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SERVICE AGED INSULATION GUIDELINES ON MANAGING THE AGEING PROCESS

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SERVICE AGED INSULATION

GUIDELINES ON MANAGING THE AGEING PROCESS

by

Working Group D1.11
'Service Aged Materials'
(Task Force D1.11.01)

Convener: D. Allan (Australia)
Members or Contributers: T. Blackburn (**Secretary**, Australia),
H. Sedding (Canada), E. Gulski (Netherlands), R. Wheatland (Australia),
S. Bhumiwat (New Zealand), B. Finlay (Australia), J. Densley (Canada),
H. Orton (Canada)

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SERVICE AGED INSULATION,

GUIDELINES ON MANAGING THE AGEING PROCESS

1. INTRODUCTION

This brochure introduces a new methodology developed through CIGRE Working Group D1.11 (Service Aged Materials) to analyse and manage service aged insulation. In contrast to the usual focus on accelerated ageing in a laboratory, this approach starts from scientific observations on aged or failed in-service equipment.

A structured methodology has been developed to link forensic evidence from failed plant with the theoretical failure modes observed from laboratory studies. Using this methodology, a range of practical options emerges for the better management of service aged plant

The service ageing of electrical insulating materials, which eventually leads to the failure of the host equipment, is usually addressed either;

(i) By scientific modelling of the ageing process in laboratories, using accelerated ageing techniques. These laboratory results are interpreted by mathematical criteria fitting the observed test data.

(ii) By engineering practitioners, for example from utility maintenance departments, based on forensic examination and informed deductions as to the failure mode.

The first approach, (i), eventually runs into difficulties with the complexities of multi-factor ageing. This makes the prediction of service ageing in operating equipment, using laboratory models inexact except for simple insulation structures.

The second approach, (ii), while precise for individual items of equipment, may be limited in its scope and does not provide an enduring analytical structure by which the lessons of each failure can be effectively used on a preventative basis in the future.

CIGRE Task Force D1.11.01, of WG D1.11, 'Service Aged Materials', endeavours to bridge the gaps evident in the approaches above and incorporate a feedback process by which the service ageing of high voltage equipment can be better anticipated and the incidence of disruptive failure reduced.

The Task Force considers the analytical process itself to be as important as the particular material studies undertaken in this report.

2. METHODOLOGY

The process developed is to work back from the knowledge base of forensic studies of failed or near failed components and firstly establish their dominant failure modes. There may be as few as two or there may be several. It is not necessary to be fully comprehensive for a successful failure mitigation process to be established.

After the dominant failure modes have been established these are correlated with the associated forensic evidence in the early, advanced or late stages of insulation degradation. This is to assist practitioners in developing a preventative maintenance strategy as soon as possible.

For a forensic study to give a complete picture, information should be available from all stages of the insulation's life. However such information is rarely available and this can limit the forensic data to that obtained from examination of units with major damage or units whose failure is imminent. The challenge is then to work back from the evidence using whatever information is available on the ageing mechanisms that lead to the observed failure mode (this can be laboratory studies or detailed monitoring of a specific item or of other equipment of the same type). As much information as possible is obtained from previously applied diagnostics and from any tests on other similar equipment.

It is valuable to establish for each equipment class a good data base of information on aged equipment: while failed equipment will always be thoroughly investigated, this may not always be done with an eye to better understanding of the ageing process. Useful information on the ageing processes during the full service life includes loading, maintenance test results, general ambient and environmental conditions and details of any site moves. This may be enhanced by using data mining techniques to display trends which may not be apparent from normal diagnostic analysis methods.

Once the ageing processes are established and defined for each dominant failure mode the key influencing factors and levels of significance can be detailed. These may be internal (eg. related to design, manufacture or installation) or external (eg. related to environmental influences).

Associated with each dominant failure mode and the related ageing processes are the time frames involved and the most relevant recognition diagnostics. From the details of the degradation processes involved, these diagnostics are able to be categorized in terms of their sensitivity to the signs of degradation associated with the failure modes.

Finally and importantly, deductions and recommendations are necessary to assist the management of the service ageing process. For example, if the dominant failure mode of a particular type of equipment is established, specific measures can be undertaken on the key influencing factors and the most sensitive diagnostics used for monitoring other similar equipment items. If the fault propagation time is established then an informed decision can be made between periodic diagnostic testing, continuous monitoring or equipment changeout.

In summary, the general process methodology proposed by TF D1.11.01 is displayed schematically in Figure 1. The diagram shows two possible failure modes in the flow chart with the associated procedure similar for each. There may be as many as four possible failure modes. The end results of the proposed process is the recommendation for optimal preventative strategy, in terms of maintenance and monitoring procedures.

To recapitulate, the methodology and analytical structure, for each identifiable failure mode which is recommended by TF D1.11.01 is as follows;

Step 1 Identify the dominant failure modes for the equipment type

Step 2 Correlate the specific failure mode with the principal forensic evidence (early, advanced, late degradation stages)

Step 3 Use all available data to define the ageing processes and time frames; use this to detail the influencing factors and levels of significance for the equipment item.

Step 4 Identify the most and least sensitive diagnostics for each degradation mode.

Step 5 Determine a preventative maintenance strategy which addresses the specific local influences, inputs the likely insulation fault propagation time and chooses the most effective diagnostics.

3. APPLICATION TECHNIQUE

3.1 Insulation Systems Case Studies

Four diverse insulation systems have been selected by TF D1.11.01 to exemplify the failure study process described. The equipment using this insulation is of major significance to power suppliers and customers. The brochure covers the following;

Section 4 Instrument transformer insulation
Section 5 Rotating machine stator winding insulation
Section 6 XLPE cable joints and terminations
Section 7 Transformer pressboard insulation

'Failure' in the context of the above includes the precursor stages leading up to failure to operate.

The four case studies range from the first case (Section 4), where the insulation studied is the major component of the equipment, to the last (Section 7), where it is one of several components in the insulation structure.

The implications of the technique in a management strategy for service aged insulation are listed in summary form in Table 1.

Where testing or diagnostic techniques are given they are of a generic nature. For example no attempt is made to differentiate between different methods of carrying out dielectric response measurements (such as recovery voltage measurement).

CIGRE TASK FORCE D1.11.01 - PROCESS FLOW CHART

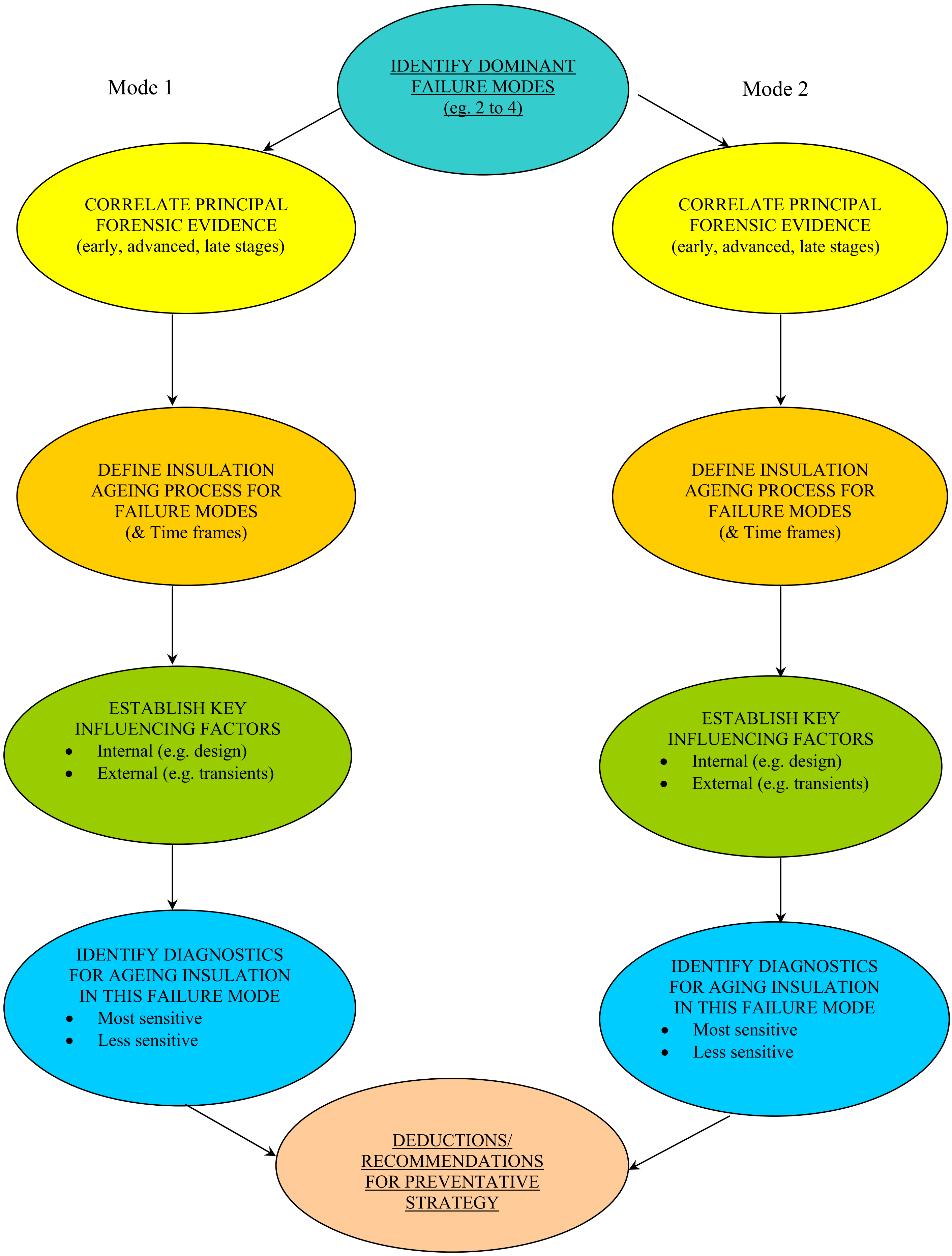


Figure 1

TABLE I

IMPLICATIONS OF METHODOLOGY IN ASSET MAINTENANCE MANAGEMENT

Stages in Methodology	Associates Sub-Stages in Methodology	Implications for a Management Strategy
Identify dominant failures modes	(Two or three modes are usually prominent)	Higher level check on equipment vulnerability
Correlate principal forensic evidence	Categorize as early, advanced and late stages of activity	Enables prompt identification of problem and action necessary on most vulnerable units
Define insulation ageing processes for failure modes	Estimate time frames from fault inception to disruptive failure	Enables informed decision on either periodic testing, continuous monitoring or immediate replacement
Establish key influencing factors	Categorize as internal (eg. design) or external (eg moisture ingress). Estimate levels of significance	Effective steps can be taken to isolate and address cause of insulation degradation
List most relevant diagnostic techniques	Categorize as 'most sensitive' and 'less sensitive'	Enables choice of diagnostic techniques most sensitive to leading indicators of insulation degradation.
Recommend maintenance or replacement strategy	(Determine relevance for similar classes of equipment not yet failed)	Informed and effective failure mitigation and maintenance strategy for equipment classes in question.

3.2 Practical Example of Methodology Application

The following simplified example of using the methodology is an illustrative study of how to investigate the insulation failure of a 132kV current transformer (CT) and to develop an effective preventative maintenance strategy using the established process and knowledge base given in Section 4.

Initial stages – (i) Identify failure mode by correlation with principal forensic evidence.

A 132kV CT has failed explosively. An examination of the remains was inconclusive due to the violence of the explosion and a consequent fire. The five remaining CTs in the substations were oil sampled and one showed high levels of hydrogen and hydrocarbons. This unit was removed and subjected to a further forensic examination. A prior study (as per Section 4) had established two dominant failure modes for current transformers; (i) Thermal instability of oil/paper dielectric and (ii) Dielectric overstressing and partial discharge activity.

The examined insulation showed physical evidence of dielectric overstressing and partial discharge activity in its advanced stages (per 4.3.1 (ii) and Appendix I). The spectrum of dissolved gases also fitted more closely this mode than thermal instability (per IEC 60599-1999). No paper taping irregularities, sharp foil edges or earth lead irregularities were noticed. It was also noted in the forensic examination that 25% of the outer layers of the insulation structure had been penetrated confirming an advanced stage of degradation. There was no “X-wax” present, giving an indication of the possible time frame involved (refer below).

The dominant failure mode has now been established and correlated with forensic evidence of dielectric overstressing and partial discharges, at an advanced stage

Intermediate stages – (iii) Determine the insulation ageing process and likely time frames and (iv) Establish the key influencing factors, internal or external.

A review of the processes associated with this failure mode (per 4.3.2) indicates three possible mechanisms in the dielectric overstressing of CT’s;

(i) internal constructional factors
(ii) ingress of contaminants
(iii) temporary external overvoltages

The forensic examination did not reveal any internal constructional defects. Temporary external overvoltages were dismissed after a review of the substation environment. The ingress of contaminants remained as the most likely cause of dielectric overstressing. As moisture was a likely contaminant, a moisture content test was conducted on the oil, giving 30 ppm, over twice the expected level. Suspicion was directed at a plugged port in the gas cushion head of the CT, which was sealed with a screwed plug and rubber washer. This was above the oil level, so imperfect sealing would not have been detected by an oil leak.

In summary, the insulation ageing process was confirmed as a lowering of discharge inception voltage within the insulation due to ingress of moisture. A short time frame was suggested by the absence of any “X-wax” and a perusal of the previous oil test results confirmed this as likely to be within one year. The key influencing factors were a design deficiency in relation to sealing, accompanied by external moisture ingress.

Final Stages – (i) Identify the most effective condition monitoring diagnostics and (ii) Provide recommendations for a preventative strategy.

Reference to section 4.3.3 indicates that oil testing involving DGA and moisture content, together with PD and DDF testing and capacitance measurement are the most sensitive diagnostics for this failure mode. To identify affected CTs in other substations it was resolved to take oil samples where feasible and to rely on DDF and capacitance measurements at 10kV where not. PD testing was considered impractical on site.

The recommended preventative strategy followed the lines of section 4.4, including; specification changes to have all plugged ports below oil level, redesigned oil seals and inspections of similar types for such problems. The choice between periodic diagnostic testing, continuous monitoring and equipment chargeout was resolved in favour of the first, based on the number with insulation damage (as determined), relatively simple seal replacement and the capability of periodic testing within the estimated failure propogation time.

4. HIGH VOLTAGE INSTRUMENT TRANSFORMER INSULATION

4.1 Preamble

High Voltage Instrument Transformers are one of the most widespread and critical items of apparatus in a high voltage transmission system. There may be typically ten to fifteen times as many instrument transformers as power transformers. Concerns about their failure are not so much the economic loss as the unpredictability of the consequences of the explosion which results.

The majority of high voltage instrument transformers which would now be classified as aged were constructed 25 – 40 years ago of oil impregnated paper insulation. For current transformers (CT's), which are the most prevalent class, the insulation is in thick, cable like layers, usually with electrostatic screening. With electromagnetic voltage transformers (MVT's) the insulation structure is more complex and varied and may also have a condenser type bushing. Capacitor voltage transformers (CVT's) have in recent years adopted polypropylene film in part or whole and may exhibit failure mechanisms less in common with those of current transformers.

The material which follows is based on the results of forensic studies of many failed specimens, of accelerated aging tests in high voltage laboratories and of published and unpublished studies of failure mechanisms. As well as including insights and experience from experts from WG D1.11 it also draws on others' experiences.

The two most dominant failure modes for this particular insulation system are:

1. *Thermal instability of the oil/paper dielectric*
2. *Dielectric overstressing and partial discharge activity*

4.2 Dominant Failure Mode No 1

Thermal instability of the oil/paper dielectric

4.2.1 Principal Forensic Evidence – (i) late, (ii) advanced, (iii) early stages

(i) Exploded insulation, often with little remaining evidence other than the approximate site of the thermal runaway and its successive disruptive failure mechanisms.

(ii) Extensive carbonization at a hot spot, often with a carbonized "burn through" hole in the insulation structure (ref Appendix)

(iii) Discoloration of copper based material, oil paper insulation or the presence of " X-wax" material. In the latter case, overheated cellulose has decomposed resulting in gases and low level ionization and wax like residues of polymerized oil molecules – fluorescent in UV light.

4.2.2 Aging Processes and Influencing Factors

Aging Processes and Time Frames:

The thermal stability of oil/paper insulation systems in CT's and VT's is dependent on the capacity of the insulation to dissipate heat generated internally by dielectric losses or transferred internally by metal component overheating or by excessive ambient temperatures. A common cause of thermal instability is the pressure of moisture or soluble polar contaminants which result in higher dielectric losses particularly at elevated temperatures. The terminal condition of such instability is thermal runaway. An internal temperature of 140° – 150°C may be considered as the borderline between safe and unsafe operating conditions.

The visible stages of the degradation process are evidenced by (i), (ii) and (iii) above and the time from inception to full propagation of thermal instability should be at least 30 or 40 years. In a minority of cases of thermal runaway however the period from inception to disruptive failure may be reduced to a matter of weeks. Known cases of thermal instability in the design must be treated very seriously as propagation times may be very short.

Influencing Factors – Internal

(i) If during manufacture there has been incomplete impregnation of the oil/paper insulation, this predisposes ionization within the dielectric and the formation of waxes and higher dielectric losses over time.

(ii) In isolated cases the cause has been incompatible mineral or synthetic oil, possibly of a high paraffinic type or contaminated in some way, which exhibits chemical instability over time and excessive losses.

(iii) The thermal design of the CT or VT must provide adequate cooling either by conduction or convection processes.

(iv) Poor contacts at any internal bolted joints, e.g. at the top of a CT hairpin can induce overheating, initially in the oil but potentially affecting the paper insulation.

Influencing Factors – External

(i) Continuous overloading in terms of current or voltage rating can lead to thermal instability.

(ii) Ingress of moisture through degraded seals or oil expansion bellows resulting in higher dielectric losses in the primary insulation is a contributing factor.

(iii) Exposure to higher than designed ambient thermal conditions, e.g. a live head CT in an environment with high external temperatures and solar radiation has been postulated as a cause of thermal runaway due to the immediate exposure to solar radiation and the lesser possibilities of convection cooling compared with a dead tank type.

(iv) Low oil level (eg due to leaks), exposing some of the insulation.

4.2.3 <u>Diagnostics for this Failure Mode</u>

Diagnostics Most Sensitive to Failure Mode and Levels of Significance

(i) Dissolved Gas in Oil Analysis

If it can be performed, i.e. if the instrument transformer is not hermetically sealed and it can be adapted for sampling of the oil, DGA is the most sensitive technique for the detection of thermal instability and hot spots. The cellulose at the thermally elevated sites is gradually destroyed leaving solid carbonic material, but also carbon monoxide and carbon dioxide.

In establishing the significant levels of these gases, the data accumulated for power transformer fault analysis can be used as a guide. CO_2 is usually the dominant gas, particularly if moisture is present (e.g. a concentration of 10,000ppm of CO_2 in a very aged CT compared with 1,000ppm of CO). However in an oxygen poor environment or particularly if the thermal instability is rapidly proceeding to carbonization, then the CO level may equal or exceed the CO_2 level.

Trending over time and comparison with similar equipment is most important in assessing the level of significance of CO and CO_2 and of other dissolved gases such as H_2 and the hydrocarbons.

(ii) Dielectric Dissipation Factor (tangent Δ)

The presence of polar contaminants, X-wax and early carbonization is frequently detectable by an increase in dielectric losses of the insulation structure. These losses increase with temperature.

A further characteristic of such aged oil paper insulation is that at elevated temperatures in particular (above 50 C) there is a reversal of the trend of rising DDF as voltage is increased.

This needs to be taken into account when investigating aged current transformers. During thermal runaway conditions the DDF may rise to 100 then to 1000 milliradians or more.

Trending over time and comparison with similar equipment is also important in assessing the level of significance of DDF.

Less Sensitive Diagnostics to Failure Mode

(i) Partial Discharge Measurement

Partial discharge measurement, a valuable diagnostic for other failure modes, may not be sensitive in cases of thermal instability. Even when the instability has advanced to the formation of X-wax or carbonization of the cellulose, the ionization mechanisms may not be detectable externally.

Dependant on the configuration that the fault path follows, partial discharge detection may be valuable at the later stages, however no strict guidelines can be given due to the many variables preceeding thermal runaway and disruptive failure.

(ii) Capacitance Measurement

For current transformer insulation where there are a number of graded electrostatic screens through the insulation structure, a comparison of insulation capacitance with the manufacturer's test results can be definitive in detecting advanced thermal degradation. The proportion of grading layers affected compared with the total number will determine the sensitivity of detection in any particular situation.

(iii) Thermal Imaging of the Instrument Transformer

If the thermal instability is advanced and is thermally conductive to an external surface, then thermal imaging can be effective if measurements are taken at times when solar radiation is low.

(iv) Other Methods

Other methods may also be effective in certain specific situations. If dielectric response testing is applied it is usually only effective at the lower voltage equipment ratings where electrostatic grading screens are not utilized. The latter may interfere with the sensitivity of detection for these techniques.

The measurement of furans in the oil may assist in identifying serious cases of thermal instability and cellulose degradation.

4.3 Dominant Failure Mode No 2

Dielectric overstressing followed by partial discharge activity.

4.3.1 Principal Forensic Evidence – (i) late, (ii) advanced, (iii) early stages

(i) Exploded insulation, often with little remaining evidence other than the site of the power arc which followed upon the erosion caused by internal partial discharge activity or external tracking.

(ii) Visible partial discharge activity through carbonized tracks and physical erosion through the paper structure or across a surface between two areas of different electrostatic potential. Occasionally these discharges have a visible erosive effect on metal or metallic based electrostatic screens.

(iii) The presence of "X-wax" material between layers of insulation. This is a result of low level ionization of polymerized oil molecules and may be detected by fluorescence under UV light. Other indications of low level partial discharge activity are isolated small carbonized spots in the insulation structure.

4.3.2 Aging Processes and Influencing Factors

Aging Processes and Time Frames:

Dielectric overstressing which drives the accelerated aging process can initiate from internal constructional factors, from the ingress of contaminants or from temporary external overvoltages. A consequence is regional overstressing and gas bubble generation or small scale puncture or tracking of the insulation. Over a period of time this results in a permanent reduction in discharge inception voltage at a particular location in the structure.

The accelerated aging process sustained from such initiating phenomena involves sustained discharges in gas filled voids at rated voltage due to the difference in dielectric constants between the gas and surrounding oil filled cellulose. Further breakdown of the oil results, due to ionic bombardment of the oil evolving more gas. This sustains and accelerates the process so that sufficient energy is eventually generated to carbonize the cellulose itself. An intermediate product, if the chemical conditions are suitable, is 'X-wax' (or 'cable wax').

The concept of inception and propagation can be useful to distinguish the respective time frames to establish the conditions which drive accelerated aging and to carry them forward until disruptive failure occurs. As in the case of thermal instability the propagation time may vary from a matter of weeks to several years. The reason for this is the criticality of the location of the partial discharges in the insulation structure. Despite this limitation however, the formulation of condition monitoring plans benefits from some assessment of most likely propagation times.

The presence and extent of X-wax in the insulation structure can be a useful indicator of a lengthy time frame involved in fault inception. However its absence does not necessarily mean the opposite.

This is possible from condition monitoring databases and with input from accelerated aging programmes in test laboratories, where such results have been published.

Influencing Factors – Internal

(i) While uncommon, incomplete impregnation of the oil/paper insulation during factory dryout, will result in gas voids and discharge initiation.

(ii) Possible constructional aspects initiating partial discharges are wide ranging. A few that have been reported are; paper taping irregularities during manufacture, resulting in a lower capacitance and hence higher voltage across an insulation section; the change from circular to eliptical shape of a CT primary conductor due to bending at the "hairpin". (With very old instrument transformers, partial discharge testing and other modern quality control techniques may not have been applied in the factory and such defects not detected).

With magnetic VT's the very fine secondary wire may have a fracture which is not easily detectable but which may be the source of an evolving discharge site (a very low voltage resistance test may detect this type of fault). Other areas of internal electrical contact which may lead to discharge initiation are the contact point of the earth connection and for live head CT's, the junction with the connecting rod through the bushing.

The designs of instrument transformers are very varied but a common area for field intensification and discharge inception is at the edge of capacitive grading screens or at any sharp wrinkles which may be present on metallic screens due to uneven shrinkage in the factory dryout process.

(iii) In the gas cushion type of instrument transformer, oil expansion or contraction is compensated for in the fixed shell by a gas (usually nitrogen) headspace. This should be maintained at an overpressure recommended by the manufacturer but caution should be exercised in continual repressurization. Cases have been reported whereby the oil has become supersaturated with gas due to a sharp temperature fall and gas bubbles have evolved from the insulation, leading to insulation failure. On the other hand, significant underpressure can also result in a similar effect, so the manufacturer's advice should be sought and followed.

(iv) Low partial discharge inception voltage due to the use of low aromatic content oils.

Influencing Factors – External

(i) Dielectric overstressing may occur through temporary system overvoltages such as isolator switching adjacent to the instrument transformer or due to an extraordinary event e.g. the failure of high voltage apparatus in the same substation.

Cases have been reported where high frequency voltage oscillations and the resultant high frequency currents through CT capacitance have generated high internal voltages across inductive internal parameters. Evidence of such is in the form of carbonized tracks across stress grading layers of a current transformer.

(ii) The ingress of moisture through degraded seals or expansion bellows results in a lowering of discharge inception voltage within the insulation and in extreme cases moisture deposits may induce an insulation surface flashover.

4.3.3 Diagnostics for this Failure Mode

Diagnostics Most Sensitive to Failure Mode and Levels of Significance

(i) Dissolved Gas in Oil Analysis

If it can be performed in a non hermetically sealed unit, DGA is the most sensitive detection technique for this mode of failure. In establishing the significance of the gases and their levels, data provided for power transformers can be used as a guide. However there may be some difference in the interpretation of gases compared with partial discharge faults in power transformers. For example, a preponderance of acetylene in relation to the expected quantities of hydrogen and methane may be evident for advanced faults in the cellulose insulation or internal arcing involving a loose earth connection.

Moisture content is an important supplementary test on the oil due to the sensitivity of this class of insulation to moisture ingress through degraded seals.

(ii) Partial Discharge and Dielectric Dissipation Factor Measurements

Both these insulation quality measurements are sensitive to insulation degradation resulting from internal overstressing. However it is not uncommon for one of them to be more sensitive than the other and occasionally both may be insensitive to an insulation fault. Put simply, if the partial discharge track is carbonized, the measured level will be small and if the defect is very localized, dielectric losses may be low.

(iii) Capacitance Measurement

For current transformer insulation where there are a number of graded screens, a comparison of overall capacitance with test certificate results or those from similar units may identify an insulation fault.

Less Sensitive Diagnostics to Failure Mode

(i) RIV Monitoring

Radio interference (RIV) has been recorded from a number of instrument transformers prior to disruptive failure. This has sometimes led to the installation of fixed RIV detectors using antenna. The major difficulty is in eliminating false alarms from many other sources of RIV e.g. isolator contacts and dry band discharges from porcelain insulators.

(ii) Thermal Imaging

Thermal imaging can be successful if the nature of the fault results in a temperature rise of portion of the external surface and if this can be distinguished from solar radiation and normal loading efforts. This is less likely than for the previous failure mode.

(iii) Gas Pressure Monitoring

The gas pressure generated by hydrogen emission in particular can be detected by a gas pressure gauge (if fitted) by maintenance staff. For expansion bellows sealing systems, expansion can be detected by a bellows position indicator.

4.4 Preventative Maintenance Strategy - Summary

In improving the reliability of ageing insulation systems of the type described it is important to establish a preventative maintenance strategy which utilizes the following;

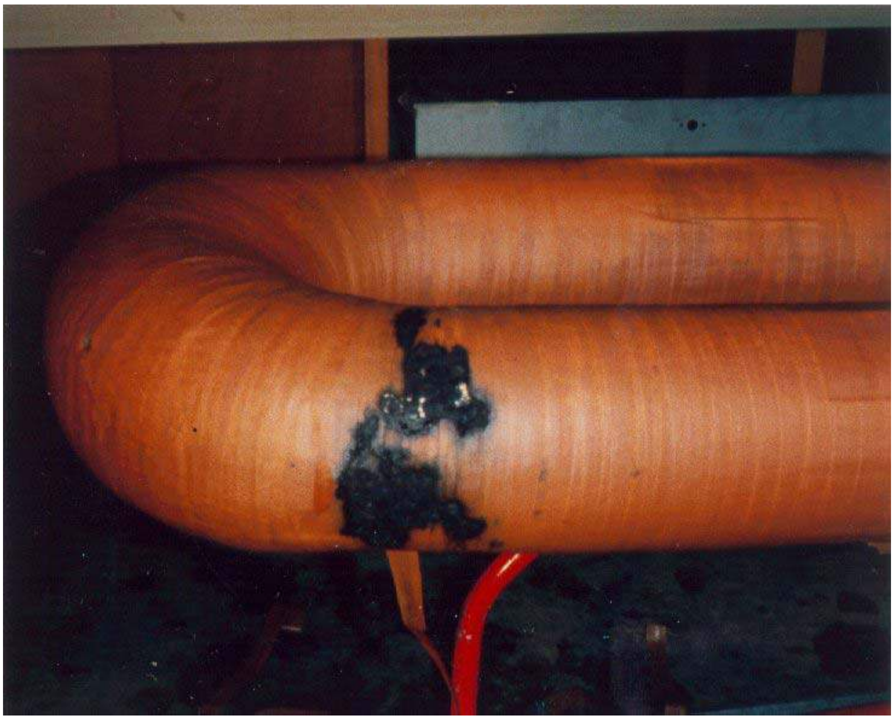
(i) Before failure, determine relevance of the key factors which influence insulation degradation in the two dominant failure modes described. Fourteen factors have been listed, a few of which are common to both failure mechanisms. This approach contributes to improved specification, design and maintenance practices.

(ii) After any failure, identify the dominant failure mode from the forensic evidence of failed or near failed specimens. The path then is to determine from the listed influencing factors, the principal cause of insulation degradation and take measures, including a choice of diagnostics to avoid recurrence. (Note: In addition to the diagnostics listed, a visual check on relative oil bellows or gas pressure levels is of prime importance).

(iii) Where insulation failures in high voltage instrument transformers have occurred and influencing factors established, determine the most likely fault propagation time. This will enable an informed choice between periodic diagnostic testing, continuous monitoring or equipment changeout.

APPENDIX 1

Photographs of insulation subjected to damage representative of the two dominant failure modes for HV instrument transformer oil impregnated paper insulation.



<u>Mode 1</u>: Thermal instability of the oil / paper dielectric

<u>Mode 2</u>: Dielectric overstressing and partial discharge activity

5. LARGE ROTATING MACHINE STATOR WINDING INSULATION

5.1 Preamble

Reliable and efficient generation of electricity requires, among many other factors, that the integrity of the stator winding insulation of the large rotating machines encountered in generating stations be maintained. This statement applies not only to the generator but also to the numerous medium and high voltage motors which are critical to plant operation and safety. Similarly the reliable conversion of electric energy into mechanical energy in industrial processes requires reliable operation of the medium voltage and high voltage motors. Generally, concerns about the failure of the stator winding insulation, especially in today's commercial environment, are focused on the economic losses incurred. A further concern is the safety of personnel and adjacent plant in the event of the failure of a safety-related drive, e.g., the primary heat transport or reactor coolant pump motor in a nuclear station. Complete destruction of a rotating machine due to stator insulation failure is rare and, therefore, the term failure encompasses economic end-of-life as well as failure to operate.

This document includes those machines constructed in the past 50 years. Certainly machines older than these are still in operation and continue to provide both generation and utilisation capability. However, the above time frame is considered of most relevance to utilities and industry and the various service providers charged with operation and maintenance of large rotating machines. This study also, for the most part, does not include some of the more recent developments in stator insulation systems (e.g., class H materials or metal-oxide loaded films for improved thermal conductivity and discharge resistance) because experience is very limited. The interpretation of diagnostic data and, ultimately, any forensic study of failures of stator insulation is significantly influenced by the following four factors,

1. Materials
2. Design
3. Operation
4. Maintenance

Consequently, proper analysis of diagnostic and forensic information should consider factors such as whether the insulation is thermoplastic or thermoset, air or hydrogen-cooled, base load or peaking, and the frequency of maintenance. A further key element to consider is that the basis of 99.9% of stator winding insulation systems is mica, a material with well known excellent discharge resistance properties. As the ageing of mica-based stator insulation tends to occur on a glacial scale relative to organic polymers, (unlike the situation with polymeric cables) operators of large rotating machines have significantly more time to react to the onset of anomalous diagnostic data.

The material which follows is based on the results of forensic studies of many failed specimens, of accelerated aging tests in high voltage laboratories and of published and unpublished studies of failure mechanisms. As well as including insights and experience from experts from WG D1.11 it also draws on others' experiences.

The most dominant failure modes for stator winding insulation systems are largely dependent upon whether the insulation is:

- thermoplastic or thermoset
- operating in an air or an elevated pressure hydrogen environment.

Consequently, three major failure modes can be identified. These are,

1. *Interturn short circuits*
2. *Reduction of groundwall insulation thickness/electrical puncture*
3. *Endwinding discharge and electrical tracking.*

Other failure modes exist, however, the above three are responsible for the majority of unplanned outages encountered by users of large machines.

5.2 Dominant Failure Mode No 1

Interturn short circuits.

5.2.1 Principal Forensic Evidence – (i) late, (ii) advanced, (iii) early stages

(i) Breakdown of the interturn insulation generates intense heat from the circulating currents produced. The failure tends to be explosive, therefore, and often results in the copper conductors in the vicinity of the breakdown melting. The ensuing damage renders any forensic examination very difficult. Turn insulation breakdowns exhibit a high propensity to occur in either the top or second coil from line end positions. Typically, the puncture is observed close to the core exit.

(ii) Observation of differential movement between turns or between the turn package and the groundwall insulation.

(iii) Evidence of thermal deterioration (resin discolouration) or partial discharge damage (erosion of resin) close to the conductor stack.

5.2.2 Aging Processes and Influencing Factors

Aging Processes and Time Frames:

The thermal and mechanical stability of stator winding insulation systems in rotating machines is dependant on the capacity of the insulation to dissipate the heat generated primarily by copper (I^2R) losses and also by dielectric losses. Consequently, consideration should be given to sustained operation at high temperatures and performance under cyclic conditions.

The visible stages of the degradation process are evidenced by (i), (ii) and (iii) above and the time from inception to full propagation of thermal instability should exceed 30 or 40 years. Unfortunately, with this type of failure mode, forensic evidence of types (ii) and (iii) can also be indicative of other breakdown mechanisms. Hence, in reality there is little sign of impending failure. Where data suggestive of this type of failure have been obtained it is commonly when large populations of the same motor have failed prematurely. Typical time frames in this case are one to five years.

Influencing Factors – Internal

(i) Incomplete resin impregnation during manufacture will result in relatively poor heat transfer from the copper to the core iron as well as an increase in the probability of partial discharge. Both mechanisms can result in void growth and hence the development of a positive feedback mechanism.

(ii) Some designs do not incorporate dedicated mica-based insulation, and are therefore prone to rapid damage in the event of delamination between turns.

Influencing Factors – External

(i) Continuous overloading in terms of current or voltage rating can lead to thermal instability.

(ii) Rapid load cycling, such as that encountered in peaking plants, can result in shearing the bond between insulation layers and the copper conductors.

(iii) Exposure to steep-fronted, high magnitude electrical transients such as those resulting from switching operations.

5.2.3 Diagnostics for this Failure Mode

Diagnostics Most Sensitive to Failure Mode and Levels of Significance

Unfortunately, there are presently no diagnostic methods that can reliably detect the onset of turn insulation breakdown. Some techniques, based on analysis of the frequency components of the current or the axial leakage flux have been developed, however, there is no public domain information documenting the success of these methods.

Less Sensitive Diagnostics to Failure Mode

(i) Partial Discharge Measurement

Partial discharge measurement, a valuable diagnostic for other failure modes, may not be useful in cases of detecting the onset of interstrand short circuits. Even where poor resin impregnation has resulted in void formation at the copper conductor/insulation interface, the partial discharge test results will likely be ambiguous. Furthermore, for this situation, the electrical stress is across the groundwall insulation and not the turn to turn component.

(ii) Dielectric dissipation factor (tangent δ)

Dissipation factor is another index of void content. However, dielectric loss measurements are hampered because they tend to average the result, i.e., the contribution of many small voids can be similar to the more dangerous situation of one large delamination.

5.3 Dominant Failure Mode No 2

Reduction of groundwall insulation thickness/electrical puncture.

5.3.1 Principal Forensic Evidence – (i) late, (ii) advanced, (iii) early stages

(i) Depending upon the proximity of the fault with respect to electrical position there will be more or less consequential damage. This phenomenon is a function of machine electrical protection schemes which are generally more sensitive to failures close to the high potential end of the winding. Breakdowns occurring nearer the neutral end have a higher probability of causing core iron damage due to the relatively slow response time of the protection. Generally, there is little remaining evidence other than the site of the power arc that followed the erosion caused by internal partial discharge, slot discharge activity or external tracking.

(ii) Visible damage due to destruction of the semicon armour or groundwall insulation layers. Such deterioration can be caused by mechanical abrasion (loose winding) or poor contact of the semicon to the core iron or internal delamination (poor impregnation and consolidation).

(iii) In air-cooled machines, a first indication of loose windings or semicon problems may be the presence of ozone. Hydrogen-cooled machines, unless monitored for partial discharge will have no immediately obvious indications, although a wedge tap survey during an outage with the field winding removed may indicate a loose winding.

5.3.2 Aging Processes and Influencing Factors

Aging Processes and Time Frames:

The aging process can result from the three factors mentioned in 5.3.1 (ii) above. The first two factors, mechanical abrasion and poor semicon contact, can result from design or installation features. These can cause, especially in air-cooled machines, high energy discharges, normal to the plane of the groundwall insulation and will have a high probability of causing severe erosion of the insulation. Failure to recognize this problem can result in catastrophic failure of the insulation within a period as short as three to five years. Unlike many insulation deterioration mechanisms this process, if detected in a timely manner, can be retarded, although not completely arrested by a number of maintenance procedures.

The third accelerated ageing factor, internal delamination and the consequent partial discharge can occur provided that the appropriate field conditions are met. Gas-filled voids within the groundwall insulation are an inevitable consequence of the construction and operation of stator winding insulation systems. The consequences of such delaminations is dependent on their location with respect to the conductor stack. Voids closer to, or at the corners of, the copper conductors are more likely to result in partial discharge, and hence further deterioration, than delaminations in the middle of the bulk groundwall insulation or close to the outer layers. Deterioration of the bond between the copper and the groundwall or turn insulation can result in failure within five years, although the breakdown is driven more by differential movement between the turns. The presence of large volumes of mica in most insulation systems sets the time frame to failure due to voids in the bulk of the ground wall insulation to the order of 40 to 50 years. Practically, most machines are rewound before this time due to other technical and economic considerations. Some variation of this time frame can be caused by other factors such as type of insulation, percentage of mica in the insulation, type of machine, and thickness of groundwall insulation.

Influencing Factors – Internal

(i) Incomplete impregnation, consolidation and cure of the insulation will result in gas voids and discharge initiation.

(ii) Failure of, or inadequacies in, the slot support system or winding installation can lead to looseness of the winding and consequent abrasion of the semicon and groundwall insulation and in turn high energy slot discharge. This problem is largely confined to thermoset insulation systems.

(iii) Poor application of the semicon material or loss of galvanic contact between the semicon and the grounded core iron can also drive the same mechanism as (ii) above with consequent reduction of groundwall thickness and risk of puncture. This problem is largely confined to thermoset insulation systems.

Influencing Factors – External

(i) Girth cracking, observed primarily on thermoplastic systems, in which thermal cycling causes tape separation and relative movement between the copper and insulation. This mechanism results in cracking of the insulation just outside the core slot leading to puncture.

(ii) Thermal cycling, especially in air-cooled machines with long cores, can result in significant shear stresses being generated between the copper conductors and the insulation due to differential thermal expansion. In some cases, delamination has occurred at this interface resulting in premature failure. Deterioration of the insulation in loose windings can be accelerated by leakage of lubricating oils or sealing oils into the stator windings

(iii) Transient events, such as close-in faults due to transformer failures or missed synchronizations, can result in the failure of weakened insulation which, under steady-state conditions would continue to function. For example, older insulation systems employing asphalt-based binding resins are likely, after many years of operation, to suffer from migration of the resin from the slot cell. Consequently, the groundwall becomes embrittled and prone to failure under the mechanical stresses imposed by a fault of the type described above.

5.3.3 Diagnostics for this Failure Mode

Diagnostics Most Sensitive to Failure Mode and Levels of Significance

(i) Partial Discharge and Dielectric Dissipation Factor Measurements

Both these insulation quality measurements are sensitive to void content. Partial discharge measurements have the advantage that, with proper interpretation, the source of the defect can be identified. However it is not uncommon for one of them to be more sensitive than the other and occasionally both may be insensitive to a significant insulation fault. There are several well documented reasons for the apparent ineffectiveness of these techniques. Dissipation factor measurements average the contribution of voids. Hence, one large void may be indistinguishable from a multitude of small, relatively harmless, delaminations. The interpretation of off-line partial discharge data is complicated by considerations of attenuation and resonances due to the winding impedances. In the case of on-line partial discharge measurements, electrical interference becomes the greatest obstacle to making a correct diagnosis of winding condition. Effective use of off-line and on-line partial discharge analysis can provide valuable information on discharge location.

(ii) Capacitance Measurement

Comparison of capacitance measurements with either manufacturer data or by examining consistency between phases can provide some useful information. For example, an anomalous increase in capacitance may indicate thinning of the groundwall layer. Unfortunately, this measurement is complicated by consideration of the effects of contaminated end windings and the non-linear behaviour of stress relieving coatings.

(iii) Ozone Monitoring

This technique is applicable to air-cooled machines only. A consequence of surface discharges is the generation of detectable quantities of ozone. Some organizations have developed on-line ozone monitors to aid in determining the state of deterioration of the windings. Unfortunately, although the method is effective in identifying windings suffering from slot and endwinding discharge, the extent of the degradation is difficult to quantify.

Less Sensitive Diagnostics to Failure Mode

(i) High Voltage Withstand Tests

These methods, whether employing ac or dc voltages, are crude go/no go tests and can result in failure of the insulation under test. The possible exception is the high voltage dc ramp test and the DC leakage test used by various utilities in Europe and North America. By definition they are short time tests and may not reveal a latent defect. The use of such a test implies a willingness to accept the consequences of failure.

(ii) Insulation Resistance and Polarization Index

These tests provide little information on the condition of the groundwall insulation. Rather, the test is used to determine whether the winding is free of gross defects and surface contamination or moisture.

(iii) Coolant Gas Monitoring

Several organizations have attempted to monitor the presence of insulation degradation by-products in the coolant gas medium, whether air or hydrogen. These attempts have been complicated by the plethora of volatiles and pyrolysates which may be present in the coolant gas.

5.4 Dominant Failure Mode No 3

Endwinding discharge and electrical tracking.

5.4.1 Principal Forensic Evidence – (i) late, (ii) advanced, (iii) early stages

(i) The severity of the consequence of damage attributable to a tracking failure in the endwindings will be dependent on whether a ground or phase-to-phase fault results. The latter fault type will likely result in severe damage to the winding rendering forensic analysis problematic. A ground fault close to the line end is still likely to cause major disruption to the insulation in the region of the fault, however, some of the evidence described below may still be visible.

(ii) Visible damage due to tracking and burning of the endwinding insulation. Further, some disruption of the stress grading layers and/or the interface with this material and the semicon may be evident.

(iii) Contamination of the endwindings due to moisture, dust or oils. In cases where endhead clearances have been improperly designed, especially in air-cooled machines, a white powder deposit will be observed in the endwindings.

5.4.2 Aging Processes and Influencing Factors

Aging Processes and Time Frames:

The aging process can result from the factors mentioned above. The common driving mechanism is disruption of the electric field conditions in the endwinding due either to poor control of endhead clearances or pollution of the endwinding surfaces. Breakdown results from erosion of the insulation by discharges and electric tracking leading to puncture. Failure to recognize this problem can result in catastrophic failure of the insulation, in a period of time which is less than the typical maintenance interval of large generators. Consequently, most failures of this type occur on motors, especially those exposed to harsh environments. In most cases this process, if detected in a timely manner, can be effectively arrested by cleaning the endheads.

Influencing Factors – Internal

(i) Inadequate design of clearances between the endheads resulting in interphase stresses higher than that of the breakdown stress of the gas medium.

(ii) Pollution of the endwindings with moisture or conductive dust or oil. The presence of conductive layers disrupts the field distribution in this region and increases the probability of tracking and erosive surface discharges.

(iii) Poor design or application of the stress grading coatings resulting in field disruption close to the core iron.

Influencing Factors – External

(i) Operation of the machine above voltage and temperature ratings can have negative consequences for the endhead clearances and the behaviour of the non-linear stress relieving coatings.

(ii) Sources of contamination such as the seal oil system in hydrogen-cooled machines or conductive dust in the case of open ventilated machines.

5.4.3 Diagnostics for this Failure Mode

Diagnostics Most Sensitive to Failure Mode and Levels of Significance

(i) Partial Discharge Measurements

Partial discharge measurements, when properly interpreted, can provide data indicative of endwinding problems driven by the mechanisms described above.

(ii) Probe Measurements

Accessibility to the endwindings of large machines renders the use of probes sensitive to radio or acoustic frequencies practical. These methods have proven successful in identifying endwinding problems. Employment of these methods assumes that the machine is on outage or shut down.

(iii) Insulation Resistance and Polarization Index

As mentioned above, these tests can be used to identify windings with high leakage currents. Low readings imply the presence of some form of leakage path.

(iv) Blackout Test

This test consists of raising the winding to a prescribed potential in a darkened environment. Although crude it can be effective in identifying sources of endwinding discharge.

Less Sensitive Diagnostics to Failure Mode

(i) Capacitance and Dielectric Dissipation Factor

These measurements assume a well defined electrode structure which does not pertain in the endwindings. Hence, measurement of these parameters is of little value in ascertaining the presence of the processes underlying this failure mode.

(ii) Ozone Monitoring

Although sensitive to surface discharge in air-cooled machines, the technique is incapable of distinguishing this type of discharge from slot discharge.

5.5 <u>Preventative Maintenance Strategy - Summary</u>

In improving the reliability of ageing insulation systems of the type described it is important to;

(i) Before failure, determine relevance of the key factors which influence insulation degradation in the three dominant failure modes described. This approach contributes to improved specification, design and maintenance practices.

(iii) After any failure, identify the dominant failure mode from the forensic evidence of failed or near failed specimens. The path then is to determine from the listed influencing factors, the principal cause of insulation degradation and take measures, including a choice of diagnostics to avoid recurrence.

(ii) Where insulation failures in high voltage rotating machines have occurred and influencing factors established, determine the most likely fault propagation time. This will enable an informed choice between periodic diagnostic testing, continuous monitoring or equipment changeout.

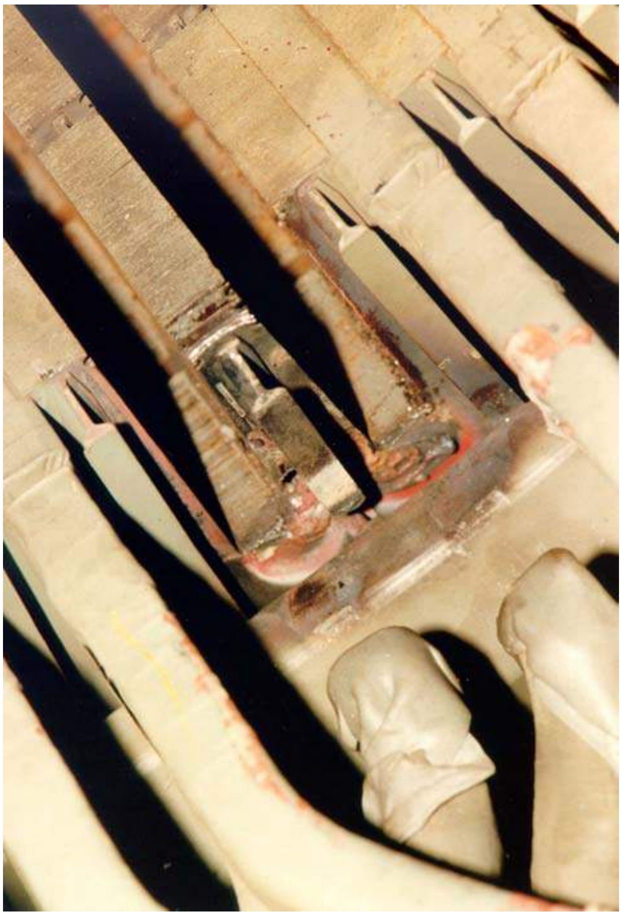
APPENDIX 2

Photographs of insulation subjected to damage representative of each of the three dominant failure modes for large rotating machine stator winding insulation

Poor impregnation & consolidation prior to failure

Partial discharge damage to resin component

Mode 1: Interturn Short Circuits



<u>Mode 2</u>: Groundwall insulation puncture

<u>Mode 3</u>: Endwinding discharge

6. FAILURE OF HV XLPE CABLE JOINTS AND TERMINATIONS

6.1 Preamble

There has been and will continue to be a increase in the use of Cross Linked Poly-Ethylene (XLPE) insulation materials in power cables. This trend is being assisted by the newer methods of cross-linking and associated processing techniques. This document is primarily directed at cables operating at high voltages, in excess of 100kV

Thirty years ago HMWPE was introduced for medium voltage underground cables in the USA before there was a clear understanding of the performance requirements for the material, particularly relative to the effect of moisture and compatibility with other semi-conducting materials. The resultant failures were a catalyst for the technical research which has yielded the high quality materials and processing techniques we have today.

For EHV power cables the future is clear, with the new extra clean compounds which are currently being successfully used for power cables from 150kV to 500 kV. In this case the development of the super smooth and extra clean semi-conductive materials has been essential.

With the exception of the problems cited for early XLPE cable designs, the most common cause of failure in cables is the inadequate performance of the outer protection medium such as the extruded sheath or jacket, which physically protects the cable. It is often surprising to find that many cable failures occur as a result of damage during installation. Thus there is a continuing demand for armoured cables or cables with extra extruded protection. Unfortunately, even after employing such techniques directly following installation, premature aging of the insulation materials occur and catastrophic failures have resulted.

Three of the most common failure modes experienced with HV cable systems are

1. Interfacial pressure problems; relaxation of stress control materials and other components within cable terminations and joints
2. Damage to the outer sheath, resulting in water ingress to the insulating material
3. Damage to the outer sheath, resulting in mechanical damage to the insulating material

This is by no means an exhaustive list, eg, connector failures also occur (more at the lower voltage levels), but one that forms a basis for this forensic investigation model. It should be noted that the three failure modes mentioned above are not usually caused by inherent defects in the cable system but are due to factors such as improper assembly, poor workmanship, or externally induced mechanical damage caused during installation or by a third party after installation.

6.2 Dominant Failure Mode No. 1

Interfacial pressure problems; relaxation of stress control materials and other components within a cable joint or termination

6.2.1 Principal Forensic Evidence – (i) late, (ii) advanced, (iii) early stages

(i) Exploded insulation and severe charring, often with little remaining evidence of the failure inception position. The reason for failure, viewed at this late stage would not necessarily be evident, making it difficult to ascertain whether the cause was relaxation of the stress control material.

(ii) Extensive partial discharge tracking typically emanating from one point on the HV conductive shield and distinctly but not necessarily directly bridging toward the earth potential electrode.
Refer Appendix 3, Figures 1 & 2

(iii) Possible signs of partial discharge tracking and/or localised overheating at the failure inception position.

6.2.2 Ageing Processes and Influencing Factors

Aging Processes and Time Frames

During installation, it is necessary to ensure that there is adequate pressure exerted by the accessory stress relief material on the cable insulation. The achievement of this adequate pressure relies on the design of the stress relief material and the use of the correct installation procedures. Pre-conditioning and installation instructions are required to clearly detail all steps necessary to achieve a satisfactory result. Correct joint and termination assembly can be verified by carrying out a specific post-installation testing program utilising an AC voltage source and selective diagnostic test techniques, see for example IEC 62067 and IEC 60840. The integrity of the outer sheath can also be verified by a DC potential test as per IEC 60229 and IEC 60840

During the service life of the cable, thermal stresses are experienced within the joint or termination, as a result of cyclic transmission of electrical power. It is imperative that the cable insulation, the stress relief material, and other components work together as one homogeneous unit to ensure adequate control is maintained upon the electric field within the accessory. Sometimes this is not the case and voids develop along an interface between the cable insulation and internal surfaces of the accessory.

The visible stages of the degradation process are evidenced by (i), (ii) and (iii) detailed above and the time from inception to insulation failure can vary from hours to weeks or longer. Known cases of internal partial discharge activity in the design must be addressed as propagation times can be very short. Trend analysis can assess the seriousness of the situation.

Influencing Factors – Internal

(i) Migration of the silicone based oil/grease; In pre-moulded stress relief designs, a silicone based oil/grease is used to lubricate the pre-moulded sleeve as it is positioned over the in-line connector and the prepared cable insulation. The oil/grease also fills any small voids that may exist on the cables' insulation surface ensuring that a satisfactory union is made between the two components. During the service life of the cable, diffusion and thermal cycling can cause the oil/grease to be 'squeezed' out from this interface area, which may leave voids that can create discharge activity. Diffusion will eventually cause the oil/grease to migrate but if voids do then form they will not necessarily cause discharges as this will depend on void size, location etc.

(ii) Installation aspects initiating partial discharges; The following possible causes are essentially due to improper workmanship and not the cable system itself. They could therefore appear equally well under the following section entitled, "Influencing Factors – External".

(a) Incorrect removal of the cable insulation semi-conductive screen

Incorrect tooling or technique can cause an excessively rough surface on the cable insulation. This may be smoothed using emery paper, however excessive sanding can lead to the insulation diameter being under-size. This diameter is critical to the successful performance of the stress relief.

Some cutting tools initially lift the insulation screen material away from the insulation before it is cut. This has an adverse effect at the final edge of the insulation screen creating a void under the screen material. This edge is typically the point of highest electric field stress within the joint. Refer Appendix Figure 3

(b) Incorrect crimp and/or compression, resulting in a high resistance joint

Causes excessive heating which will char the internals of the joint and thus deteriorate the insulation to a stage where partial discharges will occur as result of the carbonization and change the stress patterns of the joint.

(c) Insufficient electrical bonding between the conductor and the heat/corona shield employed around the in-line crimp (typically on pre-moulded sleeve designs)

The shield has a dual purpose, to conduct heat away from the in-line crimp and to smooth the electric field stress lines around the in-line crimp. It is essential that this shield be directly bonded to the HV conductor and not left 'floating'. High levels of partial discharge will result in the burning of the cable accessory insulation near the in-line crimp, leading to insulation failure.

(d) Incorrect smoothing of the in-line crimp connector on joints without heat/corona shield

Crimping leaves sharp edges around the in-line connector. Normally this does not matter because of the presence of a suitable shield. Otherwise these must be filed to remove all sharp protrusions. High levels of partial discharge would result in the burning of the cable insulation near the in-line crimp and insulation failure.

(e) *Incorrect placement of the pre-moulded sleeve on the cable*

The internal make-up of a pre-moulded sleeve consists of correctly positioned and proportioned insulating and semi-conductive materials, refer Appendix Figure 4. It is essential that these are positioned correctly with respect to the in-line connector and the cable insulation semi-conductive screen. Incorrect placement will cause severe discharge activity, leading to insulation failure.

Influencing Factors – External

(i) It is commonly accepted that the integrity of the cable insulation is sound as long as the sheath and over-sheath are still intact after laying. The ingress of moisture through degraded seals, a break in the sheath and outer sheath or permeation through the outer protective sheath, results in a lowering of the discharge inception voltage level within the insulation and in extreme cases moisture deposits may induce an insulation surface flashover or tracking.

(ii) Exposure to higher than designed ambient thermal conditions due to poor thermal resistivity of the back-fill material or poor back-filling techniques leads to excessive temperatures experienced at the insulation interface during service thermal cycling.

(iii) Excessive movement, bending or jarring of the joint or termination leads to the weakening of the interfacial tension.

6.2.3 <u>Diagnostics for this Failure Mode</u>

Diagnostics Most Sensitive to Failure Mode

Within a power cable system, the in-line joint is fully surrounded by a mechanical protection membrane. The stress relief material, either extrusion moulded, pre-moulded or manually taped, fully encapsulates the area that is affected by electrical aging. To visually inspect this area constitutes the physical destruction of the joint.
The detection of partial discharge (PD) activity within the joint or termination is the most sensitive method of determining premature aging, by recording discharge magnitude, phase, inception voltage, etc. Although some faults are easily diagnosed, typically more knowledge is needed to assess the condition of an accessory than just by the interpretation of the partial discharge activity.

(i) Partial Discharge Detection (Individual Joints)

Ultrasonic detectors, which may be hand held, with an insulated extension probe, can be effective in detecting partial discharges within a HV cable joint or termination, depending on the specifics of the situation.

In another approach, special electrical sensors can be permanently incorporated in each joint and/or termination during installation. The leads coming from these sensors can be brought to the detection equipment via electro-optical converters. Some sensors are specifically manufactured for use on individual cables to enable maximum signal transfer from the accessory to the detector. The sensors operate in the MHz frequency range giving high attenuation to external, lower frequency, electrical noise. The correct sensor can give measurements of both discharge magnitude and position to within a few millimetres.

On long cable routes, many joints are installed and each joint can be fitted with sensors allowing simultaneous PD measurement of all the accessories of each phase of the circuit during commission testing. The cost of such detection equipment makes it economically viable only for EHV or otherwise very important power cable systems.

(ii) Partial Discharge Detection (Entire Circuit)

With a suitable AC voltage source connected to one end of the cable, PD activity within cables and accessories can be detected by several sensing systems. A discharge pulse acts as a travelling wave in the cable and by making use of the time of flight principle, the location of the source of the discharge can be calculated, knowing the speed of propagation in the cable. This technique of relating the discharge site to its position along the length of the cable is often termed 'discharge mapping.' Refer to Appendix 3, Figure 5.

Less Sensitive Diagnostics to Failure Mode

(i) Optic Fibres - Thermal Mapping

The use of optic fibres for condition monitoring continues to grow. Distributed temperature measurements along the entire cable length coupled with a comprehensive analysis package allows detailed thermal mapping of the cable and joints. Thermal mapping can be successful if the nature of the fault results in a temperature rise and if this can be distinguished from normal loading efforts.

Investigations show that optic fibres are useful in monitoring many physical elements of a power cable's environment. Elements include mechanical movement, vibration and even water ingress. These elements will not directly detect aging of the insulation but can be useful in determining when abnormal events have occurred within close proximity to the cable which may have adverse effects on the insulation integrity of the system.

6.3 Dominant Failure Modes Nos. 2 & 3

Damage to the outer sheath, resulting in water ingress or mechanical damage to the insulating material. (These physical failure modes are included for completeness due to their prevalance)

6.3.1 Principal Forensic Evidence

The evidence of failure in Modes 2 & 3 is similar to that discussed in Section 6.2.1 for Failure Mode 1. However in these cases there is also likely to be external physical evidence of the nature and cause of mechanical impact either on the cable itself or through the surrounding soil or other medium.

6.3.2 Ageing Processes and Influencing Factors

The ageing processes are varied and entirely dependent on the nature and extent of the impact. The ingress of moisture through a break in the sheath will result in a lowering of the partial discharge inception voltage level within the insulation and in extreme cases moisture deposits may induce tracking leading to an insulation flashover.

6.3.3 Diagnostics for these Failure Modes

Joints or other impact sensitive areas may be physically inspected on routine visits. Otherwise Partial Discharge Detection or Thermal Mapping as per 6.2.3 may be utilized.

6.4 Preventative Maintenance Strategy - Summary

In improving the reliability of ageing insulation systems of the type described it is important to establish a preventative maintenance strategy which utilizes the following;

(i) Before failure, determine relevance of the key factors which influence insulation degradation in the dominant failure modes described. It is to be noted that a large proportion of these are related in improper joining or installation practices. This approach contributes to improved specification, design and maintenance practices.

(ii) After any failure, identify the dominant failure mode from the forensic evidence of failed or near failed specimens. The path then is to determine from the listed influencing factors, the principal cause of insulation degradation and take measures, including an appropriate diagnostic choice, to avoid recurrence.

(iii) Where insulation failures in high voltage cable joints have occurred and influencing factors established, endeavour to determine the most likely fault propagation time, eg, by trend analysis. This will enable an informed choice between periodic diagnostic testing, continuous monitoring or equipment change-out.

APPENDIX 3

Photographs of some aspects of failure Mode 1 (interfacial pressure problems) in XLPE cable joints & terminations and illustration of the 'discharge mapping 'technique

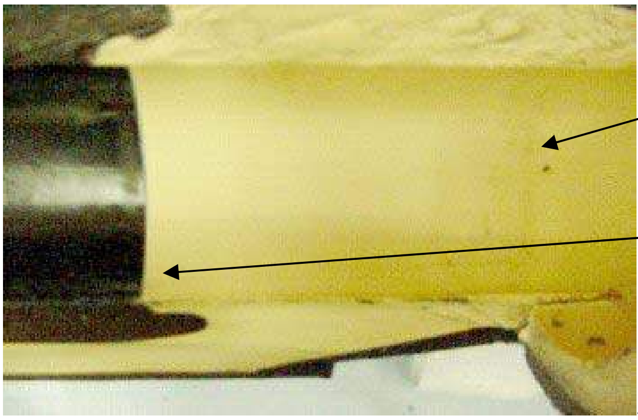


Figure 1 : PD tracks on interfacial material

Tracks as a result of insufficient interfacial pressure between the pre-moulded sleeve and the surface of the cable insulation.

The failure initiated at the edge of the HV corona shield and progressed toward the earthed electrode : Refer to Figure 2

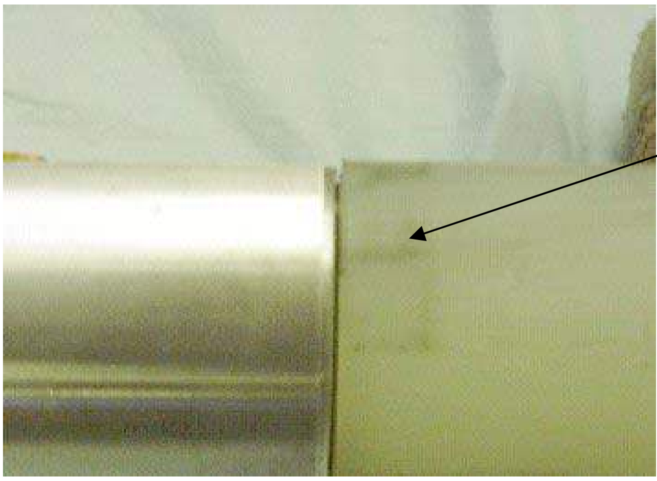


Figure 2 : PD tracks from HV corona shield

This photo shows the point at which PD commenced. Corresponding marks as those shown in Figure 1 were found on the cable insulation

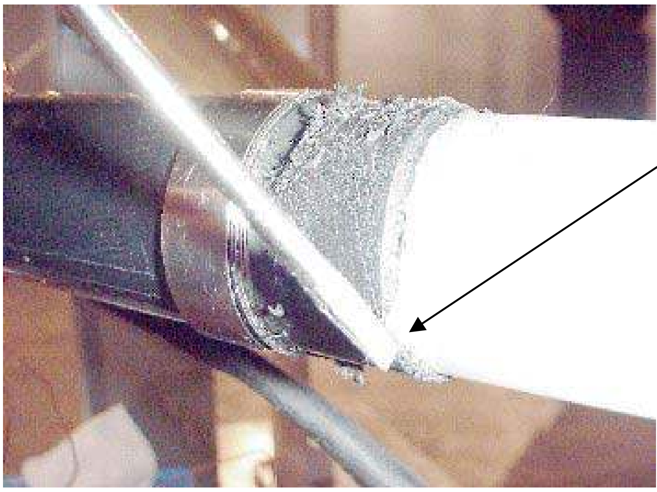


Figure 3 : Delamination of Insulation screen material

Due to incorrect removal methods, the insulation screen has become delaminated from the cable insulation material.

Air voids subsequently formed under the insulation screen causing destructive PD.

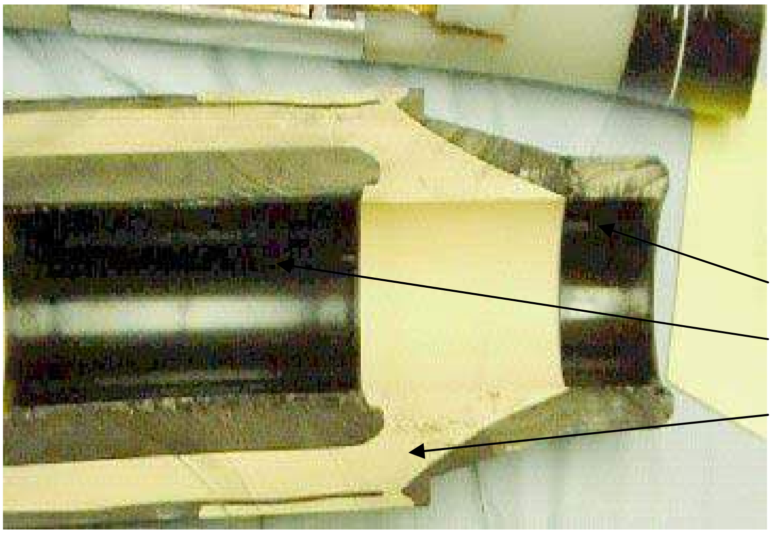


Figure 4 : Internals of pre-moulded sleeve

The positioning of the sleeve onto the cable is critical to ensure the semi-conductive sections make adequate contact with the cable material for the same potential.

Earth potential semi-conductive material

HV potential semi-conductive material

Insulating Material

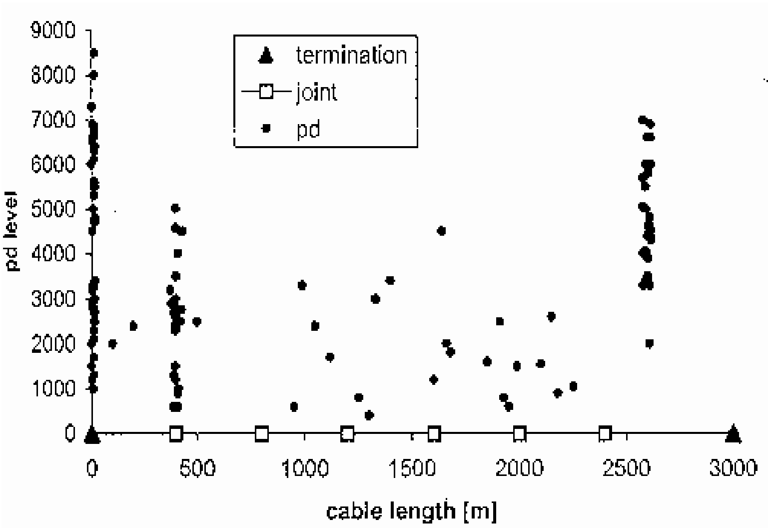


Figure 5 : 'Discharge mapping.' A PD map of a 3km cable system

Entire cable systems can be mapped for PD activity.

The correct interpretation is necessary to ensure the appropriate corrective action is taken.

7. FAILURE OF TRANSFORMER PRESSBOARD INSULATION

7.1 Preamble

Large power transformers have a range of different insulation materials within their structure, with paper, oil and pressboard the main components. All of these are subject to various operating conditions and influences which can degrade the dielectric performance of the materials and lead to premature failure of the transformer. Factors accelerating the ageing of the insulation system are varied and may be internally or externally derived. The paper, oil and pressboard have different degradation processes and may not age uniformly. There is thus a range of diagnostic techniques used for monitoring transformer condition.

One of the less well understood causes of transformer insulation failure is tracking of pressboard insulation in the transformer structure. As detailed below, this can result from a number of causes, including moisture, particulate matter deposited on the surface, high temperatures and high stress levels. Another potential cause of deterioration and perhaps failure is the formation of gas bubbles produced by short duration overloads, causing sudden temperature rises to 140 C or higher. The effects of such high temperatures depends on the moisture level present.

The following deductions are mainly laboratory-based. This is due to the sparsity of forensic examples and reports. However they have been performed with configurations which are of specific practical relevance and thus the results are indicative of the ageing and deterioration that occur in practice.

7.2 Dominant Failure Mode

Tracking of pressboard material

7.2.1 Principal Forensic Evidence – (i) late, (ii) advanced, (iii) early stages

(i) Burnt insulation, arcing damage, accompanied to varying degrees with damage as per (ii) below.

(ii) Substantial charring and carbonization of the surface and even holes, not always on surfaces in contact with high voltage but often in areas surrounded only by dielectric material. This stage is often accompanied by gas generation which in some cases is trapped and thus causes a bubbling effect in the pressboard.

(iii) In the early stages there may be little evidence of the tracking. It is in the well developed phase that visible surface signs become apparent. The required moisture content needed to initiate visible tracking may take some time to appear (aided by paper deterioration). In the case of rapid temperature escalation, the first signs may be gas bubble formation.

7.2.2 Ageing Processes and Influencing Factors

Ageing Processes and Time Frames:

The ageing process accelerators are excess moisture, high temperature, particulate matter, increased stress and trapped gas. These may be associated with poor oil processing, broken shield connections and possibly even design features producing localized overstress under some conditions.

The ageing process producing tracking arise from the interaction of partial discharges with the dielectric material resulting in its carbonization. The initial cause is generally moisture content in the pressboard, reducing the dielectric strength under tangential stress. The discharge activity is enhanced by temperature. This may be a major problem with old transformers subject to overloading and thus high temperature of the pressboard. Where tracking occurs in dielectric bound areas such as between pressboard layers, the partial discharges will generate gases and the gases may then become trapped in cavities, leading to cavity discharges in addition. This will have the effect of accelerating the deterioration.

The time frame of degradation is varied because of the different causes and configurations. However high temperatures (up to 180 C) are a major accelerating factor. Such faults may be difficult to detect even in the well-developed phase.

Influencing Factors – Internal

(i) Incomplete dryout of the pressboard at some stage in the transformer's service life.

(ii) Moist or aerated oil due to improper filling or maintenance

(iii) Particle contamination on surfaces due to advanced oil oxidation

(iv) High electrical stresses due to design or broken shield connections

Influencing Factors – External

(i) High temperature due to sudden or sustained overload, promoting deterioration of paper, moisture and gas bubble generation thus increasing the partial discharge rate and magnitude.

(ii) Impulse voltage activity. With substantial particulate matter on pressboard sheets, power frequency performance may be inferior to that under lightning or switching surges.

(iii) Moisture ingress into the oil during operation (poor sealing or breathing arrangements)

(iv) Movements due to short circuits affecting the electric stress distribution and leading to local displacement problems that may initiate or enhance tracking.

7.2.3 Diagnostics for this Failure Mode

Diagnostics Most Sensitive to Failure Mode

(i) Dissolved gas analysis will provide a reasonably good diagnostic for tracking, although if the tracking is in buried sections, with no gas outlet, the DGA may be less sensitive initially.

(ii) Partial discharge measurements (both electrical and acoustic) are technically able to detect tracking discharges and even identify the presence of tracking from the electrical patterns obtained. However, in many cases, the tracking may be isolated from the windings in such a way that electrical PD detection will be less sensitive. This is where acoustic detection is valuable.

(iii) Dielectric response measurement may be useful in detecting moisture, which is a predominant factor in tracking. However, whether the sensitivity is good enough for absolute measurements of moisture levels will depend on the case and technique in question.

Less Sensitive Diagnostics to Failure Mode

(i) Dielectric dissipation factor is of questionable value, as for isolated locations with tracking the effect on DDF will be difficult to measure.

(ii) Insulation resistance, polarization index and overvoltage tests will be similarly less able to detect such conditions.

(iii) A general analysis of the oil characteristics may also be helpful.

7.3 Preventative Maintenance Strategy

This last case study deals with an important insulation component rather than the insulation system of the equipment as a whole. However the key steps in establishing a preventative maintenance strategy are similar to those for the more complete insulation systems considered previously.

(i) Before failure, determine the relevance of the key factors which influence insulation degradation in the failure mode described. Eight factors, both internal and external have been listed. This approach contributes to improved specification, design and maintenance practices.

(ii) After any failure, confirm that this dominant failure mode of pressboard is evident from forensic examination of failed or near failures specimens. The path is then to determine from the listed influencing factors, the principal cause or causes of the insulation degradation and take measures, including a choice of the diagnostics listed, to avoid recurrence.

(iii) When insulation failures of transformer pressboard have occurred and the influencing factors established, determine the most likely fault propogation time. This will enable an informed choice between periodic diagnostic testing, continuous monitoring or equipment changeout.

APPENDIX 4

Photograph of 275kV transformer interphase pressboard insulation subjected to advanced tracking over a large area of approximately 1m^2. White areas are holes though board. Supplementary photo is a closer view of a tracking path.