzer. There are many other quantities that can be derived from the PD data, but most of these are associated with the average condition of the winding, rather than the condition of the worst site.

In principle, interpretation is comparative. That is, it is not generally possible to specify an acceptable level of Q_m or a level of Q_m at which there is a high risk of failure. The reasons are complex but relate to the inductive, capacitive, and transmission line natures of a stator winding, as well as the fact that PD is often only a symptom of the failure process, not a direct cause [26]. However, meaningful interpretation can occur by the following.

- Trending the Q_m on the same machine over time, using the same monitoring method.
- Comparing Q_m from several identical machines, using the same monitoring method.
- With some restrictions, comparing Q_m, from several "similar" machines, using the same monitoring method.

The following assumes that the electrical interference has been separated from the stator winding PD.

Trend Over Time This is the most common means of interpreting PD data, no matter which detection method is used. The idea is to get an initial fingerprint of the PD activity, such as the plots in Figure 16.6. The initial fingerprint is best when the winding is relatively new, that is, after 6 months or so of operation. If the winding deteriorates, the volume of the worst defects will increase, which increases Q_m. Thus, if Q_m increases over time, then the deterioration is increasing, and there is a greater risk of failure. Doubling of Q_m, every 6 months, is an indication that rapid deterioration is occurring and, eventually, off-line tests or a visual inspection of the winding are warranted.

PD does tend to saturate after a strong increase over time; that is, the PD may increase rapidly over several years (Figure 16.7). However, if the deterioration

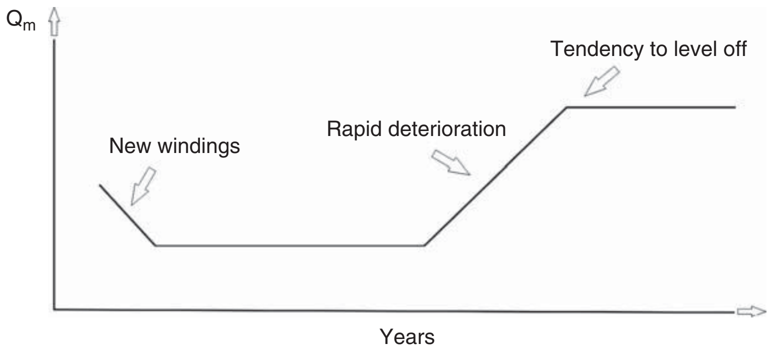

Figure 16.7 Typical trend in PD magnitude over the life of a stator winding.

is significant, Q_m and other PD activity indicators tend to level off and may even decrease. This has implications for older machines that have been retrofitted with PD sensors. It may be that the winding is already in the "saturated" state, with no increasing trend in Q_m. Thus, without the initial PD data when the machine is in relatively good condition, one may not know that the winding may already be in poor condition. Consequently, although trend over time is the most common interpretation diagnostic, comparisons to other machines are still needed to ensure that saturation has not occurred. In addition, recall from Section 16.4.1 that PD may initially be high in a new machine.

Anecdotal observations have shown that if very high groundwall PD has occurred for many years and the trend is flat, then sometimes Q_m plummets to as low 20% of previous measurements. Such behavior may indicate that winding failure is imminent. Researchers believe the reason for the drop in PD before failure is that so much of the organic material has been degraded by the PD that the carbon formed tends to "short" out the voids, reducing PD. For stators suffering from loose windings that are also contaminated with oil, the PD may decrease because the mixture of oil and graphite dust can short out the voltage between the stator coil/bar surface and the core. This will prevent PD.

For the trend to be meaningful, the trend plots should only show data collected under the same motor or generator operating conditions.

Comparisons to Similar Machines The first measurement on a machine can be more than the initial fingerprint. It may also provide some indication of the relative condition of the insulation. Comparison to other machines is needed in the case of a monitoring system installed on an older winding where the trend may be flat.

The best comparison occurs when all machines are identical, and the measurements are made with the same monitoring system under the same operating conditions. The machine with the highest Q_m will have the most severe deterioration and, thus, be most likely to fail. Because PD is erratic, differences of ±25% are not

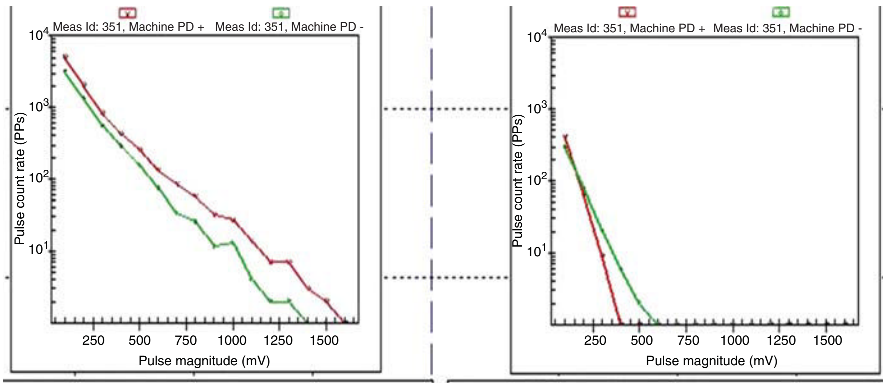

Figure 16.8 Comparison of PD activity in two stators rated 13.8 kV and 80 MVA. The stator with higher magnitude PD (left) is most deteriorated. (Source: Iris Power-Qualitrol.)

significant. However, if one machine has 10 times more activity than another identical machine, then the stator with the greatest activity should be subjected to further tests and/or inspections sooner than the other (Figure 16.8).

With the installation of 80-pF capacitive sensors on over 15,000 machines, and the widespread use of compatible instruments to test these sensors, statistical analysis has been possible on the hundreds of thousands of measurements obtained [22]. The 80-pF sensor tends to respond only to the surge impedance of a stator winding, rather than the size (capacitance) of the winding.†

The predominant characteristics that determine if machines are "similar" and thus if Q_m can be compared between them, are

- voltage rating;
- surrounding gas pressure (that is, the hydrogen pressure in a hydrogen-cooled machine, or the altitude of an air-cooled machine);
- monitoring system.

These characteristics assume that the machine is operating at its normal full load and temperature.

For the 80-pF sensors with PDA/TGA instrumentation, Table 16.1 shows the cumulative probability of obtaining a Q_m of a certain magnitude as a function of voltage [22,27]. The table indicates that for 13.8-kV windings, 25% of the machines in the database had a Q_m of 50 mV or less, 50% had a Q_m of 113 mV or less, and 90% of measurements were less than 469 mV. Thus, if the first measurement on a 13.8-kV motor indicates a Q_m of 500 mV, the user knows that this machine has higher

†If PD measurements are made at lower frequencies, then the PD pulses "see" the entire capacitance of the winding, and the larger the winding capacitance is, the lower will be the detected PD pulse. This effect can be partly compensated for by a "calibration." However, the series inductance of the winding causes resonance that affects the PD magnitude in undefined ways [26].

TABLE 16.1 Distribution of Q_m in mV for Air-Cooled Machines Using 80-pF Capacitive Couplers

Rated Voltage	2–5 kV	6–9 kV	10–12 kV	13–15 kV
25%	8	29	34	50
50%	20	70	77	113
75%	63	149	172	239
90%	228	288	376	469

PD than 90% of all other similar machines. This high reading would trigger further measurements and/or a visual inspection of the stator, as the stator is deteriorated in comparison to other stators. Visual inspections of the windings have shown that if the Q_m is higher than 90% of similar voltage machines, then it is very likely that a significant insulation system problem will be found when a visual inspection of the stator winding occurs.

As discussed in Section 1.4.4, the electrical breakdown strength of a gas depends on the pressure of the gas—the higher the pressure is, the higher will be the breakdown voltage. This pressure effect suppresses PD at higher pressures, and impacts the 90% level for the voltage class. Tables of probability of occurrence versus both hydrogen pressure and voltage have been developed for 80-pF sensors and SSCs [27]. Table 16.2 shows such tables for the 80-pF sensors, and empirically confirms that "high PD" levels are reduced when the pressure increases.

The use of a database makes interpretation of an initial measurement both feasible and objective. It is also clear that what PD levels can be considered high depends on the operating voltage of the stator and the hydrogen pressure (in the case of hydrogen-cooled machines).

Identifying Failure Processes If the Q_m trend is increasing and/or the individual reading is high in comparison to similar machines, then the PD data can sometimes be further analyzed to determine the probable cause for the high activity. The first indication of possible deterioration processes comes from the "polarity" effect [13,14,28]. As shown in Figure 15.5, PD will normally produce both positive and

TABLE 16.2 Effect of Hydrogen Pressure for Generators rated 16–18 kV on the Cumulative Distribution of Q_m (in mV) of PD from 80-pF Sensors

H2 Pressure (psi-g)	11–20	21–30	31–50	>51
<25%	57	31	25	9
<50%	116	60	50	22
<75%	188	182	110	38
<90%	313	891	249	102

negative pulses, resulting in positive and negative Q_m. If the ratio of $+Q_m/-Q_m$ is consistently:

- More than 1.5, then there is positive pulse predominance, and the PD may be mainly occurring on the surface of the coils in the slot. This is an indication that the coils are loose in the slot, or the semiconductive or grading coatings are deteriorating.
- Less than 0.5, then there is negative pulse predominance. This indicates that the PD is occurring close to the copper conductors. Such negative predominance would occur if the coils were poorly impregnated, or load cycling deterioration is occurring within the slot.
- About 1.0, or changes from sensor to sensor, then either endwinding PD is occurring, or there is delamination of the groundwall conductors, usually caused by thermal deterioration.

The polarity effect is only relevant if the PD is occurring between phase and ground, and not phase to phase. This is because phase-to-phase PD creates a positive pulse in one phase and a negative pulse in the other phase, or vice versa [29].

Further information can sometimes be obtained by measuring the effect of various machine operating factors on the PD [28]. As discussed earlier, in a machine with high activity, the PD can be affected by several operating factors such as load, winding temperature, and humidity. Although these influences make it more difficult to trend data over time, if controlled tests are done on the machine, the same influences can help to determine the likely deterioration mechanism. For example:

- If Q_m increases with increasing load (with constant winding temperature) then, perhaps, the coils/bars are loose in the slot.
- If Q_m decreases with increasing winding temperature (and increasing load in many machines), then thermal deterioration or load cycling deterioration may have occurred.
- If Q_m increases with increasing temperature (with load constant), then the stress relief coatings may be deteriorating.
- If Q_m decreases with increasing humidity, then PD is probably occurring in the endwinding, owing to electrical tracking.

Another means of identifying the cause of any high PD is to observe the patterns of the PD pulses with respect to the 50/60-Hz cycle. As discussed with respect to off-line tests (Section 15.12), many researchers have found that certain patterns tend to be associated with specific failure processes. Examples of such patterns are contained in the Appendix of IEC 60034-27-2. However, one should note that sometimes the patterns can be misleading [29,30].

If multiple failure processes are occurring, which is not uncommon on older windings, then isolating these various effects becomes difficult, even for an expert.

The above is a general guide. There are some common pitfalls with online PD interpretation, which are discussed in Reference 30.

16.5 ONLINE CAPACITANCE AND DISSIPATION FACTOR

In Sections 15.7 and 15.10, it was discussed that the off-line capacitance and dissipation factor tests can detect problems such as poor manufacturing, thermal deterioration, and winding contamination that leads to electrical tracking. Recently an online method of measuring C and DF was introduced to detect the same problems [31,32].

16.5.1 Monitoring Principle

The capacitance of the stator winding groundwall insulation can be determined from the voltage across the insulation and the capacitive current through the insulation:

$$C = \frac{I_c}{2\pi f V}$$

where f is the frequency and I_c the current through the insulation in quadrature to the voltage. Similarly, the DF is calculated from the current that is in-phase with the applied voltage. Some researchers have proposed that calculating the impedance $Z = V/I$, where I is the current into a motor stator winding that can indicate the effective C and DF of the insulation, and thus be an indicator of stator winding insulation condition [33]. Calculation of Z is of limited usefulness because the total current to the stator winding consists of the load current and the capacitive and inductive currents. Even the claim that by measuring Z, one can detect shorted turns, it is of little practical importance because, as discussed in Section 1.4.2, a turn short almost always immediately leads to a ground fault, allowing little time for remedial action.

However, if one could directly measure the stator winding capacitive current using the above equation, then C and DF could be determined. Figure 16.9 shows how the capacitive current to the stator winding can be isolated from the majority of the current to or from a stator. The method requires a high sensitivity current transformer to be placed around the combined high voltage and neutral leads of a wye-connected stator winding. The phase-end current and the neutral current on a single phase will consist of the "load current" and the capacitive current. If the capacitive current is zero, the phase and neutral currents will be identical, and the CT output in Figure 16.9 will be zero. However, if the CT is very accurate and sensitive, a net current difference will occur, which is equal to the capacitive current through the insulation. This difference in the current is very tiny compared to the normal load current—perhaps in the range of 10^{-3}. Thus, the CT must be very accurate and not be sensitive to the

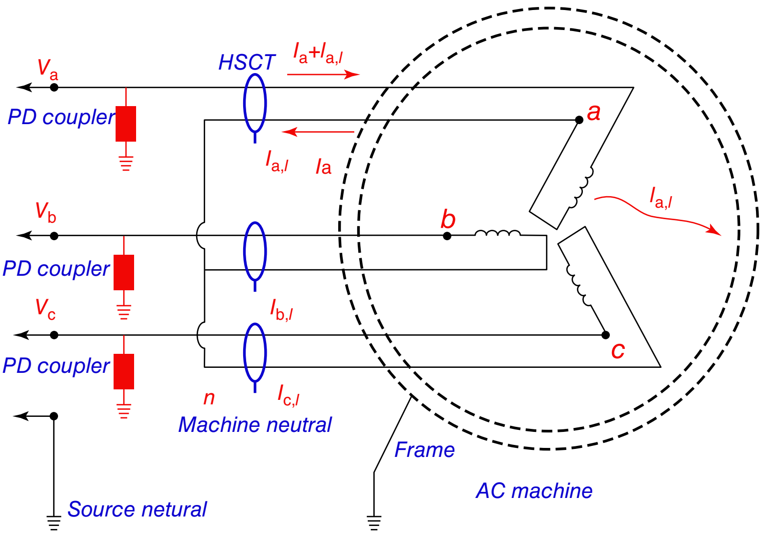

Figure 16.9 Measurement of the difference current in each phase using a very sensitive CT around the phase and neutral leads. (Source: Diagram courtesy of General Electric.)

lead placement. C and DF can then be calculated from the voltage and the in-phase and quadrature difference currents, respectively [31].

Normal differential CTs often used for protection purposes on generators are not sensitive to the small difference current. Thus, special high sensitivity CTs must be installed. This test can be used on both low voltage and high voltage windings, as long as the special CTs have the appropriate voltage rating. The larger the kilowatt rating of the motor or generator, the more difficult it will be to accurately measure the difference current. Retrofitting the CTs around the phase and neutral leads may be a challenge in some cases, and of course the method cannot be used unless the neutral leads from each phase are brought out to the machine terminal box.

16.5.2 Data Acquisition and Interpretation

To date, only periodic testing has been done with this method, although continuous monitoring would be feasible. As the primary aim of this test is to detect winding contamination (Section 8.11), and this mechanism tends to be slow, testing once per year would normally be sufficient. Testing online at low load would enhance sensitivity. GE has developed the required instrumentation.

The actual capacitance is of little interest (Section 15.7). However, if the trend of the capacitance over time is increasing, then it indicates that the winding may be contaminated. If the capacitance decreases, it may be due to thermal aging of the stator insulation. An increase in the DF over time may indicate either of these problems. A 1% change in C and DF is significant. Note that this technique determines the average condition of the winding insulation, not the condition of the most deteriorated part of the insulation. The presence of silicon carbide stress relief coatings will also decrease sensitivity.

16.6 ENDWINDING VIBRATION MONITOR

Stator endwinding vibration is an important cause of failure in two- and four-pole machines, and it is a very important failure mechanism in large turbine generators (Section 8.15). Nonmetallic endwinding vibration monitors have been developed to directly measure the presence of endwinding vibration during operation of the motor or generator.

16.6.1 Monitoring Principles

Vibration is detected by accelerometers, which produce an electrical output that is proportional to the magnitude of the acceleration that the sensor detects. By integration, the acceleration signal can also be measured in terms of vibration velocity or displacement. Most conventional accelerometers are made from piezoelectric crystals that are enclosed in a metallic shell. As these conventional accelerometers are metallic and operate near ground potential, they should not be permanently installed in the phase end of the stator endwinding. If they were, with normal pollution, it is possible that the grounded accelerometer would eventually initiate an electrical tracking failure. Although conventional accelerometers can be installed at neutral-end coils or bars, there is still some risk with their use during power system transients.

Most endwinding vibration monitoring does not use conventional accelerometers, but rather uses fiber-optic accelerometers. Such accelerometers contain no metal and are connected to the measurement instrument by means of fiber-optic cable. Thus, the sensor does not introduce any change to the potential distribution in the endwinding.

Several different optical sensors have been developed. Westinghouse introduced the first in the early 1980s [34]. Light is transmitted along a fiber-optic cable to a sensor head that contains a tiny cantilevered beam that vibrates with an intensity dependent on the acceleration. The beam modulates the light, which is transmitted back to the instrument for analysis. This first sensor was made resonant at 120 Hz, the main electromagnetic force frequency in a 60-Hz generator. Since this development was introduced, many types of fiber-optic accelerometers have been introduced. Most of the recent versions will work over a broad range of frequencies, typically a few hertz to 1 kHz [35,36], and they use a variety of physical principles. The light is derived from a laser diode operating at a fixed frequency. The light from the laser diode propagates down optical fiber to the actual accelerometer head. A nonresonant vibrating mirror can reflect the light back down the same fiber. Alternatively, the light from the laser diode is modulated by a nonresonant cantilevered beam that modulates the light that is received by a lens and transmitted along a second optical fiber. An electro-optical unit converts the modulated light back to an electrical signal. Most suppliers' sensors produce an electrical signal that is 100 mV per g of acceleration. The output of many types of optical accelerometers depends on temperature, which can cause errors. In addition, vibration of the fiber-optic cable itself (as distinct from the accelerometer sensor head) can lead to a signal output. This can also cause interpretation errors because one assumes that the entire signal should be coming from the sensor head.

The accelerometers measure vibration in one direction only. To obtain a proper idea of the endwinding vibration modes at any location, two sensors are usually mounted at each location, one to measure the vibration in the radial direction and the other to measure the vibration in the circumferential (tangential) direction. A sensor for the axial position is probably not needed, as twice-power frequency vibration in that direction is negligible.

Usually, at least six pairs of accelerometers are installed on endwindings at the connection end. Although endwinding vibration is less likely to be an issue at the nonconnection end (as there are no long leads connecting to the circuit ring bus), three or more pairs of accelerometers are sometimes installed at the nonconnection end. Some users also install a fiber-optic or conventional accelerometer on the stator core to help determine the source of any endwinding vibration.

Choosing the optimum locations (i.e., the locations most likely to vibrate) for each pair of accelerometers needs careful thought. The best way to select locations is to perform the off-line impact (bump) tests described in Section 15.23. By impacting the endwinding in a variety of locations and measuring the response with temporarily installed conventional accelerometers, the locations most likely to vibrate are identified. Siting of the sensors is best done by an experienced technician. Figure 16.10 shows a turbine generator stator equipped with endwinding vibration sensors.

If the monitoring system is installed in a hydrogen-cooled machine, the supplier will also need to supply a fiber-optic penetration.

Endwinding vibration monitoring systems were very expensive to install in the past, but the cost has been decreasing recently. To date, they are usually only installed if the user has other information indicating that failure due to endwinding vibration is reasonably likely.

16.6.2 Data Acquisition and Interpretation

The accelerometers can be read periodically or continuously monitored. Normal vibration instrumentation can be used to display the vibration magnitude or a frequency spectra, as most fiber-optic systems output the 100-mV/g signal typical of conventional piezoelectric accelerometers. Periodic testing should be done once per year, or after any power system transient that may have resulted in a high current going through the stator winding. Such transients may loosen a previously tight endwinding. Alternatively, the signals can be monitored continuously. It is important to collect data under the same load and temperature conditions. Increasing winding

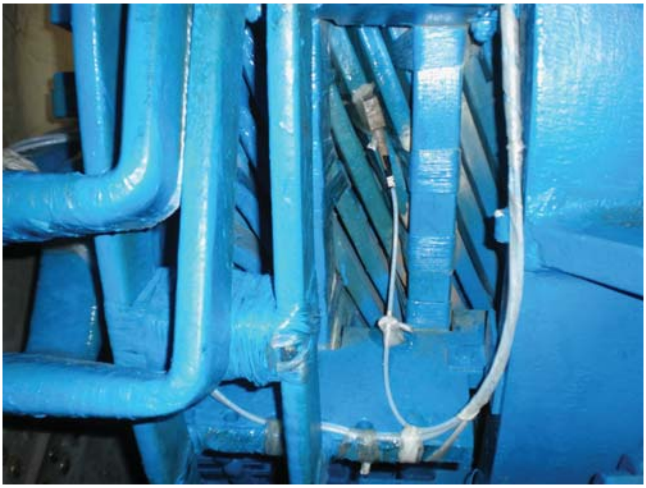

Figure 16.10 Photo of the installation of fiber-optic accelerometers on stator bars in an endwinding. (Source: Iris Power-Qualitrol.)

temperature will reduce the stiffness of the endwinding and change the natural frequencies (Section 15.23). Stator current magnitude will affect the magnetic forces acting on the endwinding, and the reactive to real power ratio affects the ratio between the tangential and the radial forces.

The instrumentation outputs the peak acceleration, velocity, and/or displacement. However, most of the results reported with endwinding vibration monitoring are in terms of displacement in mils (thousands of an inch) or micrometers (microns). Most continuous systems output an overall vibration displacement over a wide frequency range (say 20–1000 Hz). This tends to emphasize vibration in the higher frequency range, even though such vibration may be of little practical importance to the endwinding. The maximum acceptable endwinding vibration depends on the specific stator design and, thus, should be discussed with the OEM. There is no guidance on the maximum acceptable overall displacement in IEC. However, in IEEE 1129:2014, "IEEE Guide for On-Line Monitoring of Large Synchronous Generators", some guidance has been proposed. It suggests that if the total radial displacement is less than 125 μm, this is adequate. However if the total displacement is > 200 to 250 μm, then they may be cause for concern. Part of the uncertainty in establishing safe and dangerous levels for endwinding vibration may be because readings in the past were inconsistent with observed signs of endwinding vibration activity (e.g., fretting, loose bracing and blocking, and copper strand fatigue cracking). Such inconsistency may have occurred because often the sensors were not installed in the optimum (i.e., most likely to vibrate) positions. In fact, it was likely the sensors were installed in the positions least likely to vibrate!

It is also useful to observe the displacement or velocity versus frequency (Figure 16.11). The only frequencies that should normally be detected are at twice

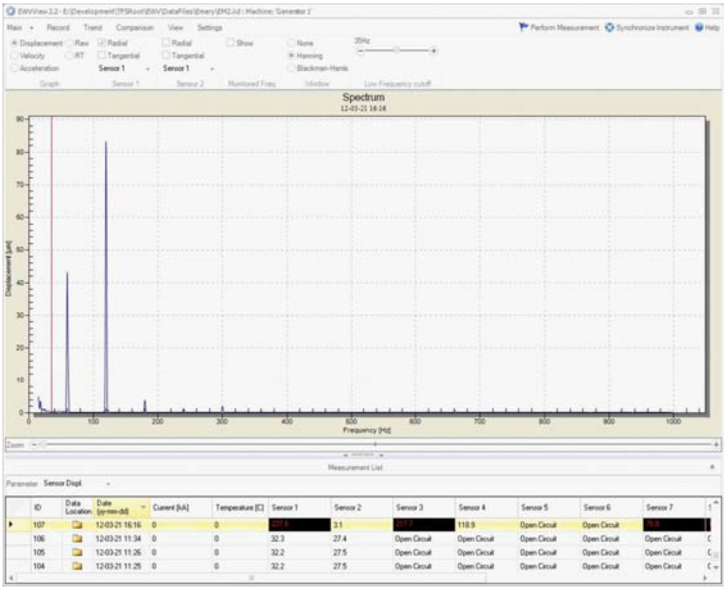

Figure 16.11 Displacement (0–90 μm) versus frequency (0–1000 Hz) for a two-pole, 60-Hz turbine generator. Note that the 120-Hz response (due to magnetic forces) is higher than the rotational speed forces at 60 Hz caused by stator frame vibration. (Source: Iris Power-Qualitrol.)

the power frequency and the once per revolution frequency (50 or 60 Hz for a two-pole machine operating in a 50- or 60-Hz power system). It would be unusual for any other frequency to be detected unless there are high power-frequency harmonics. Usually, the displacement at twice power frequency will be higher than the displacement at the rotational frequency. If the latter is higher, it implies that the main cause of the vibration is due to endwinding vibration coupling in from the stator core and frame, together with a resonant frequency near 50 or 60 Hz (for a two-pole machine).

The trend in maximum displacement over the years is also meaningful. If the displacement is gradually increasing over the years, then this is an indication that the endwinding support system is loosening up. As mentioned previously, the trend over time is only meaningful if the data is collected at the same load and winding temperature.

16.7 SYNCHRONOUS ROTOR FLUX MONITOR

In synchronous machines, this monitor measures the magnetic flux near the rotor to determine if turn-to-turn shorts have occurred in the rotor winding. This monitor has been widely applied in large turbine generators and a variation of the technology has been recently applied to salient pole rotors in motors and hydrogenerators. This is the

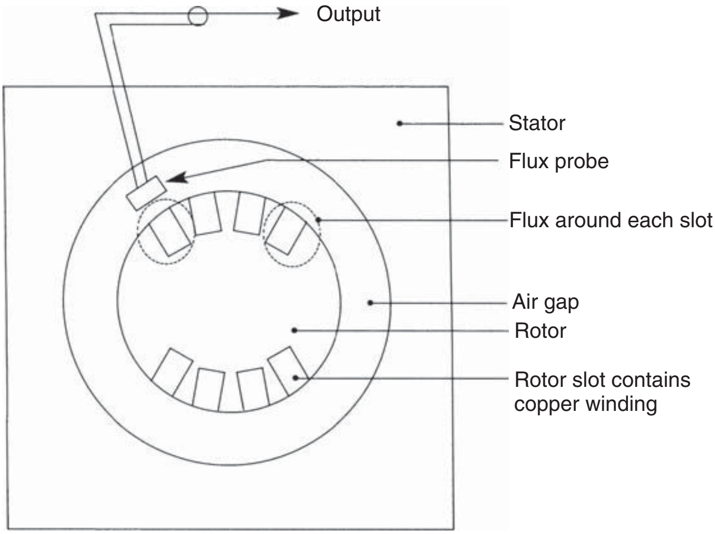

Figure 16.12 Drawing showing location of a flux probe in the 10 o'clock position in a turbo generator air gap.

most powerful means of monitoring the condition of round rotor winding insulation online. In two- and four-pole machines, bearing vibration can also be an indicator of shorted rotor turns, although for different reasons (Section 16.9.3). Rotors equipped with average rotor temperature sensing (Section 16.1.2) can also detect shorted turns because a phantom lowering of the rotor temperature apparently (but not actually) occurs.

16.7.1 Monitoring Principles

The method for round rotors is based on measuring the magnetic flux around each rotor slot. The method for salient poles depends on measuring the main magnetic flux from each pole.

Round Rotor Windings A round rotor, in addition to producing the main radial magnetic flux that crosses from the rotor to the stator, produces a local field around each slot in the rotor. This fringing flux (also called a *leakage flux*) is caused by the current flowing through the turns in each slot (Figure 16.12). Any change in the total current within a slot due to shorted turns results in a change in the "slot leakage" magnetic flux associated with the affected slot. The first monitor to detect this leakage flux was developed by Albright [37].

A flux monitoring system employs a flux probe (sometimes called an *air gap search coil*) and a digital oscilloscope or A/D converter to record the measured signals from the probe. There are two versions of the flux probe. The most widely used probe is a coil (in the shape of a solenoid) that is permanently fixed to a stator wedge and projects into the air gap between the stator and the rotor.‡ The sensor consists of a large number of turns of small-diameter magnet wire on a bobbin, with the axis of the coil oriented in the radial direction. To improve sensitivity to the leakage flux, the coil is placed 2–3 cm from the rotor surface.

The flux probe is usually mounted at the turbine end of the stator core, about 30 cm from the end of the core (unless there is a rotor magnetic wedge at that location, in which case the probe is mounted at the center of the bore away from the magnetic wedge) at the 10 or 2 o'clock position (Figure 16.12) to minimize the possibility of damage to the coil when the rotor is removed. Figure 16.13a shows a photograph of a conventional flux probe. The probe must be flexible or must contain some method of lying flat as the rotor is pulled into a stator bore, to avoid damage to the probe from the rotor and its retaining ring. This type of probe can only be installed when the rotor is not within the stator bore.

More recently, a second type of probe call the TFProbe™ has become popular where the air gap between the stator and the rotor is less than about 50 mm. This type of probe is flat and is made from a coil fabricated onto a thin printed circuit board [38]. The probe is glued to a stator tooth (not the wedge), again usually about 30 cm from the end of the core in the 10 or 2o'clock positions (Figure 16.13b). The probe detects the main radial magnetic flux with the rotor slot leakage flux superimposed on it. The main advantage of this type of probe is that it is often possible to retrofit it to a machine without having to pull the rotor.

During machine operation, the rotor flux from each slot will induce a current in the flux probe as the rotor moves past the flux probe (Figure 16.14). As each slot in the rotor passes, there will be a peak in the probe-induced voltage caused by the slot leakage flux. The peaks in the voltage can then be recorded on a digital oscilloscope or A/D converter. Each peak of the waveform represents the leakage flux around one rotor slot. An interturn fault in a coil reduces the peaks associated with the two slots containing the faulted coil. As there are fewer ampere-turns in these slots and, thus, less leakage flux, there is less induced voltage in the flux probe.

With the conventional flux probe test, the flux plot from one pole is plotted on the same axes as the inverted flux plot from the next pole (Figure 16.15). Ideally, the two flux plots should be identical. However, if there is a shorted turn in one or more of the coils around one pole, then the induced voltage will be smaller than the induced voltage from the other pole. Thus, the coils containing shorts around the pole will be different and lower in comparison to the other pole [38,39].

An important limitation of the flux probe test for round rotors in the past is that the test must be done in steps from no load to just greater than full load.§ The number

‡The earliest versions of this monitoring system used a flux probe mounted on a rod that was pushed through a gland and manually inserted into the air gap via a radial vent duct in the stator core during operation [37]. After the test, the coil was removed. Most users now opt for the permanent sensors because there is less risk of the flux probe hitting the rotor.

§The first version of the test required the shutdown of the machine and an off-line test performed to measure the flux under stator winding short-circuit conditions. The modern version, which uses a number of different load conditions, has relatively minor impact on plant production.

(a)

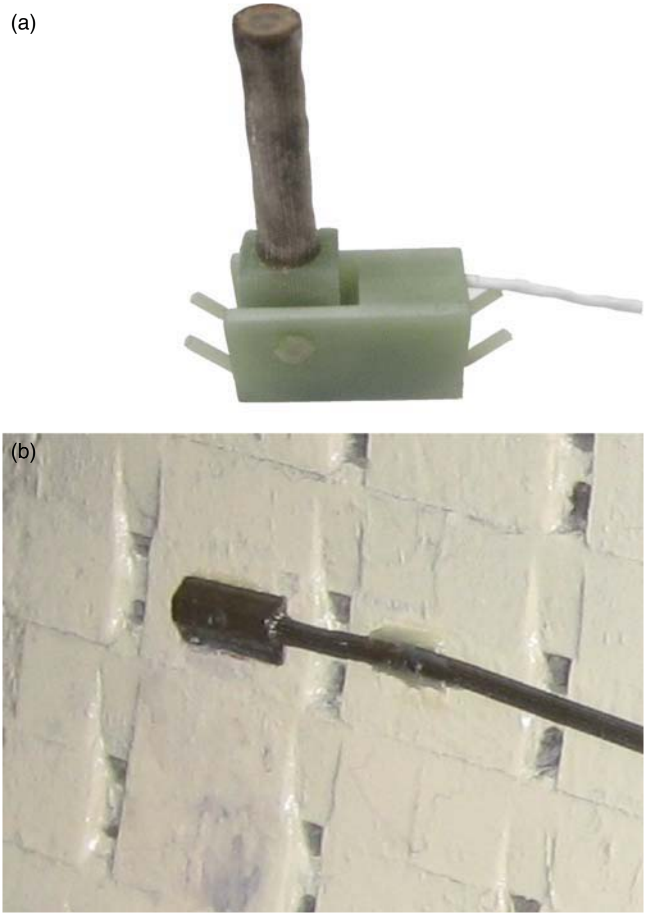

Figure 16.13 (a) A photo of a conventional wedge-mounted foldable flux probe that projects into the air gap. (b) A photo of an installed flat flux probe glued to a stator tooth. (Source: Iris Power-Qualitrol.)

of load steps required is equal to the number of coils around each pole. As the leakage flux is only one of three components of flux in the air gap (the others are the main flux from the rotor and the armature reaction flux due to the current flowing in the stator), the greatest sensitivity to the leakage flux occurs when the other two fluxes are approximately zero [38,39]. This occurs when there is a zero crossing of the flux density (the so-called flux density zero crossing or FDZC), which in turn depends on the real and reactive load of the machine. The key idea is to adjust the load so that the FDZC occurs for each slot pair (i.e., the two lags of a coil) in a pole pair. This will also minimize rotor teeth magnetic saturation that occurs if the flux is high, which attenuates the change in total flux from a shorted turn.

With more modern hardware and modifications to the algorithms, which compare the flux from two poles, the requirement for recording the probe voltages in load

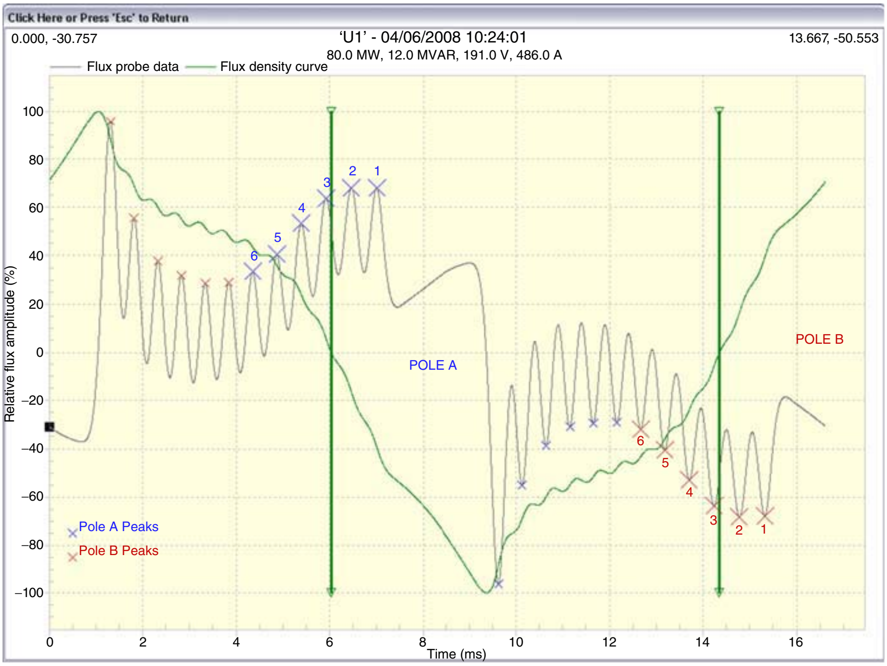

Figure 16.14 Voltage induced in a flux probe, shown by the gray (faint) line. The leading coils of each pole are numbered. The light green (smooth quasi-sinusoidal) line is the integrated flux density. The vertical dark green line is the location of flux density zero crossing. (Source: Iris Power-Qualitrol.) *See color plate section.*

steps from zero to greater than full load has become less important [38]. In many (but not all) cases, shorted turns in all coils can be detected from a single-load test. Figure 16.15 shows a short in coil 3, from a test done at low load, even though the optimum load to detect a short in coil 3 would be near full load.

This monitor has less sensitivity when applied to rotors with magnetic rotor slot wedges (older two- and four-pole turbine generators), as less leakage flux makes it into the air gap. Usually, when magnetic rotor wedges are installed, they tend to be only at the ends of the rotor slots. Thus, installing the flux probe in the center of the stator bore normally overcomes this limitation.

Salient Pole Rotors A variation of the flux probe technology for round rotors has recently been developed for salient pole machines [40]. As the air gap in such machines is usually very small compared to turbine generators with round rotors, the printed circuit coil type of probe is used (similar to that shown in Figure 16.13b). The coil is glued to a stator core tooth, and is easy to retrofit with the rotor in place.

The voltage induced in the flux probe as each salient rotor pole passes will be proportional to the magnetic flux from each pole. A shorted turn in a pole will induce less voltage as it passes the flux probe (Figure 16.16). The algorithms that interpret

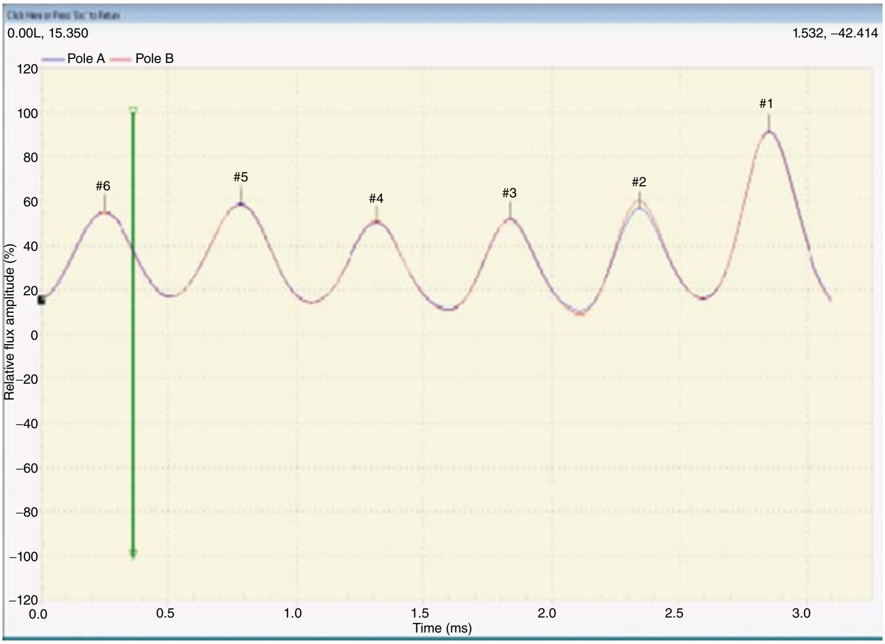

Figure 16.15 Pole-to-pole comparison that shows shorted turns detected in pole A, coil 2. Coils around pole A are blue, whereas the red line is the voltage in the coils around pole B. The vertical green line is where the flux density zero crossing (FDZC) is. (Source: Iris Power-Qualitrol.) *See color plate section.*

the flux probe voltages must be insensitive to air gap distance variations that can also affect the probe voltages. The test can be done at any machine load.

16.7.2 Data Acquisition and Interpretation

The flux probe test should be done at least once per year and after any sudden increase in the bearing vibration (Section 16.9.3). For round rotors, if the conventional flux probe test is done, then the plant operator must arrange to step the load from zero to greater than full load in steps. This may require 3–4 h to complete. If the more modern round rotor test is used [38], usually the test can be done at a fixed load (unless no shorts are detected but there is still an unexplained sudden increase in bearing vibration). Alternatively, continuous flux monitors are available [41]. Such continuous monitors can be set to automatically collect data at all loads during normal plant operation.

Unlike in stator windings, in which turn shorts rapidly lead to failure, turn shorts in synchronous rotor windings do not in themselves lead to failure. One or more shorted turns can be sustained indefinitely, as long as the required excitation is adequate and the increased level of vibration that shorted turns produce is within acceptable limits (Section 16.9.3). However, if the shorted turns are the consequence of gradual aging, more and more shorted turns may occur over time. Sufficient shorted

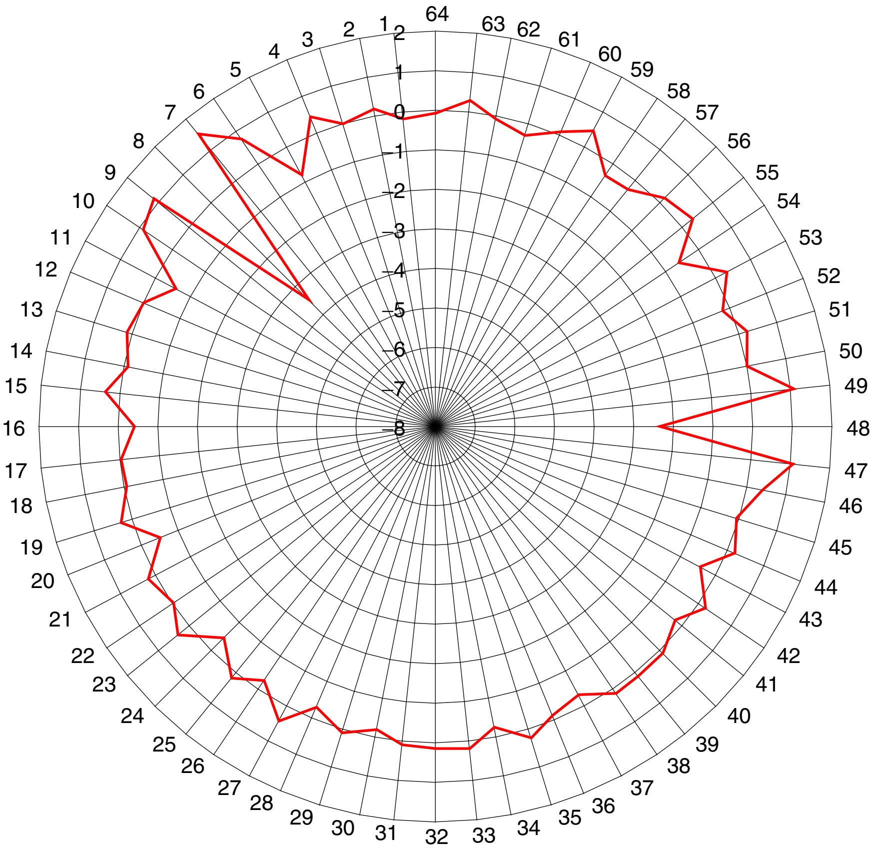

Figure 16.16 Flux probe voltage readings from a 64-pole salient pole hydrogenerator rotor. The circumferential scale is the pole number and the radial scale is a modified version of the relative voltage from a single flux probe mounted on a stator core tooth. Shorted turns are detected on poles 8 and 48. (Source: Iris Power-Qualitrol.)

turns may occur so that high rotor vibration follows, or the machine will not be able to operate over the entire specified range of power factors. In addition, if the number of shorted turns increases over time, there is a greater likelihood that a rotor ground fault may occur, which is much more serious.

A new rotor should have no shorted turns. If a shorted turn does develop over time, then increased monitoring frequency should be established. If more shorted turns appear in the same slot or on the same pole in a salient pole rotor, then serious insulation degradation is occurring, sometimes increasing the risk of a rotor ground fault. Action such as off-line testing and inspections should be considered. In addition, limitations on excitation current may be warranted until the root cause of the shorts is established. If increasing numbers of shorted turns are detected over time but are distributed through different slots or poles, then further off-line tests and inspections are warranted, but usually with less haste. Some machines have been operating with shorted turns over their entire life with no adverse consequences.

16.8 CURRENT SIGNATURE ANALYSIS

Current signature analysis (CSA) monitoring has revolutionized the detection of broken rotor bars and cracked short-circuit rings or brazed/welded joints in squirrel-cage induction motor rotors (Chapter 12). CSA can also be used to detect other motor problems such as nonuniform air gaps and rolling element bearing defects. The current in one of the power cables feeding the motor is analyzed for its frequency content. Specific spectral components in the current indicate the presence of defects in the motor during normal operation. It seems probable that future advances will also enable the detection of conditions such as problems in the driven load, gearbox defects, soft foot, and loose/defective drive belts.

CSA monitoring works best on three-phase squirrel cage induction (SCI) motors rated at 30 HP and above that are operating at or near full load. The detection of broken rotor squirrel-cage windings by CSA can sometimes also be accomplished or confirmed by bearing vibration analysis (Section 16.9.2).

16.8.1 Monitoring Principles

CSA was pioneered by Kliman [42] and Thomson [43] in the late 1970s. CSA finds the following squirrel-cage winding problems, as a minimum.

- Cracked rotor bars
- Cast rotor bars with large internal voids
- Broken bar-to-short-circuit ring connections
- Cracked short-circuit rings

In simple terms, the current flowing in a motor stator winding not only depends on the power supply and the impedance of the stator winding, but it also includes current induced in the stator winding by the magnetic field from the rotor. That is, the stator winding is a probe or "transducer" for problems in the rotor. In this way, CSA is similar to the air gap flux monitor for synchronous machines (Section 16.7), where instead of having a separate flux probe to detect rotor problems, the entire stator winding acts as the flux probe. The key issue is separating currents that flow through the stator to drive the rotor; from the currents that the rotor induces back into the stator if there is a problem. This separation is accomplished by measuring current components at frequencies other than power frequency and harmonics in the motor power supply, using high resolution frequency spectrum analyzers.

Rotor currents in a cage winding produce a three-phase magnetic field with the same number of poles as the stator winding, but rotating at slip frequency $f_2 = sf_1$ with respect to the rotating rotor, where s is the per unit slip and f_1 the 50/60-Hz power supply frequency for fixed frequency power supplies. In a symmetrical cage winding, only a forward rotating field exists. If rotor asymmetry occurs, because of cage winding cracks or breaks, there will also be a resultant backward rotating field at slip frequency with respect to the forward rotating rotor. It can be shown [42,43] that the backward rotating field with respect to the rotor induces an electromotive force and current in the stator winding with a frequency of f_{sb} obtained from the following formula:

$$f_{sb} = f_1(1 - 2s)\,\text{Hz}$$

This is referred to as the *lower twice slip frequency sideband* due to cage winding cracks or breaks. There is, therefore, a cyclic variation of current that causes a torque pulsation at twice slip frequency ($2sf_1$) and a corresponding rotor speed oscillation, which is also a function of the drive inertia. Owing to this rotor oscillation [44], an upper sideband current component is also induced in the stator winding and is enhanced by the third time harmonic flux. This speed oscillation produces an upper sideband current component with a frequency:

$$f_{sb} = f_1(1 + 2s)\,\text{Hz}$$

It is important to note that this upper sideband frequency may have a much lower magnitude or may not exist if the combined inertia of the motor and driven equipment rotor is very high, for example, the motor is driving a high inertia fan. Breaks in rotor cage windings, therefore, usually result in current components being induced in the stator winding at frequencies given by:

$$f_{sb} = f_1(1 \pm 2s)\,\text{Hz}$$

These are the classical twice slip frequency sidebands due to broken rotor bars or shorting rings and are symmetrically distributed around the fundament motor 50/60-Hz supply current. Figure 16.17 illustrates that these sidebands are quite predominant in a motor with broken rotor bars.

CSA monitoring requires that the stator current be measured on one phase, usually via a current transformer. The current is analyzed with a spectrum analyzer

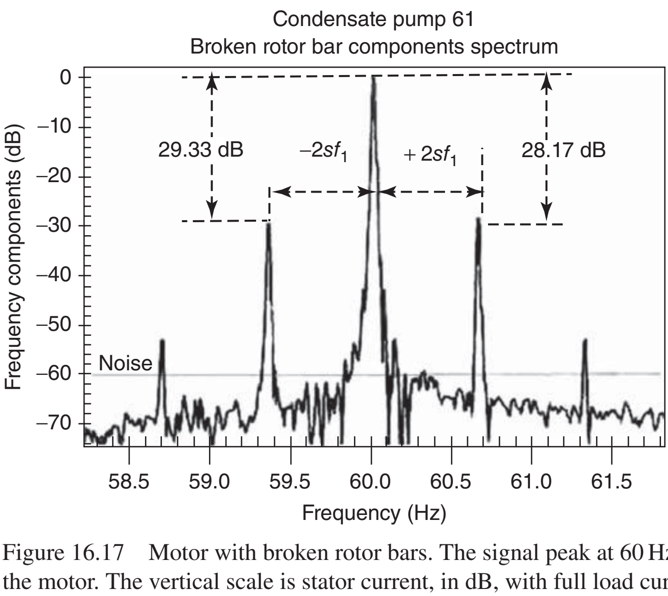

Figure 16.17 Motor with broken rotor bars. The signal peak at 60 Hz is the main current to the motor. The vertical scale is stator current, in dB, with full load current equal to 0 dB.

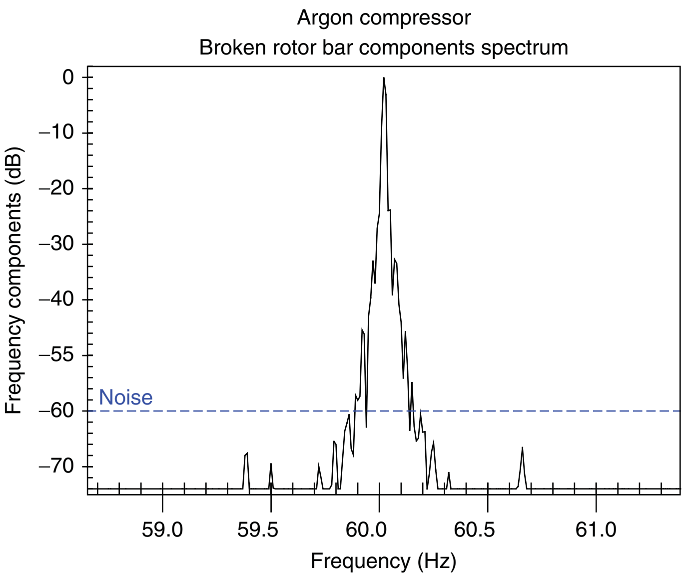

Figure 16.18 Motor with no cage winding breaks.

or customized digital signal processing unit. A typical spectrum analyzer output is shown in Figure 16.17. As illustrated by Figure 16.18, if there are no broken rotor bars, then there will be no sidebands.

If sidebands are present, then cracked or broken rotor bars or short-circuit rings are likely present. Typically, the sidebands are only 1 Hz or so away from the very large power frequency component, and the sideband currents are typically 100–1000 times smaller (−40 to −60 dB) than the main power frequency current. Consequently, exceptional dynamic range and frequency resolution are needed to accurately measure the sideband peaks due to broken rotor bars.

To detect broken rotor bars, the slip frequency must be accurately known. In early "broken rotor bar" detectors, s was measured with a stroboscope that directly detected the rotor speed (and thus allowed calculation of slip). Alternatively, slip can be detected from an axial flux probe near the rotor winding [42]. Contemporary CSA monitors have proprietary means of estimating slip from the current itself. This greatly improves the ease of performing CSA. Some of these methods are effective, but many have been shown to produce errors for small motors or motors that have a large number of poles.

16.8.2 Data Acquisition

On small motors rated at 690 V or less, the stator current in one phase can be measured with a portable clamp-on current transformer placed on a phase lead either in the motor terminal box or at the motor control center (MCC). For larger motors (those rated above 690 V), the current is usually measured by a clamp-on power frequency current transformer on the secondary of the CT that measures the supply current to the motor for protection purposes. These are almost always at the motor MCC or circuit breaker. If the motor is in operation, extreme care is needed in installing the clamp-on ammeter to measure the current spectrum. The spectrum analyzer should have a frequency resolution of 0.01 Hz for the detection of current components around supply frequency and at least 0.1 Hz for higher frequencies. For accurate analysis, a means of calculating the slip frequency is needed. The major suppliers of online motor electrical test equipment can provide software to be used with a spectrum analyzer or have a specially built analyzer to measure the slip and determine if broken rotor bars are present.

The monitoring should be done about once per year, as it is unlikely that a healthy rotor winding would deteriorate to one that is ready to eject material in less than this time, unless a bizarre event has occurred. The measurements should be repeated whenever there is a vibration signature that indicates an increase in vibration levels at rotational speed frequency or multiples of this with side bands of ±slip frequency × the number of stator winding poles (see Section 16.9.2) or a low frequency hum is noted from the motor during starting.

The testing is best performed at full load. At low load, there is insufficient current in the rotor to produce a significant reverse induction back into the stator. The minimum load for reliable interpretation is typically 35% of load. To date, most CSA monitoring is done periodically. However, continuous CSA monitors are also available.

16.8.3 Interpretation

For rotor squirrel-cage winding defects, basic interpretation requires comparison of the average twice slip frequency sideband magnitude or lower sideband (if no upper sideband is present) with the power frequency stator current. Experience shows that if the sideband becomes larger than about 0.5% of the power frequency current, then broken bars, bar-to-shorting ring joints, or breaks in shorting rings are likely.[¶] Most spectrum analyzers and purpose-built CSA instruments plot the current on a relative logarithmic scale, marked in decibels. 0 dB corresponds to the load current at 50/60 Hz. Thus, $\pm 2sf$ sidebands larger than about −45 dB usually indicate that there are broken rotor bars. The greater the sideband current is (i.e., the larger the fraction of the power frequency current is) for a given motor load, the more severe will be the rotor deterioration. As with most other monitors, it is best to trend the sideband magnitude over the years. If the sideband increases over time with approximately the same load on the motor, then it is reasonable to expect that a greater number of bars have broken in more locations or the number of shorting ring breaks has increased. At some point, there may be enough breaks in the rotor bars or shorting rings that the motor may fail to start or some winding metal may fly off the rotor to cause a stator winding failure.

[¶]As the initial CSA was performed with a spectrum analyzer, and such instruments normally record the output in decibels (rather than amperes), conventional wisdom indicates that if the sideband is less than 45 dB down from the 50- or 60-Hz current at near motor full load, then broken rotor bars are present.

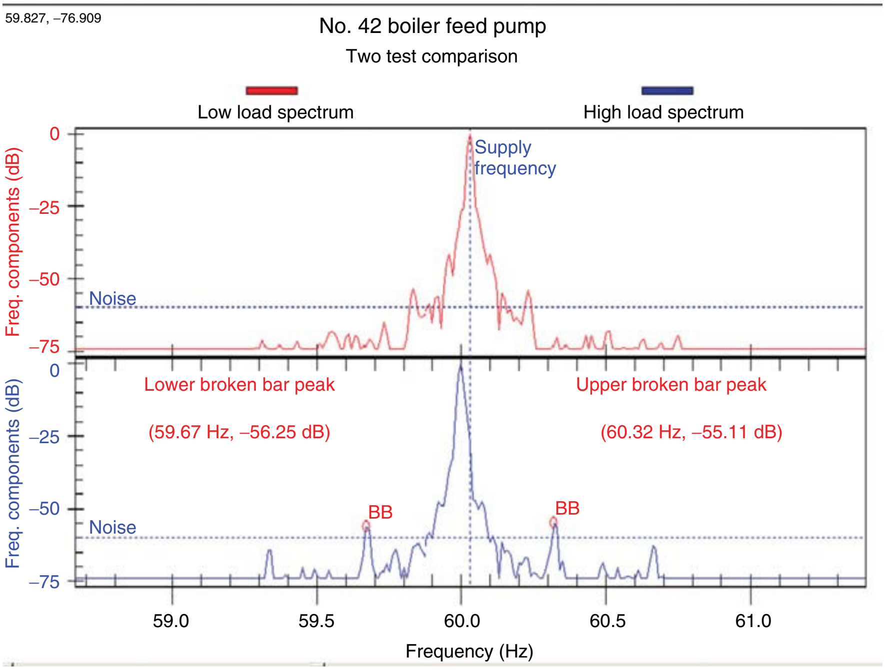

Figure 16.19 Output from a CSA instrument, with the test done at low (upper plot) and full load (bottom trace). Rotors with broken bars will show wider sidebands as the load increases. (Source: Iris Power-Qualitrol.)

One way to confirm that sidebands in the $\pm 2sf_1$ domain are due to cage winding breaks is to perform two CSA tests at significantly different motor loads. If the sidebands move further away from the fundamental 50/60-Hz current with increased load in proportion to the expected increase in slip, then cage winding breaks are confirmed as indicated by Figure 16.19, in which “BB” indicates the broken bar sidebands.

CSA may not detect bar breaks in large two- or four-pole motors if the breaks occur under metallic endwinding retaining rings, as the retaining ring itself may allow the current to continue to flow between bars. It is also important to note that twice slip frequency sidebands will be present in rotors with healthy windings if the number of spider arms supporting the rotor core at its bore is equal to or is a multiple of the number of motor poles [45] and so the presence of cage winding breaks with such rotor core support configurations is difficult.

Early CSA monitoring was prone to false positive indications (i.e., indicating that a rotor had problems when it had none) and, less frequently, missing defective rotor windings (false negatives). Thus, early users of this test had low confidence in the results. However, improvements in theory, software, and spectrum analyzer/digital signal processor resolution have made detection of rotor bar problems much more reliable.

There are many other circumstances that can cause frequencies other than the power frequency to be detected in the stator current:

- Power supply harmonics
- Eccentricity in the air gap due to bearing problems or unsymmetrical magnetic pull
- Oscillations in speed caused by the driven load (e.g., reciprocating compressors, pulverizers, gear boxes, fluid couplings, conveyors, and pulley belt drive)
- Defective rolling element bearings
- Shorted turns in stator winding coils

The latter two problems would be useful to identify, and the manufacturers of some CSA monitors have introduced software to detect them. Extensive research has improved the reliability in detecting broken rotor bars by separately identifying other causes [44].

Broken rotor cage windings do not imply that the rotor must be rewound. Similar to turn shorts in synchronous machine rotors, motors have operated with broken bars for decades. However, if more broken bars are occurring over time, it is likely that aging is occurring and the additional stresses imposed on the healthy sections of the winding will cause them to crack and fail. In addition, as the number of bar and shorting ring breaks increases, there is greater risk that a motor may not start (owing to insufficient starting torque), or chunks of the rotor winding may fly off the rotor. In addition, broken rotor bars can lead to core burning because of the passage of rotor currents between bars through the core laminations (Figure 13.5).

16.9 BEARING VIBRATION MONITOR

Periodic bearing vibration monitoring is common on most important rotating machines. Continuous bearing vibration monitoring is used for critical motors and is standard on most large generators. Although the main purpose of such monitoring is to warn of problems with the bearings, such data can sometimes be used to indicate problems with the rotor windings and stator cores. Vibration monitoring can confirm the diagnosis from CSA (Section 16.8) and rotor flux monitoring (Sections 16.7).

16.9.1 Vibration Sensors

Conventional piezoelectric accelerometers are often permanently or temporarily attached to the bearing housing. Only radial vibrations at two positions on the bearing housing, 90° apart, are usually measured in permanent installations. On the other hand, axial vibration levels are also measured in periodic monitoring, normally performed using a portable data logger, which includes a spectrum analyzer to which an accelerometer is connected. The signals from the accelerometers are broken down into magnitude versus frequency by a spectrum analyzer and are usually in velocity units of millimeters/second and/or inches/second, peak. The information from the data logger is downloaded into a computer with software that allows spectrum analysis and trending of vibration levels with time.

Shaft displacement probes are mounted on the bearing housing to measure the relative movement of the shaft. This type of monitoring is used in larger machines with sleeve or tilting pad guide bearings because it gives an indication of how much of the bearing clearance is being used up when high rotor vibration levels occur. The units used for such vibration monitoring are usually millimeters or inches, peak-to-peak.

16.9.2 Induction Motor Monitoring

If broken rotor bars are present in an SCI motor rotor, there will be an unbalanced magnetic pull on the rotor, as some of the rotor slots will not have the full current and, thus, will have less magnetic field in some portions of the rotor periphery. In addition, if a vibration frequency analysis is done, the presence of squirrel cage winding breaks will be indicated by sidebands around the rotation speed frequency and at multiples of it that are (±slip frequency × the number of stator winding poles) removed. This is illustrated by Figure 16.20, which shows such side bands around 3× operating speed [46].

As indicated in Section 13.3, vibration monitoring can also identify fabricated rotor windings having some loose and some tight bars, or die cast windings with voids on the bar sections. If the stator core is loose in the frame or nonuniform air gaps exist, there will be a high radial 2× power supply frequency vibration component that will

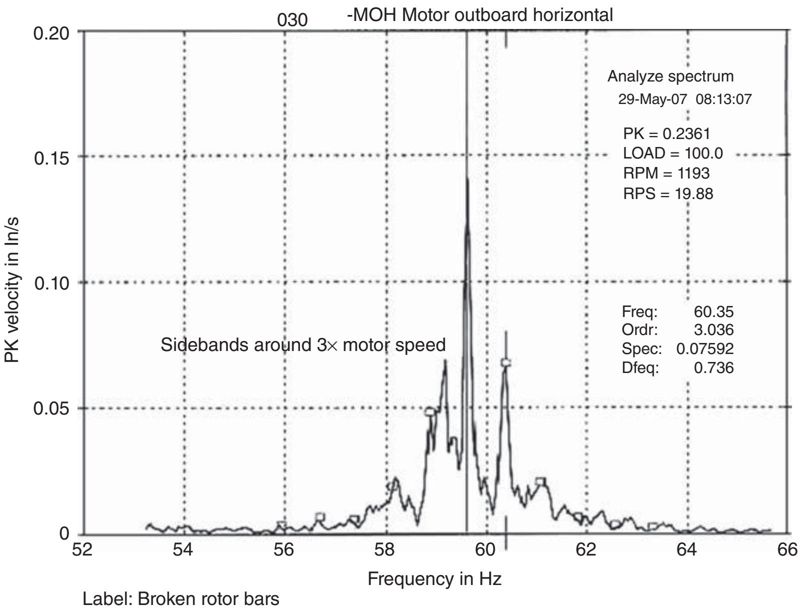

Figure 16.20 Frequency spectrum around 3× running speed for a six-pole motor with broken bars. (Source: Taken from Reference 46.)

be detected by bearing housing vibrations, if the bearings are mounted in brackets attached to the stator frame.

Interpretation of Results

- Breaks or air pockets in rotor cage windings are identified by a significant radial vibration frequency at rotational speed and multiples of this. There will be sidebands above and below these frequencies that are ± (rotor slip speed × the number of poles).
- Fabricated rotor windings with some loose and some tight bars in the slots, and die cast rotors with air pockets in the bar sections, will have significant radial vibrations at one time rotational speed frequency that change in magnitude with motor load. This problem is predominately found in two-pole rotors, which are less stiff radially than those in motors with four and more poles.
- Loose stator cores and nonuniform air gaps are identified by high vibration levels at two times of power frequency.

16.9.3 Synchronous Machine Monitoring

Shorted turns in high speed round rotors can induce rotor vibration that can be detected from accelerometers installed on the bearing housing or shaft displacement probes. A shorted turn in a rotor coil, which is installed in two slots, implies that the resistance of the coil will be smaller, as the current flows through a shorter path. Thus, the I^2R loss in the two slots where the coil is installed will be lower, resulting in a lower temperature in the affected slots. The lower temperature in the affected slots, combined with the higher temperature in the other slots, creates a "thermal bend" (Section 1.6.2). That is, the expansion of the coils and adjacent rotor body in the normal slots will be greater than the cooler slots, bending the rotor a small amount. This bend will result in a bearing vibration at the rotation speed. Thus, a peak in the frequency spectrum at rotational speed (rpm) divided by 50 or 60 may indicate that shorts are present. The vibration tends to be greater in two-pole machines, as four-pole rotors tend to be stiffer. In two-pole machines, it is easier to detect shorted turns from the thermally induced vibration when the "small" coils contain the short (these are the coils away from the quadrature axis). Coils near the quadrature axis are in slots almost 180° apart and, thus, the thermal bend tends to cancel out. The bearing radial vibration will vary with excitation current, as the greater the rotor current is, the greater will be the temperature differences between slots. Increasing vibration with increasing field current is a strong indicator of shorted turns.

Shorted turns can also give rise to unbalanced magnetic pull, especially in four-pole rotors. A short in one pole reduces the magnetic flux in this pole, whereas the flux is at full strength in the pole 180° around the rotor. This causes radial vibration at the rotational speed. Again, increasing the field current will increase the imbalance and, thus, the vibration.

As with induction motors, a loose core in any synchronous machine will also be indicated by high radial vibration at 2× supply frequency.

16.10 STATOR WINDING WATER LEAK MONITORING

An important failure mechanism of direct water-cooled stator windings is when small water leaks develop at the ends of the bars where the plumbing and electrical connections are made (Section 8.16). Minute water leaks into the groundwall insulation gradually degrade the insulation until its electrical and mechanical strengths are lost. None of the online monitors discussed earlier can detect this degradation. To date, the only method to determine if this deterioration process is occurring is to measure if the minute stator winding coolant water leaks are occurring, inferred from the leakage of hydrogen into the stator cooling water. GE has developed such a system called *SLMS-HP*, based on an undisclosed method [47]. The system can apparently detect hydrogen to water leaks as low as 6000 cm^3 per day.

Note that gross water leaks are easily detected by the water pressure drop and/or hydrogen in water detection.

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CHAPTER 17

CORE TESTING

This chapter describes the main tests that are commercially available for assessing rotor and stator core tightness and stator core insulation condition. All of the conventional forms of these tests require the motor or generator to be taken out of service.

The tests covered are

- knife test—for stator or rotor core tightness;
- rated flux test for local and general core insulation condition on larger cores (normally generators) using thermography;
- core loss test for general and local core insulation condition on smaller cores (usually motors) using watts loss;
- low flux (El-CID) test for local core insulation condition.

For each test, the purpose is described, as well as the types of machines it is useful for. The theory of the test and its advantages and disadvantages are also covered. Finally, practical guidelines on performing the test and interpreting the results are given.

The El-CID test can sometimes be performed without rotor removal. In addition, on-line monitoring of the stator core is possible with temperature sensors placed on the core (Section 16.1) and condition monitors to detect stator core overheating in hydrogen-cooled generators (Section 16.2).

17.1 KNIFE

This is a simple, commonly used test to evaluate if the core laminations are loose. It requires no specialized equipment.

17.1.1 Purpose and Theory

Well-designed and constructed cores should remain tight for the life of the machine in which they are installed. The laminations in such cores should be impenetrable with a sharp object. On the other hand, if the core is poorly designed or constructed, it will

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

relax with service and the laminations in the whole core or in sections will become loose (Chapter 13). If the core laminations are loose, shorts between the laminations will occur because of relative movement between the laminations, and if the problem is severe, pieces of core laminations may break loose from the core and cause damage to the stator and rotor windings. In a loose core, a sharp object, such as a winder's knife, can be inserted between adjacent laminations. The "knife test" is designed to evaluate subjectively the tightness of a laminated stator or rotor core.

17.1.2 Test Method

Before starting this test, remove from the surface of the core any varnish or other coatings that may be loose. If the core is of the large segmented type, loose areas may be indicated by dust from relative movement between core laminations which, if impregnated with oil that has leaked from a bearing or hydrogen seal, will have a dark greasy appearance.

The knife test involves trying to insert a standard winder's knife blade, with a maximum thickness of 0.25 mm, between the laminations at several locations around the core bore (stator), or core outside diameter (rotor). When performing this test, care must be taken to avoid breaking off the tip of the knife while it is in the core. That is, do not rock the knife blade as it is pushed between the core laminations (Figure 17.1). Instead, insert the knife (if possible) by holding the knife handle in one hand and carefully applying pressure to the back of the knife blade with the palm of the other hand.

17.1.3 Interpretation

If the blade penetrates the section of core being tested by more than 5 mm, then it is assessed to be loose. If there are many places where the knife can be inserted, repairs as described in Section 13.5 may be advisable.

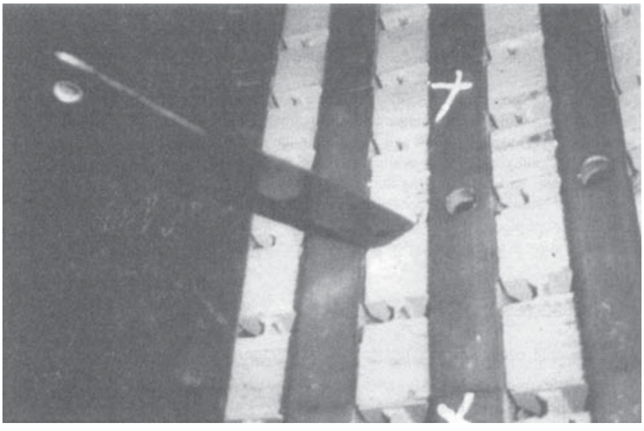

Figure 17.1 Photo of a knife being inserted between the laminations of a loose stator core.

Figure 17.2 Commercial core tester exciting a motor stator core.

17.2 RATED FLUX

There are two versions of core testing which excite the core near to full rated flux. One version is described in this section, and the other in Section 17.3. The test in Section 17.3 uses a commercial core tester (Figure 17.2) to create a magnetic flux in the core, while the power used to excite the core to a specified flux is measured. This test is normally used on the stator cores in smaller motors and generators. In contrast, the core test described in this section uses a large power supply and a custom-designed excitation winding. This test is primarily used on larger motors and generators and is called the *rated flux test*. It is also called the *ring flux*, or *loop* test. The effect of the flux is monitored using a thermal imaging camera.

The rated core flux test is the traditional method of determining the insulation integrity of any type of a large laminated stator core. The test can assess the severity of damage, locate the worst deterioration sites, detect hidden damage and, for any type of damage, it provides information to indicate whether repair is required. The major disadvantage of this test is that it requires machine disassembly and removal of the rotor before it can be performed. It also requires a large power supply. As the test is normally carried out at or near the rated back-of-core flux, it may aggravate an existing problem if core temperatures are not carefully monitored.

17.2.1 Purpose and Theory

The equipment required for this test depends on the size of the core to be checked. For small- and medium-size machines that can easily be transported to a motor service center, a commercial core tester is normally used (see Section 17.3). On the other hand, large generators have to be tested on-site using heavy cables and a local, large 50- or 60-Hz power supply.

Figure 17.3 Excitation winding made from insulated cable wound through a stator core.

This test is performed by installing an excitation winding around the stator core, as illustrated in Figure 17.3. With a commercial core tester (Figure 17.2), this winding normally consists of one or two turns of heavy cable, whereas, for large cores, the number of turns and cable size will be much greater. The excitation winding must have an appropriate number of turns and be insulated for the voltage to be applied across its ends. The axial current that flows though the excitation winding will create a circumferential flux in the back of the stator core. The voltage applied to the excitation winding should generate enough current to produce a back-of-core flux that will give approximately the rated operating flux density in the core area behind the winding slots to induce normal axial voltages between laminations. If the turns/coils in a stator core for a multiturn winding are not known, then the back-of-core flux density cannot be calculated. In such situations, a flux density of 1.3 tesla (about 85,000 lines/in.^{2}) as suggested in Reference 1 has been shown to give satisfactory test results.

When the axial current is applied to the excitation coil, any defective areas of core or tooth insulation will show up as "hot spots," that is, they will become significantly hotter than areas with healthy core plate insulation. Hot spots are created by the axial currents that are induced between steel laminations with shorted core insulation. If the insulation is good, then no axial current will flow between laminations, and there will be no unusual temperature rise. The only source of heat with good lamination insulation will then be the normal hysteresis and eddy current losses in the steel itself.

Surface defects are indicated by hot areas of the core that become evident soon after the application of the excitation current. On the other hand, in large cores, deep defects may take more than 30 min to show as high temperatures on the observed surfaces, because the surrounding "healthy" sections of core act as a heat sink.

This is the most appropriate test for determining the need to perform core insulation repairs and for determining the effectiveness of repairs. For motors, it is important to perform this test before burning out stator windings that are to be replaced and after winding burnout to confirm that this winding removal process has not caused significant core insulation deterioration. This test is often used to confirm the seriousness of core defects detected by the El-CID test described in Section 17.4.

17.2.2 Test Method

For large machines that cannot be tested with a commercial device, guidelines on the design of the excitation winding required to induce flux in the core are given in IEEE Standard 432 [2]. A 50- or 60-Hz power supply of sufficient capacity is needed to induce the required level of excitation in the core. If possible, the power supply should have the capability of raising the excitation level gradually to avoid transients that may damage the core lamination insulation during energization. Commercial core tester excitation winding power supplies have this capability. For large machines that have to be tested on-site, there is usually a 3.3- or 4.16-kV supply available from the plant distribution system. Experience has shown this to be generally adequate for testing most large machines such as turbogenerators and hydrogenerators. However, a variable autotransformer of suitable rating is difficult to obtain for testing of large turbine generators. Therefore, sudden application of the supply voltage to the core excitation winding is often unavoidable for large stator core testing.

In order to establish the required current capacity of the supply, it is first necessary to determine the excitation level needed to produce rated or near rated flux in the stator core [3]. As indicated in Reference 4, this is calculated as follows.

Excitation Coil Requirements In order to test the stator core adequately, it is necessary to magnetize the core at approximately its normal operating back-of-core flux density.

The turns of the excitation coil should encircle the stator through the main bore (after rotor is removed) and around the outer frame (Figure 17.4). A preferable

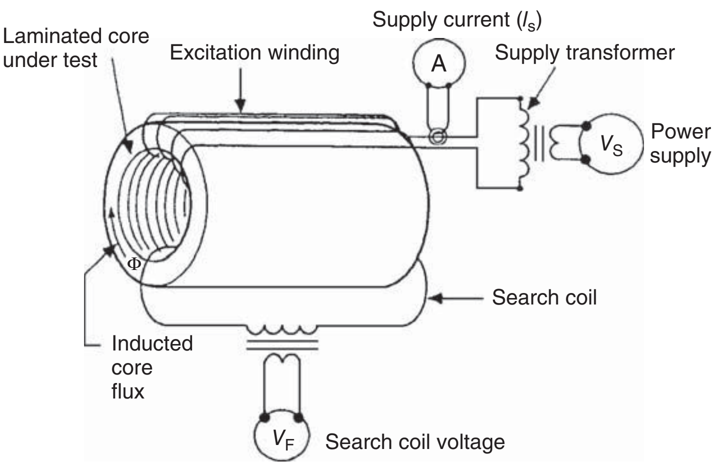

Figure 17.4 Rated flux test setup for large generator.

return route, if available, is near the outside diameter of the core, within the frame. On large diameter machines (such as waterwheel generators), the magnetizing coil should be distributed around the periphery of the stator to ensure uniform flux distribution around the entire core. A clearance of 8–30 cm should be maintained between the magnetizing-coil conductor and solid metal (i.e., metal floor, stator frame, and stator core).

A one-turn search coil is normally also passed through the stator bore to directly measure the volts per turn (VPT) induced in the excitation coil (Figure 17.4). The search coil should be made from a single turn of AWG 12–18 wire insulated adequately for the VPT applied, and it should be placed around the core, preferably diametrically opposite from the excitation coil. The actual core flux density can be measured by placing the search coil, so that it encircles only the core and does not include the frame members. On some machines, this is not possible and the error in measured flux density may or may not be acceptable. An alternative is to route the search coil leads through the radial air vents, if present, and adjust the voltage reading for the percentage of laminations not included in the search coil loop. A voltmeter connected to the search coil should read approximately the volts-per-turn value calculated as shown below.

Calculations The following factors can be used to convert the metric units used in the equations below to imperial units:

1 tesla = 64516.0 line/in.^{2}

1 m = 39.37 in.

The following calculations are performed in designing the test. VPT value for the magnetizing coil and the search coil is given by

$$\mathrm{VPT} = 4.44 f(\phi/2) \tag{17.1}$$

The flux/pole in webers is given by

$$\phi = \frac{V_{\mathrm{pg}}}{4.44 \cdot f \cdot K_{\mathrm{d}} \cdot K_{\mathrm{p}} \cdot \mathrm{ETP}} \tag{17.2}$$

where

VPT = volts (rms) per turn
V_{pp} = machine rated phase-to-phase voltage
V_{pg} = rated stator winding phase-to-ground voltage = $V_{\mathrm{pp}}/\sqrt{3}$
f = frequency in hertz
ϕ = peak-core flux/pole in webers
B = peak flux density in tesla (from manufacturer or by calculation)
D_{sb} = diameter of core at bottom of slot in meters
D_{od} = outside diameter of core in meters
NSS = number of stator slots
NP = number of stator winding poles

$$K_p = \sin\left[\frac{\mathrm{CP}}{\mathrm{FP}} \times 90°\right] \tag{17.3}$$

$$K_d = \frac{0.5}{q \sin \frac{30°}{q}} \tag{17.4}$$

CP = number of slots pitched
FP = $\frac{\mathrm{NSS}}{\mathrm{NP}}$

$$q = \text{slots/pole/phase} = \frac{\mathrm{NSS}}{(\mathrm{NP} \times 3)} \tag{17.5}$$

$$\mathrm{ETP} = \frac{\mathrm{NSS} \times (\text{turns/coil})}{3(\text{number of parallel circuits/phase})}$$

The effective length of core (L_{eff}) should be obtained from the manufacturer. If that is not possible, the value can be calculated as follows:

$$L_{\mathrm{eff}} = (\mathrm{cl} - N_v \times B_v)F_s \tag{17.6}$$

where

cl = gross core length in meters
N_v = number of ventilation ducts
B_v = width of ventilation duct in meters
F_s = core stacking factor

The stacking factor is typically 0.95, and it allows for the lamination insulation in the core.

In metric units, the equations for peak-core flux Q and back-of-core flux density B are given by (Figure 17.5)

$$B = \frac{\phi}{2 \times L_{\mathrm{eff}} \times W_y} \tag{17.7}$$

where

$$W_y = \frac{[D_{\mathrm{od}} - D_{\mathrm{sb}})}{2} \tag{17.8}$$

From the known test supply voltage V_T and the VPT value from (Equation 17.1), the number of turns for the excitation winding can be determined by direct division, that is, turns = (V_T/VPT). The result should be rounded to the next higher integer to obtain N_t, the actual coil turns. This number of turns in the excitation winding (N_t) should be used in the first trial test. For example, if the calculated flux VPT values were 1050 and V_T is 4160 V, then N_t would be 4160/1050 = 3.96. For the test, the number of turns would be four, as the turns have to be a whole number and four turns would not over flux the core area behind the teeth. The excitation level in this example would be about 99% of rated flux.

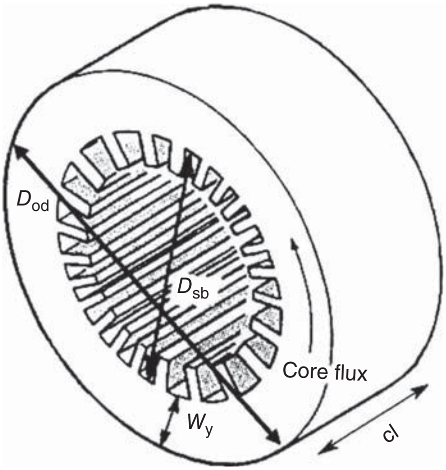

Figure 17.5 Dimensions for calculating core area.

In order to determine the size of the cable necessary for the excitation winding, data on ampere-turns per meter of mean back iron periphery corresponding to the core flux densities will be required. The curve of ampere-turns per meter versus core flux density in tesla should be obtained for the type of lamination material used in the stator core to be tested (Figure 17.6), and the excitation winding current requirement is given by:

$$I_t = \frac{\mathrm{ATM}}{N_t}[D_{od} - W_y]\pi \tag{17.9}$$

This is the magnetizing current. For a more accurate estimation of current requirements, the watts loss current should be determined as well. These two currents can then be added as vectors with 90° phase angle between them, $I_{exc} = \sqrt{(I_t^2 + I_w^2)}$. where

I_t = magnetizing coil current in amperes
ATM = ampere-turns per meter from core steel B–H curve using B from Equation 17.7 (see example in Figure 17.6)
N_t = number of magnetizing coil turns

The current obtained from (Equation 17.9) can be used to calculate the approximate minimum conductor area required for the magnetizing winding.

For small- to medium-size machines, the recommended back-of-core flux density for this test per IEEE 432 is 1.05 times the rated flux density value from Equation 17.7. For larger machines, such as turbine generators, values as low as 75% of rated flux density may be used. Moreover, as indicated earlier, if the number of turns/coil is not known, a back-of-core flux density B of 1.3 T can be used. The above formulae can also be used to calculate the excitation requirements for the version of the core test discussed in Section 17.3.

Practical considerations when setting up this test are as follows:

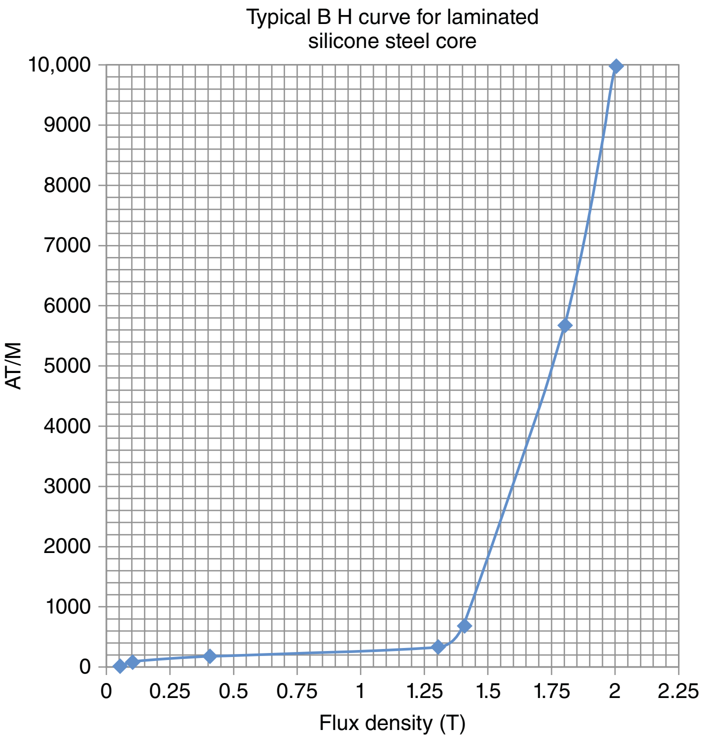

Figure 17.6 Typical core steel B–H curve. (Source: Derived from IEEE 432 information.)

- The excitation winding should be a flexible cable suitably insulated and sized for the supply voltage and expected current capacity. Where possible, the excitation winding should be at the axis of the stator bore, but it is usually more convenient to install it along the surface of the stator core bore and around the outside of the stator frame (Figure 17.4).
- The excitation winding should not obscure any areas of core having obvious damage, and care should be taken to protect the core from damage when assembling the excitation winding.
- Installed stator core thermocouples or RTD's should also be monitored during testing in addition to infrared scanning.
- The power supply for large generator core tests is usually obtained using two phases of an adequately sized three-phase 3.3- or 4.16-kV breaker. Breaker protection (over current and ground fault) should be used and properly calibrated for the expected load. A remote breaker trip switch should be installed at the test site to allow immediate shutdown of the excitation winding power supply in the event of rapid core heat up due to shorted insulation.
- The stator winding, if present, should be open circuited (to prevent induced current flow) and grounded at one location (usually the neutral).

Figure 17.7 Thermal imaging camera and special mirror to monitor stator bore temperature in a turbine generator stator core.

Note: *When testing large turbine generators, care should be exercised as significant voltages can be induced between laminations and high magnetic fields exist in and around the core.*

Commercial core testers have an on-board computer to calculate the current required to test the core. They also have built-in instrumentation to monitor the voltage applied, the current drawn, and the power absorbed by the excitation winding and core system.

Shorted laminations will create high temperatures when excited near full flux. A thermal imaging camera (infrared scanner) is used to quickly survey the whole core, detect the location of hot spots (areas with shorted laminations), and measure actual core temperatures. A special infrared mirror with nonreflecting glass, which is movable axially and rotatable, is inserted into the bore of long turbogenerator stators to better monitor developing hot spots with an infrared camera (Figure 17.7). For motor stator core testing, it is also beneficial to measure the power absorbed by the excitation winding, as described in Section 17.3. This is particularly relevant if previous power readings have been taken with the same induced core flux. A significant increase in the absorbed power compared to previous readings indicates higher core losses because of deterioration in core lamination insulation.

It is recommended that unless severe damage is detected, the duration of this test should be at least 30 min for small- and medium-size machines and up to 2 h for large machine cores, with temperature measurements taken every 15 min. This will ensure that deep-seated core faults are detected. The ambient air temperature should

Figure 17.8 Thermographic image of core with damaged core insulation indicated by dark areas.

also be monitored to allow a comparison between it and core temperatures. When large generator cores with embedded thermocouples are being tested, it is advisable to also monitor the temperatures indicated by these sensors as they may help confirm the presence of good or poor core insulation. With the full flux test, it is necessary to allow time for the core to cool down before the test can be repeated.

Caution is needed not to apply a full flux test without comprehensive thermal monitoring. Because the core is not being rapidly cooled by forced air or hydrogen during the test, thermal runaway causing melted steel laminations is possible!

17.2.3 Interpretation

The main result from the full flux test is the core temperature rise at any location with shorted laminations. Core temperatures should be monitored with a thermal imaging camera (Figure 17.8) from the instant the test flux is applied. This is necessary because the rate of temperature rise in areas of the core with damaged insulation can give a good indication of their location. If the fault is near the core surface, hot spots will appear rapidly, whereas deep-seated damage will be indicated by a more gradual increase in temperature.

Most cores with healthy insulation will still have areas that are a few degrees above the average core temperatures obtained from this test. These are due to flux concentrations. Consequently, insulation damage is not likely unless hotspot temperatures are at least 10°C above the coolest areas of the core for motors and 5°C for large generators [10]. Hotspot temperature of up to 15°C above ambient core temperature may be acceptable if attempts to remove local core insulation shorting are unsuccessful. A general core temperature rise of more than 20°C may indicate widespread core insulation degradation. Cores with this characteristic should be more frequently tested because the condition could deteriorate with time, requiring corrective action.

For motors and small generators sent to service centers for refurbishment and repair, this test should be performed on every stator core at the following stages of a repair.

a) Before removal of a stator winding to allow its replacement

b) After stator winding removal especially if a oven burnout procedure has been used to aid this

c) After any stator core repairs

For large turbogenerator and hydrogenerator stators, this test is advisable to check the condition of the stator core insulation before installing a new stator winding in it.

17.3 CORE LOSS

Commercial core loss testers (Figure 17.2) tend to be used for the smaller cores in motors and generators that are easily transported to a service center. Areas with defective core lamination insulation will require more power from the power core tester power supply than good cores. Thus, this version of the core loss test measures the power to the core in watts. Interpretation is then based on the watts loss per kilogram of core.

17.3.1 Purpose and Theory

This version of the core loss test gives an indication of the general condition of the core insulation, and, for a given core, the higher the losses per mass of core are, the poorer will be the condition. As core insulation condition deteriorates, the currents that flow between the laminations increase, thereby increasing the amount of power needed to reach a certain flux level. The results can also be trended over time. If the power loss increases for the same excitation winding configuration and applied voltage, then more lamination insulation is defective. It is also useful to perform this test before and after winding burnouts (Section 13.1) to detect any significant core insulation deterioration due to the burnout.

17.3.2 Test Method

The test setups for different sizes of machines are the same as those described in Section 17.2.2, except there is usually no search coil. As indicated in Figure 17.9, a wattmeter measurement is already incorporated in commercial core testers. If the core excitation winding system described in Section 17.2 is used, then a wattmeter is required to measure the loss. The wattmeter must be connected into the current and voltage transformers used to obtain current and voltage readings (Figure 17.9). The mass of the core should be known or measured.

17.3.3 Interpretation

For small- and medium-size motor and generator stators:

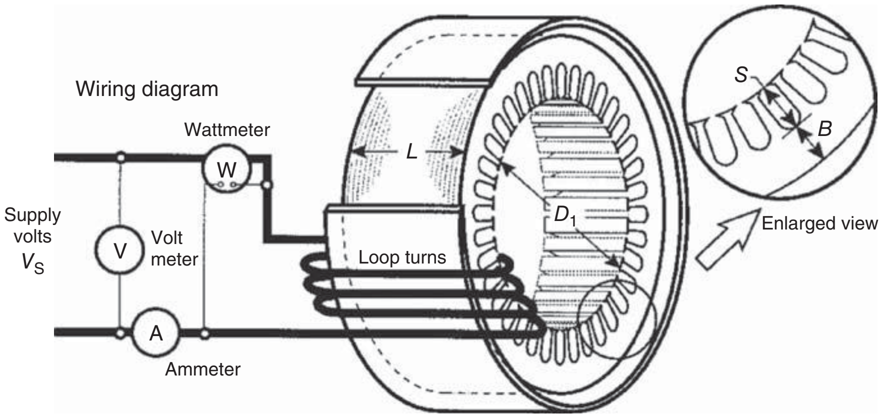

Figure 17.9 Rated flux test circuit showing excitation winding, ammeter, voltmeter, and wattmeter. (Source: Courtesy of EASA.)

- The core loss should not exceed about 10 W/kg. Cores with modern lamination steels and insulation in good condition typically have a core loss of 2–3 W/kg, whereas older cores in motors may have values as high as 6 W/kg. The weight in kilogram for such calculations is based on the volume of the core between the bottom of the stator slots and the outside diameter of the core. The density of rolled steel is 7850 kg/m^3.
- The increase in core loss from a previous test should not exceed 5% for large motor and generator stators. If such increases are seen, the cause should be investigated and, if possible, eliminated.
- Of course, the core surface temperature can also be observed with a thermal imaging camera. The hotspot temperature for a core loss test should not exceed 10°C. The general core temperature rise above ambient temperature should not exceed 20°C. If rises are greater than this, then general core insulation degradation may have occurred.

17.4 LOW CORE FLUX (EL-CID)

The traditional rated flux test described in Section 17.2 requires a significant amount of time and resources to set up if it is to be used for testing large generator stator cores. The alternative low flux test described in this section was devised by Sutton of the Central Electricity Research Laboratories in the United Kingdom in the 1980s and is now being routinely performed on large motors and generators around the world by both machine manufacturers and utilities. The main advantage of this test is that it requires a much smaller capacity power supply for the excitation winding, as only 3–4% of rated flux is induced in the core [5,6]. In fact, for most tests, the power supply can be obtained from a 120 or 220-V AC wall outlet. Moreover, this test normally takes much less time to perform than the rated flux test. Detailed information on this test is contained in Reference 6. Developments in robotic techniques have allowed

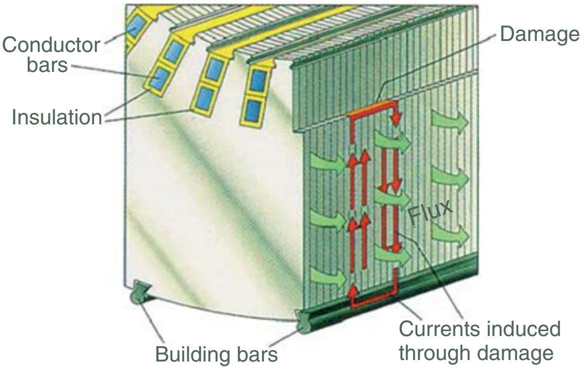

Figure 17.10 Flow of current in core with shorted laminations. (Source: Courtesy of Iris Power-Qualitrol.)

this test to be performed in large turbogenerators without removing the rotor [7] and hydrogenerators after removing a few field winding poles (Section 15.20.2).

17.4.1 Purpose and Theory

The electromagnetic core imperfection detector (El-CID) identifies the presence of faulty core insulation by an electromagnetic technique. It operates on the basis that axial currents will flow through failed or significantly aged core insulation even when a flux equivalent to a few percentage of rated voltage is induced in it (Figure 17.10). In the low flux test, these axial currents are directly detected by the magnetic field they create, rather than from the heat they create or from the power loss, as discussed in Sections 17.2 and 17.3.

The El-CID system uses a special pickup known as a *Chattock coil* (or Maxwell's "worm") to obtain a voltage signal that is proportional to the axial current flowing between laminations. This solenoid coil is wound with a double layer of fine wire on a U-shaped form. When this coil is placed in a position bridging two core teeth, the voltage induced in it by an axial fault current between the laminations is approximately proportional to the line integral of the alternating magnetic field along its length (Figure 17.11).

Applying Ampere's law for any closed loop of integration, the line integral of the magnetic field is equal to the enclosed current, in this case, the fault current. Hence, if the effects of the field in the core are ignored, the Chattock coil will give a voltage output proportional to the current (I) flowing in the area encompassed by it, the two teeth it spans, and the core behind these teeth.

The output from the Chattock coil cannot be used directly to give an indication of core insulation quality. This is because there is another component of voltage induced in it by the circumferential magnetic field generated by the excitation winding that produces the test flux in the core. Consequently, the voltage induced in the Chattock coil is the mean potential difference between teeth due to both currents (I_F) flowing between laminations and those induced circumferentially in the laminations by the excitation winding field (I_w). Fortunately, there is a phase shift between the excitation winding flux and that produced by axial fault currents as these currents are

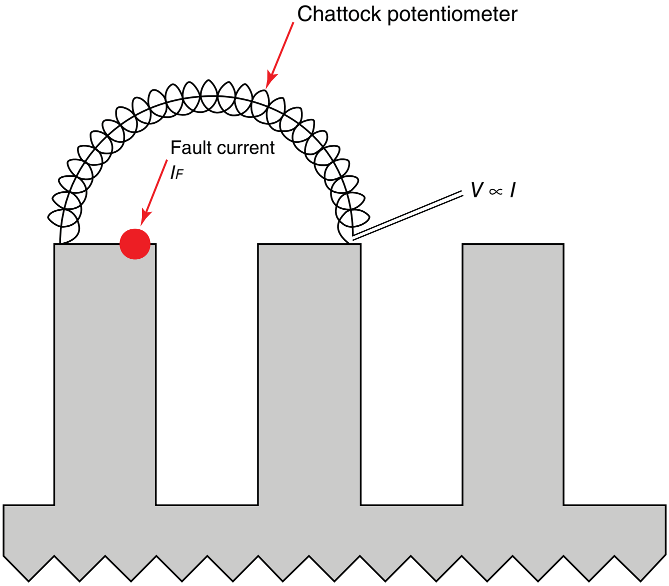

Figure 17.11 Chattock potentiometer bridging two slots. (Source: Courtesy of Iris Power-Qualitrol.)

at 90° to one another. Thus, if the voltage output from the Chattock coil is fed to a signal processor, the portion generated by the excitation winding can be eliminated to produce a voltage that is proportional to the axial component of current. The separation is done by feeding another signal from a reference coil in the excitation cable into the signal processor (see Figure 17.14).

The signal-processing unit gives an output in milliamperes that is a function of the component of Chattock coil voltage generated by axial eddy currents. If there is faulty insulation in the core or there are interlamination shorts at the core surfaces, they will be indicated by relatively high milliampere readings. Industry experience indicates that with 4% of rated back-of-core flux, the measured limit for healthy core insulation is 100 mA, which equates to a 5–10°C hotspot temperature from a "rated flux test" (Section 17.2.3). For other flux levels, this milliampere limit is adjusted in proportion to the actual flux density, for example, for 3% rated flux, the limit is $\frac{3}{4} \times 100 = 75$ mA.

17.4.2 Test Method

The El-CID test kit comes with a preformed multiturn excitation winding and one-turn trace winding for testing motor, synchronous generator, and turbine generator stator cores. A multiturn excitation winding has to be constructed for large stator cores. It is important for the excitation winding to pass through the center of the stator bore (Figure 17.12). If it is not arranged in this manner, then circulating currents can be induced in the stator winding as a result of nonuniform circumferential flux being induced in the stator core. The circulating currents can

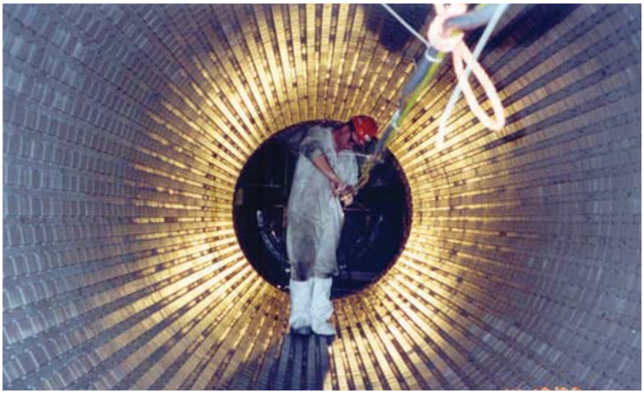

Figure 17.12 Excitation winding insalled in center of turbine generator stator bore.

influence both the PHASE and the QUAD current components measured by the El-CID instrument to give false indications of core insulation condition. For large hydrogenerators, a multicoil excitation winding (Figure 17.13) should be used and again the inner part of this winding should pass through the center of the stator bore. It is also important to ground the stator winding before commencing El-CID tests. In order to avoid any risk of induced currents circulating in the stator windings by the excitation, it is preferable that the windings are disconnected at one end and grounded at the other (usually neutral). If owing to circumstances and procedures it is necessary that the windings be grounded at both ends, then ensure that all three windings are identically grounded. Make sure that the ground bond connection route between the ends does not encircle the core or excitation wires to prevent any risk of stray currents being induced.

The setup of equipment for a stator core test is illustrated in Figure 17.14. Specific details of how to calibrate and set up the instrumentation and select the number of turns, applied voltage, and so on for the excitation winding are given in References 5, 8.

The voltage applied to the excitation winding and the current flowing through it should be recorded at the start and end of the test. This will verify whether the excitation was relatively constant throughout the test and provides good reference information for future tests.

Once all the test equipment has been set up, the test is performed by axially traversing each core slot from one end to the other at a speed of less than 0.5 m/s using an appropriately sized Chattock coil from the El-CID equipment kit. To facilitate easy slot scanning and identification of core insulation defect, the Chattock coil can be mounted in a trolley with distance encoder (Figure 17.15) that allows a plot of milliampere versus distance traveled along the slot to be recorded for future reference (Figure 17.16). As indicated earlier and in Reference 7, the cores in some large synchronous machines can be tested without removing the rotor by mounting the Chattock coil on a remotely controlled trolley that is magnetically held in contact with the stator core. For this setup, the rotor itself is used as part of a one-turn coil that induces flux in the stator core.

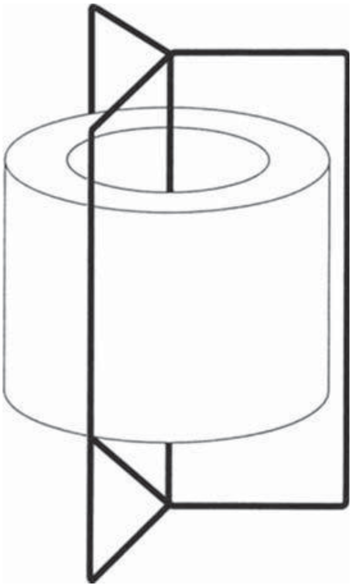

Figure 17.13 Excitation winding for hydrogenerators.

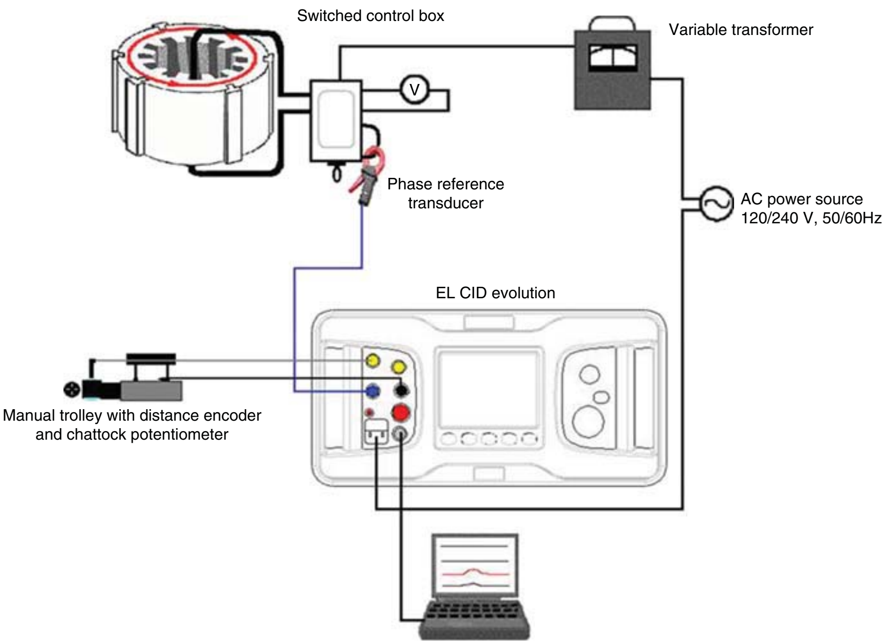

Figure 17.14 Setup of El-CID test on a stator core with a simulated plot on the computer of slot milliampere versus distance along core showing a lamination insulation defect. (Source: Courtesy of Iris Power-Qualitrol.)

Figure 17.15 El-CID trolley with Chattock coil mounted.

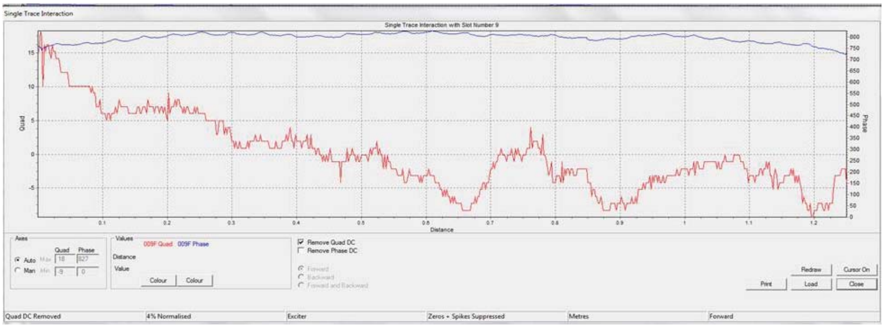

Figure 17.16 Trace of axial current (in milliampere) along a single slot from one end of the core to the other. This core is in good condition as the quadrature (Quad) current is much less than 100 mA. The vertical axis is the quadrature current (left side) and in-phase current (right side). The horizontal axis is the distance from one end of the core. (Source: Plot courtesy Iris Power-Qualitrol.)

If there is step iron at the end of the core (Section 6.6.3), it is not easy to test by wheeled vehicles such as the manual trolley or robotic vehicle. However, it is vital that this (and any other such difficult areas) is tested as thoroughly as the main body of the core, as the core end is usually more highly magnetically stressed than the body. Moreover, it is sometimes necessary to perform handheld Chattock coil tests to further investigate identified core insulation defects. The simplest method to investigate potential core insulation defects is to just manually scan them with a handheld Chattock, whereas an assistant monitors the El-CID readings to note if any untoward readings occur. Step iron traces can be saved using either time-based acquisition or a step-iron trolley.

Alternately, the El-CID software may be used to make recordings of these manually scanned areas, and this recording may be added to the main core traces. The distance accuracy is, of course, only as good as the ability of the operator to move at the specified speed. However, this still allows a permanent recording to be made and reasonably approximate comparisons between slots. If the core-end steps are sufficiently shallow, then the manual trolley may still be used over them, which would allow more precise computer records to be made.

During the test, the milliampere readings from the signal processor should be continuously monitored and at least maximum values should be recorded. The locations and polarity of any reading close to, or above, the milliampere calculated limit for a good core should be marked with a nonconductive substance and examined for signs of defects.

17.4.3 Interpretation

The main output of the low flux test is the axial current in the stator core caused by shorted laminations. Some guidelines on interpretation of the test results are as follows:

- If widespread high milliampere quadrature readings are obtained, either the core insulation is in poor condition or the signal processor has not been properly calibrated.
- If all slots give maximum quadrature readings of less than about 100 mA at 4% excitation, the stator core insulation can be considered to be in good condition [9]. Figure 17.16 shows a typical "good" low flux plot of quadrature (QUAD) current versus axial position along the slot.
- If readings above about 100 mA are obtained (Figure 17.17), the core in the area of such readings should be carefully examined for defects. If no defects

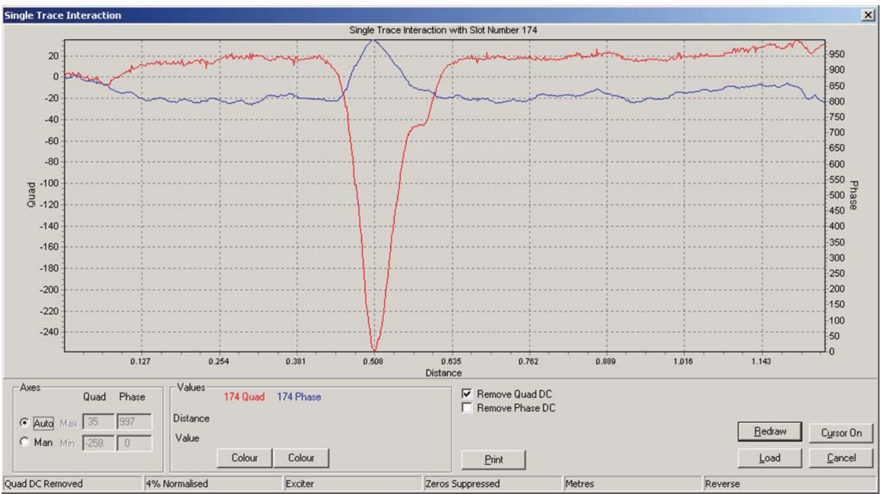

Figure 17.17 Trace of milliampere along the slot length giving indication of localized core insulation defect as indicated by high quadrature current of 258 mA and simultaneous deviation of phase current. (Source: Plot courtesy Iris Power-Qualitrol.)

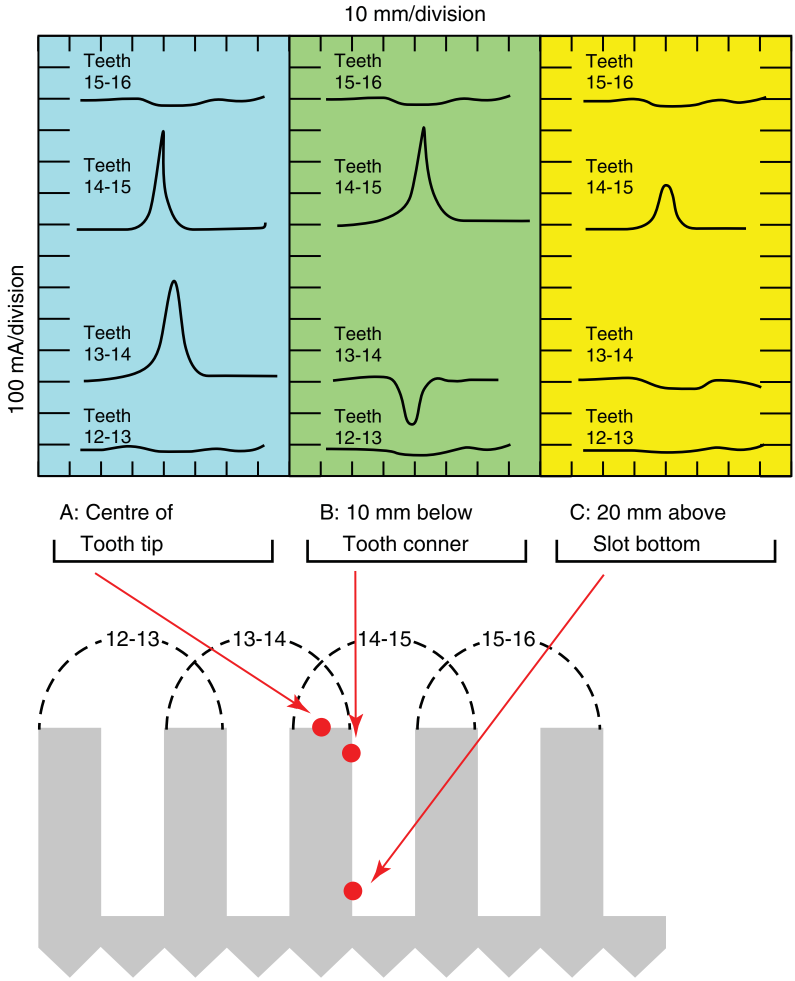

Figure 17.18 Interpretation of position and depth of core insulation defects. (Source: Plot courtesy of Iris Power-Qualitrol.)

are found, it is advisable to perform a rated flux test, as described in Section 17.2, to assess the severity of the core insulation damage.

The polarity of the signals can give an indication of a fault location. This is especially important when there is a winding in a core, as the fault may not be visible [5]. Using the guidelines given in Reference 6, the polarity of milliampere readings around a fault location can give an indication of position and depth of the damaged core as shown in Figure 17.18.

One advantage of this test is that the equipment can be left connected and is easily reenergized to check repair work done on a section of core containing shorted laminations. Unlike the full flux test, it is not necessary to allow time for the core to cool down before it can be repeated. The El-CID test does require some skill and experience on the part of the operator to determine if a fault exists and where it is located.

There are a few circumstances where circulating currents can be induced in stator windings, and these influence El-CID test readings. Such currents are possible only if there are closed paths within the stator winding, for example, if there are two or more phase parallel circuits per phase or if the three winding phases are shorted together at both line and neutral ends. The two major causes of such circulating currents are the following.

- The excitation winding is not concentric with the stator core bore.
- Core splits in hydrogenerators.

Nonconcentric Excitation Winding Winding circulating currents are only likely to occur in turbogenerators and motors if the excitation winding is not wound through the center of the stator core bore. A nonconcentric excitation winding creates asymmetry in the magnetic circuit, which can cause flux to flow up and down the stator teeth to induce circulating currents in the stator winding.

Core Splits in Hydrogenerators Circulating currents are more difficult to avoid in hydrogenerators because they generally have a high number of parallel circuits per phase and it is often not easy to install the excitation winding in the center of the stator bore. Circulating currents are particularly likely in hydrogenerator cores that are split into two, three, or more sections (see Section 6.6.2) owing to flux leakage between the core sections inducing circulating currents in the stator windings. In the vicinity of such core splits, some of the induced circumferential flux escapes from the main body of the core to cross these gaps by flowing up and down the teeth

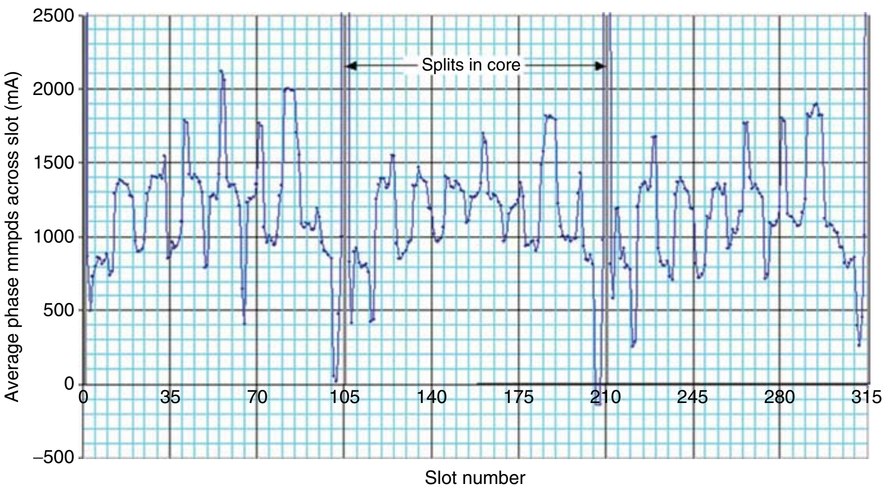

Figure 17.19 El-CID readings for each slot owing to stator winding circulating currents resulting from core splits with excitation winding centered in the stator core bore. (Source: Courtesy Iris Power-Qualitrol.)

Figure 17.20 El-CID QUAD and PHASE current comparisons along a stator slot at a core split—same shape and constant PHASE/QUAD current ratio confirms that there is no core insulation damage. (Source: Courtesy Iris Power-Qualitrol.) *See color plate section.*

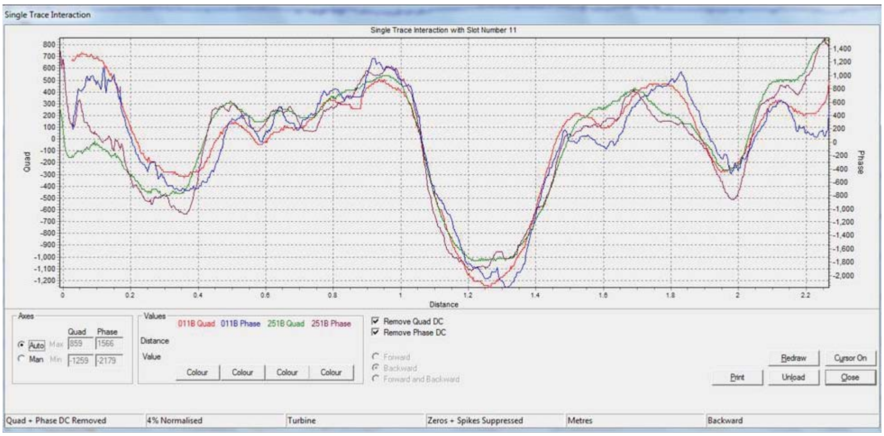

Figure 17.21 El-CID QUAD and PHASE current comparisons for two slots at core splits—similar shapes for all current plots and magnitudes for the PHASE and QUAD currents confirm that there is no core insulation damage. (Source: Courtesy Iris Power-Qualitrol.) *See color plate section.*

on either side of them, even if the excitation winding is central in the stator bore (Figure 17.13). This radial flux up and down the stator teeth links the stator winding and induces significant currents in it to produce El-CID readings well above the 100-mA threshold (Figure 17.19). There are two ways to confirm that core splits are not the cause of high El-CID mA readings. One is to compare the direct (PHASE) and quadrature (QUAD) currents measured along a core slot at a split. If the current plots have a similar shape and PHASE-to-QUAD current ratio (Figure 17.20), then excessive El-CID milliampere readings are not due to core defects. The other is to compare the PHASE and QUAD current profiles for El-CID test readings for two or more slots at core splits and, if they are similar (Figure 17.21), then again high readings are due to the core splits and not core insulation defects. The El-CID software can be used to display the QUAD and PHASE current comparisons, which are shown in Figures 17.20 and 17.21.

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CHAPTER 18

NEW MACHINE WINDING AND REWIND SPECIFICATIONS

One of the most important factors to achieve long rotor and stator winding life is the purchase specification of the machine, or in the case of an older machine, the specification of the rewind. There are several general specifications for machine windings available from global standards organizations such as IEC and IEEE. For example, the IEC 60034 series of standards outline the general performance requirements for all types of conventional motors and generators. Most of the specific requirements in the IEC 60034 series address performance in terms of ratings, temperature limits, audible noise, and vibration. In addition, the IEC 60034 series does provide a lot of agreed-upon test methods, but at least for the insulation systems, very few requirements that the tests be done. In fact, the IEC 60034 series only has one requirement for the electrical insulation: the rotor and stator windings must be shown to withstand a hipot test (Sections 15.2 and 15.6) for the groundwall insulation, and a voltage surge test (Section 15.16) for the turn insulation in multiturn coil stator winding. No other test is required that may indicate the quality or capability of the insulation. Most importantly, there is no statement on the expected life of the windings in the IEC 60034 standard series!

IEEE/ANSI C50.12 and C50.13 are general standards for salient pole and round rotor generators, as is NEMA MG1. However, again there are no requirements for the insulation beyond the hipot tests and the insulation resistance test in IEEE 43. Moreover, there is no requirement for a certain winding life in the IEEE and NEMA standards.

A general rewind guide for generators is presented in IEEE 1665 [1]. Reference 2 discusses items to consider in refurbishing motors.

If one buys a new machine or a rewind just referring to IEC, IEEE/ANSI, or NEMA standards and stating the primary ratings of power, power factor, speed, and voltage, then there will be no assurance that the windings will last beyond the warranty period. This chapter focuses on what could also be considered for inclusion in a purchase specification to achieve the desired life and reliability. Of course, if one includes all the suggestions below, it is likely that the stator and rotor windings may be more expensive than if one decides to delete some of the items.

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

18.1 OBJECTIVE OF STATOR AND ROTOR WINDING SPECIFICATIONS

Because the basic standards for motor and generator windings do not address winding insulation quality or expected life, these must be addressed by additional clauses in the purchase specification.

Perhaps the most important item to include in a purchase specification is the expected life of the machine (or winding, if it is a rewind). As discussed in Chapter 2, machine designers must select the winding insulation materials and the operating stresses (voltage, temperature and mechanical forces). In general, the higher the stress level is, the shorter will be the insulation life. For example, Class F insulation materials have been shown to have adequate electrical and mechanical strengths when subjected to a temperature of 155°C for 20,000 h (Section 2.3). Operating a Class F winding with a hotspot temperature of 155°C for more than 2.3 years implies that there will be a high risk of failure. A 2.3-year life may be considered adequate in some applications, perhaps in a traction motor, or in some safety application where operation for more than a few hours is not expected. However, most power utilities and industrial process plants expect their motor and generator windings to be able to operate without failure for 20–50 years. Clearly, this will not happen if the winding has a copper cross section and cooling system such that the stator or rotor winding operates at 155°C. As discussed in Sections 2.1.1 and 2.3.1, by operating the winding at a lower temperature, the rate of thermal aging will slow and the winding life will be increased. The winding designer can select the materials and winding design to achieve whatever thermal life the customer desires, using the principles outlined in Section 2.3. Chapter 2 describes how machine designers can achieve whatever life is desired under electric and mechanical stresses, as well as thermomechanical stresses. However, it is the user that must specify the machine environment and the expected life.

The other aspect a purchase specification should address is the quality of winding manufacture. Although there are many IEEE and IEC test procedures that can be performed on new windings in the factory, none are required (other than the hipot tests). Most of the quality tests in IEC and IEEE standards do not have "pass–fail" levels. Thus, purchasers should decide on what quality tests are relevant for their machine, what the test procedure will be (there are often many ways to measure a property) and what the pass–fail criteria will be. Sections 18.3–18.5, together with the material in Chapters 15 and 17, provide some guidance on this.

18.2 TRADE-OFFS BETWEEN DETAILED AND GENERAL SPECIFICATIONS

Generally, the more detailed the technical specification for a new machine or winding is, the more it will cost. Specifically, requiring the manufacturer to design for say a

50-year winding life, and also do all the diagnostic tests in Chapter 15, and setting difficult pass–fail criteria will have several impacts:

- The machine will be much larger for the same power/torque output. This is due to the extra copper and steel required to reduce operating temperature; extra insulation required to reduce the risk of partial discharge, and the extra slot and endwinding support to prevent coil/bar vibration. Clearly, this will increase machine cost.
- Design features may be needed to ensure a low risk of failing any of the diagnostic tests. This may increase cost.
- There will be an increased cost owing to all the testing required. In addition, the extra testing may delay delivery of the machine or winding.
- In some cases, the purchase specification may call for contradictory requirements. For example, the need to avoid endwinding vibration resonance at twice power frequency (Section 15.23) generally means that the endwindings should be as short as possible. However, this may imply that the spacing between the coils/bars in the endwinding will be reduced, increasing the risk of failure of a blackout test (Section 15.14).
- Manufacturers may not wish to use some design and processing innovations that may lower cost, but increase the risk of failing one of the requirements, owing to uncertainty of the outcome on the diagnostic tests.

Thus, machine/winding purchasers need to be mindful that asking for more tests and setting the pass–fail criteria high, which will increase the cost. Engineering judgment on the part of the specifier needs to consider the application, the importance of the machine to the process, the availability of spares and service shops that can do quick repairs, and the future maintenance costs, before the level of detail in the purchase specification can be decided.

Another aspect that might be relevant is the length of time the organization setting the specifications expects to own the plant. In the past, utilities, petrochemical plants, pulp and paper mills, etc. tended to operate a plant from commissioning until the plant was obsolete. Recently, utility and process industry companies are tending to buy and sell plants on a regular basis. Thus, if it is expected that a plant may be sold in say 10 years, it is hard to argue that the motors and generators should be specified in such detail that a 30-year or more life will result, as the seller of the plant will probably not realize those benefits.

18.3 GENERAL ITEMS FOR SPECIFICATIONS

Technical specifications for new stator and rotor windings and for the refurbishment/repair of existing stator and rotor windings should have some basic content other than technical requirements, to ensure adequate quality that will provide reliable service for their anticipated life. This means that the purchaser has to devote some time up front in preparing these technical specification requirements that should include some or all of the following:

1. Ask potential vendors to provide a list of companies to whom they have provided similar machines or services in the past few years. This list should include names of contacts at these companies together with their telephone numbers, e-mail address, etc. These people should be contacted to find out the level of satisfaction provided by the vendor. The purchaser should also evaluate vendors he or she has had recent dealings with. Any vendor that has not given satisfactory service should not be considered as a bidder for the required new machine or service.
2. Before finalizing a bidders list, the vendors' quality assurance (QA) programs should be evaluated to ensure that the expected quality of workmanship and materials will be adequate. Typically the vendor QA program should have been externally audited to confirm that it complies with ISO 9001 requirements. Moreover, the program should include the development of an inspection and test plan (I&TP) that outlines the complete manufacturing and/or repair process. This plan should indicate witness and hold points at which the purchaser has the opportunity to inspect the work done to that point and final tests on the equipment before shipment. If felt necessary, for critical machine purchases and repairs, the purchaser should conduct his or her own audits to ensure that potential vendors are complying with their QA program requirements. Such audits should include a tour of the vendor manufacturing or repair facilities to check if they have adequate manufacturing and test equipment, as well as the quality of workmanship and the cleanliness of areas such as those where new windings are installed.
3. In drawing up a bidder list, the purchaser may want to first evaluate the technical capabilities of prospective bidders. Section 19.1 identifies some of the tests that can be done to evaluate capability.
4. For repair and refurbishment work to be performed at site, for example, a large generator stator rewind, the bidder's procedures for such work should be reviewed because some of them will be different from those used in a manufacturing plant. In particular, for stator and rotor rewinds, it is essential that, if the machine is outdoors, a temporary enclosure be built to keep moisture and dirt out. Moreover, there should be a controlled entry to the site area where work is being performed with someone responsible for logging in and out any tools or equipment that could be left inside the machine.
5. It is important to check the progress and quality of the vendor's work periodically to ensure that it is satisfactory. This can be facilitated by the I&TP hold and witness points at which the vendor should contact a person or persons designated by the purchaser to see if they wish to have someone present to inspect the work done to that point. It is most important that the customer has a qualified representative present to witness final tests on the new or repaired/refurbished machine or component to ensure that it meets all of the acceptance criteria given in the technical specification. This is so because once a new machine or

repaired component is shipped or a work crew leaves the site, it becomes much more difficult to have the vendor correct any defects that may be present.

18.4 TECHNICAL REQUIREMENTS FOR NEW STATOR WINDINGS

This section deals with the specific requirements that could be included in a technical specification for a new form-wound stator winding rated 3.3 kV and above, which should give assurance of reliable service over the required life. These include upfront preparation before winding manufacture commences.

1. It is important that the rating and duty requirements as well as temperature rise limits be provided for new machines. For long thermal life, the winding temperature limit should be that for one temperature class below the insulation system rating, for example, Class 130 temperature rise for a Class 155 insulation system. Moreover, for stator rewinds, any required uprating or change in duty should be specified. The required service life should also be stated.
2. The requirements for a test to check the integrity of the stator core insulation before a new winding is installed should be included. This is equally applicable to new cores and those where an old winding has been removed. Preferably, this should be done using a rated flux test (Section 17.2), but for site rewinds, an El-CID test (Section 17.4) may be more practical.
3. If a winding is being replaced, it is important to record all the details of the existing winding, especially if the rewind is not being performed by the OEM. The following information should be specified to be recorded before the removal of the existing winding:
   - **(a)** Number of stator slots and whether multiturn coils or bars are used.
   - **(b)** Winding connections—record this information in a winding diagram that should include the locations of all stator winding temperature detectors.
   - **(c)** Coil/bar, stator slot, and stator core dimensions sufficient to replicate the stator winding.
   - **(d)** Overall winding projection, including connections, at each end of the core.
   - **(e)** Check done to ensure the condition of the stator core insulation preferably using a rated flux test (Section 17.2). However, for site rewinds, an El-CID test (Section 17.4) may be more practical.
4. The specification should cover allowable methods for winding removal when the stator winding is to be replaced. For large hydro- and turbine generators with resin rich or individually VPI'd coils/bars, hand stripping using mechanical aids should be adequate. However, other methods such as water lancing and controlled insulation burning in an oven usually have to be employed for global VPI windings. If a burnout oven is used, then temperature limits for the burnout process and the recording of actual temperatures should be specified. These temperature limits should be based on the type of core insulation used

(Section 6.5). General guidelines are a burnout oven temperature limit of 345°C if the core insulation material is not known and 400°C if the core insulation is ASTM A976-13, C5 (Sections 6.2 and 6.5). Once an old winding has been removed, the stator core slots should be cleaned to remove any resin and insulation residue. For global VPI windings, dry ice, walnut shells, or corn blasting should be specified as the use of harder materials such as glass beads and sand can cause smearing of the core laminations that result in core insulation shorting. No matter which method is used to remove an old stator winding, it is important to perform a rated flux or El-CID test after this has been done and all insulation system residue has been removed from the core slots, to ensure that no core insulation damage has occurred. During removal of multiturn coil or bar windings, the number of coil turns and conductor strand size and configuration should be recorded. Moreover, if the conductor strands are transposed, a record of the configuration used should be made.

5. There are some specific winding insulation system material requirements that should be specified to help give assurance of a reliable service life. These are

   (a) For multiturn coils, the turn insulation should be selected to withstand power system surges and partial discharge attack. For voltage ratings ≥6 kV, this requires the use of mica strand and/or turn insulation.

   (b) Both the slot and the endwinding, ground insulation should specify the use of mica tapes. The use of wrappers for the slot section should be prohibited because they promote wrinkling and inhibit resin penetration in individual and globally VPI'd resin impregnation. Coils or bars for voltage ratings ≥6 kV, and for voltages ≥3.3 kV for windings used in variable frequency converter supplied windings, should have a semiconductive (graphite) coating on the straight sections with overlapping grading material at either end. Many users prefer tapes to paints.

   (c) Slot wedges should be made from mechanically robust materials such as NEMA Grade G10 or G11 epoxy glass laminate. If magnetic slot wedges are permitted, they should be of the sandwich construction (Section 8.4.2) in which there is an epoxy glass wedge to withstand the electromagnetic forces from the stator winding and a magnetic wedge above this to provide the performance improvements that this material gives.

   (d) For voltages ≥6 kV, midsticks and fillers should be made from partly conductive material. Moreover, the midstick thickness should be sufficient to provide adequate spacing between top and bottom line end coils in different phases so as to prevent interphasal partial discharges.

   (e) Endwinding bracing should be adequate to provide sufficient support to prevent relative movement between it and the coils or bars during both starting and running. Certainly for two- and four-pole motors and generators, such support can only be provided by fixed radial solid steel or fiberglass brace rings. Where steel bracing rings are used, they should be insulated with the same number of layers of mica tape as are applied to the stator winding coil or bars. For air-cooled windings rated 11 kV or higher, the

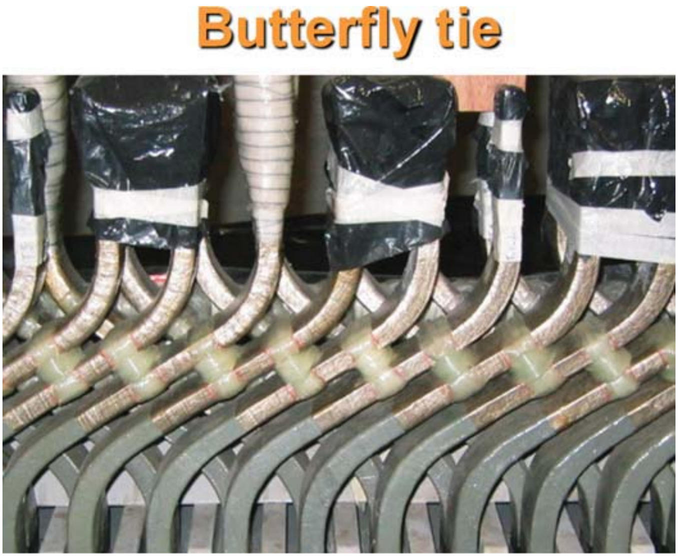

Figure 18.1 Interbar blocks covered with felt.

spacing between coils/bars in the endwinding is critical to prevent PD. The higher the rated voltage is, the greater the spacing needs to be. Specify IEEE 1799 to ensure that spacing is adequate (Section 15.14). The spacers between coils/bars should consist of felt which should be wrapped around solid blocks (Figure 18.1), and ties between the winding and radial bracing should be tight and resin saturated to ensure good support. The butterfly tying configuration (Figure 18.2) ensures that intercoil/bar blocking is kept in place. Large turbine generators also require inner and outer support baskets to ensure good endwinding support. Conformable felt or other material should be installed between fixed radial bracing rings and the coil/bar endwindings to minimize the possibility of relative movement in operation.

(f) All connections should be adequately supported and separated to prevent interphasal partial discharge activity. Consider specifying IEEE 1799.

(g) It should be stated that jacketed cables are not to be used for winding circuit ring connections as their insulation has a low PD resistance. Moreover, cable or lead cable spacing should be controlled and these components well supported to avoid interphasal PD and rubbing against stator frame components.

(h) Sample coils or bars could be made along with production ones for two purposes:

  (i) To check dimensions for fit in the stator core, windability and intercoil spacing. This can be done in the actual core or in mockup to represent it (Figure 18.3). The latter method is more appropriate for site rewinds because the coils/bars are manufactured at a remote location.

Figure 18.2 Butterfly ties at interbar blocking.

Figure 18.3 Stator core mockup to check bar fit and endwinding spacing.

(ii) For processing with the actual coils/bars used in the windings and for qualification testing (Chapter 2) and/or testing to destruction. For global VPI windings, it is a good idea to specify that a number of sample coils be made with steel or aluminum plates fitted to simulate stator slots and their leads brazed together and insulated to simulate connections. It should be specified that one of these sample coils be cut open after the first resin impregnation, but before heat curing, to ensure that there is resin penetration to the conductor stack. Sample coils that are to be fully processed by heat curing, should be fastened to the bore of the stator core to ensure that they are heated to a similar temperature as those in the stator winding before the VPI process commences.

This ensures that resin fill will be similar to that in the stator winding. For nonglobal VPI stators, the extra bars/coils can be used for voltage endurance tests (IEEE 1043/1553) to ensure good manufacture (Section 2.4.2).

6. If the winding is for operation with a fixed 50 or 60 Hz frequency sinusoidal power supply, to ensure reliable service, it is important to specify certain quality tests and inspections for new stator winding coils or bars. This is true especially if the winding voltage rating is ≥6 kV. The following tests and acceptance criteria give this assurance.

(a) High potential tests at various stages of manufacture. The purchaser and vendor should agree on AC hipot levels for fully impregnated bars/coils. The level will normally be higher than $2E + 1$. For green global VPI windings, it should be stated that high potential test levels are to be agreed between the purchaser and the vendor, which are usually much less than $2E + 1$. E is the rated phase-to-phase voltage.

(i) A 120-V power source shall be used to check for shorted strands after hipot and surge testing has been performed. No shorted (or low resistance) strands will be accepted. If additional testing is necessary, the minimum between strand resistances that should be accepted is 1.0 MΩ at 1000 V.

(ii) Bars and coils shall be clearly identified and labeled. Documentation of individual bar/coil tests must be provided.

(b) For impregnated and heat cured bars/coils rated ≥6 kV, a power factor tip-up or partial discharge test shall be conducted on each winding bar, or coil leg generally in accordance with IEEE 286 or IEC 60034-27-3, except that test voltages of 25% and 100% of the winding rated AC rms line-ground voltage shall be used (Section 15.11). Many use the following acceptance criteria before grading tape application, or with the grading tape guarded out: 80% of the coils must have a tip-up less than 0.3% (Section 15.11.3). Any coil with a tip-up greater than or equal to 1% is often rejected. The acceptance limit for any partial discharge tests on individual coils/bars should be agreed between the purchaser and the customer.

(c) A sample of 20% of impregnated and heat cured winding bars or coils ≥6 kV shall be subjected to either blackout tests or UV camera imaging tests (IEEE 1799) to ensure no visible signs of surface discharge at 1.2 × rated winding phase-to-ground voltage.

(d) All multiturn coils should be surge tested to check for turn shorts, at various stages as follows:

(i) After manufacture—on an insulated table to the full IEEE 522, Figure 1, 0.1-μs risetime voltage level, or alternatively the IEC 60034-15 level.

(ii) After winding, wedging, and bracing, but before connection—fully impregnated coils should be tested to the same level as was used after manufacture while green global VPI coils should be tested to 60–80% of this level per IEEE 522 (Section 15.16). The stator coil identification number and slot number shall be recorded.

(e) For windings with conductive PD suppression coatings in the slot, the contact resistance between the conductive coating on each coil leg/bar and core shall be measured and recorded after coil side packing is installed to ensure continuity between the two (Section 15.18). Each top and bottom bar shall be tested at three locations, which are 10 cm from each end of the stator core and at the center of the stator core. Each coil leg shall also be tested at each end of the slot. Typically a value of around 1000 Ω is acceptable.

(f) Insulation resistance measurements and then DC or AC hipot tests of individual bars or coils shall be performed once every shift during winding installation. The bars or coils installed during that period shall be hipot tested at an agreed voltage that is usually somewhat higher than $2E + 1$ kV, or its equivalent in DC voltage. For bar windings, all bottom bars shall be tested before top bar installation commences. In the event, a bar or coil fails during the test; it shall be removed and replaced with a new bar or coil at the vendor's expense. Bars and coils may be tested in groups, and for coils both leads shall be connected to adjacent coils.

7. For global VPI windings, the testing to be specified is after all connections are made, but before resin impregnation and/or curing (Figure 18.4). These tests and their acceptance criteria are as follows:

(a) Terminal-to-terminal, or phase resistances. The three recorded values must balance to within 1.0%. Note

$$\%\ \text{unbalance} = \frac{\left(R_{\text{Max Dev}}\ \text{from average} - R_{\text{Average}}\right)}{R_{\text{Average}}} \times 100$$

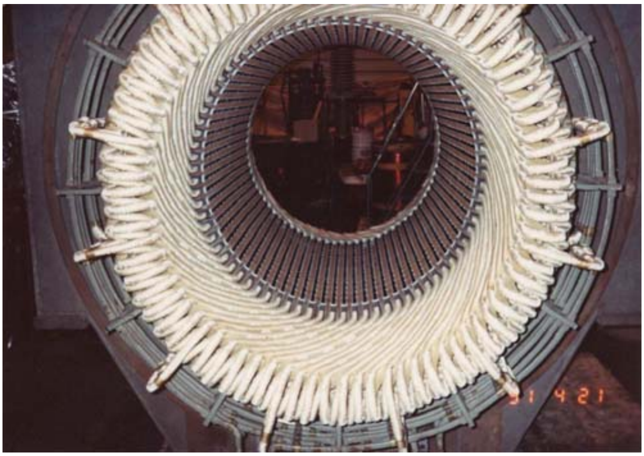

Figure 18.4 Stator winding ready for global VPI processing.

(b) Insulation resistance and polarization index tests on the complete winding or individual phases to confirm that windings are dry and free from ground insulation defects.

(c) Inspections and tests to confirm correct winding connections and phase rotation and there is adequate interphasal spacing.

(d) With the insulation completely dry, a 1.0-min hipot test to confirm that ground insulation has been properly applied. The test voltage for individual vacuum pressure impregnated (VPI) and resin-rich coils is often about 70% of the final AC hipot test level or a DC hipot test at about 100% of line-to-line voltage for global VPI windings.

8. For completely wound and impregnated stators:

(a) For resin-rich and individual VPI windings, perform wedge tap to ensure that all wedges are tight (Section 15.20).

(b) A check to ensure that all blocking and bracing is in place and interphasal spacing is adequate.

(c) Verify that stator winding temperature detectors are indicating the correct temperature.

9. It should be stated that, during winding processing, records of information such as VPI process parameters, resin-rich coil hot press temperatures, and oven temperatures are to be kept for future reference.

10. The following tests could be specified to be performed after the stator winding is fully processed. References to sections of this book, which provide details of these tests and acceptance criteria, are indicated for each test.

(a) IR and PI on individual phases to confirm that they are dry and free from ground insulation defects. During this test, the other two phases should be grounded so that both phase-to-phase and phase-to-ground insulations are tested. The test voltage and acceptance criteria shall be in accordance with IEEE Std. 43 (Section 15.1).

(b) An off-line partial discharge test to check the integrity of the slot ground insulation and adequacy of interphasal spacing (Sections 15.12, 15.14, and 15.15). If winding is to be connected to an inverter, refer to Section 15.13.

(c) Capacitance/dissipation factor tip-up tests as a baseline if periodic tests are planned after the machine goes into service (Sections 15.8 and 15.11).

(d) NEMA MG 1-20.18 water immersion test for sealed windings (Section 15.6).

(e) A winding 1.0-min AC hipot test to confirm ground insulation integrity. The hipot test voltage shall be ($2 \times$ rated line-to-line voltage + 1000 V) AC. Winding temperature detectors shall be grounded for this test (Section 15.6).

(f) A 1000-V, IR test to ground on temperature detectors with the winding grounded. The IR value should be $\geq$10 MΩ.

(g) For two- and four-pole stators, consider requiring a bump test to ensure that there are no natural frequencies near 100 or 120 Hz (Section 15.23).

11. The following tests should be considered for sample bars or coils:

(a) If the machine being manufactured is required to have a long service life, for example, 30 years, a voltage endurance test as per Section 2.4.2 (fixed frequency 50/60 Hz machines) or Section 2.4.3 (voltage source inverter supplied machines) should be considered. However, if the vendor has already performed such tests with acceptable results on sample coils or bars of similar size having the same insulation system as the one being purchased, then such test may not be required.

(b) If the machine stator core length is 2 m or longer and the stator winding will see rapid thermal cycling in service, for example, hydromotor/generators and gas turbine generators, a thermal cycling test on sample coils (Section 2.5.1) could be specified. However, if the vendor has already performed such tests with acceptable results on sample coils or bars of similar size having the same insulation system as the one being purchased, then such test may not be required.

(c) Tests to failure to assess insulation system capabilities. For all voltage ratings, some assurance of the capabilities of the stator winding insulation system being supplied can be obtained from the following tests on one or two sample coils.

(i) A surge test to 3.5 pu (where 1 pu is the peak line to ground rated voltage) or to the breakdown voltage of a multiturn coil turn insulation (see Section 15.16) and then surge tests at increasing, higher peak voltages until failure occurs or the maximum output voltage of the surge test instrument is reached.

(ii) An AC hipot test to the breakdown voltage of groundwall insulation on each coil leg. For very high voltage stator bars, this test may have to be performed with the bar immersed in insulating oil to avoid flashover. This test should be done after a turn insulation surge test, if applicable.

(iii) Dissection of coil or bar legs in both the slot and the endwinding regions to determine the location and, if possible, the reason for ground insulation failure. The dissection should also assess the quality of the coil insulation application and impregnation. The sections of coil should be examined for the following problems:

- Nonuniform groundwall insulation thickness, especially at the corners of the coil/bar slot sections (Figure 18.5).
- No sharp corners—groundwall insulation at the corners should be rounded (Figure 18.5).
- No wrinkles that indicate poor groundwall insulation application.
- No significant voids in the groundwall and around the conductor strands or turns indicating poor resin fill. This is more important in

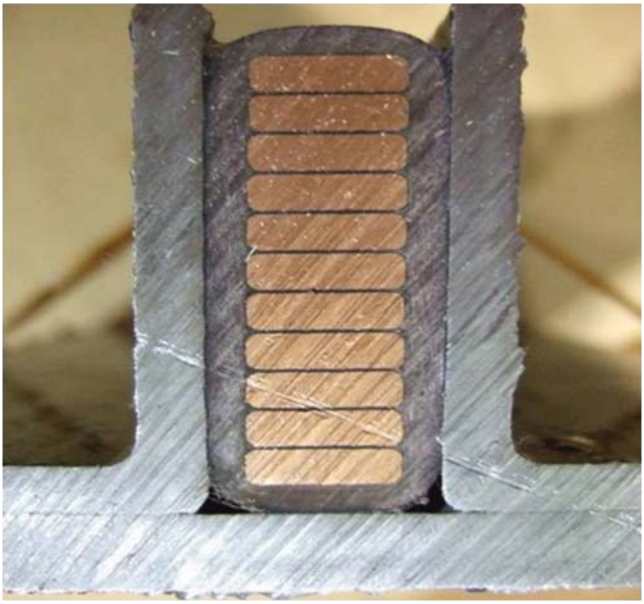

Figure 18.5 Section of sample global VPI'd coil in simulated slot.

the coil straight sections, but large voids in the endwinding area can result in coil strand movement, insulation abrasion and turn insulation failures.

18.5 TECHNICAL REQUIREMENTS FOR INSULATED ROTOR WINDINGS

This section covers possible requirements for inclusion in technical specifications for new and replacement round rotor and salient pole rotor windings. Items to consider in the refurbishment of synchronous rotors are also presented. In new machines, all of the materials used to manufacture the field winding should be new. On the other hand, when such windings have to be replaced, the original copper conductors and other metallic components can often be reused.

18.5.1 New Round Rotor Windings

The following suggested winding procedure applies to new and replacement round rotor field windings (see Section 1.6.2):

1. The rewind should be performed in a clean air-conditioned room maintained at positive pressure relative to the surrounding environment.
2. It is important that the following tests be performed at various stages of winding installation to confirm that there are no defects.

3. Slot cell ground insulation should be made of a high temperature material having a thermal rating of Class F (155°C) or higher. Nomex™ or molded epoxy glass laminates are the preferred material for these components. The slot cell insulation should project beyond the ends of the slots and be "glued" or somehow fixed in to the slots to prevent axial movement under the influence of field winding axial thermal expansion and contraction.
   - **(a)** Insulation resistance to the rotor body of coils, coil groups, and complete winding.
   - **(b)** Tests for shorted coil turns such as relative surge oscillograph (RSO) (Section 15.26) or pole drop (Section 15.25).
   - **(c)** Coil and winding resistances to check for poor connections and open circuits.
4. Turn insulation and top filler strips—these should consist of strips and/or tapes of insulation having a thermal rating of Class F (155°C) or higher. Nomex tape, Nomex pads, or epoxy glass laminates are the preferred materials, which should be coated on one side with a thermosetting epoxy or an air-drying resin that will cure and bond the insulation after field winding has been installed. In smaller generators rated up to 100 MVA or so, the top one or two turns in each coil are often fully taped in the endwinding regions to increase creepage paths to ground (Figure 18.6). For ratings above this, top turn taping is not a common practice. The turn insulation should be applied to the coils before winding them into the slots. If more than one strand per conductor is used both strands should be insulated or they need to be mechanically locked together to prevent copper dusting during turning gear operation. Up-shaft leads connecting the field winding to slip rings or a brushless exciter rotating diode rectifier should be made from copper insulated with a Class 155 material.

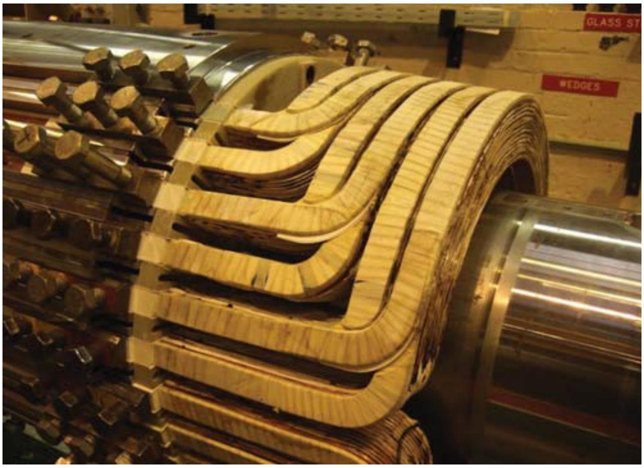

Figure 18.6 Round rotor field winding top turn taping.

5. Metal slot wedges should be made from copper alloy, magnetic steel, stainless steel aluminum, or a combination of these metals. The wedge selection should be made by the generator manufacturer. A damper (amortisseur) winding shall be provided. The conductors in this copper damper winding can be connected together at the ends by the retaining rings or by copper rings or connections.
6. Top creepage blocks shall be installed between the slot wedges and the top coil turn and should be made from a Class 155 insulation material such as NEMA G10 or G11 epoxy glass laminate, with adequate mechanical compressive strength to withstand the high radial forces imposed on them by the stator winding. Moreover, any nonmetallic components used to provide reduced mechanical stresses on field winding at the ends of the slots shall be made from Class 155 material.
7. During coil installation, temporary blocking shall be installed on the shaft at each end to support the coil endwindings and facilitate their shaping during winding. These blocks may also be required to support the endwindings during heating of thermosetting turn insulation bonding resin to cause it to flow, bond, and cure (Figure 18.7).
8. Endwinding intercoil blocking shall be made from NEMA G10 or G11 epoxy glass laminate material. This blocking shall be tight enough and secured to ensure that coil endwinding shape is maintained under the influence of thermal expansion and contraction seen during generator operation, but not tight enough to prevent endwinding compression to allow the retaining rings to be installed.
9. The slot wedges should be numbered when installed and their locations recorded on a wedge map.
10. Retaining ring insulation shall consist of high temperature sheet material(s) having a thermal rating of Class 155 or higher. Preferred materials are Nomex and NEMA Grade G10 or G11 epoxy glass laminate. The retaining ring insulation system should include a slip plane to allow unrestricted relative

Figure 18.7 Support blocks for round rotor field winding end turns.

movement between the rotor endwindings and retaining rings during winding thermal expansion and contraction. Retaining rings shall be manufactured from 18%Mn/18%Cr steel.

11. Before retaining ring installation, the field endwindings must first be compressed to allow the retaining rings to slide freely over them. The retaining rings must be heated to the appropriate temperature that ensures that their inside diameters are greater than the outside diameter of the shrink fit areas on the rotor body at the ends of the rotor slots. The retaining rings may be heated in a temperature-controlled oven, or by induction heating. The ring temperature shall be monitored to ensure that it does not exceed 300°C to ensure that the mechanical properties of the ring material are not affected. This temperature monitoring should be performed by installing temporary thermocouples, or other temperature-measuring devices on their bores. Once the rings are installed, they must be held in place until the snap rings that hold them in place in the axial direction are installed. If retaining ring outer support plates are used, they should then be installed and secured by means of new locking tabs.
12. Leads and radial studs connecting the field winding to slip rings or a brushless exciter, as well as slip rings, should be insulated with Class 155 materials.
13. Once the rotor manufacture is complete, the following tests should be performed to confirm the integrity of the field winding turn and ground insulation.
    - **(a)** Insulation resistance—should be $\geq$5.0 MΩ corrected to 40°C.
    - **(b)** Winding resistance—should be within $\pm$2.0% of design value.
    - **(c)** RSO, pole drop, or other type of test—to check for shorted turns.
    - **(d)** AC hipot test—at an rms voltage of 10 × the rated field winding voltage.
    - **(e)** During balancing at rated speed in a spin pit, perform an air gap flux test to check for shorted field winding turns at rated speed (Section 16.7) and Reference 3.

18.5.2 Refurbishment and Replacement of Existing Round Rotor Windings

This section deals with suggested procedures to refurbish existing round rotor field windings including associated mechanical parts such as the rotor body, slot wedges, and retaining rings.

The following covers the disassembly of the rotor winding and associated components and assessment of their condition for reuse.

1. The rotor slot wedges should all be given a specific identification number before removal and their positions recorded on a wedge map to ensure that they are reinstalled in the same locations after the field rewind. If wedges have to be replaced, a metallurgical analysis of the original wedge material should be made to ensure that the replacements are made from the same material. Moreover, a map of endwinding blocking locations should also be made and each

piece of blocking should be marked with a specific identification number and its location that shall be indicated on the map. Then remove the centering rings, retaining rings, retaining ring insulation, slot wedges, and endwinding blocking. When using induction heating or gas heating rings to remove the retaining rings, their temperature should be monitored to verify that it does not exceed 300°C. This should ensure that the mechanical properties of the stainless steel they are made from are not adversely affected.

2. Each field winding coil should be removed one turn at a time and shall be supported in a fixture to try and maintain their shape. All intercoil and pole jumper connections shall be removed during this process.
3. All of the turn insulation must be removed to allow the conductors to be inspected for damage such as cracks, pitting, melted sections, etc. If cracks are suspected, then their presence should be confirmed by a fluorescent dye penetrant test.
4. An assessment of whether the field winding copper can be reused should be made at this time. If replacement is needed, then the requirements for a new winding given in Section 18.5.1 apply. If the existing field winding conductors can be reused, any damaged sections of copper shall be repaired by replacing the sections with new copper of the same dimensions and grade. The grade of the existing copper should be confirmed by conducting a metallurgical test. New sections of conductor shall be brazed to the original copper using a lap joint configuration as shown in Figure 18.8. If this is not possible, then a scarf butt joint as shown in Figure 18.9 should be used. Carbon blocks shall be clamped around the connection before brazing to minimize oxidation during the brazing process. All brazed joints shall be carefully inspected to ensure complete filling of the joint with alloy.
5. The conductors should be flattened, reformed, and adjusted in length and width to return each coil to its original dimension as required.
6. All intercoil and pole jumpers are to be replaced by new omega-shaped ones made from the same grade of copper as the original. They should be of leafed construction and have the same or greater cross-sectional area.
7. The original slot cell ground insulation and all resin and other residue should be removed from the rotor slots before commencing the rewind. The method of cleaning should be indicated by the vendor.

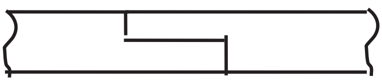

Figure 18.8 Lap joint.

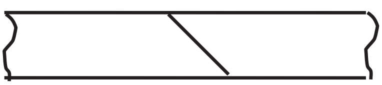

Figure 18.9 Scarf joint.

8. Endwinding blocking should be inspected to determine its condition and what materials it was manufactured from. If this blocking is made from phenolic bonded fiber, or similar material that tends to shrink with thermal aging, all of the blocking should be replaced by new blocking made from NEMA G10 or G11 epoxy glass laminate, which is a much more thermally stable material with higher temperature rating. If the existing blocking is made from NEMA G10 or G11 material, then only damaged or poor fitting blocking need be replaced.
9. The up-shaft leads and radial studs that connect the field winding to the brushless exciter or slip rings shall be removed for inspection. Such inspections shall cover:
   - **(a)** The insulation for evidence of overheating, cracking, or mechanical damage.
   - **(b)** Evidence of cracks in the conductors or studs.
   - **(c)** Evidence of damage to other hardware such as threads on nuts and bolts.
10. The following mechanical inspections should be performed and methods of repair should be proposed for any defects found. All repairs on the rotor body must be completed before field rewinding commences. If any component measurements are outside acceptance limits and significant defects are found, then these must be resolved.
    - **(a)** Clean and then inspect the rotor body bore for evidence of defects such as rust. Clean the rotor bore hole in the center of the rotor and perform a borosonic (ultrasonic) inspection for evidence of cracks. Moreover, perform eddy current inspections of the rotor slots, teeth, wedge grooves, and retaining ring shrink fit areas for evidence of cracks.
    - **(b)** All slot wedges should be cleaned and examined for the following defects:
      - **(i)** Evidence of local overheating or arcing on the surfaces including those that interface with the retaining rings.
      - **(ii)** Bowing at bottom of wedge.
      - **(iii)** Galling on loaded surfaces.
      - **(iv)** Surface pitting on the edges of the load bearing surfaces.
      - **(v)** Dye penetrant test each wedge for evidence of cracks and other defects.
      - **(vi)** Check all wedges to determine if they are magnetic or nonmagnetic, and mark this information on the wedge map.
11. Retaining rings should be inspected for evidence of moisture-induced crevice corrosion. Clean all paint, rust, and other contaminants from the surfaces of retaining rings that are to be reused. This is best done with Scotch Brite™ or similar, which should provide a polished finish. If solvents are required for cleaning, then it must be verified that they will have no effect on the mechanical properties of the retaining rings. Measure each

retaining ring to rotor body fit diameters at least at two locations. At least four measurements 45° apart should be taken at each location. Compare measurements with OEM-recommended tolerance values. Perform fluorescent dye penetrant and ultrasonic tests on the retaining rings to check for the presence of cracks and to determine their depth, if any are present.

12. If centering rings are fitted, they should be given eddy current and dye penetrant tests to check for evidence of cracks and other defects. Measure each centering ring-to-retaining ring fit outside diameters at least at two locations. At least four measurements 45° apart should be taken at each location. Compare measurements with OEM-recommended tolerance values.

Requirements for mechanical component refurbishment are:

1. Minor rotor body surface defects such as cracks may be repaired by grinding them out and then performing an inspection to confirm that the defect has been completely removed. If major defects, such as deep cracks, are found, then a metallurgical assessment of the depth and cause must be made together with an evaluation to assess whether an effective repair can be implemented.
2. If retaining ring minor surface cracks are found in these components, they can be ground out and then tested to confirm complete removal. If major cracks are found, then there is no alternative but to replace the retaining ring. If the retaining ring in question is made from 18%Mn/5%Cr steel, both it and the other ring should be considered for replacement with new ones made from 18%Mn/18%Cr steel because the former material is prone to stress corrosion cracking. If the existing retaining rings are made from 18%Mn/5%Cr steel, and no defects are found, or if the defects can be repaired, then the cost to replace them with new rings made from 18%Mn/18%Cr steel should still be investigated.
3. As with retaining rings, minor centering ring surface cracks and other minor defects can be ground out. Corrective actions for more significant defects and their associated costs should be investigated. If these plates are held in place axially with "snap rings," these should be replaced if found to be defective.
4. Any slot wedges that are to be replaced should be made from the same materials as the original ones.

The procedures for rewinding the rotor field winding should be as described in Section 18.5.1, and all insulating materials should be new.

Once the rotor repair is complete, the final tests described in Section 18.5.1 (Item 13) should be performed to confirm the integrity of the field winding turn and ground insulation.

18.5.3 New Salient Pole Windings

This section covers technical requirements that could be considered for new strip-on-edge and wire-wound salient pole windings (Section 1.6.1) for which some of the components are the same.

1. The ground insulation between the field winding coils and pole body should be made from Nomex or other similar Class 155 or higher insulation.
2. Pole washers and any packing should be manufactured from NEMA G10 or G11 epoxy glass laminate.
3. The following requirements apply to strip-on-edge pole field windings:
   (a) Strip-on-edge pole coils should be made from rectangular copper that is bent or has brazed joints to form a multiturn coil. If the coils are formed by bending, often the conductors will thicken at the inner radius of the bends, and be thinner on the outer radius. Thus, it is often necessary to grind the conductors at the inner radius to achieve the same conductor thickness across the width of the copper. Turn insulation shall be Nomex fastened to the copper coils by means of epoxy or other Class 155 or higher resin. The top and bottom two coil turns shall be 1/2 lap taped with Nomex or similar material to increase the creepage distance to the steel rotor body. The coils should be consolidated so that the turns are bonded together before the pole coils are mounted on solid or laminated electromagnetic steel poles. For solid pole designs, the bottom pole washer is installed before the pole windings are fitted, and then after the pole windings are installed, the top pole washer, bolted-on pole tip, and V-block spacers are fitted to secure the windings in place (Figure 18.10). If laminated poles are used (Figure 18.11), then the top pole washer is fitted before the pole winding is installed, and the bottom pole washer is fitted after pole winding installation.

   (b) Once installed, each pole coil shall be tested to ensure that there is adequate ground insulation resistance (Section 15.1) and there are no shorted turns (Section 15.26). If there are bolt-on-pole tips, these checks shall be repeated once they are installed.

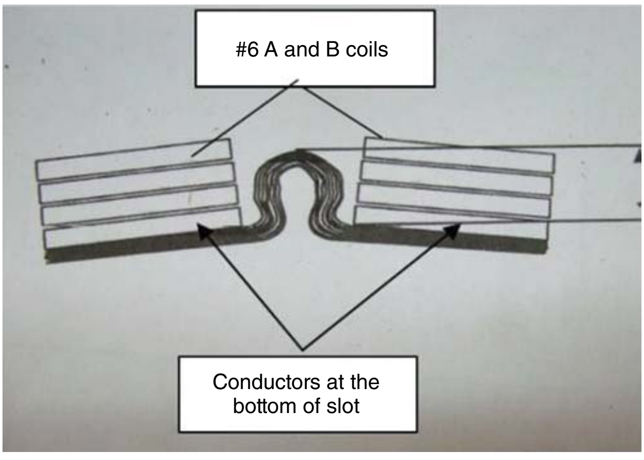

Figure 18.10 High speed salient pole rotor with strip-on-edge winding with bolt-on-pole tips and V-shaped braces.

Figure 18.11 Laminated pole with ground insulation and pole washers installed ready for wire winding.

Figure 18.12 Resin-impregnated wire-wound pole windings.

4. The following requirements apply to wire-wound pole field windings:

(a) Normally wire-wound pole windings are installed on poles made from insulated magnetic steel laminations, and a damper winding is installed in the pole tip. This damper winding should be installed before the pole winding (Figure 18.12). Wire-wound coil strands and conductors shall be made from copper insulated with high temperature enamel, Dacron glass, or both. The requisite number of turns shall be wound on the magnetic steel pole body before mounting the pole assembly on to the rotor. It is important that a Class 155 or higher bonding resin be applied between coil layers either during winding or by a vacuum pressure impregnation process after winding (Figure 18.12). In either case, this resin should be cured after application to ensure good interlayer bonding.

(b) After winding and resin impregnation, laminated pole coil assemblies are them mounted on a rotor body or rim (hydrogenerators) by means of bolts, dovetail, or "T" connections.

5. Once the pole windings are installed on the rotor, they should be connected together to form a complete winding. As with round rotor windings, leaf type omega-shaped connections should be used to make intercoil connections. These connections need not be insulated if they are adequately spaced from the rotor poles. Connections to the slip rings or brushless exciter should be insulated and mechanically supported to withstand the centrifugal forces imposed on them during operation. All bolted connections should be torqued to the appropriate level for the size, application, and grade use after reassembly. These bolts should be fitted with locking tabs to prevent them from backing off. For high speed machines and slow speed ones where the centrifugal forces are high, it is necessary to install "V"-shaped braces between poles (Figure 18.11) to prevent coil distortion. The vendor should perform calculations to determine whether such braces are required. Because these braces are normally made from steel or aluminum, they should be insulated from the pole winding coils with blocks made from a Class 155 material, with high compressive strength, such as NEMA G10 or G11 epoxy glass laminate.

6. After the pole windings are installed and connected, the following final tests should be performed:

(a) Insulation resistance between pole winding and pole body with a 500-V megohmmeter. This should be ≥ 100 MΩ.

(b) A pole drop (Section 15.25) or impedance test at as high a frequency as possible should be performed on each pole to test for shorted or missing turns.

(c) Each pole winding shall be AC hipot tested at 10 × rated field winding voltage to check dielectric strength of ground insulation.

18.5.4 Refurbishment and Repair of Existing Salient Pole Windings

This section deals with suggested procedures to refurbish existing salient pole rotor windings including associated mechanical parts.

1. If the winding is simply contaminated or has defective components such as pole jumpers, connecting leads, and "V" block insulation that can be replaced without disturbing the pole windings or it is simply contaminated with dust, moisture, or oil, then it should be possible to effect repairs without replacing the pole windings and their associated insulation. Once repairs have been completed, insulation resistance (Section 15.1) and pole drop (Section 15.25) tests should be performed after repairs to confirm the integrity of the insulation system. If the refurbishment is being performed in a service shop, then oven drying, application of a sealing resin, and oven curing are advisable after repairs.

2. If tests and inspections indicate a need to replace or reinsulate the pole windings, then repairs could be implemented as follows:

3. The winding process and tests to be performed on the replacement field winding are the same as those given in Section 18.5.3 for new windings.

(a) For solid pole designs with bolt-on-pole tips, these components have to be first removed to allow the pole winding, which will be strip-on-edge type, to be removed. If the poles are laminated, they must be demounted from the rotor shaft or rim. If more than one laminated pole is removed, match mark each pole to its location on the rotor or rim.

(b) Determine and record the pole winding magnet wire size and type of insulation.

(c) Heating strip-on-edge poles in an oven will allow easier removal of the turn insulation. Placing wire-wound poles in a burnout oven will allow the winding to be more easily removed from the pole, and the number of turns/coil to be established if this is not known. The burnout oven temperature should be controlled to avoid affecting the magnetic properties of the steel. For older types of varnish or resin-bonded pole windings, where the turns/pole is known, heating in an oven to soften the bonding resin and hand stripping of the turns is an acceptable method.

(d) If connections to slip rings or brushless exciter are made from insulated rectangular copper, and this is in good condition (no cracks or distortion), then it can be reused. In this case, the connections should be removed, the insulation stripped off them, and then they are re-insulated with an appropriate tape. On the other hand, if the conductor is damaged, it should also be replaced. Insulation used on such connections shall have a thermal rating of at least Class 155. If these connections are made from a stranded, jacketed cable, then they should be replaced with a new cable with a thermal rating of 155°C or higher.

(e) While wire-wound pole windings have to be replaced, it is usually possible to reuse the copper conductors in the strip-on-edge type. To evaluate whether this is possible, all residual insulation should be removed from the conductors and they should be checked for cracks and any other damage. If damage is only localized, sections of coil can be replaced by cutting out the damaged parts and brazing in new sections, as indicated in Section 18.5.2. On the other hand, if the conductors are badly damaged, new strip-on-edge copper coils should be manufactured.

(f) After the refurbished winding is installed perform the tests described in Section 18.5.3(6) to confirm the quality of the repair.

REFERENCES

1. IEEE 1665-2009, “Guide for the Rewind of Synchronous Generators, 50Hz and 60Hz, Rated 1MVA and Above”.
2. EPRI Report 1000897, “Repair and Reconditioning Specification for AC Squirrel-Cage Motors with Voltage Ratings of 2.3 kV to 13.2 kV”, December 2000.
3. W. G. Moore, B. M. Jagrine, and S. M. Fox, “*Factory High Speed Rotating Tests Assure Quality Generator Rotor Rewind*”, *Iris Power Rotating Machine Conference*, New Orleans, LA, USA, June 2000.

CHAPTER 19

ACCEPTANCE AND SITE TESTING OF NEW WINDINGS

This chapter describes the main tests that are available for prequalifying manufacturer's insulation systems and assessing the quality of insulation in new windings, both in the manufacturer's plant and on-site. All of these tests are designed to help give assurance that stator and rotor windings in new machines and new replacement windings will give reliable service. Many of these tests are described in Chapters 2, 15, and 17, and these are referenced where appropriate.

Guidelines on the acceptance and pass–fail criteria for each test are also given, although in many cases, these are the opinions of the authors, as many of the relevant standards do not give pass–fail criteria. It is important that such information be given in user technical specifications (Chapter 18) and be accepted by the winding supplier before placing a purchase order. We also want to point out that this testing costs money, both for performing the tests and in additional manufacturing costs that may be incurred to ensure that the manufacturer will have a high probability of passing the tests. The more testing that is required, the greater will be the cost of the rotor or stator winding. Of course the trade-off in doing more testing will be an increased probability of a long winding life with minimal maintenance.

19.1 STATOR WINDING INSULATION SYSTEM PREQUALIFICATION TESTS

For stator winding insulation systems rated at 3 kV and above (or in the case of inverter duty windings, windings rated as low as 400 V, see Section 19.1.3), it is important to gain some assurance that an insulation system provided by the manufacturer will give a long life. To ensure that a manufacturer has the knowledge, materials, and processing equipment, it is useful to ask them to perform a series of tests on sample coils/bars, some of which will be destructive in nature. The sample coils/bars should be similar to the type required by the end user and be drawn randomly from normal production. Passing of these tests can qualify the manufacturer to be on the "bidder's list." Such coil design and manufacturing qualification tests and inspections should be identified in a technical specification and be performed before a new

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

machine or replacement winding is purchased. This technical specification should indicate pass–fail criteria, and only those companies whose coils have passed all of the tests should be asked to bid for such work.

19.1.1 Dissipation Factor Tip-Up

This test, described in Section 15.11, makes use of the fact that the insulation power factor or dissipation factor of a coil or bar ground insulation will change with applied AC voltage. The magnitude of this change gives an indication of how void-free the groundwall insulation is. The test is applicable for coils/bars rated at 3 kV and above.

This test can also be performed on new coils, before accelerated aging tests (Sections 19.1.5, 19.1.7, and 19.1.8), to give an indication of the original condition of the ground insulation. If the test is then repeated during and after the accelerated aging process, changes in power factor or dissipation factor will give an indication of degradation of the groundwall insulation from aging effects such as loss of insulation bonding from thermal degradation.

Test Method To prepare coils for testing, a ground plane of aluminum foil or tinned copper mesh must be applied to the coil or bar straights. If the coils/bars represent a global VPI insulation system, then they should be fitted with steel or aluminum plates on two sides to simulate a stator slot (Figure 18.5); these plates can be used as the ground plane. If there is a silicon carbide stress-control material applied at the ends of a semiconducting layer on the coil straights, this must be guarded out and grounded for an ungrounded specimen (UST) measurement to eliminate the effects of this material on the test readings. Guarding is commonly done by wrapping aluminum foil or a semiconductive tape on top of this stress-control material and directly grounding the foil/tape (Section 15.11).

A variable-voltage AC power source and a power-factor- or dissipation-factor-measuring instrument are required. Measurements of power factor or dissipation factor are then taken at two voltages, normally 25% and 100% of rated line-to-ground voltage, and the tip-up calculated. The values obtained serve as the initial levels of the power factor for the insulation system under test.

Acceptance Criteria For new unaged coils or bars, with well-bonded and -impregnated ground insulation, many suggest that the power factor tip-up should be <0.3% and certainly no greater than 1.0%. As ground insulation ages in any aging test (Sections 19.1.5 and 19.1.7), these values will increase, and some judgment and experience are needed to relate the test values to coil insulation condition. However, at the end of the accelerated aging process, coil dissection findings can be related to test values.

19.1.2 Partial Discharge Test for Conventional Windings

Off-line partial discharge testing of complete windings and individual coils/bars in stators in conventional 50/60-Hz machines are discussed in Section 15.12. This test is similar to the tip-up test, in that it detects any voids in the stator groundwall insulation resulting from poor coil impregnation and problems with the semiconductive or stress relief coatings. The test can also detect any delamination owing to thermal and other types of aging tests. The test can be applied to any coil or bar with a semiconductive coating.

Test Method As with the power factor tip-up test, a ground plane has to be provided on the coil straights. The test requires an AC power source capable of supplying PD-free 50 or 60 Hz variable voltage to at least the rated line-to-ground voltage of the insulation system under test. PD measurements are taken for each test coil in voltage steps up to the rated line-to-ground voltage (or high voltages as agreed) of the insulation system to measure the discharge inception voltage (PDIV) and the discharge extinction voltage (PDEV). The first set of readings is taken before the commencement of any accelerated aging tests that may be required. The positive and negative PD magnitudes are measured and recorded. This test is repeated at various times throughout the accelerated aging test, and the results are trended to look for increases in PD activity. Reductions in DIV and DEV values provide another indication of deterioration in the condition of the coil ground insulation.

Acceptance Criteria New unaged coils or bars with well-bonded and -impregnated ground insulation will often have the following characteristics:

- The peak PD magnitude at rated line-to-ground voltage should be <100 pC, if measured according to IEC 60034-27-1 (originally identified as IEC 60034-27).
- PDIV should be >0.5 times rated line-to-ground voltage.
- The location of the deterioration can be determined by comparing the positive and negative PD pulses as follows:
  - **(i)** If the positive and negative PD pulses remain approximately equal, the voids are present in the bulk groundwall insulation.
  - **(ii)** If the negative PD pulses are higher than the positive ones, then it is likely that the coil ground insulation is separated from the conductor stack or the coil is poorly impregnated near the copper conductors.
  - **(iii)** If the positive PD pulses are higher than the negative ones, it is likely that the coil or bar semiconductive or grading material is defective.

19.1.3 Partial Discharge Test for Inverter Fed Windings

As discussed in Section 1.5.1, PD may be a cause of insulation failure even in random-wound windings if they are supplied by a voltage source PWM converter. To ensure that the winding does not fail from this process, a PD test, normally performed on a complete stator is done while voltage surges are applied.

Test Method The procedure described in Section 15.13 and IEC 60034-18-41 should be used. In this case, the winding is subjected to a short risetime pulse using a surge tester similar to that described in the next section.

Acceptance Criteria The PDIV should be above the levels described in IEC 60034-18-41.

19.1.4 Impulse (Surge)

As indicated in Section 15.16, this test is designed to check the integrity of turn insulation in form- and random-wound multi-turn coils. It is not applicable to Roebel bar windings. Weak turn insulation will fail when a short risetime, high voltage surge is applied to the coil.

Test Method The test procedure is described in IEEE 522 and IEC 60034-15. The surge test unit should have a risetime of 0.2 μs or shorter. The test is performed by increasing the peak voltage in steps, until the recommended peak voltage is reached. IEEE 522-1992 recommends a peak voltage for new coils of 3.5 pu, where 1 pu is the rated peak, line-to-ground rated voltage. Suggested steps are 25%, 50%, 75%, and 100% of the maximum peak voltage. The IEC version of the test is slightly different (allowing a longer risetime that will stress the turn insulation less), and recommends test voltages that are usually lower.

Acceptance Criteria There should be no change in the surge voltage waveform between low voltage and high voltage. If a change occurs, the turn insulation has failed.

19.1.5 Voltage Endurance for Conventional Windings

High voltage stresses are an important aging mechanism for 50- or 60-Hz stator windings rated at 3 kV and above, since partial discharge is created (Section 1.4.4). It is well known that increasing the voltage across the coil ground insulation will reduce the time to failure if partial discharges are present. Voltage endurance testing uses this phenomenon to identify any weakness in the ground insulation materials used and their method of application. The general principles of voltage endurance testing are discussed in Section 2.4. Any coils/bars subjected to this test must not be used in an actual machine, because the insulation is significantly aged, even if it does not fail.

The manufacture of electrical coils is a highly specialized and complex process. A large number of requirements must be satisfied before a coil can be produced that will provide long-term reliable service under various operating conditions. Some of the important requirements include material properties, material handling, shaping and forming, processing temperatures and pressures, and quality control at every stage.

Inevitable changes over time in materials, their suppliers, manufacturing methods and processes, and the staff in the design office and the shop add further challenges to obtaining a consistent high quality of the end product. The voltage endurance test provides an important means of detecting weaknesses in any of the numerous activities involved in the design and manufacture of electrical coils.

Consistent application of the test helps vendors recognize potential problems and to avoid significant costs of redesign and retooling involved in correcting mistakes. Customers benefit from a higher level of assurance of long-term reliable service from the machines as well as having a number of qualified vendors available for competitively supplying their motor and generator needs.

This test is designed to verify that the coil ground insulation and, where appropriate, semiconducting and grading materials are adequate both in material properties and in the method of manufacturing. It can reveal manufacturing defects such as

- reduced insulation thickness at coil corners (due to too high a tape tension during application or skipped layer of tape);
- wrinkles in insulation;
- poor application of semiconducting and grading materials;
- voids (due to inadequate or improper bonding resin application).

In a prequalification test, two coils or four bars are subjected to a much higher normal voltage stress between the conductors and the ground. The above-mentioned defects will cause excessive insulation electrical aging and coil failures before the end of the test. The temperature of the insulation is raised to the expected operating temperature of the coils, usually 90–135°C, depending on the type of machine and the thermal rating of the insulation system. For the most widely applied version of the voltage endurance test, the voltage stress normally used is 3.75–4.4 times the normal operating line-to-ground voltage.

Test Method IEEE Standard 1043, "Recommended Practice for Voltage Endurance Testing of Form-Wound Stator Bars and Coils for Large Generators" describes the test method. At least four test bars or two coils are fitted with steel or aluminum platens clamped in place on either side of the straight sections. Thermostatically controlled electric heaters are then fitted to the outside of the platens to raise the coil temperature to the desired level for the test. The test voltage is then applied between the coil conductors and the metal platens. At the start of the test, this voltage should be gradually increased to the required value so that no significant overshoots or spikes result from the voltage application process. The voltage is maintained for a predetermined time period, for example, 250–400 h or until a coil failure occurs [1,2].

Acceptance Criteria IEEE Standard 1553 stipulates the test voltage, temperatures, and the minimum times to failure to be used for coils/bars intended in hydrogenerators. For example, a hydrogenerator bar/coil rated 13.8 kV will be tested at the design operating temperature (generally <120°C) and either 30 kV or 35 kV, applied between the copper and the semicon. The minimum time to failure is 400 h or 250 h for the 30 kV and 35 kV test voltages, respectively. Most users choose the 30 kV for 400-hour requirement. The 35-kV variation is a more difficult test to pass, even though the minimum time to failure is only 250 h. Generally, manufacturers will have to use additional insulation to pass a 35-kV test, with the negative effect this will have on machine performance (higher operating temperature).

IEEE 1553 is intended for hydrogenerators only. However, many end users have also specified the acceptance criteria in IEEE 1553 for coils/bars intended for motors and air-cooled turbine generators. The consequence is that the insulation groundwall thickness may be higher than the manufacturer's normal practice.

Dissection of coils/bars that fail the test can often result in identifying the material and manufacturing improvements required to achieve satisfactory test results. In particular, coil construction at the points of failure should be carefully examined to determine the cause of failure.

19.1.6 Voltage Endurance for Form-Wound Inverter Fed Windings

The repetitive voltage surges from voltage source, PWM inverters can cause more rapid aging of the stator insulation system than sinusoidal 50/60-Hz voltage. In particular, the stress relief coatings can be rapidly aged by such repetitive pulses (Section 1.4.6). Thus, special voltage endurance test procedures are needed to qualify an insulation system design for such variable-speed motor applications (Section 2.4.3).

Test Method Three separate voltage endurance tests are required to qualify the insulation system for voltage source PWM drive applications: one for the turn insulation, one for the groundwall insulation, and finally one for the stress relief coatings. The first two endurance tests can be done with power frequency, but the latter must be done with voltage surges. These tests are described in detail in IEC 60034-18-42.

Acceptance Criteria IEC 60034-18-42 does not offer an absolute minimum time to failure. For the most part, IEC 60034-18-42 describes comparative test procedures where a new insulation system is compared against a service-proven system. Of course this is a weakness, as such medium and high voltage stator windings were only introduced after 2000, and it is perhaps premature to suggest that any such coils have been "service proven" yet. To partly address this, IEC 60034-18-42 does offer an overall power frequency voltage endurance test for the complete coil, which sets a voltage level based on the peak expected voltage the winding will see, and a minimum time to failure of 250 h.

19.1.7 Thermal Cycling

As indicated in Section 8.2, stator winding insulation in machines with long stator cores that see rapid starts and stops, or rapidly changing loads, is susceptible to deterioration from thermal cycling. This can affect both groundwall (Reference 3 in Chapter 15) and turn insulation (Reference 4 in Chapter 15) in multiturn coils. It is with this knowledge that IEEE Std. 1310 was developed to simulate accelerated thermal cycling duty on stator winding insulation to determine the effects on particular large generator bars and multiturn coils (Reference 3). This test is normally only performed on coils or bars rated at 3 kV or more, and is intended for use in machines that see full load changes in less than a few minutes. Bars and coils subjected to this test cannot be placed in service because they have been significantly aged.

The purpose of this test is to qualify bar/coil design and manufacturing processes for their relative ability to resist deterioration because of rapid heating and cooling due to load cycling. The test is primarily intended for machines in which the windings are indirectly cooled by air. This test does not include a simulated core and, therefore, does not identify any deterioration of the groundwall surface or structure from movement relative to the core.

This test makes use of I^2R heating, from passing AC or DC current through the test coils, and forced-air cooling to produce fairly rapid thermal cycling. Temperature variations depend on the class of insulation being tested; for example, for a Class F insulated winding, a typical temperature test profile would begin at 40°C, increase to 155°C in about 45 min, then decrease to 40°C, again in about 45 min. The test bars/coils are subjected to 500 thermal cycles. As soon as the maximum coil temperature is reached, the current is switched off and cooling is immediately initiated.

The rate of insulation deterioration in the test coils can be determined by performing nondestructive diagnostic tests before the commencement of the thermal cycling, at predetermined intervals during the test, and after the test is completed. The diagnostic tests used include dissipation factor tip-up, partial discharge, physical measurements, and a tap test to detect groundwall insulation delamination. The surge test (Section 15.16) can be used for multiturn coils to determine if significant aging of the turn insulation is occurring from thermal cycling.

Test Method Both IEEE 1310 and IEC 60034-18-34 describe test procedures for complete coils and bars. However, the IEEE procedure is more closely defined and, thus, results from different manufacturers will be more comparable if IEEE 1310 is specified. Detailed test procedures are contained in IEEE 1310. This is an involved and expensive procedure. It should be required only for large, critical machines subject to fast, frequent load changes.

Acceptance Criteria IEEE 1310 suggests several pass–fail criteria, but does not stipulate which should be used. The voltage endurance test (Section 19.1.5) is probably the most objective test to determine if the insulation is aged by thermal cycling, but it is the most expensive and requires maximum time. In this requirement, after the thermal cycling, the bars are subjected to the voltage endurance test in IEEE 1553 to determine if they still meet the criteria of 250 or 400 h.

19.1.8 Thermal Classification

As discussed in Sections 2.1.1 and 2.3, all insulation systems are given a thermal classification. This classification defines the normal maximum operating temperature for the winding, although the expected life is not defined. For example, a Class F or Class 155 system defines a normal maximum operating temperature, at the hottest spot, of 155°C.

The classification is done in accordance with test methods specified by IEEE and IEC. For example, IEEE 275 and IEC 60034-18-31 detail the test procedure for form-wound groundwall insulation systems. Such procedures require determining the thermal life of a new insulation system in model coils under accelerated aging tests, and compare the results to an insulation system with proven performance in service (Section 2.3). Thus, the expected service life at the temperature class is not stipulated. To have meaning, purchasers of windings need to not only specify the thermal class of a winding but also specify the expected service life (for example, 10, 30, or 40 years). Virtually all insulation systems in present-day use were compared to older insulation systems that were operated at many tens of degrees below the thermal class. Thus, the satisfactory service life experienced with the older insulation systems usually does not imply that the same life can be expected if operated at an operating temperature defined by the thermal class. For example, it is very unlikely that a Class F winding would operate for more than 5 years or so at a copper hot spot temperature of 155°C.

The thermal classification of a stator (or rotor) winding is normally only evaluated when a new insulation system is introduced. Thus, it would be very unusual for a winding purchaser to specify a thermal classification test be done to qualify a vendor's insulation system, as the test is very expensive. However, it is not unreasonable to ask the manufacturer for the test data of his or her present system, and what service-proven system it was compared against.

19.2 STATOR WINDING INSULATION SYSTEM FACTORY AND ON-SITE TESTS

There are a number of tests that can be performed to give a good indication of the quality of a new coil/bar or a new winding that is intended for service. Again, it is important to have a technical specification for new windings that states what tests are to be performed and the acceptance criteria for the results. This is especially true for tests that give quantitative results rather than those that have pass–fail acceptance criteria. Note that general motor and generator standards such as IEC 60034-1, NEMA MG1, and IEEE C50.12/C50.13 only require that the insulation be given a final hipot test. A hipot test will only detect seriously inadequate insulation.

It is important to note that no single test can give complete assurance of insulation system quality, so a number of different tests that evaluate the different components are required. The factory tests described below also apply to large hydrogenerator and turbogenerator windings that need to be performed after assembly at site.

19.2.1 Insulation Resistance and Polarization Index

These tests, as described in Section 15.1, are designed to determine whether coils/bars or windings are clean and dry and do not have major ground insulation defects. The tests should always be done before the high voltage AC hipot tests (Section 15.6) or surge test (Section 15.16) that are required by IEC 60034 and NEMA MG1.

Factory Tests The 1R/PI tests should be performed at the following stages of new machine manufacture:

- After manufacture of the bars or coils.

- During coil or bar winding. Usually, sections of the winding are tested after installation in the slots and wedging.
- After all the bars/coils are installed, wedged, braced, and connected. For global VPI windings, these tests should be performed before VPI to ensure that the winding is clean and dry.
- After the winding is fully processed, but before assembly.
- After the machine is completely assembled. It should be noted that such tests should be performed on directly water-cooled stator windings before the cooling system is filled with coolant.

Once the winding is fully processed, the minimum IR and PI values at the specified DC test voltage in IEEE 43 should be met. Note that older versions of IEEE 43 had considerably less stringent acceptance levels. For coils and bars that have not been impregnated yet, each manufacturer will determine the acceptance levels.

Site Tests Baseline tests should be performed before new or rewound stators are put into service and before any on-site high voltage tests such as an AC hipot test.

To obtain satisfactory readings from water-cooled stator windings, the winding must be completely drained of water and a vacuum pump used to obtain very low moisture levels in the water-cooling circuits.

19.2.2 Phase Resistance and/or Thermal Imaging

There are many electrical connections within a stator winding. One way of ensuring that the electrical connections were well made is to measure the resistance of each phase with a digital low resistance ohmmeter (Section 15.4). The resistance of each phase should be within 1% of the readings of the other phases. Alternatively, a more sensitive test is to circulate a high current through the winding and observe the temperature of the connections with a thermal imaging camera (Section 15.5). All the connections should have a temperature within 1 or 2°C of each other. This test is normally performed in a factory. However, as large hydrogenerators are often assembled at site, this test can only be done at site for such machines.

19.2.3 AC and DC Hipot

These tests are performed to determine the integrity of the winding ground insulation during the installation of new or replacement windings and before a winding is placed in service. The AC hipot is the only required high voltage test by IEC and IEEE standards before a new stator winding is accepted by the end user. As indicated in Sections 15.2 and 15.6, the magnitude of the test voltage and the use of an AC or DC test is a function of where and when the test is performed. In general, AC hipot tests are more revealing than DC tests and, thus, the AC hipot test is the preferred final hipot [5,6], even though IEC 60034-1 and NEMA MG 1 do permit the DC test as an alternative to the final AC hipot test. If a hipot test failure occurs, a repair or rewind is required. It is important that windings pass an IR and PI test before any high voltage testing is done.

Factory Tests The following tests should be performed at various stages of winding installation:

1. After coil or bar manufacture. The manufacturer will determine what the levels should be, depending on whether the coils are impregnated or "green" [5]. Often this test is done with DC.
2. During coil or bar winding and after IR and PI tests, sections of winding are hipot tested (often with DC) following installation in the slots. This procedure is designed to detect faulty coils or bars at a stage at which they can be easily removed and replaced. The test level, as with all hipot tests before complete assembly, is generally set by the manufacturer. There are wide variations among manufacturers [5]. The magnitude of the hipot voltage is a function of whether the coils are "green" for a global VP1 or fully processed. For green coils, a test value of 50–60% of the final complete winding, one-minute hipot test value is often used as a minimum test voltage. On the other hand, values of 1.33 (or more) times the final hipot test value are used for fully processed turbine generator and hydrogenerator bars, to increase the assurance of success of subsequent hipot tests.
3. After all the bars/coils are installed, wedged, braced, and connected. For global VPI windings, these tests should be performed before VPI to ensure that the winding is clean and dry. The minimum hipot voltages used for this test would be the same as or a little lower than those described in step 2.
4. After the winding is fully processed, but before assembly, a full-voltage 1-min AC hipot test should be performed, that is, $2E + 1$ for an AC test. Although NEMA MG 1 and IEC 60034 permit a DC hipot as an alternative, the AC hipot is considered to be more sensitive to manufacturing problems. Sometimes this factory test voltage is higher than $2E + 1$ kV.
5. If the winding is a sealed type, a water immersion or spray test per NEMA MG1-2000, Section 20.18 or IEEE 429 should be performed. This includes a one-minute hipot test at 1.15 times of the winding rated line-to-line voltage while the stator is immersed in or after it has been soaked for 15 min with water containing a wetting agent. IR and PI tests are required both before and after this hipot test.
6. After the machine is completely assembled, the test described in step 4 should be repeated. For very large generators, this test may be performed on-site. It should be noted that on direct-water-cooled stator windings, such tests should be performed before the cooling system is filled with coolant, especially if a DC hipot test is to be performed.

On-Site Tests On-site tests should be performed after the installation of a new machine or rewound stator. This test is important to detect any problems introduced by shipping or final site assembly. Removal of the neutral connection is required to test each phase separately with the other two phases grounded.

Most on-site testing of new stators should be done with AC [5,6]. The new winding should be subjected to a full $2E + 1$ AC hipot test before placing it in service.

If the winding is direct-water-cooled one, this test should be performed before its cooling system is filled with water.

19.2.4 Impulse (Surge)

As described in Section 15.16, the integrity of multiturn coil turn insulation can be checked by impulse or surge testing. This is most important as a quality check of new coils before and after their installation in the stator slots. The test described below is not relevant for Roebel bar windings because there is no turn insulation. Conventional lightning impulse (1.2 μs/50 μs) tests are rarely performed on the groundwall insulation as the AC hipot tests is a better indicator of the groundwall insulation condition.

Factory Tests Surge testing per IEEE Std. 522 or IEC 60034-15 should be performed at the following stages of winding installation:

- Before installing coils in slots;
- After coil installation, wedging, and bracing but before coil interconnections are made;
- After winding connection to verify that this has been correctly done; incorrect connection will show up as a phase impedance imbalance when a surge comparison test is done.

When the test is done on complete windings, high voltage interturn stress only occurs in the first few turns or coils. Thus, only the turn insulation in this part of the winding is tested. As noted in Section 15.16, determining if turn insulation puncture has occurred can be especially difficult in complete form-wound windings. Surge tests done according to IEC 60034, Part 15 are usually less stringent as this standard allows testing with a longer risetime surge voltage. This longer risetime means that there is less voltage developed across the turn insulation. IEEE 522 recommends a risetime of 100–200 ns to adequately test the turn insulation of individual coils.

For global VPI multi-turn coil windings, the surge test is normally only used on the “green” coils (i.e., before impregnation) before and after insertion in the slot, as well as after all connections are made (to check that the winding is connected together correctly). The test voltage is less than the full voltage specified in IEC 60034-15 or IEEE 522, as the epoxy is not present. However, some users specify that two spare coils are processed in the VPI tank at the same time as the stator. After curing, these coils should pass the full test voltage specified in IEEE 522 or IEC 60034-15.

On-Site Tests On-site tests are assumed to be on complete windings. As discussed earlier, a surge test on a complete winding will only test the integrity of the turn insulation in the coils connected to the phase terminals. Moreover, especially in form-wound stators, it can be difficult to determine when the turn insulation has been punctured. Thus, on-site testing is relatively rare, at least for form-wound machines.

19.2.5 Strand-to-Strand

This test is performed on new stator bars during manufacture to check the integrity of the strand insulation (Section 1.4.1), which is normally a double layer of Dacron glass or a single layer of Dacron glass over a varnished or enameled surface. This is particularly applicable to Roebel bars that have transposed strands in which the mechanical forces required to bend the strands at the transition may also cause insulation damage. For liquid-cooled stators, this test must be performed before the bar nozzles are installed and brazed to each end of the bar.

The test involves performing a 1-min AC hipot test between all adjacent strands in each bar or coil. Typically 110–220-V AC is used. If the strand insulation fails this test, the bar/coil should be scrapped or repaired if feasible.

19.2.6 Power Factor Tip-Up

This is a well-established test to determine if form-wound coils and complete windings have been properly impregnated. It is mainly a QC test for individually impregnated coils. The test is described in Section 15.11.

Standards such as IEEE 286 and IEC 60894 do not provide acceptance levels. With modern insulation systems, many users require the tip-up on all individual coils or bars (with the silicon carbide coating guarded out) to be below 0.3% (test at 25% and 100% of rated line-to-ground voltage). Acceptance levels on complete windings have not been widely accepted because the silicon carbide coatings cannot be guarded out, resulting in a tip-up that depends on both the quality of the insulation and the characteristics of the silicon carbide coating. Thus, acceptance levels for complete windings can only be set in comparison to other similar windings.

Factory Tests The test is performed on individual coils/bars after impregnation, but before the hipot tests. Some manufacturers measure the tip-up on all coils and bars, whereas others do tests on a statistical sampling basis. Testing on all bars/coils is recommended, because workmanship (and especially taping) varies from coil to coil. The test is not relevant for green (unimpregnated) coils and bars. Although some measure the tip-up on complete windings, the test can normally only serve as a baseline measurement for future trending. The off-line PD test is more relevant for complete windings.

19.2.7 Partial Discharge

The test can be used as a quality check for the impregnation and bonding of ground insulation in new coils/bars and windings, similar to the power factor tip-up test (Section 19.2.6). However, the PD test can also help to determine the root cause of any poor manufacturing. The off-line PD test is also better than the tip-up test at finding problems in complete windings, such as global VPI stators. The test is only relevant for machines rated at 3.3 kV and above, although lower voltage windings to be operated from an inverter drive may benefit from the test [7]. Off-line PD tests (Section 15.12) require specialized equipment that includes a PD-free power source.

Factory Tests Specification of acceptance criteria for factory tests will ensure that a well-impregnated and -bonded ground insulation system has been provided. Maximum PD magnitude acceptance limits are somewhat dependent on

- the instrument used to measure PD;
- the type of sensors used;
- the machine voltage;
- the cooling gas, that is, air or hydrogen.

The acceptance criteria should, therefore, be based on comparison to the results of tests on well-consolidated windings of similar voltage rating and the same type of cooling system, and measured with the same particular instrument and sensors [8]. There are no broadly agreed upon limits to PD for either coils/bars or complete stator windings, although each manufacturer may have its own in-house limits. Acceptance levels for complete windings could be set using statistical process control principles, by which windings with PD greater than, say, the mean plus three standard deviations are not accepted. The mean refers to the manufacturer's total database of results for similar windings using the PD measurement method used in the plants [8]. Although not part of any standard, we suggest that individually fully manufactured (i.e., impregnated and cured) bars and coils should have a PD level below 100 pC when tested at rated line-to-ground voltage according to IEC 60034-27-1 (formally IEC 60034-27).

As described in Section 15.12.3, the PD patterns can sometimes indicate if the problem is at the copper, within the groundwall, or on the coil or bar surface.

On-Site Tests PD tests are assumed to be on complete windings. Acceptance levels can only be set in comparison to similar machines, or by specifying that there will be little increase in PD during the warranty period of the machine [8].

19.2.8 Semiconductive Coating Test

This test, as described in Section 15.18, is used to check the grounding of the semiconductive coating on coils and bars, usually only found on windings with voltage ratings of 6 kV and above. This test can be performed on new windings as a quality check on the semiconductive coating applied, as well as that the coating is in good contact with the stator core. This test is particularly important for global VPI stator windings after impregnation.

The test is performed by measuring the resistance between each bar or coil leg semiconductive coating and the core at each end, as described in Section 15.18. The semiconductive coating on new windings can be considered to be well made if resistance values are all below about 2000 ohms.

19.2.9 Wedge Tap

This test is used to determine the tightness of stator slot wedges that are installed to prevent radial displacement of the bar or coil in the slot. In general, this test is not applicable to stators with global VPI windings because the wedges should be tightly "glued" or bonded in place to prevent coil or bar movement.

Factory Test It is important that the wedges in a new or rewound stator are initially tight because they may loosen under the influence of electromagnetic forces acting on the coils or bars during machine operation. It is, therefore, advisable, especially for large high voltage stators, to specify that this test be performed before assembly, in accordance with one of the procedures described in Section 15.20, and that the results meet the following acceptance criteria:

- No more than two adjacent wedges in the same slot are to be loose.
- No end wedges are to be loose.
- No more than 25% of the wedges in the complete winding are to be loose.
- None of the installed wedges should be cracked.

On-Site Test For large generators, this test is sometimes performed on-site before insertion of the rotor. If a stator is rewound on-site, this test should be performed with acceptance criteria the same as indicated earlier. It is important to obtain baseline test values for comparison with subsequent test results after the generator has been placed in service. For new machines, a wedge test after a year of service is critical for determining the scope of warranty work and for arresting any damage because of loose bars after the initial period of settling in the slot.

19.2.10 Endwinding Bump

For critical two- and four-pole motors and generators, it is advisable to perform a bump test (Section 15.23) on the stator endwindings to ensure that they have no natural frequencies near twice the power frequency, or at the rotational speed. As described in Section 8.15, a resonance near these frequencies can lead to rapid failure of the stator winding owing to copper fatigue and/or insulation abrasion. Usually, machines with six or more poles are much less likely to suffer this failure process, at least while the endwinding blocking and bracing is tight.

Factory Test Impact or bump testing is now a relatively easy, quick, and inexpensive test to perform on new stators in the factory. The basic method is described in Section 15.23. It requires an instrumented hammer weighing about 1 kg and temporarily installed piezoelectric accelerometers connected to a spectrum analyzer to measure the response of the endwinding to hammer impacts. There are no standardized test procedures, although an IEC working group is developing one (to be published as IEC 60034-32). However, this document, when published, will give no pass–fail criteria. Thus, the recommendations in Section 15.23.3 can be used. In principle, this test could be a type test, that is, performed only on one stator of several identical stators. However, because the manufacturing of the endwinding support system involves considerable skilled labor and mistakes are possible, it is still prudent to perform the bump test on every critical two- and four-pole machine.

On-Site Test If the test is performed at the factory, there is no need to perform at site, unless the machine has experienced a severe mechanical shock during shipping or installation.

19.3 FACTORY AND ON-SITE TESTS FOR ROTOR WINDINGS

This section deals with appropriate factory and on-site tests for all insulated rotor windings. It also covers tests for specific types of windings. As a general rule, all of these tests can be performed during winding manufacture and installation. On the other hand, it is not practical to perform some of these tests on-site on a complete winding. For smaller motors and generators that have been in service, it is often more convenient to transport them to a local repair company to perform such tests.

19.3.1 Tests Applicable to All Insulated Windings

Insulation resistance (IR), polarization index (PI), and hipot tests can be performed on the ground insulation of all three types of insulated windings covered in this section. These tests can be performed both during manufacture or rewinding and on-site, because the equipment required to perform them is quite portable.

IR and PI Tests As indicated in Section 15.1, these tests are performed to confirm whether the winding ground insulation is clean, dry, and free from major flaws such as cracks. These tests should be performed in accordance with IEEE Std. 43, which gives test voltages and minimum acceptable IR and PI values for each type of winding. These tests should always be a prerequisite to a hipot test, because low IR values increase the risk of failure. It should be noted that for random-wound or wire-wound rotor windings, PI is usually not very meaningful.

Test During Winding Manufacture During winding manufacture, these tests should be performed at the following stages:

- After coil installation, but before interconnecting coils to form a winding;
- Before resin or varnish treatment or curing to ensure that the winding is dry so that no moisture is trapped in it;
- After final winding processing, but before rotor installation;
- After the machine is completely assembled;
- Before any hipot tests.

On-Site Testing On-site, these tests should be used to confirm that the winding is clean, dry, and free from serious ground insulation defects before it is placed in service.

Hipot Tests As for stators, rotor winding hipot testing is performed to check the integrity of the winding ground insulation. The AC hipot test (Section 15.6) is used for new synchronous machine rotor windings, although they operate with an applied DC voltage, as any over-voltages seen in service are likely due to transients (rather than DC). Moreover, a percentage of the new winding value is often used for site tests on new windings and windings that have been refurbished [6]. For wound rotor windings, national and international standards also specify an AC hipot test (Section 15.6) for new windings, and again a percentage of this value is often used for site tests on new and tests windings of this type that have been refurbished. On the other hand, hipot testing of windings that have been in service is not commonly done because of concerns that if they are contaminated, they may fail and so only IR and PI tests are normally performed.

Factory Tests Hipot tests should be performed at the following stages of manufacture, but before final winding processing. The test voltage should be less than the final test value as complete winding integrity is not present until that time.

- after coil installation, but before interconnecting coils to form a winding;
- before resin or varnish treatment or curing to ensure that the winding is dry and that no moisture is trapped in it;
- after final winding processing; but before rotor installation into the stator;
- after the machine is completely assembled.

On-Site Tests Periodic hipot testing of rotor windings on-site is not commonly done. If performed, hipot levels for windings that have seen service are usually about 75% of the acceptance level.

19.3.2 Round Rotor Synchronous Machine Windings

One of the most critical components in this type of winding is the turn insulation. Consequently, it is important to check the integrity of turn insulation during manufacture, during repairs, and if the machine operating performance indicates the presence (or not) of turn shorts. The following tests can be used to detect shorted turns, although they are not effective for finding weak (but unfailed) turn insulation:

- RSO test (Section 15.26)
- Surge test (Section 15.26)
- Voltage drop test (Section 15.25)
- Air gap flux probe test (Section 16.7).

The RSO and surge tests can be performed on the rotor by itself or while it is installed in the stator. The air gap flux probe test is performed either during a rotor spin-pit test or when the machine is first put into service. On the other hand, the rotor has to be removed from the stator bore to perform the voltage drop test.

At operating speed, radial conductor loading, due to centrifugal forces, can often induce turn shorts that otherwise have a high resistance without these forces. To simulate this at standstill, checks for turn shorts should be performed at four rotor positions 90° apart. Using this technique, the coils in the 4–8 o'clock positions experience radial loading owing to gravity, which may induce turn shorts similar to those owing to radial conductor loading at speed.

Factory Tests Tests for shorted rotor turns are performed as a quality check to detect defective turn insulation after the rotor coils are installed and wedged [9]. It is advisable to perform the first test on the connected winding before the retaining rings are installed because removal of coil turns to repair defective turn insulation is much easier at this stage of assembly. A second test should be performed after the retaining rings are fitted. The radial forces exerted on the end-windings by the assembly process for these rings can convert high resistance contacts in weak insulation to turn shorts. If it is possible to run the rotor in a spin pit, or with the machine assembled and the stator winding shorted and field excitation applied, the air gap flux test can be performed to check for shorted turns before shipment (Section 16.7). Moreover, if the rotor has slip rings, an RSO test (Section 15.26) can be performed in a spin pit. This is the best test because full radial conductor loading, due to centrifugal forces, is present.

On-Site Tests As already indicated, the RSO and surge tests are easiest to perform on-site and they can be conducted with the rotor installed. If the machine has a brushless exciter, it has to be disconnected to allow direct access to the two ends of the winding. Such tests are performed to give baseline data for comparison with those from future tests to detect the condition of the rotor turn insulation. If an air gap flux probe is fitted, baseline test data should, if possible, be obtained during a short-circuit test (Section 16.7).

19.3.3 Salient Pole Synchronous Machine Windings

It is important that these windings be checked for shorted turns during manufacture and if the operating performance of in-service windings indicates that such a fault may exist. Strip-on-edge type windings are most susceptible to shorted turns, because most of their conductors are not insulated on the edges (Section 1.6.1).

Factory Tests These windings should be checked for shorted turns by performing a pole drop test at the following stages of manufacture:

- After coil winding, but before consolidation with varnish or resin;
- After coil consolidation, but before connection to form a winding;
- After winding connection;
- After the machine has been run.

Pole drop testing (Section 15.25) is the best method for checking this type of winding for shorted turns in the factory.

On-Site Tests The pole drop test is the most widely applied test to detect shorted turns (and shorted laminations) in salient pole rotors on-site. Moreover, if an air gap flux probe is fitted, baseline test data should, if possible, be obtained from a running test with field excitation applied (Section 16.7).

19.3.4 Wound Induction Rotor Windings

As with stator windings, the three-phase rotor windings in these machines are susceptible to shorted turns. In addition, bar-type windings are prone to having high resistance brazed or soldered clip connections.

Surge testing, which is normally used to check stator windings for shorted turns (Section 15.16), is the most effective method for detecting shorted turns and incorrect winding connections in wound rotor windings. It can also detect the presence of high resistance winding connections. Surge tests should be performed at all of the following stages of manufacture.

- After winding and wedging of individual coils or coil groups, but before connection;
- After winding connection, but before resin or varnish impregnation;
- After winding impregnation;
- After the motor has been run.

Another effective method of detecting high resistance connections is to pass an AC or DC current through the winding and scan the connections with a thermovision camera. High resistance connections will be indicated by much higher temperatures, as seen by the thermovision camera, than those that are properly brazed (Section 15.5).

19.3.5 Squirrel Cage Rotor Windings

The main concerns with this type of winding both during manufacture and in service are

- cracking of the bars and short-circuit rings in fabricated windings;
- air pockets in diecast aluminum windings;
- poorly brazed or welded bar-to-short circuit connections in fabricated windings.

Factory Tests It is important that quality checks to detect flaws in rotor cage windings be performed during manufacture. These should be done after the winding is installed. The most common tests used are

- Growler test (Section 15.27),
- fluorescent dye penetrant test (Section 15.28),
- rated flux test (Section 15.29),
- single-phase rotation test (Section 15.30), bar-to-short circuit ring ultrasonic tests to look for cracks.

In addition, for diecast rotors, a plug reversal and vibration test or X-ray examination is often performed to detect the presence of air pockets. The plug reversal and vibration test involves running the motor at no load, measuring vibration levels, then disconnecting and reversing two of the three phases leads to make the rotor stop and run in the opposite direction. This has the effect of heating up the rotor winding. If air pockets are present, the motor vibration levels will increase significantly after a few cycles, because of nonuniform bar expansion, which bends the rotor. The test is particularly good for two-pole motors, which are most sensitive to rotor imbalance.

On-Site Tests While the presence of rotor cage winding breaks may be detected by vibration analysis, by far the most effective test to check for rotor cage winding breaks or air pockets is stator current signature analysis as described in Section 16.8. This involves using an instrument that measures stator current and performs a spectrum analysis for side bands that are two times slip frequency removed from the fundamental 50- or 60-Hz current frequency. A baseline test, for new rotor windings, should be performed with the motor loaded to at least 35% of rated load if this type of monitoring is to be used to obtain early detection of rotor cage winding cracks or breaks. The number of rotor bars should also be noted as this may help to determine the number of rotor bars broken if this cage winding defect is present (Section 16.8).

19.4 CORE INSULATION FACTORY AND ON-SITE TESTS

These tests can be performed on new cores either in the factory or on-site. However, some are more difficult to perform on-site. This section provides details on when the tests should be performed and how easy it is to perform them on-site.

19.4.1 Core Tightness

As indicated in Section 17.1, this test involves trying to insert a standard winder's knife blade, with a maximum thickness of 0.25 mm, between the laminations at several locations around the core bore (stator) or core outside diameter (rotor). If the blade penetrates the section of core being tested by more than 5 mm, then it is assessed to be loose.

This test should be used to check the tightness of new cores before the windings are installed in them. This would normally be done in the manufacturer's plant. It can also be used on large hydrogenerators cores that are built on-site.

19.4.2 Rated Flux

The rated core flux test (also called the *ring flux* or *loop* test) described in Section 17.2 and "core loss test" (Section 17.3) are the traditional methods of determining the insulation integrity of any type of laminated stator core in an AC motor or generator.

Factory Tests For the following reasons, this is the best test for checking the integrity of the interlaminar insulation in new stator cores:

- The "core loss test" gives an indication of the quality of the core insulation by means of the power required to induce rated flux in the back of the core. If a commercial core flux tester is used, these losses are usually expressed in watts per kilogram or watts per pound of core.

- The "ring flux" or "loop" test gives an indication of the severity and location of damaged or poor quality core insulation (see Section 17.2.3) by the magnitude of hot spot temperatures and the time they take to develop.

One of these tests should be performed before the stator windings are installed, as repairs of core insulation damage is much easier at this stage of manufacture. Because there is a danger that core insulation surface shorting could occur during the installation of the slot wedges, it is advisable to repeat the test after the wedges are installed.

On-Site Tests The main reasons for performing this test on a new stator on-site would be:

- If the machine is a hydrogenerator for which the core was built on-site;
- If a baseline EL-CID test indicated a significant core insulation defect.

19.4.3 Low Flux (El-CID)

The El-CID test described in Section 17.4 is most suited for on-site testing as the test equipment is portable and easy to install.

Factory Tests The main reason for performing a factory test on a new stator core is to obtain baseline data for comparison with future site test results, and many turbine generator manufacturers now use this as a factory test. This would allow identification of developing general and local core insulation deteriorations after the machine has been in service.

On-Site Tests On-site El-CID test on new cores is normally only performed if a baseline test was not performed in the manufacturer's plant or if the core was built on-site.

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CHAPTER 20

MAINTENANCE STRATEGIES

Previous chapters have provided information on the types of materials used in motors and generators, as well as the design of the insulation systems in windings and cores. The aging processes of these insulation systems were also described, along with various online and off-line diagnostic tests that can be used to determine if specific deterioration mechanisms are occurring. This chapter discusses how the above information, together with the results of visual inspections, can be applied to maintenance strategies to assess the insulation condition in any particular rotating machine.

This chapter first provides a review of the maintenance strategies possible. It then will give guidelines on procedures to assess the insulation and indicate the relative condition of any particular machine. In many cases, enough information is given to indicate if insulation failure is imminent, or whether the winding can be expected to survive until the next major outage. The emphasis is on assessing the general condition. As suitable tests and expertise are not available for all likely deterioration mechanisms, it is not considered feasible to accurately estimate insulation condition without performing some machine disassembly to allow a visual inspection. Information on the insulation condition is necessary to decide whether the winding may readily be repaired, thus arresting the degradation, or whether a major rewind or reconstruction must be considered.

20.1 MAINTENANCE AND INSPECTION OPTIONS

The specific application and type of business will influence the inspection and maintenance strategy adopted by a user of electrical machines. Any continuous process operation, such as a utility generating station or oil refinery, usually justifies some form of planned maintenance program as the consequential costs of unscheduled downtime due to the failure of a critical machine can significantly exceed the required investment.

The extent of an inspection and maintenance program should be geared to a machine's application, consequences of failure (including lost production and revenue), redundancy, complexity, and value.

The inspection and maintenance options are as follows, and, in practice, a cost-effective strategy for an entire plant would contain a mixture of these options:

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

- Breakdown or corrective maintenance
- Time-based or preventative maintenance
- Condition-based (or predictive) maintenance.

20.1.1 Breakdown or Corrective Maintenance

This is essentially a "no maintenance" option and may be cost-effective for low value equipment for which it can be expected that outages from winding or core failures would have no safety or serious economic consequences to plant system operation. In carrying out this option, it must be recognized that a failure during service may extensively damage the machine to the extent that it cannot economically be repaired and so it must be replaced.

Decisions on whether to repair or replace a winding following breakdown will usually be determined by cost. Assessment of winding and core insulation failures using the guidelines listed in Chapters 8–13 may indicate that changes are required either in the installed equipment or in maintenance strategy, to avoid future in-service failures. A simple example is the replacement of an open-type motor enclosure by a totally enclosed equivalent when repeated failure is attributed to winding contamination and the cost of routine cleaning is not practical or cost-effective. In another case, stator winding failures due to endwinding movement could lead to a rewind with a bracing system specifically designed for repeat starts (motors) or that moves endwinding natural frequencies sufficiently away from rotational speed and two times supply frequency exciting forces (large two- and four-pole turbine generators). Similarly, sustained overheating (overloading) may indicate the need for a machine with a higher rating or rewinding with a higher temperature class of insulation.

The advantage of this option is that there is no investment in any planned program, although it requires a larger spares inventory, with significant associated costs, to cover the inevitable failures of critical machines. A disadvantage is the constant exposure to a breakdown that can have significant repercussions; for example, significant production system downtimes and repair costs.

20.1.2 Time-Based or Preventative Maintenance

This option involves performing inspections and repairs during scheduled outages or turnarounds. The timing of the outages may not, however, be optimal for electrical machines, as outages are often dictated by other considerations such as required turbine or pump work. With this maintenance option, inspection intervals vary from 1 to 10 years depending on the type of machine and if outages/turnarounds are dictated by other equipment in the plant. Alternatively, the maintenance intervals may be based on machine operating hours, for example, every 20,000 h or machine starts. Time-based maintenance has historically been recommended by motor and generator manufacturers.

A key ingredient in developing time-based maintenance programs is experience with the machines. It is necessary to build up confidence with a specific design to assess when maintenance is required. Often the suggestions for maintenance intervals come from the motor or generator manufacturers, who have presumably collected information of how long it takes for problems to develop. Where schedules permit, more frequent inspections should be conducted on a new machine until such time as the results give the assurance to increase the intervals. In addition, old machines usually require more frequent inspections and tests.

Although the aging mechanisms described in Chapters 8–13 justify routine inspection and maintenance activities throughout a machine's life, the following additional concerns merit conducting an initial inspection shortly after the machine is placed into service:

- Failures in machines of similar design
- New design features
- Incorrect installation
- Settling in/premature degradation of windings
- Actual versus specified environment
- Actual versus specified operating regime.

Any inspection and maintenance program should be flexible and sensitive to sudden changes in insulation condition in response to new operating requirements. For example, changing a generating unit's mode of operation from base load to maneuvering or peaking duty can cause winding loosening and abrasion owing to thermal cycling and acceleration of other generic insulation degradation mechanisms in both the generator and the large motors in auxiliary systems.

A manufacturer normally introduces design changes following an appropriate development program. This work may have resulted from technological change (e.g., replacement of asphalt insulation by an epoxy system), cost reduction (e.g., changing to a global VPI stator winding system from a nonglobal VPI winding), or the need to eliminate a known problem (e.g., an inadequate endwinding support arrangement). Verification of these new features comes from initial operation of production units incorporating the changes. An early inspection either detects incipient design weaknesses before significant damage occurs or gives some assurance that generic design problems do not exist. Such reassurance may be applicable to a population of similar machines following a careful examination of the first machine of that type. Nonetheless, some forms of degradation require extended time to become apparent. Therefore, a continued program of inspection of the prototype machines over several years is prudent.

Although cores and windings are assembled to be tight when shipped from the factory, they may settle during initial operation under the influence of vibration and thermal cycling. As indicated in Chapters 8–13, many electrical failures are actually mechanical in origin, that is, the original insulation capability is degraded because of movement or mechanical failure to a point where dielectric breakdown occurs. For this reason, it is essential to arrest any progressive deterioration in the winding support systems at an early stage. Experience has shown that windings retightened after a year or two in service will still be tight and in good condition when examined again following 5–10 years of operation, as long as there are no resonances at key frequencies.

Equipment is purchased assuming a certain operating environment, including atmospheric temperature, humidity, type of operation, voltage surges, etc. If the actual environment differs from the specified environment, the insulation may age more rapidly than anticipated.

Required maintenance activities during an outage will be determined by the results of diagnostic tests, inspections, and assessment techniques described in Chapters 15–17. An example of this option is to inspect a turbine generator initially after 1 year of service and every 5–6 years thereafter.

The advantage of the time-based option is that outages can be planned in advance and resources allocated accordingly, where the flexibility exists to adjust the outage timing based on previous inspection results, it can be very effective. However, there are several disadvantages to this option:

- Machines that are in good condition will be removed from service when not necessary, incurring unnecessary labor and outage costs. In addition, the machine is exposed to the risk of inadvertent damage or incorrect reassembly.
- The outage or turnaround scheduling may be dictated by other requirements.
- A preventative inspection may, on occasion, be deemed expendable in the event of workforce limitations or other corporate considerations.
- Failure mechanisms that develop in a relatively short time can still occur between inspections.
- It is possible that during an inspection outage, a mistake is made in reassembling the machine or some tools or debris are left within the motor or generator. The result is that the maintenance outage can initiate a failure.

As most machine windings are very reliable, most planned outages are not needed.

20.1.3 Condition-Based or Predictive Maintenance

An ideal maintenance program would initiate corrective activities on an electrical machine only when a problem is known to exist. With the advent of more advanced online diagnostic techniques, condition-based programs, rather than preventative or corrective maintenance programs, have become very popular in recent decades.

Assessment of a machine's winding insulation condition requires the provision of appropriate online monitoring devices describe in Chapter 16 and the application of selected off-line diagnostic tests, as described in Chapters 15 and 17. The normal (healthy) signatures from each monitoring device must be known so that any deviation provides useful intelligence. Therefore, baseline off-line test data, as indicated in Chapter 19, should be obtained.

Installed monitoring devices might include rotor and stator winding temperature detectors, accelerometers, condition (or core) monitors, airgap flux probes, endwinding vibration monitors, and partial discharge (PD) detectors. Routine monitoring of these sensors, together with auxiliary system status and actual operating load, will give an indication of machine deterioration. Outages can be scheduled to confirm any problems and to affect repairs or maintenance when significant deviations from baseline are detected.

The advantage of this maintenance option is that it will maximize the equipment's availability while minimizing the resources invested in routine maintenance activities. To be successful, this type of program may require a significant investment in monitoring equipment, in personnel to perform the monitoring and assess the results, and in the installation of sensors into the machine, during either original manufacture or disassembly of the machine during an outage. It also requires a good knowledge of the design and construction of the machine and expertise in interpreting the significance of deviations from normal. However, confidence must be built up concerning the relevance, accuracy, consistency, and reliability of the monitoring. Unfortunately, it is not known how to monitor online all the failure processes that can occur in a machine. Consequently, sufficient online monitoring that incorporates all these functions is, as yet, not available to effectively implement this option, unless at least some short-term inspection outages are taken.

Even with an effective monitoring program in place, the opportunity should always be taken to conduct a visual inspection any time a machine is opened for other maintenance purposes (Section 14.3). However, it should be recognized that a considerable amount of effort is required to dismantle the parts to carry out an effective and meaningful inspection, with a risk of damage to the machine in the process. For example, the rotor is often removed to perform a good visual examination of the stator winding. Sometimes, the amount of disassembly can be reduced using technologies such as video probes, cameras, and robotic devices that can gain access for visual inspections through small spaces, for example, the ELectromagnetic Core Imperfection Detection (El-CID) test described in Section 17.4. Furthermore, excessive application of this option to all elements of the power plant could lead to unrealistic amounts of downtime through lack of coordination.

20.1.4 Inspections

The success of any maintenance strategy is dependent on the effectiveness of the associated inspections. In addition, the planning of these inspections is governed by the particular strategy adopted.

An accurate assessment of insulation condition requires an outage, and planning should be directed at minimizing the time for which the machine is not available. A key ingredient of any planned inspection is to identify the necessary resources ahead of time and have them available when required; these resources can encompass workforce, equipment, and spare parts.

After an In-Service Failure An inspection at this time is not a planned inspection as the timing is not within the user's control. However, the adoption of a breakdown maintenance strategy inherently accepts the risk of sudden unplanned outages and general provisions should be made to handle them. Electrical machine breakdown due to insulation failure leads to a repair/replace decision rather than an assessment of condition. However, an inspection after a failure can be instrumental in determining the cause of the failure (and thus avoiding the same problem in the future), assessing the extent of corrective action, and implementing a plan to inspect similar equipment to prevent similar failures in the future.

For motors, complete spares can usually be justified for machines less than about 50 kW or so and applications in which a failure causes significant financial loss to the user if there is no spare motor immediately available. The selection of spares to be carried should also be based on the population and failure rate of similar machines in the plant and the need to implement periodic refurbishment programs to extend plant life, for example, extension of the life of a nuclear plant from 40 to 60 years. Following replacement of a failed motor, economics will dictate whether it be repaired or scrapped. The availability of competent repair contractors should be established in advance (Chapter 19); qualified organizations should be identified and listed together with their specific capabilities concerning insulation systems, size limits, and turnaround time.

For larger, more complex electrical machines, an assessment of required spare parts should be conducted after some consultation with the manufacturer. Decisions on which components to purchase and stock will be influenced by their criticality, probability of failure, cost, shelf life, number of machines of the same design, and procurement time. Approved repair techniques and replacement winding insulation systems can be documented together with sources for required consumables such as insulating tapes, and resins. Another advantage of carrying spare components, such as complete stator and rotor assemblies for large machines, is that these assemblies can be cycled through the machines to allow an ongoing refurbishment program to be implemented.

As mentioned earlier, failure causes should be monitored for signs of a trend that would lead to a review of the application and possibly equipment or component changes.

Years of Service or Operating Hours Where a time-based maintenance strategy is employed, outage planning can initially be based on the recommendations from the equipment supplier, modified by experience with similar machines. A common practice with large generators is to alternate minor and major inspections. A major inspection would include withdrawing the rotor or inspecting it using *in situ* tests and robotic techniques. The initial inspection often occurs early in a machine's life and may be identified as a contractual requirement tied to the expiration of the warranty period.

Before an inspection, any repair parts that may be required should be identified and acquired. Past experience and in-service tests are invaluable for determining the appropriate parts to be acquired. Examples are rewedging materials, insulating tapes and resins, core tightening wedges, and stress grading paint. If a major rewedging job is anticipated, the availability of specialized craftsmen should be determined. The results of previous diagnostic tests should be reviewed and compared with the new values to identify any trends. Hence, although a specific test value may in itself still be within an acceptable range, deterioration may be evident that should influence future inspection intervals. Once experience has been gained with a particular machine, the timing of inspections can be adjusted based on previous results; this could lead to either longer or shorter intervals.

Outage/turnaround planning will often be based on the requirements of many pieces of equipment, so the timing for a particular machine may have to be a compromise. Naturally, more flexibility exists for systems incorporating redundant components. As an example, where three 50% capacity pump-motor drives are installed in an auxiliary service water system for a large generating unit, one motor can be scheduled for inspection/maintenance without derating or shutting down the generating unit.

Even though future inspections have been planned based on operating time, the results of routine online diagnostic tests may indicate that earlier attention is required. For example, a PD test may raise concern for loose generator stator bars, in which case an inspection and any required remedial action should be scheduled in the next year or so.

Trend Monitoring Outage or turnaround inspections can be initiated based on excursions in an online monitor. Effective plant condition monitoring during normal operation may lead to two significant benefits:

1. Reduced maintenance costs and increased availability via elimination of unnecessary inspection and preventative maintenance for healthy equipment.
2. Identification of potentially serious states before the occurrence of damage.

Vibration monitoring has become accepted as a valuable method of tracking the mechanical health of rotating machines. A normal signature, or fingerprint, is established and vibration limits identified at which specific actions should be initiated; these may range from investigation to equipment shutdown. Likewise, insulation condition can be monitored via assessment of appropriate sensor trends and diagnostic test results. Assessments that can be made from well-proven trend monitoring systems are discussed in Chapter 16. Unfortunately, not all insulation system deterioration mechanisms can be detected with available monitoring systems. For example, deterioration of rotor winding groundwall insulation is difficult to detect, as online monitors have not been developed that can detect the processes that lead to weakened electrical or mechanical capability of the insulation. Where a monitored characteristic shows a progressive trend away from the normal value, an inspection can be planned for the first available outage. It is important that operating staff appreciate the significance of "abnormal" trends such that they can evaluate the risks of deferring inspections owing to other priorities.

20.2 MAINTENANCE STRATEGIES FOR VARIOUS MACHINE TYPES AND APPLICATIONS

Plant maintenance strategies need to be custom-designed on the basis of the following factors in order to develop a "tiered maintenance program" [1] that is designed to focus maintenance resources to a level commensurate with each generator's and/or motor's economic and safety significance. Factors to consider when developing such a program are.

- Machine criticality and outage costs
- Machine replacement/repair costs
- Redundancy
- Required workforce resources and cost benefit
- Safety requirements (for nuclear power plants and certain chemical plants)
- Machine accessibility (for equipment inside containment in nuclear power plants or hazardous locations in petrochemical plants)
- Public health considerations, such as drinking water and wastewater processing.

In this section, maintenance strategies will be discussed under the following headings.

- Turbogenerators
- Salient pole generators and motors
- Squirrel cage and wound-rotor induction motors.

20.2.1 Turbogenerators

There is no doubt that the criticality, outage costs, replacement/repair costs, and cost benefits warrant a well-designed comprehensive winding and core maintenance program for this type of machine. This should include the following elements.

Online Monitoring

- Online continuous stator winding temperature monitoring is particularly important for water-cooled stator windings as it will provide early detection of blockages in conductor strands if individual stator bar inlet and outlet water temperatures can be monitored. Such monitoring can detect blockages from debris in the stator coolant, copper oxide build-up in the conductor strands due to poor water chemistry, and loss of hydrogen-cooler water supply.
- Online monitoring for hydrogen in stator coolant will give an early warning of conductor strand breakage in water-cooled stators as the hydrogen is always at a higher pressure than the water.
- Periodic or continuous airgap flux probe monitoring is recommended for machines that may be susceptible to or have a history of turn insulation failures, as it is capable of detecting the development of a single-turn short.
- Continuous vibration monitoring can often give an early indication of developing rotor winding turn shorts.
- Continuous or periodic stator winding PD monitoring is essential to allow early detection of winding ground insulation deterioration problems as described in Section 16.4.

- For some two-pole designs, continuous endwinding vibration monitoring, as described in Section 16.6, can be beneficial if they are prone to loosening of the endwinding support system.
- In hydrogen-cooled machines known to have stator core insulation problems, monitoring of the particulates in hydrogen can detect core hotspots (Section 16.2).

Off-Line Tests These are required if no online winding monitoring is being performed, to detect insulation degradation that cannot be identified by online techniques, or to verify conditions indicated by the online techniques identified above. The number of off-line tests can be kept to a minimum if the online monitoring is performed. As discussed in Chapters 15 and 17, some of the techniques identified below do require major disassembly of the generator.

- IR and PI—These tests, described in Section 15.1, should be conducted before any high voltage AC or DC tests are performed, and if winding surface contamination is present or suspected.
- AC or DC hipot tests—There are some companies that believe in performing one of these tests on stator windings (Section 15.2 or 15.6) on a periodic basis to give some assurance that the winding will survive until the next major outage. Such tests should also be performed after any winding repairs, bar replacements and bushing repairs, or replacements to verify the integrity of such work.
- PD test—Off-line PD tests (Section 15.12) are performed to verify the results of online tests or if online monitoring devices are not fitted. In addition, the location of high PD can often be verified by the PD probe test described in Section 15.15 or the blackout test (Section 15.14).
- Winding capacitance and dissipation factor tests—These tests, described in Sections 15.8–15.11, are alternatives to the PD test and, in some cases, are used in conjunction with the PD test to determine stator winding ground insulation degradation by trending the results of periodic tests.
- Capacitance mapping—As indicated in Section 15.7, this type of testing should be performed on certain water-cooled generator stator designs that have clip joints that are susceptible to crevasse corrosion cracking. This type of degradation eventually leads to stator-cooling water seeping into the bar ground insulation, causing it to delaminate.
- Wedge tap—As indicated in Section 19.2.9, it is important that a baseline stator wedge tap be performed and a wedge map be obtained before a turbine generator goes into service. This test (Section 15.20) should be repeated before a new winding warranty runs out and periodically throughout the life of the winding. To reduce outage times, more use is now being made of robotic wedge tap devices that sometimes allow this test to be performed without withdrawing the rotor. Time savings from this approach are only achieved if the results indicate that no rewedging is required.

- RSO or surge test—These rotor tests, as described in Section 15.26, are normally only performed if running vibration data indicate the presence of turn shorts and to verify airgap flux probe data indicating such defects.
- Pressure and vacuum decay tests—Section 15.24 covers these tests, which are performed to verify whether there are any leaks in the stator-cooling systems in water-cooled stators. These tests should be performed to help confirm leaks from crevasse corrosion cracking and after any maintenance that required the stator coolant to be drained.
- El-CID test (Section 17.4)—evaluates the condition of the stator core insulation and the results are trendable. Similar to all such tests, it is important to obtain baseline results before the generator is placed in service to determine the initial core insulation condition. This test, which is relatively easy to perform, should be repeated during major outages when the rotor is removed, or when a robotic wedge tap is performed with the rotor *in situ*. In the latter case, there are a number of companies that have a robotic device that can crawl along the airgap to perform a wedge tap and an El-CID test.

Visual Inspections As discussed in Section 20.1.4, it is important to perform visual inspections of both stator and rotor insulation system components at every opportunity. When performing such inspections, particular attention should be paid to the following:

Stator

- Slot wedges for cracks.
- Endwinding bracing for looseness.
- Endwindings for evidence of PDs, especially between line-end bars in different phases, puffiness in ground insulation, insulation cracking, and flow of asphalt in windings that use this as a ground insulation-bonding agent.
- Stator core for looseness, surface damage, and localized overheating. Such inspections should include both the stator bore and as much of the back of core area as possible.
- Phase connections for evidence of cracked insulation, overheating, and loose blocking.
- Terminal bushings for evidence of cracks in the porcelain, surface contamination associated with tracking.
- Removal of some hoses or waterbox lids to allow inspection of bar ends for evidence of strand bore oxidation, blockage from debris, and wall thinning from erosion.

Rotor and slip rings

- If there is a need to remove the endwinding retaining rings for inspection, an opportunity should be taken to inspect the endwindings for copper dusting, loose blocking, displaced turn insulation, and conductor distortion.

- Visible areas of the slot portions of the windings should be inspected through radial gas ducts for evidence of turn insulation and slot packing migration and copper dusting.
- If there is a history of up-shaft lead or radial pin insulation cracking, this insulation should be periodically inspected. It should be possible to conduct such inspections without removing the rotor.
- If the rotor has slip rings, their surfaces should be inspected for pitting, grooving, and fingerprinting.
- Check radial pin insulation for cracks or other damage.
- Inter-coil and pole jumper connections should be checked for cracks and any other damage.

20.2.2 Salient Pole Generators and Motors

As with turbine generators, the criticality, outage costs, replacement/repair costs, and cost benefits warrant a well-designed comprehensive winding and core maintenance program for this type of machine if it is rated at a few megawatts or higher. This is particularly true for hydraulic generators that produce electrical power at low cost. This should include the following elements.

Online Monitoring

- Online continuous stator winding temperature monitoring is particularly important to detect blockage of cooling air passages and extensive contamination. If the machine has an air-to-water heat exchanger, such monitoring will also give an early warning of a cooling water supply loss and cooler tube blockages by debris or silt in the water supply if the cooler air outlet temperature is monitored.
- Continuous or periodic stator winding PD monitoring is most beneficial for machines with voltage ratings of 6.0 kV and above and continuous monitoring for 3.3 and 4 kV windings to allow early detection of winding ground insulation deterioration problems by PD trend monitoring, as described in Section 16.4.
- Continuous vibration monitoring (Section 16.10) in combination with airgap monitoring (Section 16.9) can often give an early indication of developing mechanical issues in the bearings, frame, etc.
- Airgap flux monitoring for mechanical problems and to detect rotor winding shorted turns (Section 16.7).

Off-Line Tests These tests are required if no online winding monitoring is being performed, to detect insulation degradation that cannot be identified by online techniques, or to verify conditions indicated by the online techniques identified earlier. The number of off-line tests can be kept to a minimum if the online monitoring described earlier is performed. As discussed in Chapters 15 and 17, some of the techniques identified below do require major disassembly of the generator.

- IR and PI—These tests, described in Section 15.1, should be performed before any high voltage AC or DC tests are performed and if winding surface contamination is present or suspected.

- AC or DC hipot tests—There are some companies that believe in performing one of these tests on stator windings (Section 15.2 or 15.6) on a periodic basis to give some assurance that the winding will survive until the next major outage. Such tests should also be performed after any winding repairs or replacements to verify the integrity of such work.
- PD tests—Off-line PD tests (Section 15.12) are performed to verify the results of online tests. In addition, the location of high PD can often be verified by the PD probe test described in Section 15.15 or the blackout test in Section 15.14.
- Winding capacitance and dissipation factor tip-up tests—These tests, described in Sections 15.8–15.11, are alternatives to the PD test and in some cases are used in conjunction with the PD test to determine stator winding ground insulation degradation by trending the results of periodic tests.
- Wedge tap—As indicated in Section 15.20, it is important that a baseline stator wedge tap is performed and a wedge map obtained before a nonglobal VPI winding goes into service. This test should be repeated before a new winding warranty runs out and periodically throughout the life of the winding.
- Pole drop test (Section 15.25) to detect rotor shorted turns.
- El-CID test—The results of this test are trendable and, similar to all such tests, it is important to obtain baseline results before the stator is placed in service to determine the initial core insulation condition. This test, which is relatively easy to perform, should be repeated during major outages when the rotor is removed.

Visual Inspections As discussed in Section 20.1.4, it is important to perform visual inspections of both stator and rotor insulation system components at every opportunity. When performing such inspections, particular attention should be paid to the following:

Stator

- Slot wedges for cracks.
- Endwinding bracing for looseness.
- Endwindings for evidence of PDs, especially between line-end bars in different phases; puffiness in ground insulation; insulation cracking; and flow of bitumen in windings that use this as a ground insulation-bonding agent.
- Stator core for looseness, surface damage, and localized overheating. Such inspections should include both the stator bore and as much of the back of core area as possible, as well as at core splits (if present).
- Phase connections for evidence of cracked insulation, overheating, and loose blocking.
- If fitted, circuit ring bus and output bus supports for surface contamination associated with tracking.

Rotor and slip rings

- Rotor windings should be periodically inspected for insulation cracking and pole winding bulging from inadequate support.
- Winding top and bottom washers should be inspected for cracks and migration.
- Interpole connections should be inspected for conductor cracking and insulation damage.
- Interpole "V" braces should be inspected for looseness and cracking in both them and the insulation between them and the winding poles.
- Amortisseur (damper) winding bars and interconnections should be checked for cracks, distortion, and migration out of the laminations.
- If the rotor has slip rings, their surfaces should be inspected for pitting, grooving, and fingerprinting.
- The condition of the visible portions of the insulation on the leads, between the slip rings or brushless exciter and field winding, should be checked.
- If the rotor is a high speed, strip-on-edge type, with bolted-on pole tips, the bolts should be inspected for looseness and cracking.

20.2.3 Squirrel Cage and Wound-Rotor Induction Motors

As these types of motors are used in a wide range of applications, from very critical to noncritical, developing a cost-effective maintenance program involves assessing each application to determine the impact of in-service failures. This is best illustrated by the following example for a large plant with many motors.

Maintenance Strategy Development The following strategy has been found to be cost-effective for plants containing a large number of motors.

- Make a list of all applications using motor-driven equipment.
- Analyze the list and assign one of the following categories to each motor application:
  - Critical—loss of production costs high, major safety concerns or environmental hazards occur if a motor fails.
  - Important—high repair costs, loss of redundancy or environmental impact if a motor fails.
  - Noncritical—no impact on plant production, safety, or environment if motor fails; repair or replacement costs are low.

Typical Maintenance Activities for each Motor Category For completeness, the following maintenance recommendations include both winding and motor mechanical component monitoring techniques.

Critical Motors

Online monitoring

- Continuous or periodic shaft and/or bearing housing vibration monitoring and trending. Periodic readings should be taken monthly.
- Continuous or periodic temperature monitoring and trending of stator windings (if fitted with resistance temperature detectors (RTDs) or thermocouples, or with thermal aging equipment of no sensors are present). Periodic measurements should be taken monthly.
- Continuous or periodic online stator winding PD monitoring for all motors rated at 3.3 kV and above.
- Continuous or periodic temperature monitoring and trending of bearings. Continuous monitoring requires that the bearings be fitted with RTDs or thermocouples. Monthly bearing housing temperature monitoring can be performed with a thermovision camera if bearing temperature detectors are not fitted.
- Stator current signature analysis for motors with fabricated rotor windings that are started frequently or are driving high inertia equipment such as induced- or forced-draft fans. Periodic readings should be taken annually and more frequently after indications of broken bars are found.
- Periodic visual inspections for evidence of unusual noises, bearing lubricant leaks, oil levels, blocked air inlets, etc. The maximum interval for these should be 1 week.
- Periodic oil analysis for oil-lubricated bearings (typically every 6 months).
- Periodic thermography for indications of overheated connections, restricted cooling, etc. and bearing overheating if no temperature detectors are fitted.

Off-line tests

- Periodic IR, PI, and winding conductivity (Section 12.3) measurements (typically every 2–4 years).
- Periodic DC step voltage or ramp tests (typically every 2–4 years).
- Periodic off-line PD, capacitance, or dissipation factor tests if online PD tests indicate an upward trend.
- If bearings are insulated, an insulation resistance measurement should, if possible, be taken every 2–4 years. The practicality of this depends on how the motor bearings are insulated.
- Insulation resistance of wound-rotor windings,

Visual inspections

At least one motor from each application should be partially or completely disassembled every 6–8 years to allow a detailed inspection of internal components for generic degradation. If only partial disassembly is performed, a video probe can be used to look at components that are not in the direct line of sight. The motor selection should be based on total running hours, number of starts, and the results of online tests and off-line inspections. Such inspections, which should also be performed when a motor is disassembled for repair, should cover the following components:

- Stator core and windings.
- Rotor core, windings, endwinding retaining rings (if fitted), slip rings (wound-rotor motors), shaft-cooling air fans, bearing journals/mounting surfaces, and shaft.
- Bearings, housings, and oil-to-water coolers (if fitted) for signs of tube bore erosion/corrosion.
- Air-to-water coolers for evidence of tube erosion/corrosion resulting in wall thinning.
- Physical condition and functional checks of all accessories including wiring and terminal blocks.

If such inspections reveal what could be generic defects, a program to inspect all motors of the same or similar design should be developed.

Important Motors

Online monitoring

- Continuous or periodic shaft and/or bearing housing vibration monitoring and trending. Periodic readings should be taken monthly.
- Continuous or periodic temperature monitoring and trending of stator windings (if fitted with RTDs or thermocouples). Periodic measurements should be taken monthly.
- Continuous or periodic temperature monitoring and trending of bearings. Continuous monitoring requires that the bearings be fitted with RTDs or thermocouples. Periodic bearing housing temperature monitoring can be performed with a thermovision camera if bearing temperature detectors are not fitted. This should be done monthly.
- Continuous or periodic online PD monitoring on motors rated 6 kV or more and critical 3.3 or 4.0 kV motors.
- Stator current signature analysis for motors with fabricated squirrel cage rotor windings that are started frequently or are driving high inertia equipment such as fans. Periodic readings should be taken annually and more

frequently after indications of broken rotor bars are found.

- Periodic oil analysis for oil-lubricated bearings (typically every 6 months).
- Periodic thermography for indications of overheated connections, restricted cooling, etc.
- Periodic visual inspections for evidence of unusual noises, bearing lubricant leaks, blocked air inlets, etc. The maximum interval for these should be 1 week.

Off-line tests

- Periodic IR, PI, and winding conductivity measurements (typically every 2–4 years).
- Periodic DC step voltage or ramp tests (typically every 2–4 years).
- If bearings arc insulated, an IR value should, if possible, be taken every 2–4 years. The practicality of this depends on how the motor bearings are insulated.
- IR of wound-rotor windings (typically every 2–4 years).
- Off-line PD for 6 kV and above motors not fitted with permanent couplers (every 2–4 years) and when online measurements indicate high levels.
- Core Loss Test (Section 17.3) if motor is sent to a service shop for repair or refurbishment.

Visual inspections

At least one motor from each application should be partially or completely disassembled every 6–8 years to allow a detailed inspection of internal components for generic degradation. If only partial disassembly is performed, a video probe can be used to look at components that are not in the direct line of sight. The motor selection should be based on running hours and results of online tests and off-line inspections. Such inspections, which should also be performed when a motor is disassembled for repair, should cover the following components:

- Stator core and windings.
- Rotor core, windings, endwinding retaining rings (if fitted), slip rings (wound-rotor motors), shaft-cooling air fans, bearing journals/mounting surfaces, and shaft extension.
- Bearings, housings, and oil-to-water coolers (if fitted) for signs of tube bore erosion/corrosion.
- Air-to-water coolers for evidence of tube erosion/corrosion resulting in wall thinning.
- Physical condition and functional checks of all accessories including wiring and terminal blocks.

If such inspections reveal what could be generic defects, a program to inspect all motors of the same or similar design should be developed.

Noncritical Motors These would receive very little maintenance as they could be run to failure. Typically, they would receive:

- Periodic bearing lubrication (grease-lubricated bearings) or replacement (oil-lubricated bearings).
- Periodic vibration monitoring (say, every 3 months).

REFERENCE

1. EPRI Report 1003095, "Electric Motor Tiered Maintenance Program", August 2002.

APPENDIX A

A.1 INSULATION MATERIAL TABLES

These tables were originally published in "Handbook to Access the Insulation Condition of Large Rotating Machines," by EPRI, Repeat EL-5036 Vol 16, 1989. Source: Reproduced with the permission of EPRI.

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

TABLE A.1-1 Laminated and Reinforced Plastic Sheet Materials for Slot Wedges and Packing, Endwinding Bracing and Packing

Material description		Laminated and reinforced plastic sheet materials							
Sources of data		NEMA Standards LI1 and LI3, Machine Design, April 1985, Insulating Circuits Desk Manual, 1979, and Insulating Materials for Design and Engineering Practice, 1962							
Applications		Slot wedges and packing, endwinding bracing, and packing							
NEMA grade		X	XP	XPC	XX	XXP	XXX	XXXP	XXXPC
Resin/reinforcing material		Phenolic/paper	Phenolic/paper	Phenolic/paper	Phenolic/paper	Phenolic/paper	Phenolic/paper	Phenolic/paper	Phenolic/paper
Test std. or ref.	Properties								
NEMA LI3	**Thermal**								
	Temperature class (°C)	105	105	105	105	105	105	105	105
	Coefficient of expansion (10^{-5} cm/cm-°C)	2	2	2	2	2	2	2	2
NEMA LI1 for 1/8 in (3.175 mm) thick material	**Electrical**								
	Dielectric strength (kV/mm)								
	Perpendicular to laminate (step by step/short time)	14.2/19.7	12.6/18.5	11.4/16.7	14.2/19.7	14.2/19.7	12.6/18.5	12.6/18.5	12.6/18.5
	Parallel to laminate (step by step/short time)	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—
	Dielectric constant (60 Hz/1 MHZ)	4.8/6.0	—/—	—/—	—/5.5	—/5.0	4.5/6.0	—/4.6	—/4.6
	Dissipation factor (60 Hz/1 MHz)	—/0.06	—/—	—/—	—/0.045	—/0.04	—/0.038	—/0.035	—/035

	Partial discharge resistance	Poor	Poor	Poor	Poor	Poor	Poor	Poor	Poor
	Mechanical								
NEMA LI1	Tensile strength (MPa)								
	Lengthwise (25/130°C)	137.8/68.9	82.7/41.3	72.3/36.1	110.2/55	75.8/37.9	103.3/51.6	85.4/42.7	85.4/42.7
	Crosswise (25°C)	110.2	110.2	58.6	89.6	58.6	82.7	65.4	48.2
NEMA LI1	Compressive strength (MPa)								
	Flatwise (25/130°C)	248.0/168.6	172.2/117	151.6/103	234.3/165.4	172.2/117	220.5/149.9	172.2/117.1	172.2/117.1
	Edgewise (25°C)	130.9	—	—	158.5	—	172.2	—	—
NEMA LI1	Flexural strength (MPa)								
	Lengthwise (25°C)	172.2	89.6	68.9	103.3	96.5	93	82.7	82.7
	Crosswise (25°C)	151.6	75.8	55.1	96.5	82.7	81.3	72.3	72.3
NEMA LI1	Flexural modulus (10^3 MPa)								
	Lengthwise (25°C)	12.4	8.27	6.89	9.65	6.2	8.96	6.89	6.89
	Crosswise (25°C)	8.96	6.2	5.51	7.58	4.82	6.89	4.82	4.82

(*continued*)

TABLE A.1-1 (*Continued*)

Material description		Laminated and reinforced plastic sheet materials							
Sources of data		NEMA Standards LI1 and LI3, Machine Design, April 1985, Insulating Circuits Desk Manual, 1979, and Insulating Materials for Design and Engineering Practice, 1962							
Applications		Slot wedges and packing, endwinding bracing, and packing							
NEMA grade		X	XP	XPC	XX	XXP	XXX	XXXP	XXXPC
Resin/reinforcing material		Phenolic/ paper	Phenolic/ paper	Phenolic/ paper	Phenolic/ paper	Phenolic/ paper	Phenolic/ paper	Phenolic/ paper	Phenolic/ paper
NEMA LI1	Shear strength (MPa) (25°C)	—	—	—	—	75.8	68.9	75.8	75.8
	Thickness range (in./cm) —minimum	0.01/025	0.01/025	0.03125/079	0.01/025	0.015/038	0.015/038	0.015/038	0.03125/079
	Maximum	2.0/5.08	0.25/635	0.25/635	2.0/5.08	0.23/635	2.0/5.08	0.23/635	0.1875/476
ASTM D229	**Water absorption** —24 h, 3.175 mm thick (%)	3.3	2.2	3	1.3	1.1	0.095	0.075	0.055
	Chemical resistance	All grades except G-5 and G-9 are resistant to dilute solutions of most acids							
		Grades G-5 and G-9 are resistant to dilute alkaline solutions; the others may be affected by such solutions							
		These *materials are* unaffected *by most organic solvents* except acetone, which may soften punching grades aromatic hydrocarbons and chlorinated aliphatics may affect silicone Grade G-7							
	Radiation resistance	Poor for all grades							

TABLE A.1-2 Laminated and Reinforced Plastic Sheet Materials for Slot Wedges and Packing, Endwinding Bracing and Packing

Material description	Laminated and reinforced plastic sheet materials
Sources of data	NEMA Standards LI1 and LI3, Machine Design, April 1985, Insulating Circuits Desk Manual, 1979, and Insulating Materials for Design and Engineering Practice, 1962
Applications	Slot wedges and packing, endwinding bracing and packing

NEMA grade		A	AA	C	CE	L	LE	G-3	G-5
Resin/reinforcing material		Phenolic/ asb paper	Phenolic/ asb fabric	Phenolic/ cotton	Phenolic/ cotton	Phenolic/ cotton	Phenolic/ cotton	Phenolic/ CFGC	Melamine/CFGC
Test std. or ref.	Properties								
NEMA LI3	**Thermal**								
	Temperature class (°C)	130	130	105	130	105	105	105	105
	Coefficient of expansion (10^{-5} cm/cm-°C)	1.5	1.5	2	2	2	2	1.8	1
NEMA LI1 for 1/8 in (3.175 mm) thick material	**Electrical**								
	Dielectric strength (kV/mm)								
	Perpendicular to laminate (step by step/short time)	3.3/5.5	—/3.8	8.7/14.2	8.7/14.2	8.7/14.2	8.7/14.2	17.7/23.6	6.3/10.2
	Parallel to laminate (step by step/short time)	—/3.1	—/—	—/4.72	—/4.72	—/4.72	—/—	—/—	—/—
	Dielectric constant (60 Hz/1 MHz)	—/5.2	—/6.25	7.5/5.5	—/5.3	—/5.6	—/5.8	—/5.5	—/8.0

(*continued*)

TABLE A.1-2 ***(Continued)***

Material description: Laminated and reinforced plastic sheet materials

Sources of data: NEMA Standards LI1 and LI3, Machine Design, April 1985, Insulating Circuits Desk Manual, 1979, and Insulating Materials for Design and Engineering Practice, 1962

Applications: Slot wedges and packing, endwinding bracing and packing

	Dissipation factor (60 Hz/1 MHz)	—/0.2	—/0.45	—/0.01	—/0.05	—/0.055	—/0.055	0.02/0.03	—/0.2
	Partial discharge resistance	Poor	Poor	Poor	Poor	Poor	Poor	Poor	Poor
	Mechanical								
NEMA LI1	Tensile strength (MPa)								
	Lengthwise (25/130°C)	68.9/—	82.7/67	68.9/31	62.0/28.3	89.6/40.3	82.7/37.2	158.5/125.2	254.9/201.4
	Crosswise (25°C)	55.1	68.9	55.1	48.2	62	58.6	137.8	206.7
NEMA LI1	Compressive strength (MPa)								
	Flatwise (25/130°C)	275.6/—	261.8/170	254.9/147.8	268.7/155.8	241.1/139.8	254.9/147.8	344.5/227.4	482.3/318.3
	Edgewise (25°C)	117.1	144.7	161.9	168.8	161.9	172.2	120.6	172.2
NEMA LI1	Flexural strength (MPa)								
	Lengthwise (25°C)	89.6	124	117.1	113.7	103.3	103.3	275.6	303.2
	Crosswise (25°C)	75.8	110.2	110.2	96.5	96.5	93	206.7	261.8

NEMA LI1	Flexural modulus (10^3 MPa)								
	Lengthwise (25°C)	15.85	11	6.9	6.2	7.6	6.9	10.3	11.7
	Crosswise (25°C)	9.65	9.65	6.2	5.5	5.86	5.86	8.27	10/3
NEMA LI1	Shear strength (MPa) (25°C)	—	82.7	—	—	—	—	124	—
	Thickness range (in./cm) —minimum	0.025/0.0635	0.0625/1587	0.03125/0794	0.03125/0.0794	0.01/0254	0.015/0381	0.01/0254	0.01/0.0254
	Maximum	2.0/5.08	2.0/5.08	10.0/—	2.0/5.08	2.0/5.08	2.0/5.08	2.0/5.08	3.5/8.89
ASTM D229	**Water absorption** —24 h, 3.175 mm thick (%)	0.95	2.5	2.5	1.6	1.6	1.3	2	2
	Chemical resistance	See Table B1-1							
	Radiation resistance	Poor for all grades							

CFGC, continuous filament glass cloth.

TABLE A.1-3 Laminated and Reinforced Plastic Sheet Materials for Slot Wedges and Packing, Endwinding Bracing and Packing

Material description		Laminated and reinforced plastic sheet materials											
Sources of data		NEMA Standards LI1 and LI3, Machine Design, April 1985, Insulating Circuits Desk Manual, 1979, and Insulating Materials for Design and Engineering Practice, 1962											
Applications		Slot wedges and packing, endwinding bracing and packing											
NEMA grade		G-7	G-9	G-10	G-11	FR-1	FR-2	FR-3	FR-4	FR-5	GPO-1	GPO-2	GPO-3
Resin/reinforcing material		Silicone/ CFGC	Melamine/ CFGC	Epoxy/ CFGC	Epoxy/ CFGC	Phenolic/ paper	Phenolic/ paper	Epoxy/ paper	Epoxy/ CFGC	Epoxy/ CFGC	Polyester/ glass mat	Polyester/ Glass Mat	Polyester/ Glass Mat
Test std. or ref.	Properties												
NEMA LI3	**Thermal**												
	Temperature class (°C)	180		155	155	105	105	105	155	155	155	155	155
	Coefficient of expansion (10^{-5} cm/cm-°C)	1	1	0.9	0.9	2	2	2	1	0.9	2	2	2
NEMA LI1for 1/8 in (3.175 mm) thick material	**Electrical**												
	Dielectric strength (kV/mm)												
	Perpendicular to laminate (step by step/short time)	9.8/13.8	10.8/13.8	13.8/21.6	13.8/21.6	—/—	12.7/20.2	14.2/17.0	14.2/19.8	14.2/19.8	—/11.8	—/11.8	—/11.8

	Parallel to laminate (step by step/short Time)	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—	—/—
	Dielectric constant (60 Hz/1 MHz)	4.5/4.2	—/7.2	—/5.2	—/5.2	—/—	—/4.8	—/4.8	—/5.4	—/5.4	4.5/4.3	4.5/4.3	4.5/4.3
	Dissipation factor (60 Hz/1 MHz)	—/0.003	—/0.017	0.03/0.025	—/0.025	—/—	—/0.04	—/0.04	—/0.035	—/0.035	0.05/0.03	0.05/—	0.05/—
	Partial discharge resistance												
	Mechanical												
NEMA LI1	Tensile strength (MPa)												
	Lengthwise (25/130°C)	158.5/—	344.5/—	310/238	310/238	82.7/41.0	86.1/43.0	96.5/—	275/212	275/212	82.7/—	69.9/—	69.9/—
	Crosswise (25°C)	127.5	275.6	275.6	275.6	62	65.4	82.7	241.1	241.1	68.9	62	62
NEMA LI1	Compressive strength (MPa)												
	Flatwise (25/130°C)	310	482.3	413.4	413.4	172.2	172.2	172.2	413.4	413.4	206.7	206.7	206.7
	Edgewise (25°C)	86.5	172.2	241.1	241.1	—	—	—	241.1	241.1	137.8	137.8	137.8
NEMA LI1	Flexural strength (MPa)												
	Lengthwise (25°C)	137.8	379	379	379	—	—	—	—	—	—	—	—
	Crosswise (25°C)	124	241.1	310	310	—	—	—	—	—	—	—	—

(*continued*)

TABLE A.1-3 (*Continued*)

Material description		Laminated and reinforced plastic sheet materials											
Sources of data		NEMA Standards LI1 and LI3, Machine Design, April 1985, Insulating Circuits Desk Manual, 1979, and Insulating Materials for Design and Engineering Practice, 1962											
Applications		Slot wedges and packing, endwinding bracing and packing											
NEMA LI1	Flexural modulus (10^3 MPa)												
	Lengthwise (25°C)	9.65	17.2	18.6	19.3	8.3	7.6	9	18.6	19.3	6.9	6.9	69
	Crosswise (25°C)	8.27	13.8	15.2	15.8	6.2	6.2	6.9	15.2	15.8	6.2	6.2	6.2
NEMA LI1	Shear strength (MPa) (25°C)	117.1	137.8	130.9	—	—	—	—	—	—	965	96.5	96.5
	Thickness range (in./cm) —minimum	0.01/025	—/—	0.01/0.025	0.01/0.025	—/—	0.03/—	0.03125/—	0.01/—	0.01/—	0.0625/159	0.0625/159	0.0625/159
	Maximum	2.0/5.08	—/—	1.0/2.54	1.0/2.54	—/—	.25/0.635	.25/0.635	1.0/2.54	1.0/2.54	2.0/5.08	2.0/5.08	2.0/5.08
ASTM D229	**Water absorption** —24 h, 3.175 mm thick (%)	0.35	0.7	0.15	0.15	2.2	0.55	0.5	0.15	0.15	—	—	0.5
	Chemical resistance	See Table B1-1											
	Radiation resistance	Silicone/glass, epoxy/glass and polyester/glass grades—good; phenolic/paper and epoxy/paper grades—poor											

CFGC, continuous filament glass cloth.

TABLE A.2 NOMEX™ High Temperature Resistant Aramid Paper for Slot Liners, Slot Packing, and Turn and Groundwall Insulations for Low Voltage Rotor Windings

Material description	High temperature resistant aramid paper					
Trade names	Nomex					
Sources of data	Manufacturer's literature for grades 410, 411, and 414					
Applications	Slot liners, slot packing, and turn and groundwall insulations for low voltage rotor windings					
Grade		410	410	410	411	414
Thickness (mils/mm)		2.0/0.05	5.0/0.13	7.0/0.18–30.0/.76	5.0/0.13–23.0/.58	7.0/0.18–15.0/.38
ASTM, UL, or NEMA standard	Properties					
	Thermal					
UL	Temperature class (°C)	220	220	220	220	220
	Coefficient of expansion (10^{-5} cm/cm-°C)					
	Electrical					
ASTM D149	Dielectric strength (kV/mm)	20	29	30	12	28.5
ASTM D150	Dielectric constant	1.6	2.4	3	1.3	2.7
ASTM 0150	Dissipation factor	0.004	0.006	0.0065	0.005	0.02
	Partial discharge resistance	Good	Good	Good	Good	Good
	Mechanical					
ASTM D828	Tensile strength (MPa) MD	75.6/63.7	114.3/96	120/100	13.8/11.6	90/76
	At 24/150°C XD	37.9/31.8	53.7/45.1	65/55	8.3/7.0	51/43
ASTM 0827	Finch edge tear strength (N) MD	93	380	580–1200	45–250	55–157
	At 24°C XD	40	150	260–580	27–170	110–260
ASTM 0689	Elmendorf tear strength (N) MD	0.8	2.2	3.3–18	1.3–6.2	—
	At 24°C XD	1.6	5.7	7.4–28	1.8–9.6	—

(*continued*)

TABLE A.2 (*Continued*)

Material description	High temperature resistant aramid paper	
Trade names	Nomex	
Sources of data	Manufacturer's literature for grades 410, 411, and 414	
Applications	Slot liners, slot packing, and turn and groundwall insulations for low voltage rotor windings	
Manuf. Lit.	**Water absorption**	Absorption rate depends on the thickness of the material, for example, a dry 3-mil sheet of Grade 410 mill reaches 50% of its equilibrium mater content in 1 h at 95% humidity, whereas a 30-mil sheet of this material will take 2 days to reach this level. These materials will absorb up to 14% water in 95% humidity
	Chemical resistance	This material has good resistance to most common acids and alkalines and is fully compatible with all classes of electrical varnishes and resins, that is, polyamides, silicones, epoxies, polyesters, acrylics, phenolics, synthetic rubbers, etc. Common industrial solvents, that is, alcohols, ketones, acetone, toluene, and xylene have a slight softening and smelling effect similar to that produced by mater. These effects are reversible when the solvent on mater is removed
	Radiation resistance	This material has good resistance to both beta and gamma radiations. Its dielectric properties are virtually unaffected by total radiation doses up to 6400 megarads. Its mechanical properties are not significantly affected until the total dose exceeds 400 megarads

MD, machine direction; XD, cross direction.

The dielectric strength is unaffected by temperatures up to 225°C. The dielectric strength values given are for room temperature and a rapid rise AC test.

The dielectric constant increases only slightly with temperature up to 250°C. and is essentially constant for frequencies up to 10,000 Hz.

The dissipation factor remains essentially constant for temperatures up to 180°C. Beyond this, it rises sharply with temperature.

The tear strength of this material is approximately proportional to its thickness.

Nomex is a trademark of DuPont.

*This material remains dimensionally stable up to 130°C. Beyond this, the expansion in the MD is moderate and in the XD, it is more rapid, for example, at 200°C, the elongation is +20% over the original room temperature in the MD dimension and +60% in the XD.

TABLE A.3 NOMEX M^{TM} High Temperature Resistant Aramid and Mica Paper for Turn and Groundwall Insulations

Material description		High temperature resistant aramid and mica paper
Trade names		Nomex M
Sources of data		Manufacturer's published literature for Grade 418
Applications		Turn and groundwall insulations
Thickness (mils/mm)		3/8–10/0.25
Test std or ref.	Properties	
	Thermal	
UL	Temperature class (°C)	220
	Coefficient of expansion (10^{-5} cm/cm-°C)	
	Electrical	
ASTMD149	Dielectric strength (ky/mm)	39
ASTMD150	Dielectric constant	2.5
ASTMD150	Dissipation factor	0.006
	Partial discharge resistance	Very good
ASTMD828	**Mechanical**	
ASTMD827	Tensile strength (MPa) MD	45/37.8
ASTMD689	At 24/150°C XD	30/25.2
	Finch tear strength MD	40–110
	At 24°C XD	22–67
	Elmendorf tear strength (N) MD	1.2–4.3
	at24°C XD	1.8–5.6
Manufacturer's literature	**Water absorption**	This depends on the material thickness, that is, the thicker the material is, the slower it absorbs moisture. It will absorb up to 14% water in 95% humidity
	Chemical resistance	Same as that for grades 410, 411, and 414, Table B2
	Radiation resistance	Same as that for grades 410, 411, and 414, Table B2

MD, machine direction; XD, cross direction.

The dielectric strength is unaffected by temperatures up to 225°C. The values given in the table were determined at room temperature by a rapid rise AC test.

The dielectric constant increases only slightly with temperatures up to 250°C and is essentially constant for frequencies up to 10,000 Hz.

The dissipation factor of this material is essentially constant up to temperature of 180°C. Beyond this, it rises sharply with temperature.

The tear strength of this material is approximately proportional to its thickness.

Nomex M is a trademark of DuPont.

*This material remains dimensionally stable up to temperatures of 130°C; in the MD, it is moderate and in the XD, it is rapid, for example, at 200°C, the elongation is +20% over the original room temperature in the MD dimension and +60% in the XD.

TABLE A.4 Micaceous Tape Insulation for Stator Groundwall Insulation Rated 3.8 kV and Above

Material description	Micaceous groundwall tape insulation
Sources of data	Manufacturer's published literature and Ontario Hydro test data
Applications	Stator groundwall insulation for steam turbine and hydraulic generators rated 13.8 kV and above

Properties/materials	Asphalt-bonded mica splittings —paper backed	Asphalt-bonded mica splittings —glass or Dacron fiber backed	Modified bitumen-bonded mica splittings—glass fiber backed	Polyester resin-bonded mica splittings—paper backed	Epoxy resin-bonded mica splittings—glass or Dacron fiber backed	Epoxy resin-bonded mica paper—glass or Dacron fiber backed	Epoxy resin-bonded mica paper with interspersed layers of mica flakes—glass fiber backed
Thermal							
Temperature class (°C)/(letter class)	130/B	130/B	130/B	130/B	155/F	155/F	155/F
Coefficient of expansion (10^{-5} cm/cm-°C)							
Radial	30	—	—	7.2	—	—	—
Lengthwise	0.685	—	1.06	0.666	—	1.2	1
Dielectric strength (kV/mm) at 120°C							
With partial discharge suppression (New/1000 h)	11.8/5.3	14.5/6.5	18.9/7.7	15.6/7.0	18.4/8.3	21.0/10.0	21.6/9.5

Electrical							
Dissipation factor new (25/125°C) at rated voltage	0.05/18	0.02/0.1	0.035/10	0.02/0.05	0.02/.05	0.01/0.045	0.02/0.06
Partial discharge resistance	Excellent	Excellent	Excellent	Excellent	Excellent	Very good	Excellent
Mechanical							
Tensile strength (MPa) at 25/130°C	13.8/0.62(100°C)	59/11.8(90°C)	28.2/5.2	45.5/19.3	—/—	172/—	116/83
Flexural strength (MPa) at 25/130°C	276/8.6	—/—	—/—	—/—	—/—	250/220	167/122
Compressive strength (MPa) at 25/130°C	—/—	—/—	—/—	—/—	—/258	265/235	286/251
Water absorption	Asphalt-backed mica-insulated coils have good resistance to moisture as long as the bonding between layers remains good. Epoxy-bonded materials have excellent resistance to moisture						
	Polyesters may hydrolyze, degrading mechanical and electrical properties						
Chemical resistance	Asphalt-bonded tapes may be degraded by solvents and moisture.						
	Polyester and epoxy-bonded tapes—these materials have excellent resistance to most weak acids, alkalines, and solvents. They also have good resistance to most lubricating oils						
Radiation resistance	Asphalt-bonded and paper-backed grades—poor						
	Other grades—good						

TABLE A.5-1 Coil Insulation for Stator Groundwall Insulation Rated 13.8 kV and Below

Material description	Coil groundwall insulation
Sources of data	Manufacturer's literature and Ontario Hydro test data
Applications	Stator groundwall insulation for motors and generators rated 13.8 kV and below

Properties/materials	Vulcanized silicone rubber	Vulcanized polyester glass reinforced silicone rubber	Asphalt-bonded mica splittings—paper backed	Asphalt-bonded mica splittings—glass or Dacron fiber backed	Modified bitumen-bonded mica splittings—glass or Dacron fiber backed	Varnish-bonded Mylar/mica paper—Mylar
Thermal						
Temperature class (°C)/(letter class)	180/M	180/M	130/B	130/B	130/B	130/B
Coefficient of expansion (10^{-5} cm/cm-°C)						
Radial	—	—	30	—	—	—
Lengthwise	—	—	0.685	—	—	—
Electrical						
Dielectric strength (kV/mm)						
1 min new/1000 h	11.4/7.5	11.0/8.0	11.5/5.0	14.5/—	18.9/7.7	—/—
Dissipation factor new (25/125°C) at rated voltage	—/—	—/—	0.05/.18	0.2/0.1	0.035/0.10	—/—
Partial discharge resistance	Good	Good	Excellent	Excellent	Excellent	Good

Mechanical						
Tensile strength (MPa) at 25/130°C	4.1/—	—/—	13.8/0.62 (100°C)	59/11.8 (100°C)	28.2/5.2 (100°C)	—/—
Flexural strength (MPa) at 25/130°C	—/—	—/—	—/—	—/—	—/—	—/—
Compressive strength (MPa) at 25/130°C	—/34	—/48	276/8.6	—/—	—/—	—/—
Water absorption	Very good resistance to moisture		Fairly good resistance to moisture			Fairly good resistance to moisture
Chemical resistance	Fairly good but material swells when subjected to solvents and lubricants such as oils		—			—
Radiation resistance	These materials have good radiation resistance		Mechanical properties are seriously degraded by high radiation fields and this leads to a reduction in dielectric properties			

Silicone rubber materials are generally not used for voltage ratings above 7 kV.

TABLE A.5-2 Coil Insulation for Stator Groundwall Insulation Rated 13.8 kV and Below

Material description	Coil groundwall insulation					
Sources of data	Manufacturer's literature and Ontario Hydro test data					
Applications	Stator groundwall insulation for motors and generators rated 13.8 kV and below					
Properties/materials						
Thermal						
Temperature class (°C)/(letter class)	180/M	180/M	130/B	130/B	130/B	130/B
Coefficient of expansion (10^{-5} cm/cm-°C)						
Radial	—	—	30	—	—	—
Lengthwise	—	—	0.685	—	—	—
Electrical						
Dielectric strength (kV/mm)						
1 min new/1000 h	11.4/7.5	11.0/8.0	11.5/5.0	14.5/—	18.9/7.7	—/—
Dissipation factor new (25/125°C) at rated voltage	—/—	—/—	0.05/.18	0.2/0.1	0.035/0.10	—/—
Partial discharge resistance	Good	Good	Excellent	Excellent	Excellent	Good
Mechanical						
Tensile strength (MPa) at 25/130°C	4.1/—	—/—	13.8/0.62 (100°C)	59/11.8 (100°C)	28.2/5.2 (100°C)	—/—

Flexural strength (MPa) at 25/130°C	—/—	—/—	—/—	—/—	—/—	—/—
Compressive strength (MPa) at 25/130°C	—/34	—/48	276/8.6	—/—	—/—	—/—
Water absorption	Very good resistance to moisture		Fairly good resistance to moisture			Fairly good resistance to moisture
Chemical resistance	Fairly good but material swells when subjected to solvents and lubricants such as oils		—			—
Radiation resistance	These materials have good radiation resistance		Mechanical properties are seriously degraded by high radiation fields and this leads to a reduction in dielectric properties			

Silicone rubber materials are generally not used for voltage ratings above 7 kV.

TABLE A.6 Enamel-Film-Covered Copper Magnet Wire for Multiturn Stator Coil Strand and Turn Insulation

Material description	Enamel-film-covered copper magnet wire
Source of data	NEMA MW 1000, Machine Design, April 1985, Insulation Circuits Desk Manual, 1979, BEAMA Electrical Insulation Conference, 1970, and Manufacturer's Papers and Literature
Applications	Strand and turn insulations for multiturn stator coils

Enamel	Polyvinyl acetal	Early polyester	Modern polyester	Polyimide	Polyester imide	Polyamide-imide	Polyester with polyamide-imide overcoat
History	Introduced in the late 1930s. First enamel used for this application, Trade names Formex, Formvar	Introduced in the mid-1950s. Trade name Alkanex R	Developed from the 1950s version. Trade name Mylar, plus others	Introduced in the early 1960s. Trade name Kapton	Developed from polyester and polyimide to give improved properties. Introduced in 1965	Developed from polyimide	Developed to improve thermal properties of polyester introduced in 1967
Thermal							
NEMA MW 1000 rating (°C)	105	130	155	220	180	220	200
Heat shock withstand	Fairly good	Fair	Good	Excellent	Very good	Good	Very good

Electrical							
Dielectric strength (kV/mm)							
25°C/at rated temperature	118/93	128/118	141/135	177/135	141/135	177/161	149/135
Dielectric constant (25°C/200°C)	—/—	—/—	—/—	3.3/3.2	3.9/4.0	3.3/3.2	
Dissipation factor (25°C/200°C)	—/—	—/—	—/—	0.008/0.024	0.009/0.008(180°C)	0.008/0.024	
Partial discharge resistance	Poor	Fair	Fair	Fair	Fair	Fair	Fair
Mechanical							
Toughness	Good	Fairly good	Good	Good	Good	Excellent	Excellent
Flexibility	Good	Good	Excellent	Excellent	Excellent	Good	Excellent
Scrape resistance	Good	Fairly good	Excellent	Fairly good	Good	Excellent	Excellent
Cut through resistance	—	—	Excellent	Excellent	Excellent	Good	Very good

(continued)

TABLE A.6 (*Continued*)

Material description	Enamel-film-covered copper magnet wire						
Source of data	NEMA MW 1000, Machine Design, April 1985, Insulation Circuits Desk Manual, 1979, BEAMA Electrical Insulation Conference, 1970, and Manufacturer's Papers and Literature						
Applications	Strand and turn insulations for multiturn stator coils						
Water resistance	Fair	Fair	Fair	Good	Good	Excellent	Excellent
Chemical resistance	—		Poor resistance to xylene	Good	Good	Excellent	Excellent
Radiation resistance	Poor	—	—	Properties remain good up to 3×10^9 rads of gamma radiation	Good	Properties remain good up to 3×10^9 rads	

The thermal rating of polyvinyl acetal may be increased by overcoating it with polyester or epoxy resin or using these as impregnants.

The above-mentioned properties may be affected by the impregnants used to bond the conductors or strands together.

TABLE A.7 Fiber-Covered Copper Magnet Wire for Stator and Rotor Coil Strand and Turn Insulations

Material description	Fiber-covered copper magnet wire			
Source of data	NEMA MW1000, Insulation Circuits Desk Reference Manual, 1979 and Canada Wire and Cable Co. literature			
Applications	Strand and turn insulations for stator and rotor coils			
Fiber	Glass	Polyester glass	Enamel + glass orglass fibers	Asbestos
History	Introduced in the 1930s as an improvement over cotton, silk, asbestos, etc.	Commonly known as *Dacron* glass. It was developed in the early 1950s to give better thermal and mechanical properties than those of glass fibers	Introduced in parallel with development of individual coverings	Has been used from the 1920s. Since then, the main improvements have been in the bonding materials
Thermal				
NEMA MW1 000 rating (°C)	Organic varnish treated: 155°C Silicone varnish treated: 200°C	Untreated: 155°C Organic varnish treated: 180°C Silicone varnish treated: 200°C	155, 180, or 200°C depending on the lowest rating for materials used in the combination	Depends on the bonding varnish, that is, 130°C for Class B Varnish
Heat shock withstand	Good	Good	Good	Fairly good
Electrical				
Dielectric strength (kV/mm)				

(*continued*)

TABLE A.7 (*Continued*)

25°C/at rated temperature	—/3.54	—/3.54	Enamel kV/mm + 3.4/—	3.4/—
Dielectric constant (25°C/200°C)	—/—	—/—	—/—	—/—
Dissipation factor (25°C/200°C)	—/—	—/—	—/—	—/—
Partial discharge resistance	Good	Good	Good	Good
Mechanical				
Toughness	Good when bonded	Excellent when fiber bonded		Fairly good
Flexibility	Poor compared to enamel	Fair		Poor
Scrape resistance	Good when bonded	Good when fiber bonded		Fairly good
Water resistance	Good when bonded	Poor		
Chemical resistance	Good for all grades			
Radiation resistance	Good for untreated Dacron glass and epoxy and silicone bonded grades. Poor for organic resin bonded grades			

TABLE A.8 Asbestos Paper in Sheet and Tape Forms of Strand and Turn Insulations in Salient Pole Rotor Windings

Material description	Asbestos paper in sheet and tape forms							
Source of data	Insulating Materials for Design and Engineering Practice, 1962 and Insulation Circuits Directory Encyclopedia, 1970							
Applications	Strand and turn insulations in salient pole rotor windings							
Thickness (mm/μm)	0.066/2.6	0.206/8.1	0.076/3	0.229/9	0.089/3.5	0.076/3.0	0.089/3.5	0.076/3.0
Impregnant	None	None	Polyvinyl acetate	Polyvinyl acetate	45°/o epoxy	25°/o epoxy	45% silicone	25% silicone
Properties								
Thermal								
Temperature class (°C)	180	180	130	130	155	155	180	180
Coefficient of expansion (10^{-5} cm/cm-°C)								
Expansion (10^{-5} cm/cm-°C)	—	—	—	—	—	—	—	—
Electrical								
Dielectric strength (kV/mm) 25/130°C	11.4/—	12.2/—	11.8/—	11.3/—	30.3/—	131/—	28.1/—	13.1/—
Dielectric constant (25/130°C)	—/—	—/—	6.0/—	—/—	2.5/—	—/—	3.5/—	5.0/—
Dissipation factor (25/130°C)	—/—	—/—	0.3/—	—/—	0.06/—	—/—	0.1/—	*0.025/—*

(*continued*)

TABLE A.8 (*Continued*)

Material description	Asbestos paper in sheet and tape forms								
Source of data	Insulating Materials for Design and Engineering Practice, 1962 and Insulation Circuits Directory Encyclopedia, 1970								
Applications	Strand and turn insulations in salient pole rotor windings								
Partial discharge resistance									
Mechanical									
Tensile strength (MPa) MD	0.93/—	0.98/—	16.1/—	9.97/—	29.6/—	16.1/—	11.5/—		17.7/—
At 25/130°C XD	—/—	—/—	—/—	—/—	—/—	—/—	—/—		—/—
Tear strength (MPa) MD	—/—	—/—	—/—	—/—	—/—	—/—	—/—		—/—
At 25/130°C XD	—/—	—/—	—/—	—/—	—/—	—/—	—/—		—/—
Water absorption	All asbestos papers are susceptible to moisture absorption, which causes significant reduction in mechanical and dielectric properties. The most susceptible are the unimpregnated grades. The use of impregnants such as polyvinyl acetate, epoxy, or silicone reduces its susceptibility to moisture absorption								
Chemical resistance	Asbestos papers have excellent resistance to most chemicals								
Radiation resistance	Asbestos has excellent radiation resistance. This is maintained with epoxy and silicone impregnants, but is reduced if a polyvinyl acetate binder is used								

APPENDIX B

B.1 INSULATION SYSTEM TABLES

These tables were originally published in "Handbook to Access the Insulation Condition of Large Rotating Machines," by EPRI, Repeat EL-5036 Vol 16, 1989. Source: Reproduced with the permission of EPRI.

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair, Second Edition. Greg C. Stone, Ian Culbert, Edward A. Boulter, and Hussein Dhirani.

TABLE B.1 AEG

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors, and Generators

Location and Type of Winding: Stator, Multiturn Diamond

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
AEG EPITHERM STATOR and COIL VPI- The Stator VPI System is used when it is possible to fit the entire stator assembly into the impregnation tank. When this system is used, the coils are wound, braced, and connected before VPI impregnation with a thermosetting epoxy resin. The Coil VPI System is used when the stator assembly is too large to fit the impregnation tank. With this system, the coils are VPI impregnated with thermosetting epoxy resin and the straights are hot press cured before the coils are wound, braced, and connected. Both systems can be sealed to pass the NEMA MG1-20.48 water test.	Class F 155 °C 2300–15,000 V	Strands are insulated with synthetic enamel overlayed with glass braid. In most cases, interlayers of mica plates with a glass fabric and a resin binder are inserted between turns.	Complete coils are insulated with half-lap layers of Micanite tape, which is a glass-fiber-backed mica paper. The tape used on the coil straights is resin rich, whereas that on the endwindings has a low resin content.	Outer corona protection Coil straights are taped with a layer of semiconducting polyester mat tape. End corona protection. A semiconducting varnish with SiC filler or asbestos tape with a semiconducting varnish.	Glass-mat-based laminates or glass fabric-based laminates.	Rows of glass-fiber bandage are interwoven between coil heads. In the “STATOR VPI” System, this bandage absorbs epoxy resin during the VPI process, and after curing, the bandage gives rigid support to the endwindings. In the Coil VPI System, the bandage is impregnated with epoxy resin prior to it being fitted.	Silicon rubber-insulated cables.	Hipot tests are conducted atvarious stages of manufacture.	

AEG "EPITHERM INDIVID-UAL COIL INSULA-TION"Coils are completely processed before winding, bracing, and connection.	Class F 155 °C 2300 V to highest practical voltages	Strands are insulated with synthetic enamel overlayed with glass braid. In most cases, interlayers of mica plates with a glass fabric and a resinbinder are inserted between turns.	Coil straights are insulated with half-lap layers of resin-rich Micanite tape, which is cured by hot pressing prior to winding. The coil endwindings are insulated with a combination of varnished glass-fiber, elastic epoxy resin, impregnated spun polyester and Micanite [with an additional polyester film] tapes applied in half-lap layers. These tapes are also applied to the coil connections.	Outer partial discharge protection. Semiconducting varnish. End partial discharge protection. A semiconducting varnish with SiC filler or asbestos tape with a semiconducting varnish.	Glass-mat-based laminates or glass fabric-based laminates.	These are braced with nonshrinking, nonhygroscopic glass-fiber reinforced molded plastic spacers, bound tightly together by tapes and fastened to support rings padded with felt.	Silicon-rubber-insulated cables.	Tan delta tests are performed on complete coils prior to winding. Hipot tests are conducted at various stages of manufacture.	The coil endwindings remain flexible after final processing. This makes coil replacement easy.

TABLE B.2 AEG Micarex

Machine Type: Squirrel Cage Induction Motors, Hydro- and Turbine Generators, Wound Rotor Induction Motors, Synchronous Motors, and Generators

Location and Type of Winding: Stator, Half Coils, Sing and Multiturn Diamond

		Insulation							
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Strand and Turn	Groundwall	Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
ASEA MICAREX Resin-rich continuous mica paper tape system Certain motors have both form-pressed coils and VPI treatment	Class F 155°C 2300–15,000 V	Strand insulation (1) Strands are covered with glass fiber yarn and impregnated with epoxy. OR (2) MICAFOLD-enameled wire folded with NOMEX M OR (3) Enamel + glass fiber or enamel + Dacron glass OR (4) In Canada, single or double Dacron glass is sometimes used. Turn insulation (1) MICAFOLD [see Point 2 above] (2) Where strand insulation alternatives, 1 and 4 are used on multiturn coils, woven glass fiber-backed mica paper resin-rich, turn tape is applied around the strands. This, or some other material demanded by the customer, may also, in some instances, be applied to alternative (3). All straight parts of the bundles are consolidated before applying the groundwall tape.	Woven glass fiber-backed mica paper resin-rich tapes applied in half-lap layers A final layer of half-lap shrink tape is applied to coils without corona protection tape. The straight part is pressed to fine toleranced dimensions.	All coils have partial discharge preventing systems. Semiconducting varnish or tape on the straight parts and a stress-relieving coating on the coil ends.	Wedge or counter-wedge systems. Ripple springs are used in some cases. For generators, the roundwrap technique is used. A semiconducting tape, with a plastic filler is wrapped around the slot section before the coils are inserted. After curing, this system ensures that the coils fit tightly in the slot. Side packing with semiconducting material is sometimes used in Canada.	Large motors are braced with glass-fiber ropes, which are VPI treated. Well-proven system using felt, laminate, glass-fiber, and epoxy is also used. For generators, a hosesupport is used. A polyester hose is filled with epoxy. After application, to support the coil ends. Knuckles are insulated with mica tape and epoxy or with polyester caps and casting resin.	Mica resin-rich tape or dry mica tape plus epoxy.	Tan delta tip-up readings on separate coils. Strand and turn AC voltage tests Testing of partial discharge preventing system. Coil dimensions and shape.	The system was introduced in 1965. The VPI version for motors was introduced in 1980, that is, resin-rich + VPI

TABLE B.3 ASEA Micapact

Machine Type: Synchronous Motors

Location and Type of Winding: Stator Half Coils, Indirect or Direct Cooled

		Insulation							
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Strand and Turn	Groundwall	Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
ASEA MICAPACT- Coils are VPI'd with thermosetting epoxy resin prior to winding, bracing, and connection.	Class F 155 °C 10,000 V to highest practical voltages	Strands are covered with glass-fiber yarn impregnated with thermosetting epoxy resin. Strands are precoated with epoxy resin. Coil straights and ends are pressed to cure this resin and consolidate strands prior to the application of groundwall tape.	Low resin content woven glass fiber-backed mica paper tape applied in half-lap layers. This is impregnated with epoxy resin by a VPI process. The coil straights are then hot pressed to cure the resin and obtain fine toleranced dimensions to give a good coil-to-slot fit.	Prior to winding, the coils are coated with a semiconducting varnish on the straight part and a stress-relieving coating on the ends.	Counter-wedges are used. The wedges are made of glass-fiber-reinforced laminate. Some designs also include ripple springs. The midstick is made of laminate. A method called *round packing* is used for fitting the bar in the slot. Roundwrap consists of a semiconductive tape with an elastic filler mass. The tape is wrapped around the straight part before the coil is put in the slot. After curing, the system gives a perfect fit of the coil to the slot.	Different methods: 1. Fixed radial brace rings made from glass fiber-reinforced polyester plastic to which the coils are lashed with glass fiber cord. Packing held in place with glass-fiber cord or tape inserted between coils to give intercoil support. 2. Hose filled with epoxy gives all support needed between coil-planes straight part etc. The knuckles are insulated with glass-mica tape and epoxy resin or glassfiber caps filled with resin.	Glass fiber mica tape and epoxy resin or prefabricated interconnections and busbars. These are insulated the same way as the coils.	Tan delta tip-up readings are taken on each coil prior to winding. Coils are taken out for special high potential tests. Strand tests on each coil. Testing of the partial discharge preventing system. Coil dimensions and shape are checked.	This system was introduced in 1960. It was further developed and improved in 1976.

TABLE B.4 Brown Boveri Micadur

Machine Type: Hydrogenerator, Air Cooled

Location and Type of Winding: Stator

		Insulation							
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Strand and Turn	Groundwall	Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Brown Boveri MICADUR	Class F 155°C Up to 28 kV	Each strand is wrapped with glass silk thread and impregnated in synthetic resin. The strands are bonded together under heat and pressure to increase the mechanical strength.	Continuous tape automatically wound over the whole length of the bar. The tape is then vacuum impregnated with a synthetic resin and cured. The primary dielectric is small mica flakes. The back is glass fabric on which the mica flakes are held together by electrostatic forces without any binder. The impregnant is a solventless resin applied under vacuum and pressure. The bar is then pressed in molds and cured in an oven.	The slot portion is coated with a conductive low resistance corona varnish. This is applied over the groundwall surface of the finished bar. Inner anti-corona protection is provided by a semiconducting glass epoxy laminate between the conductor stack and the groundwall insulation. The overhang parts of the insulated bars are coated with a semiconducting varnish having a voltage-dependent resistance for the purpose of stress grading.	The slot wedge is of a one- or two-piece tapered type made of glass epoxy laminate. Glass epoxy laminates are also used just under the wedge, between the bars, slot side and slot bottom as filler, spacer and insulation strips.	A system of beams and rings is used, in which movement [radial and tangential] is primarily avoided by built-in compression. Axial movement of the entire assembly is permitted by elastic glass epoxy leaf springs. A wedge and tension bolt arrangement is also provided for retightening during maintenance outages. Spacer plates, spacer blocks wedges with tension bolts, leaf springs, and thermosetting packings are other components of the endwinding support. They are made of fiberglass reinforced with epoxy resin. The assembly is then flooded to give a 1-mm-thick layer of resin covering to prevent movement and to keep dirt out.	The insulation of winding connec-tions is achieved by main-taining the necessary spacing and by mica insulation tape with synthetic resin.	Raw materials inspected on arrival. Record sheets accompanying each element of the winding during manufacture are statistically evaluated for each machine. Automatic strand testing at 110 V AC between strands. On the finished bar tan delta tests up to twice rated voltage; AC hipot test at four times rated voltage and checking of partial discharge protection of endwinding at the same time.	Introduced around 1960.

TABLE B.5 Brown Boveri Micadur-Compact

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors, and Generators								Location and Type of Winding: Stator, Multiturn Diamond		
		Insulation								
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Strand and Turn	Groundwall	Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Brown Boveri "MICADUR COMPACT" VPI with thermosetting epoxy resin after coil winding, bracing, and connection. System can be sealed to pass the NEMA MG1-20.48 water test.	Class F 155°C 2300–21,000 V	Small machines—synthetic resin-impregnated glass fibers Large machines—glass-fiber-backed mica paper tape. When high surge withstand capability is required, conductor strands coated with enamel are used and glass-fiber-backed mica paper turn tape is applied on top of this.	Complete coils and connections are taped with half-lap layers of glass-fiber-backed mica paper tape. A final layer of glass armor tape is applied on top of the mica paper tape.	If voltage rating is above 3000 V, a layer of anti-partial-discharge tape is applied to the coil straights. If the voltage rating is above approximately 6000 V, overlapping bands of semiconducting anti-partial-discharge paint are applied to the coil endwindings.	Slot wedge material. Epoxy resin-bonded woven glass fiber. Glass-fiber slot packing is used in slot bottoms and between top and bottom coil legs. Special flexible glass tubing is fitted under the slot wedges.	Rows of flexible glass-fiber-filled woven glass tubing are interwoven between coil heads. When these are impregnated with epoxy resin during the VPI process and cured, they give a solid support to the endwindings.	Glass fiber-backed mica paper tape.	Individual coils are surge tested after they are inserted in the slots, but before they are connected. Coil ground insulation is hipot tested a number of times before VPI and after VPI. After VPI loss factor (tan δ), measurements are taken on each phase of the winding to determine the adequacy of impregnation.	The first machine of the above type with MICADUR COMPACT insulation was produced in 1965. Since then, more than 30,000 machines have gone into service.

TABLE B.6 Brush Electrical Machines Ltd. Epoxy Novolac

Machine Type: Squirrel Cage Induction Motors; Wound Rotor Induction Motors; Synchronous Motors and Generators							Location and Type of Winding: Stator, Multiturn Diamond		
		Insulation							
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Strand and Turn	Groundwall	Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Brush Electrical Machines Ltd. "EPOXY NOVOLAC" "Resin-rich" mica paper tapes are used. Coil straights are hot press cured prior to winding.	Class F 155°C Up to 16 kV	Strand insulation is polyester "M" enamel with a polyester film-backed mica tape overlay. The turn insulation consists of half-lap layers of polyester film-backed mica paper tape impregnated with Stage-B epoxy resin. The coil straights are hot pressed to consolidate the conductor stack prior to the application of the groundwall.	The coil straights are insulated with half-lap layers of filamic Novolac tape. The endwindings, leads, and connections are insulated with half-lap layers of elastomer Novolac, over which is applied a layer of Epoflex tape and finally a layer of Terylene tape. The coil straights are cured prior to winding by hot pressing to toleranced dimensions. After winding, connection, and bracing, the complete stator is baked to cure the endwinding, connection, and lead insulation. The outer layer of Terylene tape acts to compress this during the baking process. Finally, the complete stator is dripped or sprayed with varnish and baked.	Up to 5.9 kV: none Above 5.9 kV: conducting graphite bearing tape on slot portion, semiconducting stress relief tape on endwinding.	The slot wedges are made from synthetic resin-bonded fabric. Midsticks and other packing are made from permanite.	Coil radial bracing consists of insulated fixed steel rings, padded with Stage-B epoxy resin-impregnated felt. The coils are lashed to these with glass fiber tape. Rows of blocking are fitted between coils to restrict circumferential coil movement.	Flexible stranded cable, insulated as appropriate for the system voltage.	Hipot tests at various stages of manufac-ture.	The first version of this system was introduced in 1972.

TABLE B.7 Brush Electrical Machines Ltd. Insulation System for Turbine Generators

Machine Type: Small Air-Cooled, Two-Pole Turbine Generators — Location and Type of Winding: Stator, Half Coil

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Brush Electrical Machines Ltd. "INSULATION SYSTEM FOR TURBINE GENERATORS—CLASS F" "Resin-rich" mica paper tapes are used. Coil straights are hot press cured prior to winding.	Class F 155°C Up to 15 kV	Strand insulation is epoxy resin-impregnated woven glass braid. The turn insulation consists of a layer of glass fiber-backed mica paper impregnated with Stage-B epoxy resin. Conductor stack is hot pressed to consolidate it prior to the application of the groundwall.	The coil straights are insulated with half-lap layers of glass fiber-backed mica paper impregnated with Stage-B epoxy. The same material and application procedures are used to insulate the endwinding portions except that a few layers of polyester film tape are interspersed between the layers of mica paper to give flexibility during winding. An outer half-lap layer of Terylene tape is applied to the endwindings.	The slot portion is covered with a half-lap layer of conducting graphite bearing tape with semiconducting stress relief areas at the ends.	The wedges and midsticks are made from synthetic resin-bonded fabric. Stage-B epoxy resin-impregnated felt is inserted between the coils and the slot bottoms, midsticks, and wedges to restrict coil movement.	Radial bracking is provided by blocks of insulation mounted on brackets attached to the stator core endplates and between top and bottom coil legs. Felt impregnated with Stage-B epoxy resin is inserted between these blocks and the coils. The coils and connections are then lashed to the blocks with fiberglass tape.	Insulated copper busbar.	The polyester film tape used in the endwinding groundwall replaced mica flake insulation that was used until 1983.	

(*continued*)

TABLE B.7 (*Continued*)

Machine Type: Small Air-Cooled, Two-Pole Turbine Generators

Location and Type of Winding: Stator, Half Coil

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
			This shrinks to compress the endwinding insulation during heat curing. The coil straights are hot pressed to size prior to winding. After winding, the conductor strands are bent to form coil noses before being brazed together. Strands are then insulated with strips of pure mica and the turns with mica glass elastomer tape. Any spaces between conductors are filled with mica and compound before applying mica glass silicone tape groundwall insulation and a final layer of Terylene tape. The coil-to-coil and intercoil group connections are insulated in a similar manner. After bracing, the windings are given four coats of varnish and baked to fully cure all of the insulation to them.			Circumferential bracing is provided by rows of blocking inserted between coils and lashed to them with fiberglass tape.			

TABLE B.8 Canadian General Electric

Machine Type: Hydrogenerator, Air Cooled

Location and Type of Winding: Stator Winding

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Canadian General Electric MICA MAT	Class F 155°C 13.8 kV	Solid copper strands are insulated with Dacron glass. Priorto transposition, a Stage-B resin-impregnated separator strip is inserted between the two strand decks. The resin from the separator bonds the strands during a subsequent press and cure process under heat.	Continuous tape insulation is applied in several layers. This is finished cured to required size and shape ina steel mold. Curing involves a vacuum pressure impregnation process with thermosetting epoxy resin. The primary dielectric barrier is a mica paper tape. This is bonded toa woven glass fabric backer. Epoxy resin is used as the binder in the resin-rich tape.	Thermally cured armor in the slot portion. Thermally cured, silicon carbide grading material applied to bar arms for end grading. Longitudinal bands of CRTV and RTV [Twin Tone] are press molded to each side of the bar slot portion and cured. This produces an interference fit when inserted into the slot, and prevents slot discharge and bar vibration.	Polyester glass-filled two-piece wedge. Semi-conducting fillers are placed in the slot bottom and between the two bars. Glass matp olyester fillers are used on the top as required. Ripple springs are used between top fillers and wedges.	The bar ends are lashed to insulated support rings at top and bottom. A number of turns of glass roving, saturated with polyester resin are applied. The resin cures at room temperature ensuring tight support.	Dacron felt soaked in polyester resin is inserted between the insulated conductors and support blocks. A number of turns of glass roving, saturated with polyester resin, are then applied. They are applied as tensile loops around the conductor, through the clamp and between the conductor and clamp top and bottom to lock and tighten the wrap.	Incoming materials from vendors are checked and the results are recorded. Tapes and resins having limited shelf life are kept under refrigeration. After the copper bar is cured, the cross section is checked and every strand electrically tested using automatic strand tester. After the groundwall is cured on the bar, the cross section is checked again. The bar is also checked for shape.	This is the most modern insulation system used by CGE for hydrogenera-tors.

(*continued*)

TABLE B.8 (*Continued*)

Machine Type: Hydrogenerator, Air Cooled

Location and Type of Winding: Stator Winding

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
				A continuous CRTV surface along the full length of the bar ensures electrical equalization.				A random selection is made at this point for destructive testing. Electrical tests are performed on each bar including hipot, tip up, armor resistivity, and voltage endurance. After bar to slot "twin-tone" interface is applied, resistivity is checked lengthwise along the bar and sideways from the bar armor through the "twin-tone." Sample bars are produced early enough for extensive checks before production run can begin.	

Canadian General Electric Asphalt Mica	Class B 130°C 13.8 kV	Alternate strands are insulated with 17-mil-thick layer of Dacron glass fiber and bonded together with resin. The same material is used to build 75-mil-thick turn insulation.	About 300-mil-thick thermoplastic asphalt micasystem 2 or 3 pass process used in which mica paper or mica Dacron tape was hand wound to half or one-third of the final thickness. This was impregnated with asphalt under heat and vacuum followed by pressing in molds to desired shape and size. The whole process of taping and impregnation was repeated until the final insulation thickness was obtained.	Thermally cured semiconducting paint applied on the slot portion. Asbestos armor tape wound on top for positive grounding in the slot stress grading paint applied to bar ends starting with a half inch over-lap on the semiconductive paint extending out of the slot. The stress grading paint is continued past the first bend.	Maple blocks impregnated with paraffin, for moisture proofing. Alternatively, wedges were made of permalior textolite blocks. Semi-conductive textolite used for depth packing and center packing. Sidepacking not usually necessary as the bar was installed in the slot using interfer-ence fit.	The bar ends are lashed to insulated support rings resting on support brackets. Archbracing was provided by H-shaped woodblocks placed between coils to form a continuous circle.		This system was introduced by GE prior to 1950 and continued into the 1960s when the epoxy mica "MICA MAT"system was developed. The performance of machines with asphalt-mica insulation was sensitive to Quality Assurance exercised in manufacture to ensure lack of voids with in the ground wall insulation and to ensure positive contact between the insulated coiland the slot sides. On some machines, a layer of fiber glass tape was incorporated over the slot armor nearthe slot exit as a fire retardant in the event the asphalt began to flow out of the slot.

TABLE B.9 Canadian General Electric Mica Mat

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors and Generators

Location and Type of Winding: Stator Multiturn Diamond

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
CANADIAN GENERAL ELECTRIC COMPANY LIMITED "MICA MAT" [Varnished Coils] Individual coils are varnish dipped and baked prior to winding.	Class "B"130°C 2300 V – 7000 V	"Alkanex" enamel, polyester glass fibers or a combination of the two.	GE "Mica Mat" materials used to insulate coils and connections. This consists of reconstituted mica and glass cloth sandwiched between two layers of mylarfilm material. "Mica Mat" wrappers are used on the coil straights while a tape form of this material is used on the end heads and connections. An outer half lap layer of glasscloth armor tape is applied to the complete coil and connections. The coils are dipped in a Class "B" polyester varnish and baked prior to winding. After winding, bracing, and connections, the complete stator winding is given additional dips and bakes.	This is applied when the machine voltage rating exceeds 5200 V. Conducting paint is applied to the coil straights and this is overlapped with bands of semiconduct-ing grading paint or tape where the coil emerges from the slot. These tapes could be asbestos and should be treated accordingly.	Wedge material consists of a polyester glass laminate. Slot packing consists of polyester glass cloth laminate in the bottom of the slot. Between the coils, a laminate of glass matte with polyester film bonded to each side is used. The top of the slot is glass cloth laminate with polyester felt on the coil side only. Extra fillers are of the same material.	"Permafil" treated glass roving is used to lash the coils to insulated radial support rings and to one another. Rows of "Textolite" or wood blocking are inserted between coils to provide circumferential bracing. These are held in place by the "Permafil" roving material used to lash the coils together. After the completed winding has been dipped and baked the Permafil roving becomes solid and tough.	All connections are insulated with the same materials as in the coils. The number of layers vary with the voltage. This is over-taped with treated glass tape.	Coils are hipot and surge tested at various stages of manufacture.	This system was introduced to CGE Peterborough Plant in 1958. It was gradually phased out after the introduction of the Mica Mat Epoxy VPI System in 1968.

TABLE B.10 Canadian General Electric Low Voltage and Medium Voltage Mica Mat

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors and Generators							Location and Type of Winding: Stator, Multiturn Diamond		
		Insulation							
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Strand and Turn	Groundwall	Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
CANADIAN GENERAL ELECTRIC COMPANY LIMITED Low Voltage "MICA MAT" EPOXY VPI. VPI with thermosetting epoxy resin after coil winding, bracing, and connection. System can be sealed to pass the NEMA MG1-20.48 water test.	Class F 155°C 2300–7000 V	Alkanex enamel, polyester glass fibers or a combination of the two. It should however be noted that other materials may be used on large motors with high ratings. Bonding strips are applied between strands and on the sides of strands on the coil straight sections, which are consolidated by hot pressing prior to coil spreading.	GE "MICA MAT" materials used to insulate coils and connections. The original versions of this consisted of reconstituted mica with glass cloth sandwiched between two layers of Mylar film material. In small- and medium-sized machines, the coil straights are insulated with a "MICA MAT" wrapper, whereas in the large machines, a tape form of this material is used. The coil endwinding and connections are insulated with half-lap layers of "MICA MAT" tape. A half-lap layer of glass cloth armor tape is applied to the coils and connections.	This is applied when the machine voltage rating exceeds 5200 V. Conducting paint is applied to the coil straights and this is overlapped with bands of semiconducting grading paint or tape where the coil emerges from the slot. These tapes could be asbestos up to 1982 and should be treated accordingly.	Wedge material consists of a polyester glass laminate. Slot packing consists of conductive polyester glass cloth laminate in the bottom of the slot. Between the coils, a laminate of glass matte with polyester film bonded to each side is used. The top of the slot is conductive glass cloth laminate next to coil side covered with a glass cloth laminate with polyester felt bonded to one side. Extra fillers are made of the same material.	The GE tieless bracing system described below is used. Fixed outer insulated steel or polyester glass radial bracing rings are fitted to the coil arms. Floating inner polyester-impregnated glass ropes are used between top and bottom coil arms. A putty-like thermosetting polyester glass material is inserted between these rings and the coils. When heat cured, it provides both radial and tangential supports. Rows of absorbent felt pads are inserted between coils to provide additional tangential support and connections are blocked with felt and lashed to the coil noses.	All connectionsare insulated with the same materials as in the coils. The number of layers varies with the voltage. This is overtaped with treated glass tape.	Coils are hipot and surge tested at various stages of manufacture.	This system was introduced to CGE Peterborough Plantin 1968.

(*continued*)

TABLE B.10 (*Continued*)

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors, and Generators

Location and Type of Winding: Stator, Multiturn Diamond

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
CANADIAN GENERAL ELECTRIC COMPANY LIMITED Medium Voltage "MICA MAT" EPOXY VPI. VPI with thermosetting epoxy resin after coil winding, bracing, and connection. System can be sealed to pass the NEMA MG1-20.48 water test.	Class F 155°C 7001–14,000 V	"Alkanexenamel," polyester glass fibers or a combination of the two as strand insulation. It should however be noted that other materials may be used on large motors withhigh ratings. Turn insulation is Stage-B epoxy mica tape applied half-lap in multiple layers prior to bobbin winding. The turn tape is press cured after spreading.	GE "MICA MAT" materials used to insulate coils and connections. The original versions of this consisted of reconstituted mica with glass cloth sandwiched between two layers of Mylar film material. From 1977 to 1980, only the Mylar bearing "MICA MAT" tapes were used. After 1980, the first three layers next to the turn insulation were non-Mylar tapes, with the remaining layers being the Mylar bearing "MICA MAT." The coil endwinding and connections are insulated with half-lap layers of "MICA MAT" tape. A half-lap layer of glass cloth armor tape is applied to the coils and connections.	Conducting paint is applied to the coil straights and this is overlapped with bands of semiconduct-ing grading paint or tape where the coil emerges from the slot. The length of the grading varies with the voltage and the type of grading tape used. These grading tapes could be asbestos up to 1982 and should be treated accordingly.	Wedge material consists of a polyester glass laminate. Slot packing consists of conductive polyester glass cloth laminate in the bottom of the slot. Between the coils, a laminate of glass matte with polyester film bonded to each side is used. The top of the slot is conductive glass cloth laminate next to coil side covered with a glass cloth laminate with polyester felt bonded to one side. Extra fillers are made of the same material.	The GE tieless bracing system described below is used. Fixed outer insulated steel or polyester glass radial bracing rings are fitted to the coil arms. Floating inner polyester-impregnated glass ropes are used between top and bottom coil arms. A putty-like thermosetting polyester glass material is inserted between these rings and the coils. When heat cured, it provides both radial and tangential supports. Rows of absorbent felt pads are inserted between coils to provide additional tangential support and connections are blocked with felt and lashed to the coil noses.	All connections are insulated with the same materials as in the coils. The number of layers varies with the voltage. This is overtaped with treated glass tape.	Coils are hipot and surge tested at various stages of manufacture.	This system was intro-duced in 1977 at CGE Peterbor-ough plant.

TABLE B.11 Electric Machinery Duraguard VPI System

Machine Type: Squirrel Cage Induction Motors, Synchronous Motors and Generators

Location and Type of Winding: Stator, Multiturn Diamond

		Insulation							
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Strand and Turn	Groundwall	Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Electric Machinery "DURAGUARD-VPI System" Except for the large diameter machines coils are wound, connected, and braced before VPI impregnation with thermosetting epoxy resin. When stator assembly is too large for post-impregnation, coils are pre-VPI impregnated with Stage-B epoxy resin, which is fully cured after winding, bracing, and connection. Windings can be sealed to pass NEMA MG1-20.48 water test.	Class F 155°C 2300–15,000 V	Standard is polyester glass or amide imide film with polyester glass overlay. Polyester glass is usually used alone as strand insulation, but rarely used alone as turn insulation. When voltage between turns is high and/or high supply system surge voltages are expected, additional turn insulation in the form of mica paper tape is applied.	Endwindings and connections are insulated with half-lap layers of mica paper tape. Coil straights for smaller lower voltage machines are insulated with a mica paper sheet wrapper and those for the larger higher voltage ones with half-lap layers of mica paper tape. In all cases, a final half-lap layer of polyester glass tape is applied to the entire coil. When the coils are pre-VPI impregnated, the connections are insulated with Stage-B epoxy resin-impregnated mica papertapes.	For machines rated above 5 kV, an outer layer of conductive tape is applied to the slot portion of the coil. Stress grading materials are used to terminate the conductive tape.	Both mid and bottom sticks are fitted. Slot wedge material is polyester glass laminate.	Coil heads are lashed with polyester tape to fixed brace ring(s) padded with a thick layer of polyester felt. Polyester felt packing is inserted between coils. Supplementary glass rope support rings may be used on the coil endwindings and/or the connections. When the coils are preimpregnated with epoxy resin, the felt and glass rope used for bracing are preimpregnated with a Stage-B epoxy resin.		1. After completion of insulated coils: – a surge test. – a DC over potential test for voltage ratings of 5 kV and above. – a strand-to-strand test with 500 V Meggerif coils have transposed strands. 2. During the winding process: – a surge test of each coil after wedging. – a DC over potentialtest of coil groupsafter wedging and connection.	This system was introduced in 1971, and since this time, there have been significant improvements in the insulation materials and winding manufacturing processes. It is used on all form wound stators except for two-pole generators rated above 25 MVA. Two-pole turbine generators from the 1950s will have asphalt-impregnated coils with mica splitting tapes. In the late 1960s, the coils were impregnated with polyester resin for high voltage windings.

(*continued*)

TABLE B.11 (*Continued*)

Machine Type: Squirrel Cage Induction Motors, Synchronous Motors and Generators

Location and Type of Winding: Stator, Multiturn Diamond

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
								3. Upon completion of winding, connection, and bracing: – a DC over potential test on each phase of the winding. 4. After final impregnation and curing: – a DC over potential test on each phase. If voltage rating is 5 kV or higher, a step voltage test is performed. – a dissipation factor test on each phase if rating is above 5 kV. – a water immersion test if sealed winding capability is to be verified.	This was changed to the Duraguard process in 1978 for generators up to 25 MVA. Larger generators up to 100 MVA had polyester resin-impregnated coils. In 1987, the system will bechanged to epoxy resin-impregnated mica paper tapes.

TABLE B.12 General Electric Micapal

Machine Type: Turbine Generator

Location and Type of Winding: Stator, Direct Liquid Cooled

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
General Electric "MICAPAL"	Class B 130°C 10–260 kV	Solid and hollow copper strands are insulated with flocked asbestos, bonded with phenolic varnish. Two "vertical" separator strips, containing Stage-B epoxy resin for bonding of strands, are placed between pairs of strand tiers after transposition. Four- and six-strand-wide bars from sets of these two-strand-wide transposed tiers.	A resin-rich tape is machine-applied over the whole bar in several continuous layers. It is then cured under vacuum pressure process. The primary dielectric tape consists of mica flake and mica paper. The mica in these materials is sandwiched between a woven glass fabric and a thin layer of nonwoven polyester fabric. Epoxy resin with solvent is used as the binder.	Slot armor consists of asbestos cloth tape coated with semiconducting varnish. Slot end suppression is provided by asbestos-based tape graded down in thickness from the slot exit.	Cotton cloth phenolic two-piece tapered wedge to apply radial pies sure. Side ripple spring to provide lateral pressure. Conforming material in bottom and mid slots. Slot contents are consolidated by hosemolding, whereby a hose is placed between the top bar and a temporary wedge is pressurized while the winding is heated.	The entire endwinding cage is secured to prevent radial arid circumferential movements. The support system can move axially in response to thermal expansion cycles. Outer axial support arms are mounted to the stator flange by support brackets, which permit the axial movement. Support rings of polyester resin and glass fiber are mounted on the support arms and placed between top and bottom bars.	Armored with resin-impregnated glass tape. Held in polyester glass laminated clamps with cured, conforming material against the lead surfaces. Heavy-duty glass roving is also used for support.	Resin reactivity, viscosity, and other material tests, strand-to-strand test, hipot test at four steps, and insulation resistance check. A sample bar from each machine is given a battery of tests including tan delta and destructive tests.	The first machine with this insulation began service in 1954. It was phased out over several years after new system was introduced in 1976. The endwinding bracing system described has the trade name Tetra-Loc.

(*continued*)

TABLE B.12 (*Continued*)

Machine Type: Turbine Generator

Location and Type of Winding: Stator, Direct Liquid Cooled

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
		The slot section of the strands is consolidated by molding before taping of the groundwall. For two-turn windings, epoxy mica is applied as turn insulation.	The resin is contained in the preimpregnated tape and is applied during taping. It is cured by thermosetting in an autoclave, using modified bitumen as the pressure medium. Air and solvents are drawn off during the vacuum pressure cycle to minimize voids.		The conforming material at the bottom and mid slots is impregnated with epoxy. The side ripple spring is loaded with conducting material to ensure electrical contact with slot walls.	Resin-impregnated glass-fiber ties secure the rings to the support arms, the top bars to the bottom bars, and the top bars to the rings. An additional polyester-resin glass fiber “nose ring” is located on the layer of top bars just inboard of the series loops. It is secured to support amiss by adjustable tension resin-impregnated and glass roving straps, which provide additional radial restraint. The stator bars are impressed deeply into conforming radial blocking strips placed between the bars and the rings. The blocks also provide tangential restraint as do resin-impregnated glass fiber straps, which encircle adjacent bars.			

TABLE B.13 General Electric Micapal II

Machine Type: Turbine Generator

Location and Type of Winding: Stator, Direct Liquid Cooled

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
General Electric "MICAPAL II"	Class B 130°C Up to 30 kV	Early machines used flocked asbestos with phenolic varnish. After approximately 1979, each strand was wrapped with two layers of continuous filaments of glass fiber and treated with epoxy varnish. This process was phased in over several years. Two "vertical" separator grips, containing Stage-B epoxy resin for bonding, are placed between pairs of strand tiers.	A resin-rich tape is machine-applied continuously over the whole bar in several layers. It is then cured under vacuum pressure process. The primary dielectric consists of mica paper. It is sandwiched between a woven glass fabric and a thin nonwoven polyester fabric. The tape is preimpregnated with solventless epoxy resin. The groundwall is thermosettingly cured in an autoclave having modified bitumen as the pressure medium.	Slot armor consists of asbestos cloth tape coated with semiconducting varnish. In 1981, the asbestos armor was phased out and replaced by glass. End suppression is provided by semiconductive impregnated tape.	Cotton cloth phenolic two-piece tapered wedge to apply radial pressure. Side ripple spring to provide lateral pressure. Conforming material in bottom and mid slots. Slot contents are consolidated by hose-molding whereby a hose is placed between the top bar and temporary wedges is pressurized while the winding is heated. The conforming material at the bottom and mid slots is impregnated with epoxy resin.	The entire endwinding cage is secured to prevent radial and circumferential movements. The support system can move axially in response to thermal expansion cycles. Outer axial support arms are mounted to the stator flange by support brackets, which permit the axial movement. Support rings of polyester resins and glass fiber are mounted on the support arms and placed between top and bottom bars.	Armored with resin-impregnated glass tape. Held in polyester glass-laminated clamps with cured conforming material against the lead surfaces. Heavy-duty-glass roving is also used for support.	Resin reactivity, viscosity and other material tests, strand-to-strand test, hipot test at four steps, and insulation resistance check. A sample bar from each machine is given a battery of tests including tan delta and destructive tests.	The first machine with this insulation entered service in 1976. The differences from its predecessor are (1) elimination of mica flakes and exclusive use of mica paper as the dielectric barrier in groundwall insulation; (2) use of epoxy binder that can be used without solvent; and (3) addition of a nonwoven fabric backer to the insulating tape composite.

(*continued*)

TABLE B.13 (*Continued*)

Machine Type: Turbine Generator — Location and Type of Winding: Stator, Direct Liquid Cooled

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
		Four- and six-strand-wide bars are built up from sets of these two-strand-wide transposed tiers. The strands are consolidated under heat and pressure before taping of the groundwall.	Thick L-shaped support pieces enclose the bar to help shape and size the slot section in autoclave.		The side ripple spring is loaded with semiconducting material to ensure electrical contact with slot walls.	Resin impregnated as fiber to secure the rings to the support arms, the top bars to the bottom bars, and the top bars to the rings. An additional polyester-resin glass-fiber "nose ring" is located on the layer of top bars just inboard of the series loops. It is secured to support arms by adjustable tension resin-impregnated, glass roving straps, which provide additional radial restraint. In the late 1970s, the "nose ring" and straps were replaced, with a blocking and glass fiber tie system between series loops, series loops and connection ring ends, and connection ring back sets and the support structure to provide better support in this region. The stator bars are impressed deeply into conforming radial blocking strips placed between the bars and the rings. The blocks also provide tangential restraint as do resin-impregnated glass fiber straps, which encircle adjacent bars.			The changes were made to avoid uncertain supply of flake mica to simplify and improve control of production processes and to improve mechanical properties.

TABLE B.14 General Electric

Machine Type: Medium-sized Turbine Generator

Location and Type of Winding: Stator, Diamond

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
General Electric "Asphalt-Mica Insulation System"	Class B 130°C	Strand insulation is Dacron glass fiber wherein the Dacron fuses at processing temperature to solidify the structure. A single-layer "vertical" separator strip is placed between the two strand tiers during transposition. The strands are consolidated under pressure before taping of the groundwall insulation.	An unimpregnated tape is applied continuously over the whole bar in several layers. The primary dielectric consists of layers of mica paper with a selected number of layers of mica flakes. It is sandwiched between layers of Mylar or paper. One or two glass cloth strips that run the length of the bar may be included to control the effects of thermal expansion in service. In a vacuum pressure cycle, asphalt impregnates the groundwall.	Bar armored in the slot section with asbestos or Nomex-based material applied as a tape and painted with semiconducting paint.	Cotton fabric phenolic wedges are used to apply radial pressure on the bars in the slot.	A conformable system uses soft oversize impregnated felt between the armature bars and binding bands. The resin in the felt is cured by subsequent heating. The binding bands are supported from the core end clamping structure by outer axial supports.	Leads of stranded untransposed conductors are insulated with the same system as the bars. They are supported on the outer axial supports of the endwinding support system.	Individual coils and assembled winding are subjected to AC overpotential tests at set stages of manufacture. Insulation resistance and polarization index are measured.	

(*continued*)

TABLE B.14 (*Continued*)

Machine Type: Medium-sized Turbine Generator

Location and Type of Winding: Stator, Diamond

		Insulation							
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Strand and Turn	Groundwall	Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
General Electric "MICAPAL HT Armature Insulation System"	Class F 155°C	Strand insulation is Dacron glass fiber wherein the Dacron fuses at processing temperature to solidify the structure. A single-layer "vertical" separator strip containing Stage-B resin for bonding of the strands is placed between the two strand tiers during transposition. The strands are consolidated under pressure before taping of the groundwall insulation.	A resin-rich tape is machine applied continuously over the whole bar in several layers. It is then cured in a vacuum-pressure process. The primary dielectric barrier consists of mica paper with glass fabric backing. The tape is preimpregnated with epoxy resin. The thermoset groundwall is the result of curing in a hydraulic autoclave.	Asbestos or Nomex-based armor is taped over the insulation in the slot section and is painted with semiconducting paint. End arms are graded electrically outside the slot using silicon carbide tape.	Cotton fabric phenolic wedges are used to apply radial pressure on the bars in the slot. A "herring-bone" pattern allows the wedge to deflect during wedging thereby permitting radial followup should shrinkage occur in the slot contents.	A conformable system uses soft oversize impregnated felt between the armature bars and binding bands. Theres in in the felt is cured by subsequent heating. The binding bands are supported from the core end clamping structure by outer axial supports	Leads of stranded untransposed conductors are insulated with the same system as the bars. They are supported on the outer axial supports of the endwinding support system.	Individual coils and assembled winding are subjected to AC over potential tests at set stages of manufacture. Insulation resistance and polarization index are measured.	

TABLE B.15 General Electric Company

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors and Generators

Location and Type of Winding: Stator, Multiturn Diamond

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
GENERAL ELECTRIC COMPANYGE "MICA MAT" epoxy VPI. After coil insertion, connection, and bracing, the wound stator is given multiple VPI treatments in a thermosetting epoxy resin. System can be sealed to pass the NEMA MG1-20.48 water test.	Class F [155°C] 2300–7000 V	Prior to 1984, polyimide-enameled wire or combination of enameled wire overlapped with polyester glass or glass fibers. After 1984, a corona-resistant-filled polyester-enameled wire or combination of filled enameled wire overwrapped with polyester glass or glass fibers.	GE "MICA MAT" is used to insulate the coils. "MICA MAT" is constructed of a resin-saturated mica composite sandwiched between glass and polyester film for added strength and protection. In small- and medium-sized machines, the coil straight sections are insulated by wrapping with a "MICA MAT" sheet.	Partial discharge protection is applied when the machine voltage rating equals or exceeds 5200 V. Prior to 1984, conducting paint was applied to the straight sections of the coil. The conducting paint was overlapped with a semiconducting paint or tape where the coil emerges from the slot. After 1984, a conducting tape was applied on the coil straight sections in place of the glass armor.	The coil is wedged the entire length of the stator core. The wedges are made of polyester glass laminates or polyester glass pultrusions overwrapped with glass cloth. Slot packing is polyester fiberglass fillers and a felted Nomex [or varnished glass] filler is placed between the top of the coil and the wedge. This prevents the wedge from damaging the coil, and when the felt is VPI resin impregnated, it forms a solid blocking for a secure fit of the coils in the slot.	The coil end projections are braced using the GE Coil-Lock Bracing. The bracing consists of the following: Absorbent felt-covered fiberglass rope[s] between the top and bottom coil arms. Rows of absorbent felts are inserted between coil arms in the winding. When resin impregnated during VPI and cured, they provide solid blocking. A thermosetting polyester putty is rolled onto the OD of the winding end projection such that it penetrates between coil arms.	The connections and circuit rings are insulated and armored with the same tapes used in the groundwall insulation.	Coils are high potential tested and surge tested at various stages of manufacture.	This Class F VPI insulation system was introduced in the early 1970s at the LM&G Schenectady plant.

(*continued*)

TABLE B.15 (*Continued*)

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors and Generators

Location and Type of Winding: Stator, Multiturn Diamond

		Insulation							
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Strand and Turn	Groundwall	Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
		Bond strips are applied by hot pressing to the sides of the strands to consolidate the straight section of the coil prior to spreading.	On large machines, the coil straight sections are insulated with multiple half-lapped layers of "MICA MAT" tape. The coil leads and end projections are insulated with multiple half-lapped layers of "MICA MAT" tape. The entire coil and leads are taped with a half lap of glass armor tape.	The conducting tape is then overlapped with a semiconducting tape or paint where the coil emerges from the slot.		A steel outer ring is then positioned over the polyester putty. This metal ring is then attached to the stator core with steel brackets. When cured, it provides both radial and tangential supports. Additional rings may be applied on the OD and ID of the stator winding depending on size and rating. Permafil roving is used to attach and support the connection bundle on the end of the stator winding. On larger machines, this roving is used to tie coils to the metal bracing ring[s] for added support.			

GENERAL ELECTRIC COMPANY "MICA MAT" epoxy VPI [vacuum pressure impregnation]. After coil insertion, connecting, and bracing, the wound stator is given multiple VPI treatments in a thermosetting epoxy resin. System can be sealed to pass the NEMA MG1-20.48 test.	Class F [155°C] 7001–14,000 V	Prior to 1985, glass overwrap was used as strand insulation and the turn insulation was made up of half-lapped layer[s] of "MICA MAT" tape. Since 1985, a partial discharge-resistant-filled polyester enamel has been used as strand insulation and the turn insulation is made up of half-lapped layer[s] of "MICA MAT" tape.	GE "MICA MAT" is used to insulate the coils. "MICA MAT" is constructed of a resin-saturated mica composite sandwiched between glass and polyester film for added strength and protection. The coil straight sections, end projections, and leads are insulated with multiple half-lapped layers of "MICA MAT" tape. The entire coil and leads are taped with a half lap of glass armor tape.	All 7001–14,000 V machines have partial discharge protection. Prior to 1984, conducting paint was applied to the straight sections of the coil. The conducting paint was overlapped with a semiconducting paint or tape where the coil emerges from the slot. After 1984, a conducting tape was applied on the coil straight sections in place of the glass armor.	The coil is wedged the entire length of the stator core. The wedges are made of polyester glass laminates, or polyester glass pultrusions overwrapped with glass cloth. Slot packing is polyester fiberglass and a felted Nomex [or varnished glass] filler is placed between the top of the coil and the wedge.	The coil end projections are braced using the GE "Coil-Lock Bracing." The bracing consists of the following: Absorbent felt-covered fiberglass rope[s] between the top and bottom coil arms. Rows of absorbent felts are inserted between coil arms in the winding. When resin impregnated during VPI and cured, they provide solid blocking. A thermosetting polyester putty is rolled onto the OD of the winding end projection such that it penetrates between coil arms.	The connections and circuit rings are insulated and armored with the same tapes used in the groundwall insulation.	Coils are high potential tested and surge tested at various stages of manufacture.	This high voltage Class F insulation system was introduced in the early 1970s at the LM&G Schenectady plant.

(*continued*)

TABLE B.15 (*Continued*)

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors and Generators

Location and Type of Winding: Stator, Multiturn Diamond

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
		Prior to 1985, a bond strip was applied by hot pressing to one side of the turns to consolidate the straight section of the coil prior to spreading. Since 1985, bond strips are applied by hot pressing between turns to consolidate the straight section of the coils prior to spreading.	GE "MICA MAT" is used to insulate the coils. "MICA MAT" is constructed of a resin-saturated mica composite sandwiched between glass and polyester film for added strength and protection. The coil straight sections, end projections, and leads are insulated with multiple half-lapped layers of "MICA MAT" tape. The entire coil and leads are taped with a half lap of glass armor tape.	This conducting tape is then overlapped with a semiconducting tape or paint where the coil emerges from the slot.	This prevents the wedge from damaging the coil, and when the felt is VPI resin impregnated, it forms a solid blocking for a secure fit of the coils in the slot.	An insulated steel outer ring is then positioned over the polyester putty. This metal ring is then attached to the stator core with steel brackets. When cured, it provides both radial and tangential supports. Additional rings may be applied on the OD and ID of the stator winding depending on size and rating. Permafil roving is used to attach and support the connection bundle on the end of the stator winding. On larger machines, this roving is used to tie the coils to the metal bracing ring[s] for added support.			

TABLE B.16 General Electric Company

Machine Type: Synchronous Motors, Synchronous Generators

Location and Type of Winding: Rotor, Salient Pole

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
GENERAL ELECTRIC COMPA-NYASPHALT MICA	Class B 7001–14,000 V	A glass overwrap was used as strand insulation, and the turn insulation was made of half-lapped layer(s) of asphalt mica tape.	Asphalt mica tape was used to insulate the coils. The coil straight sections, end projections, and leads were insulated with multiple half-lapped layers of asphalt mica tape. The insulated coils then were treated in hot asphalt under pressure to impregnate and consolidate the insulation. The entire coil and leads were taped with a half lap of asbestos armor tape. The coils had to be heated prior to winding to make them flexible for insertion.	All 7001–14,000 V machines received partial discharge protection. Conducting paint was applied to the straight sections of the coil. The conducting paint was overlapped with a semiconducting paint or tape where the coil emerges from the slot.	The coil is wedged the entire length of the stator core. The wedges were made of cotton laminates. Slot packing was semiconducting cotton phenolic laminate fillers.	The coil end projections were braced using the following: Fiberglass rope(s) between the top and bottom coil arms. An insulated steel outer ring was positioned over the end projections of the winding. This metal ring is then attached to the stator core with steel brackets. Additional rings were used depending on machine rating. These rings provide radial and tangential supports. Cotton phenolic blocks were placed between coil arms. Permafil roving was used to attach and support the connection bundle on the end of the stator winding. This roving was also used to tie the coils to the bracing ring and also the blocks between coils.	The connections and circuit rings are insulated and armored with the same tapes used in the groundwall insulation. A resin was brushed in between tape layers.	Coils were high potential tested and surge tested at various stages of manufacture.	This high voltage Class B insulation system is no longer produced by LM&G. It was replaced by the high voltage Class F VPI insulation system, which was introduced in the early 1970s.

(*continued*)

TABLE B.16 (*Continued*)

Machine Type: Synchronous Motors, Synchronous Generators

Location and Type of Winding: Rotor, Salient Pole

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
GENERAL ELECTRIC COMPANY Low Voltage "MICA MAT" epoxy VPI [Class-13] After coil insertion, connecting, and bracing, the wound stator is given multiple VPI treatments in a thermosetting epoxy resin. System can be sealed to pass NEMA MG1-20.48 water test.	Class B [130°C] 2300–7000 V	Prior to 1984, "Alkanex"-enameled wire or combination of enameled wire overwrapped with polyester glass or glass fibers. After 1984, a partial discharge-resistant-filled polyester-enameled wire or combination of filled enameled wire overwrapped with polyester glass or glass fibers.	GE "MICA MAT" is used to insulate the coils. "MICA MAT" is constructed of a resin-saturated mica composite sandwiched between glass and polyester film for added strength and protection. In small- and medium-sized machines, the coil straight sections are insulated by wrapping with a "MICA MAT" sheet. On large machines, the coil straight sections are insulated with multiple half-lapped layers of "MICA MAT" tape.	Partial discharge protection is applied when the machine voltage rating equals or exceeds 5200 V. Prior to 1984, conducting paint was applied to the straight sections of the coil. The conducting paint was overlapped with a semiconducting paint or tape where the coil emerges from the slot. After 1984, a conducting tape was applied on the coil straight sections in place of the glass armor.	The coil is wedged the entire length of the stator core. The wedges are made of polyester glass laminates or polyester glass pultrusions overwrapped with glass cloth. Slot packing is fiberglass fillers and a felted Nomex [or varnished glass] filler is placed between the top of the coil and the wedge.	The coil end projections are braced using the GE "Coil-Lock Bracing." The bracing consists of the following: Absorbent felt-covered fiberglass rope[s] between the top and bottom coil arms. Rows of absorbent felts are inserted between coil arms in the winding. When resin impregnated during VPI and cured, they provide solid blocking. A thermosetting polyester putty is rolled onto the OD of the winding end projections such that it penetrates between coil arms. A steel outer ring is then positioned over the polyester putty. This metal ring is then attached to the stator core with steel brackets.	The connections and circuit rings are insulated and armored with the same tapes used in the groundwall insulation.	Coils are high potential tested and surge tested at various stages of manufacture.	This class B VPI insulation system was introduced in 1966 at the LM&G Schenectady plant.

GENERAL ELECTRIC COMPANY Low Voltage "MICA MAT" epoxy VPI [Class-13] After coil insertion, connecting, and bracing, the wound stator is given multiple VPI treatments in a thermosetting epoxy resin. System can be sealed to pass NEMA MG1-20.48 water test.	Class B [130°C] 2300–7000 V	Bond strips are applied by hot pressing to the sides of the strands to consolidate the straight section of the coil prior to spreading.	The coil leads and end projections are insulated with multiple half-lapped layers of "MICA MAT" tape. The entire coil and leads are taped with a half lap of glass armor tape.	This conducting tape is then overlapped with a semiconducting tape or paint where the coil emerges from the slot.	This prevents the wedge from damaging the coil, and when the felt is VPI resin impregnated, it forms a solid blocking for a secure fit of the coils in the slot.	When cured, it provides both radial and tangential supports. Additional rings may be applied on the OD arid ID of the stator winding depending on size and rating. Perrnafil roving is used to attach and support the connection bundle on the end of the winding. On larger machines, this roving is used to tie the coils to the metal bracing ring[s] for added support.

TABLE B.17 Louis Allis

Machine Type: Squirrel Cage Induction Motors

Location and Type of Winding: Stator, Multiturn Diamond

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation			Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
		Strand and Turn	Groundwall	Partial Discharge Protection					
Louis Allis "ARMOR-SEAL" VPI with thermosetting epoxy resin after coil winding, bracing, and connection. Windings can be sealed to pass NEMA MG1-20.48 water test.	Class F 155°C 2300–13,200V	Heavy polyester film and double wrap of fused polyester glass yarn.	Glass-backed epoxy resin-bonded mica paper tape applied in half-lap layers around complete coil. An abrasion-resistant covering of glass tape is applied over the groundwall.	—	—	Rope or fixed padded radial brace ring[s] at each end. Felt blocking applied between coils.		—	This system was introduced around 1970.
Louis Allis "ARMOR-COTE" After coil winding, bracing, and connection, complete winding is cycled through a series of immersions in epoxy varnish and oven bakes.	Class F 155°C 2300–13,200 V	Heavy polyester film and double wrap of fused polyester glass yarn. A shrink tape and epoxy adhesive are applied to the coil straights and hot pressed to consolidate them before application of groundwall.	Glass-backed epoxy resin-bonded mica paper tape impregnated with polyester varnish applied around complete coil. An abrasion-resistant covering of glass tape is applied over the groundwall.	—		Rope or fixed padded radial brace ring[s] at each end. Felt blocking applied between coils.	—	—	The present version of this system was introduced in 1978.

TABLE B.18 NEI Peebles Electric Products

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors and Generators

Location and Type of Winding: Stator, Multiturn Diamond

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
NEI Peebles Electric Products "MICAPAC" "Resin-rich" tapes and wrappers used for groundwall. Coil processing is completed prior to winding. This system is qualified for Class 1E Nuclear Applications [IEEE Std 323]	Class F 155°C 2300–7200 V	Depends on peak volts/turn [PVPT]. Up to 30 PVPT-fused double Dacron glass 31–50 PVPT-fused double Dacron glass over heavy synthetic enamel 51–100 PVPT-mica paper over heavy synthetic enamel. Coil straights are painted with epoxy resin and hot press cured to consolidate the conductor stack prior to the application of the groundwall insulation.	Glass-backed mica paper wrappers impregnated with Stage-B epoxy resin are used on the coil straights and a tape form of this material is applied half lap to the endwindings. Coil leads are insulated with a single or double layer of acrylic glass sleeving for lower voltages. For higher voltages, this may be covered, or replaced, with mica paper tape. The complete coil is taped with one half-lap layer of Dacron glass, and at this time, lead exits are sealed with silicone rubber [RTV]. The coil straights are hot pressed to toleranced dimensions dipped and baked in polyester varnish prior to winding.	None up to 5000 V. Coil straights are coated with semiconducting paint [3–30 kilohms per square] for 5000–7200 V. No grading.	Polyester glass laminate or Epoxy glass laminate or polyester glass semiconducting laminate [1–10 kilohms/square] for 5000–7200 V. Aramid paper slot liner up to 5000 V. Semiconducting laminate side panels for 5000–7200 V.	Five classes based on fault or starting duty insulated steel or Stage-B glass-polyester rope surge rings fixed or floating 13-stage glass polyester ties. Stage-B polyester mat blocks and padding. Stage-B glass polyester cord diamond ties.	Jumpers are insulated the same way as coil leads. Connections are sealed with silicone rubber and double or triple sleeved if bayonet type and/or padded with Stage-B polyester mat seal, half lap taped with Stage-B mica paper tape and Dacron glass tape if loop type. Leads are ethylene-propylene or silicone rubber cables with fine stranding. Stage-B glass-polyester tape chain ties.	In process: (1) Hipot 1.25 [$2E + 1$] kV RMS, 60 Hz, 5 s. (2) Surge 1.77 [$2E + 1$] kV peak/group < 0.2 μs rise, 5 s. Sampling: Two coils/set or 1% of production batch. (1) Delta tan delta (2) Breakdown/side (3) Endturn breakdown Acceptance per ANSI/NEMA MG1.	This system is used for standard industrial applications.

(*continued*)

TABLE B.18 (*Continued*)

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors and Generators

Location and Type of Winding: Stator, Multiturn Diamond

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
NEI Peebles Electric Products "MICAPAC l" "Resin-rich" tapes and wrappers used for groundwall. Complete coils are cured prior to winding, bracing, and connection.	Class F 155°C 7201–18,000 V	Strands are insulated with either fused double Dacron glass, heavy synthetic enamel, or both up to 50 V PVPT. If the PVPT > 50 V for each 50 V, one half-lap layer of glass fiber-backed mica paper turn tape is applied. Coil straights are painted with epoxy resin and hot press cured to consolidate the conductor stack prior to the application of the groundwall insulation.	Glass fiber-backed mica paper wrappers, impregnated with Stage-B epoxy resin, are used on the coil straights and a tape form of this material is applied half lap to the endwindings and coil leads. At this time, silicone rubber [RTV] lead seal is also applied. The complete coil is covered with an outer half-lap layer of glass fiber armor tape. A sacrifice layer of shrink tape is then applied to the endheads and leads.	Prior to winding, conducting varnish, with bands of semiconductive varnish at the ends, is painted on to the coil straights and endturn bends. Semiconducting laminates are used for slot wedging and packing. Coil straights are painted 1–1.5″ past the core ends with 3–30 kilohms per square resistivity paint.	Polyester-glass semiconducting laminates [1–10 kilohms per square] wedges, fillers and separators. RTDs embedded in separators. Polyester-glass semiconductinglaminate [1–10 kilohms per square] side panels.	Five classes based on fault or starting duty insulated steel or Stage-B glass polyester rope surge rings fixed or floating. Stage-B glass polyester ties. Stage-B polyester mat blocks and padding. Stage-B glass polyester cord diamond ties.	Jumpers are insulated the same way as the coil leads. Loop-type connections are padded with Stage-B Dacron felt and insulated with Stage-B mica-glass tape. One half-lap layer of Stage-B Dacron-glass armor tape covers insulation. Leads are ethylene propylene or silicone rubber unshielded with fine stranding.	In process: (1) Hipot 1.3 [$2E + 1$] kV RMS, 60 Hz, 60 s individual coils. 1.25 [$2E + 1$] kV RMS, 60 Hz, 5 s coil groups in slots (2) Surge 1.77 [$2E + 1$] kV peak/group, 5 s <0.2 μs rise. Sampling: two coils/set but not less than 1% of each production batch. (1) Delta tan delta (2) Breakdown per side (3) Endturn breakdown Acceptance: Per ANSI/NEMA MG-1 RTD leads have metallic armor grounded.	This insulation system is used for normal high voltage industrial applications.

	The coil straights are hot pressed to toleranced dimensions, and then complete coils are baked to cure and consolidate the groundwall. Prior to winding, the coils are given a final dip and bake in varnish. After winding, bracing, and connection, the connections are insulated with half-lap layers of glass fiber-backed mica paper tape impregnated with Stage-B epoxy resin and outer layer of glass armor tape. The entire stator is then baked to cure the connection insulation.	Grading bands are 5–5.5″ wide painted 0.5″ overlapping with 10 Ω to 10 megohms per square resistivity paint.		Steel cable hangers are padded with Stage-B Dacron felt. All ties are Stage-B glass polyester.

TABLE B.19 NEI Peebles Electric Products

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors and Generators

Location and Type of Winding: Stator, Multiturn Diamond

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
NEI Peebles Electric Products "MI-CASEAL II" "Resin-rich" tapes and wrappers used for groundwall. Coil straights are cured by hot pressing prior to winding. Bondable epoxy mat tape layer seals against moisture and resists dynamic abrasion.	Class F 155°C 2300–7200 V	Depends on peak volts/turn [PVPT]. Up to 30 PVPT-fused double Dacron glass 31–50 PVPT-fused double Dacron glass over heavy synthetic enamel. 50–100 PVPT-mica paper over heavy synthetic enamel. Coil straights are painted with epoxy resin and hot press cured to consolidate the conductor stack prior to the application of the groundwall insulation.	Glass-backed mica paper wrappers impregnated with Stage-B epoxy resin are used on the coil straights, and a tape form of this material is applied half lap to the endwindings. Two outside half-lap layers of Stage-B epoxy mat tape are then applied. Finally, one half-lap layer of Dacron/Mylar tape is applied to the coil straights and Dacron tape to the endwindings. The coil leads are insulated with layers of varnished mat tape and two outer layers of Stage-B mat tape applied half lap. At this time, epoxy paste lead seal is applied.	None up to 5000 V. Coil straights are coated with semiconducting paint [3–30 kilohms per square] for 5000–7200 V.No grading.	Polyester-glass laminate or Epoxy-glass laminate or polyester-glass semi-conducting laminate [1–10 kilohms/square] for 5000–7200 V. Aramid paper slot liner up to 5000 V or semiconducting laminate for 5000–7200 V.	Five classes based on fault or starting duty insulated steel or Stage-B glass-polyester rope surge rings, fixed or floating. B-stage glass polyester ties, Stage-B polyester mat blocks and padding. Stage-B glass polyester cord diamond ties.	Jumpers are insulated the same way as coil leads. No bayonet connections permitted. Loop-type connections are padded with varnished Dacron mat tape, sealed with epoxy putty and V, lap Stage-B epoxy mat tape [two layers]. Leads are ethylene-propylene rubber with fine stranding. Stage-B glass polyester tape chain ties.	In-process: (1) Hipot 1.25 [$2E + 1$] kV RMS, 60 Hz, 5 s. (2) Submersion 1.25 E [RMS, 60 Hz] 60 s submerged <0.2 μs rise 5 s. Sampling: two coils/set or 1% of each production batch. (a) Delta tan delta (b) Breakdown per sidec] Endturn breakdown Acceptance: Per ANSI/NEMA MG-1.	This system is used for severe moisture and corrosive atmosphere applications. Also used in abrasive particulate environments.

This system is capable of passing ANSI/NEMA MG-1-20 water test.			The coil straights are hot pressed to toleranced dimensions prior to winding. After winding, bracing, and connection, the connections are insulated in the same manner as the endwindings. Final treatment of completed winding involves baking and coating with varnish.						
NEI Peebles Electric Products "Micaseal III" "Resin-rich" tapes and wrappers used for groundwall.	Class F 155°C 7201–18,000 V	Strands are insulated with either fused double Dacron glass, heavy synthetic enamel, or both.	Glass fiber-backed mica paper wrappers, impregnated with Stage-B epoxy resin, are used on the coil straights and a tape form of this material is applied half lap to the endwindings and coil leads. At this time, epoxy paste lead seal is applied. The complete coil is covered with an outer half-lap layer of glass fiber armor tape.	Prior to winding, conducting varnish with bands of semiconducting varnish at the ends is painted on to the coil straights and endturn bends.	Polyester-glass semiconducting laminates [1–10 kilohms per square] wedges, fillers, and separators. RTDS imbedded in separators.	Five classes based on fault or starting duty insulated steel or Stage-B glass polyester rope surge rings, fixed or floating. Stage-B glass polyester ties. Stage-B polyester mat blocks and padding. Stage-B glass polyester cord diamond ties.	Jumpers are insulated the same way as the coil leads. Loop-type connections are padded with Stage-B Dacron felt and insulated with Stage-B micaglass tape.	In process: (1) Hipot 1.3 [2*E* + 1] kV RMS, 60 Hz, 60 s individual coils. (2) Submersion 1.3E [RMS, 60 Hz, 60 s submerged <5 μA leakage] individual coils.	This insulation system is used for severe environment high voltage applications. Also used in abrasive particulate environments.

(*continued*)

TABLE B.19 (*Continued*)

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors and Generators							Location and Type of Winding: Stator, Multiturn Diamond		
		Insulation							
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Strand and Turn	Groundwall	Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Complete coils are cured prior to winding, bracing, and connection. Bondable epoxy mat tape layer applied to endturns, leads, and connections seals against moisture and resists dynamic abrasion. This system is capable of passing ANSI/NEMA MG1-20.48 water test.		If the PVPT exceeds 50 V, one half-lap layer of glass fiber-backed mica paper turn tape is applied. Coil straights are painted with epoxy resin and hot press cured to consolidate the conductor stack prior to the application of the groundwall insulation.	Two half-lap layers of Stage-B epoxy mat tape are then applied to the endheads and leads. The coil straights are hot pressed to toleranced dimensions and then complete coils are baked to cure and consolidate the groundwall. Prior to winding, the coils are given a final dip and bake in varnish. After winding, bracing, and connection, the connections are insulated with Stage-B glass-backed mica paper tape and sealed with Stage-B epoxy mat and an outer layer of armor tape. The entire stator is then baked to cure the connection insulation. Finally, the stator is given two coats of baking and air dry varnishes.	Semiconducting laminates are used for slot wedging and packing. Coil straights are painted 1–1.5″ past the core ends with 3–30 kilohms per square resistivity paint. Grading bands are 5–5.5″ wide, painted 0.5″ with 10 Ω to 10 megohms per square resistivity paint.	Polyester-glass semi-conducting laminate [1–10 kilo-hms per square] side panels.		Two half-lap layers of Stage-B epoxy mat tape are anchored with half-lap layer of Dacron tape on the outside. Leads are ethylene propylene or silicone rubber, unshielded with fine stranding. RTD leads have metallic armor grounded. Steel cable hangers are padded with Stage-B Dacron felt. All ties are Stage-B glass-polyester.	(3) Hipot 1.25 $[2E + 1]$ kV RMS, 60 Hz, 5 s coil groups in slots. (4) Surge 1 77 $[2E + 1]$ kV peak/group, 5 s <0.2 μs rise coil groups in slots. Sampling: two coils/set but not less than 1% of each production batch. (a) Delta tan delta (b) Breakdown per side (c) Endturn breakdown Acceptance: Per ANSI/NEMA MG-1	

TABLE B.20 NEI Peebles Electric Products

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors and Generators							Location and Type of Winding: Stator, Multiturn Diamond		
		Insulation							
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Strand and Turn	Groundwall	Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
NEI Peebles Electric Products "VI-SEAL" Coils are VPI'd and partially cured prior to winding, bracing, and connection. This system is capable of passing the NEMA MG1-20 48 water test	Class F 155°C 2300–7200 V	Up to 50 PVPT-fused double Dacron glass over heavy synthetic enamel. 51–100 PVPT-mica paper tape over heavy synthetic enamel. Coil straights are with epoxy resin and hot press cured to consolidate the conductor stack prior to the application of the groundwall insulation.	Low resin content glass fiber-backed mica paper wrappers are used on the coil straights and a tape form of this material is applied half lap to the endwindings and leads. The complete coil is taped with one half-lap layer of Dacron glass armor tape. At this time, treated Dacron felt lead seal is applied. The insulated coils are VPI'd with a solventless thermosetting epoxy resin and then surface cured by baking in an oven.	None up to 5000 V. Coil straights are coated with semiconducting paint [3–30 kilohms/square] for 5000–7200 V. No grading.	Polyester-glass laminate or Epoxy-glass laminate or polyester-glass semiconducting laminate [1–10 kilohms/square] for 5000–7200 V. Aramid paper half-slot liners are used to prevent coil straights from bonding to the core during curing thus facilitating winding repairs [up to 5000 V]. Semiconducting laminate side panels for 5000–7200 V.	Five classes based on fault or starting duty insulated steel or Stage-B glass polyester rope surge rings, fixed or floating. Stage-B glass polyester ties Stage-B polyester mat blocks and padding. Stage-B glass polyester cord diamond ties.	Jumpers are insulated the same way as coil leads. Loop-type connections are padded with Stage-B Dacron felt and insulated with Stage-B mica paper tape. One half-lap layer of Dacron-glass armor tape is applied outside. Leads are ethylene-propylene rubber with fine stranding. Stage-B glass polyester tape chain ties.	In process: (1) Hipot 1.1 [$2E + 1$] kV RMS, 60 Hz, 5 s (2) Surge 1.55 [$2E + 1$] kV peak/group <0.2 μs rise, 5 s [testing done on partially cured windings]. Sampling: two coils/set or 1% of each production batch (a) Delta tan delta (b) Breakdown per side (c) Endturn breakdown Acceptance: Per ANSI/NEMA MG-1 [all windings fully cured].	This system is used for severe moisture and conducting dust [carbon black] or acid atmospheres. Not recommended for basic, solvent- or oil-laden atmospheres without specific evaluation.

(*continued*)

TABLE B.20 (*Continued*)

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors and Generators

Location and Type of Winding: Stator, Multiturn Diamond

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
			Finally, before winding, the coil straights are hot and cold pressed to toleranced dimensions. Nomex slot liners are used to give the coils mechanical protection during winding. The coil connections are sealed with Dacron felt treated with Stage-B epoxy resin, and insulated with Stage-B mica paper tape. An outer layer of Dacron glass tape is then applied half lap. Finally, the complete stator is baked, double dipped in varnish and baked to seal it.						

NEI Peebles Electric Products "PARABOND" "Resin-rich" tapes and wrappers used for groundwall and turn insulations. Coil straights are hot press cured prior to winding.	Class F 155°C 2300–15,000 V	Glass fiber-backed mica paper tape impregnated with Stage-B epoxy resin. This tape is applied in butt layers and allows the conductors in the coil straights to be consolidated by hot pressing prior to the application of the groundwall. Numbers of layers depends on the instantaneous voltage withstand [minimum two layers up to 5 kV].	Glass fiber-backed mica paper sheet material, impregnated with Stage-B epoxy resin, is used on the coil straights. A tape form of this is used on endwindings leads and connections. The coil straights are hot press cured to toleranced dimensions prior to winding, bracing, and connection. A half-lap layer of polyester fiber tape is applied to the leads, endwindings, and connections. After winding, bracing, and connection, the complete stator is immersed in a thermosetting epoxy varnish and then oven baked to cure this and the endwinding, lead, and connection insulation.	Windings rated above 4200 V have conducting varnish, with bands of semiconductive varnish at the ends, applied to the coil straights, and endturn bends. Semiconduct-inglaminates are used for slot wedging and packing. Coil straights are painted 1–1.5″ past the core ends with 3–30 kilohms per square resistivity paint. Grading bands are 5–5.5″ wide, painted overlapping 1/2″ with 10 Ω to 10 megohms per square resistivity paint.	Epoxy glass laminate slot wedges and midsticks are used up to 5 kV. Polyester-glass semi-conducting laminates [1–10 kilo-hms per square] are used as wedges, fillers, separators, and side panels at 5 kV and above RTDs are imbedded in semiconduct-ing separators at 5 kV and above.	Radial bracing is provided by fixed and/or floating glass-fiber support rings. Felt padding, impregnated with Stage-B epoxy resin, is fitted between the coils and these rings and between coils to limit circumferential coil movement. The coils are tied to the brace rings with glass fiber tape (Stage-B). The numbers of rings and spacer rows is based on the fault or starting duty.	Jumpers are insulated in the same manner as coil leads. Winding leads are fine-strand synthetic rubber insulated. Several terminal housing arrangements permit phase insulation or phase segregation up to 15 kV and 750 MVA [0.25 s] through fault if specified.	Hipot and interturn insulation tests are performed during the manufacture of the coils and windings. Tan delta and partial discharge tests, on individual coils, can be performed, prior to winding, to check the quality of the insulation on the slot portion. Coils rated above 6000 V meet the limits given in BEMA REM500 for partial discharge and loss tangent levels. Surge testing limits are 60 kV peak > 0.1 <0.25 μs rise.	This system is provided in machines manufactured in the United Kingdom and was introduced around 1970.

TABLE B.21 Reliance Electric

Machine Type: Squirrel Cage Induction Motors; Wound Rotor Induction							Location and Type of Winding: Stator, Multiturn Diamond		
		Insulation							
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Strand and Turn	Groundwall	Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Reliance Electric "RANDOM WOUND" Conductors consist of a number of round wires connected in parallel. Coils are wound, braced, and connected before the stator is dipped in a thermosetting epoxy resin.	Class F 155°C 2300 V	Strand insulation is heavy polyester covered with a layer of Dacron glass fibers. The ends of the conductors in each coil are sleeved with silicone rubber-insulated fiberglass material.	A polyamide mica [Nomex M] slot liner provides ground insulation in the slot. This material is also used as phase-to-phase insulation in the endwindings.	None required.	Slot closure U-shaped polyester glass laminate midstick-polyamide (Nomex) strip.	Coils are lashed together. After epoxy resin dips and bakes, the complete endwinding becomes self-supporting,	Stranded copper insulated with an extruded hypalon jacket.		
Reliance Electric "ENDURASEAL" VPI with thermosetting epoxy resin after coils are wound, connected, and braced. Windings can be sealed to pass NEMA MG1-20.48 water test.	Class F 155°C 2330–13,200 V	1. Turn-to-turn voltage up to 25 V—heavy polyester amide imide. 2. Turn-to-turn voltages between 25 and 50 V—heavy polyester amide imide + Dacron glass fibers.	Polyamide mica tape applied in half-lap layers plus an outer layer of woven glass fiber armor tape.	6600 V ratings have a half-lap layer of conductive tape on the coil straights. In addition to this, voltage ratings above 6600 V have overlapping bands of semiconductive paint on the ends of the conductive tape layer.	Slot wedge: Polyester glass laminate. Midstick: Polyamide (Nomex) Bottom stick: Polyamide (Nomex).	Steel or epoxy rope radial brace rings. Steel rings are insulated with polyamide mica tape and an outer layer of woven glass fiber tape.	Stranded copper conductor covered with an extruded modified ethylene propylene rubber jacket.	1. Material tests: (a) Magnet wire samples are subjected to dielectric bend and heat shock. (b) Groundwall tape samples are subjected to thickness checks and tensile tests.	This system was introduced around 1970 and is still being used by both United States and Canadian manufacturing plants.

3. Turn-to-turn voltages greater than 50 V—heavy polyester amide imide + polyamide mica tape (Nomex M). Note: 2. Above is also standard on high output machines.				Polyester felt is applied on top of this to act as a cushion for lashing coils to rings. High speed motors have fixed steel brace rings; low speed ones have floating rings. Intercoil blocking consists of polyester glass laminate covered with polyamide felt.	Stranded copper conductor covered with an extruded modified ethylene propylene rubber jacket.	(c) Resin is given gel time tests. 2. Tests on wound stator before VPI: (a) Turn-to-turn impulse voltage tests on individual coils after winding but prior to connection. (b) High voltage tests on the groundwall. 3. Tests on wound stator after VPI: (a) Comparative steep wave front voltage tests on each phase. (b) High voltage tests on groundwall. 4. Water immersion test per IEEE 429 and NEMA MG 1-20.48.

(*continued*)

TABLE B.21 (*Continued*)

Machine Type: Squirrel Cage Induction Motors; Wound Rotor Induction							Location and Type of Winding: Stator, Multiturn Diamond		
		Insulation							
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Strand and Turn	Groundwall	Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Reliance Electric "FORM WOUND CLASS B"	Class B 130°C 2300 and 4000 V	1. Up to 25 V rms per turn—heavy polyester amide imide or double Dacron glass fibers. 2. Above 25 V rms per turn—heavy polyester amide imide plus double Dacron glass fibers. Note: Machines with high ratings will have insulation as in 2 above no matter what the volts per turn might be. The coils are dipped and baked in polyester varnish to consolidate the coil stack prior to application of the groundwall insulation.	The coil straights are insulated with polyester or epoxy resin-bonded glass fiber/mica flake/glass fiber wrapper. The endheads are insulated with half-lap layers of acrylic resin-coated glass fiber tape. The coil leads are insulated with acrylic resin-coated glass sleeving or mica tape. The oil straights are hot pressed to consolidate them prior to winding. An outer half-lap layer of acrylic-coated Dacron glass armor tape is applied to the complete coil. The coils are dipped in polyester varnish and baked prior to winding. A glass fiber-mica flake-Mylar slot liner is fitted. After winding, connection, and bracing, the complete winding is dipped and baked in a polyester varnish.		Polyester glass laminate slot wedges	Insulated, supported steel brace rings provide radial bracing. Large high speed motors will have two rings per end, but others will only have one. Polyamide [Nomex] conformable padding is inserted between the coils and radial support rings. Coil-to-coil bracing is provided by polyamide polyester glass laminate blocks covered with polyamide felt. Until the stator is dipped and baked, these are held in place by the lashings that tie the coils to the radial brace rings.	Stranded copper conductor insulated with a hypalon or extruded polymeric jacket.		

TABLE B.22 Siemens

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors and Generators

Location and Type of Winding: Stator Multiturn Diamond

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Siemens "MICALASTIC" [formerly PROTOLASTIC 1963–1968] "Resin-rich" mica folium is used on the coil straights and a high resin content tape on the endwindings. The coil straights are "hot press" cured prior to winding. After the winding is completely insulated and braced, the endwindings and connections are impregnated by slowly rotating them through a bath of unsaturated polyester resin, which is cured while the stator is rotated.	Class F 155°C 1100–13,800 V	A two-layer overlapped polyester foil-backed mica tape is used for both strand and turn insulations. Insulation thickness depends on voltage range.	A high resin content polyester foil-backed micafolium wrapper is applied to the coil straights and a high resin content mica tape to the endwindings and connections. The coil straights are hot pressed to toleranced dimensions prior to winding.	This is applied when the machine voltage rating is higher than 4400 V. Conductive paint is applied to the coil straights. For voltage ratings higher than 6600 V, a semiconductive silicon carbide-filled polyester tape is used for stress grading. This overlaps the conductive paint on the ends.	Top, bottom, and midsticks are used and are made from epoxy glass laminate. Slot wedges are normally a magnetic type and consist of an epoxy resin/iron powder composite.	All machines have fixed radial brace rings to which the coils are tied. Epoxy molding material is applied between the coils. In addition, felt padding between the coils and brace rings provides a cushion that locks coil-to-coil and the coils to the rings.	Silicone rubber insulated leads between the winding and terminal box.	Tests are performed at the following stages of manufacture. 1. After coil insulation is complete; turn insulation is surge tested and dissipation factor is taken on 10% of coils. 2. The ground insulation is retested after the coils have been inserted into the slots. 3. The turn and ground insulation are tested after slot wedging and endwinding bracing is complete, but before connections are made.	This system was introduced for small- and medium-sized machines of the above types in 1963 and a number of improvements have been incorporated since then. Magnetic wedges came into general use in 1968.

(*continued*)

TABLE B.22 (*Continued*)

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors and Generators

Location and Type of Winding: Stator Multiturn Diamond

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
							4. After the winding has been connected, impregnated, and cured, it is given a final hipot test. 5. Water spray testing is performed if sealed winding capability is to be demonstrated. 6. The complete machine is given a final hipot test prior to shipment. Dissipation factor and other insulation system measurements are made as specified by the customer.		
Siemens "MICALASTIC VPI"VPI with epoxy resin after coils are wound, connected, and braced. Windings can be sealed to pass NEMA MG1-20.48 water test.	Class F 155°C 2300–20,000 V	Since 1973, glass-backed mica paper tapes, applied in butt layers, have been used. The standard is two butt layers.	Glass-backed mica paper tapes are applied in half-lapped layers to the coils and connections.	This is applied when the machine voltage rating is 5 kV or higher.	Top, bottom, and midsticks are used. Slot wedges are normally a magnetic type and consist of an epoxy resin/iron powder composite.	High speed machines have fixed radial brace rings to which the coils are tied. Medium-speed machines have fixed or floating rings.	Cable is normally used to connect the winding to the terminal box. This is insulated with silicone rubber or mica-silicone insulation. In some instances, busbars insulated with the same materials as the groundwall and VPI'd with the windings is used.	Hipot and surge voltage tests are performed at the following stages of manufacture. 1. Insulated unimpregnated coils are surge tested for turn insulation and DC hipot tested for ground insulation.	This system was introduced for large machines of the above types in 1965/66.

In the first step of development, glass and glass-polyester film-served wires, combined with mica strips for interturn insulation, were used. This was followed in 1969 by polyester fiber-reinforced mica tapes.	These tapes contain a catalyst that causes the epoxy impregnating resin to gel within the impregnation bath under pressure. An outer surface layer of tape acts as a diffusion barrier to protect the impregnating resin bath in the VPI tank. An improved version, for special high performance needs, using glass and polyester film-backed mica tapes in combination was presented in CIGRE Paper 15–09, 1982.	A half-lap layer of carbon-filled polyester tape is applied to the coil straights, and semiconductive overlapping bands are applied to the ends as an electric grading on the insulation surface.	In slow speed machines, radial bracing is provided by floating rings. Glass roving padding is applied between the coils and the rings to provide a cushion and to lock the coils to the rings. Blocking between coils is provided by glass felt pads. In the case of severe service conditions, coils may be arch bound at the locations where the glass felt pads are situated.	2. The ground insulation is retested after the coils have been inserted into the slots. 3. The turn and ground insulation are tested after slot wedging and bracing of the endwindings, but before closing connections. 4. After the winding has been connected, impregnated, and cured, dissipation factor measurements are taken and it is given a final hipot test. 5. Water spray “wet-test” on complete sealed winding and/or surge voltage strength proof test on additional coils if ordered.	At this time, it was a Class B system as mica tapes with synthetic backing materials were not available then. Magnetic wedges came into general use in 1968. The system was upgraded to Class F in two steps: in 1969, with the introduction of fiber-reinforced polyester web-backed mica paper tapes; and in 1973/1975, with the introduction of glass-backed mica tapes.

TABLE B.23 Siemens

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors and Generators

Location and Type of Winding: Stator, Multiturn Diamond

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Siemens Energy and Automation [formerly Allis-Chalmers until 1978 and Siemens-Allis until 1985] "SILCO-FLEX" Silicone elastomer groundwall insulation vulcanized by pressure and heat to form a homogeneous mass. System can be sealed to pass NEMA MG1-20.48 water test.	Class H 180°C 2300–15,000 V	Strand insulation is fused Dacron glass [normally double Dacron]. For low turn-to-turn voltage stresses and stator winding voltage ratings, the strand insulation serves as turn insulation. When the turn-to-turn voltage exceeded 40 V rms/turn and/or the stator winding line-to-line voltage rating exceeded 4800 V, silicone elastomer tape was applied to the turns.	Silicone elastomer tape [trade name Silastic] is applied half lap to the complete coil, leads, and connections. A special bonding paste is applied between the layers of tape. A final armor coatings of half-lapped glass-backed Silastic tape is also applied. The insulation on the coil straights is vulcanized by hot pressing prior to winding.	This was used on the higher voltage ratings. It consists of a layer of asbestos tape, applied to the coil straights, which is painted with a semiconductive varnish. Bands ofalkyd enamel grading paint are applied to the ends of the asbestos tape layer.	Slot wedges and fillers are made from a phenolic-based laminate or a melamine resin-bonded glass mat material.	Radial bracing is provided by lashing the coils to Silastic-insulated steel rings. The rings in high speed machines with long endwindings are supported by brackets attached to the core end flanges.	Winding extension leads were made from the same materials as the winding conductors and were insulated with silicone rubber tape material.		This system was introduced in 1955 for voltage ratings up to 7 kV. It was extended to 15 kV in 1959. It was phased out with the advent of the MICLAD VPI system in 1965. The majority of machines built with this insulation system had voltage ratings below 4800 V.

Siemens Energy and Automation [formerly Allis-Chalmers until 1978 and Siemens-Allis until 1985] "MICLAD" Coils are VPI'd with thermosetting epoxy resin after winding, bracing, and connection. System can be sealed to pass NEMA MG1-20.48 water test.	Class F 155°C 2300–15,000 V	Strand insulation was either fused double Dacron glass or enamel. For low turn-to-turn voltage stresses and stator winding voltage ratings, the strand insulation serves as turn insulation. When the turn-to-turn voltage stress was high [approximately 40 V rms/turn or above], the strand insulation was enamel, and half-lap glass-backed mica tape turn insulation was used.	Glass fiber-backed mica tape applied half lap to the complete coil. For voltage ratings below 4200 V, a half-lap layer of Dacron glass armor tape was applied. [See "Partial Discharge Protection" for armor coating applied to windings rated for 4200 V and above.]	This was applied to the windings of machines with voltage ratings of 4200 V and above. A conductive armor tape was applied to the slot portion of each coil leg, and a nonconductive Dacron glass armor tape was used on the coil ends and leads. The ends of the conductive tape were terminated outside the slot by "stress cones" consisting of one or more layers of half-lapped mica tape. The number of layers depended on the voltage rating and this tape overlapped the ends of the conductive tape layer applied to the coil slot portion.	The coils are secured in the slots by the epoxy resin applied, by a VPI process, to the complete winding. The slot wedges and fillers are manufactured from glass mat polyester.	Two alternative methods are used: (1) Motors of all sizes; Radial and circumferential bracings are provided by encapsulating the end heads in epoxy resin. A glass-reinforced plastic mold is used to achieve this. The encapsulating rings may be attached to the stator frame to give some additional support. Additional blocking is fitted to high speed motors with long endwindings. This consists of a ring of conformable packing between top and bottom coil legs and rows of fiber blocking between coils. (2) Large motors; the coils and connections are tied to fixed brace rings, which provide radial support. Fiber rope rings may also be fitted between coil legs and to inner legs. Rows of circular fiber spacers inserted between adjacent coils are held in place by bindings.	The insulating material is the same as that applied to the coil groundwall and is covered with an outer layer of Dacron glass armor tape. This insulation is impregnated with epoxy resin during the VP1 process.	Prior to VPI: - turn-to-turn and hipot tests on individual coils. After VPI: - an AC hipot test on complete stator winding.	This system was introduced in 1965 and was phased out in 1986.

TABLE B.24 US Motors

Machine Type: Squirrel Cage Induction Motors

Location and Type of Winding: Stator, Multiturn Diamond

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
US Motors "EVERSEAL" VPI with thermosetting epoxy resin after coil winding, bracing, and connection. System can be sealed to pass the NEMA MG1-20.48 water test.	Class F 155°C 2300–6900 V	Class H heavy polyester base with polyamide imide overcoat. An outer layer of fused double Dacron glass wrapping is used for ratings above 5000 V and for larger 4000 V machines.	Complete coil is taped with half-lap layers of glass fiber-backed polyester-bonded mica paper tape. An outer layer of polyester tape is also applied. This protects the groundwall during coil insertion and shrinks during the preheat prior to VPI to compact the mica paper groundwall tape. Connections insulated with mica paper tape, over sleeved with glass sleeving or with a double sleeve of semitreated glass fibers over acrylic tubing as required.	Not required for ratings up to 5000 V. For ratings above this voltage, special mica tapes are used for groundwall insulation.	Slot wedges made from extruded haysite. Mid- and bottom sticks also made from this material.	Fiberglass rope or supported, padded, steel brace ring[s] at either end. Packing in endwindings absorbs VPI resin to give solid support to coil heads.	Stranded copper insulated with EPDM.	1. Magnet wire is checked for continuity. 2. Turn-to-turn surge tests are performed on coils prior to insertion in the slots and afterward. 3. Surge test is performed on connected winding prior to VPI. 4. Hipot test is performed prior to VPI and afterward. 5. Megger and hipot tests are performed after assembly. 6. If a sealed winding capability is to be verified, NEMA MG1-20.48 is performed.	This system was introduced around 1971. Earlier machines had mica splittings groundwall insulation.

TABLE B.25 Westinghouse Thermalastic

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors							Location and Type of Winding: Stator, Multiturn Diamond		
		Insulation							
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Strand and Turn	Groundwall	Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Westinghouse “THERMALASTIC” [as manufactured in their Buffalo Plant]. VPI with thermosetting resin after winding, bracing, and connection [Post Impregnation]. Initially, polyester resins were used, but from around 1960, they were replaced by epoxy resins. Windings can be sealed to pass the NEMA MG1-20.48 water test.	Class F 155°C 2300–5000 V	Ratings up to 3000 V have epoxy resin-impregnated Dacron glass covering. Higher voltage ratings have enamel with a Dacron glass covering. The coil straights are consolidated by hot pressing prior to the application of the groundwall.	Dacron or glass fiber-backed mica splittings material used. The coil straights are insulated with a sheet wrapper form and the endwinding leads and connections with a tape form. The mica splittings materials were replaced by mica paper around 1970. A final half-lap layer of glass fiber tape is applied to the complete coil.	Not required for voltage range covered by this system.	Rows of short Micarta wedges at the ends and middle of the slots. This improves cooling as there is less restriction for air leaving the rotor and entering stator. Micarta is also used for mid- and bottom sticks, if fitted.	Radial bracing is provided by lashing the coils, with fiberglass cord to insulated steel brace rings covered with a layer of polyester felt. The felt acts as a cushion and after thewindings have been VPI’d, this locks the coils to the rings. Slow speed machines have floating rings. High speed machines with long endwindings have rings supported by brackets attached to the stator core end flanges. Circumferential bracing is provided by rows of polyester felt blocking inserted between coils.	Stranded cable covered with an insulating jacket.		This was the first Westinghouse post impregnation system and was introduced in 1956. It was much easier for Westinghouse to first try this type of system on the smaller machines manufactured in their Buffalo plant. A similar system is manufactured in Westinghouse’s Hamilton plant in Canada.

TABLE B.26 Westinghouse Thermalastic

Machine Type: Turbine Generator, Water-Cooled Stator, Gas-Cooled Rotor

Location and Type of Winding: Stator Winding

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Strand and Turn	Insulation: Groundwall	Insulation: Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Westinghouse "THER-MALASTIC"	Class B 130°C Up to 25 kV	Each strand is wrapped with continuous filament-type plied glass fiber. This glass covering is then treated with epoxy varnish.	Dacron-backed mica flake tape impregnated with thermosetting epoxy resin is applied in layers over the entire conductor bar, using an autocratic taping machine. Resin impregnation is completed using vacuum pressure technique in a bath of low viscosity epoxy resin. The bar is heat cured to final dimensions while being pressed in a mold.	Conducting varnish on polyester mat tape armor applied in the slot, and high resistance Coronox applied to endturns.	Molded glass Micarta NEMA Grade G11 core with KEVLAR overlay. Semi-conducting glass Micarta used on one side of the slot for side packing.	Support brackets spaced around the machine and G20 fixed to the stator core provide the outer boundary for the end basket. Glass epoxy support rings provide bracing in the radial direction. Two rings rest on the support brackets. One ring is placed between the top and bottom layers and one ring on the inside of the top winding layer. The latter two rings are radially split, jacked apart hydraulically, and the resulting gap is filled in to recreate a continuous ring. The tension thus introduced restrains the coils radially. Blocking and banding provides tangential restraint. Glass banding unifies each phase group into a separate structure. Phase blocks then links all phase groups together by providing a continuous, tangential brace for the endwinding. Impregnated conformable materials are applied between coils to consolidate the endwindings. Bracing is finalized while the endwinding is heated.		Formed coils are checked for internal short circuits between strands. Insulated coils are checked for proper application of ground wall insulation. Final values of short circuit and hipot tests are approved after testing finished coils. During winding process, ground test of bottom coils checks for shorts, checks for internal shorts between tubes and conductors, and hipot tests are carried out.	Introduced in 1949 with polyester impregnating resin. This was replaced by a thermosetting epoxy resin around 1970.

TABLE B.27 Westinghouse Thermalastic

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors and Generators							Location and Type of Winding: Stator, Multiturn Diamond		
		Insulation							
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Strand and Turn	Groundwall	Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Westinghouse "THERMALASTIC" (first version as manufactured in E. Pittsburgh). The coils were VPI'd with thermosetting polyester resin and the straight portions hot pressed to size prior to winding, bracing, and connection.	Class "B" 130°C 2300–15,000 V	Generally, machines with voltage ratings of 2300 and 4000 V had glass fiber braid on the conductor strands. Higher voltage ratings had two butt layers of mica tape consisting of mica splittings sandwiched between two layers of cellulosic paper. After about 1960, 4000 V coils had mica strand and turn insulations.	Mica splittings sandwiched between two layers of cellulosic paper, which was later changed to woven glass fibers. For ratings up to 6900 V, a sheet form of this material was used on the coil straights. The endwindings and connections were insulated with a tape form. On machines rated above 7000 V, tape was used throughout. Around 1970, mica paper replaced the splittings.	None on 2300 V and 4000 V ratings. Machines rated for 6600 V and above had acetylene black painted on the coil straights. In addition to this, coils for ratings above 7000 V had a semiconductive layer of beech char that overlapped this conducting coating.		Radial bracing is provided by fixed insulated steel brace rings with resin-impregnated Dacron felt padding inserted between the rings and the coil heads. The coils were lashed to these rings with glass fiber cord. Rows of Micarta blocks were inserted between coils and lashed together with glass fiber cord to provide circumferential bracing. In high voltage machines, where the spacing between coils is large, these blocks were wrapped with resin-impregnated Dacron felt.	Busbar insulated with the same materials as that used in the coil groundwall.	Coils were hipot tested at voltages higher than the final winding hipot value, during winding manufacture.	This system was introduced for voltages up to 6900 V in 1951, and in 1953, it was extended to the higher voltage ratings. In 1960, the THERMALASTIC epoxy system, with post-VPI impregnation, was introduced and this new system was used for all but the largest machines after this time.

TABLE B.28 Westinghouse Thermalastic Epoxy

Machine Type: Squirrel Cage Induction Motors, Wound Rotor Induction Motors, Synchronous Motors and Generators

Location and Type of Winding: Stator, Multiturn Diamond

		Insulation							
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Strand and Turn	Groundwall	Partial Discharge Protection	Slot Wedging and Packing	Endwinding Bracing and Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Westinghouse "THER-MALASTIC EPOXY" [as manufactured in East Pittsburgh]. The coils are VPI'd with thermosetting epoxy resin after winding, bracing, and connection are complete [Post impreg-nation].	Class F 155°C 2300–15,000 V	Machines with ratings up to 3000 V have Dacron glass fibers impregnated with epoxy resin, for strand or conductor insulation. Above 3000 V, strands are insulated with Dacron glass fibers or enamel and the turn insulation is Mylar-backed mica paper.	Glass or Dacron fiber-backed mica splittings material is used. For rating up to 7000 V, a sheet wrapper form is used on the coil straights and a tape form on the endwindings and connections. Coils for voltage ratings above 7000 V have tape on the straights. Around 1970, the mica splittings material was replaced by mica paper for ratings up to 6900 V. Around 1970, the groundwall was changed to 50% mica splittings for ratings of 7–15 kV. A final layer of glass fiber armor tape is applied to the complete coil.	This is normally only provided for ratings of 13.2 kV and above. It consists of a semiconductive layer of tape, applied to the coil straights, with overlapping bands of silicon carbide grading paint on the ends.	Rows of short Micarta slot wedges are fitted at the ends and center of core. Micarta is also used for midsticks and for bottom sticks, if fitted.	Radial bracing is provided by lashing the coils, with fiberglass cord, to insulated steel brace rings covered with a layer of polyester felt. Brace rings for high speed machines with long endwindings are supported by brackets attached to the stator core end flanges. Circumferential bracing is provided by rows of polyester felt blocking inserted between coils.	Mica paper insulated busbar.	Hipot tests on groundwall at various stages of manufacture. Surge voltage tests to check quality of turn insulation.	This system was introduced in 1960 for voltage ratings up to 6.9 kV and was extended to 15 kV in 1972.

Westinghouse "THER-MALASTIC EPOXY" [as manufactured in Round Rock Texas].The coils are VPI'd with thermosetting epoxy resin after winding, bracing, and connection [Post Impreg-nation].	Class F 155°C 2300–15,000 V	Machines with rating up to 3000 V have Dacron glass fibers impregnated with the epoxy resin, for strand and conductor insulation. Above 3000 V, the strands are insulated with Dacron fibers or enamel and turn insulation is layers of Dacron on glass-backed mica paper.	Glass or Dacron fiber-backed mica splittings material is used. For ratings up to 6900 V, a sheet wrapper form is used on the coil straights and a tape form on the endwinding leads and connections. Coils for voltage ratings above 7000 V have tape on the straights. Around 1980, mica paper replaced mica splittings for ratings up to 6900 V and replaced 50% of the mica splittings material for higher voltages. A final layer of glass fiber armor tape is applied to the complete coil.	This is provided for higher voltage ratings. It consists of a layer of semiconducting tape with overlapping bands of silicon carbide [trade name Coronox] grading paint at the ends.	Row of short Micarta slot wedges are fitted at the ends and center of the core. Micarta is also used for midsticks and for bottom sticks, if fitted.	Radial bracing is provided by lashing the coils with fiberglass cord to insulated steel brace rings covered with a layer of polyester felt. Brace rings for high speed machines with long endwindings are supported by brackets attached to the stator core end flanges. Circumferential bracing is provided by rows of polyester felt blocking inserted between coils.	Normally stranded cable covered with an insulating jacket. Higher ratings may have mica paper insulated busbar connec-tions.	Hipot tests on groundwall at various stages of manufacture. Surge voltage tests to check quality of turn insulation.	The Round Rock plant was opened in 1977 and has taken over most of the machine ratings formerly manufactured in the East Pittsburgh plant, which no longer manufactures large machines of the type covered by this description.

TABLE B.29 Brown Boveri Strip-on-Edge-Type Salient Pole Winding

Machine Type: Synchronous Motors and Generators							Location and Type of Winding: Rotor, Salient Pole
		Insulation					
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Turn	Ground	Wedging, Packing and Bracing Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Brown BoveriStrip-on Edge-types alient pole winding.	Class F 155°C 100–500 V	Nomex impregnated with Stage-B epoxy resin binder. Coils are pressed and cured prior to being fitted on to the poles.	Nomex strips wound and glued around the pole body and epoxy-glass frames fitted both above and below the coils.	Glass-fiber packing, impregnated with epoxy resin, is fitted under the lower epoxy-glass frame ground insulation. This is compressed when the pole tips are bolted on and cured after all the coils have been fitted and connected. V-shaped supports are bolted between poles to provide radial bracing.	Woven glass tape applied in half-lap layers and impregnated with resin.	Coils are tested for interturn and ground faults prior to connection and after overspeed tests.	This system was introduced in 1970.

TABLE B.30 Brush Electrical Machines Ltd

Machine Type: Synchronous Motors, Synchronous Generators

Location and Type of Winding: Rotor, Salient Pole

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Turn	Insulation: Ground	Insulation: Wedging, Packing and Bracing Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Brush Electrical Machines Ltd. "STRIP ON EDGE TYPE" Wide and thin rectangular conductors formed in a concentric helix and insulated to form a rotor field winding.	Class F 155°C	Two layers of resin-coated Nomex interleaved between turns. In addition, the top and bottom turns are taped with resin-treated glass to provide additional creepage to ground. The coils are hot pressed to consolidate both of them and the turn insulation before mounting them on the pole body.	The pole body is insulated with Nomex prior to mounting the coils. The coils are given a final spray with oil- and moisture-resistant finishing varnish.	Springs are inserted in blind holes in the rotor body under the bottom insulating washer. These springs ensure that the coils are under positive pressure from the bolted-on pole tips. Insulated 'V'-shaped clamps, which interface with the winding, are bolted between coils to provide bracing against centrifugal forces.		Temporary sliprings, to which the field winding is connected, are fitted to the rotor if brushless excitation is used. Tests during manufacture include hipot, insulation resistance, and impedance measurements to check for interturn shorts. Impedance checks are performed before and after overspeed tests. Megger and hipot tests are performed with the machine running and stationary.	This type of winding is used on larger four- and six-pole synchronous motors and generators.

(continued)

TABLE B.30 (*Continued*)

Machine Type: Synchronous Motors, Synchronous Generators

Location and Type of Winding: Rotor, Salient Pole

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation			Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
		Turn	Ground	Wedging, Packing and Bracing Materials			
Brush Electrical Machines Ltd. "MULTILAYER CONCENTRIC TYPE" Multilayer wire wound coils are either directly on to cruciform or to bolt-on poles.	Class F 155°C	Rectangular conductors are bonded together and to the groundwall insulation with a specially formulated resin.	Poles are insulated with layers of glass fiber tape coated with resin.	The coil endwindings are supported by synthetic resin-bonded fabric blocks braced by steel bars that pass through the laminated poles. On higher speed machines insulated 'V'-shaped braces are inserted between the poles to give the coils additional support. These braces fit under the pole tips which retain them.		Temporary sliprings, to which the field winding is connected, are fitted to the rotor if brushless excitation is used. Tests during manufacture include hipot, insulation resistance and impedance measurements to check for interturn shorts. Impedance checks are performed before and after overspeed tests. Megger and hipot tests are performed with the machine running and stationary.	This type of winding is used on smaller four- and six-pole machines and slower speed machines of all ratings.

TABLE B.31 Brush Electrical Machines Ltd

Machine Type: Small Air–Cooled, Two-Pole Turbine Generators

Location and Type of Winding: Rotor, Concentric

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Turn	Insulation: Ground	Insulation: Wedging, Packing and Bracing Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Brush Electrical Machines Ltd. "INSULATION OF CYLINDRICAL ROTORS FOR TURBINE GENERATORS"	Class F 155°C	In the slot sections, the main turn insulation consists of Nomex strips inserted between the conductors. The insulation on the top two and bottom conductors are with a half-lap layer of glass fiber paper impregnated with Stage-B epoxy resin. In the coil endwindings, alternate conductors are insulated with strips of flexible glass fiber-backed mica paper varnished to their top and bottom sides. A half-lap layer resin-impregnated glass fiber-backed mica paper tape is then applied to these conductors. An additional half-lap layer of untreated glass tape is applied to the top and bottom conductors. Once the winding is insulated and inserted into the slots, the conductors are electrically heated and pressed down to a predetermined size.	In the slot, the ground insulation consists of a trough of Nomex paper. In the endwindings, the insulation consists of layers of Nomex sheet.	The slot wedges are made from extruded alloy. Micanite strips are used for slot bottom packing. Packing is also inserted under the slot wedges and this consists of glass fiber-backed hard mica strips varnished together and to the Nomex slot liner. The endwinding radial bracing is provided by nonmagnetic endcaps fitted over layers of mica paper and Nomex, which are ironed on. Intercoil bracing is provided by blocks of synthetic resin-bonded woven cotton lashed together with synthetic resin-bonded glass fiber tape. The uncured insulating materials are seasoned at working temperatures to ensure winding stability.	Polyester film-backed mica paper tape. Epoxy resin impregnated.	Impedance tests are performed after overspeed tests to check for shorted turns. After the winding is connected and braced, it is hipot tested at 1.5 kV to check the ground insulation.	

TABLE B.32 Canadian General Electric Strip-on-Edge Edge Wound and Picture Frame

Machine Type: Hydrogenerators

Location and Type of Winding: Rotor, Salient Pole

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Turn	Insulation: Ground	Wedging, Packing and Bracing Materials	Quality Assurance Tests	Comments
Canadian General Electric Strip-on-edge "EDGE WOUND AND PICTURE FRAME" coils for rotor held windings	Up to the early 1970's, Class 'B' 130°C Beyond the early 1970s, Class F 155°C [Note sold as Class B]	Up to the early 1970s, asbestos paper bonded with shellac varnish under pressure. In addition, the turn insulation on the top and bottom two turns of "Picture Frame:" [strip on edge] coils are reinforced with shellac-bonded glass tape to increase creepage distances to ground. This reinforcing was dropped with the introduction of molded fiberglass collars, which incorporate a lip to increase the creepage distance to ground. After the early1970s, the shellac-bonded asbestos paper was replaced by Nomex bonded with a thermosetting Epoxy resin.	Up to the early 1970s, the insulation on the pole body was asbestos sheeting bonded to it with shellac varnish. After the early 1970s, the shellac-bonded asbestos was replaced by MICA PLATE [a glass fiber-backed epoxy resin-bonded mica flake material]. Pole collar [washer] materials are as follows- Textolite from the 1940s to the 1960s- Permali was sometimes used in the 1940s and the 1950s- Epoxy-molded fiberglass from 1967 to the early 1980s- from the early 1980s to date, molded fiberglass top collars and Epoxy glass blocks for bottom spaces.	The winding is tightly wedged between the underside of the pole tip and rotor body. In the latest designs, the conductors are integrally bonded to the pole body and top collar insulation to prevent relative movement.	Coils are tested for interturn shorts prior to assembly on to the pole body. Connected winding is hipot tested to ground.	These two types of winding are used on hydraulic generators. "Edge wound" coils are made from one continuous piece of copper strip. "Picture frame" types are made from copper strips. Joined at the corners.

TABLE B.33 Electric Machinery Field Winding

Machine Type: Turbine Generator

Location and Type of Winding: Rotor, Cylindrical

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Turn	Insulation: Ground	Insulation: Wedging, Packing and Bracing Materials	Main Field Leads	Quality Assurance Tests	Comments
Electric machinery field winding for two-pole generators [cylindrical rotors]	Class F 155°C 500 V	NOMEX strips coated with thermosetting adhesive. The coil stacks are consolidated with heat and pressure after winding into the slots.	Ground insulation in the slots consists of preformed "cells" made of semirigid epoxy-glass laminate.	The winding is isolated from the slot wedges by strips of rigid epoxy-glass laminate. Endwindings insulated from retaining rings by sheets of epoxy-glass laminate. End-turn blocking is made of polyester glass laminate.	The leads are solid copper bars placed in a rigid insulating tube in the rotor shaft and connected to the field winding by insulated copper studs.	A number of AC and DC tests of the turn and ground insulation are made at various steps of the manufacturing process.	This system was introduced in the late 1960s. Prior to that, various rigid mica composites were used as ground insulation and asbestos composites as turn insulation.

TABLE B.34 Electric Machinery Strap Copper and Wire Wound Types

Machine Type: Synchronous Motors, Synchronous Generators

Location and Type of Winding: Rotor, Salient Pole

		Insulation					
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Turn	Ground	Wedging, Packing and Bracing Materials	Winding Extension Lead and Insulation	Quality Assurance Tests	Comments
Electric Machinery "STRAP COPPER TYPE" Strip-on-edge type	Class F 155°C 40–80 V	Nomex sheet material bonded to thin rectangular conductors with thermosetting adhesive. The coil stack is usually consolidated by hot pressing after fitting it on to the pole.	Polyester film/polyester mat composites are used to insulate the conductors from the pole body. The upper and lower conductor surfaces are insulated from the pole tip and body with polyester/glass laminate sheet material.	The coils are supported radially by metal bridges bolted between the poles.The bridges are insulated from the coils with strips of epoxy-glass laminate bonded to the coil surfaces with epoxy resin saturated felt.	Coil leads are usually uninsulated and bolted to standoffs mounted on the rotor body. Main field leads are usually silicone rubber-insulated cable protected with a glass overbraid or sleeve. In large high speed machines, the main field leads are sometimes made of solid copper bars placed in a rigid insulating tube in the rotor shaft and connected to the winding by insulated copper studs.	AC hipot tests are performed on the turn and ground insulation at various stages of manufacture.	This system is used on large high speed synchronous motors and generators since 1975.
Electric Machinery "WIRE-WOUND TYPE" Multilayer wire wound type	Class F 155°C 100–300 V	Film enamel, polyester glass or a combination of these two materials. The conductors are bonded together by "wet winding" them with thermosetting epoxy bonding adhesive which is then heat cured.	Polyester film/polyester mat composites are used to insulate the conductors from the pole body. The upper and lower coil sides are insulated from the pole tip and body with polyester/glass laminate sheet material.	Same as above.	Coil leads are insulated with silicone rubber or acrylic-coated glass sleeving.	AC hipot tests are performed on the turn and ground insulation at various stages of manufacture.	This system is used on medium and slow speed synchronous motors and generators since the mid-1960s. It underwent significant evolutionary change since that time. Prior to that, other materials were used including cotton-covered wires with asphalt or phenolic varnishes as bonding compounds.

TABLE B.35 General Electric Gas Cooled Rotor Winding

Machine Type: Turbine Generator

Location and Type of Winding: Rotor, Cylindrical, Gas Cooled

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation			Endwinding Bracing and Materials	Quality Assurance Tests	Comments
		Turn	Ground	Slot Wedging and Packing			
General electric gas-cooled rotor winding	Class B 130°C Up to 700 V	Polyester glass laminate bonded to conductor surface used in slot and endwinding portions of coil.	Two L-shaped, molded laminate pieces of sandwich construction insulate the sides and bottom of the slot, overlapped at bottom. The material used in the "L" pieces has varied as materials of greater mechanical toughness were developed. Molded trough retaining ring insulation of sandwich construction to provide mechanical support and to permit movement of the conductors under thermal expansion and contraction cycles.	Glass-polyester laminate spacer above top turn in slot provides radial separation from aluminum or steel slot wedge or copper amortisseur.	Glass-polyester blocking separates and supports the coils and restricts their movement under stresses owing to temperature changes and rotational forces. The turn insulation in the slot is continued in the endturn. The outer surface of the coils is insulated from the retaining ring by a cylinder of tough molded insulation.	• Turn insulation—visually inspected. • Slot armor—each piece of slot armor is hipot tested. Samples are checked for dimensions and tested for mechanical flexural strength and ultimate dielectric strength after manufacture, but before assembly. • Creepage blocks—samples of components are tested for mechanical conformance. • Shorted turn test—winding checked for shorted turns before assembly of retaining ring and with a flux probe, at speed, during balance runs.	Electric requirements are normal direct voltage plus brief alternating overvoltage if generator loses synchronism [for a rectifier-type exciter]. Mechanical requirements are to tolerate abrasion and lateral pressure during winding and during cycles of starts and stops and of heating and cooling. Forces due to radial acceleration of as much as 5000 g's due to rotation must also be tolerated.

(*continued*)

TABLE B.35 (*Continued*)

Machine Type: Turbine Generator

Location and Type of Winding: Rotor, Cylindrical, Gas Cooled

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation			Endwinding Bracing and Materials	Quality Assurance Tests	Comments
		Turn	Ground	Slot Wedging and Packing			
						• Hipot test—each coil is hipot tested after assembly. Completed field winding is hipot tested after blocking of endwinding, before and after assembly of retaining ring and prior to shipment. Insulation resistance and polarization index measurements are taken prior to each hipot of the assembled winding. • Winding resistance check—carried out after assembly of retaining ring and before shipment. • Megger test—carried out prior to shipment.	

TABLE B.36 General Electric

Machine Type: Medium-sized Turbine Generator (below 240 MVA)

Location and Type of Winding: Rotor, Concentric

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation			Endwinding Bracing	Quality Assurance Tests	Comments
		Turn	Ground	Slot Wedging and Packing			
General Electric Field Winding	Class B 130°C	Insulation strips are inserted between turns, or alternate layers are taped with mica tape.	"L"-shaped rigid armors are used to insulate the sides and bottom of the slot section. For conventionally cooled windings, two "L"-shaped caps or one "U"-shaped cap is fitted over the top of the copper and outside of the armor. For conductor-cooled windings, a laminated creepage block above the top turn provides radial separation from the steel wedges. Retaining-ring insulation of sandwich construction supports centrifugal load of the endwindings.	For conventionally cooled windings, fiber "chafing strips" are placed over the top of the caps to protect them from the subsequent wedging operations. The wedges are nonmagnetic steel.	Epoxy-glass laminate end blocking separates and supports the coils and restricts their movement under stresses owing to temperature changes and rotational forces. The turn insulation in the slot is continued in the endturns.	Turn insulation is visually inspected. Each piece of slot armor is hipot tested. Armor samples are tested for dimensions and mechanical performance. Coils are tested for short-circuited turns. Completed field winding is high potential tested at key stages of manufacture.	For machines built after the mid-1970s, this system was not used being replaced by the Class F Field Insulation System.

(*continued*)

TABLE B.36 (*Continued*)

Machine Type: Medium-sized Turbine Generator (below 240 MVA)

Location and Type of Winding: Rotor, Concentric

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation			Endwinding Bracing	Quality Assurance Tests	Comments
		Turn	Ground	Slot Wedging and Packing			
General Electric "Class F Field Insulation System"	Class F 155°C	Insulation strips are inserted between turns, or alternate layers are taped with mica tape.	"L"-shaped rigid armors are used to insulate the sides and bottom of the slot section. For conventionally cooled windings, two "L"-shaped caps or one "U"-shaped cap is fitted over the top of the copper, and outside of the armor. For conductor-cooled windings, a laminated spacer above the top turn in slot provides radial separation from the steel slot wedges. Retaining-ring insulation of sandwich construction supports centrifugal load of the endwindings.	For conventionally cooled windings, fiber "chafing strips" are placed over the top of the caps to protect them from the subsequent wedging operations.	Epoxy-glass-laminate end blocking separates and supports the coils and restricts their movement under stresses owing to temperature changes and rotational forces. The turn insulation in the slot is continued in the endturns.	Turn insulation is visually inspected. Each piece of slot armor is hipot tested. Armor samples are tested for dimensions and mechanical performance. Coils are tested for short-circuited turns. Completed field winding is high-potential tested at key stages of manufacture.	The system was introduced in the mid-1970s.

TABLE B.37 NEI Peebles Electric Products

Machine Type: Synchronous Motors and Generators

Location and Type of Winding: Rotor, Salient Pole

		Insulation					
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Turn	Groundwall	Wedging, Packing and Bracing Materials Protection	Wedging Extension Lead and Insulation and Packing	Quality Assurance Tests	Comments
NEI Peebles Electric Products "EI-1.5.4." This system is used on layer wound rotor pole windings, that is, Multilayer wire wound type. This is a sealed insulation system capable of passing the ANSI/NEMA MG1-20.48 Water test. This system is qualified for Class 1E Nuclear applications [IEEE Std. 323]	Class F 155°C Up to 600 V	Conductor strands are insulated with fused double Dacron glass over heavy synthetic enamel. The first and last turns of the first layer are insulated with 1 1/2" wide strip of aramid paper inserted under and folded over the wire as it is wound on the insulated pole body. The first and last turn insulations of the subsequent layers may be reinforced in a similar way around the corners, if needed. All crossovers shall be insulated as above.	Strips of epoxy glass fiber mat material are fitted to the pole corners to reinforce the aramid paper in sheet form wrapped around the pole body while being coated with epoxy resin adhesive. Polyester glass laminate washers are assembled over the pole body wrap and bonded in place to form ends of the "bobin" to be wire-wound. Coil lead is formed insulated and anchored under the first layer. Epoxy resin adhesive is brushed on the entire surface of each layer before winding the next. Completed coil is compressed against its pole body and baked under pressure to achieve strong and uniform bonds. Finally, the poles with cols cured are VPi'd with thermosetting epoxy resin and baked to seal them against moisture or other contaminants.	Fully cured wire wound poles are self-contained and self-supporting up to certain size and speed limits. Nonmagnetic interpolar wedges are used above these limits. Epoxy-glass fiber mat padding is used to fit wedges.	The leads are formed from copper foil strips looped around wire ends, insulated and anchored under all the wires of the first and last layers of the coil on one or both ends of the pole. Each lead is insulated with 30 mils of aramid paper cut in strips 1′ wider than the copper foil and folded over and under it. Soldered connections are sealed and bondable with epoxy putty.	In process: a. Dielectric absorption at 500 Vdc. b. Impedance voltage drop. c. Hipot 1.23 [$2E + 1$] kV RMS 60 Hz, 5 s. d. Submersion 1.25 [E] V RMS, 60 Hz, 60 s each pole with temporary cable leads [sealed with RTV]. Sampling: [discretionary] 25% overspeed 5–15 min, complete rotor. Acceptance: Per ANSI/NEMA MG-1.	This system is used for applications where the environment is severe.

(*continued*)

TABLE B.37 (*Continued*)

Machine Type: Synchronous Motors and Generators						Location and Type of Winding: Rotor, Salient Pole	
		Insulation					
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Turn	Groundwall	Wedging, Packing and Bracing Materials Protection	Wedging Extension Lead and Insulation and Packing	Quality Assurance Tests	Comments
NEI Peebles Electric Products "MICAPAC (0)" [El-1 .5.0]. This system is used on layer wound rotor pole windings, that is, multilayer wire wound type. This system is qualified for Class 1E nuclear applications [IEEE Std 323].	Class F 155°C Up to 600 V	Conductor strands are insulated with fused single or double Dacron glass over heavy synthetic enamel. The first and last turns of the first layer are insulated with 1-1/2′ wide strip of glass fiber-backed mica paper inserted under and folded over the wire as it is wound on the insulated pole body. First and last turns of subsequent layers shall be insulated in this manner around corners and on crossovers.	Strips of polyester mat material are fitted to the pole corners to reinforce the pole body insulation, which consists of the same material in sheet form wrapped around the poles while being coated with solventless polyester resin adhesive. Polyester glass laminate washers are assembled over the pole body wrap and bonded in place to form ends of the "bobin" to be wire-wound. Coil lead is formed, insulated, and anchored under the first layer. Polyester resin adhesive is brushed on the entire surface of each layer before winding the next. Completed coil is compressed by clamps against its pole body and based under pressure to achieve strong and uniform turn-to-turn bonds.	Wire-to-wire bonds of polyester resin are relied upon to maintain coil integrity up to certain size and speed limits. Nonmagnetic inter polar wedges fitted over Stage-B polyester mat padding are used above these limits.	The leads are formed from copper foil strips looped around wire ends, insulated, and anchored under the first and last coil layers on one or both pole ends. Each lead is sandwiched between three folded-over strips of glass fiber-backed mica paper cut 1" wider than the copper foil. All foil-to-wire connections may be brazed or soldered. Polyester mat strip may be used in lieu of mica-glass on the outside of the sandwich.	In-process: a. Hipot 1.25 [2*E* + 11 kV RMS. 60 Hz, 5 s. b. Impedance voltage drops individual poles. Sampling:[discretionary] 25% overspeed 5–15 min complete rotor. Acceptance: Per ANSI/NEMA MG-1.	This system is used for normal industrial applications. Prior to 1980, this system could be used as a Class B [130C] sealed system when encapsulated in a thixotropic epoxy compound MV-20.10 applied by brush to coil surfaces.[known as "MICASEAL"]

TABLE B.38 Reliance Electric Push-Through Bar Type

Machine Type: Wound Rotor Induction Motors

Location and Type of Winding: Rotor, Bar Wave

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation			Wedging Extension Lead and Insulation	Quality Assurance Tests	Comments
		Turn	Ground	Wedging, Packing and Bracing Materials			
Reliance Electric "PUSH-THROUGH BAR TYPE" The rotor has semiclosed rotor slots, which necessitate a push-through type of winding.	Class 'B' 130°C 1000 V maximum	Half-lap layers of glass fiber tape on each bar plus Glastic strips between top and bottom bars in the slot. After being insulated and prior to winding, the bars are dipped and baked in varnish to bond the insulation on them. Glastic sheet material is inserted between the top and bottom layers of the endwindings.	A polyamide [Nomex] slot liner extends beyond the ends of the slot. Jumpers, neutral leads, and terminal leads are insulated with half-lap layer of Dacron glass fiber tape. After winding, bracing, and connection are complete, winding is rotated through a trough of thermosetting varnish and then baked.	Bottom sticks. Glastic. Endwinding radial bracing is provided by fiberglass banding applied on top of the endwindings. The semienclosed rotor slots and wedges retain the windings in the slot region. Intercoll bracing is provided by means of polyamide [Nomex] felt blocking, which is impregnated with varnish by the rotational dipping process.	Same as connections between phases and the sliprings and windings.	High potential tests to ground and between phases. Comparative surge tests on phases to check for correct connections and poor soldered joints between bars.	

TABLE B.39 Siemens Strap Wound Field Coils

Machine Type: Large Synchronous Motors, Generators, Condensors, and Hydrogenerators

Location and Type of Winding: Rotor, Salient Pole

		Insulation					
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Turn	Ground	Wedging, Packing and Bracing Materials	Wedging Extension Lead and Insulation	Quality Assurance Tests	Comments
Siemens Energy and Automation [formerly Allis Chalmers until 1978 and Siemens Allis until 1985] "STRAP WOUND FIELD COILS" Strip-on edge type of winding with conductors manufactured from thin rectangular copper.	Class "B" 130°C until 1984 when temperature class was upgraded to Class "F" 155°C For voltages up to 500 V DC	Resin-impregnated asbestos paper. Because the edges of the conductors are bare, the top two and bottom two endturns are taped to increase creepage distances. The tape used was Dacron glass, which was bonded with epoxy resin. In 1985, this special turn insulation was replaced by a U-shaped, fiberglass channel, which covered the two top and bottom turns. The coils are consolidated by hot pressing prior to installation on the poles. This makes the resin in the insulation flow and bonds the conductors together. With the advent of the "Integrated Pole" construction, aromatic polyamide fiber replaced the asbestos material. This is bonded to the conductors with a heat-reactive acrylic resin.	The coils are insulated from the pole body by wrapping it with "Fish Paper" or "Leatheroid." With the advent of the "Integrated" construction, the coils were insulated from the pole body by polyamide paper. The coils are secured to the poles by pouring an epoxy potting resin between them and the pole body. Where totally encapsulated coils are required, this is achieved by applying a thinveneer of reinforced resin to the bare outer coil edges.	Pole tip and contoured base collars are fitted during pole installation. A Fuller Board filler is inserted between the base collar and the coils to give a tight fit between the coil and the pole in the radial direction. Insulated V-shaped steel braces are bolted between poles to help prevent winding movement under the influence of centrifugal forces. The base collar was eliminated with the introduction of the "Integrated Pole" design since, with this construction, the coil is banded to the pole.	Resin-filled Dacron-glass tape.	These include coil impedance measurements and hipot tests.	The original system was introduced around 1960 and was converted to the new "Integrated Winding and Pole Piece" design in 1962. In 1984, the system was upgraded to Class F [155°C temperature rise].

TABLE B.40 Siemens Energy

Machine Type: Synchronous Motors, Synchronous Generators

Location and Type of Winding: Rotor, Salient Pole

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation			Wedging Extension Lead and Insulation	Quality Assurance Tests	Comments
		Turn	Ground	Wedging, Packing and Bracing Materials			
Siemens Energy and Automation [formerly Allis-Chalmers till 1978 and Siemens-Allis till 1985] "INTEGRATED ROTOR COILS" Multilayer wire wound field windings. This is a sealed coil system.	Class "B" 130°C 250 V max	Fused double Dacron glass used as both strand and turn insulations. Turns are bonded with thixotropic epoxy resin.	The formed coils are wrapped with resin-filled glass fiber material. In some cases, the coils are consolidated by heat pressing before they are mounted on the poles. With this construction, the pole body is wrapped with the same insulation as was used on the coil outer wrap. Further heat pressing consolidates this insulation and bonds the coil to the pole body. An alternative construction method involves winding the coils directly onto the poles and then heat pressing them. Again resin-filled glass fiber material is used to insulate the pole body.	Resin-filled packing material is fitted between the underside of the pole tip and the coil. Some coils are secured to the poles by pouring an epoxy potting compound between the pole and the coil. Glass mat polyester collars are often used between the pole tip and the coil.	Resin-filled glass fiber insulation is used to insulate the leads.	These included impedance measurements and AC hipot tests after curing.	This system was introduced in 1956 and was developed to improve reliability and be consistent with the Silco-Flex stator winding system introduced in1955. The temperature class could be upgraded to Class H with the development of Silicone resins. This had very limited application for standby generators in a 5-year period beginning in 1968. This system was phased out around 1972 when the "WET WOUND INTEGRATED ROTOR COILS" system was introduced [see below for details].

(*continued*)

TABLE B.40 (*Continued*)

Machine Type: Synchronous Motors, Synchronous Generators

Location and Type of Winding: Rotor, Salient Pole

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation			Wedging Extension Lead and Insulation	Quality Assurance Tests	Comments
		Turn	Ground	Wedging, Packing and Bracing Materials			
Siemens Energy and Automation [formerly Allis-Chalmers till 1978 and Siemens-Allis till 1985] "WET WOUND INTEGRATED ROTOR COILS." Multilayer wire wound field windings. A "wet wound" process ensures good conductor bonding. This involves drawing the copper conductor through a bath of thixotropic epoxy resin as it is wound directly on to the pole. This is a sealed coil system.	Class "F" 155°C 250 V max	Polyester enamel is used as both strand and turn insulations. The epoxy bonding resin applied during the "wet wound" process provides some additional turn insulation.	The pole body insulation is polyamide paper [Nomex]. A polyester glass mat collar is placed between the pole tip and the coil. The outer coil surface, between the pole tip and the rotor body, is wrapped with glass tape, saturated with epoxy resin.	The thixotropic epoxy resin used in the "wet wound" process bonds the coils to the poles. Phenolic blocks are inserted between poles and bolted to the rotor spider arms to provide coil support.	These are insulated with glass tape and an epoxy binding resin.	Each coil receives impedance measurement, a turn-to-turn surge test and a hipot test.	This system was introduced in 1972.

TABLE B.41 Westinghouse Gas-Cooled Rotor Winding (Axial Flow)

Machine Type: Turbine Generator, Water-Cooled Stator, Gas-Cooled Rotor

Location and Type of Winding: Rotor, Cylindrical Concentric

		Insulation					
Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Turn	Ground	Slot Wedging and Packing	Endwinding Bracing and Materials	Quality Assurance Tests	Comments
Westinghouse Gas-Cooled Rotor Winding [Axial Flow]	Class B 130°C Up to 500 V	Glass melamine laminate Nema Grade G-5 bonded to the conductors.	Single piece, precision-molded, glass-epoxy mica-laminated slot cell.	Teflon-coated NEMA Grade G-11 epoxy glass spacer sandwiched between channels of glass. Melamine laminate separates the top turn from the damper winding and the nonmagnetic wedge.	The turn insulation in the slot is continued in the endturn. Glass epoxy Micarta blocking is used in the endturn area to maintain coil alignment. A retaining ring liner provides a slip layer for relative motion between the retaining ring and the endwinding. This liner is a glass epoxy cylinder with Teflon cloth laminated to the inner diameter.	Insulation dimensions, position and adhesion to copper, alignment at edges and holes, and dielectric test are checked during manufacture of coils. During rotor assembly, impedance, insulation resistance and hipot tests are conducted at various stages. Insulation resistance and hipot tests are repeatedafter balance.	Electric creepage at the top of the slot is provided by high pressure, thermosetting laminates that are selected for their dimensional stability under high pressure and operating temperature. Minimum creepage distance from conductor to ground is 18.3 mm.

TABLE B.42 Westinghouse

Machine Type:
Synchronous Motors, Synchronous Generators

Location and Type of Winding:
Rotor, Salient Pole

Manufacturer Trade Name and Type of System	Temperature Class and Voltage Range	Insulation: Turn	Insulation: Ground	Insulation: Wedging, Packing and Bracing Materials	Wedging Extension Lead and Insulation	Quality Assurance Tests	Comments
Westinghouse "WIDE EDGE WOUND TYPE" rotor field winding strip-on-edge type	To 1965 Class B 130°C 1965 to date Class F 155°C 100–500 V	Up to 1965, the material used was asbestos paper, which was bonded to the conductors with shellac varnish. The bottom two turns are reinforced with shellac-bonded glass fiber tape. From 1965 to date, Nomex with a thermosetting epoxy resin bonding agent is used. The complete coil is consolidated by hot pressing prior to mounting it on the pole body.	The conductors are insulated from the pole body with paper or glass fiber-backed mica splittings. Prior to the mid-1970s, an alternative backing material was asbestos paper. Micarta is used for the washers that insulate the coils from the pole tip and the rotor body. The year 1980 saw the introduction of an integral epoxy-bonded mica plate pole body and pole tip washer ground insulation system, which maintains a Class F rating.	When required, insulated wedge-shaped coil brackets are bolted between adjacent coils to brace the winding. Micarta sheet material is inserted between these brackets and the winding. The winding is tightly wedged between the underside of the pole tip and rotor body.		Coils are tested for interturn shorts prior to assembly on to the pole body. Connected winding is hipot tested to ground.	This type of winding is used on large high speed motors, engine-driven generators, and hydraulic generators; the highest speed being 1200 rpm.

Westinghouse "CONCENTRIC RECTANGULAR WIRE TYPE" Multilayer wire wound type	To the mid-1960s, Class B 130°C. From the mid-1960s to date, Class F 155°C 100–500 V	The rectangular strands or conductors are insulated with enamel or glass fiber serving. Until the mid-1960s, the strands were bonded together with shellac varnish. After this time, the bonding agent used was a high strength thermosettingepoxy resin to attain a Class F rating. The coils are either wound on a form and heat cured prior to installation on the pole body, or they are wound onto the pole body before the bonding resin is cured.	The conductors are insulated from the pole body with paper or glass fiber-backed mica splittings. Prior to the mid-1970s, an alternative backing material was asbestos paper. For the class B system, Micarta is used for the washers that insulate the coils from the pole tip and the rotor body. The washers used in the Class F system are made from epoxy-bonded fiberglass. The year 1980 saw the introduction of an integral epoxy-bonded mica plate pole body and pole tip washer ground insulation system, which maintains a Class F rating.	The windings are braced by ensuring that they are tightly wedged between the underside of the pole tip and the rotor body.		Coils are tested for interturn shorts prior to assembly onto the pole body. Connected winding is hipot tested to ground.	This type of winding is used on medium- and slow-speed synchronous motors and generators.

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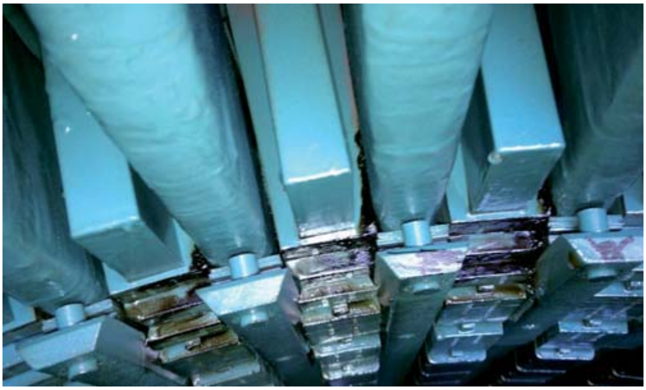

Figure 8.7 “Greasing” at the side of the stator wedges caused by movement of the wedges.

Figure 8.8 Photograph of a stator slot taken from the axis of an air-cooled machine. The stator wedges have been removed in one slot, exposing the top of a coil. The semiconductive coating on the coil connected to the phase terminal has disappeared (turned white).

Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing, and Repair,
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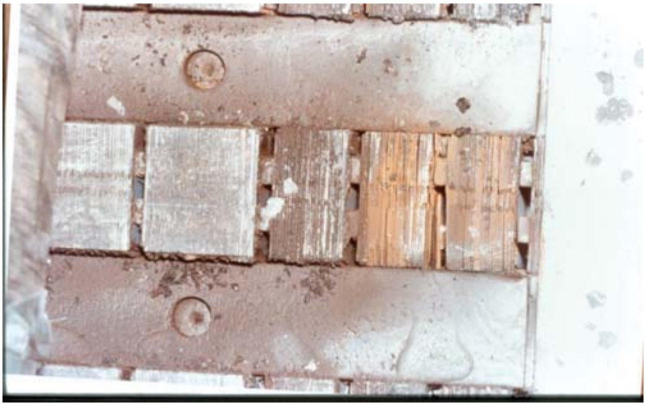
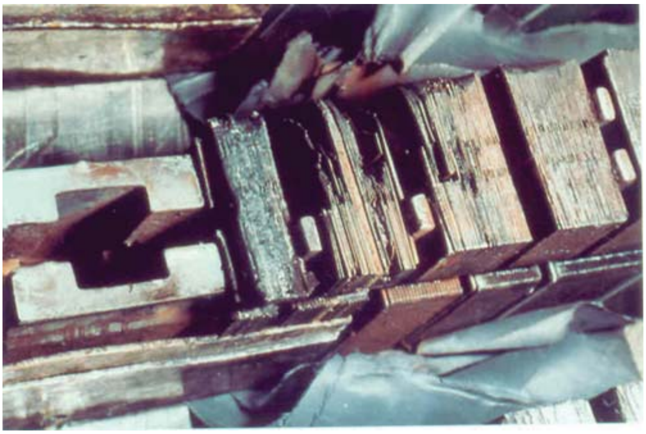
Figure 8.18 Photo of a stator winding degraded by acids in chimney flue gas.

Figure 8.20 PD between adjacent coils in different phases results in white powder on the stator bar surfaces.



(a)



(b)

Figure 13.7 Visual symptoms of loose core. (a) Dusting on tooth tips from loose core and lamination insulation abrasion. (b) Broken tooth laminations from loose core.

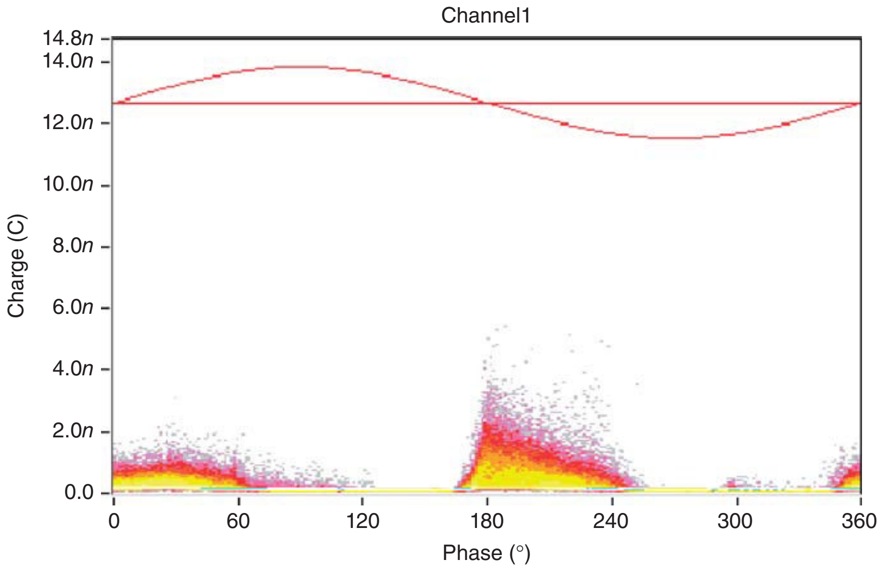


Figure 15.6 PD display with respect to the AC cycle. The color of the dots indicates the number of PD pulses per second. Note in the plot, all the PD pulses are shown as positive pulses due to the characteristics of the PD detector. (Source: PDTech-Qualitrol).

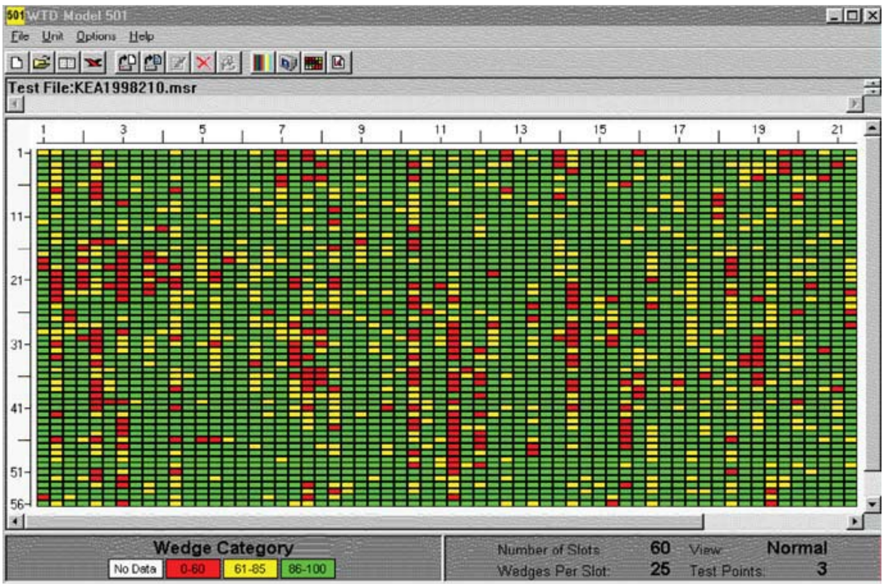


Figure 15.9 Map of wedge tightness versus slot number (vertical scale) and axial wedge number (horizontal scale). Green is tight, red is loose, and yellow is indeterminate. (Source: Iris Power-Qualitrol).

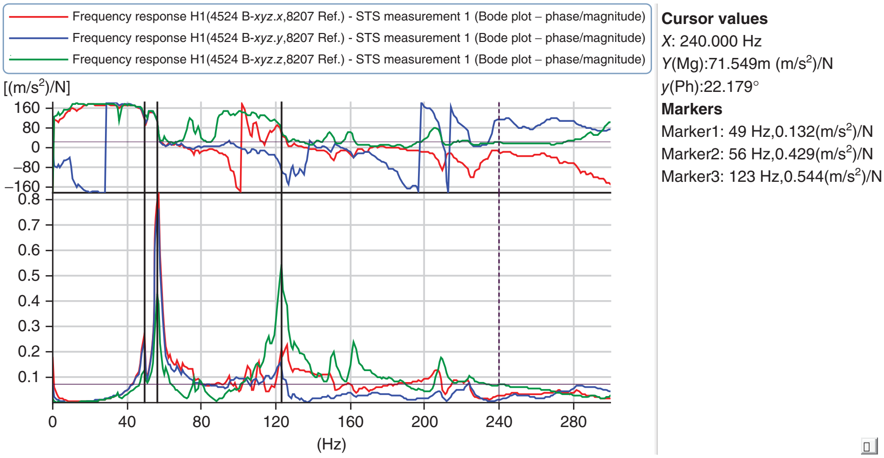


Figure 15.11 Bump test result from the endwinding of a 60 Hz two-pole turbine generator. The upper plot is the phase angle of the response while the lower plot is the normalized amplitude of the response in terms of acceleration per Newton of impact force. Unfortunately, there are significant resonant peaks at 60 and 120 Hz on this machine, which implies that the endwinding is likely to vibrate. The three lines represent vibration in the radial, circumferential, and axial directions. (Source: Iris Power-Qualitrol).

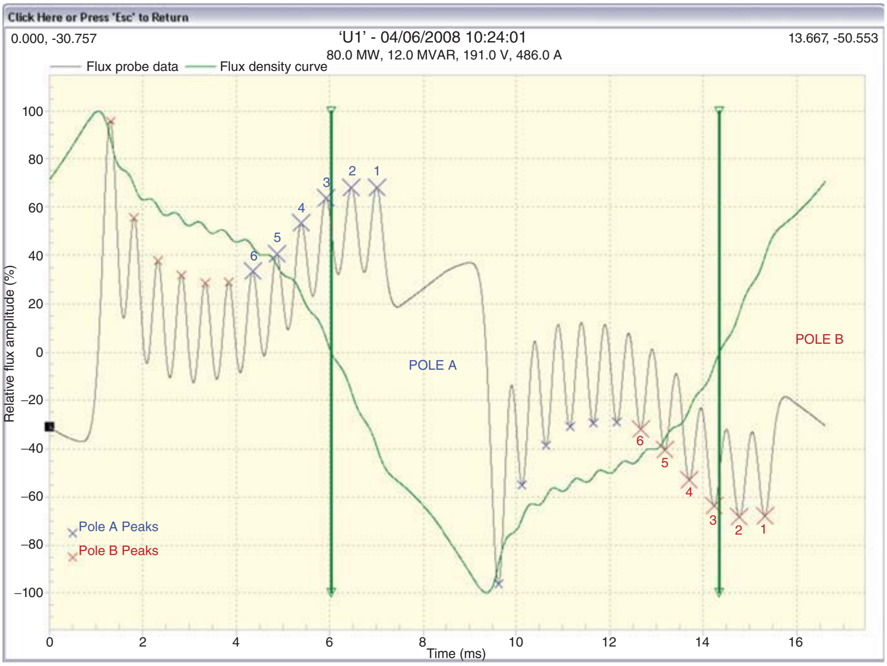


Figure 16.14 Voltage induced in a flux probe, shown by the gray (faint) line. The leading coils of each pole are numbered. The light green (smooth quasi-sinusoidal) line is the integrated flux density. The vertical dark green line is the location of flux density zero crossing. (Source: Iris Power-Qualitrol.)

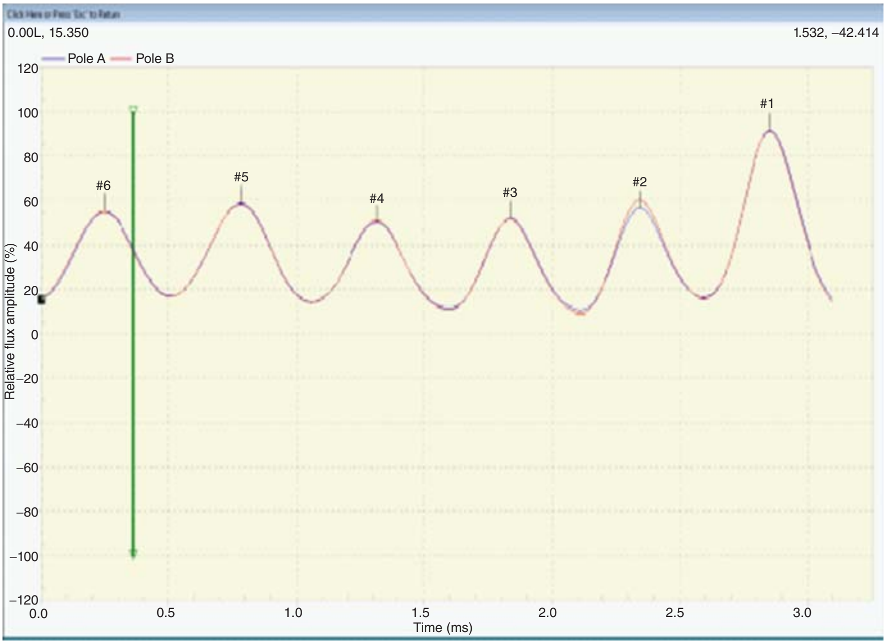


Figure 16.15 Pole-to-pole comparison that shows shorted turns detected in pole A, coil 2. Coils around pole A are blue, whereas the red line is the voltage in the coils around pole B. The vertical green line is where the flux density zero crossing (FDZC) is. (Source: Iris Power-Qualitrol.)

Figure 17.20 El-CID QUAD and PHASE current comparisons along a stator slot at a core split — same shape and constant PHASE/QUAD current ratio confirms that there is no core insulation damage. (Source: Courtesy Iris Power-Qualitrol.)

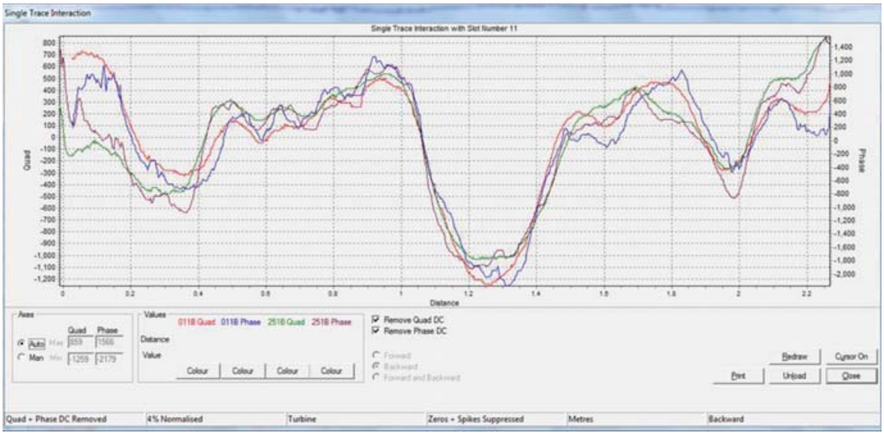


Figure 17.21 El-CID QUAD and PHASE current comparisons for two slots at core splits—similar shapes for all current plots and magnitudes for the PHASE and QUAD currents confirm that there is no core insulation damage. (Source: Courtesy Iris Power-Qualitrol.)

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