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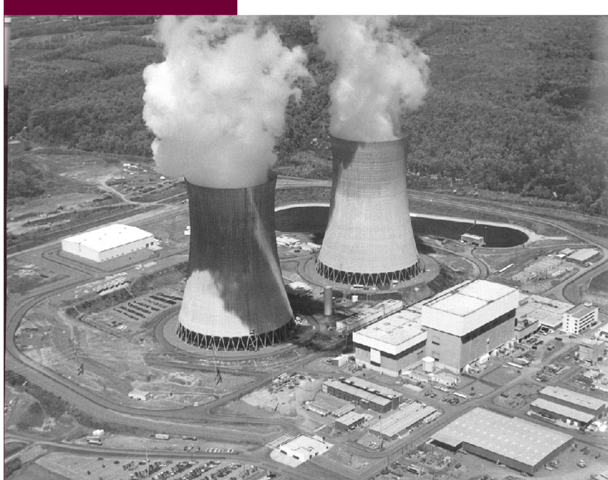
Plant Support Engineering: Switchyard Component End-of-Expected-Life Considerations and the Need for Planning



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Plant Support Engineering: Switchyard Component End-of-Expected-Life Considerations and the Need for Planning

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Final Report, December 2008

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PRODUCT DESCRIPTION

The purpose of this report is to alert plant managers and component/system engineers to the point in the life of switchyard components when long-term or contingency planning is desirable to preclude end-of-life failures, or to make their impact manageable. This report defines the expected life of switchyard components and specifies actions that can be taken to identify the onset of end-of-life failures and to reduce the cost of responding to them.

Results and Findings

Based on expert input, this report identifies the signs of end-of-life failure mechanisms and provides condition-monitoring techniques that can be used to determine if switchyard components are succumbing to failure. It also details the lead times that the condition-monitoring techniques can provide between the point of detection and the point of near or complete failure. Finally, this report reviews the logistics related to the replacement of switchyard components, including the length of time required under various scenarios. This information is useful in determining the need for contingency or long-term planning for specific/outlined switchyard components.

Challenges and Objectives

The report is for plant managers and component/system engineers responsible for equipment reliability and the assessment of the impact of failures on plant operations. The report identifies the point when long-term aging mechanisms can result in catastrophic failures, how to detect the onset of such conditions, and the impact of responding to an in-service failure. Using this information, the plant staff can assess alternatives such as: preparing for component replacement or refurbishment, improving condition-monitoring systems, and developing contingency plans (should a failure occur).

Applications, Value, and Use

This is the fourth end-of-expected-life report. Depending on the industry response to these documents, the Electric Power Research Institute (EPRI) will generate reports for further components and systems, modify the content of the reports, or determine that no further reports are needed. These reports are expected to be of use to personnel responsible for the long-term planning of equipment operation, and should help them determine when actions are needed to preclude end-of-life failures.

EPRI Perspective

Life cycle management and long-term planning efforts have generally focused on resolving issues with systems and components that have caused continuous problems for plants. This project provides the impetus to plan for the prevention and mitigation of equipment failures. The report focuses on equipment that has typically provided trouble-free service, but is likely to degrade and fail due to long-term aging. With information on expected life, monitoring techniques, and logistics issues, the need for long-term planning can be determined. Once the need has been confirmed, existing utility methods for assessment of alternatives or EPRI economic decision-making tools such as *Life Cycle Management Value Planning Tool Code, Version 1.0* (EPRI, 1003455) and *Life Cycle Management Plato Code* (EPRI, 1002860) may be used to support planning. Additional review of preventive maintenance and condition monitoring that may be applied throughout the life of switchyard and substation components is contained in the *Guidelines for the Life Extension of Substations* (EPRI, 1001779).

Approach

The goal of this project is to provide decision-making information used to determine when a long-term or contingency plan is needed as various switchyard components approach their expected end of life. The report has intentionally been kept short in order for users to readily understand key issues and be ready to make quick decisions concerning long-term planning for these components. The report uses tables to provide key information on expected life, condition-monitoring techniques useful for detecting the onset of end-of-life conditions, key stressors that would shorten the expected life, and logistics associated with replacement during a planned outage or failure. Discussions have also been kept short. References are provided to allow readers to obtain more detailed information, if desired—much of which is contained in other EPRI reports.

Keywords

Expected life
Condition monitoring
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Substations
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CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 INTRODUCTION

With the implementation is license renewal, nuclear plant staffs must determine if the reliability of long-lived components are sufficient for operating 60 or more years. Staff considerations must take into account the actions necessary to preclude in-service failures of major components or contingency plans to ensure a rapid return to service if a failure occurs.

The purpose of this report is to alert plant managers and component/system engineers to the point in the life of switchyard components when long-term or contingency planning is desirable to preclude end-of-life failures or to make their impact manageable. This report defines the expected life of various components typically found in a switchyard and specifies actions that can be taken to identify the approach of end-of-life failures or to reduce the cost of responding to them. The components covered by this report are high-voltage air-blast circuit breakers, high-voltage sulfurhexafluoride (SF_6) circuit breakers, current and potential devices, high-voltage disconnect and ground switches, bus insulators and connections, structural components, and lightning arrestors. Protective relaying, transformers, batteries and chargers, and wave traps are not included in the scope of this report. Oil circuit breakers are not covered due to their limited use in the industry. Transformers are covered by *Plant Support Engineering: Large Transformer and-of-Expected-Life Considerations and the Need for Planning* (Electric Power Research Institute [EPRI], 1013566).

Expected life is defined as the time from the start of service to the point when the basic, periodic maintenance regime must be changed to either a major refurbishment or replacement of the equipment to preclude catastrophic failure of a component. In this report, the expected life is based on expert judgment. The expected life is the point through which components receiving appropriate maintenance and condition monitoring would be expected to provide satisfactory service. After that point, a catastrophic failure would be more likely. The predictions of expected life will help utilities determine when heightened monitoring and maintenance, refurbishment, or replacement would be prudent. Figure 1-1 provides the basic concept of expected life and its relationship to the need for planning. It is not possible to make precise end-of-life predictions due to variations in service conditions, maintenance practices, and equipment capability. Large variations in actual end of life are possible. The values given here are meant to support the process of and need for planning. Reviewing the need for a long-term or contingency plan well before the end of the expected lives of these components can be valuable. Knowing the condition and location of suitable replacement components, the lead times before failure provided by condition-monitoring techniques, the availability of transportation routes, and the logistical and outage issues associated with large component failures may help determine that having long-term or contingency plans in place early is appropriate.

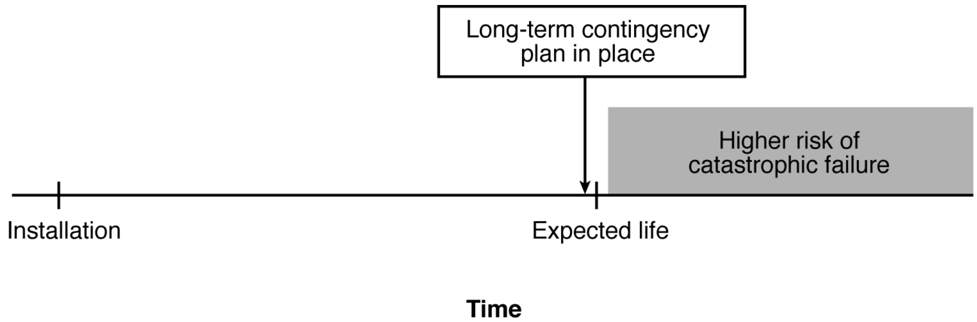

Figure 1-1
Expected Life and Long-Term Planning

The value of expected-life estimates for equipment results from avoiding or limiting the effect of catastrophic failures from degradation mechanisms not addressed by normal maintenance. Expected-life estimates will make a plant's technical staff more aware of the need to consider alternative equipment-reliability strategies beyond normal maintenance regimes. These estimates will also help the technical staff support business cases indicating that investments in maintenance of plant equipment are warranted.

This report has been generated to help in determining the need for long-term plans. It is not meant to be a basis for the plan or for determining the types of normal maintenance and monitoring that should be applied to switchyard components. Other EPRI reports and methods have been developed for those purposes. For example, the *Nuclear Plant Life Cycle Management Implementation Guide* (EPRI, TR-106109) [1] and the *Life Cycle Management Value Planning Tool (LcmVALUE) Code* (EPRI, 1003455) [2] provide programs that may be used to perform economic assessments of alternative plans. Figure 1-2 shows the context for the use of this report.

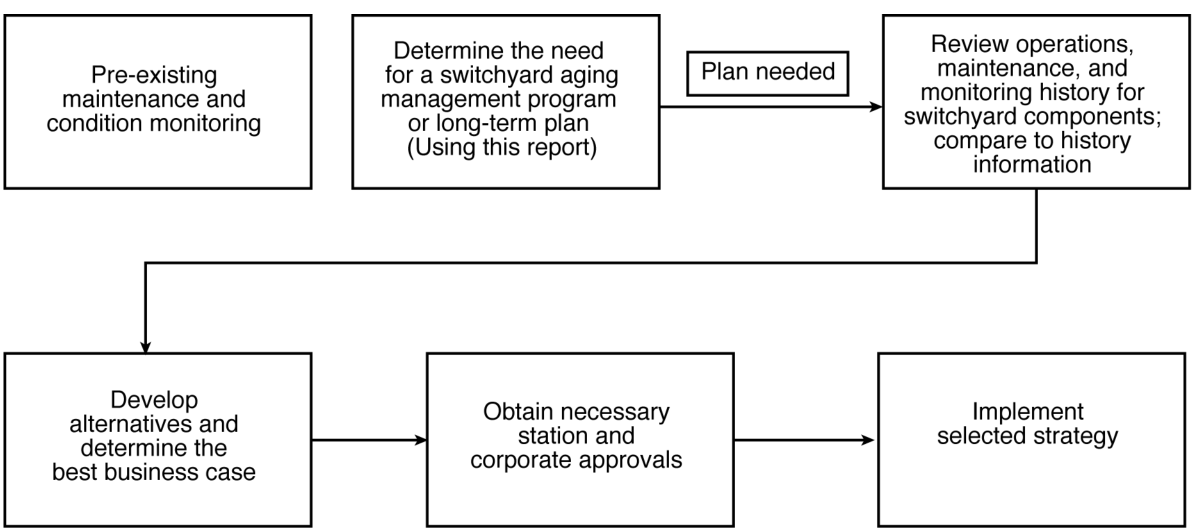

Figure 1-2
Context of Expected-Life Issues

In addition to identifying the expected lives of long-lived switchyard subcomponents, this report identifies condition-monitoring techniques that will be useful for identifying the onset of failure mechanisms that could lead to a catastrophic failure arising from end-of-life failure mechanisms. The degree to which the condition-monitoring results provide a leading indication is described. This lead time establishes the urgency for contingency planning and the need for replacement or refurbishment.

The report details the logistics related to equipment replacement or refurbishment. These logistics provide an estimated timeframe for the procurement of replacement components and the details of installing and readying them for service.

With the information in this report, a utility can decide on the most appropriate course of action and its expected costs. A utility may wish to proceed with the development of an LCM plan as defined in *Nuclear Plant Life Cycle Management Implementation Guide* (EPRI, TR-106109) [1] and supported by EPRI Report 1001779 [3] to develop contingency plans or to implement another form of long-term planning.

2 EXPECTED-LIFE CONSIDERATIONS

The expected lives for long-lived switchyard components are provided in Tables 2-1 through 2-8. It is anticipated that the failure of these components could lead to an extended or complete loss of their use. In the tables, the large switchyard components are broken down into their major subcomponents. It is expected that these major subcomponents could be broken down into their component piece-parts, which would have shorter life spans. Proper maintenance and replacement activities should allow for longer service life for the major subcomponents. The estimated lives stated in Tables 2-1 through 2-8 provide a good estimate for how long these major subcomponents should function with reasonable maintenance before long-term aging creates a catastrophic failure. Due to the unavailability of strong statistical data for the failure of these major subcomponents, their expected lives were determined by expert judgment.

Estimating Station-Specific Expected Lives

The expected-life timeframes for the switchyard components listed in Tables 2-1 through 2-8 are based on the assumption that reasonable maintenance, inspection, and monitoring activities have been performed throughout the service life of these components. Additionally, it is assumed that appropriate corrective actions have been taken in response to the inspection and monitoring findings. Information is provided on degradation mechanisms and the appropriate preventive maintenance activities to support the expected-life information provided. This information should support site-specific evaluations of the life-expectancy range that applies to the site's switchyard components. The specified condition-monitoring techniques are intended to be used throughout the component's life rather than just near the end; this allows for timely and proactive action by the site to address emerging component degradation and aging issues. The information in Tables 2-1 through 2-8 focuses on the identification of long-term aging mechanisms that could lead to catastrophic failure rather than shorter-term mechanisms that are readily identifiable, correctable, and generally will not lead to failure if rectified in a reasonable amount of time. Preventive and predictive maintenance activities that can increase the length of expected life are listed in the tables and short descriptions of these activities are given in the following sections. Detailed descriptions of these and other useful preventive maintenance tasks applicable to switchyard components are discussed in *Guidelines for the Life Extension of Substations: 2002 Update*, (EPRI, 1001779) [3].

The expected lives for the switchyard components listed in Tables 2-1 through 2-8 can be best achieved if the site at which the component is located has a comprehensive preventive maintenance (PM) program similar to those identified in the applicable sections of *PMB C/S 1.5 Preventive Maintenance Basis Database* (EPRI, 1011923) [5]. The Institute of Nuclear Power

Operations' (INPO's) topical report TR4-40[1] [7] indicates that the majority of switchyard events during the period from 2000 to 2004 were caused by ineffective maintenance programs. By improving the maintenance program for switchyards, sites would improve the overall site reliability. Additionally, TR4-40 cites the need for added vendor oversight during maintenance to reduce deficiencies in human performance.

Since it is assumed in Tables 2-1 through 2-8 that normal maintenance has been performed, deviations from comprehensive, scheduled PM programs could impact expected life and should be evaluated. These tables also assume that minor problems—that could ultimately lead to catastrophic failure if not corrected—have been addressed. The key focus of these tables is end-of-life failure mechanisms that are likely even if good maintenance practices have been followed. Since the life expectancies in these tables are generic, service condition and industry operating experience should be used to assess plant-specific expected end of life.

[1] INPO reports are available only to INPO members and participants.

Table 2-1
Expected Life, Diagnostics, and Logistics for Switchyard Components: Air-Blast Circuit Breakers

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Air-blast circuit breaker: interrupter assembly.	Flashover.	Mechanical failure, loss of dielectric medium related to mechanical malfunction, air contamination (compressor oil), mechanical failure, particulate contamination, over-voltage, or high-contact resistance (heat generation increasing aging factor on composite material and aluminum castings).	Inspection of circuit-breaker-interrupter assembly upon completion of manufacturer's first major inspection cycle or after clearing/operating on major fault interruption. Timing and contact-resistance tests. Air moisture test.	Approximately 20–25 years between major refurbishments; extended use may not be cost effective.	Standard operational wear will cause normal degradation of interrupter assembly. Major fault interruption (for example, over-voltage) may cause major component breakdown and damage.	Thermography. [3] Air-system contamination, high-contact resistance, or slow main-contact timing.	Techniques are effective and well-established.	Depends on severity of damage to interrupter components. May require complete pole replacement or replacement of complete circuit breaker if other major components affected.	Days to weeks.	N/A	Possibly extensive (Weeks to a month). See Notes 1 and 2.
Air-blast circuit breaker: Porcelain insulators.	Flashover/ loss of insulation properties. Mechanical failure.	Contamination due to age, environmental influences (such as pollution). Mechanical failure due to flange cement expansion due to freeze/thaw cycles.	Inspect and clean external bushing surfaces; replace if porcelain is cracked or chipped, or if high levels of tracking are seen along insulator surface; replace upon unacceptable hi-pot or power-factor tests. Flange cement caulking.	Typically 20 years, but subject to environment and climatic zone.	If contaminated, may fail quickly, especially in wet conditions.	External visual inspection for contamination, cracks, chips, or broken insulator skirts. High-potential (hi-pot) and power-factor testing, per rating specifications Ultra-sound, hydrostatic pressure test.	Techniques are effective and well-established.	If deteriorated, contaminated or failed, it can be cleaned or replaced. If failure induces fault, low likelihood of reparability.	Days to a week.	N/A	Days to a week.

Note 1: Time-to-replace duration is dependent on the availability of materials and components no longer in standard production.
Note 2: Materials and components may be required to be manufactured, or an adaptation of an equivalent may be designed. In both cases, long lead times may be required. Therefore, critical spare parts should be identified and obtained in advance.

Table 2-1 (continued)
Expected Life, Diagnostics, and Logistics for Switchyard Components: Air-Blast Circuit Breakers

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Air-blast circuit breaker: air system.	Flashover, failure to operate.	Compressor failure, air leakage, valve failure, moisture, compressor blow-by, or oil contamination.	Visual inspection of air compressor system and general maintenance. Remove moisture by use of air/water separator. Check oil level/lockout. Replace/overhaul air compressor components. Service air/oil separator. Calibrate pressure switches. Replace oil. Visual inspection. [6]	Typically 20 years.	Standard operational wear will cause normal degradation of air system components, mainly due to moisture or compressor oil breakdown.	Inspect for compressor oil in air system, moisture in air system above manufactures specification. Air consumption and blast valve operation tests [3]: Monitor air pressure, compressor run time, temperature, oil consumption, piston blow-by, inter-stage pressure.	Techniques are effective and well-established.	If removed from service before failure, very likely to be repairable.	Days to a week.	N/A	Days to a week.

Table 2-1 (continued)
Expected Life, Diagnostics, and Logistics for Switchyard Components: Air-Blast Circuit Breakers

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Air-blast circuit breaker: operating controls.	Failure to operate (open or closed). Failure to alarm or lock out following electrical failure of control relays and switches.	Stored energy system failure, failure to alarm or operate when signaled, and failure to clear fault as a result. Auxiliary contact linkage lubrication, aging of lubricants.	Visual inspection of all electrical components, electrical and mechanical functions testing of controls and their components.	Between 20–25 years.	Slow degradation of components related to electrical components. Pneumatic components may wear slowly also, depending on number of operations.	Visual inspection of all electrical components. Function testing of electrical relays, switches. Mechanical parts must be operating freely and without failure to complete motion. Fault recorder data analysis. Timing/travel test. Control wire insulation resistance test. Breaker monitor. Monitor AC and DC voltage. [6].	Techniques are effective.	Repairable upon inspection. Major mechanical control components may require complete replacement depending on failure mode.	Days to weeks.	Major failure of mechanical parts may require complete disassembly and replacement of components.	Days to weeks.
Air-blast circuit breaker: structural components.	Fracture of structure components, hardware loose.	Mechanical stress, corrosion, vandalism, stress due to human error (for example, structure hit with vehicle). If failure occurs, damage to auxiliary equipment may be possible.	Repair, weld, or replace damaged hardware or structure components. Remove corrosion and seal with appropriate primer, paint, or anti-corrosion material.	Typically 25 years.	May be years before actual failure. However, if stressed due to external influences, failure can occur immediately.	External visual inspection for damage, corrosion. Inspect hardware for tightness.	Techniques are effective and well-established.	Repairable upon inspection and availability of de-energized bus, where applicable.	Days to a week.	Temporary supports are required when replacing major structural supports.	Days to a week.

Table 2-1 (continued)
Expected Life, Diagnostics, and Logistics for Switchyard Components: Air-Blast Circuit Breakers

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Air-blast circuit breaker: grading capacitors.	Flashover, dielectric oil loss.	Fault across capacitor, capacitor insulator, and reduced fault rating of circuit breaker. Oil leakage (depending on capacitor type). Gassing. Over-voltage.	Measure resistance and capacitance. Breaker monitor. Power-factor test. [6]	Between 20–25 years.	Slow degradation influenced by loss of oil and loss of capacitance properties. Aging rubber bellows.	Visual inspection for contamination and oil leakage. Oil level verification.	Techniques are effective and well-established.	Successful repairs are likely if oil loss is noted during inspection. If failure induces internal fault, it may require a major inspection and there is a low likelihood of reparability.	Major failure may be repaired only with total replacement.	Major failure of capacitor can cause other main component failure, damage, or deterioration.	Days to weeks.

Table 2-2
Expected Life, Diagnostics, and Logistics for Switchyard Components: SF_6 Circuit Breakers

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
SF_6 circuit breaker: interrupter assembly.	Flashover.	Mechanical failure, dielectric breakdown, (if applicable), over-voltage, high-contact resistance, or slow timing.	Inspection of circuit breaker interrupter assembly upon completion of manufacturer's first major inspection cycle or after clearing/ operating on major fault interruption. Timing and contact resistance tests, SF_6 gas testing.	Between 20–25 years.	Standard operational wear will cause normal degradation of interrupter assembly. Major fault interruption (for example, over-voltage) may cause major component breakdown and damage.	SF_6 gas contamination, high-contact resistance, or slow main-contact timing.	Techniques are effective and well-established.	Depends on severity of damage to interrupter components. May require complete pole replacement or replacement of complete circuit breaker if other major components affected.	Days to weeks.	Components exposed to faulted SF_6 gas require specific personnel protective equipment and disposal.	Days to weeks.
SF_6 circuit breaker: porcelain insulators.	Flashover/ loss of insulation properties.	Contamination due to age or environmental influences, such as pollution.	Inspect and clean external bushing surfaces; replace if porcelain is cracked or chipped, or if high levels of tracking are seen along insulator surface; replace upon unacceptable hi-pot or power-factor tests.	20 years.	May fail quickly if contaminated, especially in wet conditions.	External visual inspection for contamination, cracks, chips or broken insulator skirts. Hi-pot and power-factor testing, per rating specifications.	Techniques are effective and well-established.	If deteriorated, contaminated, or failed, it can be cleaned or replaced. If failure induces fault, there is a low likelihood of reparability.	Days to a week.	N/A	Days to a week.

Table 2-2 (continued)
Expected Life, Diagnostics, and Logistics for Switchyard Components: SF_6 Circuit Breakers

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
SF_6 circuit breaker: SF_6 gas system.	Flashover, loss of SF_6 gas.	Leakage, SF_6 gas breakdown. Flange corrosion and sealing surface deterioration.	Visual inspection of SF_6 gas system. Verification of alarms and density monitor calibration.	20 years.	Standard operational wear will cause normal degradation, depending on environment. Loss of SF_6 gas due to major leak may immediately cause breaker failure.	Leak detection device and tools (for example, Snoop, halogen leak detector, infrared camera). Sampling of contaminated SF_6 gas.	Techniques are effective and well-established.	Likely to be replaceable if SF_6 gas is deteriorated, contaminated, or faulted. If failure induces internal fault, there is a low likelihood of reparability.	Days.	Faulted SF_6 gas requires specific personnel protective equipment and disposal.	Days.
SF_6 circuit breaker: electrical/mechanical controls.	Failure to operate, failure to alarm, or lock out on control relays and switches electrical failures. Mechanism dashpot failure.	Stored-energy system failure. Failure to alarm or operate when signaled; failure to clear fault as a result. Over-travel due to dashpot failure.	Visual inspection of all electrical components; testing of electrical & mechanical control functions and controls components.	Between 20–25 years.	Slow degradation of components related to electrical components. Mechanical components may wear slowly also, depending on number of operations.	Visual inspection of all electrical components. Function testing of electrical relays, switches. Mechanical parts must be operating freely and without failure to complete motion.	Techniques are effective.	Repairable upon inspection. Major mechanical control components may require complete replacement, depending on failure mode.	Days to weeks.	Major failure of mechanical parts may require complete disassembly and replacement of components.	Days to weeks.

Table 2-2 (continued)
Expected Life, Diagnostics, and Logistics for Switchyard Components: SF_6 Circuit Breakers

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
SF_6 circuit breaker: structural components.	Fracture of structural components. Hardware loose.	Mechanical stress, corrosion, vandalism, stress due to human error (for example, structure hit with vehicle). If failure occurs, damage to auxiliary equipment may also occur.	Repair, weld or replace damaged hardware or structural components. Remove corrosion and seal with appropriate primer, paint or anti-corrosion material.	Typically 25 years.	Can be years before actual failure. However, if stressed due to external influences, failure may occur immediately.	External visual inspection for damage or corrosion. Inspect hardware for tightness.	Techniques are effective and well-established.	Repairable upon inspection and availability of de-energized bus, where applicable.	Days to a week.	Temporary supports are required when replacing major structural supports.	Days to a week.
SF_6 circuit breaker: grading capacitors.	Flashover. Oil leakage (depending on capacitor type).	Fault across capacitor, capacitor insulator, and reduced fault rating of circuit breaker. Gassing. Over-voltage.	Measure resistance/ capacitance. Breaker monitor. Power-factor test. [6]	Between 20–25 years.	Slow degradation influenced by loss of oil and loss of dielectric properties.	Visual inspection for contamination and oil leakage. Oil level verification.	Techniques are effective and well-established.	If loss of oil is noted with inspection, component is likely repairable. If failure induces internal fault, it may require a major inspection and have a low likelihood of reparability.	Major failure may be corrected only with total component replacement.	Major failure of capacitor can cause other main component failure, damage, or deterioration.	Days to weeks.

Note 1: Time-to-replace duration is dependent on the availability of materials and components no longer in standard production.
Note 2: Materials and components may be required to be manufactured, or an adaptation of an equivalent may be designed. In both cases, long lead times may be required. Therefore, critical spare parts should be identified and obtained in advance.

Table 2-3
Expected Life, Diagnostics, and Logistics for Switchyard Components: Bus Insulators

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Bus insulator: porcelain insulators.	Flashover/ loss of insulation properties.	Surface contamination due to age or environmental influences (such as pollution). If failure occurs, damage to adjacent equipment may also occur. Vandalism.	Inspect and clean external bushing surfaces; replace if porcelain is cracked or chipped, or if high levels of tracking are seen along insulator surface; replace upon unacceptable hi-pot or power-factor tests. Apply silicone grease for locations with high salt or dirt contamination.	Between 35–40 years.	If contaminated, may fail quickly, especially in wet conditions.	External visual inspection for contamination, cracks, chips or broken insulator skirts. Hi-pot and power-factor testing, per rating specifications.	Techniques are effective and well-established.	If deteriorated, contaminated or failed, it can be cleaned or replaced. If failure induces fault, low likelihood of reparability.	Days to a week.	N/A	Days to a week.
Bus insulator: structural components.	Fracture, hardware loose.	Mechanical stress, corrosion, vandalism, stress due to human error (for example, structure hit with vehicle). If failure occurs, damage to adjacent equipment may also occur as a result.	Repair, weld, or replace damaged hardware or structure components. Remove corrosion and seal with appropriate primer, paint, or anti-corrosion material.	Between 35–40 years.	Can be years before actual failure. However, if stressed due to external influences (for example, vehicle hits), failure may occur immediately.	External visual inspection for damage, or corrosion. Inspect hardware for tightness.	Techniques are effective and well-established.	Repairable upon inspection and availability of de-energized bus, where applicable.	Days to a week.	Temporary supports are required when replacing major structural supports.	Days to a week.

Note 1: Time-to-replace duration is dependent on the availability of materials and components no longer in standard production.
Note 2: Materials and components may be required to be manufactured, or an adaptation of an equivalent may be designed. In both cases, long lead times may be required. Therefore, critical spare parts should be identified and obtained in advance.

Table 2-4
Expected Life, Diagnostics, and Logistics for Switchyard Components: Bus Work

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Bus work: bus.	Fractures, corrosion.	Broken welds, cracked bus channels, or environmental conditions due to pollution. If failure occurs, damage to auxiliary equipment may occur as a result.	Visual inspection. Remove corrosion, repair, weld, or replace damaged bus work channels as required.	Between 35–40 years.	Failure may occur quickly when a crack or break develops on bus channel.	Visual inspection for damage or corrosion. Inspect hardware for tightness. Thermography. [3]	Effective.	Repairable upon inspection and availability of de-energized bus where applicable.	Days to weeks.	N/A	Days to weeks.
Bus work: connections.	Corrosion, connection thermal or partial discharge (PD) wear/damage, or connection failure.	Corrosion, high resistance values, thermal tracking, or arcing damage due to PD.	Visual inspection, remove corrosion, repair, weld, or replace damaged bus work channels as required. Contact resistance testing.	Between 35–40 years.	PD and thermal damage due to loose connections or loose connection hardware may generate damage to connections over time. If connection comes loose, failure may occur immediately.	Visual inspection for damage or corrosion. Inspect hardware for tightness on bus connections. Thermography. [3]	Effective.	Repairable upon inspection and availability of de-energized bus where applicable.	Days to weeks.	N/A	Days to weeks.

Table 2-4 (continued)
Expected Life, Diagnostics, and Logistics for Switchyard Components: Bus Work

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Bus work: support-clamp system.	Mechanical failure, thermal or PD, wear/damage, or connection failure.	Corrosion; loose electrical support strap hardware.	Visual inspection, remove corrosion, repair, weld, or replace damaged support clamp system straps as required.	Between 20–25 years.	PD due to loose support-clamp system strap hardware may generate damage to support clamp system straps and bus channel over time. If support clamp system straps come loose, failure may occur immediately.	Visual inspection for damage or corrosion. Inspect hardware for tightness on bus straps. Thermography. [3]	Effective.	Repairable upon inspection and availability of de-energized bus where applicable.	Days.	N/A	Days to weeks, depending on parts availability.

Note 1: Time-to-replace duration is dependent on the availability of materials and components no longer in standard production.
Note 2: Materials and components may be required to be manufactured, or an adaptation of an equivalent may be designed. In both cases, long lead times may be required. Therefore, critical spare parts should be identified and obtained in advance.

Table 2-5
Expected Life, Diagnostics, and Logistics for Switchyard Components: Disconnect and Ground Switches

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Disconnect and ground switch: Live parts.	High-resistance, arc wear, or thermal wear. Failure to open or delayed timing out of synchronization (parallel operation of all three phases).	Misalignment Blade over-rotation. Arcing contact wear. Seized components due to environment, climate exposure, or lack of operation.	Visual inspection, operations and function testing, contact resistance, lubrication of contact parts. Inspect condition of corona rings, and arrestors.	Typically 35 years.	Slow degradation of components related to live parts. Seizing may occur over time depending on environment. Immediate failures can occur if wear rate and contact resistance are high.	Visual inspection of all live components in open and closed positions, function testing, and contact resistance. Thermography. [3]	Techniques are effective and well-established.	Repairable by major component replacement following inspection or upon failure.	Days to weeks.	N/A	Days to weeks.
Disconnect and ground switch: insulators.	Flashover/loss of insulation properties.	Contamination due to age. Environmental influences (such as pollution).	Inspect and clean external bushing surfaces; replace if porcelain is cracked or chipped, or if high levels of tracking are seen along insulator surface. Replace upon unacceptable hi-pot or power-factor tests. Apply silicone grease for locations with high salt or dirt contamination.	Typically 35 years.	If contaminated, may fail quickly, especially in wet conditions.	External visual inspection for contamination, cracks, chips or broken insulator skirts. Hi-pot and power-factor testing, per rating specifications.	Techniques are effective and well-established.	If deteriorated, contaminated, or failed, it can be cleaned or replaced. If failure induces fault, there is a low likelihood of reparability.	Days to a week.	N/A	Days to a week.

Table 2-5 (continued)
Expected Life, Diagnostics, and Logistics for Switchyard Components: Disconnect and Ground Switches

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Disconnect and ground switch: operating linkage.	Failure to operate, failed linkage connectors, or broken linkage.	Corrosion Loss of lubrication Seized components due to environment, climate exposure, or lack of operation.	Visual inspection, operations and function testing, lubrication of moving and drive parts.	Typically 35 years.	Slow degradation of components related to moving and drive parts. Seizing may occur over time, depending on the environment and climate.	Visual inspection of all moving and drive parts in open and closed positions. Mechanical function testing.	Techniques are effective and well-established.	Repairable by major component replacement following inspection or failure.	Days to a week.	N/A	Days to a week.
Disconnect and ground switch: structural components.	Fracture of structure components.	Mechanical stress. Hardware becomes loose. Corrosion. Vandalism. Stress due to human error (for example, structure hit with vehicle). If failure occurs, damage to adjacent equipment may also occur.	Repair, weld, or replace damaged hardware or structural components. Remove corrosion and seal with appropriate primer, paint, or anti-corrosion material.	Typically 35 years.	Can be years before actual failure. However, if stressed due to external influences, failure may occur immediately.	External visual inspection for damage and corrosion. Inspect hardware for tightness.	Techniques are effective and well-established.	Repairable upon inspection and availability of de-energized bus, where applicable.	Days to a week.	Temporary supports are required when replacing major structural supports.	Days to a week.

Table 2-5 (continued)
Expected Life, Diagnostics, and Logistics for Switchyard Components: Disconnect and Ground Switches

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Disconnect and ground switch: controls.	Failure to operate or spurious operation.	Loss of control voltage. Electrical component failure. Wiring error. Interlock failure.	Functional testing of all electrical controls and verification of condensation heaters operation. Verification of all mechanical parts; operational function testing.	Typically 35 years.	Slow degradation of components related to electrical components. Mechanical components may wear slowly also, depending on number of operations.	Visual inspection of all electrical components. Function testing of electrical relays, switches. Mechanical parts must be operating freely and without failure to complete motion.	Techniques are effective.	Repairable upon inspection.	Days to weeks.	Major failure of mechanical parts may require complete disassembly of control cubicles.	Days to weeks.

Note 1: Time-to-replace duration is dependent on the availability of materials and components no longer in standard production.
Note 2: Materials and components may be required to be manufactured, or an adaptation of an equivalent may be designed. In both cases, long lead times may be required. Therefore, critical spare parts should be identified and obtained in advance.

Table 2-6
Expected Life, Diagnostics, and Logistics for Switchyard Components: Free-Standing Oil-Filled CTs

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Free-standing oil-filled current transformer: conservator.	Flashover.	Oil leakage.	Visual inspection. Level-indicator inspection.	Between 20–25 years.	Slow degradation influenced by loss of oil. Unit can experience a major failure upon loss of oil below manufacturer's minimum oil level.	Visual inspection for contamination and oil leakage. Oil level verification.	Techniques are effective and well-established.	Successful repair is likely if loss of oil is noted with inspection. If failure induces internal fault, it may require a major inspection, and there is a low likelihood of reparability.	Oil filling: days. Major failure: weeks to months, if repairable.	Major failure may only be repaired with total replacement.	Days to weeks.
Free-standing oil-filled current transformer: porcelain.	Flashover. Loss of insulation properties.	Contamination due to age. Environmental influences (such as pollution).	Inspect and clean external bushing surfaces. Replace if porcelain is cracked or chipped, or if high levels of tracking are seen along insulator surface. Replace upon unacceptable hi-pot or power-factor tests.	Between 20–25 years.	May fail quickly if contaminated, especially in wet conditions.	External visual inspection for contamination, cracks, chips, or broken insulator skirts. Hi-pot and power-factor testing, per rating specifications.	Techniques are effective and well-established.	If deteriorated, contaminated, or failed, it can be cleaned or repaired. If failure induces fault, low likelihood of reparability.	Weeks to a month	Major failure may only be repaired with total replacement.	Weeks to a month.

Table 2-6 (continued)
Expected Life, Diagnostics, and Logistics for Switchyard Components: Free-Standing Oil-Filled CTs

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Free-standing oil-filled current transformer: secondary connection terminal box.	Short circuit. Arcing.	Corrosion. Moisture accumulation. Insulation degradation.	Visual inspections to ensure condensation heaters are on and operational. Terminal box must be inspected for water intrusion. Inspect internal and external wiring for tightness.	Between 20–25 years.	Slow degradation influenced by loss of condensation heaters and moisture accumulation.	Heater resistance test and verification, along with heater function testing. Water or water marks found in junction box indicate water intrusion.	Effective.	Water intrusion can be repaired immediately. Arcing and short circuit tracking marks must be inspected and traced. Any breakdown in wiring or terminals must be replaced.	Days to weeks.	Depending on style and type of current transformer, terminal box replacement or component repair requires oil reclaiming to low level.	Days to weeks.
Free-standing oil-filled current transformer: structural components.	Fracture. Hardware loose.	Mechanical stress. Corrosion. Vandalism. Stress due to human error (for example, structure hit with vehicle). If failure occurs, damage to auxiliary equipment may also occur.	Repair, weld, or replace damaged hardware or structure components. Remove corrosion and seal with appropriate primer, paint, or anti-corrosion material.	Between 20–25 years.	May be years before actual failure. However, if stressed due to external influences, failure may occur immediately.	External visual inspection for damage or corrosion. Inspect hardware for tightness.	Techniques are effective and well-established.	Repairable upon inspection and availability of de-energized bus, where applicable.	Days to a week, depending upon whether CT is damaged by support failure.	Temporary supports are required when replacing major structural supports.	Days to weeks.

Table 2-6 (continued)
Expected Life, Diagnostics, and Logistics for Switchyard Components: Free-Standing Oil-Filled CTs

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Free-standing oil-filled current transformer: high-voltage primary connections.	Corrosion. Connection wear or damage due to loose hardware. Connection failure.	Corrosion. High-contact resistance values. Tracking. Arcing on connections due to loose hardware or improper installation.	Visual inspection. Remove corrosion, reinstall with new contact grease, and repair/replace damaged connections. Contact resistance testing. Thermography.	Between 20–25 years.	PD and thermal damage due to loose connections or loose connection hardware may generate damage to connections over time. If connection comes loose, failure may occur immediately.	Visual inspection for damage and corrosion. Inspect hardware for tightness on bus connections. Thermography.	Effective.	Repairable upon inspection and availability of de-energized bus, where applicable.	Days to weeks.	N/A	Days to weeks.
Free-standing oil-filled current transformer: dielectric oil.	Flashover.	Contamination; leakage; moisture in water; breakdown of oil insulation properties.	Oil sampling, power factor.	Between 20–25 years.	May be years before actual failure. However, dielectric failure can be immediate if moisture or contamination occurs.	Oil sample testing (combustible gas analysis) Discolored oil.	Effective and well-established.	Contaminated oil can be replaced using process equipment. However, if contamination is high, additional internal components may be affected and will require further inspection and diagnoses.	Weeks to a month.	Oil process and contaminated-oil disposal can be a high environmental risk, which may slow repair process down.	Days.

Note 1: Time-to-replace duration is dependent on the availability of materials and components no longer in standard production.
Note 2: Materials and components may be required to be manufactured, or an adaptation of an equivalent may be designed. In both cases, long lead times may be required. Therefore, critical spare parts should be identified and obtained in advance.

Table 2-7
Expected Life, Diagnostics, and Logistics for Switchyard Components: Free-Standing Potential Transformers

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Free-standing potential transformer: conservator.	Flashover.	Oil leakage.	Visual inspection. Level indicator inspection.	Between 20–25 years.	Slow degradation influenced by loss of oil. Unit can experience a major failure upon loss of oil below manufacturer's minimum oil level.	Visual inspection for contamination and oil leakage. Oil level verification.	Techniques are effective and well-established.	Component will likely be repairable if loss of oil is noted with inspection. If failure induces internal fault, it may require a major inspection, and there is a low likelihood of reparability.	Oil filling: days. Major failure: weeks to months, if repairable.	Major failure may be corrected only with total replacement.	Days to weeks.
Free-standing potential transformer: porcelain.	Flashover. Loss of insulation properties.	Contamination due to age. Environmental influences (such as pollution).	Inspect and clean external bushing surfaces; replace if porcelain is cracked or chipped, or if high levels of tracking are seen along insulator surface. Replace upon unacceptable hi-pot or power-factor tests.	Between 20–25 years.	If contaminated, may fail quickly, especially in wet conditions.	External visual inspection for contamination, cracks, chips or broken insulator skirts. Hi-pot and power-factor testing, per rating specifications.	Techniques are effective and well-established.	Can be cleaned and/or replaced if only deteriorated, contaminated, or failed. If failure induces fault, there is a low likelihood of reparability.	Weeks to a month.	Major failure may be repaired only with total replacement.	Weeks to a month.

Table 2-7 (continued)
Expected Life, Diagnostics, and Logistics for Switchyard Components: Free-Standing Potential Transformers

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Free-standing potential transformer: secondary-connection terminal box.	Short circuit. Arcing.	Corrosion. Moisture accumulation. Insulation.	Visual inspections to ensure that condensation heaters are on and operational. Terminal box must be inspected for water intrusion. Inspect internal and external wiring for tightness.	Between 20–25 years.	Slow degradation influenced by loss of condensation heaters and moisture accumulation.	Heater resistance test and verification, along with heater function testing. Water or water marks found in junction box indicated water intrusion.	Effective.	Water intrusion can be repaired immediately. Arcing and short circuit tracking marks must be inspected and traced. Any breakdown of wiring and terminals must be replaced.	Days to weeks.	Depending on style and type of PT, terminal box replacement or component repair is possible, but may require lowering or removing oil.	Days to weeks.
Free-standing potential transformer: structural components.	Fracture. Hardware loose.	Mechanical stress. Corrosion. Vandalism. Stress due to human error (for example, structure hit with vehicle). If failure occurs, damage to auxiliary equipment may also occur.	Repair, weld, or replace damaged hardware or structure components. Remove corrosion and seal with appropriate primer, paint, or anti-corrosion material.	Between 20–25 years.	May be years before actual failure. However, if stressed due to external influences, failure may occur immediately.	External visual inspection for damage or corrosion. Inspect hardware for tightness.	Techniques are effective and well-established.	Repairable upon inspection and availability of de-energized bus, where applicable.	Days to a week	Temporary supports are required when replacing major structural supports.	Days to weeks.

Table 2-7 (continued)
Expected Life, Diagnostics, and Logistics for Switchyard Components: Free-Standing Potential Transformers

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Free-standing potential transformer: high-voltage primary connections.	Corrosion. Connection wear. Damage due to loose hardware. Connection failure.	Corrosion. High-contact resistance value. Tracking or arcing on connections due to loose hardware or improper installation.	Visual inspection. Remove corrosion, reinstall with new contact grease, and repair/replace damaged connections. Contact resistance testing.	Between 20–25 years.	PD and thermal damage due to loose connections or loose connection hardware may generate damage to connections over time. If connection comes loose, failure may occur immediately.	Visual inspection for damage, corrosion. Inspect hardware for tightness on bus connections. Use corona camera on loose connection.	Effective.	Repairable upon inspection and availability of de-energized bus where applicable.	Days to weeks.	N/A	Days to weeks.
Free -standing potential transformer: dielectric oil.	Flashover.	Contamination. Leakage. Moisture in water. Oil-insulation properties broken down.	Oil sampling. Power factor.	Between 20–25 years.	May be years before actual failure. However, if moisture or contamination occurs, dielectric failure can be immediate.	Oil sample testing. Discolored oil.	Effective and well-established.	Contaminated oil can be replaced using process equipment. However, if contamination is high, additional internal components may be affected and will require further inspection and diagnoses.	Weeks to a month	Oil processing and contaminated oil disposal can have a high environmental risks, which may slow down the repair process.	Days.

Note 1: Time-to-replace duration is dependent on the availability of materials and components no longer in standard production.
Note 2: Materials and components may be required to be manufactured, or an adaptation of an equivalent may be designed. In both cases, long lead times may be required. Therefore, critical spare parts should be identified and obtained in advance.

Table 2-8
Expected Life, Diagnostics, and Logistics for Switchyard Components: Lightning Arrestors

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Lightning arrestors: insulator.	Flashover.	Contamination. Insulation breakdown. Leakage current is a concern for Metal Oxide Varistor (MOV) arrestors.	Visual inspection to check for cracked, contaminated, or broken porcelain, or evidence of a flashover.	Typically 30 years.		Visual inspection. Electrical testing. Power-factor testing. Megger testing. Operational testing.	Techniques are effective and well-established.	The component is likely to be cleanable and/or replaceable if it is only deteriorated, contaminated, broken, or failed. If failure induces fault, there is a low likelihood of reparability.	Hours to days.	Major failure may be repaired only with total replacement.	Hours to days.
Lightning arrestors: gap type.	Flashover at system voltage.	Water ingress is a concern if seals deteriorate.	Visual inspection of seals for signs of deterioration (cracking, crazing).	Typically less than 30 years.	Once seal fails, water will slowly enter arrestor due to rain and high-humidity conditions.	Visual inspection. Electrical testing. Power-factor testing.	Techniques are effective and well-established.	If seal is replaced before ingress of water, repairs will work. If internals are contaminated with water, replacement is likely to be needed.	Hours to days.	Major failure may be repaired only with total replacement.	Hours to days.

Table 2-8 (continued)
Expected Life, Diagnostics, and Logistics for Switchyard Components: Lightning Arrestors

Expected Life					Diagnostics			Logistics			
Failure Location/ Component	**Failure**	**Degradation/ Influence**	**Preventive Maintenance Supporting Expected Life**	**Life Expectancy**	**Time from Normal to at or Near Failure**	**Diagnostic Methods**	**Diagnostic Effectiveness**	**Repairable**	**Time to Repair**	**Repair Issues**	**Time to Replace**
Lightning arrestor: MOV type.	Lowering of conduction point.	Multiple voltage surges at or above operating voltage tend to cause a reduction in operating voltage.	Measurement of leakage current. Thermography.	Typically less than 30 years.	Once leakage current becomes excessive, operation at or near system voltage may occur.	Measurement of leakage current. Iidentification of elevated temperature by thermography.	Techniques are effective and well-established.	Detection of excessive leakage current or high temperature will require replacement.	Hours to days.	Major failure may be repaired only with total replacement.	Hours to days.

Note 1: Time-to-replace duration is dependent on the availability of materials and components no longer in standard production.
Note 2: Materials and components may be required to be manufactured, or an adaptation of an equivalent may be designed. In both cases, long lead times may be required. Therefore, critical spare parts should be identified and obtained in advance.

Major End-of-Life Failure Mechanisms and Factors that Affect Them

Tables 2-1 through 2-8 provide a number of end-of-life failure mechanisms for switchyard components and factors that affect those mechanisms. The following sections detail this information on a component basis. Applicable condition-monitoring techniques are discussed in Section 3, and that discussion is not meant to be all-inclusive, since many other useful methods exist. The additional methods and their usage are described in *PMB C/S 1.5 Preventive Maintenance Basis Database Client/Server, Version 1.5* (EPRI, 1011923) [5].

In addition to the applicable failure mechanisms, information is provided to indicate the types of preventive maintenance required to retard the degradation most likely to lead to these failure mechanisms. For a number of the conditions, removal of the component from service and the performance of maintenance will be necessary. Some problems may require the component to be shipped to a maintenance facility where it can be repaired or refurbished.

Air-Blast Circuit Breakers

Modern air-blast circuit breakers are large, complex components with numerous failure mechanisms. The main failure mechanism of concern is failure of the high-pressure air system due to leakage to the atmosphere. This air leakage can result in moisture-laden, atmospheric air being drawn in as pressurized air leaks out, creating a venturi effect. The continuous passage of high-pressure air over a very small area can cut a groove into the metal (wire-drawing) that can *never* be effectively sealed. As the air leaks out, the compressed-air system will attempt to replenish the lost air, resulting in excessive compressor run time. A compressor can run enough extra hours to drastically reduce the time between maintenance periods and prematurely shorten the expected life of the machine. Additionally, compressor parts and accessories will wear out sooner than necessary, potentially causing additional downtime. Oxygen-induced embrittlement of seals, seats, and gasketing of all types (including O-rings) can occur. This natural aging process—coupled with a less than perfect environment, and possible compressor oil seepage into the dry air system and/or the main breaker components—may cause the elastic seals to become less flexible. In the worst-case scenario, seals, gaskets, and O-rings can become completely brittle and lose their ability to expand and contract to the surrounding metallic and ceramic components during temperature changes. The components will have lost the ability to effectively seal the intended surface and will allow the pressurized air to escape to the atmosphere. These air-system failures can best be addressed with the following preventive maintenances (PMs): check oil level/lockout, replace/overhaul air compressor components, service air/oil separator, calibrate pressure switches, replace/overhaul dry-air system, and inspect piping for leaks [3].

Air-blast circuit breakers are vulnerable to electrical failures as well as air-system faults, with the following major failure mechanisms of highest concern:

- High-resistance load path
- Mechanism failure
- Equipment operating linkage failure

- Stored-energy system failure
- Control circuit failure

A high-resistance load path may be due to surface contamination of the main contacts, wearing or worn main contacts or load-carrying parts, or loose connections on the main breaker contacts. This type of failure mechanism will lead to the breaker having an inadequate path for current flow, thus leading to breaker damage from overheating. The most effective preventive maintenance tasks to address this mechanism are visual inspections, contact resistance checks, and the checking and retorquing of connections during de-energized conditions. Mechanism and operating linkage failures can occur due to aging or excessive wear of circuit breaker mechanical-operating components. The most effective preventive maintenance tasks to address this mechanism are overhaul, exercise of the breaker, verification of mechanical tolerances, electrical and mechanical function testing, and visual inspection.

Stored-energy system failure occurs when the pneumatic, hydraulic, or spring mechanism used to open and close the circuit breaker fails because of wear or aging. The most effective preventive maintenance tasks to address this mechanism are changing oil, belts, and filters; changing or filtering hydraulic oil; cycling or forcing hydraulic fluid flow; bleeding the air tank; replacing/overhauling air compressor components; verifying mechanical tolerances; replacing or overhauling the dry air system; and visually inspecting for leaks.

Control circuit failure occurs when faults develop in the electronic controls for a circuit breaker. The most effective PM task is the performance of a circuit functional test to ensure proper operation.

SF_6 Circuit Breakers

Sulfur hexafluoride (SF_6) is an excellent gaseous dielectric for high-voltage applications. It has been used extensively in high-voltage circuit breakers and other switchgear employed by the power industry. Applications for SF_6 include gas-insulated transmission lines and gas-insulated power distribution substations.

The combined electrical, physical, chemical, and thermal properties offer many advantages when used in power switchgear. These advantages include:

- Size reduction
- Simplified design
- Weight reduction
- Ease of installation

- Reliable operation
- Ease of handling
- Quiet operation
- Ease of maintenance

SF_6 has excellent heat transfer characteristics. The ability to transfer heat is an extremely important property of a gaseous dielectric.

SF_6 possesses a high dielectric strength, which helps minimize arcing. Also, the dissociated molecules rapidly recombine after the source of arcing is removed. This makes SF_6 uniquely effective in quenching arcs. When spurious arcing occurs, SF_6 is approximately 100 times as effective as air in quenching the arc.

Utilizing its unique heat-transfer and arc-quenching characteristics, the SF_6 in circuit breakers acts to extinguish the arc as a result of an open operation. As a result of some fault-load and/or multiple normal-load circuit breaker operations, SF_6 gas can eventually break down and require reprocessing or replacement. In addition, its broken down properties can contribute to deterioration of a circuit breaker’s main contacts, seals, insulators or tank walls, as well as deterioration of operability and serviceability of equipment.

SF_6 gas leaks can lead to deterioration of sealing components much like air leaks. In addition, loss of SF_6 gas creates an unserviceable piece of equipment (for example, lock-out condition) and even the possibility of major dielectric failure. Continued loss of SF_6 gas contributes not only to the deterioration of the environment[2], but also to increased maintenance costs (since SF_6 gas is expensive). Leaks will result in both additional material costs for SF_6 gas and in labor to re-fill and test the SF_6 gas.

The air-operating systems for SF_6 circuit breakers obtain air from either a whole substation air-ring main supply system fed from a centrally located compressor plant or from a dedicated compressor mounted at or adjacent to the individual circuit breaker. Both systems have air compressors. These air compressors require periodic inspection and occasional maintenance since they are rotating machinery and cyclic in this application [3].

Both substation-wide and local (to the circuit breaker) air systems are fundamentally the same. The major difference in maintenance activity is that the ability to perform maintenance/overhaul for the latter is usually restricted to the time when the associated circuit breaker is out of service. The other obvious difference is that a central system usually operates at a much higher pressure. The primary problems with such air systems are air leaks in the associated valves, piping, pressure switches, and gauges. Although these problems are relatively infrequent, they should be corrected as soon as possible after detection. Left unrepaired, the leaks could cause excessive compressor run time, forcing early overhaul/maintenance and possibly the failure of the breaker to close when required if the leak is large [3].

[2] SF_6 is a greenhouse gas that has a potential effect 2,400 times that of CO_2. It also has a projected atmospheric lifetime of 3,200 years.

In addition, long-term leaks can erode the valve seat or sealing face to an extent that, not just a seal, but major component replacement or repair may be needed. This erosion process is termed wire-drawing. As stated previously, many sizes and design variants of SF_6 gas circuit breakers exist that should be maintained as recommended by the manufacturer, keeping in mind that the duty requirements and the ambient environment will have an effect on the frequency of maintenance [3].

Second to the leakage problems in the air system, but just as troublesome, are problems with air compressors. As breakers age, the compressors and their components have inherent problems. Some manufacturers produced poorly designed unloader valves that malfunctioned frequently. This type of valve allows the compressor to start without pressure on the cylinder heads and expels the moisture collected after each stage of compression. The valve's failure prevents the compressor from delivering air to the breaker [3].

Operating temperature plays an important part in compressor performance. An excessive amount of heat creates problems, which in turn produces more heat, thereby compounding the adverse condition. Intake and, especially, exhaust valves are adversely affected by excess heat, which inhibits their ability to seat properly. Improper seating allows restricted high-pressure airflow and produces more heat. Aging safety and shutoff valves, motor starter contact deterioration, wintertime heater failure, and compressor piston ring wear-out also contribute to the problems associated with compressors [3].

To keep pace with the leaks, a compressor can run enough extra hours to prematurely shorten the expected life of the machine and the life of the circuit breaker. A compressor with high run-time hours and low maintenance can contribute to the introduction of oil into the internal components of the circuit breaker. In air-blast circuit breakers with badly maintained compressors, oil works its way into the breaker tank and contact areas causing severe issues with reservoirs, contacts, and operating rods. In addition, this has led to damaged pneumatic control assemblies, which acquire air from compressor units. Compressor parts and accessories will then wear out sooner than desired, potentially causing down time. The pressure-reduction fill-valve will be adversely affected when called upon to operate excessively [3].

Both air-blast and SF_6 circuit breakers may be considered at end of life when the cost of service and spare parts is larger than the cost of a complete breaker replacement, or when a major failure has occurred and components (such as interrupters or control mechanisms) are not easily repaired due to wear or failure.

Bus Insulators

Surface contamination of bus insulator bushings can be a problem in areas where there are larger concentrations of airborne particles, such as near coal plants that discharge soot or near the seacoast where salt spray and fog is prevalent. Various airborne materials such as dust, salt, and industrial effluents can contaminate insulator surfaces. The buildup of surface contamination is gradual, and in most areas, such contamination is washed away by rain; the glazed insulator surface aids this contamination removal. The two most common failure mechanisms associated with surface contamination of bushings are partial discharge (PD) and electrical flashover.

Tracking over the surface or burning through the condenser core is typically associated with PD. The first indications of this type of problem are an initial increase in power factor. As the deterioration progresses, an increase in capacitance will be observed [10]. If there is a large buildup of contamination, this will enable the conductor voltage to track along the surface more easily and can lead to insulator flashover. The most effective preventive maintenance for both these mechanism is a thorough visual inspection to check the protective resistive coating applied to the exterior of bushings, as well as scheduled, periodic cleaning of foreign matter and contamination. Additionally, power-factor testing and results may reveal increases in baseline bushing power-factor levels, indicating an increased risk for PD. Bushing flashover has been known to destroy bushings, resulting in damage to surrounding equipment along with the bushing itself. Some plants use “dummy” (non-energized) bushings and then evaluate their condition periodically to determine if the in-service bushings need maintenance.

Bus Work

Outdoor buswork is designed for a long, trouble-free service life. Its life expectancy can be shortened by various conditions. Specific trouble modes that can affect the bus and structure systems are mainly related to physical deterioration [3]. The most likely failure mechanism associated with this physical deterioration is related to the loosening or corrosion of the buswork or connections. The bare, metallic bus conductor may be corroded by atmospheric pollution and condensation. Coastal switchyards and installations in or near industrial areas are often subject to these types of attack. Bolted joints, such as conductor terminations and splices, may become loose and overheat as a result of thermal cycles. Any loose busbar or terminal connection will cause overheating that can lead to equipment malfunction or failure. Overheating in a bus or terminal connection will cause a discoloration in the busbar that can be visually identified. An overheating busbar condition will feed on itself and may eventually lead to the deterioration of the bus system and its connected equipment [3].

Aluminum-to-copper connectors can be damaged by galvanic corrosion, which occurs when two dissimilar metals are in contact in a common electrolyte, such as moist air. The galvanic potential difference between these two metals causes corrosion. Corrosion can be severe enough to break the electrical connection between the dissimilar metals. The most commonly recommended preventive maintenance activities used to address bus failure mechanisms are visual inspection (to identify and remove corrosion) and contact resistance testing (to indicate changes in the physical characteristics of the current carrying connections). Connection deterioration can be detected through thermography or using a corona camera.

Disconnect and Ground Switches

In general, manufacturers state that operating linkages for disconnect and ground switches should require no maintenance. However, in areas with contaminated atmospheres or where operation under severe winter weather conditions is common, some lubrication at pivot points is required. Manufacturers state that the lubricant should be durable even when exposed to the elements and retain its viscosity over a wide temperature range. Because the lubricants are usually applied in the field (sprayed on the pivot points), two problems typically arise. First, because the various linkages are not disassembled, one cannot be certain that the applied lubricant has sufficiently penetrated the joint. Second, many lubricants “gel” over time and lose their effectiveness as they are exposed to the elements and the temperature variations. Some utilities have reported that the lubricant can evolve into a glue-like substance that actually hinders the switch movement. Lubricants can also capture airborne contaminants, increasing the contamination problem. A visual inspection of the areas that contain lubrication (for example, pivot points) may not provide any indication on the condition of the lubricant. The best way to ascertain the effectiveness of the switch lubrication is to exercise the switch (when de-energized) several times while observing the movement of the various switch components [3].

Disconnect and ground-switch contacts can become troublesome depending on the frequency of operation and their degree of exposure to harsh environmental conditions. The atmosphere can contaminate the contact surfaces and cause pitting. Contact pitting will reduce the switch’s current-carrying capability. Fatigue can occur over time, and the switch contacts might need to be reworked, repaired, or replaced. The current-carrying contact parts will require preventive and corrective maintenance that includes, but is not limited to, cleaning and the removal of contact pitting [3].

The insulators supporting the switch and containing the operating rod(s) are subject to failure from age, contamination, and physical damage. Damaged insulators may cause the switch to be thrown out of alignment, resulting in damage to the rest of the switch. It should also be noted that cracked insulators may have resulted from unusual stresses placed on the switch from a misaligned switch or a switch that has been subjected to mechanical loads greater than the loads for which it was designed. A high-potential (hi-pot) or power-factor test will aid in identifying insulator problems [3]. It is recommended that sites perform a functional check, inspection, and thermography of the switch annually; operate the switch at least bi-annually; and perform vendor-specified maintenance, including teardown, every 10–12 years for switches that are not operated at least bi-annually or every 25–30 years for switches that are maintained regularly [7].

Disconnect switches and ground switches should be considered end of life based on station or industry reliability. In situations where the costs associated with component wear and/or failure repairs exceed the costs of replacement, a disconnect switch and ground switch should be considered at or near end of life.

Current and Potential Transformers

The following possible failure mechanisms are identified as the most common for current transformers (CTs) and potential transformers (PTs) [3]:

- Corrosion
- Porcelain failure
- Weld failure

- Bushing failure
- Oil dielectric failure
- Oil leakage

In general, instrument transformers' maintenance instructions involve external parts such as cleaning the porcelains or maintaining the paint and terminals. There is essentially nothing that can be maintained on the internal parts. There have been a few generic terminal problems at the top of instrument transformers that were corrected by removing the metal cap at the top. These were special operations outside the normal maintenance or life extension. Manufacturers do not generally recommend disturbing the oil, even to take oil samples for analyses. However, a number of problems in both types of instrument transformers have made it necessary to remove oil for testing. The history of current transformer operation shows that the oil does deteriorate in some current transformers; therefore, the oil should be tested intermittently. In addition, recent EPRI research has shown that periodic oil testing can detect certain forms of insulation degradation. The deterioration normally involves increases in the power factor of the oil—particularly at elevated temperatures—as the transformer operates for several years in service. This deterioration is believed to be related to the use of oils that had less than desired properties for extrahigh voltage (EHV) application. Because instrument transformers contain a small volume of oil, it is not recommended that oil sampling be performed while the transformer is live [3].

A number of capacitive voltage transformers have failed in service as the result of manufacturing problems. It has been reported that some capacitive voltage transformers failed because they were not applied properly on the system. The number of voltage transformer problems to date has not been great enough to initiate the actions taken for current transformers [3].

The following preventive maintenance measures for coupling capacitor voltage transformers/potential transformers (CCVT/PT) are recommended by INPO in the Topical Report TR4-40 [7]:

- Perform a scoping evaluation to add continuous CCVT/PT secondary-voltage monitoring with alarming capability. The alarming relays should have adjustable low- and high-voltage setpoints. This monitoring technique will provide early warning of failure.
- Identify the service life of all CCVT/PTs in the switchyard. Replace units with more than 23 years of accumulated service life. Vendor and industry reliability predictions all converge to a 20-25 year average life. Units with old oil-paper insulation technology have resulted in catastrophic failures. Today, units are insulated with polypropylene film, high-purity kraft paper, and synthetic oil that should be more reliable and less prone to catastrophic failures.
- Use optical aids like telescopes or high-powered binoculars to perform a detailed visual inspection for oil leaks or stains on all switchyard CCVT/PTs on a monthly basis.
- Perform Doble tests, including power-factor, dissipation-factor, capacitance, and dielectric strength every six years on CCVT/PTs.
- Replace Westinghouse PCA-5 CCVTs at the earliest opportunity. CCVTs of this type have experienced catastrophic failures in the recent past.

- Evaluate the feasibility of using infrared thermography for the detection of incipient CCVT/PT failures. Temperature monitoring may provide early warning, since most of the catastrophic failures have involved overheating of the insulating oil in the units.
- Perform an evaluation for an enhanced maintenance program similar to CCVT/PTs for CTs since more catastrophic failures have been reported in the industry for them than with PTs.

Lightning Arrestors

Lightning and surge arrester failures may be classified either as functional deterioration, which affects the protective characteristics, or as a mechanical/insulation deterioration, which affects the function as an insulator. Electrical failures of modern-day arresters are relatively few and, in most cases, can be attributed to the following [3]:

- Direct or nearly direct lightning strokes
- Long-duration surges resulting from switching
- Prolonged over-voltages
- Pressure build-up and resultant porcelain breakage, or pressure-release vent rupture due to:
  - Excessive arc by-products caused by close-in lightning stroke where currents exceed arrester ratings.
  - Excessive internal pressure resulting from currents even within rating, if moisture and/or other contaminants are present in arresters. Moisture and/or other contaminants may accumulate in arrester housings due to breathing caused by faulty seals or through porcelain cracks or blown vents.

Contamination of the external porcelain surface may be caused by industrial, environmental, or climatic conditions. This contamination may lead to failure due to uneven external stress distribution on the porcelain surface and consequent flashover. The use of silicone grease to control surface leakage has been known to be a flashover hazard if wind-blown hay or salt-grass sticks to the surface and is then followed by rain, fog, or snow that wets the contaminated surfaces. The use of extended creepage skirts is recommended in areas where salt or industrial contaminants such as cement dust, fly ash, or similar airborne material is a factor [3].

The following preventive maintenance measures for lightning and surge arrestors are recommended by INPO in the Topical Report TR4-40 [7].

- Perform periodic ultrasonic testing on all surge arresters. Take periodic SF_6 gas samples on a more frequent basis and analyze for indications of degradation or contamination.
- Replace gap-type surge arresters with metal-oxide type surge arresters if moisture seals are deteriorated.
- EPRI has demonstrated an *in situ*, non-intrusive method for testing energized MOV surge arresters. A leakage-current monitor is used to measure total watts lost. A key factor is the trending of results and looking for an increase in leakage current as the action point.

For MOV lightning arrestors, excessive leakage during operation, exposure to line and station lightning, or fault surges over an extended period of time will indicate that the component is nearing end of life. Component condition can be determined by evaluation testing such as power-factor testing, per manufacturer standards. For gap-type lightning arrestors, the loss of seal and resulting moisture ingress usually indicates the component is nearing end of life.

Structural Components

The strength of structures, whether made of steel, aluminum, or concrete, does not decrease with age if the integrity of the material is maintained. Therefore, structures should last for the life of the substation unless flaws or degradation are present. Possible problems include corrosion, deformation, buckling, and cracking of members as well as connection deficiencies such as loose, missing, or damaged bolts and cracked welds. Foundations should generally retain their strength throughout the life of the substation unless deterioration occurs. Possible problems include settling, cracks, spalling, honeycombing, exposed reinforcing steel, anchor bolt corrosion or deformation, and missing grout. The best preventive maintenance for structures and bolted connections is a periodic, thorough visual inspection to identify the corrosion and degradation before it progresses. Additionally, stations should periodically confirm that cathodic protection systems are operating properly [3].

3 CONDITION MONITORING RELATED TO END OF EXPECTED LIFE

This section of the report describes the condition monitoring techniques and preventive maintenance that can detect many of the aging and failure mechanisms described in Section 2. It also covers off-line tests and inspections designed to confirm the presence of that aging, as well as detect component degradation that cannot be identified from on-line monitoring. The trending of monitoring results is key to the identification of end-of-life conditions and conditions that could lead to early end of life, if they are not corrected.

Confirmatory and Alternate Diagnostic Methods

Circuit Breaker Travel/Timing Test

Circuit breaker travel/timing tests are specifically designed for commissioning, maintenance and condition assessment of a circuit breaker (for example, SF_6 gas, air-blast, oil-filled, or vacuum). The timing/travel tests determine the specific operating condition of the main contacts, as well as the control mechanism. The breaker travel/timing test evaluates the operation of the breaker during its cycles (open/close and close/open) dynamically, including mechanism movement and event timing, and reveals their problems. This test is applicable to any high-voltage breaker with an external operating mechanism [6]. The test indicates delays in opening and closing of the breaker that could cause arcing and possible failure when the breaker is called upon to change state.

High Potential Test

Hi-pot testing is used mainly for bus and/or gas insulated substations (GIS), due to the costs of testing. This test is an electrical insulation integrity test that stresses the system with high AC or DC voltage and measures current leakage to ground. This test is very similar to insulation resistance testing, but measures current rather than resistance. Integrity of vacuum and gas interrupters can be measured with this test. This is a go/no-go test that exposes the electrical insulation to multiples of the operating voltage. Success indicates that the insulation can satisfactorily operate under operating voltage at that particular time.

Insulation Power-Factor Test

This test is an electrical insulation integrity test using a 60 hertz (Hz) signal measuring the phase angle of current and voltage of the test signal. Transformers, breakers, cables, and rotating equipment insulation can be evaluated using this method. Aging effects such as moisture/carbon buildup can be determined using empirical comparisons. Corrective measures (for example, drying or filtering insulating oil) may be necessary as a result of this testing.

AC Power Factor and Dielectric Loss

This test measures the power factor of insulation systems and the proper values of grading capacitors and resistors when there is evidence of loss of weatherproofing or moisture present in air-blast circuit breakers. In these cases, complete electrical testing may be required to include contact resistance across the main contacts, main-contact timing, and electrical-mechanical function testing. Proper operation of air-blast circuit breakers depends on the quality of the compressed air and how its low level of relative humidity and moisture affects the internal insulating integrity.

Lubricant Analysis

Almost all lubricants can be sampled and analyzed for deterioration and/or contamination. Lubricant analysis is a commonly used technique for air compressors. Wear-particle analysis is also used along with lubricant testing. Degraded lubricants will lead to failure of the equipment being lubricated if not corrected [6].

Oil Quality Analysis

Oil analysis is useful for all oil-filled switchyard components. Arcing, low-energy sparking, or overheating of the insulation results in the decomposition of the insulating oil and surface that can result in combustible and noncombustible gases being generated. These conditions can occur singly or as several simultaneous events resulting in the generation of gases. The two principal causes of gas formation within a component are thermal and electrical disturbances. Gases are also produced from the decomposition of oil and insulation exposed to arc temperatures. There is a link between ratios of common fault-gas concentration, specific fault types, and the nature and severity of the component fault.

Oil analysis consists of testing for dielectric strength, acidity, interfacial tension, power factor resistivity, steam emulsion number, color, and pour point. Based on operating history, specific tests (such as a metal particle test) may be needed. Dissolved gas in oil is treated as a separate technology. Oil quality analysis is used to determine the condition of insulating oil and its continued usefulness as an insulator [6].

Partial Discharge Detector (Acoustic)

PD is an electrical phenomenon that occurs when the voltage value is sufficient to produce ionization that partially bridges the insulation between conductors. This phenomenon can lead to degrading the insulating properties and subsequent failure. By listening to a component using a high-frequency fault detector, it is possible to accurately detect partial discharge and determine the location within the component.

This test also is used to detect the initial insulation breakdown in transformer windings, coupled capacitor voltage transformers, insulators, and terminations [6, 9].

Partial Discharge Detector (Electrical)

PD detection is used to detect incipient failures before significant damage has occurred in insulators and terminators. This testing uses electrical sensors to detect insulation breakdown from particulate contamination and other dielectric problems [6].

Daytime Corona Detector

Corona discharges can be a significant threat to the integrity of nonceramic insulators (NCI) due to the organic nature of the housing material. For transmission-class insulators (69 kV and above), corona can be a problem, not only in contaminated but also in clean environments. From worldwide experience, it has been identified that a majority of NCI applications are under relatively clean or lightly contaminated conditions. On NCI, corona can be present locally for long periods of time due to inadequate hardware design, damaged hardware, and deficient interfaces because of improper design or manufacturing. Field inspections on 230 kV and 500 kV insulators confirm the existence of corona even under relatively dry and clean conditions. In practical high-voltage systems, it is difficult to avoid corona in the field, especially under wet and contaminated conditions. Hence, knowledge of the corona discharge magnitude and damage threshold of the housing material is essential [11].

Electrical engineers' awareness of corona and arcing effects is growing in recent years and is backed up by worldwide research. Corona and arcing on power lines and substations generate audio noise (environmental consideration) and radio interference (safety issues), in addition to accelerating the degradation of various grid components (such as ceramic and NCI), and are indicators of defective components that may cause outage.

Contact Resistance Check

This test uses an ohmmeter to check the resistance value of equipment and compare the reading with the specification in the applicable drawing or marked on the equipment to detect equipment degradation or failure. This test is a troubleshooting aid in determining the source of a circuit failure. Resistance checks can also be part of an alignment or calibration procedure. Circuit-breaker contacts should be tested using a micro-ohmmeter and include terminal connections. If resistance exceeds industry-accepted standards, then the problem should be corrected. Test data should be trended to detect a change from an initial or previous test. If a change of 15 micro-ohms or more is detected, then an internal inspection is warranted [3].

SF_6 Gas Analysis

SF_6 gas analysis is used to determine the SF_6 gas circuit-breaker condition. One test takes a sample from a SF_6 breaker manifold and analyzes it for fluorinated hydrocarbon byproducts that result from electrical arc associated with SF_6 interrupter operation. Another test is an in-service leak detection using the EPRI-supported GasVue laser camera. The camera is based on CO_2 laser backscattering technology. It employs an infrared detector to identify leaks of SF_6 around equipment seals, joints, and bushings. The characteristic of SF_6 is that the gas absorbs—but does not emit—infrared light. Using the camera, the laser scans the equipment. A leak appears as an inky black plume against a lighter background on a black and white monitor [3].

Temperature Monitoring

Temperature can be used as a measurement for predicting switchyard equipment failure. Typical areas of assessment include top oil, connectors, switches, transformers, and compressor stages. High, low, or inconsistent temperatures can all provide information in predicting or detecting failures. Thermometers, infrared imaging, bi-metallic sensors, resistance temperature detectors, thermocouples, and temperature-sensitive materials are instruments used for this condition monitoring [6].

Thermographic Analysis

Infrared imaging is used to locate hot spots in electrical equipment that are indicative of high-resistance connections, weak contacts, or mismatched phases. Prediction is best when based on relative comparisons of readings from the same monitoring point over a period of time. These readings are then used to develop historical (relative) patterns and correlation with adverse conditions and other analysis methods [6].

Thermography can also be useful in evaluating breakers. Overheating of an interrupter can be indicative of a high-contact resistance or loose part. Entrance bushings and results between phases can be compared. Usually, any difference of more than 5°C between phases or entrance bushings should be questioned, especially if the circuit breaker is operating below its rating. In addition, some components, such as connection materials and gasketing, have absolute temperature limits that must be monitored. Thermographic inspection is typically performed quarterly or semi-annually, but at least annually. Also, as-needed thermographic monitoring should be considered if changes in equipment alignment or loading occur [3].

4 LOGISTICS AFFECTING END OF USEFUL LIFE AND RECOVERY FROM FAILURE

Proactive replacement of a switchyard component during a planned outage can occur more rapidly than replacement of a component that fails in service, even when a spare component exists on site. The following sections provide an indication of the time needed for restoration to service after a significant failure or an adverse condition monitoring result indicates that removal of the component from service is prudent.

Logistics Issues

There are four logistics scenarios that exist for switchyard components:

- The planned *repair* of a component based upon monitored indications or conditions
- The planned *replacement* of a component based on monitored indications or conditions
- The unplanned *repair* of a component due to an unanticipated failure
- The unplanned *replacement* of a component due to an unanticipated failure

Each of these scenarios has cost and schedule impacts, with the unplanned scenarios affecting switchyard availability more severely. The following paragraphs provide an indication of the time necessary for restoration of service, as well as special circumstances that may affect a specific component following failure.

The majority of switchyard events are caused by unreliable switchyard equipment resulting from ineffective maintenance programs, as indicated in the INPO Topical Report TR4-40. Improving the preventive maintenance programs for switchyard equipment would improve overall plant reliability. The majority of switchyard-related equipment problems were caused by a lack of preventive maintenance and could have been prevented by implementing effective maintenance programs that identify components requiring periodic maintenance and testing. Switchyard equipment-related incidents have continued to increase over the last few years [7].

Air-Blast and SF_6 Circuit Breakers

Circuit breakers are the components most likely to fail during normal operations. For very large breakers, a single pole for a 345 kV breaker may weigh 3 tons. Unfortunately, most breakers and breaker components do not receive preventive maintenance while in storage. It is recommended that these components receive periodic inspections and thorough condition assessments to verify their continued operability and storage conditions (that is, packaging and storage pressure for air or SF_6 gas equipment).

A circuit breaker condition assessment is used to indicate the need of extensive or enhanced maintenance. Such maintenance should be targeted to enable the circuit breaker to achieve its present anticipated life. The next step is to review any further requirements and options for refurbishment, up-rating, or repair to reinforce this life expectancy or when seeking life extension. The major factors affecting this decision are:

- The inspection, maintenance, and diagnostic test history for the breakers.
- The service history of the breaker should be compared with that of other breakers of the same type and rating on the system. Any change of usage with time should be noted.
- A review of industry troubles and failures as reported by industry technical groups.
- The breaker manufacturer's specific recommendations. Review the manufacturer's recommendations, such as service advisories and availability of modification and up-rating kits. When a manufacturer has modification and up-rating kits available for an older circuit breaker, it implies that the particular circuit breaker type can be capable of providing service for some time yet to come.

In the event that a strict book-life replacement policy is not to be followed and life extension is sought, the criteria for the end of life has to be established. To do this, a definition is required. For some transmission assets, the end of life is relatively easy to determine—and, hence, predictable—as there are few or no subcomponents to consider, (for example, bus-bars and conductors), or they are essentially static items, (for example, cables and capacitors). For the dynamic, multi-component switching devices, a more complex definition of end of life is required. The most complex air-blast circuit breakers with 36 interrupters have more than 20,000 component parts, of which 1500 are moving (dynamic) and 2500 items are seals in various forms. In general, it is a combination of individual failure modes occurring at an increasing or unexpected rate on a combination of subcomponents that renders the circuit breakers and other switching devices unreliable. This eventually becomes an unacceptable level of unreliability, rather than total failure, and is taken as the end of life for such complex items because in a transmission plant, a "replace on failure" strategy cannot be supported. As the device approaches this period, these events cause increasing disruption to the system and a high-resource cost for the repair and maintenance commitment to keep it in service. It is recognized that this end of life is therefore not a clear, single point in time. It is more a range of ages for all similar assets based on the historic and present usage, the exposure to the natural and industrial atmospheric conditions, the strengths and weaknesses of the original design, and the level and quality of the present and historic maintenance activity. This range is characterized for the generic design-type from the earliest to the latest onset of significant unreliability. To be able to estimate when these ages are likely to occur requires some understanding of the weaknesses and the condition of the assets [3].

The following example illustrates how the major factors might be used in the analysis of whether to repair, refurbish, or replace a specific circuit breaker. The condition assessment of a circuit breaker is assumed to have been performed, and it has been shown to be capable of continued service. However, there is a question as to whether the breaker's rating would be adequate a few years from now. The options are:

- **Repair.** To repair the breaker, the following must be available:
  - Modification kits to improve the circuit breaker's operation
  - Up-rating kits to improve the circuit breaker's rating to make it more closely match that of a new breaker or at least the projected rating requirement of the system location
- **Refurbish.** This often takes the form of a mid-life reconditioning where the declared or anticipated life is greater than 25 years and in some cases as long as 60 years. The condition assessment provides an idea of the cost to repair, refurbish, and, as appropriate, up-rate the circuit breaker. Refurbishment could reduce continuing maintenance costs initially, but it must be assumed that maintenance costs would rise again in the future, and at a faster rate than if dealing with the original breaker when it was new. The rate would certainly be faster than with a modern, new circuit breaker. For this reason, the extensiveness of any refurbishment performed is important, especially if all of the life-limiting factors have not been addressed, since issues will develop in the later years of the life of the now old circuit breaker. This continuing commitment is balanced against the fact that the new replacement circuit breaker is likely to be one of the latest SF_6 circuit breakers that have reduced maintenance requirements, require no maintenance for at least 25 years or 10,000 operations (in some designs), and have a proven electrical and mechanical endurance capability. The economics of the true capital-to-operational cost balance has to be considered.
- **Replace.** When replacing the circuit breaker with a new unit, it should be one of the newer SF_6 single-pressure (puffer) designs or the even newer self-blast circuit breaker. Besides the cost of the new circuit breaker itself, the following possible costs need to be considered:
  - Cost of built-in condition-monitoring or life-management system.
  - Cost to remove the old circuit breaker. (However, if the user has other circuit breakers of the same type and rating, this breaker is a valuable asset as a source of spare parts.)
  - Cost to replace the foundation if it needs to be replaced or altered.
  - Cost of the associated disconnectors (disconnect switches) and bus arrangement if they need to be altered or replaced to accommodate the new breaker.

These considerations should be examined carefully and full costs compared for the various options. Circuit breakers' maintenance costs have traditionally been high, compared with other apparatus; so potential savings (or costs) should not be overlooked [3].

Insulators and Bushings

Unlike a larger apparatus, a replacement bushing is not a high-cost item. The cost of the service outage and the manpower and equipment necessary to replace a bushing usually exceeds the item's cost by a large margin. However, there are other factors that motivate repair or refurbishment for the vast number of bushing sizes and ratings now in service. Some manufacturers now provide a repair service that uses all of the original hardware but provides a new core and a complete set of new gaskets. Frequently, the cost of this service will be less than for a new bushing. There are service shops that can perform partial repairs using the same parts, including the core, and it would be necessary only to provide new gaskets. The proper drying of a bushing that has been contaminated with moisture can be very difficult when the bushing has a condenser-foil system. Prior to attempting drying, verification that the drying can be accomplished to an acceptable level of power factor (within both a utility's time and cost allowance) is recommended. Whenever new or refurbished bushings are ordered, a utility should attach a specification that covers what is expected to be accomplished and what maximum limits for power factor and capacitance would be acceptable [3].

Bus Work

Aging equipment typically requires increased maintenance to maintain a level of reliability equivalent to that of newer equipment. Eventually, the increased cost of maintenance and decreased confidence in the equipment's ability to operate as needed requires that a decision to replace a piece of equipment be made. The decision on whether to replace, refurbish, or repair the damage to the bus and structures will depend on the condition, historical data, design basis, and the associated costs of the bus and structure system.

After considering the present condition of the bus and structure system, its history should be reviewed when deciding to replace or refurbish the bus and structures. The primary method of reviewing this history is through the data collected during routine preventive maintenance. A review of the data may identify recurring problems that require replacement or refurbishment of the system or parts of the bus and structures.

In practice, there are not many components of the bus or structures that can be refurbished. Since these components serve mechanical functions, they tend to fail in modes that require replacement, rather than refurbishment. However, the components can sometimes be repaired if the damage is not too severe. Physical damage to the insulators in the form of damaged skirts may be able to be repaired. Severe cracking or tracking may require replacement. Evidence of overheated bus and joints, excessive corrosion problems on supporting steel, and spalled or honeycombed concrete foundations that expose rebar are other types of problems that should be evaluated for their impact on the life and function of the substation in the replacement and refurbishment decision-making process.

Reviewing the design basis of the system is an important part of the process. The parameters used to design the buswork, insulators, supporting structures, and foundations should be reviewed to determine if the values and assumptions used in the calculations are still valid. Current system fault levels may now be higher and impose heavier loading on the system during faults.

The bus conductor size should also be checked to determine if its ampacity is sufficient for the higher load currents. If the conductor size is no longer satisfactory, the ampacity of the bus should be increased by increasing the conductor size. The larger bus size will also increase the mechanical strength of the bus.

If the cantilever strength of the insulators is insufficient to withstand the short-circuit forces and other loads, the insulators should be replaced with higher strength insulators. The load on the existing insulators can also be reduced by adding additional bus supports that shorten the bus spans. However, the addition of supports may prove to be difficult in many installations.

The major cost to be considered is the cost associated with outages caused by deterioration of the system and the downtime needed to rectify the problem. Although the problems differ in nature geographically, the equipment damage, interruptions, loss of service to customers, and operating personnel safety problems result in the same general concerns. The cost of the materials needed to repair the system has to be compared to the cost of replacement. Again, if the degree of damage is low, it may be more cost effective to repair the system and prevent further deterioration. With higher degrees of damage, the cost of repair materials and manpower may surpass the cost of replacing the system [3].

Disconnect and Ground Switches

When a utility purchases a new switch from a manufacturer, spare components are usually ordered initially or obtained from the manufacturer when needed. However, as a switch ages, it becomes increasingly difficult to obtain spare/replacement parts because, as manufacturers improve their switch designs, older designs are discontinued. Obtaining or maintaining spare/replacement parts for older switches typically involves the following options:

- The manufacturer may provide spare/replacement parts upon request, but this may take weeks to obtain and at a premium cost.
- Some utilities have their shops or local (outside) shops manufacture spare parts when needed, but not all utilities are able to do this.
- Some utilities will retire certain switches by replacing them with new ones and then use the retired switches for spare/replacement parts. Switches that use cap and pin insulators are examples of replacement parts that may be available only from a utility’s stock or from retired switches.

The availability of replacement parts is a factor that must be considered when deciding if refurbishment is feasible. Many companies have purchased new switches because replacement parts were too difficult or expensive to obtain for older equipment.

Aging equipment typically requires increased maintenance to maintain a level of reliability equivalent to that of newer equipment. Eventually, the increased cost of maintenance and decreased confidence in the equipment's ability to operate as needed requires that a decision to replace a piece of equipment be made.

Deciding whether to continue to maintain and/or refurbish an older switch or to replace it with newer equipment can be a complex problem. This decision must consider economic factors as well as intangible items that affect the decision-making process. Some of the influencing factors can be objectively quantified, but other factors can only be estimated or subjectively included in the process [3].

Current and Potential Transformers

Although instrument transformers have the same components as power transformers, their service duty and construction are quite different. Voltage or potential transformers have small volt-ampere ratings; therefore, the conductors are quite small compared to distribution and power transformers. Freestanding current transformers used for metering and control are constructed along the same lines as bushings. Some free-standing CTs may be almost 5 m tall, and must be transported and stored vertically. This can make movement difficult with standard trailers. Additionally, some older switchyards may contain CTs with polychlorinated biphenyl- (PCB-) laden oil [3].

There is very little that can be done to extend the life of the internal parts of instrument transformers. However, the following information has been obtained from some of the participating utilities on maintenance and life-extension practices involved with instrument transformers.

One concern with aged current transformers is the presence of "X" wax in the oil and insulation. The "X" wax is a polymer formed by partial discharges in oil/paper systems. If such polymers have been formed, it is virtually impossible to remove the wax from the interior of the insulation. The presence of the "X" wax is believed to contribute to higher PD intensities and creates dielectrically weak areas in the insulation system. There is no way to determine the presence of the wax with external tests. Oil testing is required. The presence of "X" wax is generally indicated by:

- Hydrogen of 1000 ppm or higher
- Oil power factor at 100°C greater than 5%.

Oil power factors as high as 15% at 100°C have been measured in some EHV current transformers. If the power factor is this high, it will be difficult to remove all of the contaminated oil from the insulation.

Many utilities have chosen to use on-line monitoring of their current transformers, which covers oil dissolved-gas analysis (DGA), oil temperature, ambient temperature, and moisture in oil measurements, all correlated with load. In addition, advanced systems offer bushing leakage assessment and monitoring, which can be tabulated and monitored via alarm and annunciation control panels. Utilities can choose to remove current transformers from service when there is an indication of possible failure. Other utilities have chosen to initiate a program to replace the oil-filled CTs with gas-insulated designs or optical sensors, since there are no ready solutions for failure-prone CTs.

Lightning Arresters

Before an arrester is replaced, the electrical system should be studied to determine if the arresters currently in use are of adequate design and capability to protect the equipment and system. A study of the system parameters is recommended if it becomes necessary to replace either one or a set of arresters. When selecting an arrester, the objective is to determine the minimum rated arrester that will have a successful service life on a power system. An arrester of the minimum practical rating is usually preferred because it provides the greatest margin of protection for the insulation of the equipment. Use of a higher rating arrester increases the capability of the arrester to survive on the power system under adverse conditions and thus may result in equipment damage [3].

To decide which rating is most appropriate for a particular application, consideration must be given to the following system stresses to which the arrester will be exposed:

- Continuous system voltage
- Temporary power frequency over-voltages
- Switching surges
- Lightning surges
- Short-circuit current

Arresters in service are continuously exposed to a normal power frequency voltage. For each arrester rating, there is a recommended limit to the magnitude of the voltage that may be continuously applied. This limit has been termed the “maximum continuous operating voltage” (MCOV) of the arrester. Operation at voltages exceeding the continuous capability may, for example, cause metal oxide elements to operate at higher than normal temperatures, which may lead to premature arrester failure or a decreased useful life.

The arrester rating must be selected so that the continuous power-system voltage applied to the arrester is less than or equal to its continuous-voltage capability. However, experience over many years of arrester use indicates that, in typical installations, the rating of an arrester should be at least 1.25 times the MCOV level.

Considerations should include a visual inspection, out-of-service test, or in-service test to determine if the replacement of an arrester is necessary. Arresters currently in stock or storage should be verified as acceptable before installation. The following are suggested actions:

- Visually examine the surge arrester.
- Perform dielectric-loss and resistance tests.
- Verify that the unit's characteristics are adequate for the system location.
- Verify that the unit's characteristics closely match other units in the set for that location.
- Verify that the other remaining arresters are still satisfactory for this application.

In addition, it is the general consensus among utilities not to mix silicon-carbide units with metal oxide units in the same stack and not to mix silicon-carbide stacks with metal-oxide stacks in the same set of arresters.

Age frequently dictates the need for a more careful inspection/test program, the cost of which could soon exceed the cost of arrester replacement. Blown pressure vents, soot around seals, and loose connections are indicative of problems or failures that can be identified by visual inspection. Proper operation of an arrester is vitally important to protect transformers and associated equipment from lightning strikes and other system surges. AC dielectric loss (watts) and capacitance, along with infrared tests, are widely used to help evaluate the condition of arresters for future use.

Lead Time and Availability of Parts and Components

Lead times for part replacements, major overhaul components; and in some cases, minor components of aged (>15 years) substation switchgear, CTs, PTs, VTs, and lightning arrestors can be extensive due to age, unavailability of parts, and cost to remanufacture. Most older switchgear equipment is no longer in standard production and has a high cost and long lead time because suppliers may need to manufacture parts from raw materials as they are needed.

For replacement of new equipment, standard delivery time of 15–20 weeks for 245 kV equipment and below can be expected. Standard delivery for equipment 345 kV and above can range from 24 weeks to a year, especially for equipment in the 550 kv and above range. Specific lead times will depend on the component specification (for example, special or custom requirements for controls, integrated CTs, special ground fault, and short fault relaying).

For bus and bus insulators, manufacturers build and manufacture equipment fairly quickly. In most cases, locally based manufacturers have a supply stock, and some carry "emergency" stock for special common applications.

The lead times for PTs and free-standing CTs also depend on voltage class and specification details, and have approximately the same timeframes as switchgear.

Recommended Condition Assessments

Overall, scheduled maintenance and condition inspections should be performed on all substation equipment to reduce the possibility for unscheduled outages, unplanned maintenance repairs, and/or unplanned equipment replacements. This will also limit the opportunity for catastrophic failures that result in not only the loss of the failed piece of equipment, but can damage surrounding equipment as well.

Users should consider a 5–10 year maintenance program (depending on specific application), where trends and assessments on deterioration or reduced life expectancy can be assessed. Most manufacturers provide detailed maintenance programs. These programs are based on the manufacturer's recommendations for PMs, general maintenance, and completed overhauls.

Table 4-1 can be referenced for refurbishment and replacement considerations. However, each application must be considered specifically, and the following table must be used only as a guide for reference.

Table 4-1
Switchyard Component Logistics

Component	Lead Time	Approximate Overall Cost	Comments
Air-blast breaker refurbishment	Days to weeks, depending on application and specific equipment design and requirements.	\$20,000 to \$200,000 or higher	For equipment that is no longer in production, spare parts and materials may be provided by non-original equipment manufacturer (OEM) service companies. However, OEMs may have specific programs for minor, intermediate, and major breaker refurbishments.
Air-blast breaker replacement	Weeks to months, depending on application and specification.	\$25,000 to \$250,000	Depending on application and specification, air-blast circuit breakers may be replaced with SF_6 breakers. OEMs have standard designs that may reduce lead times when application and specification allows.
SF_6 breaker refurbishment	Days to weeks, depending on application and specific equipment design and requirements.	\$10,000 to \$150,000 or higher	For equipment that is no longer in production, spare parts and materials may be provided by non-OEM service companies. However, OEMs may have specific programs for minor, intermediate, and major breaker refurbishments.
SF_6 breaker replacement	Weeks to months, depending on application and specification.	\$25,000 to \$250,000	OEMs have standard designs that may reduce lead times when application and specification allows.
Disconnect and ground-switch refurbishment	Days to weeks, depending on application and specific equipment design and requirements.	\$10,000 to \$80,000 or higher	In most cases, OEMs have specific programs for minor, intermediate, and major breaker refurbishments.
Disconnect and ground-switch replacement	Days to months, depending on application and specific equipment design and requirements.	\$15,000 to \$90,000 or higher	In most cases, OEMs have equipment designs that can be retrofitted in place with minor effect to existing infrastructure (for example, support structure, control wiring, etc).

Table 4-1 (continued)
Switchyard Component Logistics

Component	Lead Time	Approximate Overall Cost	Comments
CT refurbishment	Days to weeks, depending on application and specific equipment design and requirements.	$20,000 to $60,000 or higher	For equipment that is no longer in production, spare parts and materials may be provided by non-OEM service companies. OEMs may have specific programs for minor, intermediate, and major breaker refurbishments. However, due to improved manufacturing practices and improved technical design, replacements are a better alternative for higher voltages (such as 345 kV and above).
CT replacement	Weeks to months, depending on application and specification.	$20,000 to $90,000	OEMs have standard designs that may reduce lead times when application and specification allows.
PT refurbishment	Days to weeks, depending on application and specific equipment design and requirements.	$40,000 to $80,000 or higher	Majority of PT designs do not allow for refurbishments and are easily replaced when service and spare parts are not available or in cases where repairs and materials exceed the cost for new replacement.
PT replacement	Days to weeks, depending on application and specific equipment design and requirements.	$40,000 to $80,000 or higher	OEMs have standard designs that may reduce lead times when application and specification allows.
Lightning arresters refurbishment	Days to weeks, depending on application and specific equipment design and requirements.	$40,000 to $80,000 or higher	Majority of lighting arrester designs do not allow for refurbishments and are easily replaced when service and spare parts are not available or in cases where repairs and materials exceed cost for new replacement.
Lightning arresters replacement	Days to weeks, depending on application and specific equipment design and requirements.	$40,000 to $80,000 or higher	OEMs have standard designs that may reduce lead times when application and specification allows.

5 CONCLUSIONS

Few utilities currently have programs in place to proactively replace substation equipment; however, the practice is growing. The functional end of life is often easy to determine and is the result of a catastrophic failure, inability to restore operation within specification, or lack of spare parts. Economic end of functional life may be harder to establish. The present condition of the equipment, anticipated timing, the cost of future maintenance, and the probability and risk of failure influence the analysis of economic end of life. In evaluating risk (the probability of an event occurring and the consequences of that event), not only must the direct replacement costs be considered, but other potential expenses (such as environmental cleanup and replacement power) and intangibles (such as customer satisfaction) must also be considered. Complete maintenance histories, including projected costs and present condition, are vital for making equipment end-of-life decisions.

Tables 2-1 through 2-8 indicate that the useful life of most switchyard components is in the range of 20–35 years if they are adequately maintained and monitored to detect significant aging and have timely corrective actions taken to prevent failures. Longer component lives are possible under less stressful conditions on the equipment and with the use of well-programmed maintenance, where equipment is brought to an almost "as new" condition within the manufacturer's recommended refurbishment period. These tables also indicate the aging mechanisms most likely to cause major component degradation and the effectiveness of available monitoring techniques for their detection. Details of these aging mechanisms and their effects are provided in Section 2. However, it is important to note that an unusual transient event, such as a driven equipment failure, can cause early component failures.

Information on currently available on-line monitoring techniques and off-line tests and inspections is provided in Section 3. This information can be used to review current plant condition monitoring programs. This review details whether considerations should be given to investments in the purchase of additional and/or more modern diagnostic equipment to provide earlier detection of component aging that can lead to failure. Section 4 provides information and techniques that can be used to evaluate the repair versus replacement options for components that have experienced significant aging and are in service in a plant that is required to operate for another decade or more. Information is provided on how to evaluate the various factors and costs of component refurbishment, component replacement, and new component purchases.

6
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