

Plant Support Engineering: Large Transformer End-of-Expected- Life Considerations and the Need for Planning

Technical Report



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Plant Support Engineering: Large Transformer End-of-Expected-Life Considerations and the Need for Planning

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PRODUCT DESCRIPTION

The purpose of this report is to alert plant managers and component/system engineers of the point in life of large, oil-filled transformers when long-term planning or contingency planning is desirable to preclude end-of-life failure or to make its impact manageable. This report defines the expected life of large, oil-filled transformers 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.

Results and Findings

Based on expert input, the report identifies the onset of end-of-life failure mechanisms and provides condition monitoring techniques that can be used to determine if the transformer is succumbing to failure. It also conveys the lead times that the condition monitoring technique can provide between the point of detection and the point of near or complete failure. Finally, the report covers a discussion of the logistics related to replacement of a transformer including the length of time required under varied scenarios. This information is useful in determining the need for contingency or long-term planning for an aging transformer.

Challenges and Objectives

The report is aimed at plant managers and component/system engineers responsible for equipment reliability and assessment of the impact of failures on plant operations. The report indicates the time at which long-term aging mechanisms can result in catastrophic failures and provides insights in identifying the onset of such conditions and the impacts of responding to an in-service failure. Given an understanding of this information, the plant staff can then assess alternatives such as preparing for replacement or refurbishment of the transformer, improvement of condition monitoring systems, and/or the development of contingency plans should a failure occur.

Applications, Value, and Use

This is the first End-of-Expected-Life report. There is one more in development for generators, with three more schedule to be developed in 2007. Depending on the industry response to these documents, EPRI will generate reports for further components and systems, modify the content of the reports, or determine that no further reports are needed. The reports are expected to be of use to personnel responsible for long-term planning for operation of equipment and should help such personnel to determine when actions are needed to preclude end-of-life failures.

EPRI Perspective

Life cycle management (LCM) 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 for beginning the planning for prevention and mitigation of equipment failures, mainly focusing on equipment that has generally 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 Electric Power Research Institute (EPRI) economic decision-making tools such as *Life Cycle Management Value Planning Tool (LcmVALUE) Code* (EPRI product 1003455) and *Lcm Plato Code* (EPRI product 1002860) may be used to support planning. Further planning information for transformers may be found in the *Life Cycle Management Planning Sourcebooks, Volume 4: Large Power Transformers* (EPRI report 1007422). Additional discussions of preventive maintenance and condition monitoring that may be applied throughout the life of the transformer are contained in the *Preventive Maintenance Database* (EPRI product 1011923) and the *Power Transformer Maintenance and Application Guide* (EPRI report 1002913).

Approach

The goal of the project was to provide decision-making information to determine when a long-term plan or contingency plan is needed as transformers approach the expected end of life. The report has purposely been kept short so that users could readily understand key issues and be ready to quickly make decisions concerning long-term planning for large transformers. 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 upon failure. Discussions have also been kept purposely 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

Large oil-filled transformers

Logistics of transformer replacement

Condition monitoring

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INTRODUCTION

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

The purpose of this report is alert plant managers and component/system engineers of the point in life of large transformers when long-term or contingency planning is desirable to preclude end-of-life failure or to make its impact manageable. This report defines the expected life of large, oil-filled transformers 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 transformers covered by this report are large, oil filled transformers with oil coolers, such as main step-up transformers, substation auto transformers between substations with different transmission voltages, and auxiliary and startup transformers.

Expected life is defined as the time from start of service to the point when the basic periodic maintenance regime needs to be changed to one of a major refurbishment or replacement of the equipment to preclude catastrophic failure of a component. In this report, the expected life has been determined by polling experts on large, oil-filled transformers. The experts provided estimates of the point through which transformers receiving appropriate maintenance and condition monitoring would be expected to provide satisfactory service. After that point, a catastrophic failure would be more likely. These 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. Reviewing the need for a long-term and/or contingency plan well before the end of the expected lives of large transformers can be valuable. Knowing the condition and location of spare transformers, the lead times before failure provided by condition monitoring techniques, the availability of transportation routes, and the logistical and outage issues associated with transformer failures may indicate that having long-term or contingency plans in place early is appropriate.

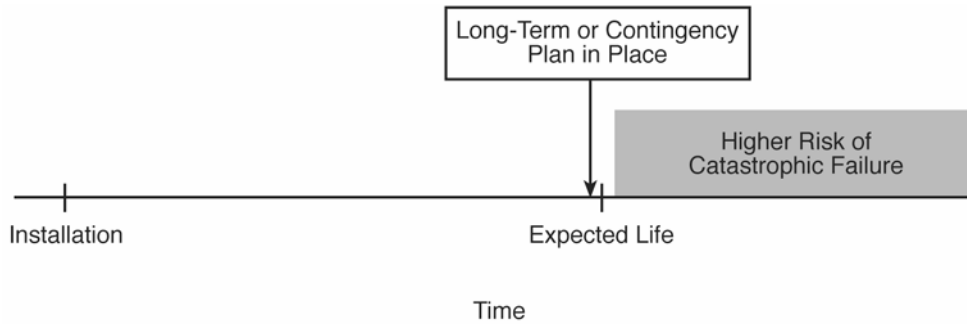


Figure 1-1
Expected Life and Long-Term Planning

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 plant technical staff more aware of the need to consider alternative equipment reliability strategies beyond normal maintenance regimes. It will also help technical staff support business cases indicating that investments in 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 large transformers. Other EPRI reports and methods have been developed for those purposes. For example, *Life Cycle Management Planning Sourcebooks, Volume 4: Large Power Transformers* (EPRI report 1007422) [1] provides a discussion of the overall life cycle management (LCM) planning process, presents transformer failure data for the industry, discusses appropriate maintenance, and monitoring, and discusses possible alternative plans. This information can be used to compare to plant-specific information in order to determine how plant transformers have fared with respect to the overall industry. The report describes sources of plant-specific data and the means of evaluating that data. *Life Cycle Management Value Planning Tool (LcmVALUE) Code* (EPRI product 1003455) [2] provides a program that may be used to perform economic assessments of alternative plans. Figure 1-2 shows the context for the use of this report.

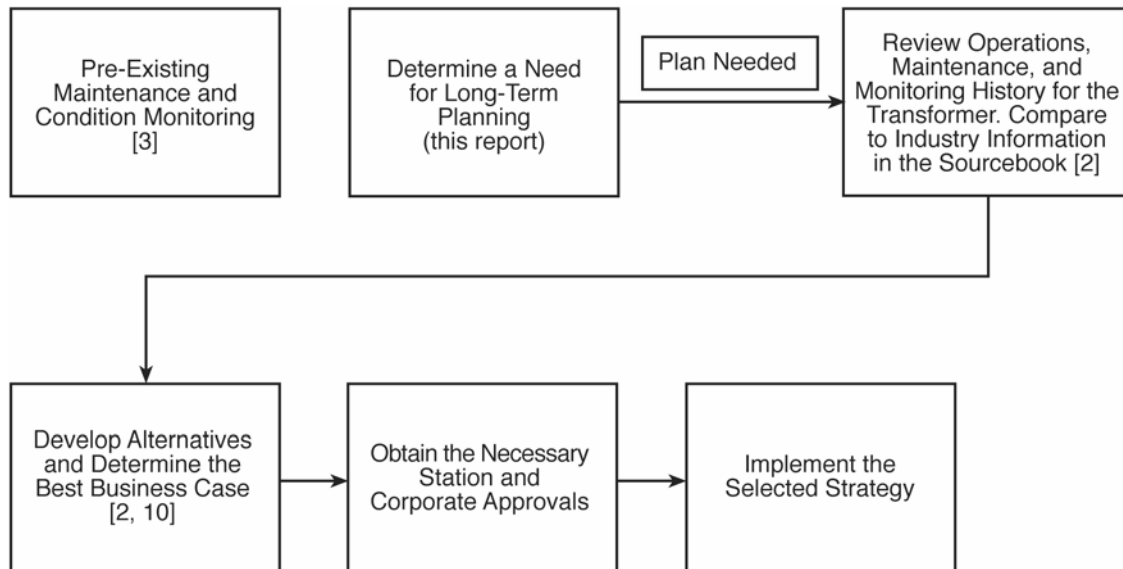


Figure 1-2
Context of Expected-Life Issues

In addition to identifying the expected life of long-lived transformer 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 related to end-of-life failure mechanisms. The degree to which the condition monitoring results provide a leading indication is provided as well. This lead time is supplied for use in considering contingency planning and/or the need for replacement or refurbishment before or at the end of expected life.

The report describes the logistics related to equipment replacement or refurbishment and/or the development of contingency plans. These logistics discussions provide an estimate of time for the procurement of a replacement transformer and the time and cost of moving a spare in place and readying it for service. For large transformers, these times can be quite long, leading to extended outages.

With the information in the report, a utility can make a decision on the most appropriate action to take and the expected costs associated with the action. A utility may wish to proceed with the development of an LCM plan as defined in *Nuclear Plant Life Cycle Management Implementation Guide* (EPRI report TR-106109) [3] and supported by EPRI report 1007422 [1] to develop contingency plans or to implement another form of long-term planning.

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EXPECTED-LIFE CONSIDERATIONS

Table 2-1 provides the expected-life of long-lived transformer components that upon failure could ultimately cause either a long-term or complete loss of use. Many other subcomponents have shorter lives, but diligent maintenance and replacement practices allow long-term use of the transformer. The listed expected lives indicate the point to which there is reasonable certainty that the transformer can perform its function. Thereafter, without intervention, the probability of catastrophic failure increases from long-term degradation.

The life expectancies listed in Table 2-1 are based on expert opinion rather than statistical data, which are not available. The life expectancies are provided to support planning activities and to indicate the point at which planning is desirable for additional monitoring and maintenance, refurbishment, or replacement as appropriate.

Estimating Station-Specific Expected Lives

The transformer component expected-life ranges in Table 2-1 are based on the assumption that reasonable maintenance, inspection, and monitoring activities have been performed throughout the service life of the transformer and that appropriate corrective actions have been taken in response to the inspection and monitoring findings. The Degradation Influence and Preventive Maintenance Supporting Expected Life information is provided to support station-specific evaluation of the part of the Life Expectancy range that applies to the station's transformer(s). It is not the intent to indicate that the listed condition monitoring techniques should be applied only at or near the end of expected life. Many of the listed techniques and others are expected to be used throughout the life of the transformer in order to identify failure mechanisms that could lead to early failure. For example, dissolved combustible gas analysis is a condition monitoring technique that should be applied to transformers throughout their lives. Other techniques, such as infrared thermography, are useful in detecting abnormalities, such as a clogged heat exchanger or a cooling fan that is running in reverse. The information in Table 2-1 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 corrected in a reasonable period of time.

Life expectancy of these major subcomponents can be affected by the lack of maintenance performed on the transformer and by grid/electrical system disturbances, such as through faults and voltage surges. Maintenance activities that can improve the length of expected life are listed in Table 2-1 and short descriptions of these activities are given in the following sections. Detailed descriptions of these and other useful preventive maintenance tasks are discussed in

EPRI report 1007422 [1] and *Power Transformer Maintenance and Application Guide* (EPRI report 1002913) [4]. Evaluation of the maintenance and operating experience for a transformer will help determine whether a shorter or longer expected life is likely.

Operating the transformer under higher than normal stresses, such as over temperature or excessive operating voltages, will shorten the life of the transformer. Table 2-1 indicates the stresses that influence and could shorten expected life. Evaluating the historical incidences of elevated stressors will also help improve the estimation of the expected life for a specific transformer. For example, if the transformer is oversized and operated well below normal load limits, the thermal life of the transformer would be significantly longer. Conversely, if the transformer coolers function poorly due to lack of maintenance and the transformer operated for long durations during summer at or above normal operation thermal limits, the thermal life would be shorter. This review is not meant to definitively identify the expected life, but rather to determine if adverse conditions that could shorten life have occurred. Through faults or bushing faults are significant factors that would stress winding and core integrity. If the transformer experienced a number of through faults, expected life could be shortened due to the loosening or breakage of internal components.

Table 2-1 was also developed under the belief that the oil has also been monitored for moisture content and that any significant increases in moisture content as indicated by oil analysis will be corrected by identifying the source of ingress and repairing it. It also assumes that the oil was conditioned as needed to preclude breakdown of the oil and the insulating oil.

**Table 2-1
Expected Life, Diagnostics, and Logistics for Large 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 [Confirmatory] (see Note 1)	Diagnostic Effectiveness	Repairable	Time to Repair	Repair Issues	Time to Replace
Potentially Catastrophic											
Winding insulation	Electrical breakdown	Thermal aging; contamination; worsened by high operating temperature	Clean coolers; maintain cooling fans and verify direction of flow; verify circulating pump operation; verify single core ground; monitor transformer temperature; calibrate temperature monitor.	30–40 years	0–1 1/2 years or more (see Note 2)	Gas-in-oil analysis (high CO and CO ₂ with H ₂ and without hydrocarbons indicates paper degradation; high CO and CO ₂ with CH ₄ C ₂ H ₆ and C ₂ H ₄ indicate overheating of insulation.) [Furan in oil analysis (insulating paper assessment)]	Techniques are well established and linked to transformer failure mechanisms.	If transformer fails, low likelihood of reparability. If removed from service before failure, possibly repairable, but may require shipping to service facility.	Not readily definable	Oil must be removed from transformer; breathable air needed for internal inspection.	See Table 4-1
Internal bus supports	Failure of under-designed supports leading to tracking to ground	Multiple faults in adjacent equipment and transmission lines	No useful maintenance. Repair upon identification.	20–30 years [2]	Days to months	Gas-in-oil analysis (H ₂ or C ₂ H ₂ [acetylene] indicates arcing. C ₂ H ₂ is indicative of high-intensity arcing and is more serious.) [Acoustic partial discharge detection]	Techniques are well established.	If transformer fails, moderate likelihood of reparability. If removed from service before failure, very likely to be repairable on site.	4–8 weeks	Oil must be removed from transformer; breathable air needed for internal inspection. After repairs, lengthy oil reconditioning needed. Transformer may have to be removed from tank to repair (see Note 3).	If failed, see Table 4-1. If not failed, replacement unlikely to be needed.

**Table 2-1 (continued)
Expected Life, Diagnostics, and Logistics for Large 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 [Confirmatory] (see Note 1)	Diagnostic Effectiveness	Repairable	Time to Repair	Repair Issues	Time to Replace
Core	Multiple grounds; leads to circulating currents in core and overheating	Assembly error; vibration; loss of insulation between core and tank	Identify additional grounds possible; no useful maintenance.	40 years [2]	Not available	Transformer temperature; gas-in-oil analysis [Core insulation resistance]	Techniques are well established.	If transformer fails, low likelihood of reparability. If removed from service before failure, very likely to be repairable on site.	4-6 weeks	Oil must be removed from transformer; breathable air needed for internal inspection. After repairs, lengthy oil reconditioning needed. Transformer may have to be removed from tank to repair (see Note 3).	If failed, see Table 4-1. If not failed, replacement unlikely to be needed.
Core	Loss of ground leading to static charge buildup and arcing	Assembly error; vibration	Core grounding verification possible; no useful maintenance.	40 years [2]	Not available	Transformer temperature; gas-in-oil analysis (H ₂ or C ₂ H ₂ [acetylene] indicates arcing. C ₂ H ₂ is indicative of high-intensity arcing and is more serious.) [Acoustic partial discharge detection]	Techniques are well established.	If transformer fails, low likelihood of reparability. If removed from service before failure, very likely to be repairable on site.	4-6 weeks	Oil must be removed from transformer; breathable air needed for internal inspection. After repairs, lengthy oil reconditioning needed. Transformer may have to be removed from tank to repair (see Note 3).	If failed, see Table 4-1. If not failed, replacement unlikely to be needed.

Table 2-1 (continued)
Expected Life, Diagnostics, and Logistics for Large 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 [Confirmatory] (see Note 1)	Diagnostic Effectiveness	Repairable	Time to Repair	Repair Issues	Time to Replace
Core and winding	Loosening; leading to damage of lamination insulation or chafing of insulation	Multiple faults in adjacent equipment and transmission lines; vibration	N/A	40 years [2]	Relatively rare event	Increased 60 Hz noise, acoustic monitoring. [Frequency response analysis - an off-line test]	Techniques are well established.	If transformer fails, low likelihood of repairability. If removed from service before failure, very likely to be repairable.	Depends on severity of damage to insulation and laminations. May require repair in service shop.	Oil must be removed from transformer; breathable air needed for internal inspection. After repairs if done locally, lengthy oil reconditioning needed.	Replacement may be necessary to correct damage. See Table 4-1.
Oil-filled bushings	Insulation failure	Internal contamination; low oil; voltage surge (lightning); manufacturing problem; cracked porcelain	Inspect and clean external bushing surfaces; repair oil leaks; replace if leak cannot be repaired; replace if porcelain is cracked or chipped.	>15 years	If externally contaminated, may fail quickly, especially in wet conditions. Internal issue may worsen relatively rapidly.	External visual inspection for contamination and oil leakage. Oil level verification. Infrared thermography. [Power factor testing]	Techniques are effective and well established.	If deteriorated or failed, likely to be replaceable. If failure induces internal fault, low likelihood of repairability.	Days to a week	N/A	N/A
Solid bushings	Insulation failure	Chipped or cracked porcelain	Inspect and clean external bushing surfaces; replace if porcelain is cracked or chipped; replace on unacceptable power factor test.	>15 years	If externally contaminated, may fail quickly, especially in wet conditions. Internal issue may worsen relatively rapidly.	External visual inspection for contamination. [Power factor testing]	Techniques are effective and well established.	If deteriorated or failed, likely to be replaceable. If failure induces internal fault, low likelihood of repairability.	Days to a week	N/A	N/A

**Table 2-1 (continued)
Expected Life, Diagnostics, and Logistics for Large 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 [Confirmatory] (see Note 1)	Diagnostic Effectiveness	Repairable	Time to Repair	Repair Issues	Time to Replace
Conservator tank	Bladder failure allowing moisture contamination of oil and paper insulation	Thermal aging of rubber bladder	Periodically inspect bladder or diaphragm. Respond to bladder failure relay.	40 years [2]	Failure not immediately damaging.	Gas-in-oil analysis (moisture and air). [Physical inspection]	Techniques are effective and well established.	Repairable on site. Partial drainage of oil necessary.	4 weeks; possibly less	N/A	Should not be necessary if corrected within a reasonable period.
Tank	Weld failure/leakage	Corrosion/untreated external rust	Remove rust and paint as appropriate.	40 years + [2]	Slow process	Visual external examination.	Easy to detect and correct.	Clean rust and repaint area.	Easy to correct at unit outage	N/A	N/A

Note 1. Not all condition monitoring methods are listed. Commonly used methods with reasonable ability to detect the listed end-of-life failure mechanism are listed. See discussion.

Note 2. The time from leaving the "normal state" to failure assumes at least yearly diagnostics. If continuous on-line diagnostics are employed, earlier detection is possible, and months of earlier warning may be possible.

Note 3. Removal of the transformer from the tank is generally done only at a repair facility. Accordingly, the time to repair can be greatly extended by having to ship the transformer to and from the repair facility.

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

Table 2-1 lists a number of end-of-life failure mechanisms and factors that affect them. The following sections discuss this information. The discussion of condition monitoring tests is not meant to be all inclusive, and many other useful tests exist. The additional tests and their usage are described in *PMB C/S 1.5 Preventive Maintenance Basis Database Client/Server, Version 1.5* (EPRI report 1011923) [5] and EPRI report 1002913 [4]. The basis for intervals for transformer maintenance and inspections under severe and mild operating conditions are provided by EPRI report 1002913 [4].

The following discussions are provided to indicate the types of preventive maintenance required to retard the degradation when a means of preventive maintenance exists. The discussions also indicate condition monitoring activities that detect the adverse condition. For a number of the problems, removal of the transformer from service and the performance of internal maintenance will be necessary. Some problems will require the transformer to be shipped to a maintenance facility where the internals can be removed for repairs or refurbishment.

Winding Insulation Degradation

The winding insulation of these transformers is comprised of heavy craft paper between layers of the windings, between the windings, and between phases of multi-phase transformers. Over long periods of time, the effects of temperature will cause the cellulose in the craft paper to break down. The rate of degradation is logarithmically proportional to temperature. Accordingly, a transformer whose windings operate at or near the normal operating temperature limit for long periods will age much faster than one that operates 10 to 20°C or more lower than the rated normal operating temperature. If a transformer is known to have to operate near normal operating limits each summer, cleaning the coolers, verifying the operability of the cooling fans, and verifying the direction of flow prior to each summer operating period is very important. The verification of cooling oil pump flow is also important. Infrared assessment of the coolers will indicate if there is flow blockage within a cooler. Verification of cooler function is especially important for locales with long, hot summers and grids having summer peaking conditions. Thermal aging is expected to be slower for locations with lower summer temperatures and winter peaks. EPRI report 1011923 [5] indicates that cooler maintenance and calibration of indicators, such as the temperature indicator, can affect the failure rate by 50% or more. Infrared imaging is particularly useful in identifying problems with the cooling system.

In addition, localized heating within the transformer can cause rapid localized damage to the insulating paper. Conditions such as eddy current heating in the core, arcing, and loose connections can cause localized heating and rapid deterioration of insulating paper in the vicinity of the problem. If any of these conditions are recognized by dissolved combustible gas assessments or other monitoring methods, appropriate actions to monitor the condition and to repair it are recommended. Furan analysis indicates when the paper insulation is deteriorating significantly from either localized thermal aging or general aging from long-time thermal conditions.

While not listed in Table 2-1, wetting of the paper insulation will greatly reduce its capability to withstand voltage. Wetting would occur if there is an air or oil leak that allows the transformer to breathe in moisture. If a significant level of water is detected in the oil, the leak should be repaired as soon as possible, and the oil should be treated to reduce moisture content, which in turn reduces the moisture content of the paper. Moisture intrusion is not an end-of-life degradation mechanism. Moisture intrusion could happen early in life if seals fail or are improperly installed. If the cause is not corrected, continued ingress of moisture could cause an early failure.

Internal Bus Supports

Busses in the transformers connect the windings to the bushings. These busses need to be supported in a manner that prevents the busses from moving significantly upon inrush and fault currents. In some transformers, the bus supports were underdesigned such that they could break or crack upon being subjected to through faults. Failure mechanisms that could result are tracking paths between the bus and ground through the crack area or shorting of the bus to surrounding conducting surfaces during the next through fault.

There are no effective preventive maintenance activities for underdesigned bus supports. However, should arcing or overheating be indicated by dissolved gas analysis or other means, further investigation, confirmatory monitoring, and repairs should be implemented. EPRI report 1011923 [5] indicates that dissolved gas analysis is an important test method for assessing transformer conditions. Partial discharge evaluation is another possible way to detect bus support failure if tracking is occurring.

A transformer with underdesigned bus supports is sensitive to through fault currents that cause the busses and windings to thrash. Accordingly, evaluating the number of fault events that have occurred in the electrical vicinity of the transformer will provide information indicating where this failure mechanism is likely to occur. Also, certain vintages of transformers are known to be prone to this type of problem. Industry experience with similar designs and manufacturers can provide insights for any specific transformer.

Loss of Core Ground or Multiple Core Grounds

The transformer core is grounded to preclude buildup of static charge on the core that could cause a flashover to the windings. Accordingly, loss of the core ground is an unacceptable condition. At the same time, the core is composed of layers of sheet steel that are insulated from each other in order to prevent eddy currents from overheating the core and, in turn, the winding. Multiple grounds on the transformer core could short the core layers and allow eddy currents to cause heating of the insulation and windings. Although a fairly rare condition, multiple grounds on the core would need to be corrected. The severity of the overheating can be determined by the results of the dissolved combustible gas analysis. While there are no useful preventive maintenance actions for loss of ground or multiple grounds, testing of the core ground system is possible during transformer shutdown. Depending on how and where the core is grounded in the

design, the ground system may be repairable locally, or the transformer may have to be moved to a repair shop to allow the windings to be removed from the tank. EPRI report 1011923 [5] lists core ground assessment as part of calibration and testing that would change the failure rate by 50% or more if not performed.

Loss of the core ground or the occurrence of additional grounds is associated with the number of instances of through fault currents. Evaluating the number of fault events that have occurred in the electrical vicinity of the transformer will provide information indicating where this failure mechanism is likely to occur.

Loosening of Core and Winding

Many clamps and wedges are used to construct a transformer. These clamps and wedges are constructed of insulating fiber board. If these wedges come loose due to the trashing of the coils during through faults, the winding and/or core can loosen, leading to chafing of the insulation, and could lead to failure. There are no preventive maintenance activities that will preclude such loosening; however, the use of periodic acoustic or vibration monitoring following a major through fault could identify loosening. Assessment of the importance of an increase in vibration and the identification of the location of the problem within the transformer will require a transformer expert and/or the support of the manufacturer. EPRI report 1011923 [5] indicates that not performing vibration analysis will cause less than a 25% increase in the failure rate. However, should faults occur close to a large transformer causing a large through current, acoustic monitoring after a return to service would determine if significant loosening of transformer internal components has occurred. The more numerous the number of through faults, the higher the likelihood that loosening could be a problem for a transformer as it nears end of life.

Insulation Failure of Bushings

Maintaining the electrical condition of transformer bushings is very important. Bushings have shorter lives than the overall transformer. Their failure can cause severe to catastrophic damage to the transformer winding. Paying close attention to the condition of the bushings is a key factor in ensuring that the transformers attain their expected lives.

The two basic types of bushings are oil-filled and solid insulation. Both may be subject to external flashover if the external surface becomes contaminated or significantly damaged. Soot, dirt, and salt spray are some of the causes of contamination. Cracks or the loss of segments of the bushing petticoats could result in a reduction of their ability to withstand surge voltage. Visual inspection and cleaning are effective means of detecting physical problems and eliminating contaminants that build up on the surface over time. In some areas where contamination levels are high, surface treatments, such as silicone grease, may be used to absorb contaminants as they deposit on the bushing surface, thereby retaining the surface insulation length that is desired.

Oil-filled bushings are filled with insulating oil. Possible dominant failure mechanisms include the leakage of oil from the bushing into the transformer tank with air replacing the oil, and the loss of the top seal allowing water and moisture to enter. Loss of oil is detectable by the use of infrared thermography. The oil-filled section will run warmer due to better heat transfer than the air-filled section. If moisture is entering the bushing, the oil level is likely to be higher than required due to the fact that water is heavier than oil.

The insulation of solid bushings may degrade with time. Periodic power factor testing will identify such deterioration. Such tests require the transformer to be out of service and disconnected. EPRI report 1011923 [5] indicates that this activity should be part of the normal periodic testing and calibration for the transformer.

Conservator and Transformer Breathing System Failures

Atmospheric pressure changes frequently, and a transformer must be allowed to breathe to preclude over-pressure and vacuum conditions in the tank. Transformers with conservator tanks generally have bladders or diaphragms in the conservator with atmospheric pressure on one side and transformer oil on the other in order to allow for changes in atmospheric pressure. Failure of the bladder or diaphragm could lead to rapid moisture buildup in the oil and winding insulation. These systems generally have a desiccant on the breather. Some conservators may have just a breather with a desiccant and not employ a bladder or diaphragm. In all cases, maintaining the desiccant helps preclude moisture ingress. Oil analysis can also be used to detect water ingress. Inspection of the condition of bladders and diaphragms when used should be part of the normal periodic maintenance activities. EPRI report 1011923 [5] indicates that evaluation of the desiccant color should be performed during system engineer walkdowns every three months and that such walkdowns are critical to long life of the transformer. The PM Database indicates that oil analysis should be performed on an annual basis.

Tank Leakage

Seal and gasket leakage should be detectable by walkdowns and oil analysis. Tank seam leakage should not be a significant problem if the seams and welds are inspected for rust. Any noticeable rust on the tank should be removed. The affected area of the tank should then be treated and painted. Leakage of tank welds would be likely only if rusting were allowed to go unchecked for extremely long periods.

The tank could rupture upon a fault internal to the transformer. Such a fault is likely to cause irreparable damage to the transformer, making the transformer unusable.

3

CONDITION MONITORING RELATED TO END OF EXPECTED LIFE

As large, oil-filled transformers reach the point where long-term aging is causing a higher likelihood of failure, condition monitoring becomes increasingly important. Section 5 of EPRI report 1007422 [1], Section 6 of EPRI report 1002913 [4], and Section 6 of *Transformer: Basics, Maintenance, and Diagnostics* [6] provide discussions of condition and performance assessment methods that may be performed both on line and off line. This section discusses tests for assessing end-of-life conditions. The discussion is not all inclusive. Other tests exist and may be useful in assessing end-of-life conditions.

Table 3-1 lists a diagnostic method and a confirmatory condition monitoring method for each of the failure mechanisms that could lead to catastrophic failure due to advanced aging. The table also indicates the range of the possible periods from time of first detection of an abnormal condition to a time near or at the failure point.

In EPRI report 1007422 [1], gas-in-oil analysis is listed as a primary means for determining the nature of the problems within a large, oil-filled transformer. Gas-in-oil analysis can indicate deterioration of the paper insulation, overheating of an insulated part of a transformer, overheated metal components, partial discharges, water in contact with the steel core, overheating of the core, and arcing. Different gases and concentrations of gases allow differentiation between deterioration types. Table 3-1 indicates the relationship of the gases to advanced aging failure mechanisms.

Gas-in-oil analysis can be judged on a total dissolved combustible gas basis or on the basis of individual gases in the oil. Table 5-1 of EPRI report 1007422 [1] lists the limits for total dissolved gas concentrations in the transformer oil for four conditions ranging from normal through excessive degradation. It also lists the limits for individual gases that are indicative of specific failure modes. Based on *Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers* [7], Table 3-2 provides these total and individual gas limits. Note that the limits for some gasses are much smaller than for others. The limit for carbon dioxide concentrations can be a factor of 7 times higher than the limit for carbon monoxide. Because carbon dioxide can be so dominant, its concentration is not counted in the total dissolved combustible gas limit. When one or more dissolved combustible gasses exceed normal operation limits, it is important to increase the frequency of testing and to determine the rate of change in the presence of the gases. Observing the change in the rate of gas generation will indicate whether the degradation is proceeding slowly or accelerating. Evaluation of the individual gases is recommended because observation of only the total dissolved combustible gas could mask the

changes to acetylene, ethane, and ethylene. Acetylene is indicative of severe arcing in the transformer. Ethane and ethylene, along with methane, are indicative of breakdown of the mineral oil.

Per “Nuclear Electric Insurance Limited (NEIL) Transformer and Switchyard Standards” [8] presentation, NEIL uses similar conditions to those listed in Table 3-1, but indicates that at Condition 4, NEIL will review continued insurance coverage if the utility/plant operator decides to continue operation.

Table 3-2 provides recommendations for rate of gas generation limits developed by the Bureau of Reclamation for their large transformers [6]. Evaluating the rate of generation of combustible gases should provide earlier warning that deterioration is progressing rapidly and would indicate a more immediate need for action than by assessing quantities of dissolved gas alone. For example, if the dissolved hydrogen increased from 100 to 500 ppm in a six-month period, dissolved gas analysis would indicate Condition 2 (Greater than normal, begin analysis [Table 3-1]). Rate of gas generation analysis would take the difference from the previous measurement (400 ppm) and divide it by 6 months to get 67 ppm/month, which would indicate that the transformer is in Condition 4 (Action [Table 3-2]). In this case, the rate of gas generation would indicate that more intense study and action is required than just the analysis of gas quantity.

Table 3-1
Dissolved Combustible Gas Action Limits (ppm)

Condition	H ₂ Hydrogen	CH ₄ Methane	C ₂ H ₂ Acetylene	C ₂ H ₄ Ethylene	C ₂ H ₆ Ethane	CO Carbon Monoxide	CO ₂ Carbon Dioxide	TDCG (see Note 1)
1. Normal operation.	100	120	35	50	65	350	2,500	720
2. Greater than normal, begin analysis.	101–700	121–400	36–50	51–100	66–100	351–570	2,501–4,000	721–1,920
3. High level of insulation degradation. Sample frequently to establish trend of gas evolution.	701–1800	401–1000	51–80	101–200	101–150	571–1,400	4,001–10,000	1,920–4,630
4. Dissolved gas in this range indicates excessive decomposition. Continued operation could result in failure of the transformer.	>1800	>1000	>80	>200	>150	>1,400	>10,000	>4,630

Note 1. Total dissolved combustible gas excluding CO₂.

Table 3-2
Dissolved Combustible Gas Rate of Gas Generation Limits (ppm generation/month) [6]

Condition	H ₂ Hydrogen	CH ₄ Methane	C ₂ H ₂ Acetylene	C ₂ H ₄ Ethylene	C ₂ H ₆ Ethane	CO Carbon Monoxide	CO ₂ Carbon Dioxide
1. Good	<10	<8	<.5	<51	<8	<70	<700
2. Fair	>9 <30	>7 <23	>.4 <1.5	>50 <101	>7 <23	>69 <220	>699 <2100
3. Poor	>29 <50	>22 <38	>1.49 <2.5	>100 <201	>22 <38	>219 <350	>2099 <3500
4. Action	>49	>37	>2.49	>200	>37	>349	>3499

Confirmatory and Alternate Diagnostic Methods

In addition to the commonly used diagnostic for identifying end-of-life failure mechanisms, Table 2-1 provides a test for confirming the existence of the presence of the failure mechanism. Other confirmatory tests may be used as well. Further tests may be identified from EPRI report 1002913 [4]. Short descriptions of the confirmatory tests are provided here.

Furan in Oil Test

When transformer insulating paper decomposes thermally, oil-soluble chemical compounds are released in addition to carbon monoxide and dioxide gases. These are furanic compounds with 2-furfuraldehyde being the principal one [4]. The furanic compounds are identified through the use of high-performance liquid chromatography. Normally, operating transformers have less than 100 ppb (parts per billion) of furans. Table 6 of *Transformer: Basics, Maintenance, and Diagnostics* [6] provides further detail on furan limits.

Acoustic Partial Discharge

Arcs and partial discharges within the transformer give off acoustic signals that travel through the oil and may be detected on the outside surface of the transformer tank. To detect arcs and partial discharges, multiple acoustic sensors are attached to the outside of the transformer. Data are recorded and analyzed by a computer. Systems may be temporary or continuous in nature.

Core Insulation Resistance

The core must be insulated from the windings and tank and connected to the tank through a single ground strap. The ground strap can be disconnected, and the insulation resistance of the system between the ground strap and ground can be measured. If a short remains, it is indicative of one or more additional grounds that would cause eddy current heating of the core and adjacent insulation and oil.

Frequency Response Analysis

Frequency response analysis testing can detect looseness in the winding and core. The test is performed off line. A transformer has both inductive and capacitive coupling that provide a characteristic frequency spectrum response when subjected to a low-voltage pulse or a low-voltage frequency sweep. This response will change when the core or winding shifts or is misshaped. The test is performed by comparing the current measurement to an initial measurement taken on the same or identical transformer. Figure 6-5 of EPRI report 1002913 [4] provides the difference in response for a loose winding to a tightly clamped winding.

Power Factor Testing

Power factor testing is an off-line test and is performed with voltages up to 10,000 Vac. When an insulator has deteriorated, the dielectric power losses through the insulation increase. The power factor is defined as the cosine of the voltage to the current phase angle. A perfect insulator has no losses, and the phase angle between the voltage and current would be 90° ($\cosine\ 90^\circ = 0$). In a real insulator, the power factor should be very low. There should be little or no change in power factor over time in a healthy insulation system.

Combustible Gas in Oil Monitoring Frequency

Most nuclear plants perform dissolved gas analysis once every six months on equipment operating normally. Some types of transformer degradation proceed slowly such that detection six months after it starts provides a reasonable lead time between detection and the point of failure. Others proceed rapidly once they begin such that six-month intervals would not be useful. Generally, when gas-in-oil analysis indicates that the transformer is operating in Condition 2, per Table 3-1, the frequency of sampling is increased to monthly. As the condition worsens, sampling is increase to weekly or even daily. However, if the condition is worsening rapidly, the delay in performing the laboratory tests (1–2 days) may be too long to be helpful.

One means of providing more timely results is to install a continuous gas-in-oil analyzer. The original on-line monitors detected hydrogen gas in the oil and alarmed when limits were exceeded. New systems can assess the full list of combustible gas in the oil and provide an immediate indication of problems without the delay that could occur with six-month interval samplings. The following section is provided to indicate the progression of failure that has occurred in a few instances to show the variability of times to failure from the time of detection.

Main Power Transformer Failure (INPO SER 3-06) [9] describes the progression from essentially normal gas levels through the point of failure for a main transformer. The trend from Condition 1 to Condition 2 progressed slowly and took over a year. Thereafter, the trend in gas concentration increased such that Condition 4 was exceeded in less than four months, and failure occurred shortly thereafter. Even though the utility had been preparing the spare transformer at the time of the failure, the rapid deterioration rate subsequent to July 2005 precluded having the full-sized spare ready. The short, three-month window, from the point at which Condition 3 was

exceeded, precluded options other than the use of an existing spare transformer. Because a full-size transformer that was available was not in a serviceable condition, the plant had to return to service with a 90% capacity transformer and operate at reduced capacity until a full-size transformer could be placed in service. Figure 3-1 shows the rate of degradation by action levels and also shows the point at which the rate increased suddenly, approximately four months before failure.

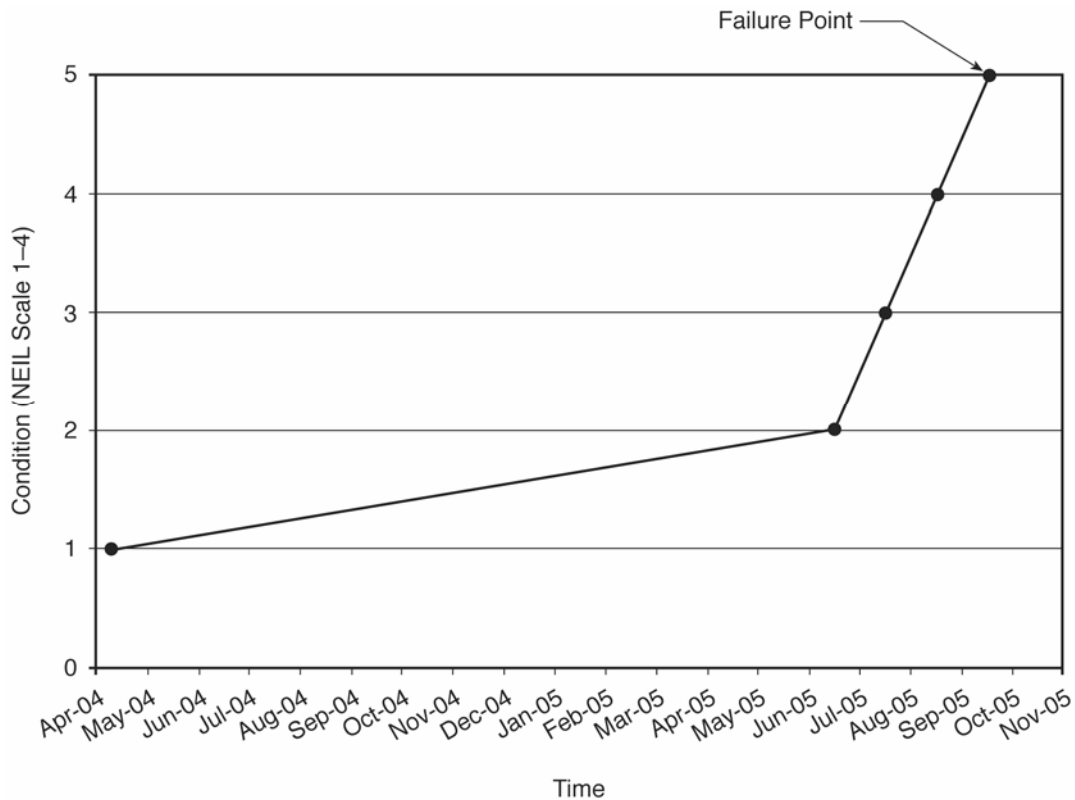


Figure 3-1
Progression Through Condition Levels from Time of Exceeding Condition Level 1 Through Failure of a Specific Main Unit Transformer

Main Power Transformer 2 Taken Off Line Due to Excessive Gassing (INPO OE 12812) [10] describes an event where the transformer gas in oil was monitored on a weekly basis. The unit was being operated while in Condition 2. Within a one-week period, the total gas in oil result shifted from 1267 to 2469 ppm. Periodic purging of the gas volume with nitrogen was begun in order to limit the amount of combustible gas in the transformer and to reduce the gas in oil results. About one month later, the off gas generation rate began climbing again, even though 24-hour purging with nitrogen was underway. Load on the main generator was decreased twice over the next few days, after which the unit was taken out of service to allow the transformer to be inspected and repaired. From the start of this event through having to remove the transformer from service was approximately nine weeks.

Supplement 2 to U2 Scram Due to Lightning Strike and Fire in Main Power Transformer (INPO OE 13116) [11] describes an event where no warning was observed when the transformer failed. In this failure, a design error caused undersized bus bars to be used that overheated and caused loosening of the bus bar support system. A through fault from the flashover of a transmission line off site caused the bus to move and create a phase-to-phase fault.

As shown by these examples, in some cases, there is no early warning. In such cases, the transformer has a sudden failure, or on-line monitors indicate a serious problem that requires immediate removal from service. In other cases, the lead time, as indicated by condition monitoring, between transition from an elevated level of concern to failure can be of intermediate length (weeks to months), giving reasonable time to start corrective measures. In nearly all cases, the lead times are shorter than the time necessary for the procurement of a new transformer. Generally, condition monitoring data allow plant operators to contact transformer experts and bring additional assessment tools into play. Often the monitoring results allow the operator to remove the transformer from service prior to a catastrophic failure. The results also allow operators to consider the risk of continuing to use the transformer.

4

LOGISTICS AFFECTING END OF USEFUL LIFE AND RECOVERY FROM FAILURE

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

Logistics Issues

Two basic types of replacements are planned replacement and replacement upon in-service failure. There is a third condition in which a transformer fails while in service, but is repairable in place (for example, a condition such as a bushing failure that does not damage the internals of the transformer). Depending on the time to repair, such a failure may be repaired in place or the spare may be installed to shorten the outage time. The following sections describe issues associated with spares, replacement, and off-site repairs.

Spare Transformers

The three major logistic issues related to spare transformers are the existence of a spare transformer, the condition of the spare, and the location of the spare. The first issue is whether a spare transformer exists. If there is no spare, a search will be required to determine if a similar transformer exists that may be purchased and transported to the site or if a new transformer must be purchased and manufactured.

Assuming that a spare exists, the spare must be properly maintained, and its condition must be known. A spare that has not been properly receipt inspected and tested upon arrival at the site and maintained over the years is likely to be unacceptable for service. *Main Power Transformer Failure* [9] describes an attempt to use a spare transformer after the failure of a main unit transformer. The spare had had oil sampling performed, but had never had an internal inspection until the time of attempted use. This spare was found to have copper spatters and internal bus connection anomalies that could not be readily repaired. Accordingly, an undersized transformer had to be put in place, causing a reduction in plant output.

Location of Spare

Spare transformers may be located on or off site. Some utilities have a system spare for like transformers, which may be located at another station or substation. Transportation of large transformers is not a trivial issue. Even moving a transformer a few hundred yards requires the oil to be removed and a major rigging effort in order to move the transformer in place. Once the transformer is in place, it must be refilled with oil, and the oil and transformer must be treated to remove contaminants and moisture that entered during the transfer process.

If the transformer must be shipped from another site, a special underslung rail car or a Schnabel car may be required to allow the transformer to be moved through the height and width restrictions of the railroad rights of way. The availability of the special car and the planning with the railroads and the Department of Transportation may add to the period needed to ship the transformer. If the transformer must be moved by road, very special transporters with 16 or more axles may be necessary. Department of Transportation approval may be needed for moving the transformer by road.

Some plants may use river and ocean transportation via barge or a combination of barge and land transportation. Barge transportation also entails obtaining approvals. In addition, special cranes may be necessary to load and unload the barge.

A key issue is whether the railroad rights of way to the site remain in acceptable condition. The railroad rights of way originally used to ship equipment to the site may have deteriorated or have been removed from service such that moving large loads could be a problem.

Upgrades and Spare Transformers

Upgrades may have required the main transformer to be upgraded with respect to cooling or to have been replaced with a larger transformer. If so, the spare transformer should have been upgraded or replaced to preclude having to run the plant at a reduced output should an in-service failure occur.

Planned Replacement

Case 1. Replacement with a Staged Spare or New Transformer

In this scenario, a spare or new transformer is staged adjacent to the transformer to be replaced. The replacement transformer is filled with oil. The oil is filtered and moisture is removed.¹ The appropriate on-site tests are completed. During the plant outage, the old transformer will be moved from its location, and the replacement transformer will be carefully moved into place,

¹ Care must be taken during the initial operation of a transformer that has had its oil dried. Static charge buildup, especially in cool weather, can occur when oil is pumped through the winding, leading to flashovers of the transformer insulation. Cooling pumps should remain in automatic temperature control condition rather than be manually placed in the on position. See Section 4.6 of EPRI 1002913 [4].

connected, and an acceptance test must be performed. Table 3-1 lists the activities and an estimated period of one to two weeks to complete the installation. The period covers only installation. Much of the previous work involving the movement of the new or spare transformer to the new location and preparing it adjacent to the transformer to be replaced may take several weeks. In addition, if a new or spare transformer is being used that does not match the original transformer, many modification packages may have to be prepared. Also, modifications may be needed to mounting pads, leads, and instrumentation and control connections for the transformer.

Failure in Service – No Spare

Case 2. No Transformer Available

In this case, a transformer has failed, no spare is available, and a transformer suitable for the application cannot be identified. A new transformer must be purchased. If transformers of this type have not been purchased recently, it is very likely that the existing transformer specification will have to be upgraded to include current technical and test requirements. The procurement documents must be issued, and the transformer must be manufactured and subjected to acceptance tests at the manufacturer's site. The oil will have to be removed, and the transformer will have to be shipped by rail or ground using special vehicles (for example, Schnabel cars and 16- or more axle tractor trailers). Special permission is likely to be needed from the Department of Transportation in order to move the transformer through railroad rights of way or on highways. Once on site, the transformer must be moved to the final location, inspected for transportation damage, refilled with oil, have the oil processed, and subjected to acceptance tests. Table 4-1 lists the activities, and an estimated period of 100 weeks or more may be needed to complete them. Most plants will take any viable option other than this one, including installing an undersized transformer and operating at reduced output. In addition, unless the replacement transformer is identical in configuration to the original transformer, modifications to the connections, mounting, and cooling systems may be required in order to allow the transformer to be used.

Case 3. Transformer Is Available in the Market Place

In this scenario, a transformer is available in the market place that is known to be in serviceable condition. The transformer must be emptied of oil, shipped to the site, placed in its final location, inspected, and filled with oil; the oil has to be processed; and the transformer must be subjected to acceptance tests. Table 4-1 lists the activities and states that an estimated five or six weeks may be necessary to complete them. Unless the replacement transformer is identical in configuration to the original transformer, modifications to the connections, mounting, and cooling systems may be required in order to allow the transformer to be used. Such modifications may significantly extend the required time to install and test the transformer.

Failure in Service – Spare Exists

Case 4. Spare Available But Condition Unknown

In this case, the two possibilities that exist are that the spare is unfit for service or through testing and processing of oil and any other maintenance activity, it is ascertained that the transformer can be made ready for service. In the first instance, a different transformer must be located or manufactured. The result is the same as in Case 2 or 3 with one to two additional weeks that will be lost due to the need to evaluate the unfit spare.

In the second instance, the spare is found to be acceptable. Table 4-1 lists the activities and states that an estimated time of four to seven weeks may be necessary to complete them if the spare is off site. Two and a half to four weeks may be necessary to complete the activities if the spare is on site.

Case 5. Spare Exists and Is Known to Be in Satisfactory Condition

In this case, the spare transformer has been maintained and tested to ensure that its acceptability is fully understood. The spare may be located off site and would require the removal of the oil, transportation to the site, inspection, refilling, and processing of the oil. Table 4-1 states that it may take three to six weeks to complete these activities. If the spare is on site, Table 4-1 lists that an estimated two and a half to five weeks may be necessary for the completion of the activities. The spare transformer may not be identical to the original. In this case, additional time is likely to be needed in order to implement modifications to allow the spare to be used.

The lead times for Cases 2, 3, and 4 may be partially offset by beginning preparation activities at the onset of adverse condition monitoring results for the in-service transformer. Evaluating the condition of the spare transformer, preparing work plans, and other activities can reduce outage time should the transformer need to be replaced or if it fails in service. While Table 4-1 lists activities associated with replacement, additional time may be necessary to perform cleanup should the in-service transformer fail catastrophically. Tank rupture and fire are not unusual in such cases.

**Table 4-1
Transformer Replacement Logistics**

Case	Condition	Procurement	Manufacture	Shipping	Site Preparation and Testing	Total Duration
1	No failure: Fully prepared transformer staged adjacent to the transformer to be replaced. Oil in tank and processed.	N/A	N/A	N/A	Remove old transformer, shift new transformer in place, perform tests: one to two weeks.	One to two weeks Note: If three single-phase transformers are being installed, the duration is likely to be four or more weeks.
2	Failure: No spare	No useful transformer available. Procure new unit. Update specification and issuance: one to two weeks.	Manufacture new transformer, perform specified manufacturing tests: 80+ weeks.	Remove oil. Obtain specialty rail car or over-the-road vehicle, identify route, obtain permissions for moving oversized load, and ship: one to three weeks.	Transfer transformer to final location, inspect, refill with oil, process oil, perform on-site tests, and place unit in service: two to three weeks.	84 to 88 weeks
3	Failure: No spare, but transformer available in market place (possibly undersized)	Useful transformer available (possibly undersized with respect to need) and known to be in good condition.	N/A	Proceed the same as Item 2: one to three weeks.	Transfer transformer to final location, inspect, refill with oil, process oil, perform on-site tests, and place unit in service: two to three weeks.	Five to six weeks

**Table 4-1 (continued)
Transformer Replacement Logistics**

Case	Condition	Procurement	Manufacture	Shipping	Site Preparation and Testing	Total Duration
4	Failure: Spare available but condition is unknown	N/A	N/A	<p>Evaluate before shipping. If off site and acceptable, proceed with shipping per Case 2 or 3: Two to four weeks including pre-shipping evaluation and testing.</p> <p>If on site, evaluate before moving the transformer to the final location. Remove oil, and move to final location: a few days to one week.</p> <p>If unacceptable, proceed with the best option of Case 2 or 3 with one to two weeks added to the schedule.</p>	<p>If acceptable, proceed the same as Case 1 or 2: Two to three weeks.</p>	<p>If acceptable and off site: Four to seven weeks</p> <p>If acceptable and on site: Two and a half to four weeks (see Note 1)</p> <p>If not acceptable: Case 1 or 2 with one to two weeks additional time</p>
5	Failure: Spare known to be in service-ready condition	N/A	N/A	<p>If off site, proceed the same as Item 1: one to three weeks.</p> <p>If on site, remove oil, and relocate to final position: A few days to two weeks.</p>	<p>Transfer transformer to final location, inspect, refill with oil, process oil, perform on-site tests, and place unit in service: Two to three weeks.</p>	<p>If off site: Three to six weeks</p> <p>If on site: Two and a half to five weeks (see Note 1)</p>

Note 1.: Some plants have a spare phase adjacent to the associated transformer in a ready-to-use condition. If one of the phases fails, the wiring and bus work to the phases are reconfigured to take the failed phase out of service and place the spare in service. This reconfiguration takes approximately two days.

5

CONCLUSIONS

Table 1-1 indicates that the useful life of a large, oil-filled transformer is between 30 and 40 years with insulation or bus supports being the most likely to fail due to age. For the insulation, thermal aging of the paper insulation is the likely cause of failure. The life of the insulation can be shortened further by ingress of moisture or elevated operating temperatures. Internal bus supports, especially for transformers from the early 1970s, may also cause failure, especially if the transformers have been exposed to numerous through faults².

Having a spare transformer is a business decision on the part of a plant owner. However, a spare that has not been maintained and tested to ensure its readiness may be unfit for service and may be the equivalent of having no spare. If the spare is located off site, the availability of rail or road rights of way and special vehicles must be considered. The condition of the rights of way is also a consideration if a transformer must be shipped off site for repair or if a new transformer is purchased.

Replacement of an aging transformer may be necessary if condition monitoring results indicate the onset of deterioration. Proactive replacement can preclude catastrophic failure that could lead to environmental cleanup problems if the transformer tank fails. Catastrophic failure often leads to a transformer fire. Given adverse condition monitoring indications, the removal of a transformer from service prior to failure may allow for repair or refurbishment of the transformer and may shorten the unit's return-to-service time than if a catastrophic failure had occurred.

In the replace-before-failure scenario and in a proactive replacement scenario, the replacement transformer can be staged adjacent to the transformer to be replaced. Most preservice inspection, oil processing, and testing can be performed prior to a plant outage so that a transformer can be replaced in the shortest period possible.

The previous information has been provided in order to allow the reader to determine if long-term or contingency planning is desirable for large transformers and to help identify possible outage durations that could be expected and logistics problems that can occur. The choice to plan and the type of planning to employ are left to the reader. EPRI reports TR-106109 [3] and 1007422 [1] provide the information and methodology for LCM assessment. EPRI report 1003455 [2] provides an economic assessment tool that may be used to prepare cost assessments of different alternatives.

² A through fault is a fault external to the transformer that causes very high currents to flow through the transformer windings and causes high magnetic forces on the internal components of the transformer.

6

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A

QUESTIONS TO CONSIDER

The following questions can be used to determine the need for developing a long-term or contingency plan for a large, oil-filled transformer that is at or is approaching its expected end of life.

Expected Life

1. Has an evaluation of the expected life of the transformer been conducted?
2. Have industry and site-specific operating and maintenance experiences related to the transformer been assessed?
3. Has the transformer experienced failures that may have stressed long-lived transformer components?

Condition Monitoring and Assessment

1. What is the frequency of combustible gas in oil analysis? Are individual combustible gas limits assessed? (see Table 3-1) Are trends in the periodic results evaluated?
2. Has an on-line combustible gas analyzer been considered or installed?
3. Has an analysis of the rate of generation of combustible gases in oil been considered or used in assessing the condition of large transformers? (see Table 3-2)
4. Is the condition of on-line monitoring systems and alarms, such as temperature monitors, Buchholz relays, and gas analyzers, known to be acceptable?
5. Are operators and operations managers aware and trained in responding to condition monitoring results and transformer alarms?
6. Has the overall battery of predictive maintenance tests and assessments (for example, infrared thermography of transformer components, power factor testing of bushings, inspections for leaks, and a confirmation of function of cooling systems) been reviewed for adequacy with respect to a transformer approaching or at its expected end of life?

Logistics Questions

1. Does a spare transformer exist?
2. If a spare does not exist, has a contingency plan been developed to optimize the replacement time should a failure occur?


Questions to Consider

3. Are personnel (engineers and technicians) who understand transformer repair and replacement issues (such as transformer inspection and testing, oil treatment, and relay system connection and testing) available to the plant?
4. If a spare exists, is the spare known to be in satisfactory condition for service?
5. Is the spare on site? Is it stored away from the transformer it is meant to replace or located adjacent to it? (Some plants have the spare transformer mounted permanently such that reconfiguration of the leads allow the spare to be put in service in a matter of days.)
6. If stored away from the transformer that the spare is meant to replace, are the logistics understood for moving the spare into position and putting it in service?
7. If the spare is located off site, are the transportation logistics, such as availability of special rail cars or trucks, condition of rights of way, and special permissions from the Department of Transportation, understood?
8. If the spare is a common system or industry spare, are modifications to the transformer, foundation and mountings, bushings, and so on necessary to allow use?

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