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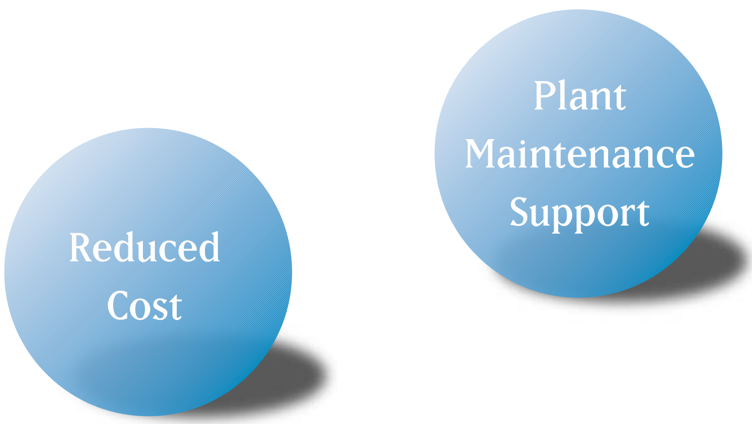
Nuclear Maintenance Applications Center: Switchgear and Bus Maintenance Guide

Technical Report



Nuclear Maintenance Applications Center: Switchgear and Bus Maintenance Guide

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REPORT SUMMARY

This report provides guidelines for switchgear and bus maintenance based on industry experience and consensus among utility personnel and equipment manufacturers. Industry operating experience and component failures are reviewed to highlight specific maintenance issues.

Background

Switchgear bus failures have led to loss of power to electrical loads connected to the buses, causing subsequent plant trips and initiating challenges to power plants and various other industrial facilities. Switchgear maintenance is primarily focused on the circuit breaker and instrument and control compartments. In recent years, circuit breaker replacement has become popular due to obsolescence and the availability of circuit breakers using newer technology and better designs. However, passive switchgear components, such as the switchgear enclosures (compartments) and electrical bus, are not being replaced.

Fortunately, passive switchgear components typically exhibit high reliability and long life. As a result, switchgear components other than the circuit breaker and instrument and control compartment components are often undermaintained. Significant economic consequences can result from bus failures and associated downtime from unplanned outages or bus maintenance. In nuclear power plants, switchgear components supply power to critical loads, and downtime of a switchgear bus can lead to plant shutdown or could result in a limiting condition for operation.

Power plants continue to identify aged and degraded switchgear components and electrical bus and bus insulation. In 2004, electrical bus insulation was identified as an issue in the Nuclear Maintenance Applications Center (NMAC) Annual Maintenance issues survey. Electrical bus maintenance tasks do not appear to be well documented or well established; it was thought that the industry would benefit from the development of guidance on switchgear bus inspection and testing. In 2005, the industry's circuit breaker users groups expressed unanimous support for the development of bus maintenance guidance.

Objective

- To provide guidance on switchgear and bus maintenance practices that represents a utility consensus and to consider switchgear manufacturers' recommendations

Approach

This guidance on switchgear and bus maintenance practices was developed in a review of industry operating experience (primarily failure data and subsequent corrective actions, along with regulatory information) and industry literature related to the switchgear and electrical bus. The review included documents from the Institute of Nuclear Power Operations, U.S. Nuclear Regulatory Commission, EPRI, input from a utility and vendor technical advisory group, and a review of vendor manuals, utility procedures, and industry aging management guidelines. Applicable international experience from nuclear power plants was also considered.

Results

This report identifies low- and medium-voltage switchgear bus inspection and testing techniques, guidance on corrosion identification and mitigation, silver-plating practices and criteria, and information on making or validating electrical (power) connections. In addition, this report provides inspection guidance of switchgear compartments that house potential transformers, current transformers, other transformers, and cable connections to buses. This report is a result of a collaborative industry effort with participation from various utility and manufacturing personnel and extensive use of technical references, many of which are EPRI reports related to the maintenance of low- and medium-voltage switchgear.

This guidance is intended to assist end users by providing a comprehensive set of guidelines to effectively manage low- and medium-voltage switchgear bus failures and to enhance existing switchgear maintenance programs.

EPRI Perspective

As the nuclear and fossil power plant fleet continues to age, replacement of circuit breakers due to aging and obsolescence is becoming a more common occurrence. Although circuit breakers are being replaced, the electrical bus and switchgear enclosures and associated components are typically not being replaced. Based on operating experience, industry failures, and feedback from the industry's circuit breaker users groups, addressing the issue of switchgear and bus maintenance was necessary and prudent to preclude potential failures due to inadequate maintenance.

Keywords

Bus
Maintenance
Switchgear
Metal-enclosed bus
Nonsegregated bus

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1
INTRODUCTION

Preventive and predictive maintenance of electrical switchgear is an important part of ensuring reliability and integrity of electrical distribution systems. Switchgear maintenance is typically focused on servicing active components, such as circuit breakers and protective relays, and on servicing the cable compartments. These components are frequently inspected and tested, and as they age or fail, they are replaced with components of newer design. However, the passive switchgear components, such as electrical buses and enclosures for potential transformer (PT) and current transformer (CT) connections, normally remain untouched and in their original configuration.

Electrical failures (faults) of electrical switchgear buses have occurred in both nuclear and fossil electric power generating units as well as in various industrial facilities. However, under current switchgear maintenance programs, electrical bus continues to remain a low priority and an overlooked maintenance component.

Switchgear bus failures typically occur because of degradation of electrical connections and insulation. Root causes include age, contamination (dirt and debris), poor sealing or coating practice, lack of maintenance or inspection, degraded silver-plating, and degraded or improper electrical connections.

Considering that plant life extension is likely for most domestic U.S. nuclear power plants, it appears that the existing switchgear fleet is expected to continue in service for years to come. Consequently, switchgear aging and bus maintenance are a concern. The U.S. Nuclear Regulatory Commission (NRC) specifically addresses passive switchgear components and electrical bus in NUREG-1801, Volume 2, Sections VI and XI.E4 [1].

The intent of this report is to emphasize the significance of switchgear and bus maintenance and fill the need for comprehensive guidance on bus inspection and testing.

Section 2 provides an overall description and design of the various types of switchgear buses. Industry operating experience is typically presented as either qualitative data (descriptive information) or quantitative data (computation of a failure rate); for this report, qualitative data are addressed and evaluated in Section 3. The operating experience is descriptive information about bus failures and degradation. Bus failure mechanisms are evaluated in Section 4. Monitoring techniques used to detect the failure mechanisms are described in Section 5, and the specific maintenance issues (developed to address bus degradation and failure mechanisms) are detailed in Section 6. Section 7 provides a list of acronyms used throughout this report, and Section 8 includes a comprehensive list of references.

1.1 Objective

The objective of this report is to provide guidance on switchgear and bus maintenance practices, which represents a utility consensus; it also presents switchgear manufacturers' recommendations.

1.2 Scope

This report includes bus maintenance guidance for metal-enclosed low-voltage (LV) and metal-clad medium-voltage (MV) switchgear assemblies. LV switchgear is nominally rated between 208 Vac and 600 Vac; the majority of applications are at 480 Vac or 600 Vac. Also applicable are panel-boards for lower ac voltages (for example, 230 Vac) and for dc applications. MV switchgear is nominally rated between 2.5 kV and 38 kV. This report covers 4.16-, 7.2-, and 13.8-kV rated switchgear, which are used in the majority of power plant applications.

In addition to the switchgear bus compartment, this report addresses maintenance of switchgear compartments that house PTs, CTs, other transformers, and power cable connections.

1.3 Information Sources

The following sources of information were reviewed and considered in the development of this guidance:

- Utility personnel experience
- Manufacturer instructions and maintenance manuals
- Selected plant switchgear maintenance procedures
- Industry publications on switchgear maintenance
- Regulatory documents that address switchgear buses and electrical buses

In addition, the following Institute of Nuclear Power Operations (INPO) and EPRI databases and documents were reviewed and considered in the development of this report:

- INPO, Significant Event Evaluation Information Network (SEE-IN) provides up-to-date information and listings of industry-wide component problems that are documented in the following references:
  - Operating Experience Reports (OEs)
  - Operations and Maintenance Reminders (O&MRs)
  - Significant Event Reports (SERs)
  - Significant Event Notifications (SENs)
  - Significant Operating Experience Reports (SOERs)

- INPO, Nuclear Plant Reliability Data System (NPRDS), and Equipment Performance and Information Exchange (EPIX) databases provide equipment failure reports and sort by equipment code, system code, vendor, failure mode, plant, and so on.
- EPRI Generic Communications Database, Version 3.0, Release 5.0, September 2002, provides applicable generic communications sorts for safety-related structures, systems, and components (SSCs) only by equipment name, type of NRC document, aging mechanisms, and aging effects for the following NRC documents:
  - Generic Letters (GL)
  - Information Bulletins (IEB), Notices (IN), and Circulars (IEC)
  - Regulatory Issue Summaries (RIS)
  - Generic Safety Issues (GSI)

A detailed list of references is provided in Section 8.

1.4 Illustrations

All illustrations in this report are typical and might not be applicable to a specific switchgear model or vintage. Pictures are of actual installations.

1.5 Terminology

Common industry terminology is used to reduce confusion and maintain consistency. Manufacturers' terminology is also identified when appropriate.

1.6 Conversion Factors for Units Used in This Report

Parameter	English to SI Units
Length	1 in. = 2.54 cm
Temperature	°F = 1.8 (°C) + 32
	°K = °C - 273.15
Torque	in.lb = 16.272 N.m
	ft.lb = 1.356 N.m
	ft-kip = 1.356 kN.m
Yield Strength	ksi = 6.894747 MPa

2
DESIGN AND DESCRIPTION

2.1 Switchgear General Description

Switchgear buses are associated with equipment for switching, interrupting, metering, protecting, and regulating associated with the generation, transmission, distribution, and conversion of electrical power.

2.1.1 Low-Voltage Metal-Enclosed Switchgear

LV switchgear is nominally rated between 208 Vac and 600 Vac. The majority of applications are at 480 Vac or 600 Vac. Typical continuous bus current ratings are 1600A, 2000A, 3000A, 3200A, 4000A, and 5000A.

LV switchgear completely enclosed on all sides and top with sheet metal. Metal-enclosed construction is used up to 1000 V. The main buses consist of copper bus bars or, in some cases, tin-plated aluminum bars, which are enclosed in a metal compartment.

The bus compartment is located in the rear of the LV switchgear unit. Horizontal and vertical buses connect all equipment in the unit. LV bus is normally uninsulated, and metal barriers between the bus and rear field cable terminations are optional. The LV circuit breakers are contained in individually grounded metal compartments and controlled either remotely or from the front of the unit. Refer to Figures 2-1 and 2-2 for examples.

Figure 2-1
Eaton/Cutler-Hammer DSII Low-Voltage Switchgear

Figure 2-2
General Electric AKD-10 Low-Voltage Switchgear

2.1.2 Motor Control Centers (MCC)

Similar to LV switchgear, MCCs are nominally rated between 208 Vac and 600 Vac, with the majority of applications at 480 Vac or 600 Vac. Typical continuous MCC current ratings are 300, 600, 800, and 1200A.

MCCs are completely enclosed on all sides and the top with sheet metal. Vertical sections or stacks are bolted together to make an MCC unit. The front of each vertical stack contains removable compartments or buckets with hinged doors, and each bucket contains the feeder disconnecting device (breaker or disconnect switch) along with control and protection components (control transformer, contactor, thermal overload relays, and so on). A small adjacent compartment in each vertical stack provides space for associated control and power cables.

The MCC bus work is at the rear and is almost always inaccessible unless the buckets are removed. Typically MCCs are located against a wall, although large MCCs (that is, those that contain many buckets) might be free-standing with sections mounted back-to-back. When buckets are inserted, stabs on the rear of the bucket plug into the vertical bus. The main horizontal bus is usually at the top of the MCC; standard horizontal bus ratings are usually 600 and 800A, with optional ratings as high as 3200A. Each vertical bus has ratings of 300 and 600A typical, with optional ratings as high as 1200A. Bus bars are usually tin-plated copper. Refer to Figure 2-3 for an example of the typical bus arrangement.

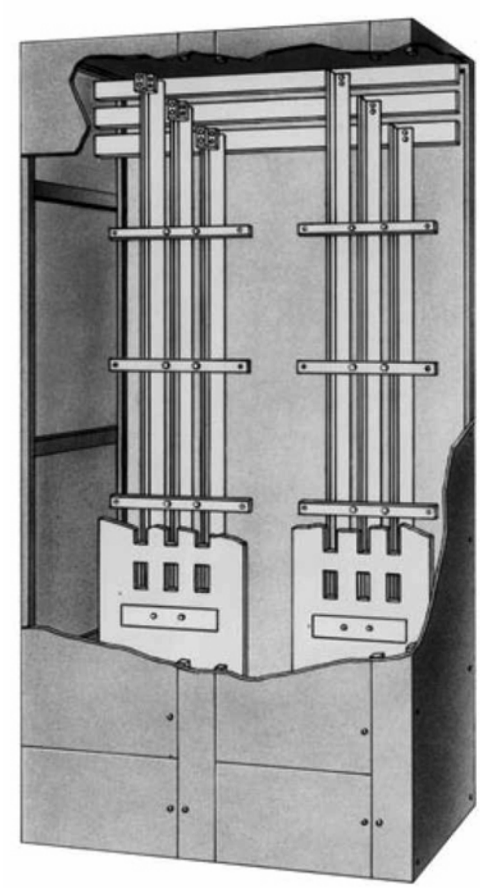

Figure 2-3
MCC Buswork Sketch (buckets cut away)

2.1.3 Medium-Voltage (MV) Metal-Clad Switchgear

MV switchgear is nominally rated between 2.5 kV and 38 kV. The majority of power plant applications are at 4.16, 7.2, or 13.8 kV, and they use air-magnetic or vacuum circuit breakers. Typical continuous bus current ratings are 1200A, 2000A, and 3000A.

The MV switchgear structure is generally an assembly of steel housing units that are normally mounted side by side and connected both mechanically and electrically to form a metal-clad switchgear structure. For older switchgear, each air circuit breaker occupies a single vertical unit. The front of the switchgear enclosure has hinged doors and contains the circuit breaker and PT compartments, as shown in Figure 2-4.

Figure 2-4
Medium-Voltage Switchgear

In the newer vacuum switchgear, two breakers normally occupy a single vertical unit, a two-high configuration, as shown in Figure 2-5.

Figure 2-5
Eaton/Cutler-Hammer Medium-Voltage Vacuum Switchgear

The rear of the switchgear enclosure normally has bolted-on panels and contains the buswork, CTs, and power cable connections. Each compartment is separated from the others by metal barriers. The main buses are copper bus bars or, in some cases, tin-plated aluminum bars. Electrical connections between bus bar segments (and sometimes CTs) are bolted for overlapping segments and/or with similar bolted metal plates if a gapped butt connection is necessary for thermal expansion. The bus bars are connected to the primary disconnect studs at the back of the circuit breaker compartment. Some bus construction is welded and does not include bolted joint connections. This is illustrated in Figures 2-6 and 2-7.

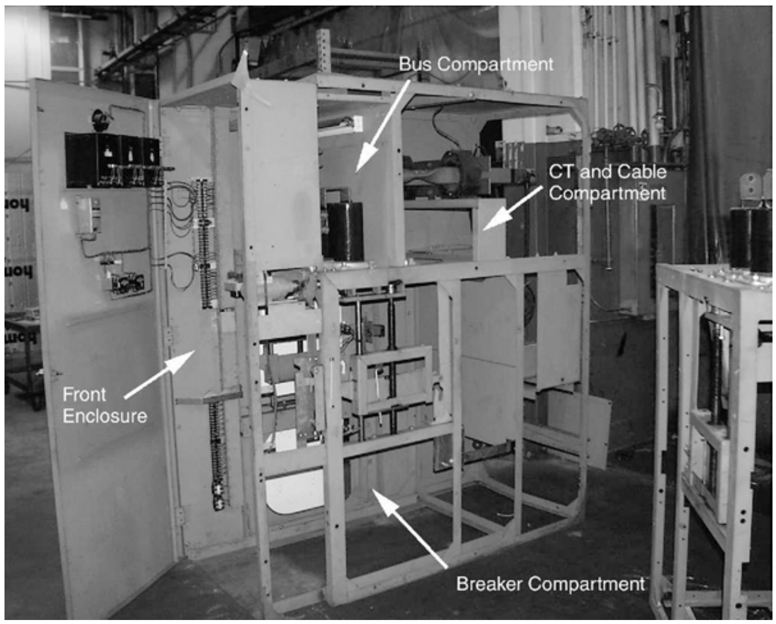

Figure 2-6
15-kV Switchgear Cubicle (metal barriers removed)

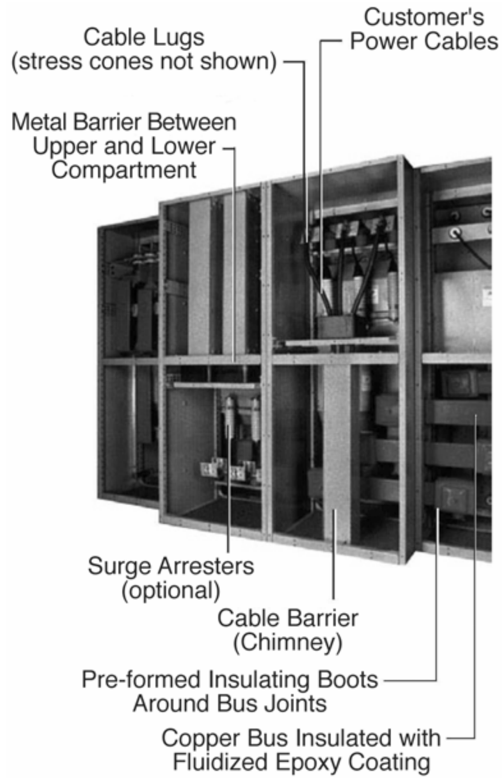

Figure 2-7
Eaton/Cutler-Hammer VCP-W MV Switchgear Bus Compartment

Bus conductors and connections are covered with fire-retardant insulating material. Insulation deterioration can result from air gaps in the insulation associated with older MV switchgear designs. The insulation deterioration can lead to failure if not detected by visual inspection or testing. Some areas are not easily inspected without disassembly.

Principles from this report can apply to other LV and MV equipment, such as bus ducts with similar design features and attributes. Refer to Figure 2-8 for an example.

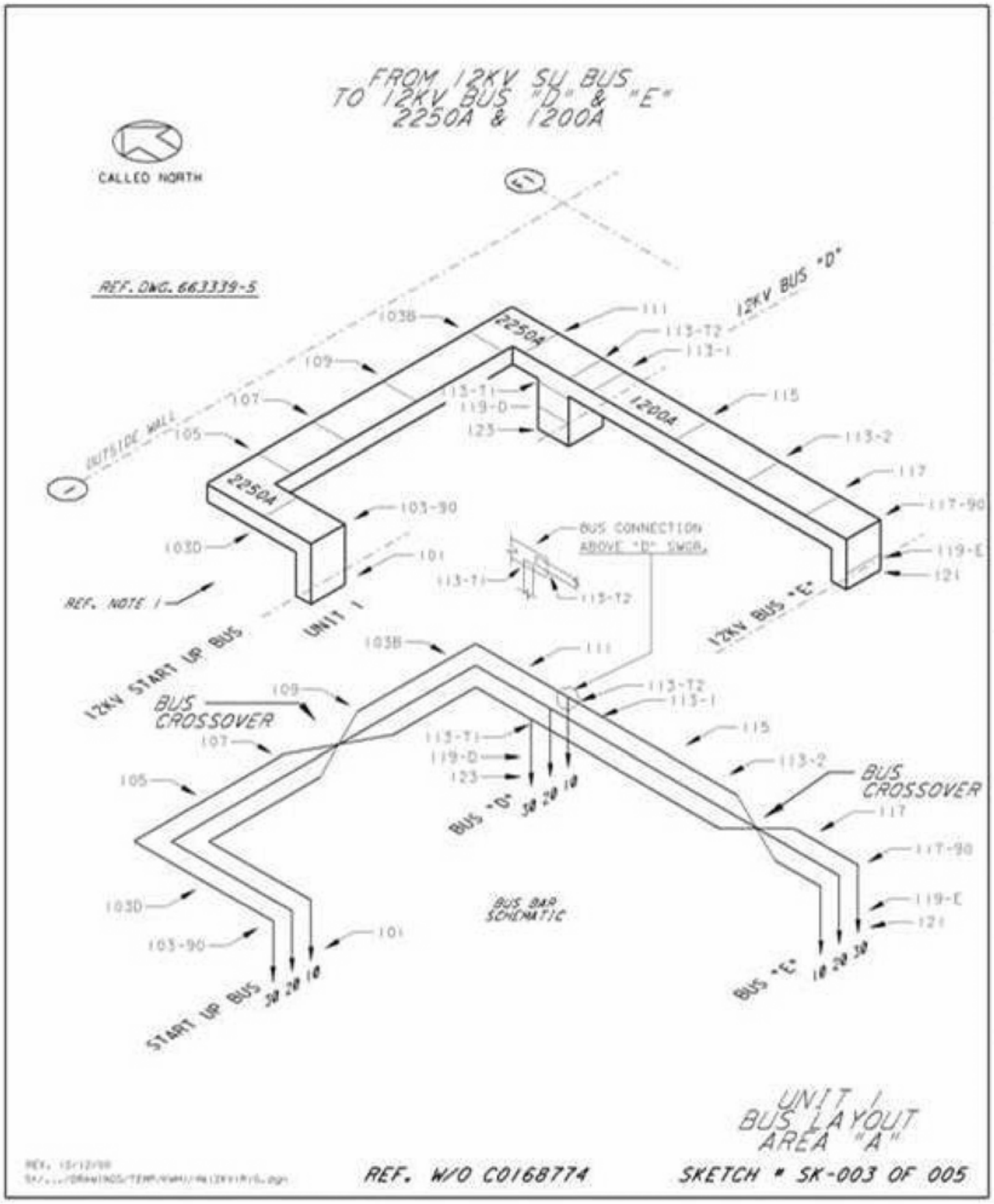

Figure 2-8
Bus Duct Drawing

2.2 Design Considerations

The design considerations [2] for switchgear buses and bus ducts are important to the understanding of proper maintenance because the objective of preventive maintenance is to restore the equipment to as near original design conditions as possible.

2.2.1 Location

An indoor switchgear or bus duct is typically provided with a degree of protection against limited amounts of falling dirt but might not prevent the entry of dust or liquids. Outdoor switchgear or bus ducts are typically housed in ventilated enclosures intended to provide protection against wind and dust, rain, sleet, and the formation of external ice. Locating switchgear in an explosive environment is not typical or recommended.

Typically switchgear is not mounted in locations where vibration or shock is present. Should vibration or shock have an impact on switchgear assemblies, more frequent maintenance might be required to ensure the integrity of the switchgear bus.

Bus ducts can run horizontally or vertically (such as on an outside wall of a building). Vertical runs are more difficult to inspect and can collect dirt, debris, and water at the bottom.

2.2.2 Ambient Temperature

Typical ambient design temperatures are -30ºC to 40ºC. Special considerations above or below these temperatures are considered special design requirements.

2.2.3 Voltage

Maximum voltage is the highest root mean square (rms) voltage for which the bus is designed. Buses are typically designed for the service voltage of 95% to 105% of the nominal voltage.

2.2.4 Power Frequency

A switchgear is designed for a rated frequency of 50 or 60 Hz.

2.2.5 Continuous Current

A switchgear is designed for the maximum current in rms amperes at rated power frequency that can be continuously carried by the bus, including connections without causing temperature rises in excess of specified limits for the insulation or structural and enclosure materials. If ambient temperature is expected to exceed the rated maximum, ampacity derating of the bus is necessary.

2.2.6 Short-Time Withstand Current

A switchgear is designed to withstand the short-time current during fault conditions. It is the limit of available rms symmetrical current at which the bus might be required to withstand the short-time duty cycle. The duty cycle is 0.5 seconds of current flow separated by 15 seconds of zero current flow at maximum rated voltage.

2.2.7 Short Circuit Current

The short circuit is the limit of available rms symmetrical current at rated maximum voltage for a period of at least four cycles.

2.2.8 Insulation Levels

The insulation level of the switchgear is designed to provide dielectric characteristics to withstand both power frequency withstand voltage and basic impulse withstand insulation level (BIL) for MV switchgear.

2.2.9 Temperature Limits for Insulation

The total temperature limit, which is the sum of temperature rise limit and ambient temperature, is based on the class of the insulation material. Typical insulation classes are 90, 105, 130, 155, 180, and 220 and correspond to the rating in degrees celsius. The total temperature limit values are for the hottest spot temperature.

2.2.10 Temperature Limits for Buses and Connections

Temperature limits are based on total temperature and temperature rise of buses and connections and might not exceed those limits. Allowable temperature limits for copper connections are lower than silver or tin surfaced connection joints. Welded joints are not considered connecting joints. The total temperature limit values are for the hottest spot temperature.

2.2.11 Bus Construction and Materials

The bus is typically copper, aluminum, or both. Insulation is designed for high dielectric strength and immunity to contamination and degradation. The bus duct is typically constructed of steel, galvanized steel, or aluminum [1]. The sections of duct are joined together and use sealant or gaskets for protection.

Table 2-1 provides a list of the American Society of Testing Materials (ASTM) standards useful in the selection and procurement of material when performing bus maintenance.

Table 2-1
Suggested List of ASTM Material Standards

Standard	Title
D 150-98 (R2004)	Standard Test Methods for AC Loss Characteristics and Permittivity (Dielectric Constant) of Solid Electrical Insulation
D 1654-1992	Standard Test Method for Evaluation of Painted or Coated Specimens Subjected to Corrosive Environments Document
D 229-2001	Test Methods for Rigid Sheet and Plate Materials Used for Electrical Insulation
D 257-99	Standard Test Methods for DC Resistance or Conductance of Insulating Materials
D 2671	Standard Test Methods for Heat-Shrinkable Tubing for Electrical Use
D 412-1998A (R2002) e1	Standard Test Methods for Vulcanized Rubber and Thermoplastic Elastomers – Tension
D 5374-93 (R2005)	Standard Test Methods for Forced-Convection Laboratory Ovens for Evaluation of Electrical Insulation
G 21-1996 (R2002)	Standard Practice for Determining Resistance of Synthetic Polymeric Materials to Fungi
D 2303	Standard Test Methods for Liquid-Contamination, Inclined-Plane Tracking, and Erosion of Insulating Materials
B 187/B 187M – 02	Standard Specification for Copper, Bus Bar, Rod, and Shapes and General Purpose Rod, Bar, and Shapes

2.2.12 Power Cable Terminations

The bolt hole arrangements for cable terminations are typically of standard design (that is, for acceptance of standard conductor terminals). The bolt length of bus splice connections, including bolts, washers, and nuts, should not impact the dielectric integrity of the bus.

2.2.13 Ground Bus

A ground bus provides the grounding for the non-current carrying switchgear assembly and equipment.

2.2.14 Special Design Considerations

Special design considerations apply for switchgear located in environments that might challenge the proper operation of the buses. More frequent maintenance can be required to mitigate adverse effects caused by the following:

- Environment with fumes, oil, or corrosive vapors

- Environment with abrasive, magnetic, or metallic dust
- Totally enclosed non-ventilated equipment is derated

Specific design considerations can include the following:

- Corrosive resistance finishes
- Use of protective greases
- Non-oxidizing grease used on conductive joints
- Heaters for elimination of condensation

Ventilated enclosures can be provided with disposable or washable dust filters that might require periodic replacement or cleaning.

Heat and humidity can result in fungus that can cause adverse effects on switchgear bus systems. Fungus resistant coatings that are compatible with the insulation materials and bus surfaces and that do not reduce the dielectric or flame resistant properties can be used to mitigate the effects of fungus. ASTM-G21-1996 (R2002) [3] provides information and guidance regarding resistance of synthetic materials to fungi.

2.3 Design, Production, and Performance Testing

Testing at the factory (or a third-party qualification facility) prior to delivery to the end user demonstrates compliance with the design and reveals potential defects in manufacturing or material. Design tests include:

- Lightning impulse withstand test for MV switchgear.
- Insulation level test, which demonstrates the ability of the insulation to withstand maximum rated voltages at power frequency.
- Continuous current test, which demonstrates compliance with design ratings and determines that temperature and temperature rises are within acceptable established limits.
- Short-time withstand current test, which demonstrates mechanical and thermal capability of buses, bus structures, and connections.
- Short circuit current test, which demonstrates the mechanical capability of buses, bus structures, and connections for high specified currents for prescribed time. Typically, the current value is related to short circuit rating for associated circuit breakers.

Mechanical endurance tests do not apply to bus systems or structures because this is a cyclic condition, such as racking breakers in and out, and is typically based on cycles of operation that do not occur with bus systems or structures.

Production tests for bus and bus insulation and structures include dielectric testing.

Field dielectric performance tests are typically performed at 75% of the value of tests performed at the factory. Field dielectric tests are performed only after the equipment is installed and/or restored to good condition and is free of debris, corrosion, or moisture.

3 INDUSTRY EXPERIENCE

3.1 General

The failures and degradation described in this section relate to the electrical bus and the switchgear bus, not to circuit breakers or other active electrical components associated with switchgear and MCCs. The active components are addressed by other EPRI and industry documents.

As mentioned in Section 1.3, the review of industry experience included a literature search of the NRC, EPRI, and INPO web sites to identify documents that addressed switchgear bus and electrical bus failures and degradation. The document searches included NRC information notices, bulletins, and circulars, and also a search of the various INPO operating experience databases. In addition, various other industry documents contain compilations of operating experience for switchgear bus [4, 5]. Also, several NRC NUREG documents, which address switchgear bus and electrical bus, were reviewed for information about degradation and failure mechanisms.

Two reports from Sandia National Laboratories, SAND93-7027 [6] and SAND96-0344 [7], were also reviewed for qualitative information on bus operating experience.

Over the years, switchgear bus failures have occurred at various power generation plants and industrial facilities, resulting in significant economic consequences. Failures of MV electrical bus bars, principally involving 4160- and 6900-Vac buses, have resulted in bus bar electrical faults and fires, electrical power system undervoltage conditions, plant transients, reactor trips, and engineered safety feature actuations.

Failure of the bus bars has been attributed to cracked bus bar insulation (bus sleeving) combined with the accumulation of moisture or debris in the bus bar housings. Insulation failure, along with the presence of moisture or debris, provided undesired phase-to-phase or phase-to-ground electrical tracking paths, which resulted in catastrophic failure of the buses.

Industry experience also includes failures of bus ducts caused by cracked insulation and moisture or debris buildup internal to the bus duct. Experience has also shown that bus work in the bus ducts exposed to appreciable ohmic heating during operation can experience loosening of bolted connections related to repeat cycling of connected loads.

Sandia Report 96-0344 [7] identified cracks in switchgear bus insulation, which resulted from high ambient temperature and contamination from bus bar joint compound. To prevent such failures, the NRC's Interim Staff Guidance (ISG)-17 (a license renewal document) under its Proposed Aging Management Program (AMP) XI.E4 [8], provided guidelines for periodic inspection of metal-enclosed buses. This guidance includes ensuring the following are addressed:

- Internal portions of bus duct assemblies are free of corrosion, debris, excessive dust buildup, and moisture intrusion.
- Electrical buses and their supports are free of insulation cracking.
- Bolted connections of the buses are secure.

NRC Information Notice 89-64 [9] and NRC Information Notice 98-36 [10] provide examples that illustrate the importance of the periodic inspection of bus ducts and the potential problems that can arise from age-related bus duct failures.

Instances of the loosening of the bus bar connecting bolts at several plants due to thermal cycling have been reported in Sandia National Laboratory Report SAND96-0344 [7] and NRC Information Notice 2000-14 [11]. The NRC notice identified torque relaxation of splice plate connecting bolts as one potential cause of a bus duct failure. The corrective actions performed included vendor communications, additional training, improved preventive maintenance and an upgrade to the bus design. Review of the INPO and OEA databases identified causes of the failure to be foreign material and under-designed bus ducts [12].

Additionally, the external portions of bus ducts and structural supports can be inspected in accordance with a plant-specific structural monitoring program [1].

Sections 3.2 and 3.3 provide details of specific events related to switchgear and bus duct failures.

3.2 Industry Failures – Noryl Bus Insulation

The industry has addressed cracked Noryl insulation in various ways. Some plants have taped the cracked areas and are monitoring them for future degradation. Other plants have completely replaced the Noryl insulation with new insulation.

According to NRC Notice 89-64 [9], electric power utilities have addressed some of these concerns in the following ways:

- Replacing damaged bus bar sections with bus bars that were covered with insulation of a different type
- Substituting yellow bus bar joint compound (GE D50H109) for the black joint compound previously used
- Modifying bus bar enclosures to restrict ingress and accumulation of water and debris
- Instituting enhanced periodic inspections and cleaning of bus bars and their housings

An industry survey dated February 2006 [13] regarding Noryl insulation indicated that most plants included in the survey have taped the degraded insulation as an interim measure and are monitoring for future trends. Most survey respondents have replaced or plan to replace the degraded Noryl insulation. Replacement of the insulation is the recommendation from SAL 315.1 [14] and SAL 315.2 [15] as the final repair.

The following sections describe several of the Noryl insulation failure events.

3.2.1 Palo Verde Unit 1 – NRC Notice 89-64 [9]

In 1988, a phase B to ground fault occurred on a 13.8-kV non-Class 1E bus. The fault ionized the air surrounding the bus and caused all three phases to short to ground. Failure of the bus, initiated by the phase B to ground fault, was attributed to cracked and brittle Noryl insulation and dirt that had accumulated in the cubicles. These conditions led to arc tracking, which caused the single phase-to-ground fault. This fault propagated into a three-phase-to-ground fault and the subsequent rupture and ignition of the unit auxiliary transformer (UAT). Figure 3-1 shows the bus damage.

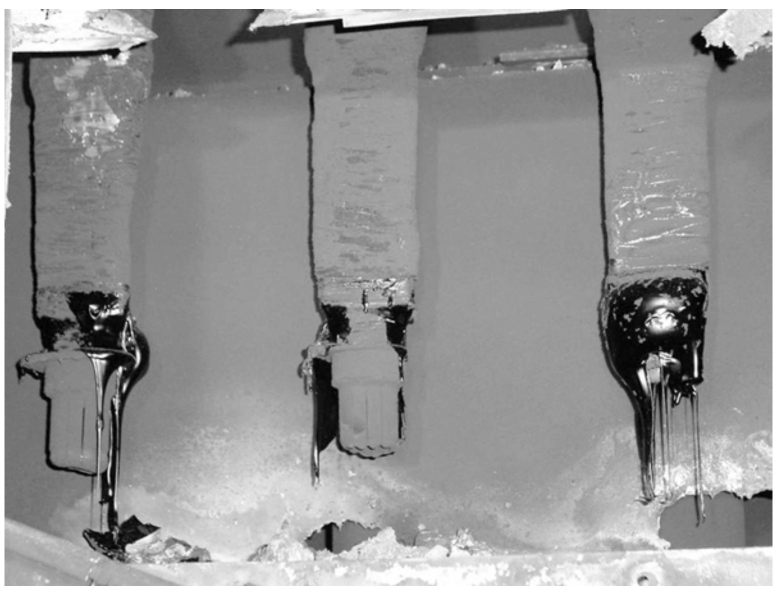

Figure 3-1
Palo Verde Damage

3.2.2 TVA Browns Ferry Unit 2 Nuclear Plant – NRC Notice 89-64 [9]

In 1989, a bus fault to ground occurred on the secondary (4160-V) side of the unit station service transformer, causing an engineered safety feature actuation. The fault also caused damage to the 4160-V bus, the bus duct, and the transformer bushing connections on all three phases.

The fault was attributed to the following:

- Deterioration of the Noryl insulation above the bus joint
- Poor design of the bus duct, which allowed condensation to collect
- Inadequate implementation of the vendor-recommended preventive maintenance

3.2.3 Kewaunee Nuclear Power Plant – NRC Notice 89-64 [9]

In 1988, when the plant was at 93.3% power, a reactor trip and associated turbine trip were generated as a result of undervoltage (UV) conditions on 4160-V buses 1-1 and 1-2, which supply power to the reactor coolant pump and main feedwater pump motors.

Investigations of the UV condition on the buses revealed that an electrical fault had occurred on the bus because of insulation failure. The bus bar, which was a 1/2-in. x 4-in. flat copper bar, was rated at 4000 amperes per phase, encapsulated with Noryl flame-retardant insulation, and enclosed in aluminum ducting with screened ventilation slots on the top and bottom.

The cause of the event was failure of the insulation on the bus bar and the accumulation of water and debris around the bus, which provided a tracking path for the fault. The bus bar ran horizontally into the auxiliary building underneath areas where debris could fall into the bus work. Additionally, water from a plastic drain hose, located on the floor above the faulted section of the bus, was suspected to have dripped onto the bus work.

A similar event had occurred in 1987, when a reactor trip and associated turbine trip occurred as a result of an UV transient on the same 4160-V buses. In this case, a phase-to-ground fault occurred on the bus bar from the “X” winding of the main auxiliary transformer to 4160-V buses 1-3, 1-4, 1-5, and 1-6. This bus bar was similar to the one identified previously, except that it was a flat aluminum bar that was rated at 3000 amperes. The cause of this event was also failure of insulation on the bus bar compounded by the accumulation of particulate debris. The bus bar was located perpendicular to the turbine building ventilation fans, which pulled dust-filled air through a section of the bus bar. Dust and metallic powder that had collected on the cracked bus bar insulation provided a tracking path for the phase-to-ground fault.

3.2.4 Sequoyah Unit 1 – NRC Notice 89-64 [9]

In 1983, when Unit 1 was at 100% power, startup bus 1B at Unit 1 failed because of a phase B to C fault, which propagated to ground. The failure was attributed to degradation of Noryl insulation on the Westinghouse Model EN-265 bus. Further investigation revealed several degraded areas in the bus insulation at the support blocks.

3.2.5 Millstone Unit 1 – NRC Notice 89-64 [9]

In 1987, when Unit 1 was at 100% power, a visual inspection of the 4160-Vac load centers showed that horizontal Noryl bus bar insulation was cracked. The problem was attributed to a manufacturing defect on General Electric Company (GE) metal-clad switchgear type M-26 (4160 Vac) and type M-36 (6900 Vac). Apparently, during the manufacturing process, black bus bar joint compound (GE D50H47) contaminated the Noryl insulation and over several years caused the insulation to crack.

3.3 Industry Failures – Other

The following provides the highlights of select switchgear bus failure events that are unrelated to Noryl insulation failures.

3.3.1 Bruce Nuclear Generating Station, Canada [16]

The Bruce station experienced corona on their 13.8-kV switchgear. Partial discharge (PD) testing both on-line and off-line confirmed insulation degradation, as explained in Section 5.5. Holes were identified in the solid copper bus with silver plating. The remediation project involved upgrading the switchgear insulation with epoxy coatings on conductors and silicone on thru-insulators to minimize PD. The duration of the project was approximately three weeks. Figures 3-2 and 3-3 illustrate corona damage in the area of the switchgear bus.

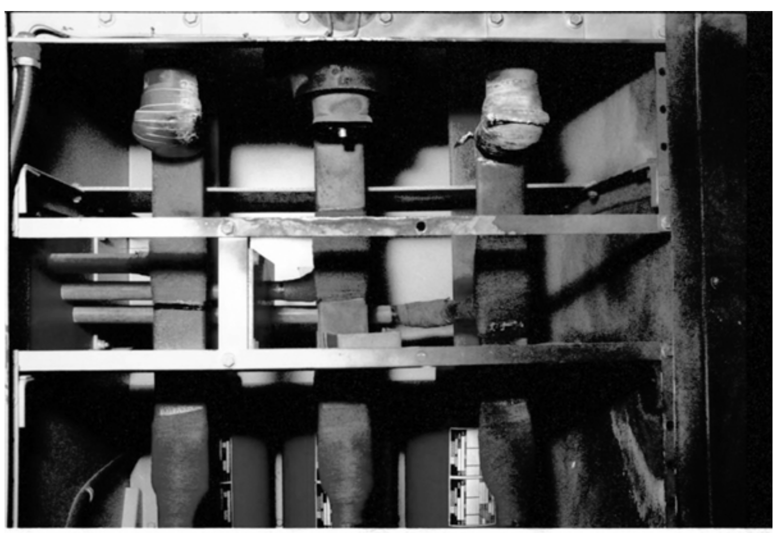

Figure 3-2
Bruce Corona Damage – Bus Area

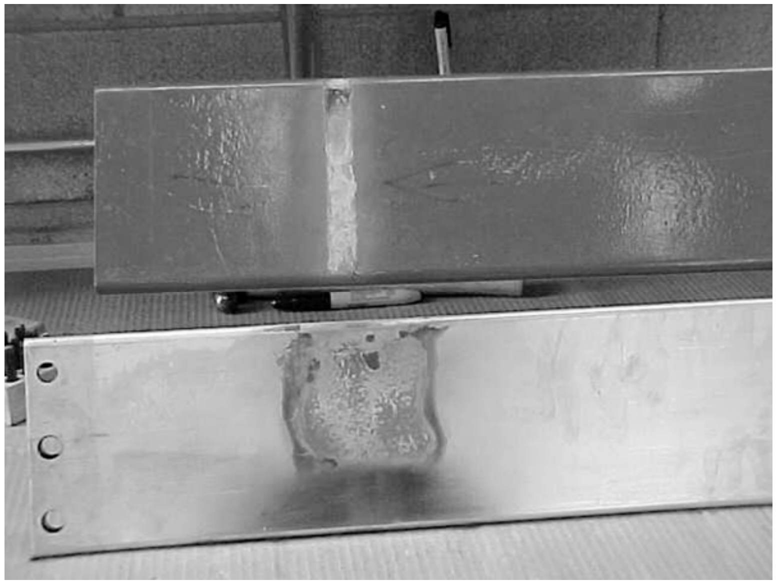

Figure 3-3
Bruce Corona Damage – Insulator Area

3.3.2 Diablo Canyon Nuclear Power Plant – NRC Notice 2000-14 [11, 12]

In 2000, a phase-to-phase electrical fault occurred in a 12-kV non-Class 1E electrical bus duct from the unit auxiliary transformer to the switchgear that supplied the reactor coolant pumps and circulating water pumps. The fault caused a turbine trip and consequent reactor trip, but because this section of bus could not be isolated from the main generator, the fault lasted for four to eight seconds until the generator field voltage decayed. The fault occurred at a point where the bus duct passed under the 4-kV Non-Class 1E bus from the startup transformer. The original 12-kV bus duct fault and the resultant arcing caused a fault in the 4-kV bus duct directly above the original failure. The 12-kV circuit breaker that supplied the 4-kV startup transformers and the faulted 4-kV bus duct downstream of the transformer tripped in response to this second fault, which resulted in a loss of power to all 4-kV vital (safety-related) and non-vital buses.

The auxiliary and startup transformers are connected to the on-site distribution switchgear by 1/2-in. x 6-in. bus bars. All three phases are enclosed in a single non-segregated aluminum duct. The startup and auxiliary 12-kV and 4-kV non-vital switchgear are located within a common room. To connect the two sources of off-site power to multiple switchgears within the room, there are many crossing bus ducts above the switchgear. The non-vital 4-kV bus ducts from both auxiliary and startup power are in close proximity for extended runs.

The bus work in the room was a combination of aluminum and copper bus bars connected with aluminum splice plates secured by four 1/2-in. bolts. The bus bars and splice plates were silver-plated at the connection points to ensure conductivity. The bus bars had a nominal 3/16-in. gap between them at the splice plate to allow for thermal expansion. The 12-kV bus bars had a 6-in. air gap between phases, which is slightly below the required air gap for uninsulated conductors; therefore, the bus bars and connections were insulated with a combination of sleeves and wraps. The 4-kV bus bars were similarly insulated. Figures 3-4 and 3-5 show the extent of the damage.

Figure 3-4
Diablo Canyon Bus Duct Damage

Figure 3-5
Diablo Canyon Bus Duct Damage

Besides deenergizing all non-vital 4-kV power within the plant, the loss of both sources of non-vital power also caused a loss of the 480-Vac power supply to the switchyard control building. This failure led to a loss of power to the charger for the switchyard batteries. The eventual depletion of the switchyard batteries would have led to a loss of control power in the switchyard serving both Diablo Canyon units. The loss of control power would have disabled remote control of the switchyard high-voltage circuit breakers.

The plant concluded that a center bus bar overheated at a splice joint, which caused a polyvinyl chloride (PVC) boot insulator over the splice joint to smoke. Eventually, heat-induced failure of fiberglass insulation on adjacent phases resulted in phase-to-phase arcing. The fault and resultant fire destroyed any direct physical evidence of the root cause; however, the following factors could individually or jointly have led to the failure:

- Inconsistent silver-plating
- Currents approaching bus capacity
- Undersized splice plates
- Torque relaxation of connecting bolts
- Undetected damage from a 1995 explosion of Auxiliary Transformer 1-1

The plant examined the various design issues associated with the 12-kV and 4-kV buses. Buses with operating currents near design limits were judged to be operable because the expected temperature at the plant was considerably lower than the ambient temperature assumed in the vendor heat rise test acceptance criteria.

Figure 3-6 shows the subsequent bus duct repair.

Figure 3-6
Diablo Canyon Bus Duct Repair (external view)

Planned actions to prevent recurrence included the following:

- Inspect and torque the bolted connections on the 3750-amp bus and replace splice plates on the bolted connections with full-face copper splice plates.
- Inspect and torque splice plate connections on the 4-kV auxiliary buses.
- Upgrade the 2250-amp 12-kV buses from aluminum to copper.

3.3.3 Prairie Island Nuclear Generating Station [17]

In August 2001, while transferring buses to the Unit 1 Main Transformer as part of normal startup, a catastrophic failure occurred on one of the primary disconnect assemblies (PDA) on a breaker. Damage from the subsequent fault and fire resulted in a unit shutdown to effect repairs for approximately six weeks.

The root cause investigation determined that a connector PDA between the breaker and the bus had failed, causing the air to ionize, leading to a phase-to-phase fault. The specific failure mode that brought about the PDA failure was difficult to determine due to the general condition of the equipment following the event, as shown in Figure 3-7. However, one of the root cause investigation primary actions was to inspect PDAs prior to racking circuit breakers to the connected position.

Figure 3-7
Prairie Island Switchgear Damage

Subsequent to the August 2001 event, PDAs on other circuit breakers were found to be in poor condition. All six PDAs on one breaker were glued in place due to the high temperatures experienced, and this caused the NO-OX to run and then lacquer, as shown in Figure 3-8. One of the breaker terminals showed signs of significant overheating as well.

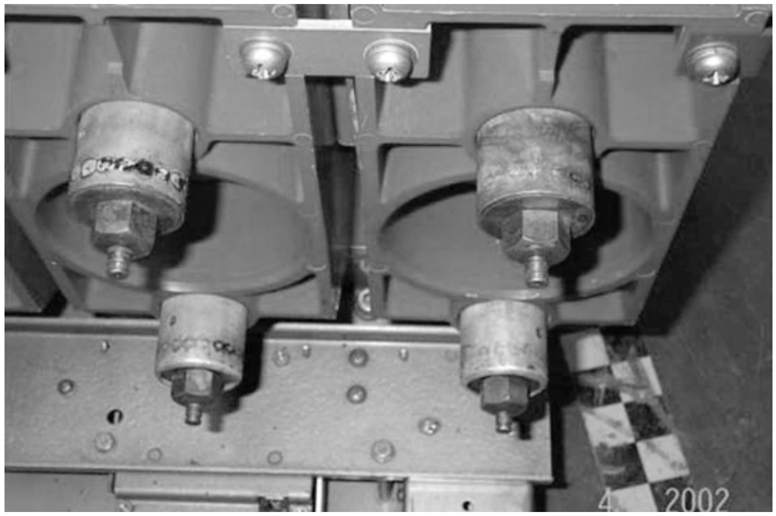

Figure 3-8
Prairie Island PDA Overheating Damage

Cubicle-to-cubicle resistance checks taken from bus stab to bus stab revealed that the resistance was well within the acceptable limits (typically 40 μΩ). Then, using a ground/test truck (not a practice for measuring contact resistance), resistance to the adjacent cubicle was measured and found to be relatively high (typically 1,111 μΩ). The ground/test truck was not able to make a good electrical connection to the bus stabs.

When the bus stabs were removed from the bus, what appeared to be NO-OX had baked on the bus stabs; it had prevented a good electrical connection through the ground truck. The bus stabs were replaced, and the subsequent cubicle-to-cubicle resistance measurements through a ground truck were significantly lower (typically 44 μΩ).

Several of the PM changes resulting from these events and investigations were:

- Inspect circuit breakers prior to racking them to the connected position.
- Stop the use of abrasives, such as Scotch-Brite pads, for cleaning silver-plated terminal connections.
- Use the ground/test truck for measuring electrical connection to the bus.
- Define an alternative method that includes the PDAs for measuring circuit breaker contact resistance.
- Explicitly call out the inspection and cleaning of bus stabs in procedures.
- Increase awareness of the condition of the silver-plated connection surfaces.

The events and investigations presented the concern that thermography did not indicate the potential overheating condition, perhaps because thermography is a snapshot, and there are difficulties due to the physical layout of the equipment.

3.3.4 Station Blackout Event at Taiwan Power Maanshan Nuclear Power Plant [18, 19]

In March 2001, a significant station blackout event occurred. The 4.16-kV bus A failed due to bus grounding. This led two breakers to trip, and both the 345-kV and 161-kV off-site sources could not supply electric power to the 4.16-kV essential bus B. The root cause of the incident was judged to be insulation degradation of a circuit breaker. An electrical arc made the ambient air ionize inside the switchgear cubicle, and the electrical buses were seriously damaged.

Based on investigation reports by staff and independent review teams, the breaker fault on the 4.16-kV essential bus A was the main cause of this incident. One possible cause of breaker fault was determined to be insulation degradation of B-phase electric connection end before the incident.

The Taiwan Power Company improved the surveillance program for the breakers of all essential buses.

3.3.5 Byron Unit 1 – NRC Notice 98-36 [10]

In 1996, with the Unit 1 reactor shut down more than a month for a refueling outage, off-site power was lost when one of the two Unit 1 SATs isolated because of a phase A to B current differential relay operation. The second SAT tripped as designed when the first SAT failed. Both EDGs automatically started, and all safe-shutdown loads automatically sequenced on to the ESF buses. Because the reactor was shut down, power to non-ESF buses was lost, and two service water pumps and a station air compressor common to both Byron units tripped. Without the service water pumps, Unit 2, which was operating at full power, had no cooling water to many loads, including the main generator auxiliaries, station air compressors, condensate pumps, and condensate booster pumps. Subsequently, Unit 2 was manually tripped.

The licensee determined that the SAT that initially tripped underwent a phase-to-ground fault on a Phase B insulator. The failed insulator was located outdoors, about halfway between the SAT and the auxiliary building. After the fault, the arc continued down the bus bar, increasing in width until it involved the other two phases. Air and water present in the bus bar duct were heated by the arc and resulted in pressurization of the duct.

Chronic water leakage through inadequately caulked insulator mounting holes and through an improperly compressed gasket caused degradation of the insulator metal inserts and insulator material between these inserts. Eventually, the bus flashed to ground through the degraded insulator and initiated the transient.

3.3.6 Perry – NRC Notice 98-36 [10]

In 1997, Perry was operating at full power when an automatic reactor scram occurred following a three-phase fault in one of two high-voltage secondary winding termination compartments of the UAT. The fault resulted in the actuation of the auxiliary transformer phase differential relay, a main generator lockout, a main turbine trip, and fast closure of the turbine control valves.

The plant determined that the fault had developed as a result of an accumulation of moisture and dust that had entered the termination compartment housing where a 2-in. piece of gasket material was missing from the compartment housing-to-transformer sealing surface. The missing piece of gasket material might have been lost during work performed when replacing the auxiliary transformer following failure of the transformer on May 30, 1996. The cause of that failure was attributed to inadequate original design, poor assembly practices, or both.

3.3.7 Point Beach Unit 1 – NRC Notice 98-36 [10]

During a severe storm in January 1998, a ground in the LV-side bus duct caused the failure of the Unit 1 SAT. This failure and a failure of the 13.8-kV automatic bus transfer to the Unit 2 SAT resulted in the loss of normal power to the Unit 1 safeguard buses. The EDGs subsequently started and restored power to the buses. Unit 1 remained at 98% power throughout the transient, and Unit 2 was in cold shutdown.

The plant attributed the failure of the transformer to the buildup of condensation internal to the buses and long-term insulation degradation in the bus duct on the LV side of the transformer. Before the transformer failed, the circuit breaker for a heater designed to keep the bus duct dry would not remain closed. Consequently, in August 1996, the licensee left the circuit breaker open and wrote a work order for its repair. However, work schedulers did not recognize that the bus duct heater was inoperable with the circuit breaker open, and the work order was erroneously classified as minor maintenance and given low priority. At the time the transformer failed, the work order was in the backlog of maintenance items. In addition to the inoperable heater, the licensee determined that the lack of a routine inspection program for the bus ducts might have contributed to the event. Inspection of the bus ducts after the transformer failed revealed insulation breakdown that would likely have been identified during a periodic inspection program.

3.3.8 Brunswick Units 1 and 2 – NRC Notice 88-11 [20]

During an inspection of MCCs and switchboards classified as Class 1E, as well as some not classified as 1E, Carolina Power and Light (CP&L) found that numerous 5/16-in. silicon bronze carriage bolts connecting the bus bars had failed. These bolts are used to ensure electric connection and not structural integrity. The percentage of failed bolts approached 35% in some inspected equipment. In one case both bolts in a splice had failed, and there was evidence of high-resistance-induced overheating.

In 1973, during bus bar installation, CP&L noted many failures of the bolts used to splice the bars and connect battery cables. The licensee discussed this problem with GE, and it was discovered that the 18 ft.lb torque identified on a drawing was incorrect. The correct value was 9 ft.lb. This drawing had been provided to the architect/engineer, United Engineers, and was used during construction in 1973. In addition, no lubricant was specified or used; however, had a lubricant been used, torquing to 9 ft.lb would have increased the bolting stress, which could also lead to bolt failure.

After 10 years of power production, CP&L instituted a program to inspect the internals of MCCs and switchboards. This program had a rotating inspection schedule that allowed for 10% of the equipment to be inspected at each refueling outage. By 1986, approximately 40% of the equipment had been inspected. After finding one or two failed bolts in each inspected MCC (approximately 4% failure rate), CP&L concluded that an accelerated inspection program was necessary. The accelerated inspection, which also involved the dc switchboards, revealed as many as 19 failed bolts out of 54 bolts in one of the dc switchboards, or a failure rate of about 35%. The dc switchboards were not part of the initial inspection because they were shared between both units, and simultaneous outages were required to perform the inspection.

The existence of this problem can be determined by checking installation instructions, verifying torque values, and/or by visual examinations. Re-torque of these bolts might not be adequate to ensure their continued service; replacement might be necessary.

3.3.9 ITE Imperial Series 5600 MCCs – NRC Circular 77-03

In 1976, a fire occurred in a safety-related ITE Imperial Series 5600 MCC [21] at Three Mile Island Unit No. 2. The fire was caused by a partial engagement of the plug-in connector assembly of a combination circuit breaker/starter unit with the vertical MCC bus. This resulted in a high-resistance contact between one connector stab and a vertical bus bar with localized overheating of the stab. The hot stab ignited a vertical insulation backwall that was made of fiberglass polyester. The backwall was provided by the vendor as a barrier between the normally energized vertical bus and the breaker/starter unit compartments.

A similar fire occurred in an ITE Series 5600 Motor Control Center at the Trojan Nuclear Station earlier in 1976 as a result of a mis-stab of the plug-in connector assembly to the vertical bus. Subsequent to this fire at Trojan, ITE reportedly issued a technical instruction letter to nuclear power plants using these MCCs advising them of the potential connector misalignment problem and recommending procedural steps to preclude future occurrences. This instruction was received by Three Mile Island Unit No. 2 and was in the process of being implemented, but the breaker/starter unit that caused the fire had not yet been checked as recommended in the ITE Instruction Letter.

The MCC fire at Three Mile Island Unit No. 2 essentially destroyed the entire MCC. The insulation backwall continued to burn after the MCC was deenergized, and the fire progressed upward and ignited a similar plastic barrier near the top of the MCC, which was provided to separate the horizontal bus from the wire-way. The fire apparently continued along the horizontal barrier, igniting the other vertical backwall barriers and destroying most of the breaker/starter unit in the MCC.

3.3.10 Crystal River 3 – INPO O&MR 300 [22]

Crystal River 3 was operating at 93% power when a fault in one of the 6900-V auxiliary buses supplying the reactor coolant pumps caused a scram when two of the four pumps were lost. The root cause of the fault was not determined because of the damage to the bus, but the most plausible explanation was a loose-bolted connection on a bus bar, which caused an electrical arc, ultimately causing a phase-to-phase fault. Many other bolted connections in the 6900-V buses (and also the 4160-V buses) had incorrect torque values.

3.3.11 Isophase Bus Failures

Other INPO items identified during the review, SER 1-90 [23], SER 4-04 [24], and O&MR 414 [25], involved problems with the isophase bus associated with the main generator or the step-up transformers. Isophase bus is not within the scope of this report; however, the issues identified are quite similar to switchgear bus maintenance and inspection. These issues are loose connections, insulation failure (and subsequent arcing), the presence of debris (including metallic objects) in the duct, insulation deterioration, and broken laminate (a flexible link) on the aluminum. Many of these problems were undetected because maintenance practices were inadequate, and inspectors did not look at the entire bus or at the insulation and laminate in the duct.

3.4 Effects of Failures on Production Loss

Table 3-1 provides data regarding the effect of various equipment-type failures on production loss. They indicate that the failure of the primary switchgear bus at 15 kV and above is obviously farther upstream in the electrical distribution system and typically results in a greater percentage loss of production [7].

Table 3-1
Percentage of Failures Resulting in Production Loss

Equipment	Percentage of Failures Resulting in Production Loss	Accessible for Maintenance	Most Common Highest Level Distribution Voltage	Current Common Maintenance Practices
Switchgear Bus – Bare	50%	No	5/15 kV	PD
Switchgear Bus – Insulated	20%	No	≥15 kV	PD
Cable Terminations	18%	Yes	5/15 kV	Thermography of connections
Bus Duct	15%	Yes	5/15 kV	Thermography of joints/bus plugs
Cable	13%	Yes	<600 V	Megger
Cable Joints	9%	Yes	<600 V	Thermography of connections
Circuit Breakers	8%	Yes	<600 V	High-pot, inspection, cleaning and lube

3.5 Failure Mode of the Switchgear Bus Insulation System

The failure mode of the switchgear bus insulation system is also shown by the end-user input [26] and is summarized in Table 3-2.

Table 3-2
End-User Survey of Damaged Part of Bus

Switchgear Bus – Insulated	% of Failures
Insulation – Other	90
Insulation – Bushing	5
Other Electrical – Auxiliary	5
Total	100

3.6 Lessons Learned

Failures associated with switchgear bus systems have occurred because of lack of maintenance, including the lack of inspections for extended periods. Failure mechanisms can be detected by inspection and testing of switchgear bus systems on a periodic basis. Normally inaccessible areas should also be checked.

Redesign and/or upgrades of switchgear bus systems from the 1970s and earlier, including minimizing air gaps in the insulation systems, provide a better design and minimize corona.

Improved insulation material can prevent the formation of chlorides leading to corrosion. The new materials have better resistance to heat than the old materials.

Technology has provided new methods for successful testing, including PD for MV switchgear, fiber optic technology for temperature monitoring, arc flash detection, acoustic monitoring, and thermography.

Having adequate silver-plating thickness on switchgear bus joints can minimize related failures.

When maintenance is performed on switchgear bus and metal-enclosed bus, the bolted connections must be made in accordance with approved procedures that provide clear guidance on good bolting practices for electrical bus. In addition, inspections of the bus duct should include a check of the enclosure and the associated supports.

4
FAILURE MECHANISMS

Periodic inspections and maintenance can preclude failures associated with failure mechanisms. Evaluation of the potential of any failure mechanism should establish periodic inspection commensurate with the potential for failure.

Sections 4.1 through 4.7 explain the failure mechanisms that have been observed for switchgear buses and electrical buses.

4.1 Corona

Corona is the ionization of the nitrogen in air caused by an intense electric field. Ozone and a cracking sound result from corona. A white powder can form as a result of the breakdown of the insulation.

The burning of insulation can release conductive carbon, which results in a very labor-intensive cleanup due to the widespread distribution of the conductive carbon. Conductive carbon deposits or corona can lead to failures. Corona and surface tracking are the key failure mechanisms associated with switchgear bus failures.

Air gaps or voids between bus bar and insulation and insulation support barriers can lead to corona at the air gaps. Figure 4-1 is an example of corona damage from switchgear at a fossil-fired generating station.

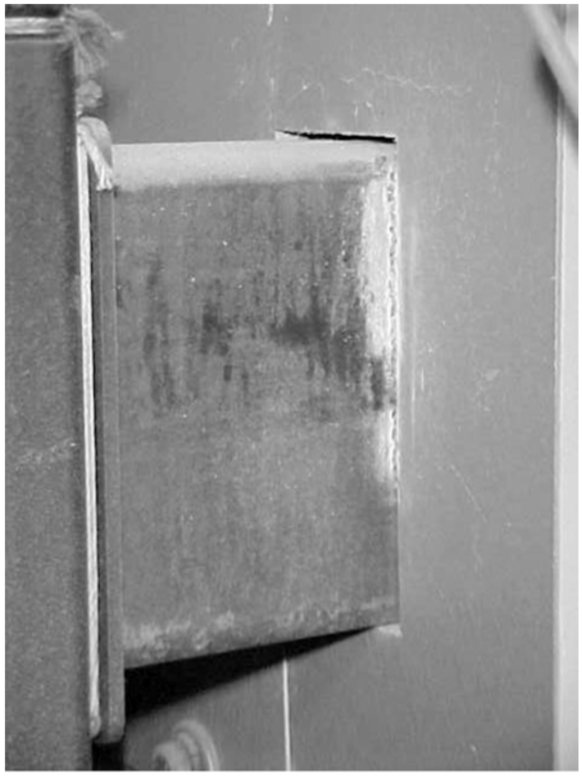

Figure 4-1
Fossil Plant Corona Damage

Corona is a serious issue in MV metal-clad switchgear because of its highly destructive nature. It is the cause of most flashovers in the equipment. Typically, after 10 years of operating history at greater than 11 kV, signs of PDs or corona are noted. After 20 years, physical evidence of material breakdown, such as pitting, tracking, and treeing can be evident.

4.2 Overheating

Overheating is usually caused by heat generated at electrical connections due to high resistance at degraded (loose or relaxed) connections. It can also be caused by actual bus loads at or above the design rating. Overheating can also result in degradation of insulation materials; chlorides can be released as a result of degradation of certain PVC material when heated in excess of the material temperature limit.

Cyclic overheating can cause thermal stresses at the electrical connection with consequent loosening of the connection. This further degrades the connection, causing higher joint resistance and increased heating.

4.3 Insulation Deterioration

Insulation deterioration, particularly associated with older MV switchgear designs, can result from air gaps in the insulation. The insulation deterioration can lead to failures (for example, phase-to-phase or phase-to-ground MV faults, or PT or CT secondary wiring faults, as noted in Figure 4-2) if the deterioration is not detected by visual inspection or some other inspection and/or monitoring means (refer to Section 5). Some areas might not be easily inspected without a switchgear outage and partial disassembly.

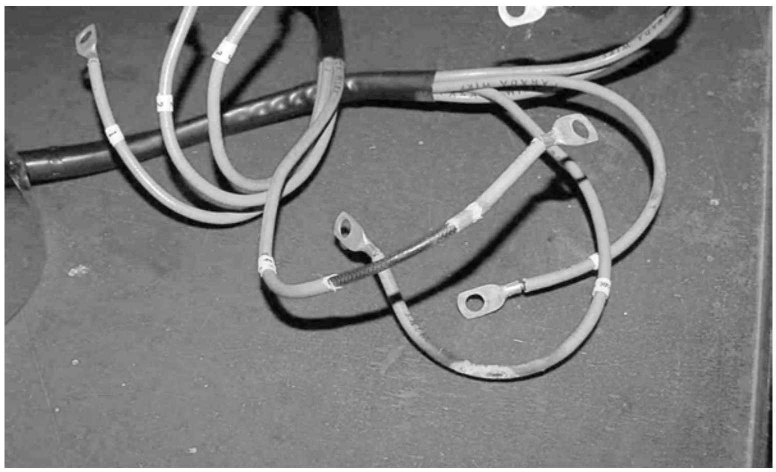

Figure 4-2
Bruce Corona Damage of Wire Insulation

4.3.1 Contaminants

Contaminants (dust, debris, bugs, and small animals) can cause direct conductive paths to ground or a breakdown of the insulation dielectric.

4.3.2 Adverse Environment

In dusty environments, switchgear needs filtered ventilation systems, which require periodic maintenance, including filter cleaning or replacement. Dust can lead to degradation and potential failures. Filtered ventilation of the switchgear is recommended to eliminate contamination from all dusts, but especially in atmospheres potentially exposed to coal dust.

Switchgear locations in areas with high humidity might need more frequent maintenance to mitigate the effects of the humidity. Switchgear compartments should have space heaters, either thermostatically controlled or continuously energized, to prevent condensation. Fungus-resistant material is available.

Locations near salt water might lead to corrosion (see Section 4.4) and subsequent deterioration and failure of the bus. Moisture entering the switchgear at any location should be cleaned up and eliminated at the source.

Ionization of the air inside the switchgear along with other factors present in the switchgear (such as other conductive paths to ground caused by contaminates) can propagate into more devastating results.

4.4 Corrosion

Corrosion is defined as the deterioration of a base metal resulting from a reaction with its environment. More specifically, it can be described as the influence of reactive gases in an environment that causes corrosion. Corrosion is accelerated by increased concentration of contaminants, elevated temperature, and high humidity. Time of exposure is a factor in the degree of degradation.

The installation of electrical equipment in adverse environments containing corrosive gases, liquids, or dust can cause severe and rapid deterioration of the equipment. Electrical components most affected are those fabricated of copper, aluminum, and silver compounds. Frequently, the consequences of corrosion include costly unexpected downtime and additional maintenance costs. Corrosion could possibly result in fire and/or personnel injury.

Gradual electrical degradation of both the conducting and insulating portions of electrical connectors is commonly observed in power plant environments. Electrical connectors can fail to function because of the formation of small amounts of corrosion products, often virtually invisible, on contacting surfaces. A more obvious category of corrosion attack is the visible corrosion of metallic components (produced by crevice corrosion, pitting corrosion, and galvanic corrosion).

Corrosive environments frequently require the use of approved protective greases, coatings, or corrosion-resistant insulating material.

4.5 Incorrect Design

The design of the switchgear bus system must match the operating conditions of the system. Industry experience has noted that design margin is important in a reliable electrical system. If a switchgear bus system is not designed properly, catastrophic failures can result. Failures have occurred when design margins are small and degradation is present, which further reduces margins during actual operating conditions.

4.6 Incorrect Material

Incorrect material can result in breakdown in insulation due to inadequate thermal or dielectric capabilities of the material. Bolting material should match the configuration and material of the bus joints to provide the correct rates of thermal expansion and preclude loose connections at the bus joints. Adequate silver-plating at bus joints can reduce resistivity and reduce heating at the joints. Heating at the joints could lead to the breakdown of the insulation material, possibly releasing chemicals and vapors that can have an adverse affect on metals and reduced insulation effectiveness.

4.7 Improper Maintenance

4.7.1 Bus Connections

Cleanliness and pressure between the conducting surfaces (that is, torque of fasteners) ensures good, high-conductivity connections. The manufacturer's instructions regarding torque and other special instructions should be followed.

4.7.2 Cable Connections

Cable, termination kits, and lug manufacturers' instructions should be followed when making cable terminations. Like bus connections, the conductivity of the cable terminations is dependent on cleanliness and pressure between the conducting surfaces.

4.7.3 Switchgear Auxiliary Compartments

Compartments containing CTs and PTs can be the weakest point of the switchgear bus. The deterioration of the components along with changes in environmental or system conditions can result in catastrophic failures.

4.7.4 Switchgear Grounding

Ground bus connections should be treated the same as current-carrying connections. A low-resistance ground provides adequate protection and safety. The preferred method is to use NEMA two-hole or four-hole lugs and/or connectors.

4.8 Impact of Failure Mechanisms on Switchgear Components

4.8.1 Buses

The primary failure modes are usually loose connections, overheating, or excessive corrosion by abnormal exposure.

4.8.2 Primary Bus Conductors

MV primary bus conductors and connections are covered with insulating material throughout. The primary failure modes are usually insulating material failure due to overheating or broken insulating material.

4.8.3 Current Transformers

The primary winding/bus failure is usually caused by overheating and short circuits.

4.8.4 Voltage (Potential) Transformers

The primary failure mode is usually overheating.

4.8.5 Fuses

Fuse failure is frequently caused by the stresses imposed by cyclic heating associated with cyclic loading.

4.9 Switchgear Cubicle Aging Mechanisms

Table 4-1 lists failure mechanisms associated with switchgear bus cubicle components and typical programs adopted to improve the reliability of the associated equipment [5].

Table 4-1
Switchgear Cubicle Aging Mechanisms

Component	Material	Aging Effects	Aging Mechanism	Typical Aging Management Program
Racking Mechanism	Steel	Binding	Corrosion, lack of lubrication, inactivity	Periodic PM cleaning and lubrication
		Loose/missing parts	Vibration, cycling	Visual inspection, overhaul
		Distortion	Physical damage, handling	Visual inspection
Disconnects/ Stabs	Copper, brass, silver	Arcing, loss of contact	Lack of or excessive lubrication, spring annealing, poor alignment	Surveillance testing, periodic PM, visual inspection, overhaul
Housing	Metal or plastic	Discoloration, cracking, splitting, loss of label	Overheating, vibration, cycling	Visual inspection
Current and Potential Transformers	Various	Discoloration, melting, burning, short circuit	Insulation failure, overheating	Visual inspection, testing

4.10 Aggregate Failure Effects

Bus failures can result from a combination of the environment and improper maintenance. These synergistic mechanisms can accelerate degradation, leading to failure. Special consideration should be given to environments that can contain multiple challenges to the integrity of the bus connections or insulation systems.

5
MONITORING

The following monitoring technologies can be used in performing the predictive maintenance of switchgear buses and bus-associated enclosures and components. For each technology listed, the following areas are addressed:

- Technology
- Equipment used
- Advantages
- Limitations
- Complexity-installation/usage
- Application considerations – design and industry experience

5.1 Thermal Imaging

5.1.1 Technology

Thermal imaging, also called thermography, consists of non-contact infrared or heat pictures from which temperature measurements can be made. Thermal imaging relies on the line of sight to the bus connection being monitored.

Infrared imaging systems scan equipment and structures, then instantly convert the thermal images to visible pictures for quantitative temperature analysis. By detecting anomalies often invisible to the naked eye, thermography can allow corrective action before costly system failures occur.

Implementing a predictive maintenance program that includes thermal imaging is a good way to increase system reliability by locating and correcting degrading components before they cause interruptions in service.

5.1.2 Equipment

An infrared camera is a non-contact device that detects infrared energy (heat) and converts it into an electronic signal, which is then processed to produce a thermal image on a video monitor and perform temperature calculations. Heat sensed by an infrared camera can be very precisely quantified, allowing the user to not only monitor thermal performance but also identify and evaluate the relative severity of heat-related problems. Built-in visual imaging, automatic functionality, and infrared software development can provide cost-effective thermal analysis solutions.

5.1.3 Advantages

As an electrical connection loosens and/or relaxes, its resistance increases, which causes increased temperature due to the current flowing through the connection. This increased temperature at the connection, or hot spot, can then cause further loosening and component failure.

Thermography can quickly locate hot spots and determine the severity of the problem. The camera user can instantly locate and document degraded connections, fuses, circuit breakers, wiring, and other electrical components. Repair can then be scheduled, enhancing productivity and safety while averting unscheduled system shutdowns. Thermography is non-intrusive; therefore, the switchgear can remain in service while collecting data for analysis. Thermography is typically controlled by procedure at most nuclear plants; a user can be trained to perform the procedure (and to use the equipment) with little difficulty.

5.1.4 Limitations

Thermography requires a direct line of sight to the energized connection or component being monitored; therefore, it must be performed while electrical panel doors are open. Thermographic surveys should be performed during periods of maximum possible switchgear loading but no less than 40% of rated load.

5.1.5 Complexity

5.1.5.1 Installation

There are no installation requirements directly associated with the use of the thermography equipment. However, if it is considered economical, and they do not already exist, viewing windows can be installed in switchgear to allow for a direct line of sight to the areas to be monitored without the need for panel removal.

5.1.5.2 Usage

Training on the use of the thermography equipment and interpretation of the data being collected needs to be considered. The actual use of the equipment to collect the data is not labor intensive. However, if the areas to be monitored are inaccessible, any required disassembly (for example, removal of bolt-on panels) must be considered. Safety considerations associated with adequate shielding of personnel from the potentially dangerous effects of electrical fields or contact with live parts should be considered. When panels are removed for monitoring, protective (arc flash) clothing is usually required.

5.1.6 Application Considerations

5.1.6.1 Design

There are no design requirements directly associated with the use of thermography. Viewing windows can be designed or retrofit into the switchgear to allow for a direct line of sight to the areas to be monitored.

5.1.6.2 Industry Experience

The normal heating effect of the current in energized buses can be compensated by comparing the compartment temperature with that of neighboring compartments carrying similar loads, by trending the temperature readings of a particular unit over time, or by comparing a thermal image to a baseline signature. Additionally, a temperature comparison of all three phases should be made while accounting for the potential effects of phase current unbalance. The typical frequency for thermographic inspection is one year because of the quick, non-intrusive nature of the task and the ease with which many adjacent cubicles can be surveyed at one time and location. This task interval is significantly shorter than the times to first failure anticipated for bus failure causes.

The compartment thermographic scan should include the inspection for unusual heating of the circuit breaker and truck, cubicle, and bus work.

5.2 Acoustic (Ultrasonic)

Breakdown of insulation systems and associated arcing can produce waves, which can be detected by ultrasonic energy measurement. Ultrasonic corona detection can be used in predictive maintenance, but the technology is not applicable to LV equipment because the corona phenomenon does not occur at these lower voltages.

5.2.1 Technology

This acoustic emission test can detect discharge, such as arcing, tracking, and corona from all high-voltage components.

The probe contains a high-sensitivity, piezo-electric, ceramic sensor element, which responds to frequencies in the range 100–130 kHz. The sensor element detects ultrasonic signals and the tuned frequency response of the element is 100 kHz; this frequency is the optimum for detecting ultrasonic signals generated from PD within the compartment under test. The signal produced by the piezo-electric element is amplified by a high signal-to-noise ratio pre-amplifier. This amplifies both the signal and the noise but increases the signal-to-noise ratio and decreases the effect of attenuation on the signal. The amplified signals are processed by an analyzer, which reads maximum peak and the number of peaks (count) above an adjustable threshold to generate data to be trended.

5.2.2 Equipment

The piezo-electric probe is attached magnetically to the exterior of the switchgear or transformer casing under test. Data recording and software are available to provide trending and analysis of the data.

5.2.3 Advantages

The acoustic monitor is non-intrusive, portable, and does not require installation other than attachment of the magnetic probe to the compartment or component to be tested.

5.2.4 Limitations

The detection of the acoustic spectrum requires direct line of sensing to the source. Therefore, similar to thermography, obstacles can prevent proper detection.

5.2.5 Complexity

5.2.5.1 Installation

There is no installation required because the sensor is mounted to the switchgear exterior.

5.2.5.2 Usage

The use of the equipment and analysis of the data require minimal training.

5.2.6 Application Considerations

Acoustic testing for MV switchgear has been suggested by the EPRI Maintenance and Diagnostics Center [5]. The technology is used extensively to detect the occurrence of PD to assess the existing condition of switchgear bus systems.

5.3 Optic (Light Sensitive) – Temperature

Fiber optic technology can be used to monitor temperatures at bus joints or other locations where temperature sensing is needed to measure for abnormal temperatures.

Optical temperature sensor systems measure electrical connections. A temperature sensor is bolted directly to the bus work and an optical fiber safely carries the signal out of the compartment and to the sensor cabinet. The interrogator generates a light wave, which is sent through the optical cable to the sensor. When the temperature is applied to the sensor, fundamental parameters of the light, such as intensity or wavelength, are changed. The modified light is reflected back through the cable to the interrogator, where it is carefully measured to determine the amount of change in the light wave. Algorithms are then used to convert the optical signal to a calibrated electronics signal, which is connected to the data recorder.

5.3.1 Technology [27]

An optical fiber sensing loop is wrapped once around the conductor/bus/joint location to be tested. A light source sends light through a waveguide, creating two linearly polarized light waves. Through the use of an optical fiber, the light passes through a quarter wave plate, creating right and left circularly polarized light from the two linearly polarized light waves. The two light waves traverse the fiber sensing loop around the conductor/bus, reflect off a mirror at the end of the fiber loop, and return along the same path. While encircling the conductor/bus, the magnetic field induced by the current flowing in the conductor/bus creates a differential optical phase shift between the two light waves due to the Faraday Effect. The two optical waves then travel back through the optical circuit and are finally routed to the optical detector, where the electronics demodulate the light waves to determine the phase shift. The magnitude of the phase shift between the two light waves is proportional to the current, and an analog or digital signal representing the current is sent to the data recorder for real-time or trending current measurement.

5.3.2 Equipment

The equipment includes a fiber-optic temperature sensor, fiber-optic conductors, and an analyzer.

5.3.3 Advantages

Fiber optics are immune to electromagnetic interference (EMI) and radio frequency interference (RFI) and are intrinsically safe.

5.3.4 Limitations

The installation of the equipment typically requires an outage because the sensors are permanently mounted in close proximity to the bus joints.

5.3.5 Complexity

5.3.5.1 Installation

Manufacturers offer the system for application with initial purchase of switchgear assemblies, but existing switchgear can be retrofit with the system. Retrofit involves an outage of the switchgear, and installation requires mounting the sensors at the desired locations and routing the fiber optic cables to the analyzer location. Proper planning is needed to ensure that the system installation does not impact the planned outage duration.

5.3.5.2 Usage

Once the system is installed, data analysis is provided by the connection of the monitoring equipment/analyzer to the sensor fiber optic cables. Therefore, usage is not labor intensive.

5.3.6 Application Considerations

Fiber-optic temperature monitoring technology can also be used to monitor the joints on the bus duct to trend and predict future performance. This technology has been installed and is used successfully in the industry [12].

5.3.6.1 Design

The layout and mounting of the sensors and the routing of the fiber optic cables to the analyzers should be provided to collect the necessary data to allow for collection and trending and provide for analysis on the performance of the switchgear.

5.4 Optic (Light Sensitive) – Arc Flash [28]

Demands for a high level of availability have meant that maintenance work on switchgear must be carried out under live conditions, thus considerably increasing the potential risk to personnel and equipment. Arc faults are included in the sources of potential risk associated with LV switchgear.

Arc faults are usually caused by:

- Human error (handling errors)
- Degraded insulation or faulty contact points
- Rodent damage (for example, rodent entry through the cable ducts)

Arc faults produce a rapid increase in temperature (in 10 milliseconds up to approximately 13,000°K) inside the switchgear. The high temperature can:

- Initiate melting and evaporation processes inside the assembly and cause formation of toxic gases
- Cause partial or complete destruction of the switchgear and secondary damage to a building
- Result in long production downtimes and high costs

Arc fault protection by means of design measures might restrict the effects of the arc fault to inside the assembly when it is closed, but it is ineffective if the assembly is open. This requires an additional protection system that detects an arc in an installation and measures the fault current. On detection of a fault, the arc protection relay trips the applicable circuit breaker to isolate the fault.

5.4.1 Technology

The arc fault detection system consists of light and current sensors and electronic analysis units (arc protection relays). The light sensors use optical fiber technology to monitor the bus bars as well as connection systems along the entire length. In the event of an arc fault, the light emitted by the fault and the fault current is detected by the sensors and analyzed. The analyzer(s) trips all the feeder circuit breakers on the main bus bar system in which the arc fault occurs so that all sources feeding the arc fault are disconnected. The total time from arc fault detection to source disconnection is primarily determined by the tripping times of the circuit breakers and is typically 30–70 ms.

The switchgear can be returned to service once the arc has been quenched, the fault has been eliminated, damage (if any) has been repaired, and insulation tests have been completed.

5.4.2 Equipment

The system consists of point sensors and line sensors to monitor the switchgear assembly. The arc fault current is detected by transducers connected to the line side of each feeder circuit breaker. Fiber-optic cables connect the sensors to an analyzer.

5.4.3 Advantages

Arc flash technology is very fast acting and has been demonstrated to isolate a fault quickly to prevent extensive damage. An arc protection system operates faster than conventional protection relays, thus damage caused by an arc fault can be kept to a minimum. Total fault clearing time is an order of magnitude faster for the arc flash technology versus conventional protective relays.

The extent of damage resulting from an arc fault can only be minimized if the arc fault is detected and quenched in a very short time and the faulty assembly is isolated from the supply. Protective devices must detect the rise in current and the effect of light in the event of an arc fault and quench this within 5 ms.

5.4.4 Limitations

The installation of the equipment typically requires an outage because the sensors are mounted in close proximity to the areas where the arc flash can occur and should be detected.

5.4.5 Complexity

5.4.5.1 Installation

Manufacturers offer the system for application with initial purchase of switchgear assemblies, but existing switchgear can be retrofit with the system. Retrofit involves an outage, the mounting of the sensors at the desired locations in the switchgear, and routing of the fiber optic cables to the analyzer location. Proper planning is required to ensure that the system installation does not impact the planned outage duration.

5.4.5.2 Usage

The operation is automatic. Data recording and acquisition allow for the analysis of the conditions to properly assess events.

5.4.6 Application Considerations

Fiber-optic technology can also be used to monitor the presence of an arc or arc flash to mitigate the effects of a condition that could result in a more catastrophic condition for the switchgear. Arc fault protection provides for the improved availability of the electrical power system by providing personnel protection, system protection, system functional protection, and maintenance under live conditions. The system is a passive system.

The operation of the switchgear assembly can be restored once the arc has been quenched, the fault has been eliminated, damage (if any) has been repaired, and insulation tests have been completed.

Arc faults rarely occur. Accident statistics show that arc faults make up less than 25% of all accidents involving electricity. Nevertheless, the risks of this type of accident must not be overlooked.

5.4.6.1 Design

An arc protection relay is a protective device used to maximize personnel safety and minimize material damage. The arc fault protection system is provided to minimize optical radiation, heat flow, and sound, which are elements that can be dangerous to maintenance personnel or other personnel in the general area of the switchgear under fault conditions. Pressure waves, hot particles, metallic fumes, and pyrolysis products can also result under or as a result of fault conditions.

The level of protection must be designed and installed to prevent an arc fault within the assembly.

5.4.6.2 Industry Experience

Arc flash detection systems are currently in use in Canada, Ireland, and South Africa [29].

5.5 Partial Discharge [30]

The measurement and monitoring of PD activity in MV switchgear and bus duct (segregated and non-segregated) has proven to be an effective tool in determining the condition of their insulation systems. Typical sources of PD in switchgear and bus duct are as follows:

- Potential transformers
- Deterioration of bus supporting structures
- Defects in cable terminations
- Current transformers
- Locations where a ground is located close to a high-voltage conductor (for example, insufficient live parts clearance)
- Bus insulation with a dirty or moist surface
- Insulation structure on the circuit breaker
- Arcing contacts on the breaker
- Arcing primary stabs

5.5.1 Technology [31]

PD is an electrical pulse or discharge in a gas-filled void or on a dielectric surface of a solid or liquid insulation system. The discharge partially bridges the gap between phase insulation-to-ground or phase-to-phase insulation. The discharges are small arcs, which can deteriorate the insulation and lead to failure. PD involves analysis of materials, electric fields, arcing characteristics, pulse wave propagation and attenuation, sensor spatial sensitivity, frequency response and calibration, and noise and data interpretation.

Distinguishing between the PD signal to be measured and the external noise from motor brushes, thyristor firing, control electronics, and arcing or sparking anywhere else on the site is accomplished by analyzing the waveform parameters and filtering out non-PD signals. Periodical noise is automatically detected by processing a large number of power frequency cycles and finding synchronous pulses. Cross-coupling noise (that is, a pulse of the same origin that is picked up by several sensors) is rejected by comparing amplitudes and phases of related signals. To reject other types of noise, some channels are assigned as noise channels to discount the noise information.

5.5.2 Equipment

Sensors in switchgear cubicles are typically installed at the main breaker, the breaker before a tie breaker, and every other breaker between the main and tie. Typically two types of sensors are used, and the signals are wired to an analyzer.

5.5.3 Advantages

PD can detect corona and surface tracking, thus preventing failure of the switchgear bus by the failure of the insulation system.

Continuous PD monitoring allows for ongoing monitoring with multiple rates of rise and low and high PD setpoints, along with remote diagnostics. Trending of PD values is a valuable tool in identifying problems.

Switchgear can be tested using an acceptance criterion adopted to demonstrate that PD is not a concern. Additional problems that might be detected include loose phase connections and arcing ground connections.

Poor or unacceptable insulation conditions cannot be differentiated from slightly degraded conditions with traditional testing methods. PD testing identifies the regions of insulation voids and/or gaps; appropriate corrective actions can then be taken before insulation failure occurs.

5.5.4 Limitations

The inception level for PD has been noted at 11 kV. Testing at 9 kV can provide some margin for assurance that the phenomenon is not occurring [12].

There are situations in which PD arcing might have progressed to the point at which permanent damage, or tracking, has already occurred and near failure conditions have been reached. Under this condition, PD test results can indicate a decreased level of PDs. During this condition, traditional methods (for example, the megger test) more accurately reflect the insulation condition. A traditional high-potential (HI-POT) test can cause insulation failure during the test period. For this reason, trending is recommended for the first year of PD testing [32].

5.5.5 Complexity

5.5.5.1 Installation

The initial installation involves an outage. Installation includes the mounting of the sensors at the desired locations in the switchgear and the routing of the wiring to the analyzer location. Proper planning is required to ensure that the system installation does not impact the planned outage duration.

5.5.5.2 Usage

Once the system is installed, the recorded data can be trended. Software is available to assist in the analysis of the data. Techniques can be used to discriminate the noise signals from actual PD activity that can be adverse to switchgear performance. Training should be considered on the system.

5.5.6 Application Considerations

5.5.6.1 Design

Ideally, it would be advantageous to install sensors in every switchgear cubicle. In practice, sensors are usually installed at the main breaker, the breaker before a tie breaker, and every other breaker between the main and tie. Sensor placement can be determined by the following two methods:

- Reviewing a one-line diagram
- Performing a survey and evaluation

Typically the following two types of sensors are used to test switchgear:

- In the current transformer terminal block – The natural coupling capacities between the high-voltage conductor and the current transformer are used to couple the high-frequency PD signals to the sensor.
- Radio frequency current transformer (RFCT) – This is installed around the cable sheath grounding wire.

Design considerations associated with a PD system for MV switchgear are included in Appendix A.

5.5.6.2 Industry Experience

The implementation of continuous PD monitoring has been successfully applied to MV applications [31]. An electric power utility has successfully used PD technology to provide assurance on a new, upgraded design.

Canadian standards have adopted acceptance criteria of 100 picocoloumbs (pC) for new switchgear. The standards for PD started in Canada in the 1970s [12].

6
MAINTENANCE

This chapter provides guidelines for bus inspection and testing for LV and MV switchgear and associated electrical buses. In addition, this guidance also addresses inspection and testing considerations for switchgear enclosures and components that are typically available for inspection during bus outages only.

6.1 General Maintenance Considerations

The following are general considerations for switchgear maintenance:

- Consider the manufacturers' instructions that are provided in the manuals for the specific model and type of switchgear.
- The design of bus systems joints might have welded bus joints in lieu of bolted bus joints.
- Switchgear maintenance should provide for the inspection and elimination of corona or carbon tracking. Lubricate (where prescribed) and tighten all components of the switchgear.
- Efforts should be made to exclude foreign material when the switchgear is open. When away from the switchgear, it should be secured to prevent foreign material from entering.
- Vacuuming is a preferred method of cleaning because compressed air might blow dust or other foreign materials into components and undesired locations.
- Reports should completely document inspection and test results.
- Consider additional diagnostic and predictive maintenance (PdM) tasks, such as thermography, acoustic monitoring, and equipment inspection reports to move to more condition-directed maintenance.
- Periodically review industry operating experience to ensure that preventive maintenance procedures include all applicable lessons learned and guidance.
- Maintain an adequate inventory of potentially obsolete components to ensure that spares are available throughout the remaining period of operation.

6.2 Safety and Personnel Qualification

Safety is essential when performing maintenance on energized or potentially energized electrical equipment. Safe practices include the use of approved procedures, policies, and good work practices. Manufacturers' literature can provide an understanding of the design of the equipment, potential dangers present, and methods for safe operation of the equipment when performing maintenance.

Only trained and qualified personnel using plant- or facility-approved procedures should perform switchgear bus maintenance. The testing individuals must be capable of performing maintenance and tests activities. They must also be capable of analyzing test data to allow for the safe return to service of equipment.

The following safety precautions are recommended:

- Verify that all components are deenergized.

  Bus maintenance typically requires a bus outage for work on or in the vicinity of energized equipment. Work is performed only after equipment is verified deenergized and alternate feeds are isolated. Ensure all energy sources are tagged out to preclude inadvertent energization. Remove any stored electrical energy by grounding. Mechanical stored energy should be removed by discharging spring mechanisms prior to work.

- Follow procedures.

  Adhere to applicable policy, procedures, training, and safe work practices.

- Exclude foreign material.

  Efforts should be made to exclude foreign material when the switchgear is open. When away from the switchgear, it should be secured to prevent foreign material from entering.

- Conduct a safety briefing.

  A safety briefing should be performed prior to commencement of work.

- Post warning signs.

  The maintenance area should be secured from unauthorized personnel and appropriate temporary warning signs or tape placed to prevent personnel injury.

- Use personnel safety grounds.

  Install personnel safety grounds and document them. Safety grounds need to be removed prior to returning equipment to service.

- Perform zero energy check.

  There might be multiple power sources to be considered associated with switchgear maintenance, such as control power, space heater power, maintenance receptacles, and other sources of power used in the switchgear assembly.

- Expect the unexpected.

  Prior to opening energized equipment and prior to inspection, maintenance, or testing, methods should be employed to assess the conditions associated with the energized equipment. Ultrasound and thermography can be considered for assessing the condition of the equipment to minimize the potential for personnel injury and property damage.

- Be aware of flashover danger.

  Corona can cause a degradation in insulation, and the byproducts can lead to a condition that could result in flashover in switchgear. Corona can be identified by visual inspection, but changing environmental conditions, such as humidity, ambient temperature, operating temperature, decreases in air flow and air density can affect the results associated with corona degradation inside switchgear.

  The effects of corona can be more detrimental with time because the rate of degradation might increase due to corona. Other by-products of corona are ozone and nitric acid. Nitric acid can lead to corrosion, and ozone in the right concentration has an odor that can be identified.

- Use only approved chemicals for the activity and application.

  Mixing chemicals can lead to reactions that can cause personnel injury or damage to equipment. Refer to the applicable material safety data sheet (MSDS) for chemicals and properties.

- Ensure adequate ventilation.

  Provide adequate ventilation and/or respirator protection associated with conditions that can have hazardous health consequences or where vapors might be present.

6.3 Cleanliness and Surface Preparation for Electrical Connections

6.3.1 Silver-Plated and Tin-Plated Conductors

Little preparation is required for aluminum and copper conductors plated with silver or tin. Cleaning the conductor with a solvent to remove any dust or other foreign material is sufficient. Abrading or cleaning with a wire brush removes the plating and should be avoided. An inert sealing compound can be used to prevent air and moisture from entering the joint.

6.3.2 Aluminum Conductors

In preparing an unplated aluminum conductor for assembly, first remove the dirt or foreign material from the conductor. Apply a chemically active sealing compound and abrade the surface using:

- Fiberglass brush
- Emery cloth or emery paper

- Wire brush
- Draw file

After the surface has been abraded, the contact surfaces can be bolted.

6.3.3 Copper Conductors

Unplated copper conductors should be abraded using the same method described for aluminum. Assemble copper conductors using an inert sealing compound. Sealing compounds containing suspended metallic particles are intended for use with aluminum cable to aid in the penetration of oxide film. Appropriate sealing compounds provide significantly lower joint resistance in copper conductors.

In assembling bolted electrical connections, large, flat washers should be used on both sides of the bus. In special cases or in cases in which reliability is critical, Belleville washers can be used in place of the large, flat washers.

6.4 Bolted Electrical Connections

Sound bolted electrical connections are the most important attribute in bus maintenance. The three most important aspects are:

- Materials
- Torque – Fasten torque for bus joints and cable connections
- Cleanliness and surface preparation for electrical joints

6.4.1 Material

Bus materials are copper, aluminum, silver-plated copper, and silver-plated aluminum. The choice of material or plating is to minimize resistivity at the connection. Material compatibility can prevent dissimilar metals that can lead to degradation and potential failure of bus connections.

An electrical connection must be designed to remain tight and maintain good conductivity through a large temperature range. Meeting this design requirement is difficult if the materials specified for the bolt and the conductor are different and have different rates of thermal expansion. For example, copper and aluminum bus materials expand faster than most bolting materials. If thermal stress is added to stresses inherent at assembly, the joint members or fasteners can yield. If plastic deformation occurs during thermal loading, the joint can be loosened when the connection cools [33].

Only approved joint compounds should be used. Mixing joint compounds can lead to chemical reactions, which can cause personnel injury or damage to equipment (for example, bus corrosion or insulation degradation).

The electrical bus can be coated with a NO-OX-ID compound to prevent formation of oxides that can increase resistance. This is done typically where the plug-in stabs of the units (for example, MCC buckets) engage the bus [34]. However, opinions on this practice differ from plant to plant.

The following recommendations apply:

- Special cleaning and coating requirements for aluminum prevent the formation of a high-resistivity aluminum oxide film on the exposed metal.
- Aluminum bolts are recommended for use with aluminum buses in order to achieve the same coefficients of thermal expansion. Aluminum bolts are often lubricated to prevent galling during assembly.
- Bronze bolts are ideal for use with copper buses. The two materials have nearly the same coefficients of thermal expansion.
- Low carbon steel bolts are **not** recommended for power connections.
- High-strength steel bolts are recommended for use with copper or aluminum buses because of their low cost. Coating these bolts with zinc (that is, galvanizing) reduces oxidation and corrosion. Because high-strength steel bolts have a relatively low coefficient of thermal expansion, Belleville washers should be used.
- The coefficient of thermal expansion for austenitic stainless steel bolts is comparable to that of copper bus. These bolts are suitable for corrosive environments. Class 1 bolts are not recommended for use with aluminum buses. Class 2 bolts are appropriate for any application.
- The bolt length of bus connections (including bolts, washers, and nuts) should not impact the dielectric integrity of the bus. In other words, the bolt should be of sufficient length to fully engage the nut, but it should not protrude beyond the nut to a point where minimum live part clearances become an issue or insulating materials are mechanically stressed.

6.4.2 Plating

Bus connections plated with tin can be provided with aluminum bus systems but are not typical. The tin plating costs less than silver, but it is not deemed the best alternative for bus connections.

Bus connections can be plated with silver, which provides low resistance at the connection because the resistivity of silver is less than copper or aluminum typically used in bus bar construction. Silver has the highest electrical and thermal conductivity of any metal and is the typical choice for switchgear assemblies.

Silver plating is typically not a process that occurs at an electrical generation facility. Therefore, the services and process occur at a third-party location, which requires shipment of the electrical bus sections. Plating is typically a specialized process that should be performed in a controlled manufacturing environment. The thickness of the plating is important to ensure the proper contact surface.

NRC Information Notice 2000-14 Failure Analysis [35] indicated that many of the bus bars and splice plates had only a thin layer of silver plating (see Section 3.3.2). Laboratory analysis determined that the silver plating on one splice plate had partially separated from the base aluminum, and corrosion products were found on the aluminum surface. If this separation had existed at the point of the fault, it would have created higher resistance and, therefore, more heat at the connection. The laboratory stated that the most likely source of corrosive compounds was the polyvinyl chloride insulating boot. Silver plating was also observed flaking off the aluminum bus bars at two other splice joints not directly affected by the fault.

6.4.3 Torque [36]

Torque provides a measure of force at the bus connection that reduces the resistivity of the connection and minimizes the possibility of contamination of the joint or corrosion due to contaminants. However, torque is not a direct measure of force, which is the key element in a sound electrical connection. Friction can impact the torque values. A well-lubricated fastener is stressed to a higher force for the same torque than one that is not lubricated. For example, a lubricated fastener can fracture at the higher force.

Torque values for a bus connection can be provided by the manufacturer. Torque values on bolts can range ±25% using a torque wrench. The use of a Belleville washer or direct tension indicator might reduce inaccuracies associated with torque values and the variability associated with bolt lubrication.

A torque procedure includes initially tightening the bolts finger tight followed by the use of a torque wrench to half of the recommended torque value. The torque sequence should ensure a uniform pressure applied to the mating connection surfaces. The appropriate symmetrical torque sequence can ensure full clamping force and contact area.

6.4.3.1 Torque for Electrical Bus Bars

The measurement of torque on bolted connections provides an indication of the force at a connection point. Force is related to torque. Torque readings can be affected by lubrication; therefore, different torque values apply to lubricated versus fasteners that are not lubricated. Care should be taken not to exceed the listed torque values, which could lead to failure of the fastener hardware or damage to the associated bus or connector plates.

Bolted connections must meet minimum torque specifications or low resistance appropriate for the application. If torque values are not given by the manufacturer, a baseline can be developed based on existing connections, and torque values can be trended. A decrease in the as-found torque readings is an indication of a relaxation of the connection. Subsequently higher operating temperatures at the connection can occur, leading to degradation of the insulation system. Recommended torque values from EPRI TR-104213 [33] are provided in Appendix B.

Tables B-1 through B-8 in Appendix B give recommended torque, bolt stress, and bus stress for various combinations of bolt and bus materials. The operating conditions assumed in developing these tables are:

- Assembly temperature: 70°F
- Maximum allowable operating hot spot temperature: 221°F
- Short circuit or overload temperature: 297°F
- Total temperature change from assembly to overload: 227°F

6.4.3.2 Bolt Torquing

A torque wrench or other torque limiting tool is used to assemble electrical joints. The bolt is tightened until the required torque is achieved. If the procedure is stopped prior to achieving the required torque, the breakaway torque can be significantly higher and might not represent the actual joint tightness.

6.4.3.3 Terminal Blocks and Pressure Terminals

Equipment such as terminal blocks, molded case circuit breakers, starters, and overload relays are usually marked with the correct installation torque.

6.4.3.4 Special Problems

Increased temperature difference in electrical bolted joints is due to high short circuit ratings or increased current duration. The temperature of an electrical bolted joint will rise, and the stress can increase with increasing current duration. If this temperature increase is not taken into consideration, loosening and failure of the joints might result. Belleville washers selected to be flat or almost flat at the installation torque can be used to accommodate the temperature increase. In extreme cases, using an oversized bus should be considered.

Hydrogen embrittlement is a recurring problem with Belleville washers. When they are electroplated, the plating process forces hydrogen into the metal grain boundaries. If the hydrogen is not removed, the washer can spontaneously fail at any time while in service. Although hydrogen embrittlement occurs infrequently, it is recommended that electroplated Belleville washers not be used. Hydrogen embrittlement does not affect Belleville washers having other finishes.

Note that in Revision 1 of the GALL Report [1], the NRC dropped its recommendation for torque checks on bolted connections. The industry took the position that removing insulation and tightening the bolts had a negative impact on the continuity of the circuit. This position was accepted by the NRC.

6.5 Maintenance Intervals

There are a number of factors that should be considered when determining an appropriate maintenance frequency. These factors include, but might not be limited to:

- Safety significance
- Manufacturers' recommendations
- Environmental conditions
- Industry experience
- Current condition of bus and switchgear components
- Maintenance history
- Operating history
- Relative economic significance

Typical U.S. nuclear power industry practices for switchgear buses include maintenance intervals between 6 and 12 years in an environment that is clean and where temperatures are below 40°C.

At the time this report was published, *PM Basis Database* (EPRI Report 1011923) did not have guidance (a PM basis) that specifically addressed switchgear bus maintenance. The *PM Basis Database* did provide a PM basis for switchgear, medium voltage. This component in the PM basis database addressed cubicle preventive maintenance and cubicle overhaul. It was considered that cubicle overhaul tasks were more closely aligned with a bus outage and switchgear and electrical bus maintenance. Because of this, the maintenance intervals provided by the *PM Basis Database* also agreed with the industry's consensus of a 6–12 year maintenance interval.

Table 6-1
Preventive Maintenance Basis for Medium-Voltage Electrical Distribution System Breakers [5]

Medium-Voltage Switchgear								
Task Name	**CHS**	**CLS**	**CHM**	**CLM**	**MHS**	**MLS**	**MHM**	**MLM**
Thermography – Breaker and Cubicle (including bus)	1Y	1Y	1Y	1Y	1Y	1Y	1Y	1Y
Cubicle – Detailed Inspection	4Y	4Y	6Y	6Y	6Y	6Y	6Y	6Y
Cubicle – Overhaul	8Y	8Y	12Y	12Y	12Y	12Y	12Y	12Y

Abbreviations: C = Critical, H = High Duty Cycle, L = Low Duty Cycle, S = Severe Service, M = Mild Service, Y = Years

6.5.1 EPRI 2002 Survey

An EPRI 2002 survey of bus maintenance for nuclear power plants [37] included the PM frequency, tasks, and tests performed. The range in PM frequency is noted in Table 6-2 for the various PM tasks. There was a contrast in PM frequency noted for the more functionally important equipment (safety related versus non-safety related).

Table 6-2
EPRI 2002 Survey – Bus Maintenance for Nuclear Power Plants

PM Task	Functional Importance *	Frequency Range ** (years)
Thermography	Safety- and Non-Safety-Related	0.5–1
Megger Testing	Safety- and Non-Safety-Related	3–12
Bolt Tightness	Safety- and Non-Safety-Related	4–12
Inspection and Cleaning	Safety- and Non-Safety-Related	3–12
Micro-Ohm Check	Safety-Related	6–10
Micro-Ohm Check	Non-Safety-Related	10–12
Doble Testing of Bus	Safety- and Non-Safety-Related	5

* There is a distinction between functional importance for safety-related and non-safety-related. Appropriate consideration should be given to non-safety-related components, of which the consequences of failure can have significant indirect impact on safety or economy.

** The PM frequency for specific equipment that was exposed to an adverse environment might be shorter. In some cases the LV switchgear PM maintenance was performed at longer intervals than the MV switchgear.

A significant number of the participants in the survey noted megger, thermography, and bolt tightness checks. A small population of the participants included Doble testing. One participant in the survey noted bolt tightness, megger, cleaning, and inspections on a 20-year frequency for all switchgear listed. Thermography was typically done at six-month intervals for cubicles.

6.5.1 EPRI-Utility Survey – August 2005

A survey in August 2005 [38] polled several nuclear power plants and asked for descriptions of the maintenance activities performed on MV switchgear, plans for future maintenance intervals, and additional comments.

The results of the survey indicated that maintenance intervals ranged from 4.5–15 years. Except for special cases, such as unique environmental conditions, most plants were planning on maintaining or extending the maintenance interval to at least nine years for non safety-related switchgear. One plant surveyed performed switchgear maintenance on a six-year frequency for the safety-related switchgear.

The survey indicated that there was no indication by the surveyed personnel that they would decrease the maintenance interval to fewer than nine years except in a special case involving special environmental conditions and another plant concerning safety-related applications.

The survey indicated that there was special consideration applied to the more functional important switchgear and those in an environment that could challenge the operation of the switchgear due to adverse environmental conditions.

6.6 Visual Inspections

Inspection techniques focus on bus joints and connections for the evidence of overheating, tracking, cracking, corrosion, or insulation boot degradation.

6.6.1 Bus Connections and Insulator Inspection

The following procedures are recommended:

- Inspect bus material for electrical or thermal stress by markings or flaking of varnish coatings.
- Inspect low points in bus for signs of moisture debris accumulation.
- Inspect for foreign objects and loose tools or fallen parts.
- Inspect flexible boots for material condition signs of degradation or soft material.

- If accessible, inspect connections and check for the correct torque value. Inspect for discoloration, insulation, and supports for cracking or blistering. Thermography or low-resistant measurement is an alternate method to determine the adequacy of a connection. Perform a comparison of measured values.
- Inspect the internal portion of the bus ducts for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion.
- Inspect the bus insulating system for signs of embrittlement, cracking, melting, swelling, or discoloration, which might indicate overheating or aging degradation.
- Inspect the (internal) bus supports for structural integrity and signs of cracks.
- Inspect insulation materials for discoloration and cracking.
- Inspect insulators for cleanliness, signs of heating, corrosion, degradation, cracks, and loose bolts.
- Inspect the bolted connections transformer for signs of heating, corrosion, degradation, cracks, and loose bolts.
- Clean insulation, insulators, bus hardware, and joint covers with a cleaner that is suitable for the material and application.

6.6.2 Cable Connections

Inspect for the following:

- Discoloration of insulation
- Stress cone connections for cracking or blistering damage
- Bolted connection using calibrated torque wrench and/or micro-ohmmeter
- Shield connections and condition for MV cables

Also, perform a continuity test on shield connection.

6.6.3 Acceptance Criteria

Electrical bus and associated insulation are to be free from unacceptable visual indications or surface anomalies that suggest that conductor insulation degradation exists. There should be no unacceptable indication of corrosion, cracks, foreign debris, excessive dust buildup, or evidence of water intrusion. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of intended function.

Inspection of bus ducts associated with an aging management program can sample bolted connections on the bus. Bus connections can be checked for proper torque or proper connection resistance using a low-range ohmmeter.

The physical configuration of buses, including the number of connections, can influence readings due to the cumulative resistance values at each joint and needs to be considered. This activity also includes internal visual inspection of the bus ducts to identify aging degradation of insulating and metallic components and water and/or debris intrusion.

6.6.4 Circuit Breaker and Instrumentation and Control Compartments

Switchgear compartments that house components or accessories normally inaccessible during normal operations are recommended for inspection and maintenance during a bus outage due to arc-flash and related concerns. Electrical dangers, such as shock, electrocution, arc flash, and arc blast, can always be present on the job, but proper training and safety strategies can minimize the likelihood of injuries and fatalities.

Moving parts should be free and have smooth movement. If they are infrequently operated, verify proper operation. All areas and components should be free from dust, dirt, or damage. No loose parts, tools, or debris should be present.

Higher temperatures in CTs can indicate other circuit problems, such as open contacts on the meter switch. Thermography can identify higher temperatures that can prevent catastrophic failure.

A fuse list can be developed to control the configuration of fuses installed in switchgear. Fuse replacement can be done to minimize the potential for failure due to the cyclic stresses noted on fuses because of the cyclic heating associated with cyclic loading on the fuses.

The following inspections and/or testing techniques should be considered for switchgear components and accessories accessible during bus outages. The steps are not in any order and should be staged as appropriate in accordance with plant procedures as required [34].

6.6.4.1 Visual Inspection

- Loose or fallen parts
- Terminal blocks
- Cubicle bolting
- Cubicle heaters
- Indicator lights and resistors
- Foreign objects and tools
- The racking mechanism access door

6.6.4.2 Bus Connections

- Remove covers, tape, or boots from bus connection to be inspected.
- Inspect connection for overheating, corrosion, and loose bolts.
- Remove old joint compound using paint thinner, varsol, or alcohol when repairing joints.
- Remove pitting or oxidation from unplated copper or aluminum surfaces by sanding, filing, or wire brushing. Do not use abrasive methods on plated surfaces; maintain at least 90% of original material on unplated surfaces.
- Ensure that proper torque values are obtained.
- For Belleville washers, flatten, then back off 1/8 turn.
- Re-grease all joints to prevent oxidation; grease the external connections to prevent oxidation.
- Replace or reinstall all rubber boots (no PVC).

6.6.4.3 Insulators

- Inspect for broken or cracked insulators.
- Repair or replace as necessary.
- Ensure tight assembly, including that lock washers are flattened.

6.6.4.4 Shutters and Shutter Mechanism

- Perform a visual inspection. Ensure that the actuating arm is not bent or damaged.
- Ensure that there are no misalignments and the shutter operates freely. Clean and remove old lubricant and apply new lubricant.
- Inspect the hardware for degradation, discoloration, cracking and brittleness. Industry experience has shown that solvents that might have been used on shutter parts could show chemical attack to the hardware.
- Inspect for binding or sagging parts. This can be an indication that parts need replacement.

6.6.4.5 Primary Stationary Disconnects

- Open or remove the shutter and inspect primary stab moldings for tracking or degradation. Inspect the primary contacts for overheating, corrosion, pitting, and loss of silver plate.
- Remove any hardened grease and note that personnel should exercise caution as the use of abrasive pads could remove silver plate. After cleaning of the primary stab, re-lubricate.

6.6.4.6 Current Transformers

- Inspect for hairline cracks of outer shell and stem.
- Inspect for chips.
- Inspect for overheating.
- Epoxy molding compound should be checked for breakdown (thumbnail test).

6.6.4.7 Potential Transformers

- Inspect primary connections for proper alignment and cleanliness.
- Inspect fuse clips and fuses to be securely fastened.
- Inspect PT mounting for tightness.
- Inspect PT molding for cracks.
- Inspect trunnion for movement without free play.
- Inspect moving and stationary ground stab for proper engagement and free from excessive wear.
- Lubricate as required.

6.6.4.8 Control Wiring Inspection

- Inspect cable connections for bolting tightness.
- Inspect for discoloration of insulation.
- Inspect stress cone connections for cracking or blistering damage.

6.6.4.9 Cell/Auxiliary Switches

- Visually inspect cell and/or auxiliary switches and associated mechanisms.
- Perform continuity check.
- Verify switch alignment.
- Inspect contacts.
- Check linkage and switches for freedom of movement.
- Adjust linkage as needed.
- Inspect for tightness of mounting switches and linkage.
- Clean and lubricate switches and linkage.

6.6.4.10 Secondary Disconnects

- Visually inspect conductor strip bends located at end of the secondary disconnect.
- Inspect for signs of arcing or overheating.
- Inspect molding for cracks or broken fins.
- Check hardware for tightness.
- Clean conductor strips of any contamination.

6.6.4.11 Fuse Block Inspection

- Inspect fuse blocks, fuses, and fuse clips for overheating.
- Inspect fuse block for cracks or chips; clean, inspect, and note results for blade alignment and bus connections.
- Inspect for deterioration or corrosion.
- Verify continuity of fuses.
- Verify correct fuse size.
- Inspect fuse ferrule for cracking or separations.
- Check that fuses are held securely by fuse clips; if applicable, measure contact gap reading acceptance criteria provided by the manufacturer.
- Repair or replace if necessary.
- Provide record of repair or replacement.

6.6.4.12 Ground Stab

- Inspect for scoring.
- Inspect for bending.
- Inspect cleanliness.
- Inspect for alignment.
- Inspect for tightness of bolting.

6.6.4.13 Cubicle Guide Rail Inspection

- Inspect for bending.
- Inspect for misalignment.
- Inspect for damage.

6.6.4.14 Breaker Position Indicator

- Ensure that the circuit breaker position indicator is installed and legible.

6.6.4.15 Spring Discharge Actuator

- Ensure that the discharge actuator is installed.
- Inspect for damage.
- Ensure that the discharge actuator is functional (this can be checked during breaker removal).

6.6.4.16 Lightning Arrestors

- Inspect porcelain for cracks (if applicable).
- Clean arrestor.
- Torque cable connections.

6.6.4.17 Fans

- Inspect for signs of heating, looseness, free movement, or damage.
- Check for proper operation.

6.6.4.18 Filters

- Clean or replace to maintain proper air flow.

6.6.4.19 Space Heaters

- Inspect for discoloration or damage.
- Check electrical connections for tightness.
- Check for operation.

6.7 Testing

The following tests should be considered in maintenance planning as appropriate.

6.7.1 Connection Resistance

Connection resistance or the measure of resistivity associated with a connection point provides an indication of the adequacy of the connection. Higher resistance can lead to overheating and subsequent failure of the insulation and electrical conductor. The physical configuration of the bus, including the number of connections, can influence readings due to the cumulative resistance values at each joint. Cumulative resistance values can be used for large bus sections with multiple connections considering individual joint resistance values. Baseline values can be established and trended with future measurements to provide assurance of the adequacy of each connection. This can establish a systematic approach to identify deviations or outliers. An acceptance criteria could include a method to investigate values that deviate more than 50% from the lowest value.

6.7.2 Insulation Resistance

6.7.2.1 Megger

A 2500-V megger can be used to determine insulation levels phase to phase or phase to ground. Typical values are in the 100–200 megohm range for bus insulation systems. Values are typically taken for at least one minute to stabilize readings.

6.7.2.2 High Potential

A HI-POT test for one minute at dc voltages at least two times the bus operating voltages can be performed to check the integrity of the bus insulation system. Ensure potential transformers are racked out prior to performing the test. The impact of a HI-POT test must be evaluated for the bus bar, the insulation, and the connections.

6.7.2.3 Doble

A Doble [39] test at 5- to 25-kV ac can be performed to check the integrity of the bus insulation system. The Doble testing method uses ac characteristics whereas HI-POT and megger use dc voltages. Doble testing provides ac characteristics of the insulation system. Doble testing involves dielectric theory, which includes ac dielectric loss, power factor, and capacitance measurements. Doble testing is sometimes referred to as a power-factor test. The Doble testing requires disconnecting the device from the power system. The concept of Doble testing includes measurement of variables of insulation as affected by deterioration, contamination, deformation, or movement of the conductor and noting changes in measured characteristics.

In addition to bus insulation systems, Doble testing can be applied to dry instrument transformers and current transformers. The test voltage should not exceed the voltage rating of the instrument transformer to ground. A test in which the voltage is increased from 25% to the maximum value can indicate a breakdown voltage at which corona can occur.

Doble testing is an ac test; therefore, power factor can be obtained. Power factor values can be baselined and trended. Based on the test results, either more frequent tests might be required or immediate investigation should be considered with regard to the degradation of the insulation system or a transformer.

6.7.3 Acceptance Criteria for Insulation Resistance Testing

Table 6-3 is a typical set of test voltage values used for switchgear bus insulation resistance testing.

Table 6-3
Test Voltage for Switchgear Bus Insulation

Bus Voltage	Doble Test Value	HI-POT Test Value	Megger Test Value
4160 kV	5 to 10 kV ac	15 kV to 20 kV dc	(2500 Vdc)
6900 kV	5 to 25 kV ac	15 kV to 25 kV dc	
13800 kV	10 to 12 kV ac	30 kV to 40 kV dc	

Acceptance criteria for these tests can be absolute values with a tolerance or can be a comparison of two or more values applying a differential value for acceptance, as shown in Table 6-4.

Table 6-4
Insulation Testing Acceptance Criteria

Bus Voltage	Doble Acceptance Criteria Value	HI-POT Acceptance Criteria Value	Megger Acceptance Criteria Value
4160 kV	See note *	100–200 Megohms	1000 Megohms for 4160 V 5000 Megohms for 6900 and above
6900 kV			
13,800 kV			

* The power factor testing results in an equivalent parallel circuit of capacitance and resistance values. The better the insulator, the more capacitance and less resistance (approaching 90°) measured in the insulator. The less capacitance and more resistance (approaching 0°) measured in the insulator, the less dielectric capabilities of the insulation. The insulation of the electrical system is critical to the reliability of the electrical system. Changes in power factor from near 90° to 0° might indicate degradation of the insulation system.

6.8 Contingency Plans

Contingency plans should be developed for degraded conditions associated with switchgear buses. A reduction in load or load swapping can be implemented to minimize the impact on bus connections or components. This plan can avoid a complete bus outage until the time that the required repairs are completed based on a more appropriate scheduled time frame for needed repairs. The scheduling might provide an economic benefit to the operation of the electrical system and associated process systems and potentially ensure power generation and associated revenue.

Cables can be used to replace switchgear bus although this is typically an interim measure until permanent repairs are made, which are labor intensive and can require another bus outage. Several plants observed cracking of the Noryl sleeve material on the switchgear buses during a scheduled outage inspection. Taping was used as the repair in lieu of replacement of the Noryl sleeve material due to time constraints during the scheduled outage.

6.9 Corrective Maintenance and Repairs [12]

6.9.1 Repairs

Quality control requirements and oversight should be considered in the follow-up of repair or replacement activities as required.

6.9.1.1 Taping

Taping can be used to repair damaged or degraded arrears of insulation systems. It can also be used in lieu of rubber boots when performed in accordance with manufacturer's instructions considering insulation level, overlap, putty, and methods to facilitate future removal. Varnish can be applied over the final tape surface.

6.9.1.2 Heat Shrink

Heat shrink tubing can be used in lieu of rubber boots when performed in accordance with manufacturer's instructions. Manufacturer's instructions should be followed for the application to assure the integrity of the insulation system.

6.9.1.3 Silicone RTV

RTV can be used to fill air gaps to minimize the effects of corona. Apply RTV to fill gaps where bus goes through slots.

6.9.1.4 Insulation Sleeves

Insulation sleeves are available to repair the insulation on bus joints that have degraded due to material that has overheated and released chlorides.

6.9.1.5 Potting Compounds

Potting compounds can be used to repair advanced eroded bus insulation. The two-part formula is mixed and can require special documentation to implement the repair because of the process involved. Potting compounds are used similar to RTV to fill air gaps to minimize the effects of corona.

6.9.1.6 Epoxy

Epoxy can be used to fill voids on porcelain insulators. The epoxy can then be coated with varnish. Possibly more than one coat of varnish might be required.

6.9.1.7 Post-Repair Testing

Completed repairs should be tested using methods described in this section to ensure that the desired insulation and resistivity levels are achieved.

6.9.1.8 Post-Repair Housekeeping

Upon completion of the repair and associated testing activities, ensure that the removal of tools, rags, and material for foreign material exclusion (FME) is completed.

6.9.2 Replacements

Insulation deterioration can result from air gaps. Mitigation for the effects of air gaps present in older switchgear designs can reduce the adverse effects associated with corona, which can eventually lead to failures.

New designs can replace old designs available during bus outage to improve the adverse affects caused by air gaps in older switchgear designs.

The following considerations are associated with disassembly and reassembly of switchgear bus related components:

- Identification of all parts is important because it can facilitate re-assembly. Photographs can also be useful in maintaining the correct configuration and assembly.
- After removal, the unitized storage of components can assist in re-assembly.
- Special care associated with porcelain insulators is required to prevent damage.

The key components associated with switchgear bus replacements are described in Section 6.9.2.1.

6.9.2.1 Bus Bars

Bus bars can be replaced if significant degradation is present that can inhibit the bus design function. Also bus bars can be upgraded if it is prudent to obtain a higher ampacity rating. New bus bars can be manufactured with a coating to provide insulation and physical protection. The coating can be a varnish material.

Identification of the bus section, phase, and cubicle section by marking or tagging can allow for future traceability. Spare parts might be limited, so special care to prevent damage can assist in a successful reinstallation. Leaving the insulation on the bus system can prevent damage to the bus while transporting it. If bus bar design is marginal, a larger bus bar can increase the ampacity of the bus. Plating at joint connections should be the minimum thickness for the design requirements.

6.9.2.2 Splice Plates

If the splice plate design is marginal, larger splice plates can increase the ampacity of the bus. Plating at joint connections should be the minimum thickness for the design requirements.

6.9.2.3 Insulation

Cracked, damaged, or aged insulation should be replaced to minimize corona and further degradation to the bus system. Materials requirement considerations are contained in the design section of this report.

6.9.2.4 Boots

Slip-on or shrink-on boots can be replaced during bus maintenance. Newer improved materials might be available for replacement. Materials requirement considerations are contained in the design section of this report.

6.9.2.5 Instrument Transformers

Replacement of instrument transformers can preclude future failures. Current transformers are the more commonly replaced instrument transformers based on the results of periodic inspections. New current transformers can replace old current transformers that have degraded due to aging or overheating.

6.9.2.6 Fuses

The replacement of fuses on a periodic basis can eliminate failures due to aging and cyclic operating conditions that tend to result in eminent fuse failure. A controlled fuse list can provide fuse attributes, such as size, type, and manufacturer to assist in replacement.

6.10 Bus Upgrades and Replacements

An upgrade of a bus system can include the following:

- Replacement of hardware, such as bolts, nuts, and washers with improved material
- Replacement of the insulation system on the bus
- Replacement of boots at joints
- Reduction or elimination of air gaps between bus conductors and insulation and between insulation and bus supports
- Configuration control associated with bus components to provide traceability on maintenance on discrete components of the bus system
- Installation of windows in switchgear to allow visual inspection and thermography of bus systems

Considerations for a bus refurbishment or upgrade should consider the following:

- Bus layout: Plan and elevation views of the bus routing duct. The drawings should list and identify all assemblies provided by the manufacturer. Typical cross-section views of the bus should include ratings, housing size, weight per foot, material descriptions, and bus duct structural support locations.
- Equipment terminations.
- Details of the bus enclosure connection to the equipment.
- Bill of material for shipment.
- List and identify parts for field assembly.

Some examples of corrective actions for major switchgear bus replacement and/or repair are:

- Change bolt material to carbon steel.
- Apply epoxy coating on switchgear bus.
- Use stainless steel Belleville washers torque.
- Add silicone bronze and lock washers.
- Replace splice plates and copper bus with larger size ones to achieve higher ampacity. Silver plating on joints should be dipped to at least 1 mil thickness.
- Add fiber-optic temperature monitoring to heavily loaded bus duct joints.
- Replace all PVC boots at joints.
- Produce isometric drawing of splice joints having unique ID numbers.
- Eliminate air gaps on older switchgear designs.

Figure 6-1 depicts repairs and upgrades to a 12-kV switchgear bus.

Figure 6-1
Diablo Canyon Bus Duct Repair

6.10.1 Post-Replacement Testing

Completed repairs should be tested using methods described in this section to ensure the desired insulation and resistivity levels are achieved. Prior to testing, ensure that insulation is provided at all areas where disconnection is provided to isolate other sections or components that are not being tested. Current transformer should be shorted prior to performing bus testing.

6.10.2 Housekeeping

Upon completion of the repair and associated testing activities, make sure the removal of tools, rags, and material for FME is obtained.

7
ACRONYMS

ABB	ASEA Brown Boveri
AMG	Aging Management Guideline
ANSI	American National Standards Institute
ASTM	American Society of Testing Materials
BIL	Basic Impulse Insulation Level
CT	Current Transformer
dc	Direct Current
EMI	Electromagnetic Interference
EPIX	Equipment Performance and Information Exchange
EPRI	Electric Power Research Institute
FME	Foreign Material Exclusion
GALL	Generic Aging Lessons Learned
GL	Generic Letter
GSI	Generic Safety Issue
IEB	Information Bulletin
IEC	Information Circular
IEEE	Institute of Electrical and Electronics Engineers
IN	Information Notice
INPO	Institute of Nuclear Power Operations
IOE	Industrial Operating Experience
ISG	Interim Staff Guidance
LCO	Limiting Condition for Operation
LR	License Renewal
LV	Low-Voltage
MCC	Motor Control Center

MSDS	Material Safety Data Sheet
MV	Medium-Voltage
MVDS	Medium-Voltage Electrical Distribution System
NETA	National Electric Testing Association
NMAC	Nuclear Maintenance Applications Center
NPRDS	Nuclear Plant Reliability Data System
NRC	U.S. Nuclear Regulatory Commission
NUREG	Nuclear Regulation
OE	Operating Experience
O&MR	Operations and Maintenance Reminder
pC	Picocoloumbs
PD	Partial Discharge
PDA	Primary Disconnect Assembly
PM	Preventive Maintenance
PdM	Predictive Maintenance
PT	Potential Transformer
PVC	Polyvinyl Chloride
RFCT	Radio Frequency Current Transformer
RFI	Radio Frequency Interference
RIS	Regulatory Issue Summary
RCM	Reliability-Centered Maintenance
SEE-IN	Significant Event Evaluation Information Network
SEN	Significant Event Notification
SER	Significant Event Report
SOER	Significant Operating Experience Report
SSC	Systems, Structures, and Components
TAG	Technical Advisory Group
Vac	Volts Alternating Current
Vdc	Volts Direct Current

8
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A
DESIGN CONSIDERATIONS FOR PD MONITORING SYSTEMS

The sensing technology should provide measurement of all discharges through the direct sensing of the electro-magnetic wave generated by a partial discharge (PD). Measurements should be performed on-line, and switchgear equipment should be energized under normal operational conditions, using measurement equipment specifically designed for this purpose.

A.1 PD Sensors

PD sensors should detect PDs through sensing of the electrical impulses generated by the PDs (including corona, surface tracking, or minute sparks in insulation voids, as well as arcing and sparking). Sensitivity of PD sensors and measurement technology must be sufficient to detect early stages of defect development by measuring PD of low levels (less than 100 pico-coulombs). PD occurring within the cubicles as well as PD emanated by external sources (cable terminations, cables, bus ducts, connected transformers, motors, and so on) within the short distance thereof and appearing at the PD sensors must be sensed.

A.2 PD Sensor Connections and Installation

Three 80 pF coupling capacitors should be mounted and connected phase to ground in approximately every third feeder cubicle (one per phase). Actual placement can be based the physical layout of the switchgear. Each sensor should be wired to a central location and connected to the PD relay. For each incoming and feeder cable the cable drain shield should pass through a radio frequency current transformer (RFCT) before the shield is grounded. The secondary winding of the RFCT should be wired to a central point and connected and be available for future diagnostic capabilities. Instructions should be provided with the switchgear for proper installation of the PD sensors on the cable shields.

A voltage reference source, such as a potential transformer, must be available in the switchgear. If one does not exist, a voltage reference sensor must be installed on one of the PD sensors. Sensing for PDs at the ends of the switchgear line-ups only should not be considered acceptable unless the lineup is fewer than six cubicles.

A.3 PD Relay

The PD relay should be capable of providing predictive on-line alarms and protection for PD-induced insulation deterioration resulting from voids, cracks and/or surface tracking, or corona activity.

PD relay inputs:

- 15 input PD signal channels.
- 1 noise channel.
- 3 analog inputs for temperature, humidity, and other specified parameters.

PD relay outputs:

- Two (2) dry contacts for alarm function.
- One (1) dry contact for indicating system status.
- One 4-20-mA signal to indicate the percentage of the channel with the highest PD activity as it relates to the alarm set point.
- An RS-485 connection for networking and remote communications.

PD relay features:

- Digital display on the unit that cycles through each monitored channel.
- Built-in noise rejection algorithms.
- Dedicated noise channel where identified noise requires cancellation.
- PD relay should be capable of using input from all types and manufacturers of radio frequency PD sensors, coupling capacitors, radio frequency current transformers, Rogowski coils, radio frequency voltage sensors, and existing RTDs.
- Suitable for use in operating temperature range from -40°C to +85°C.
- A suitable modem exists for remote communications and access to the relay.

PD relay should be programmable from the front keypad and display. Programmable features should include:

- Each channel is individually programmable.
- Low-level noise levels should also be programmable for each channel.
- Programmable continuous high PD level monitor.
- Display should be able to be programmed to continuously cycle current information, machine parameters, and last PD readings.

- Based on a typical relay monitor set for four times per day, PD relay should have up to 2000 days of on-board data storage. The frequency of collecting monitored test data should be programmable. It should be capable of being collected at preset fixed times or fixed time base.
- Each PD channel should have complete setting independence, including warning and alarm thresholds for each of two (2) PD parameters (PD intensity and PD magnitude).

PD relay should be provided with the following software:

- Software must be Microsoft Windows based and have the ability to download the data directly from the relay monitor or remotely through a modem (land line or cellular).
- The software should be able to display graphical trending of PD quantities including:
  - Pulse magnitude.
  - Pulse repetition rate.
  - PD intensity, which should be a value directly related to the amount of energy in the discharge.
  - Temperature and humidity.
  - Phase-resolved data in a graphical format.
- The user should have the ability to graphically compare data between channels, as well as correlate the PD quantities to the monitored environmental factors, such as temperature and humidity.

B

ELECTRICAL CONNECTION TORQUE VALUES

All tables in this Appendix are from the EPRI *Bolted Joint Maintenance and Application Guide* [36].

Table B-1
Tightening Torque for Screws

Test Wire Size Installed in Terminal (AWG or MCM)	Tightening Torque for Slotted Head Screws No. 10 and Larger (in.lb)		Tightening Torque Using Hexagonal Head External Drive Socket Wrench (in.lb)
	Slot Width < 0.047 in. Slot Length < 1.4 in.	Slot Width > 0.047 in. Slot Length > 1.4 in.	
22–10	20	35	75
8	25	40	75
6-4	35	45	110
3	35	50	150
2	40	50	150
1	-	50	150
1/0–2/0	-	50	180
3/0–4/0	-	50	250
250–400	-	50	325
500–750	-	50	375
800–1000	-	50	500
1250–2000	-	-	600

Slot width is the nominal design value. Slot length is measured at the bottom of the slot.

Table B-2
Tightening Torque for Slotted Head Screws Smaller Than No. 10

Slot Length of Screw (in.)	Tightening Torque for Slot Width of Screw < 0.047 (in.lb)	Tightening Torque for Slot Width of Screw > 0.047 (in.lb)
< 4.32	7	9
5.32–7.32	7	12
1.4	9	12
9.32	-	15
> 9.32	-	20

Data are for use with No. 8 and smaller conductors. Slot lengths are measured at the bottom of the slot. For values of slot length that are between those specified, use the torque value from the shorter length screw.

Table B-3
Tightening Torque for Recessed Socket Screws

Socket Size Across Flats (in.)	Tightening Torque (in.lb)
1/8	45
5/32	100
3/16	120
7/32	150
1/4	200
5/16	275
3/8	375
1/2	500

Table B-4
Bronze Bolts Used with Copper Bus

Bolts: ASTM F-468 No. 651 Copper Bus: ASTM B-187 Temper H04							
Bolt Size	**Torque**		**Installed Tensile Load**	**Installed Stress**	**Thermal Stress**	**Total Bolt Stress**	**Bus Stress**
(in.)	**ft.lb**	**in.lb**	**(lbs)**	**(ksi)**	**(ksi)**	**(ksi)**	**(ksi)**
1/4–20	5	60	1200	37.73	0	37.74	5.21
5/16–18	10	120	1920	36.64	0	36.64	7.36
3/8–16	20	240	300	41.29	0	41.29	7.12
1/2–13	40	480	4800	33.83	0	33.83	4.90
5/8–11	55	660	5280	23.36	0	23.36	3.77

All stresses are within the elastic range (less than the 45 ksi yield strength for bronze bolts and the 40 ksi yield strength for copper bus).

Table B-5
High Strength Steel Bolts Used with Copper Bus

Bolts: SAE Grade 5, ASTM A-325, ASTM A-490 Copper Bus: ASTM B-187 Temper H04							
Bolt Size	**Torque**		**Installed Tensile Load**	**Installed Stress**	**Thermal Stress**	**Total Bolt Stress**	**Bus Stress**
(in.)	**ft.lb**	**in.lb**	**(lbs)**	**(ksi)**	**(ksi)**	**(ksi)**	**(ksi)**
1/4–20	5	60	1200	37.73	15.72	53.46	7.34
5/16–18	12	144	2304	43.97	14.52	58.49	11.79
3/8–16	20	240	3200	41.29	15.05	56.34	9.70
1/2–13	50	600	6000	42.23	15.59	57.82	8.37
5/8–11	95	1140	9120	40.35	15.26	55.61	8.97

All torque values are for zinc-plated bolts.

Table B-6
Austenitic Stainless Steel Bolts Used with Copper Bus

Bolts: ASTM A-193 Type 1, Class B8A Copper Bus: ASTM B-187 Temper H04							
Bolt Size	**Torque**		**Installed Tensile Load**	**Installed Stress**	**Thermal Stress**	**Total Bolt Stress**	**Bus Stress**
(in.)	**ft.lb**	**in.lb**	**(lbs)**	**(ksi)**	**(ksi)**	**(ksi)**	**(ksi)**
1/4–20	5	60	1200	37.74	0	37.73	5.21
5/16–18	10	120	1920	36.64	0	36.64	7.36
3/8–16	20	240	3200	41.29	0	41.29	7.12
1/2–13	40	480	4800	33.83	0	33.83	4.90
5/8–11	55	6600	5280	23.36	0	23.36	3.77

Bolts of most sizes are stressed into the plastic range (over the 30 ksi yield strength but less than the 75 ksi tensile strength). This is acceptable because no additional thermal stresses are present.

Table B-7
Aluminum Bolts Used with Aluminum Bus

Aluminum Bolts Used with Aluminum Bus Bolts: ASTM Aluminum, Grade 2024-T Aluminum Bus							
Bolt Size	**Torque**		**Installed Tensile Load**	**Installed Stress**	**Thermal Stress**	**Total Bolt Stress**	**Bus Stress**
(in.)	**ft.lb**	**in.lb**	**(lbs)**	**(ksi)**	**(ksi)**	**(ksi)**	**(ksi)**
3/8–16	15	180	3428	44.23	0	44.23	7.63
1/2–13	25	300	6857	48.32	0	48.32	7.02
5/8–11	40	480	5485	24.27	0	27.27	3.91

All torque values are for lubricated bolts.

Table B-8
High Strength Steel Bolts Used with Aluminum Bus

Bolts: SAE Grade 5, ASTM A325, ASTM A-490 Aluminum Bus: ASTM B-317 Grade 6061-T61							
Bolt Size	**Torque**		**Installed Tensile Load**	**Installed Stress**	**Thermal Stress**	**Total Bolt Stress**	**Bus Stress**
(in.)	**ft.lb**	**in.lb**	**(lbs)**	**(ksi)**	**(ksi)**	**(ksi)**	**(ksi)**
1/4–20	5	60	1200	37.74	29.48	67.22	9.41
5/16–18	12	144	2304	43.96	26.14	70.10	14.13
3/8–1	20	240	3200	41.29	27.59	68.88	11.86
1/2–13	50	600	6000	42.28	34.10	76.38	11.10
5/8–11	95	1140	9120	40.35	28.16	68.51	11.05

All torque values are for zinc-plated bolts.

C
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ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

Electric Power Research Institute (EPRI)

报告概要

目的

- 为开关设备和母线维护提供代表能源产业意见的指南，考虑开关设备制造商的维护规则

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Objectif

- Fournir des conseils sur des pratiques en matière d'entretien de mécanisme et de bus de données en considérant les recommandations des constructeurs de mécanismes.

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Objetivo

- Ofrecer una guía sobre las prácticas de mantenimiento de las barras y el aparellaje eléctrico que constituya una referencia común de uso general así como informar sobre las recomendaciones hechas por los fabricantes del aparellaje eléctrico.

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