UNIVERSITY OF KWA-ZULU NATAL

RELIABILITY ANALYSIS OF POWER TRANSFORMERS

(Case: Eskom Distribution Eastern Region,
1MVA to 80MVA power transformers)

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Reliability Analysis of Power Transformers
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by

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Abstract

This dissertation analyses the reliability of power transformers and its impact of failure on system performance. Eskom Distribution, Eastern Region, is used as a practical case study, which has an installed transformer base of 6066MVA comprising of 428 transformers ranging from 1MVA to 80MVA with voltage levels of 6.6kV to 132kV.

The literature review illustrates the theory and principles of transformers, evolution and changes in design criteria, the function of cellulose and insulating oil, failure modes, operations and maintenance practices and factors affecting the distribution systems performance. This study included a conditional assessment and an oil analysis review of transformers at Eskom. A method to trend multiple oil samples was developed and illustrated.

The research further investigates the reliability of series and parallel systems using actual component reliability values. A study was conducted to establish the degree of network firmness. Transformer failure data was analysed and were shown to be characteristic of a bathtub curve. Defects from on site inspections were analysed and identified oil leaks as a maintenance focus area. The Distribution Supply Loss Index was determined to be the major impact Key Performance Index due to transformer failures. Transformer failures using statistical methods, showed HV/LV winding to be the main component to fail. The cost of a transformer failure to Eskom and the customer was determined.

International Benchmarking was investigated to establish the criteria for network reliability indices and to compare the network infrastructure and performance of international utilities and Eskom. The later part of the study involved the analysis of a risk ranking methodology to establish a risk ranking matrix. The transformers were ranked according to the matrix, identifying the high risk focus areas. Projects were raised within Eskom to replace the identified high risk transformers.

This study has concluded that the reliability of transformers is impacted by the changes in transformer design, increased maintenance defects and inadequate transformer protection at substations. The reduced oil volume per kVA, increased hot spot and ambient temperature, and compact tank designs have resulted in the cellulose being overheated and fault gases being produced during normal operating conditions. The increase in load demand from the existing transformer fleet and a reduction in capital expenditure to maintain and build additional substations have also contributed to accelerated aging, since the transformers are forced to operate at 100 percent loading. There is an increase in transformer maintenance defects due to insufficient operational staff, high staff turnover, reduced skills transfer, and insufficient network contingencies to allow for planned outages to clear the defects identified. The failure analysis showed that the main component to fail is HV/LV windings. The winding failures were traced to there being no or inadequate transformer protection at ~20% of substations.

Declaration

The work submitted in this dissertation is the result of my own investigation, except where otherwise stated.

It has not already been accepted for any degree, and is also not being concurrently submitted for any other degree.

Signed: ______________________________

Name: ______________________________

Date: ______________________________

Table of Contents

List of Figures

List of Tables

List of Acronyms and Abbreviations

BIL	Basic Insulation Level
DGA	Dissolved Gas Analysis
DP	Degree of Polymerisation
MVA	Mega Volt Ampere
DC	Direct Current
TPI	Transformer Priority Index
KPI	Key Performance Indicator
WCF	Weighted Condition Factor
IFT	Interfacial Tension
kVA	kilo Volt Ampere
kWh	kilo Watt hour
TDCG	Total Dissolved Combustible Gases
MTTF	Mean Time to Failure
MTBF	Mean Time between Failures
OLTC	On load Tapchanger
ppm	parts per million

Chapter 1: Introduction

1.1. Background

There has been an increasing need for power transformers to be reliable in the competitive market. Specialized and highly volatile process in the textile, mining, semiconductor, electronics, and business sectors have demanded a reliable electrical supply be available 24 hours a day, with minimum number of planned outages.

Power transformers play a vital role in power distribution systems by facilitating the transfer of power to end users. It consists of three major components:

- An active part consisting of a magnetically permeable core and a set of windings (insulated low resistance conductors wound around the core);
- An insulation and cooling system - insulation paper and mineral oil surrounding the active part;
- A transformer tank, connection terminals and accessories.

In the recent years, the transformers components have failed catastrophically [1] [2] resulting in an interruption of supply and extended outages, customer dissatisfaction and loss of revenue.

There is a worldwide trend involving major losses of power transformers on a frequent basis. These failures are as a result of an increase in the utilization of equipment, the deferment of capital expenditure and a slow down on maintenance spending. Globally, there is an increase in power consumption and this is putting a strain on the existing transformer fleet and hence causing them to age rapidly.

In the context of South Africa, the causes of transformer failures are not well researched.

Case: There is an urgent need to identify high risk transformers, determine the dominant cause of failure, establish the reason for the dominant cause of failure, estimate the future failure rate and create an action plan to address the high risk transformers.

1.2. Current state of the industries power transformers

Countries are installing new transformers for capacity increases, but the older transformers are forced to cope with the pressures imposed on them. Several countries have undertaken surveys to quantify the age and state of their power transformers. During 1997 and 2001 the United States experienced 94 failures resulting in claims costing $286,628,811 [3]. The most dominant cause of failure in their case has been insulation failure. Nine of these 94 failures are for transformers aged 0 to five years and sixteen are for transformers greater than 25 years old.

A study done in 1995 [4] showed that the average age of transformers rated 66kV, 10MVA and over in Australia and New Zealand is 28.6 years, with a large number of transformers been over the 40 year mark. Doctor Tapan's [5] study indicates that the 30 percent of the 132kV grid transformers in the United Kingdom were over 40 years old and almost 80 percent of the power transformers were over 20 years old. This study involved analysing the accelerated ageing of oil and paper samples.

The evaluation of the phenomena of transformer failure has largely been attributed to insulation breakdown. Research has been carried out by Y. Tachibana et al [6], showing the merits of using diagnostic methods to determine the condition of the insulating medium within the transformer and hence prevent failures and identify high risk transformers.

1.3. Reliability

In the context of a transformer, reliability is defined as the probability that the transformer will perform in a satisfactory manner for a given period when used under specific operating conditions [7]. The concept of reliability has elements such as probability, satisfactory performance, time cycle, and operating condition.

Probability is a quantitative term representing the number of times that an event can occur during a specified time. Transformer failures will occur at different points of time, thus these failures are described in terms of probability. The reliability of transformers is hence directly dependent on the probability of failure [7]. The satisfactory performance of transformers is established by what is considered satisfactory. This is dictated by the needs of the customer.

The aspect of Time represents a measure against which the degree of a system's performance can be related. Time is critical in reliability measurements because it expressed in terms of 'Mean Time Between Failure' (MTBF) or 'Mean Time To Failure' (MTTF). This provides the ability to predict the probability of the transformer surviving without failure for a designated time [7].

The operating condition under which a transformer is expected to function is another dimension of determining reliability. These conditions comprise of elements such as geographical layout, anticipated operational time, operational profile, impact of temperature cycling, vibration, shock, etc. These factors are applicable under operating mode, storage mode, and during transport to site. The reliability of a transformer can be drastically reduced during transportation, handling and storage as compared to actual operation in a system.

The above elements are critical in determining the reliability of a transformer. The reliability of a transformer is thus an inherent characteristic of design and hence the desired reliability should be addressed by defining the transformers operational requirements.

1.3.1. System evaluation

The evaluation of a system to determine its reliability is based on reliability concepts and measures. The concepts are failure rate, probability function, reliability models, mean time between maintenance (MTBM) , availability, system effectiveness and life cycle cost.[7] [8]

a).Reliability Function:

. The reliability function R(t) is defined as:

$$R(t) = 1 - F(t) \qquad \text{Eq 1-1}$$

F(t) is the probability that the system will fail by time t

b) Failure Rate:
The failure rate is the rate of failures within a specified time interval. The failure rate per hour is expressed as

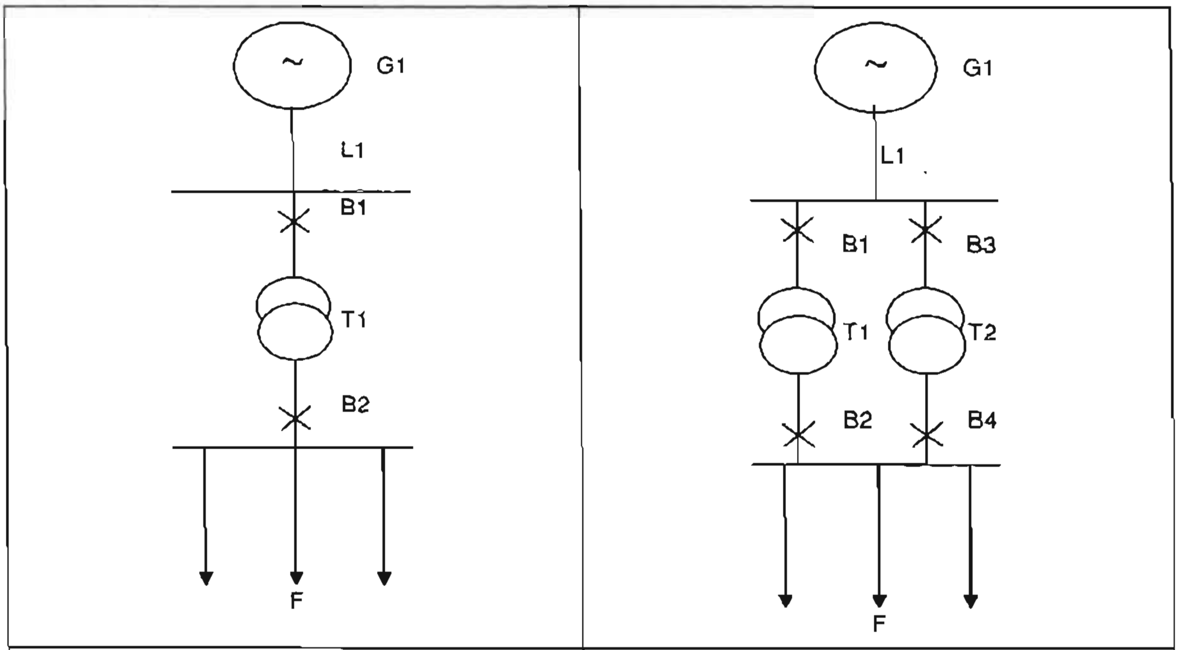
$$\lambda = \text{Number of failures / Total operating hours} \qquad \text{Eq 1-2}$$

c). Mean time between failures:
The MTBF is expressed as

$$MTBF = \frac{1}{\lambda} \text{ hours} \qquad \text{Eq 1-3}$$

1.4. Utility systems

The role of the transformer is to facilitate the transfer of power to the end user. This role is vital in the sense that, a failure of the transformer in a radial system would result in the failure of the system. In a parallel system, redundancy is provided by a second transformer. This is however, not always the case as capital requirements do not always make this possible. Therefore majority of systems have single transformer arrangements incorporated into their substation design and the reliability of the transformer and all its components will ultimately dictate the reliability of the radial system.



(a) Radial System (T1) | (b) Parallel System (T1&T2)

G1= Generation Source; L1= Transmission Line; B1=B2=B3=B4= Breaker
T1=T2= Power Transformer; F= Distribution Feeders

Figure 1-1: Power distribution system

The overall reliability of the radial system is dependent on reliability of each component. Figure 1-1 has parallel transformers T1 and T2. The reliability of the overall system is increased because of the parallel transformers.

1.4.1. Radial systems

A radial system requires that all components operate in a satisfactory manner for proper performance. A radial system with two components is shown in Figure 1-2 [9]. The system will function only if A and B are in operation. The reliability of the system is expressed as

$$R_{system} = (R_A)(R_B) \qquad \text{Eq 1-4}$$

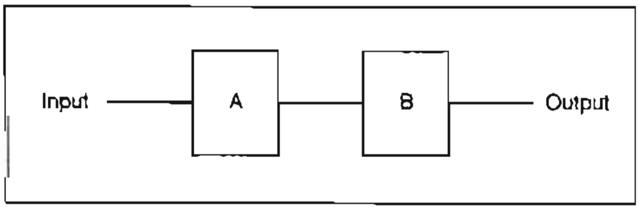


Figure 1-2: Radial system model

If the reliability of A = 0.99 and B=0.99 then using Eq 1-4

$$\begin{aligned} R_{system} &= (R_A)(R_B) \\ &= (0.99)(0.99) \\ &= 0.9801 \end{aligned}$$

This shows that in a radial system, the reliability of the system is lower than the lowest components reliability.

1.4.2. Parallel systems

A parallel system has several of the same components in parallel and all components must fail to cause total system failure. A parallel system with two components is shown in Figure 1-3 [9]. The system will function if either A or B, or both are in operation. The reliability of the system is expressed as:

$$R_{system} = R_A + R_B - (R_A)(R_B) \qquad \text{Eq 1-5}$$

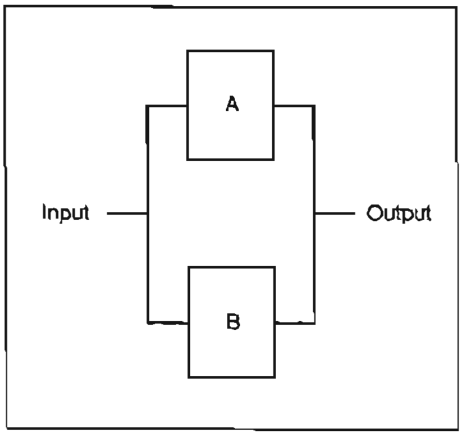


Figure 1-3: Parallel system model

If the reliability of A = 0.99 and B=0.99 then using Eq 1-5,

$$\begin{aligned} R_{system} &= R_A + R_B - (R_A)(R_B) \\ &=(0.99) + (0.99) - (0.99)(0.99) \\ &= 0.9999 \end{aligned}$$

This shows that the overall system reliability increases with identical components in parallel.

1.5. Research problem

Distribution systems are experiencing numerous transformer failures. The failure is in most cases, due to the failure of a specific component within the transformer and not necessarily "old age". The failures that occur are random and unpredictable.

Hypothesis:
Analyzing the existing state of the power transformers and the determination of the dominant cause of failure will help identify the high risk focus areas allowing a plan of action to reduce these risks, hence minimizing future transformer failures.

1.6. Rationale for the dissertation

There are no generally accepted and published documents regarding generally accepted rules to analyse reliability of power transformers and the application on typical utility systems. Some research done to date shows that reliability studies are done on a per system bases [10] based on specific utility configurations.

1.7. Research methodology

- Collect and verify data on power transformer failures over the period 1999 to 2006.
- Analyze the failure modes of previous failures over the eight year period and identify the most dominant cause of failure.
- Present the data in the form of: Failure by Voltage Ratio, Make, Age, MVA and Manufacturer.
- Quantify the cost of transformer failures to the business.
- Calculate the failure rate of power transformers
- Perform Dissolved Gases-in-oil Analysis (DGA) on the power transformer fleet. Eskom TSI Laboratory. Cost (R120 000)
- Perform Degree of Polymerization (DP) tests on a sample size (Age/MVA) to determine the condition of the paper insulation. Tests to be done at Eskom TSI Laboratory. (Cost: R100 000)
    - The results of the DGA and DP tests will assist in identifying the high risk transformers.
- Identify the High Risk Transformers
- Plan of action, to rectify/overcome the future occurrence of failure
- Present recommendations for future work

1.8. Research objective

1. Determine the reliability and impact of transformer failures within the distribution system.
2. Demonstrate this for the Eskom Eastern Region transformers.
3. Establish a risk ranking matrix for transformers within the system.
4. Recommendations for improvements in operations and maintenance practices and transformer procurement specifications.

1.9. Summary description of the dissertation

Chapter 1: Introduction

1.1. Proposal, motivation, the value of the objectives
1.2. Utility systems
1.3. Reliability concepts
1.4. Objective of the dissertation

Chapter 2: Transformer design, reliability and failure mode analysis

2.1. Basic principles of transformer operations
2.2. Major transformer components
2.3. Evaluation of modern and older transformer designs
2.4. Design criteria of old and new transformers
2.5. Cellulose products used in power transformers
2.6. Mineral oil used in power transformers
2.7. Transformer faults and failures
2.8. Power transformer failure modes
2.9. Eskom's operations and maintenance practices
2.10. Eskom's transformer protection philosophy
2.11. Reliability of transformers

Chapter 3: Condition assessment of transformers

3.1. Generics of transformer
3.2. Maintenance methodology
3.3. Site inspections
3.4. Oil analysis
3.5. Dissolved gas in oil analysis
3.6. Electrical testing
3.7. Eastern region transformer condition analysis
3.8. Case study – Failed 20MVA transformer analysis

Chapter 4: Reliability analysis of power transformers

4.1. Reliability of a simple network
4.2. Network sensitivity
4.3. Reliability of transformer and its components
4.4. System to mitigate un-reliability
4.5. Design reliability
4.6. The impact of reliability on system performance
4.7. Transformer failure analysis
4.8. The cost of a transformer failure

Chapter 5: Transformer risk ranking and associated KPI's

5.1. Transformer risk ranking matrix
5.2. International KPI benchmarking
5.3. Causes and mitigation of poor reliability

Chapter 6: Conclusion and Recommendations

2.0. Chapter overview

The power transformer's in Eskom's power system is one of the most critical components. It is the single largest substation asset and almost 60 percent of the substation costs are attributed to the transformer. The current trend towards providing the customer with a reliable electrical supply has forced Eskom to drastically improve system performance and the reliability of the electricity supply [11].

Power transformers are technically complex and with its high capital values, Eskom expects the transformers to have a long life expectancy and be both financially and economically viable. The decision to replace an aging fleet of transformers requires unique decision making abilities. The cost associated with premature or unexpected failures can be several times the price of a new transformer, due to the damage of surrounding equipment and the potential losses incurred by the customer from production losses.

The frequency and severity of transformer failures are of concern. Both old and new transformers have failed. Studies have been conducted [12] on transformer fleets globally showing the cause and impact of failure. However, there is no available data on the state of Eskom Distribution's transformers, its reliability and impact to system performance after a failure occurs.

Thus an understanding of several key areas of transformer designs, operation, maintenance, reliability, testing, and evaluation is necessary. This will aid in assessing condition of all power transformers at Eskom

2.1. Basic principles of transformer operations

The power transformer is an alternating current (ac) machine that has two windings, linked via a magnetic iron core. When an ac voltage is applied to the primary winding, a magnetic field is produced. This field induces and e.m.f. in the secondary winding. The purpose of a transformer is to convert ac voltage from one level to another.

The magnitude of the input voltage V_2 is usually different from the output voltage V_2. If $V_2>V_1$ the transformer is a step up transformer. If $V_2<V_1$ it is a step down transformer. The most basic elements of the transformer are the primary and secondary side winding and the magnetic core.

These three basic elements allows for the oscillation of the magnetic field. The core is made of several layers of high grade laminated silicon sheet steel coated with insulating material, which is approximately 0.3 mm in thickness. The purpose of creating laminated sheets is to reduce eddy currents in the core material. The insulation of the sheet steel reduces heating losses and does not allow for magnetic losses. The primary and secondary coils are made of copper which has extremely high conductivity and very low resistance.

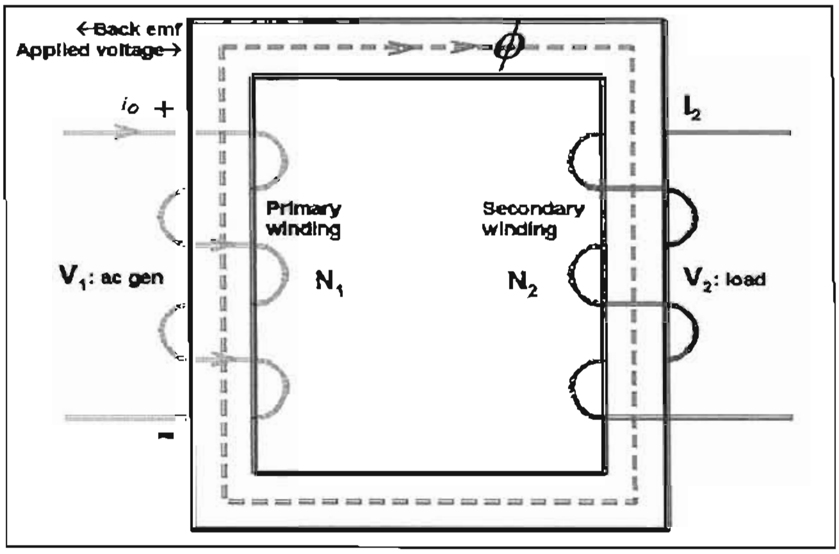


Figure 2-1: Simple transformer with no-load on secondary

The block diagram of Figure 2-2 illustrates the basic principle of operation. The applied voltage causes a magnetization current to flow, the magnetization current sets up a flux in the core; the core flux induces a back e.m.f. which balances the applied e.m.f.

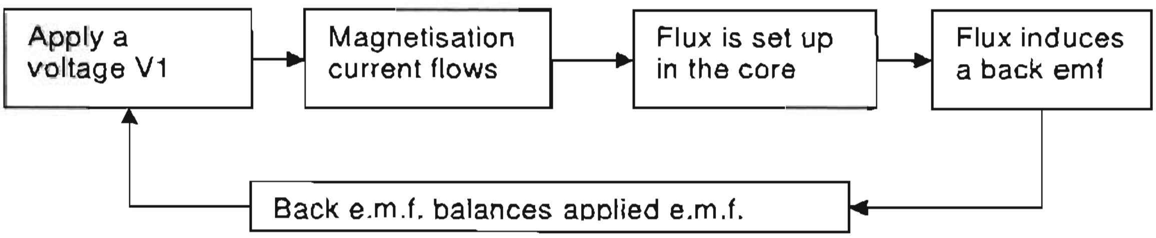


Figure 2-2: Basic principle of transformer operation

2.2. Major transformer components

[13]

a) Transformer main tank:

The main tank houses the iron core, windings and oil. The tank serves to protect the inner components and provides a means to dissipate the heat generated by the core and windings to the atmosphere.

b) Primary and secondary Bushings:

The bushings allow for the jumpers to enter the main tank and reduce the extremely high stress fields that are created at the point of entry into the main tank. The bushings outer shell is made of porcelain. The inner part of the bushing is could be made of paper foil wrappings, oil impregnated paper, epoxy and fibre glass.

c) Cooling medium:

The cooling medium used is oil. The type of cooling could be natural, with radiator fins, or forced cooled with cooling fans placed on the radiator. The placement of fans allows for increased MVA output for ONAN transformers.

d) Additional components:

The transformer also consists of pressboard, other solid insulating material, the tapchanger, surge arrestors, primary and secondary side breakers, protection equipment, and devices such as pressure relief valves, buchholtz, internal current transformers, conservator tank, explosion vents, oil sampling points, etc.

2.2.1. Core materials

a) Magnetic materials

From the inception of transformer designs, laminated iron cores we used instead of air. From the 1890 to current years, technology made it possible to improve the quality of the core's steel, core design and the methods used to manufacture the cores. The initial designs used soft iron [14] as the material for the core. In the later years the discovery of silicon alloyed with low carbon content, further reduced the hysteresis losses. This set the trend for the future, hence the use of crystal orientated iron silicon alloys are used as the core material in transformers

In the 1935 the process of hot rolling of the iron-silicon alloys changed to cold rolling making the total core losses lower. This cold rolling process allows for the creating of grain orientated silicon steel.

b) Core insulating materials

Varnish [15] was used initially as a core insulating material in the early years of transformer design to create a high resistance path to the eddy currents. This evolved to the use of phosphate or organic resin treatments. These materials provide superior heat resistance and prevent rusting of the steel when stored in a warehouse. Power transformer designers use magnesia to increase the surface insulation of the sheet steel.

2.2.2. Core construction

The core uses laminated grain oriented cold rolled silicon steel. The cores for power transformers are made using laminations laid flat. A mitred joint is used. This butt lap core arrangement with joints at 45^0 angles complements the cold-rolled steels magnetic direction. The air gaps between the ends of the lamination are overlapped by the next lamination layer. This method of construction results in the least amount of eddy currents. The value of the no-load excitation current is determined by the air gaps in the joints of the laminations [16].

2.2.3. Tapchanger

The tapchanger allows for a percentage change of output voltage within certain limits, maintaining a constant output voltage and power. A common practise is to house the tapchanger windings in the high voltage side of the transformer. The windings and taps are either contained with the oil volume of the main tank or in most cases it is housed separately in it own tank mounted on the side of the transformers main tank. There are two types of tapchangers, i.e. on-load tapchangers and off-load tapchangers [16].

<u>a) On-load tapchanger</u>

The tapping mechanism is housed separately and connected via barrier boards to the tapping winding. The tapchanger has main contacts that are rated to carry full load current. There is an automatic control circuit with a motor that raises and lowers the tap position depending on the dynamics of the load being supplied by the transformer.

<u>b) Off-load tapchanger</u>

The off-load tapchanger can only be operated when the transformer is not supplying any load. It does not have load make contacts. There is a manual lever on the side of the main tank with a tap position indicator. The operator will de-energise the transformer, change the tap position and lock the handle in its new position and then re-energise the transformer. This type of arrangement is used for when it is not necessary to automatically regulate the output voltage or in cases were the source substation is used as the regulation point.

2.2.4. Bushings

Bushings are one of the most vulnerable components of transformers, and many catastrophic failures have occurred over the years - the result of internal deterioration or contamination of a bushing. Figures 2-3 and 2-4 [17] illustrate the effects of voltage and temperature, respectively, on the C_1 insulation of two 115 kV bushings of the same type and vintage: one bushing is in good condition with low power factor while the other is degraded and has high power factor.

Figure 2-3 shows that the power factor for the good bushing does not change with voltage up to its rated value. The power factor of the degraded bushing increases from an above-normal value at low voltage, to appreciably higher values as the voltage is increased to the operating line-to-ground level. The curve for the degraded bushing shown in Figure 2-3 should not be interpreted to mean that all degraded bushings behave exactly the same with respect to voltage. The intent here is to show that many forms of insulation degradation are likely to produce a similar pattern of increasing power factor with voltage.

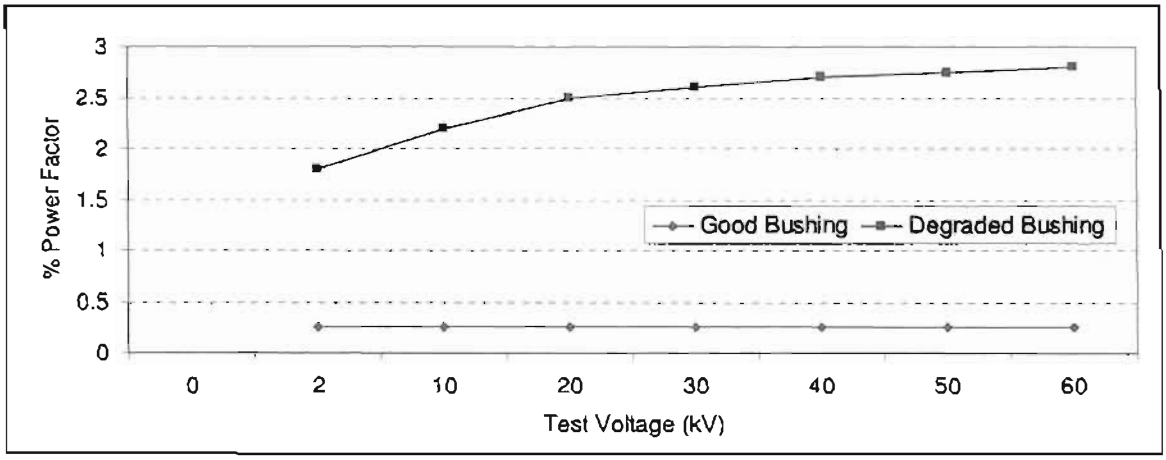


Figure 2-3: Percentage bushing power factor versus test voltage

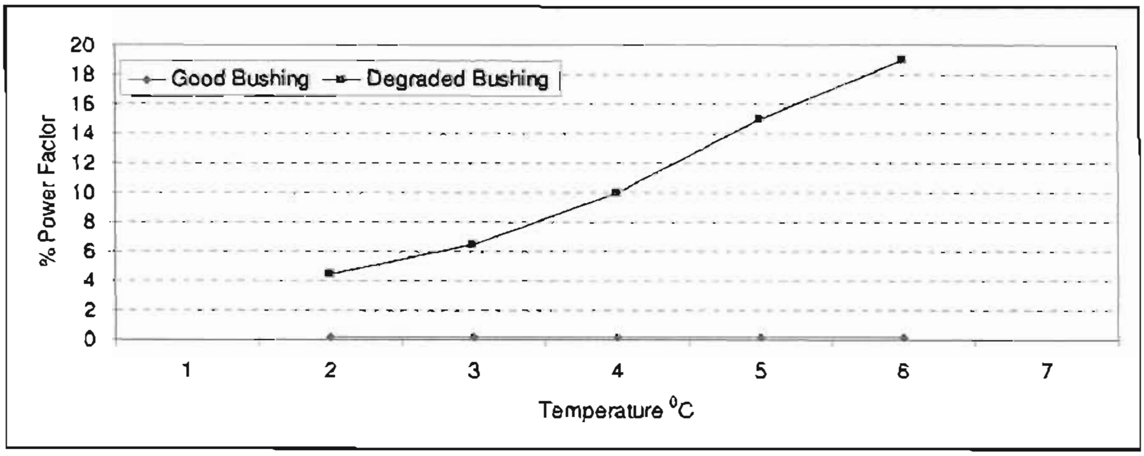


Figure 2-4: Percentage bushing power factor versus temperature

Figure 2-4 shows the behaviour of the same two bushings when they were placed in an oven. The temperature was varied and measurements were performed at low voltage. The slope of the power factor versus temperature curve of the degraded bushing was enormous compared to the good bushing. Many forms of insulation degradation appreciably increase the slope of the power factor versus temperature characteristic. Figures 2-3 and 2-4 illustrate that voltage and temperature tend to highlight insulation degradation.

2.2.5. Surge arrestors

System faults, operator switching and lightning create very fast transients or surges that approach the transformer. These transients or surges have to ability to stress the transformer insulation material due to the higher than normal voltages being applied across turn-to-turn windings, and ground. Surge Arrestors clamp these transients and surges and protects the transformer. The surge arrestor is located as close as possible to the bushing. At Eskom, the surge arrestors are mounted on brackets welded onto the main tank lid. The surge arrestors used are the metal oxide type. These surge arrestors can dissipate a surge rapidly to ground, within it's joule rating.

2.2.6. Transformer cooling

The windings and the iron core are contained within the main tank. The windings, iron core and pressboard material inside the tank is submerged in oil. One function of the oil is to absorb the heat generated by the total losses and once heated within the tank, a natural circulation is established. This ensures that the cooler oil drops to the bottom of the tanks and the hot oil rises to the top thereby dissipating the heat to the surrounding air via the tank walls and radiator. This action regulates the temperature within the transformer.

A newly modified forced oil cooling system in the market, comprises of a bypass filter (BPF). The BPF intakes hot oil from the transformer top and delivers it at the inlet of the oil-circulating pump. The BPF has been proved and justified by quantitative evaluation of the measured and theoretically predicted deteriorated (without installation of BPF) characteristics [18].

2.2.7. Alarms and indicating devices

The alarms and indicating devices on a transformer helps with online condition monitoring and alerts the operator of a malfunction or fault operation. A description and function of these devices are provided below [19].

a) Temperature indicators

The temperature of the transformer is of utmost importance. It is necessary to know the winding temperature and the top oil temperature. There are temperature limits that must be followed to obtain maximum life of the transformer and maintain minimum insulation damage. The indicators will also allow for the switching-on of cooling fans and tripping of the transformer under overload conditions

b) Breathers

A transformer 'breathes' during operation due to changes in load and the expansion and contraction of the oil and components contained in the main tank. The dryness of the oil must be maintained while breathing. This is achieved by using a holder with silica gel connected to the end of a breather pipe. The colour of the silica gel serves as an indication as to when it must be replaced.

c) Pressure relief valves

When internal arcing or faults occurs within the transformer and large amounts of gases are released in the oil within an instant in time, enormous pressures are created inside the main tank. If the pressure is not released, the seals on the transformer may be damaged and the tank may bulge, releasing large amounts of oil to the environment. The pressure relief device will rupture when the pressure exceeds between 69 to 104KPa. The device is usually located on the top side of the main tank.

d) Buchholtz

Faults occurring within the transformer create gas bubbles. These bubbles will flow upwards into the buchholtz of the transformer. The buchholtz has two setting, alarm and trip. Slow generation of gasses will result in an alarm indication being sent via the supervisory system to a system operator. The trip setting, when activated by severe internal faults will immediately send a signal to the master trip relay, isolating the transformer from the network.

2.3. Evaluation of modern and older transformer designs

Transformers have undergone many changes over the past decades. The short circuit strength has been decreased, the volts per turn have increased and an overall reduction has been made on the basic insulation level, due to lower oil volume per kVA. Older transformer designs had minimal volts per turn. There was no compromising on insulation and very high oil volumes were used per kVA. The predicted life of these transformers was as high as 400 years.

The use of modern technology has optimised the design of today's transformers. The current day transformers are optimised to contain minimal materials and space. This design approach will stress the windings, the iron core and the insulation. The predicted life of these transformers is questionable. Since the life of a transformer is ultimately determined by its insulation.

2.3.1. Increased volts per turn

The electrical stress within a transformer is directly related to the number of volts per turn. The last five decades have seen an increase in the volts per turn used. Manufactures have to increase the volts per turn because of the demand for larger transformer MVA ratings from physically smaller sized transformers. Table 2-1 [20] shows the change in volts per turn over the years.

Current extra high voltage transformers have volts per turn of 200 volts. This high inter-turn voltage has negative consequences on the windings. The stresses between turns are higher, the paper and oil insulation is stressed and any small manufacturer error may result in gasses been produced within these high stress areas.

Table 2-1: Change in volts per turns over years

Year	Volts/Turn
1915	2-4
1932	8-10
1975	19-20
Present	200 (EHV)

2.3.2. Reduced basic insulation levels

Transformers are now built with reduced insulating materials i.e. both oil and paper. This reduction is driven by financial reasons and the need to produce transformers at a cheaper rate in the competitive market place. Figure 2-5 [21] [22] illustrates how BILs changed over the years with increasing voltage levels. The advantages of lower BILs are reduced losses and greater efficiency. This reduction in BIL can be justified for use in a system if, correctly rated and placed surge arrestors, together with the protection and circuit breakers, are used to protect the transformer.

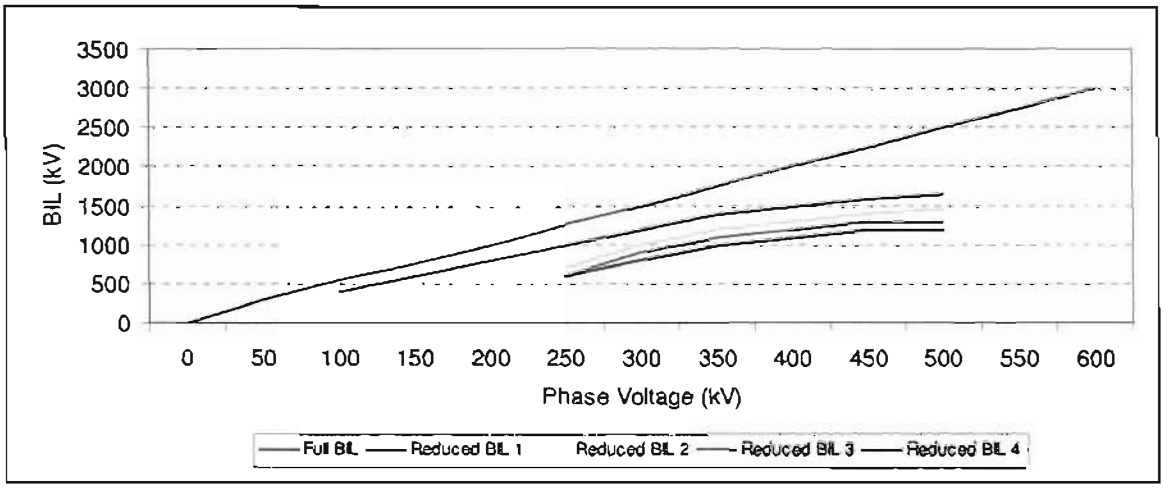


Figure 2-5: Several commonly used levels of transformer BILs versus rated voltage.

2.3.3. Reduced impedances

Another avenue that has being explored by transformer designers is the reduction of the transformers impedance. Lower impedance translates to lower losses created by the inductive resistance. This allows a smaller quantity of paper to be used in high voltage transformers. The downside to this approach is a reduced ability for the transformer to withstand higher short circuits. Figure 2-6 [23] shows the reduction in transformer impedance over the past fifty years.

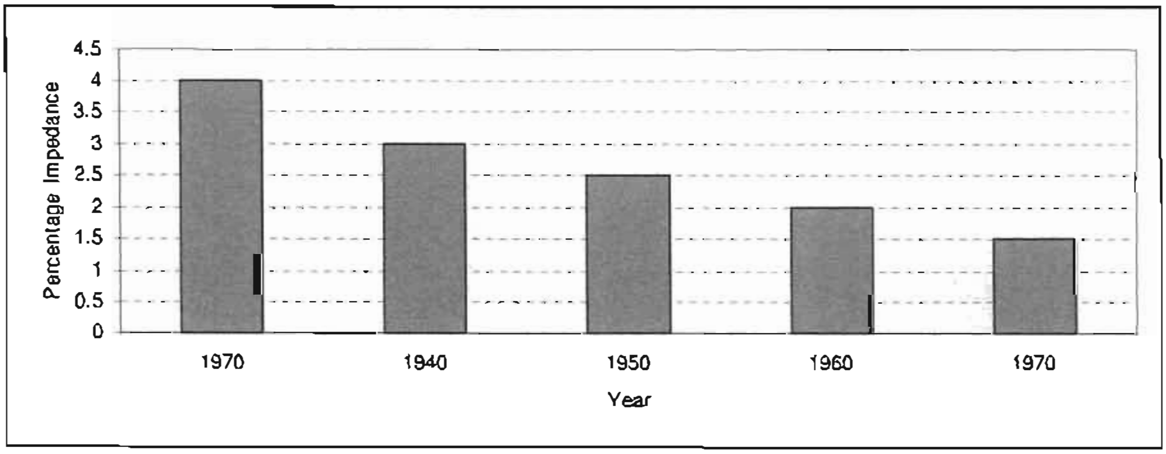


Figure 2-6: Historical comparison of distribution transformer impedance.

2.3.4. Reduction in physical size

The physical size of transformers has also been reduced [24] due to the global market place and the need to transport the transformers by ship or road. The largest physical MVA rating has increased from 100MVA, 230kV in 1950 to over 1000MVA 765kV. Manufactures achieve these very high MVA ratings by using better quality steel, by lowering the BIL and impedance, by increasing the volts per turn, using thermally upgraded paper, improving the cooling methods and substantially reducing the oil volume per kVA.

2.3.5. Reduced insulation system

The reduction in oil volume has negative effects. It has a reduced ability to remove water from the cellulose paper and has increased concentrations of contaminants. Table 2-2 below [25] shows the quantity reduction in oil volume from 1915 to current.

Table 2-2: Reducing in oil volume per kVA over years

Year	Litres Oil/kVA
1915	17.034
1930	8.517
1945	4.259
1960	2.839
1975	1.457
1977	1.211
1979	0.946
Present (EHV transformers)	0.170

2.3.6. Installed power transformer per year

The average age of substation transformers are between 20 to 40 years. The installed power transformer capacity has reduced from 185GVA in 1974 to about 50GVA in 1999. Figure 2-7 below [26] shows this twenty five year declining trend.

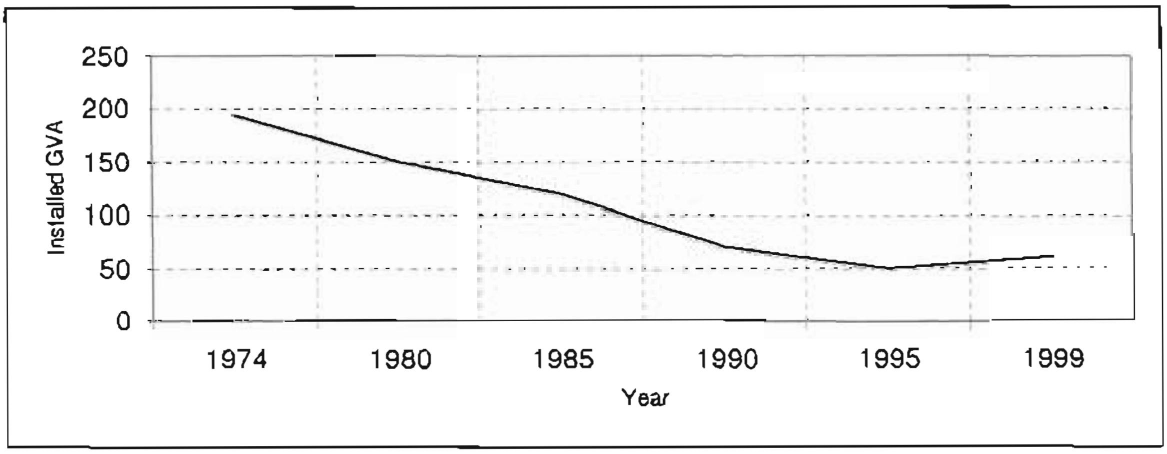


Figure 2-7: Installed power transformer capacity per year

During 1974 and 1999, the load growth was approximately 2% and transformer utilization increased by 22% as shown in Figure 2-8. A 22% load increase equates to a 37% increase in hot spot temperature. The average hot spot rise in 1974 was 50 ^{0}C. In 1999, the average hot spot rise is 73 ^{0}C. This increase reduces the insulation life by approximately eight times [26]. According to IEC 60354, hot spot rise over oil is $\propto Hg_r k^y$ where y=1.6 for O.N. and O.F. transformers. Therefore, a 22% increase in load will result in a 37% increase in hot spot temperature.

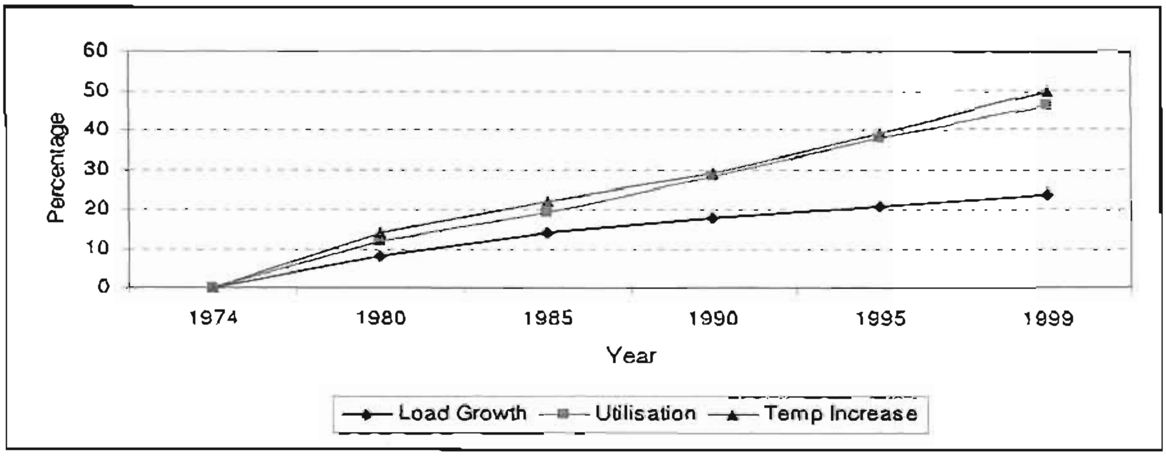


Figure 2-8: Load growth versus utilization and temperature increase

2.4. Changes in design criteria of transformers

Heating occurs throughout the transformer during operation. The heat developed is non-uniform. The highest temperature experienced within the transformer is the hot spot temperature. This is the point of greatest thermal stress. Three factors are used to determine the upper temperature limits:

- The average annual ambient temperature,
- The average winding rise at full load above the ambient temperature,
- The temperature allowed for the hotspot.

The maximum hotspot temperature is determined by the addition of the above three temperatures. The limit on past designs of oil filled transformers was 55^{0}C average winding temperature rise and 65^{0}C hotspot temperature. The comparison of the past and present designs is illustrated in Table 2-3 below [27]. Post 1963, the average allowable winding temperature rise moved from 55^{0}C to 65^{0}C with a corresponding hotspot temperature of 110^{0}C for IEEE only. IEC is 98^{0}C and Eskom uses this value.

Table 2-3: Comparison of winding and hotspot temperature rises over years

Temperature Criterion	Design Criteria Temperature ^{0}C (pre 1963)	Design Criteria Temperature ^{0}C (post 1963)
Ambient temperature	40^{0}C	30^{0}C
Average winding rise due to load	55 ^{0}C	65^{0}C
Estimated allowance for hot spot	10^{0}C	15^{0}C
Hottest spot temperature	105^{0}C	110^{0}C

2.5. Cellulose products used in power transformers

The purpose of the insulating system in a power transformer is to insulate the high voltage and low voltage windings from the iron core and the main tank. The solid insulation used within the transformer is kraft paper, pressboard and wood. These three items of solid insulation are termed cellulose products.

2.5.1. Function of solid material

The cellulose products have the ability to withstand the stresses created by the high voltages, both electrically and mechanically. The inherent qualities of the solid insulation system are as follows:

(a) Withstand impulse and transient surges,
(b) Short circuit withstand of the mechanical and thermal stresses that accompany the event,
(c) Transfer heat away from the inner core to the oil,
(d) Display a constant characteristic over the service life period of the transformer.

The life of the insulating material determines the life of the transformer. Weakening of the cellulose may cause the transformer to fail. The cellulose is weakened when its dielectric properties are lost or compromised, and has reduced mechanical strength.

2.5.2. Classifications of solid insulating materials

The solid insulating material used in power transformers is classified according to Table 2-4 [28]. Class 105 (A) is most commonly used in Eskom's power transformers. A combination of the materials used, mechanical strength, and moisture resistance will ensure a good quality insulation system.

Table 2-4: Thermal classification of electrical insulation

Class / Designation	Maximum Permissible Temperature ^{0}C	Typical Materials
Class 90 (Y) or (O)	90	Un-impregnated cellulose cotton silk
Class 105 (A)	105	Impregnated cellulose, cotton or silk
Class 120 (B)	120	Cellulose triacetate
Class 130	130	Mica, glass fibre, asbestos with organic binder
Class 155 (F)	155	Cellulose triacetate
Class 185 (H)	185	Cellulose triacetate
Class 220	220	Cellulose triacetate
Class over 220 (C)	>220	Mica, porcelain, glass quartz, inorganic materials

2.5.3. Oil-impregnated cellulose

Chemical structure

Cellulose is formed from repeated glucose units (sugar). The molecular formula for cellulose is: $(C_6H_{10}O_5)_n$. The letter n denotes the number of repeated units making up the molecule and is known as the Degree of Polymerisation. Figure 2-9 shows the chain structure of the cellulose molecule [29].

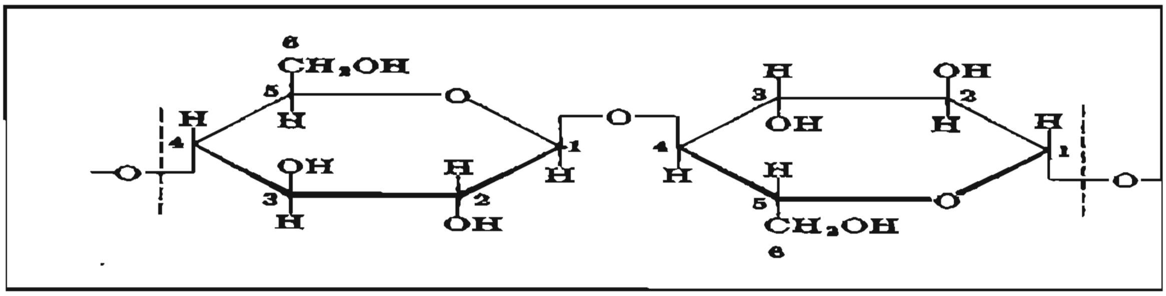


Figure 2-9: Cellulose molecule

The cellulose used in transformers are made-up of approximately 1200 glucose rings, with a molecular weight of 1500000 and consists of thousands of glucose ring arrangements. The mechanical strength is determined by the length of the cellulose molecules [30].

2.5.4. Insulation properties

The cellulose used in power transformers has the following properties:, Permittivity, Dielectric loss and Tan delta. The permittivity and losses within the cellulose is determined by the polarization of the cellulose. When the transformer is un-energised, the molecules within the cellulose have no polar orientation. They are regarding as been at dielectric rest. When the transformer is energised, the molecules within the cellulose move. This causes a negative charge to accumulate on the positive side and vice-versa. The effects of this creates an opposing electric field and thereby a diminished applied voltage.

2.5.5. Dielectric loss measurements

The dielectric condition of the cellulose material can be determined by performing a power factor or loss tangent measurement [31]. Dielectric faults, the presence of moisture, contaminates, and degradation of the oil affects the loss tangent values and the power factor. Dielectric faults are affected by conduction and debris. The presence of moisture will accelerate the ageing of the cellulose. Contamination in the form of metallic particles, carbon sludge and acids attack the windings and increases the dielectric losses between windings.

2.6. Mineral oil used in power transformers

The oil is blood for the transformer. It allows efficient cooling by convection and radiation. The oil is a dielectric, and acts as an arc quenching medium [32]. The oil from a transformer can be sampled and analyzed for any abnormalities within the transformer. Oil and paper has a dielectric strength of 12kV and 40kV per mm respectively. When the paper is impregnated with oil, their combined dielectric strength is almost 64kV/mm. The suitability of oil for transformer use is because of its stable long term properties and it has an acceptable flow rate under varying temperatures. The oil does not react with other chemicals and most importantly, it does not a pose a risk to health and safety provided there are no additives e.g. PCB. Refining crude oil produces mineral oil.

2.6.1. Specifications for mineral oil, electrical usage

The international standard for the electrical use of mineral oil are IEC60296, and ASTM D3487. These two standards state the minimum requirements. Other internationally used standards for mineral oil are: BS148, VDE 0370, Doble TOPS.

2.6.2. Measurable properties of mineral oil

Mineral oil have the measurable properties as illustrated in Table 2-5 [33].

Table 2-5: Measurable properties of mineral oil

No.	Property	Measurability
1.	Cooling	Viscosity, Pour Point, Viscosity index
2.	Electrical insulation	Breakdown voltage, Dissipation factor, Impulse Breakdown, Resistivity, Water content
3.	Life time	Oxidation stability, Inhibitor content, Solubility, Acidity
4.	Material compatibility	Sulfur content, Corrosive sulfur, Aromatic content
5.	Health, safety, environment	PCB, Flash point, Aromatic content
6.	Information carriers	DGA, Density, IFT, Furanic compounds, Gassing tendency

2.6.3. Quality type tests of mineral oil

Table 2-6 [34] summarizes the physical, electrical and chemical tests performed, to establish the quality of the mineral oil.

Table 2-6: Summary of quality type tests

Physical	Electrical	Chemical
Color	Dielectric Strength	Neutralization. Number.
Visual	Power Factor	PCB
Interfacial	Tension Dielectric	Constant Inhibitor
Relative Density	Resistivity	Water
Viscosity	Impulse Breakdown	Oxidation Stability
Flash/Fire Point	Gassing Tendency	Carbon Type

2.6.4. Oil testing as a condition indicator

The purpose of testing mineral oil is to determine if the oil is deteriorating. It also lets us know if there were any problems within the transformer. The sampling time and types of tests for a power transformer will not necessarily be the same. It will depend on the location of the transformer in the power system, its loading profiles and percentage usage, the age of the transformer, information on through faults, and the cost to perform the test. The routine tests could be done annually or for fault trending purposes, it can be done daily or weekly.

It is recommended that primary tests (DGA, Moisture and Color) be done annually on power transformers. Secondary tests (FFA, BDV, Acidity, IRES, IFT) should be done on a two year or greater cycle. Table 2-7 [35] provides an explanation for each of the specified tests

Table 2-7: Condition monitoring using oil analyses

Primary and secondary tests	Purpose of test
Dissolved Gas	Detection of faults
Degree of Polymerization	Paper insulation degradation
Moisture in oil	Insulation dryness
Breakdown voltage	Dielectric integrity
Resistivity	Quality
Acidity	Ageing, sludge
Interfacial Tension	Ageing, sludge & Contamination

2.6.5. Key gases

Fault types listed in Table 2-8 [36] can be found by performing a DGA test and the gasses found in the oil can diagnose the problem.

Table 2-8: Key gasses produced by faults

Fault Type	Primary Gasses	Secondary Gasses
Partial Discharge	Hydrogen	
Dielectric (arcing/sparking)	Hydrogen, Acetylene	Ethylene
Dielectric (power arc)	Hydrogen	Methane, Ethylene, Acetylene
High operating temperature	Methane, Ethane	Carbon Monoxide
Thermal hotspot	Ethylene	Methane, Ethane
Overheated Cellulose	Carbon Monoxide	Carbon Dioxide

2.6.6. Moisture analysis, effects and testing

The presence of moisture in oil [37] has many negative consequences. The dielectric strength can be reduced, the oil may saturate under reduced loading conditions. Under conditions of loading the transformer above its nameplate rating, increase heat in the copper will cause bubbles to be formed. There is also the issue of accelerated insulation ageing brought about by moisture and inter-turn failures.

The moisture in power transformers could be as a result of a lack of drying or using slightly wet cellulose during the manufacturing process. Depending on the size of transformer, it could be transported to site without oil and under gas pressure. Incorrect site installation procedures could result in cellulose wetting. When the transformer is in service, oil could enter the transformer via the silica gel breather (if not properly maintained), during oil top-ups, when bushings are been replaced, when opening the inspection cover, etc. The most significant source of moisture will be from the breakdown of the cellulose caused by ageing.

The moisture in oil can be determined using assessment techniques, such as moisture in cellulose charts, performing moisture and dew point measurements, conducting insulation resistance and power factor tests, and the use of polarization techniques such as RVM, PDC, FDS.

2.6.7. Condition assessment of power transformer using DGA

The use of dissolved gas-in-oil analysis (DGA) is a very important condition monitoring tool. It has the ability to produce comprehensive results for large or minute quantities of dissolved gasses, including the ability to determine faults of an intermittent nature. The cost of taking samples and laboratory testing is very affordable for the benefits it displays. There is a more costly option than laboratory testing, online DGA units. The DGA results is very useful to help in diagnosing a fault, however, the interpretation of the results must be done by experienced persons.

When faults are developing within a transformer, there will be an increasing trend in the concentration of related gasses, until it reaches an equilibrium. Faults that are inactive, will display constant gas levels. Issues surrounding the solubility and the dispersion of the gasses may make the interpretation of C_2H_2 and H_2 trending a challenge.

2.6.8. DGA interpretation

The interpretation of the DGA key gasses are based on IEEE Key Gas Method [38], comprising of CO, H_2, CH_4, C_2H_4, C_2H_6, C_2H_2. The presence of high levels of CO and 60 to 90 Percentage total combustible gas (%TCG) is considered to be normal. Any higher levels of CO and %TCG may be abnormal. High levels of C_2H_4 and more than 10 %TCG is regarded as abnormal. High levels of H_2 and high C_2H_2 is considered serious. High levels of C_2H_4 and high levels of C_2H_6 is not considered as being serious.

2.7. Transformer faults and failures

It is evident that the life of a transformer is determined by it insulation, i.e. cellulose paper and oil. The lifespan of the transformer will most likely be achieved by correct maintenance and if site inspections and testing are carried out during the transformers useful life. However, transformers fail for various reasons.

2.7.1. Causes of transformer faults

The following is a list of the most common factors that may cause a transformer fault:

- Poor workmanship at the factory,
- Inadequate transformer design,
- Incorrect handling procedures,
- Incorrect packaging for transit,
- Incorrect installations,
- Operator errors,
- Overloading beyond its capability,
- Inadequate surge protection and subsequent line surges,
- Improper/Insufficient maintenance,
- Lightning and switching surges,
- Human or animal contact.

In the period 1965 to 1974, a total of 131 transformers were burnt due to electrical faults costing 2,1billion dollars. This translates to a failure rate of 3.4 percent of the insured transformer base [39].

2.7.2. Analysis of transformer failures globally

The primary causes of transformer failures during the period 1963 to 1976 [39] is shown in Table 2-9 [26] and Table 2-10 [26] below.

Table 2-9: Primary causes of power transformer failures

Causes of Failure	Percentage	
	1963	1975
Lightning surges	26.4	32.3
External short circuiting	8.5	13.6
Poor workmanship by manufacturer	7.3	10.6
Deterioration of insulation	10.2	10.4
Overloading	4.5	7.7
Moisture	11.4	7.2
Inadequate maintenance and improper operation	6.4	6.6
Sabotage, vandalism	4.9	2.6
Loosening of connections	3.7	2.1
Misapplication, Operator Error, Poor Owner or repairer's workmanship	16.7	6.9
Total Percentage	**100%**	**100%**

Table 2-10: Indication of initial component to fail in a transformer

Transformer Component	1963	1975	1976
High Voltage Windings	57.3	58.0	48.0
Low Voltage Windings	14.7	19.8	23.0
Bushings/Insulators	5.3	8.8	2.0
Leads	11.4	4.4	6.0
Tap Changers	5.3	3.2	0
Gaskets	0	0	2.0
Other	6.9	5.8	19.0
Total Percentage	**100.0%**	**100.0%**	**100.0%**

In the 1980 failures were attributed mostly to through faults (28 percent) and tap changers (17 percent). Figure 2-10 shows a plot of the failures from 1969 to 1980 [28].

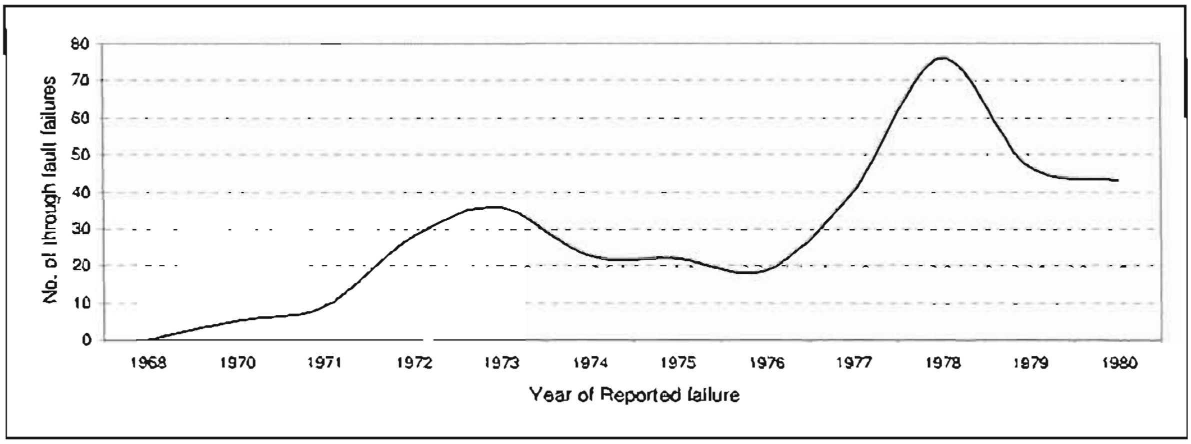


Figure 2-10: Reported power transformer failures caused by through faults

2.7.3. Transformer characteristic failure curve

Faults caused by the manufacturer, during delivery, and incorrect installation usually manifests from day one up to the first year of service (infant mortality). Thereafter, the transformers failure rate is constant and random. In the later years, the transformers fail due to ageing. This is depicted in Figure 2-11, know as the bathtub curve [40].

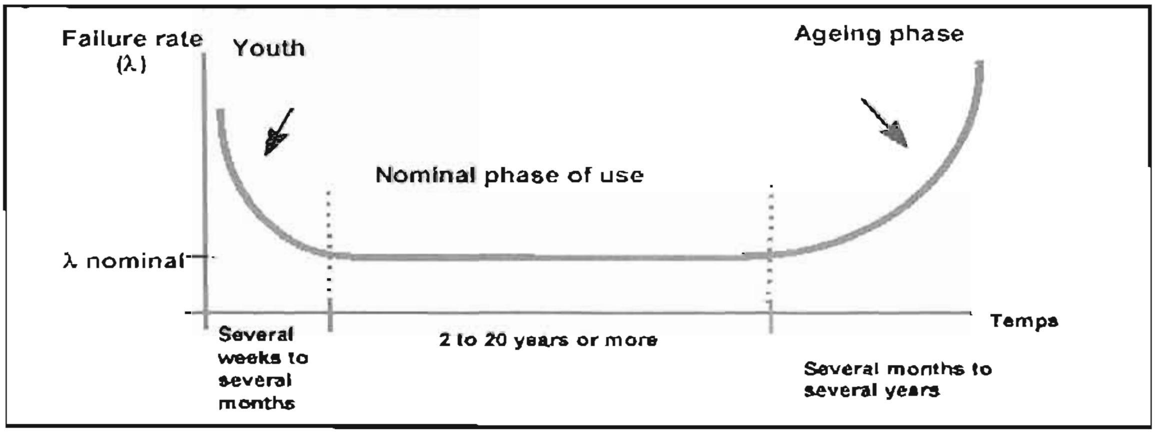


Figure 2-11: Transformer bathtub curve

2.8. Power transformer failure modes

The failure of a transformer can be attributed to thermal, dielectric, mechanical and unknown failures.

2.8.1. Thermal failure

There are three main types of thermal failures [41]. The first type is intrinsic ageing of the paper on the winding. This usually occurs over a long period of being in service. The second type occurs from accelerated local ageing of the paper on the winding. The last type is the failure of the core to frame insulation and failure of connections, leads, etc. The winding insulation reaches the end of its useful life when the paper around the winding has minimal mechanical strength and electrical properties, becoming brittle and leading to inter-turn short circuits.

When a transformer is loaded above its nameplate rating, there are many risks. The moisture in the paper may form bubbles due to the heating of the copper windings. The insulation will suffer accelerated ageing and hence decrease the useful life of the transformer. The heat generated within the transformer will cause the expansion of the oil, creating an internal pressure that will exceed the design characteristics of the seals, gaskets and bladders, resulting in oil leaks. The increased heat in the copper can have a negative effect on its mechanical properties. The operation of an on-load tapchanger may operate beyond its current carrying capabilities and excessive wear may occur.

2.8.2. Dielectric failure

The design specification of a transformer specifies that it must be able to withstand system voltage, switching spikes and transients of specified magnitudes. Therefore the insulation system is designed to these specified conditions. However, there are some oversights when the calculations and modeling are been performed. The stress distribution calculation can be incorrect or there could be insufficient phase insulation or inadequate clearances between the windings, bushings and tapchanger with reference to ground.

Once the transformer has being delivered to site and has been energised, the transformer can suffer service related faults which invariably cause dielectric failure. The presence of moisture could cause the flashover of barrier boards brought about by phase to phase tracking. When the transformer is overloaded, the moisture in the insulation could change to a gaseous state resulting in the presence of bubbles. There are often particles in oil caused by the breakdown of the paper fibers, sludge and carbon that increase the likely hood of dielectric failure. Accelerated ageing or intrinsic ageing will cause the paper to become brittle and this can lead to inter-turn faults.

2.8.3. Mechanical failure

Power transformers are also designed and constructed to withstand fault current based on their MVA rating and impedance. The frequency of the faults is limited by the magnitude of the faults currents. The transformers designed in the earlier years were not simulated on a computer package prior to construction since the computer programs were only available in the later years. The mechanical failure experienced by the older transformers could be attributed to the non-availability of simulation packages. Some older transformer designs were not tested and hence failed in service. There are instances were the clamping pressure was inadequate and a fault sustained through the transformer would result in the loosening of the core. A transformer that has an optimized design with regard to tank size, core size, volume of oil etc, will fail mechanically if subjected to fault currents beyond its capability or for more than the allowable number of rated faults.

The ageing of the insulation system could also result in a transformer failure. After many years of service, the insulation shrinks thus substantially reducing the clamping pressure and this could bring about failure if subjected to fault currents. If the winding are subjected to currents higher than the nameplate rating, the winding can be deformed. This deformation will create an electromagnetic imbalance. This means greater stress during fault conditions.

The impact of faults very close to the transformer is a common cause of winding movement. The magnitude and frequency of these faults should be minimized or reduced. If a diverter in the tapchanger compartment open-circuits during operation, this may cause the tapping windings to fail.

Mechanical faults or potential faults that are related to mechanical damage are difficult to detect. The dissolved gas-in oil analysis will indicate problems only after insulation damage has occurred. If the inspection covers on the main tank are opened, and a visual inspection is performed, it is very difficult to find any problems, since the problems could be internal to the surface windings or in difficult to see places. Electrical tests may or may-not diagnose a fault. Therefore, it is important to stress that mechanical damages are extremely difficult to detect before the transformer fails. The mechanical failure of a transformer may be attributed to hoop buckling of the inner winding, conductor tripping, conductor telescoping, failure of the coil clamping system, total loss of insulation, spiral tightening of the winding, and any displacements of the leads in the main tank.

2.8.4. Cost of unserved energy

Table 2-12 provides an indication of the unserved energy cost calculated at a peak kWh rate [42]. These costs are incurred by the customer per kWh without electricity.

Table 2-11: Unserved energy costs at a peak kWh rate

Commercial/Industrial Customer	Cost in Rand's per kilo Watt Hour lost
Industry	R 19.40
Mining	R 19.40
Commercial	R 14.85
Agricultural	R 4.55
Rural	R 4.55
Residential	R 2.22
Traction	R 1.19

2.9. Eskom's operations and maintenance practices

The following operations and maintenance practices are followed at Eskom Distribution Eastern Region.

- N-1 contingency on part of distribution system
- Firm transformer substation
- Partial back feeding via reticulation networks
- Use of rings in cable networks
- Refurbishment of aging assets
- Preventative maintenance programs and strategies
- Adequate strategic stock levels

Annual oil sampling is conducted to assess the condition of the transformer. The results indicate the percentage moisture in the oil, the electric strength and the concentration of gases. They are used to diagnose any developing faults. Tapchanger maintenance is done every six years or 100 000 operations.

2.10. Eskom's transformer protection philosophy

Two protection philosophies are followed at Eskom. The first is for transformers greater than 10MVA. The second is for transformers less than 10MVA.

2.10.1. Protection of transformers - 10MVA and above

The following protection is used at Eskom for transformers of nominal rating above 10 MVA [43]:

- Biased differential protection HV IDMTL and Instantaneous Phase Over-current protection.
- HV IDMTL Earth Fault protection
- HV REF
- LV IDMTL Phase Over-current protection
- LV DTL/IDMTL Earth Fault protection.
- LV REF.
- Tertiary IDMTL Phase Over-current protection
- Tertiary DTL/IDMTL Earth Fault Protection
- Surge devices, pressure devices, oil and winding temperatures.

2.10.2. Protection of transformers - less than 10MVA

The following protection is used at Eskom for transformers of nominal rating up to and including 10 MVA [43].

- HV IDMTL Earth Fault protection
- HV IDMTL and Instantaneous Phase Over-current protection.
- HV REF.
- HV Breaker fail.
- LV IDMTL Phase Over-current protection
- LV DTL/IDMTL Earth Fault protection.
- LV REF.
- SFT Timer
- Surge devices, pressure devices, oil and winding temperatures.

2.11. Reliability of transformers

Failures and overloading of transformers impact the distribution systems reliability. Catastrophic failures of transformers can cause power interruptions to thousands of customers. Under these conditions, spare or mobile transformers are often used to replace the failed transformer. Some networks are switched-over to restore supply to part of the affected customers. When a spare or mobile transformer is not available, in-service transformers are overloaded to supply the affected customers. The overloading of these transformers results in loss of life. This short term strategy maintains supply to the customer. However, in the long term, the reliability of the overloaded transformers is drastically reduced.

The reliability of transformers in terms of aging is defined through the hazard rate curve which characterises the transformers operating life. Figure 2-12 [44] shows the increase in distribution transformer failure as a function of age.

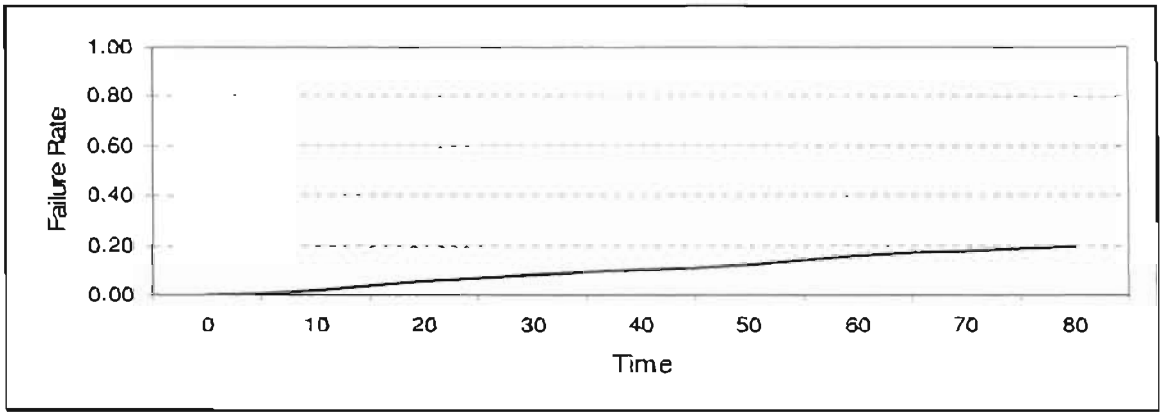


Figure 2-12: Distribution transformer failure rate curve

2.11.1. Reliability concept

Reliability of a transformer is a general term that refers to the probability of its satisfactory operation [10] over its intended life. Reliability is a function of the time-average performance of a transformer, in different loading situations, after different faults and during different outages. The transformers reliability can only be judged by considering the system's behaviour over an appreciable period of time. Reliability concepts are failure rates, mean time between failure, mean time to repair, availability and downtime.

2.11.2. Availability concept

The availability of a transformer is determined by the percentage of time it is in operation. Availability is expressed as [45]:

$$\text{Availability} = \frac{(\text{Mean Time Between Failure})}{(\text{Mean Time Between Failure}) + (\text{Mean Time To Repair})}$$

Increasing the reliability of a transformer by reducing risk and failure rate will result in increased transformer availability. This is ensured by managing risk in terms of risk assessment, residual life, transformer health reviews, condition based maintenance and reliability centered maintenance.

2.11.3. Maintainability concepts

a) Loading

The loading of a transformer is dependent on the condition of the insulation and age. As the transformer ages, the peak load of the transformer should be reduced in order to increase the expected lifespan of the transformer Figure 2-13 [44] shows a load de-rating curve for a power transformer with an expected 40 year lifespan.

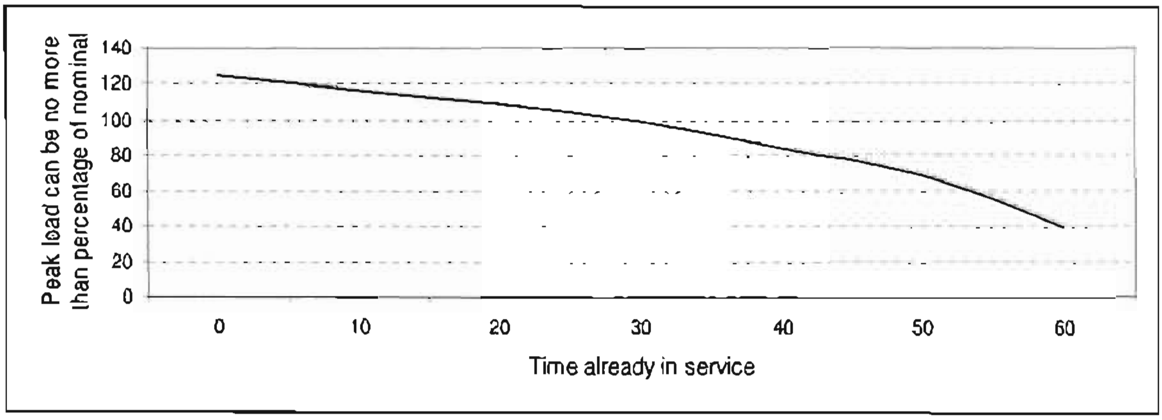


Figure 2-13: Transformer de-rating curve to achieve 30 year remaining lifetime.

b) Short circuit faults

Short circuit faults cause movement of the coils as a result of axial and radial forces incident to a short circuit. According to IEEE Std. C57.12, a transformer shall withstand a 2 second bolted fault at the transformer terminals. On an in service transformer, not every short circuit fault results in the transformer being tested, to determine the condition of the winding. The stress experienced by a transformer and is withstand capability is show in Figure 2-14 [46].

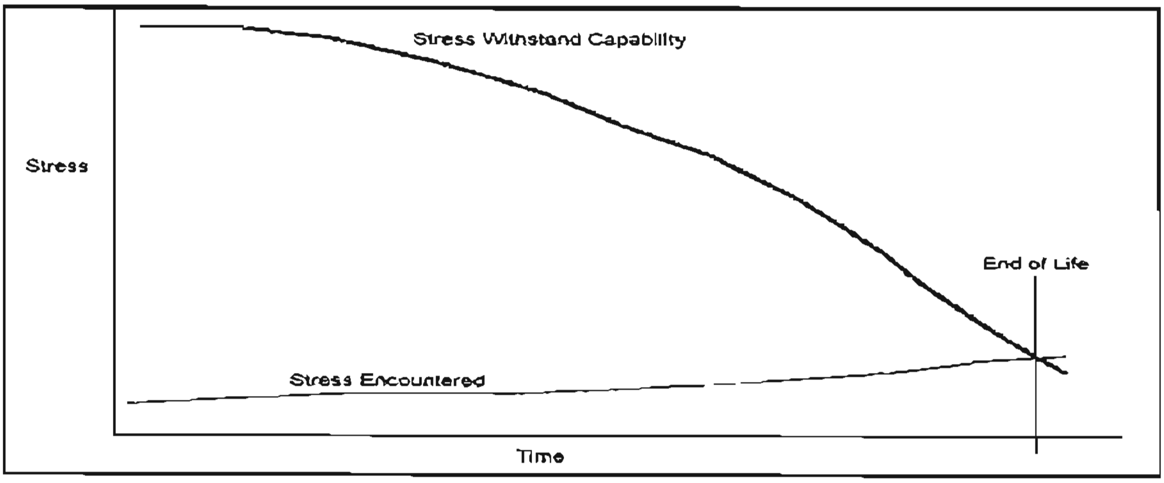


Figure 2-14: Stress withstand capability over transformer's lifetime.

The transformers stress withstand capability is gradually reduced by overheating. A modified graph as shown in Figure 2-15 [46] shows the stress withstand capability over a transformer's reduced lifetime.

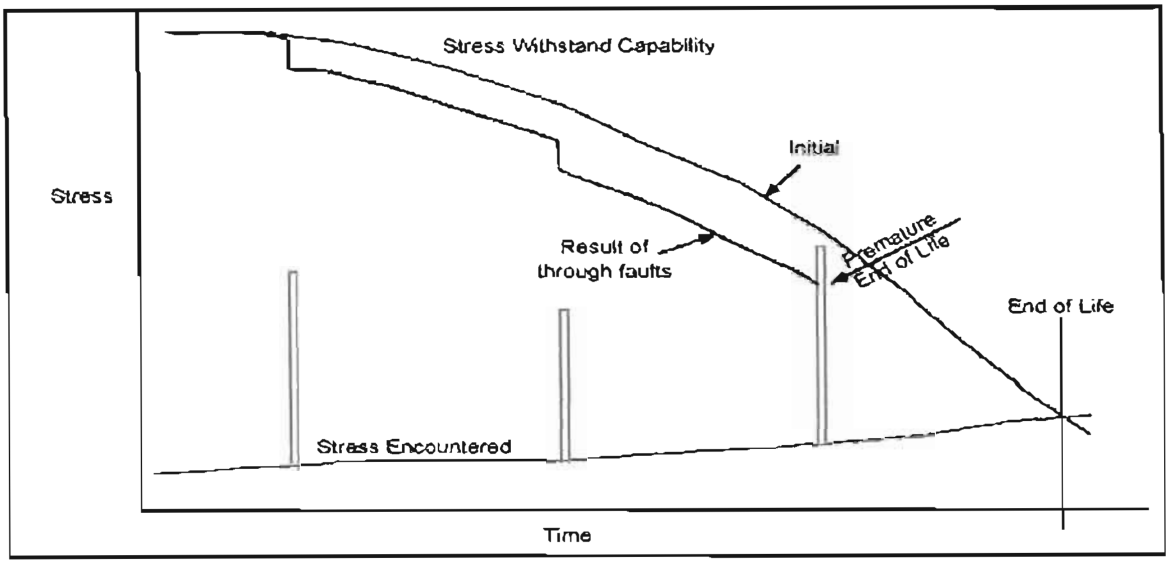


Figure 2-15: Stress withstand capability over transformer's reduced lifetime.

In Figure 2-15, the transformer experiences three through faults. The first two faults causes a reduction in the transformers stress withstand capability and hence cannot withstand the third fault.

2.11.4. Design life

The theoretical design life of a transformer is 432 years [47]. However, studies in 1965 showed that that the average life was 22 years, this reduced to 11 years in 1988, 14 years in 1992 and 14.9 years in 1998 [48]. Currently, transformers are designed by a manufacturer to last 35 years, under idea operating and maintenance conditions (according to Eskom's Distribution specification DISSCAAD3 for distribution transformers).

2.11.5. Economic life

The purchase price of transformers [49] by Eskom is shown in Table 2-13.

Table 2-12: Power transformer purchase price

Transformer Rating	Cost
2.5MVA	R520,000
5MVA	R877,500
10MVA	R1,495,000
20MVA	R1,885,000
40MVA	R2,275,000
80MVA	R3,965,000

The cost of the transformer is depreciated over 25 years. Any major work is capitalised against the transformer's book value over another 25 years.

2.11.6. Technical life

The technical life expectancy of a transformer is determined by several factors. It depends upon design, historical events, operating conditions, its actual state and future conditions. Most of the present methods emphasis is on the condition of the insulating material. The life expectancy of a transformer is not only determined by temperature, load and water but also by the number of short-circuits, over-voltage, design weakness, repairs and moving.

2.11.7. Key design challenges

Short-circuit withstand capability is essential for the long-life performance of transformers. In power transformers, many design elements are aimed at taking care of physical conditions during normal operation, such as presence of electric current, magnetic fields, heat generation in conductive materials, and so on. Hence the need to have adequately shaped current carrying conductors and insulating structures, a laminated steel core, heat transfer media and cooling equipment. One needs a set of structural materials adequate to correctly operate at substantially steady-state conditions.

When a transformer is loaded at rated power, the dynamic forces that act on the winding conductors because of the interaction of their current with the surrounding leakage flux are negligible. If short-circuit events could be prevented, it would be possible to size the conductors with reference to requirements other than mechanical strength under short circuit conditions, such as temperature rise limitation and loss reduction. However, the capability to withstand the high forces under short circuit conditions is a critical factor. This is especially applicable to large power transformers with relatively low impedance, which are in turn connected to high capacity electric networks. This is often the key point of transformer design.

When a short-circuit occurs, the currents through the windings normally attain values in an order of magnitude higher than the rated currents, and therefore the forces climb by a factor of two. They represent a challenge for designs, even though the fault condition may typically last for less than a second.

The forces involved are time-varying pulsating forces applied to the transformer's structures, particularly the windings. The stress magnitude depends principally on the dynamic reaction of the structures, whose inertial masses in certain situations may provide a positive contribution to the stability; while in other situations may give rise to an amplification of forces and stresses.

2.12. Chapter summary

This chapter has covered aspects of the basic principles and operation of power transformers. It presented the differences in design between the old and new transformer. The properties and testing of mineral oil and solid cellulose materials were examined. The latter part of this chapter presented the global perspective on power transformer fault and failures. This has resulted in a better understanding on the complexity of a transformer, providing the grounding to continue with the research.

3.0. Chapter overview

This chapter illustrates the maintenance methodology of power transformers used within Eskom Distribution Eastern Region. The focus is on maintenance steps taken, and site inspections. The role and analysis of oil sampling is discussed in detail. The analysis is divided into dissolved gas in oil analysis, degree of polymerization, moisture and electric strength. The diagnostic methods used in the oil sampling practice will be illustrated. The theory and examples of electrical tests are explored. A case study of a failed 20MVA 132/11kV transformer is conducted and the results are analysed using the theory presented.

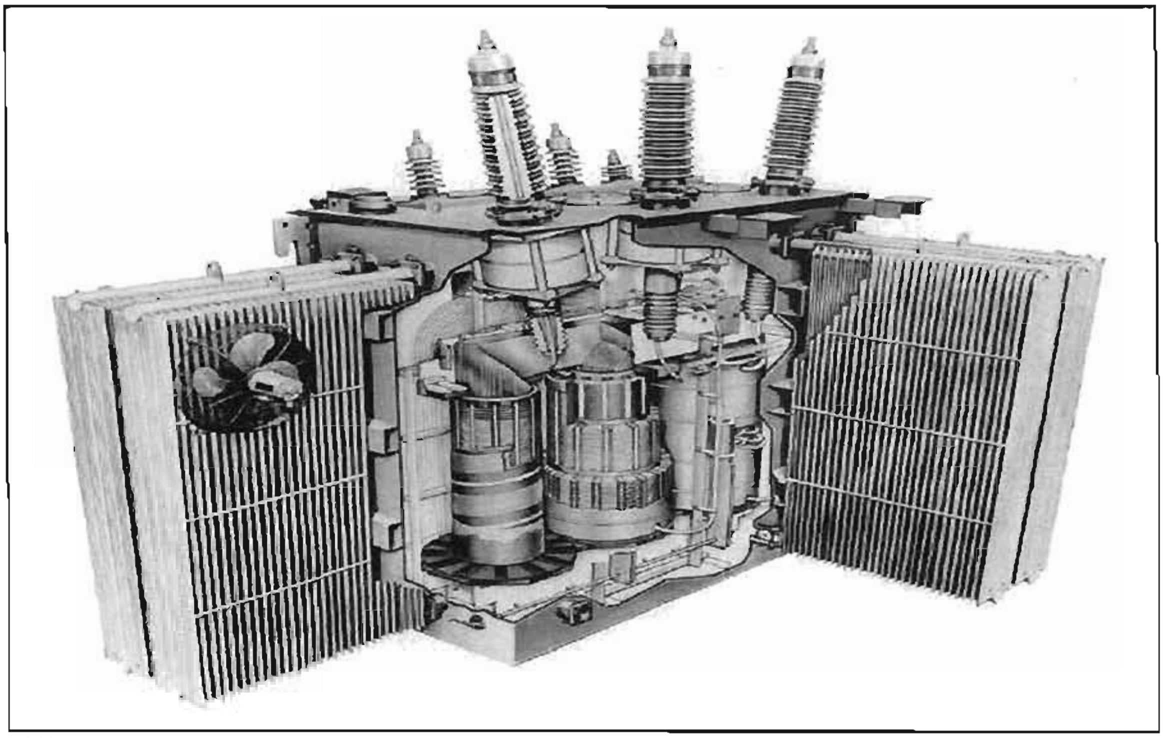
3.1. Generics of transformer

A transformer is a passive device which transforms alternating electric energy from one circuit to another through electromagnetic induction [50]. It consists of a core and two or more windings (active part.) A changing current in the primary winding creates an alternating magnetic field in the core. The core multiplies this field and couples most of the flux through the secondary windings. This in turn induces an alternating voltage in each of the secondary coils according to Faraday's law.

The non active part is the steel tank that houses the core, winding and oil. The connections to the windings are made via bushings. The windings are insulated with Kraft paper and are clamped in place with cellulose spacers. The tank is filled with transformer insulating oil. The insulating oil serves four purposes:

- Provides dielectric strength
- Provides heat transfer
- Protects the paper insulation
- Acts as a carrier for gasses, testing serves as a diagnostic tool for the condition monitoring of the transformer.

The transformer also has a tapchanger which regulates the output voltage. Cooling fans and fins are located on the outside of the tank and help to regulate the internal temperature.



[51]

Figure 3-1: Transformer generic layout

3.2. Maintenance methodology

A power transformer that has been installed in a power system and energized to supply a load will operate in "normal" mode. During operation, the core and winding will vibrate. The oil will circulate by natural or forced circulation. If fans are fitted, they will operate at a predetermined set point, creating convection. The on-load tap changer will raise or lower its tap position as per loading requirements.

The normal operation will generate heat. The heat will steadily age the oil and cellulose. As the oil temperature increases and decreases, so will the oil level. Inadequate oil preservation systems (silica gel) will result in the transformer breathing air. The fans and pumps will eventually need maintenance, as specified by the manufacture. The tapchanger will require inspection and contact maintenance depending on the number of operations. Externally, the main tank will be exposed to the environment. Depending on the environmental condition, the tank and metal parts may corrode or degrade. If the corrosion is left unattended, leaks may develop or if gaskets fail and they are not maintained, this could also result in oil leaks and may eventually become an environment concern.

In the later years of operation, moisture may be present in quantities that are a risk to the insulation system. The core may become loose due to ineffective clamping pressure and may be unable to withstand mechanical forces created by fault currents. Since the issues surrounding normal operation are known, plans can be implemented to take corrective action to prevent premature failure. Routine maintenance is one of the measures used to counter the effects of wear and tear [52].

3.2.1. Routine maintenance

A visual inspection is conducted on all of Eskom's power transformers on a monthly basis. Defects found are reported and then scheduled based on their type and severity. Routine maintenance will include the replacement of silica gel, minor repairs, and replacement of rusted breather pipes, bolts and nuts. In most cases, routine maintenance will not require an outage and can be performed while the transformer is energized.

3.2.2. Maintenance steps

A summary of the maintenance steps taken for power transformers at Eskom are listed in Table 3-1 below. The tests are shown for critical and non critical power transformers, with the frequency of each activity.

Table 3-1: Eskom's transformer maintenance steps.

Tests	Frequency	Critical Trfr	Non Critical Trfr
Core Magnetizing Tests	5 yearly	x	
Insulation Resistance	5 yearly	x	x
Tan Delta Bushing	5 yearly	x	
FRA Test	5 yearly	x	
Tapchanger Minor Service	5 years or 25000 ops	x	x
Tapchanger Major Service	5 years or 100000 ops	x	x
Monthly Inspections	Monthly	x	x
Infrared Scanning	Yearly	x	x
Acidity	1 yearly	x	x
Dissolved Gas Analysis	1 yearly	x	x
Oil Moisture Content	1 yearly	x	x
Electric Strength	1 yearly	x	x
Furanic Test	1 yearly	x	x
Winding Temp Calibration	5 yearly	x	x
Oil Temp Calibration	5 yearly	x	x

A typical power transformer maintenance program at Eskom is as follows:

a) Every Month with the transformer on-load:

- External visual inspection
- Check oil levels
- Check and re-set maximum temperature indicators
- Check breather
- Check cooler function
- Check tapchanger function and operations

b) Every Year with the transformer on-load:

- Oil sample (DGA, furans, oil quality)
- Service breather
- Infra-red site survey

c) Every five years with the transformer disconnected:

- Repair oil leaks.
- Repair tank and cooler corrosion and re-paint.
- Top- up oil.
- Check and calibrate temperature indicators.
- Check Buchholz relay operation.
- Inspect OLTC contacts and change if necessary.
- Check OLTC timing.
- Check OLTC oil and change if necessary

3.3. Site inspections

Site inspections are carried out monthly by Eskom's Technical Service Centre staff. The defects identified are reported and captured on Maximo [53] for the repairs to be scheduled.

3.3.1. Limitations

The site inspection is limited to what can be seen visually from ground level. The quality of the inspection is impacted by the skill level of the person conducting the inspection. Follow-up audits show that not all defects are identified. This is attributed to high staff turnover and insufficient skills transfer to new employees.

3.3.2. Eskom's site inspection sheet

An inspection sheet is used when conducting an inspection. A typical sheet is shown below in Figure 3-2.

Area: PMB	TSC: EDENDALE	Substation HOSPITAL		Date:	
TRANSFORMERS					
Identification / Bay / Feeder		TRFR 1	TRFR 2		
1 Oil levels / Leaks	• Main				
	• Bushings				
	• Divetor / Tap change				
2. Gauge glasses	• Main				
	• Bushings				
	• Divetor				
3. Transformer temperatures	• HV Winding • MV Winding				
	• LV Winding • Oil				
4. Silica gel breathers	• Main • Divertor / Tap changer				
5. Tertiaries insulated					
6 Cooling system / Fans working					
7. Oil catchment area					
8. Tap change	• Pressure relief valve				
	• Buch				
9. Transformer	• Pressure relief valve				
	• Buch				
10. Tap change cyclo's	• Tapchanger				
	• Trfr				
11. Record Max and Min tap position and reset					
12. Surge arrestor's condition.	• HV • MV				
	• LV				
	• Neutral • Tertiary				
13. NEC /R / AUX	• Oil Temp indicator (**Do not reset**)				
	• Bushings				
	• Oil levels				
	• Oil leaks				
	• Gauge, glasses				
	• Breather				
	• Pressure relief valve				
	• Bucholtz				

Transformer legend (Report by exception only, leave blank if no defect found)

Oil leaks	Silica gel breather	Gauge glasses	Tap changer	Trfr general
1) R,W,B leak on base 2) R,W,B Leak on gauge glass 3) R,W,B Leak on head 4) main tank leaking 5) Buchholz Leaking 6) Radiator leaking 7) Radiator valves leaking 8) Conservator leaking **Labels** 9) Label not fitted 10) Label broken/peeling 11) Wording incorrect 12)) PCB Label not on site	13) Silica gel > 30% pink 14) No oil in dashpot 15) Dashpot overfull 16) Breather cracked/broken 17) breather not fitted 18) Silica gel pink from top 19) Dashpot cracked/broken 20) Breather Air flow blocked 21) Silica gel baked 22) Dashpot dirty	23) R,W,B gauge glass cracked 24) R,W,B Oil level low 25) R,W,B gauge glass stained 26) R,W,B no oil level 27) R,W,B gauge glass painted 28) R,W,B oil level high 29) Trfr Conservator oil level low 30) T/C oil level low 31) T/C oil level high 32) Trfr Conservator oil level high	33) T/C condition 34) T/C Wiring 35) T/C Heater not working 36) T/C Door not latching 37) T/C Door sealing defective **Earthing** 39) Earthing incorrect 40) Earthing loose 41) No earthing 42) R/W/B S/A not earthed	43) Fans not working 44) Limit switches rusty 45) Bund valves closed 46) Bund drain blocked 47) Rusty pipes 48) Rusty tank 49) Rusty conservator **Surge arrestor** 50) R/W/B S/A Blown 51) R/W/B S/A not fitted

Figure 3-2: Transformer inspection sheet used at Eskom.

Defects identified and captured over a 4 year period was analysed and summarized in Figure 3-3. The defects were categorized according to the following categories: oil leaks, silica gel, rust, OLTC, bushing, low oil, faulty cyclo meter, breather and fans. The major problem that was identified is oil leaks. The average number of leaks per year is 98. This indicates that 25 percent of Eskom's transformers have moisture ingress related problems. The leaks are not always repaired due to staff shortages and the difficulty of obtaining an outage due to network constraints.

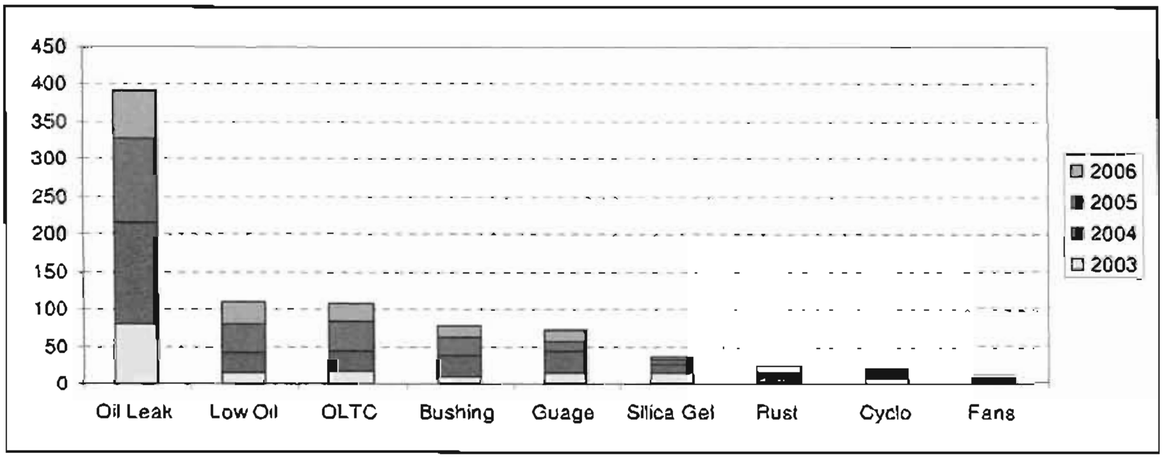


Figure 3-3: Eskom's routine maintenance defects

3.4. Oil analysis

The insulating system of a transformer consists of solid insulation and the insulating oil. The insulating oil used within Eskom is of a Napthenic base. In order to achieve the optimum lifespan of the electrical equipment, the insulation system needs to be free of contaminants such as moisture and particles.

The oil surrounds the core, windings and the insulating material. The oil has three functions. To provide insulation, cooling and to provides meaningful information on the health of the transformer. By using oil in a transformer, the physical size of the transformer can be reduced because oil has better insulation properties than air. With oil being an integral part of the power transformer and in close contact with other insulating materials, as well as the current carrying components, it is one of the best mediums to determine the transformer's health. Thus regular sampling and testing of insulating oil taken from transformers is a valuable technique for monitoring the condition of transformers [54]. If corrective action is taken timeously, based on the condition of the insulating oil, excessive ageing and transformer failures can be reduced or prevented.

The common tests carried out Eskom on insulating oil are moisture content, dielectric strength, dissolved gases analysis, acidity and degree of polymerization tests. These test results are used to determine the power transformers condition. The DGA is used extensively to determine the abuse of a transformer or a developing fault. An understanding of oil and how the gases are generated when the oil breaks down under heat and arcing is important in conducting an analysis. Furanic analysis is a very good indicator as to the life expectancy of the cellulose insulation [55] and can be used to calculate the remaining useful life of the transformer.

3.4.1. The role of analysis

Oil analysis is one of the means by which the health of the windings, core and paper insulation may be monitored without opening the transformer. Furanic analysis is used in conjunction with routine oil analysis. The analysis and interpretation of oil samples is not an exact science [56] and experience in transformer oil analysis is essential. It is also essential that the analyst understands the transformer failure modes and have the maintenance history of the transformer to be able to accurately analyze the sample data. The person that does this analysis should have a sound knowledge of transformers and the technical background on which to make a sound engineering decision.

The understanding of the oil sampling process is a key to a successful analysis as well. Was the sample taken correctly? Was the sample left for two weeks before being sent to the laboratory? What was the transformer's top oil temperature when the sample was taken? Answers to these questions will give insight to the analysis and are influenced by the sampling process. Corrective action taken following the analysis is equally important.

Without action being taken, the entire process would be pointless. The action may be to adhere to annual or bi-annual sampling, or to increase the sampling frequency when a fault trend is developing. From the data, the maintenance staff can assess the risk or make an engineering decision on the transformer to be removed from service. The interpretation of the chemical analysis plays a vital role in ensuring that the electrical network is in a reliable condition.

3.4.2. Sample point

This is critically important for the data interpretation as the comparison between consecutive samples must be made from the same sample point [57]. However, the comparison between bottom main tank and top main tank of a transformer is generally considered the same (due to the oil circulating through the windings and cooling fins). When a fault is developing a higher concentration of gas may be found in the Buchholz relay than in the main tank, depending on the mode of generation. In general, trending should only be performed utilizing a common sampling point, however when a single investigative sample is taken i.e. after a major fault, multiple samples may be taken (Bottom Main Tank and Buchholz) to cover all gas generation modes.

3.4.3. Dielectric breakdown

In transformers, oil is used in conjunction with oil impregnated paper to provide insulation. However, oil is not as strong as the oil impregnated paper. The dielectric constant of oil is less than paper so that the oil tends to be more stressed than paper. As a result of this, it may be stated that oil is the weak link in the transformer and it is obvious that the condition of the oil is of great importance. Dielectric strength is the insulation properties that the oil inherently displays.

The analytical test carried out determines the voltage at which the oil breaks down over a set distance [58]. The tests are normally repeated and an average is taken as the result. Moisture content and dielectric strength are related and have an inverse relationship i.e. if the concentration of water in the oil is high the dielectric strength is low and vice-versa. When this occurs there are normally other contaminants that are present in the oil and these could be from other sources within the transformer tank. Carbon (from the tapchanger), paper, wood and other material particles are common.

Particles in the oil decrease the dielectric strength of the oil. The degree of reduced electric strength depends on the particle type involved, particle size and the water content of the oil. Paper, copper, iron, wood and dust particles may be found in oil. All of these particles are detrimental to the dielectric strength of oil. Paper particles and large amounts of water can be detrimental to the dielectric strength, as these particles absorb water from the oil and become semi-conductive. The temperature of the oil also plays a vital role. As the viscosity decreases with the rise in temperature the particles tend to settle to the bottom of the tank. However, if there is a high concentration of particles at a lower temperature, the particles are held in suspension by the higher viscosity and lower the dielectric strength.

3.4.4. Moisture content

Water, even in minute quantities [59], is harmful to power transformers because water is attracted to places of the highest electrical stress where it has the greatest detrimental effect. Water accelerates the deterioration of both the insulating oil and the insulating materials used inside the transformer. Once deterioration has been initiated more water is produced. This is a self supporting cycle and once the paper has been degraded it can never be returned to its original condition. Water also has a detrimental effect on the dielectric properties of oil, either on its own or in conjunction with cellulose particles. Where concentrations are high enough, free water may also be generated within the transformer, which can lead to electrical breakdown. Water can originate from two sources:

- The atmosphere: if the transformer is free breathing with poorly functioning/leaking drying equipment, oil leaks causing moisture ingress.
- Internal sources: the degradation of cellulose and by-products of heated insulating oil.

With only a small amount of water present in the insulation paper there is a greater fall in the electric strength. As an example, with 4 % water content in paper there is a 10 % fall in the electric strength of oil impregnated paper but with 8 % water content the value of the electric strength falls by 40 % [60].

The partial discharge tendency increases as the water content rises. The highest stress points are adjacent to the hottest parts of the structure and the current carrying conductor, thus they have the lowest water content. Therefore during operating under normal loading this is not a problem, but when the unit is de energized for long periods, the water is then evenly distributed throughout the paper insulation if the oil is carrying an excess of water. Once the transformer is re-energized there is a high risk of the transformer developing partial discharge at the high stress points with probable catastrophic damage.

With the migration of water from the insulation to the oil as the transformer operating temperature rises, the oil will become more and more 'wet'. As the temperature of the oil increases so does its ability to receive water (this phenomenon is referred to as the saturation point curve [61] where the water is dissolved in the oil to the point of saturation where water particles start to form). As the oil ages, the capability of the oil to hold more and more moisture, increases. Thus the saturation point curve shifts higher. This is not normally a problem until the oil cools substantially. It is at this time the oil and water separate and water droplets form. The distribution of moisture in a transformer is a function of the overall temperature of the transformer. As the temperature increases the water moves from the paper to the oil and as it cools down it moves from the oil back into the paper. At any given time the paper holds 9 % of the total moisture content of the transformer. The paper/oil equilibrium forms the basis of relative analysis of the moisture content of the paper by measuring the water content of the oil. Equilibrium can take in excess of a week of operation to achieve a constant temperature.

For many years Eskom has used a standard of 20 ppm to indicate that the transformer is wet, however temperature has an influence on the amount of water that is present in the oil. Further, the age of the oil plays a vital role in the amount of moisture present in the oil. A modified Pipers chart as shown in Figure 3-4 [62] is used to indicate the allowable limits of water in oil.

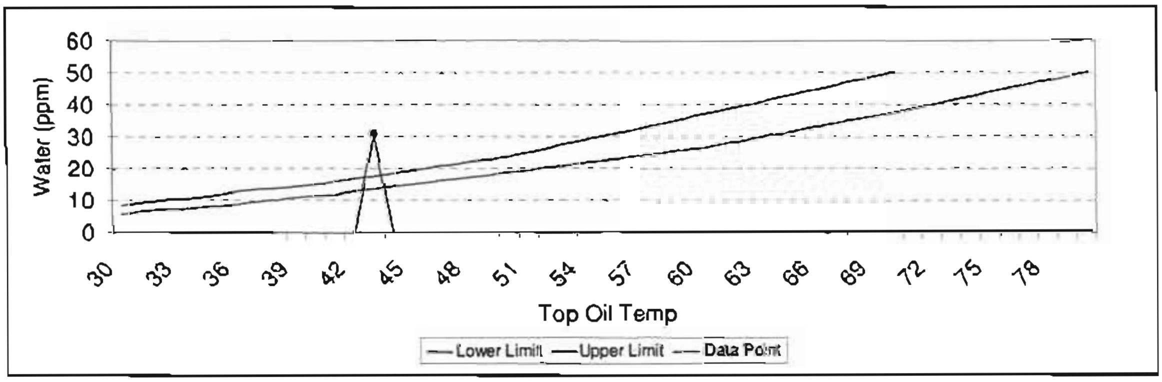


Figure 3-4: Modified pipers chart

A data point plotted below lower limit is an acceptable reading. A data point between the lower and upper limit is a developing problem and require action from a transformer specialist. A data point above the upper limit indicates that the cellulose and paper is wet. The transformer will have to be further evaluated and probably removed from service. The transformer will require the paper to be dried under a vapour phase and the winding re-clamped.

3.4.5. Acidity

Acids in the oil originate from oil decomposition/oxidation products. Acids can also come from external sources such as atmospheric contamination. An increase in the acidity is an indication of the rate of deterioration of the oil with sludge as the inevitable by-product of an acid situation which is neglected. The rate of acid build-up is accelerated as the acid itself acts as a catalyst for the formation of more acids. The critical neutralization or acid number is 0.25mg KOH/gram of oil. This is illustrated in Figure 3-5 [63].

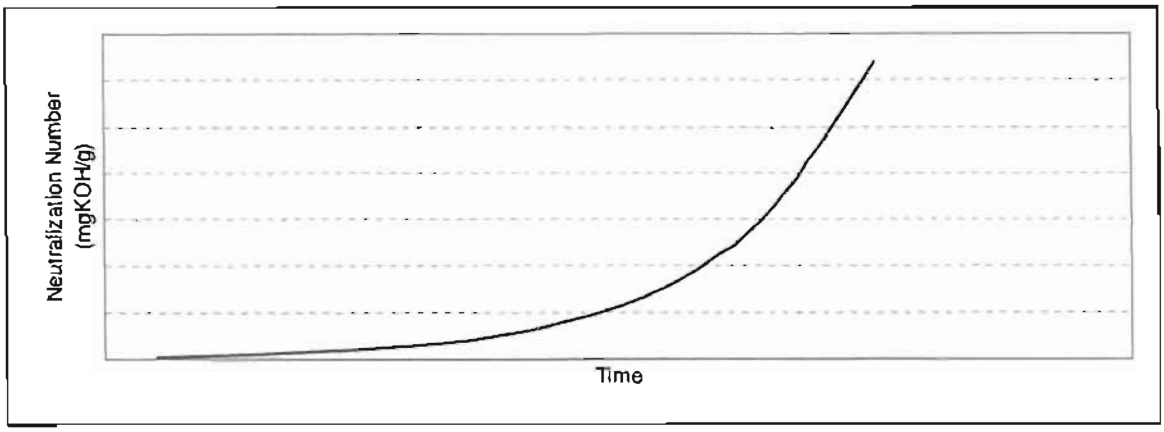


Figure 3-5: Acid buildup over time

The ageing of the cellulose results in the build-up of sludge. This process can be hastened by moisture and free access to oxygen. The sludge builds up in progressive layers with varying degrees of hardness, depending on how the unit has been operated and the length of time the equipment was in service.

3.4.6. Interfacial tension

The interfacial tension test (IFT) [64] is used by transformer oil laboratories to determine the interfacial tension between the oil sample and distilled water. The oil sample is placed in a beaker of distilled water at a temperature of 25 ^{0}C. The oil will float because its specific gravity is less than that of water. There should be a distinct line between the two liquids. The IFT number is the amount of force (dynes) required to pull a small wire ring upward a distance of 1 centimetre through the water-oil interface. A dyne is a very small unit of force equal to 0.000002247 pound. Good clean oil will make a very distinct line on top of the water and give an IFT number of 40 to 50 dynes per centimetre of travel of the wire ring.

As oil ages, it is contaminated by tiny particles. Particles on top of the water extend across the water-oil interface line which weakens the surface tension between the two liquids. Particles in oil weaken interfacial tension and lower the IFT number. IFT and acid number together are an excellent indication of when the oil needs to be reclaimed. It is recommended the oil be reclaimed when the IFT number falls to 25 dynes per centimetre. At this level, the oil is very contaminated and must be reclaimed to prevent slugging, which begins around 22 dynes per centimetre [56].

If oil is not reclaimed, sludge will settle on windings, insulation, cooling surfaces, etc., and cause loading and cooling problems. This will greatly shorten the transformers life. There is a definite relationship between acid number, the IFT, and years-in-service. Figure 3-6 [65] shows this relationship. The curve shows the normal service limits both for the IFT and the acid number.

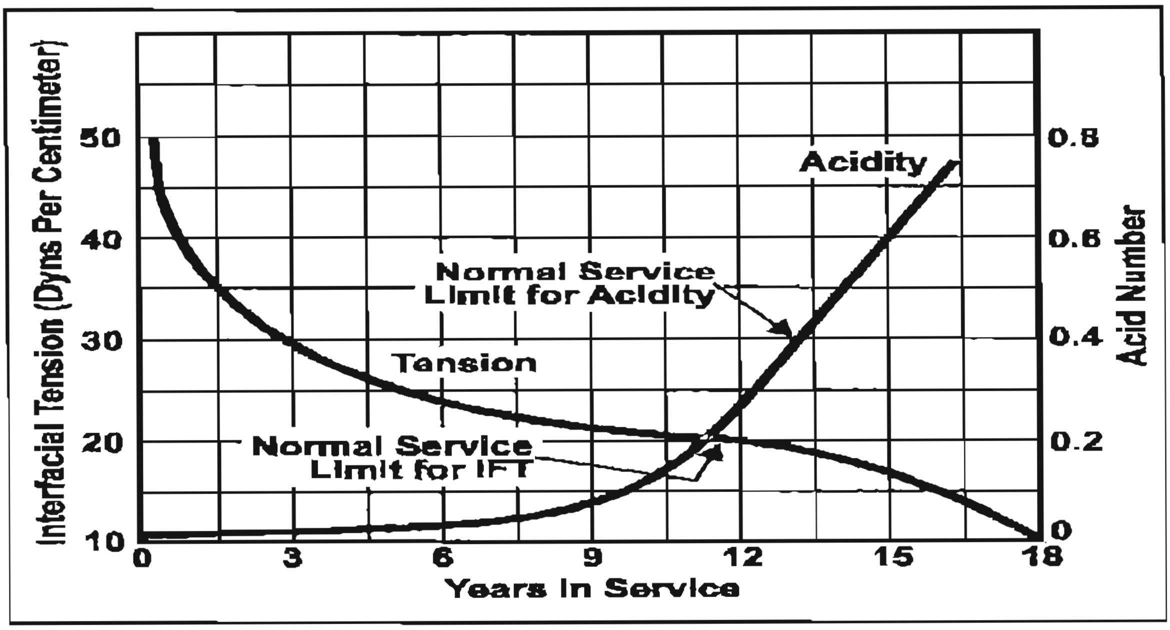


Figure 3-6: Relationship between acid number, IFT and years in service

3.4.7. Furans

The paper insulation comprises cellulose, which is a polymer consisting of long chains of glucose rings, joined by glycosidic bonds. The number of these glucose rings is referred to as the degree of polymerization (DP) of the cellulose. Cellulose decomposition results in the formation of glucose, moisture, carbon monoxide, carbon dioxide and some organic acids. Glucose is unstable and has very low solubility in the transformer oil. The dehydration of the glucose molecules is responsible for the production of furanic derivatives, which are partially soluble in the oil.

The results obtained, from the furanic's in the oil, is used to calculate the degree of polymerization, which will give an indication of the level of deterioration of the solid insulation system. Cellulose degradation is accelerated by the presence of moisture, oxygen and temperature, which are all available to the cellulose in the environment of the transformer. The benefit of this analysis is to establish a maintenance program to stall the rate of degradation or to take the unit off-line for immediate action prior to a failure [66].

3.4.8. Interpretation of furanic compounds

In healthy transformers, there are no detectable furans in the oil, or they are less than 100 ppb. In cases where significant damage to paper insulation from heat has occurred, furan levels have been found to be at least 100 ppb and up to 70,000 ppb. The furan numbers in Table 3-2, can be used for assessment [47]. The first column in Table 3-2 is used for transformers with non-thermally upgraded paper, and the second column is for transformers with thermally upgraded paper.

Table 3-2: Furans, DP, percent of life used, of paper insulation

55^0C Rise Transformer 2FAL (ppb)	65^0C Rise Transformer Total Furans (ppb)	Estimated (DP)	Estimated Percentage of Remaining Life	Interpretation
58	51	800	100	Normal Aging Rate
130	100	700	90	
292	195	600	79	
654	381	500	66	Accelerated Aging Rate
1 464	745	400	50	
1 720	852	380	46	
2 021	974	360	42	
2 374	1 113	340	38	Excessive Aging Zone
2 789	1 273	320	33	
3 277	1 455	300	29	
3 851	1 664	280	24	High Risk of Failure
4 524	1 902	260	19	
5 315	2 175	240	13	End of Expected Life of Paper Insulation and of the Transformer
6 245	2 487	220	7	
7 337	2 843	200	0	

3.5. Dissolved gas in oil analysis

3.5.1. Origin of gases in transformer oil

Corona, thermal heating and arcing cause gases to be produced in insulating oil. This is due to the breakdown products of the oil under electrical and thermal activity [61].

3.5.2. Partial discharge

This is a fault of low level energy which usually occurs in gas-filled voids surrounded by oil impregnated material. Bubbles in the actual oil may cause partial discharge, especially when the bubble is in a high electrical stress area. However, the main cause of decomposition that results in partial discharge is ionic bombardment of the oil molecules. The major gas produced is hydrogen and the minor gas produced is methane [61].

3.5.3. Thermal faults

A small amount of decomposition occurs at normal operating temperatures. As the fault temperature rises, the formation of the degradation gases change from methane to ethane to ethylene. A thermal fault at low temperature, typically lower than 300°C, produces mainly methane and ethane with some ethylene as shown in Figure 3-7 [67].

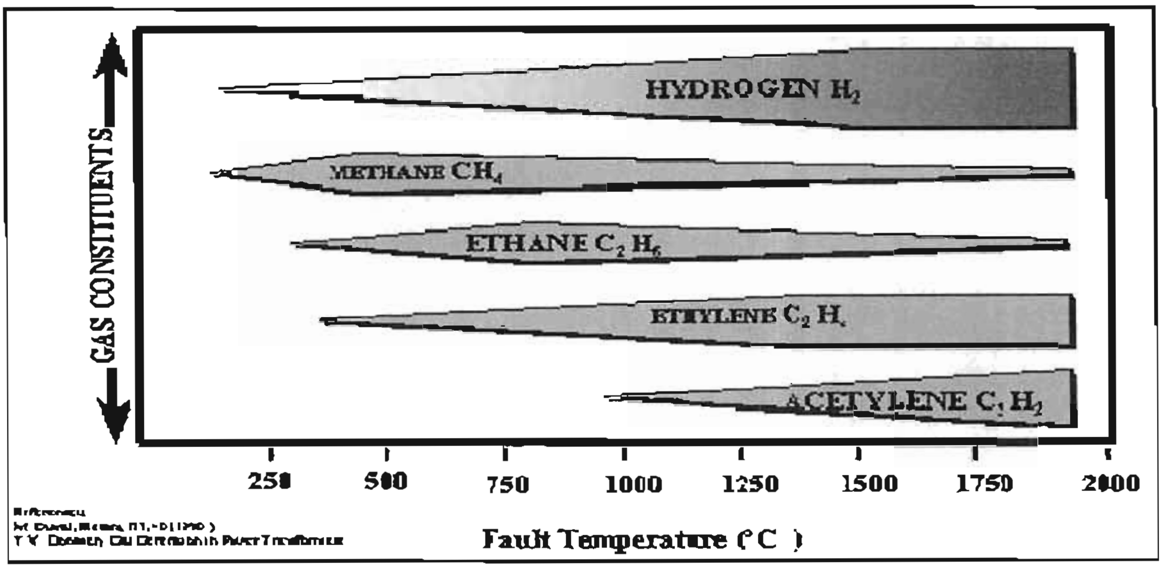


Figure 3-7: Production of methane and ethane at low temperature

A thermal fault at higher temperatures, typically higher than 300°C, produces ethylene. The higher the temperature becomes the greater the production of ethylene. Extremely high temperatures ~ 1000°C may bring on the presence of acetylene.

3.5.4. Arcing

An arcing fault is caused by high-energy discharge. In most cases the discharge has a power follow-through. In arcing, the major gas produced is acetylene. Power arcing can cause temperatures of over 3000 °C to be developed. If the cellulose material is involved, carbon monoxide and carbon dioxide are generated [67].

3.5.5. Ageing

A normally ageing conservator type transformer should have a CO_2/CO ratio of about 7. Any CO_2/CO ratio above 11 or below 3 should be regarded as perhaps indicating a fault involving cellulose, provided the other gas analysis results also indicate excessive oil degradation, as shown in Figure 3-8 [67]. Dissolved gas analysis is a valuable technique for detecting and identifying faults occurring within equipment that is in service. Heat or electrical discharges occurring inside the power transformer result in the decomposition of the insulating oil and other insulating materials. This decomposition causes gases to be formed which will re-dissolve into the oil. A sudden large release of gas will not dissolve in the oil and this will cause the buchholz relay to activate and trip the transformer.

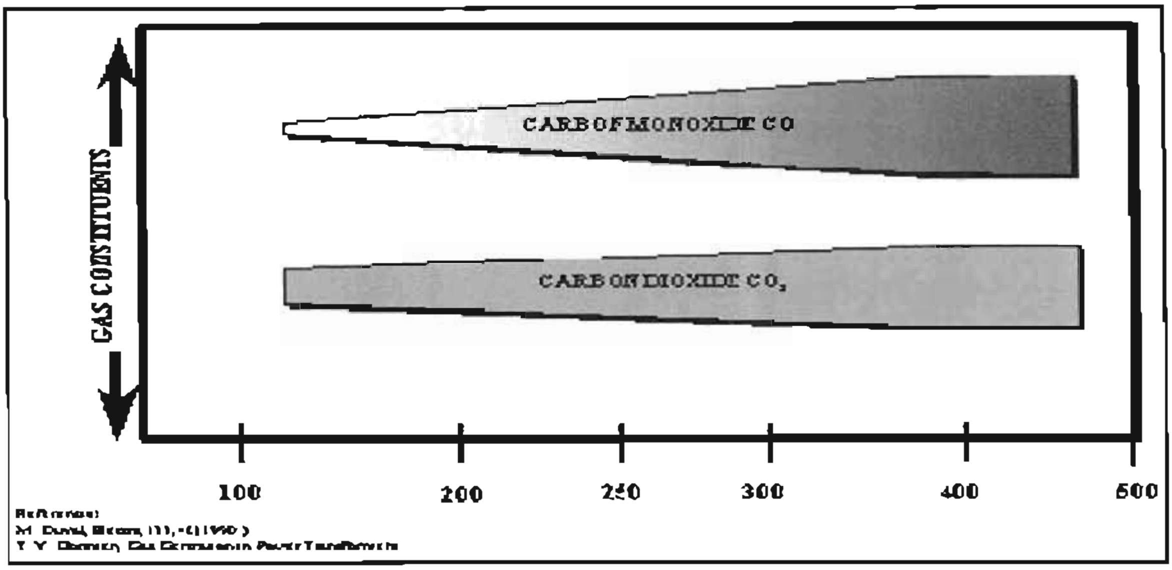


Figure 3-8: Production rate of CO and CO_2 on a temperature scale

By separating and measuring the gases dissolved in the oil, the engineer can identify the presence of an incipient or developing fault. Insulating oil and solid cellulose insulating materials will degrade and breakdown under thermal and electrical stress. This process will produce gases of varying composition and concentrations relating to the severity of the fault or stress applied to these materials. These gases dissolve in oil and thus need to be extracted and analyzed in a laboratory after a sample of the oil is taken.

The nature and composition are indicative of the type and severity of the fault in the transformer. The production of these gases and their rate of production are important factors when analyzing an oil sample and determining the type of fault and ultimately the evolution of the fault. Degradation of the oil will produce hydrogen, methane, ethane, ethylene and acetylene. Whereas partial discharge will produce hydrogen and methane as key gases, arcing will produce acetylene and hydrogen and as the fault temperature increases so will the amount of acetylene.

Overheating of oil, partial discharge and arcing will produce hydrogen, methane, ethane, ethylene and acetylene. Hot spots will overheat the oil and will produce ethylene and measurable concentration of hydrogen. The temperature at which the oil breaks down gives an indication as to what the fault type is. There are many higher hydrocarbon gases generated when the chemical links in the oil are broken but not all the gases are as important as Table 3-3 [67].

Table 3-3: Important fault gases

Combustible gas	Hydrogen	H_2
	Methane	CH_4
	Ethane	C_2H_6
	Ethylene	C_2H_4
	Acetylene	C_2H_2
	Carbon Monoxide	CO
Non combustible gas	Carbon Dioxide	CO_2
	Oxygen	O
	Nitrogen	N

3.5.6. Interpretation of dissolved gas analysis

There are various international guidelines on interpreting dissolved gas (DGA) data. These guidelines show that the interpretation of DGA is more of an acquired skill.

- Rogers Ratio Analysis Method
- IEC 60599 Ratio Method.
- Trend / Combustible gases production per day.
- California State University Sacramento – Guidelines for combustible gases.
- IEEE production rates.
- Total Dissolved Combustible Gases.

3.5.6.1. Rogers Ratio

The Rogers Ratio method [67].uses four ratios of dissolved gas concentration to generate a code that will determine the nature of the fault. These codes are shown in Table 3-4. The results of the ratios are shown in Table 3-5.

Table 3-4: Rogers Ratio table of codes

Ratios		< 0,1	0,1 to 1	1 to 3	>3
CH_4/H_2	R1	5	0	1	2
C_2H_6/CH_4	R2	0	0	1	1
C_2H_4/C_2H_6	R3	0	0	1	2
C_2H_2/C_2H_4	R4	0	1	1	2

Table 3-5: Rogers Ratio results of ratio table

	R1	R2	R3	R4
Normal	0	0	0	0
Partial Discharge	5	0	0	0
Overheating <150°C	1 or 2	0	0	0
Overheating 150°C to 200°C	1 or 2	1	0	0
Over heating 150°C to 200°C	0	1	0	0
General conductor overheating	0	0	1	0
Winding circulating currents	1	0	1	0
Core and tank circulating currents	1	0	2	0
Overheated joints	1	0	2	0
Flashover without power follow-through	0	0	0	1
Partial discharge with tracking	5	0	0	1 or 2
Continuous sparking to floating potential	0	0	2	2
Arc with power follow-through	0	0	1 or 2	1 or 2

3.5.6.2. IEC 60599 ratios

The method in IEC 60599 [38] is the most up to date of the ratio methods. The method uses only three ratios as against the four used in the Rogers ratio method. Table 3-6 tabulates the IEC codes.

Table 3-6: IEC 60599 ratio method

		Code of range of ratios			
		$\frac{C_2H_2}{C_2H_4}$	$\frac{CH_4}{H_2}$	$\frac{C_2H_4}{C_2H_6}$	
	Ratios of characteristic gases <0,1 0,1 - 1 1 – 3 >3	 0 1 1 2	 1 0 2 2	 0 0 1 2	
Case No.:	Characteristic fault				Typical examples
0	No fault	0	0	0	Normal ageing
1	Partial discharge of low energy density	0	1	0	Discharges in gas-filled cavities resulting from incomplete impregnation, or super saturation or cavitations or high humidity.
2	Partial Discharge of high energy density	1	1	0	As above, but leading to tracking or perforation of solid insulation.
3	Discharge of low energy	1-2	0	1-2	Continuous sparking in oil between bad connections of different potential or to floating potential. Breakdown of oil between solid materials.
4	Discharge of high energy	1	0	2	Discharges with power follow-through. Arcing – breakdown of oil between windings or coils or between coils to earth. Selector breaking current.
5	Thermal fault of low temperature range <150^{0}C	0	0	1	General insulated conductor over heating.
6	Thermal fault of low temperature range 150^{0}C to 300 C	0	2	0	Local overheating of the core due to concentrations of flux. Increasing hot spot temperatures; varying from small hot spots in core, shorting links in core, overheating of copper due to eddy currents, bad connections (pyrolitic carbon formation) up to core and tank circulating currents.
	Thermal fault of Medium temperature range 300^{0}C to 700 C	0	2	1	
	Thermal fault of low temperature range >700^{0}C	0	2	2	

It is useful to use either of the two ratio methods as they cancel out the anomalies found in the methods of analysis. In the daily analysis of oil samples there are variances of 10%. Therefore small variations are found between samples tested even on the same day with the same instrument. The ratio method has its faults and the analyst must be aware that when more than one fault is developing then the ratios become scrambled and do not provide the best information i.e. the code produced does not have a diagnosis.

There are two other methods that can be used to interpret the gases present i.e. Duval and Doernenburg. The Doernenburg ratios are best for gases taken from the gas phase of the transformer. Duval will assist in the analysis but there is no leeway for a condition that is called normal ageing. Both the ratio methods needs to have minimum limits to prevent from dividing by zero (acetylene can be zero and normally is zero) and secondly prevent the ratios from producing incorrect diagnosis. The ratios can produce codes that mean a fault is occurring on low values of dissolved gases. Hydrogen should be above 50 ppm and the other gases over 10 ppm.

3.5.6.3. California State University Sacramento Guidelines

The California State University Sacramento Guidelines serve as a good guide. Table 3-7 is used as a reference and when the individual gases indicate "elevated" it is time to start investigating further.

Table 3-7: California State University Sacramento Guidelines for combustible gases

Gas	Normal	Abnormal	Interpretation
Hydrogen	<150 ppm	>1000	Arcing, corona
Methane	<25	>80	Sparking
Ethane	<10	>35	Local overheating
Ethylene	<20	>100	Severe overheating
Acetylene	<15	>70	Arcing
Carbon Monoxide	<500	>1000	Severe overloading
Nitrogen	1 % to 10 %		Normal Ageing
Oxygen	0,2 % to 3,5 %		Normal Ageing
Total Combustible gases	<720	>5000	Total Combustible gas limit
Carbon Dioxide	<10000	>15000	Severe overloading

3.5.6.4. Total Dissolved Combustible Gases

This method was developed by the IEEE Society [38] and covers not only the determination of a faults severity and its nature, but also offers some indication as to the follow-up action that is necessary. To calculate the Total Dissolved Combustible Gases (TDCG) all the combustible gases found in the analysis are summated.

$$\begin{aligned} TDCG &= H_2 + CO + CH_4 + C_2H_6 + C_2H_4 + C_2H_2 \\ &= \text{Hydrogen} + \text{Carbon Monoxide} + \text{Methane} + \text{Ethane} + \text{Ethylene} + \text{Acetylene} \end{aligned}$$

Table 3-8: TDCG sampling frequency guide

1	<720	Operating satisfactorily
2	721 to 1920	Fault(s) may be present
3	1921 to 4630	Fault(s) are probably present
4	>4630	Continued operation could result in unit failure.

The TDCG can be monitored over time and Table 3-9 [38], is a useful guide for determining the frequency of sampling. The TDCG is calculated in ppm per day as follows: the difference between the previous TDCG value and the current TDCG value divided by the number of days between the samples.

Table 3-9: Determination of sampling frequency for ppm/day

Trend TDCG ppm/day	Condition 1	Condition 2	Condition 3	Condition 4
< 10	Annual	Quarterly	Monthly	Weekly
10 to 30	Quarterly	Monthly	Weekly	Daily
> 30	Monthly	Monthly	Weekly	Daily

3.5.6.5. Key Gas Method of analyzing dissolved gases.

The key gas method relates the fault to a set of graphs that illustrate the relative proportions of each gas with regard to the Total Dissolved Combustible Gases. This chart is created by calculating the TDCG then the relative key gas values (carbon monoxide, hydrogen, methane, ethane, ethylene and acetylene) as a percentage of the TDCG. Once these values are inserted into the chart they are represented as bars on the chart. A relative match can be found from Figures 3-9 to 3-12 [38]. Once a match is made the fault that is represented by the matched pattern is the fault that is occurring. This method is not useful when two different types of faults are occurring at once.

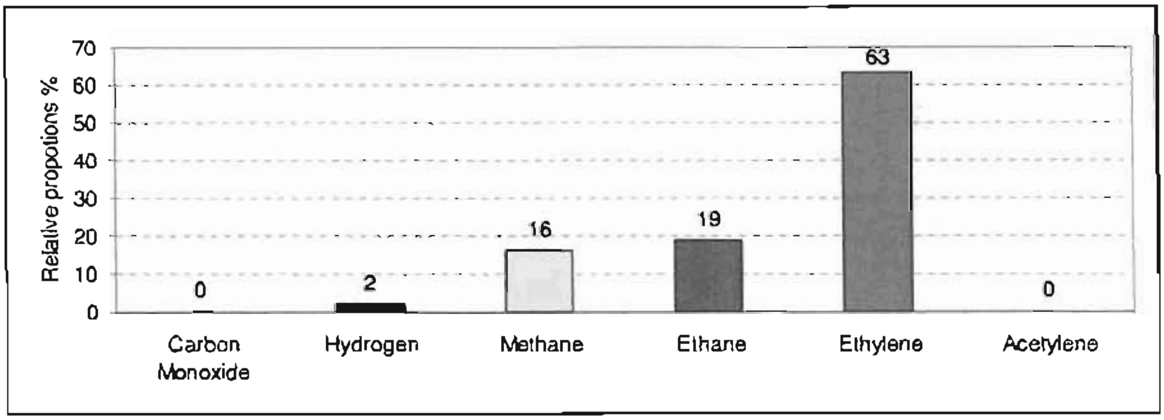


Figure 3-9: Overheated oil

Decomposition products include ethylene and methane, together with smaller quantities of hydrogen and ethane. Traces of acetylene may be formed if the fault is severe or involves electrical contacts. The principal gas is Ethylene.

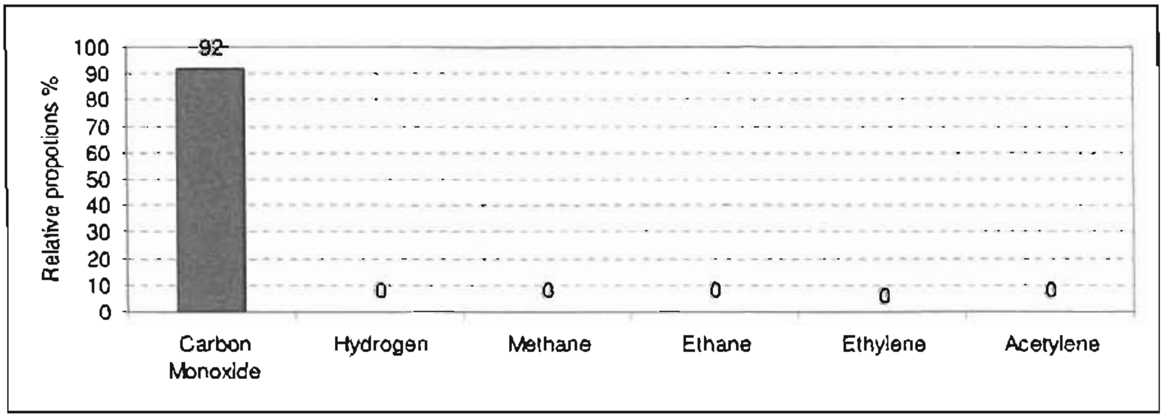


Figure 3-10: Overheated cellulose

Large quantities of carbon dioxide and carbon monoxide are evolved from overheated cellulose. Hydrocarbon gases, such as methane and ethylene, will be formed if the fault involves an oil impregnated structure. The principal gas is Carbon Monoxide.

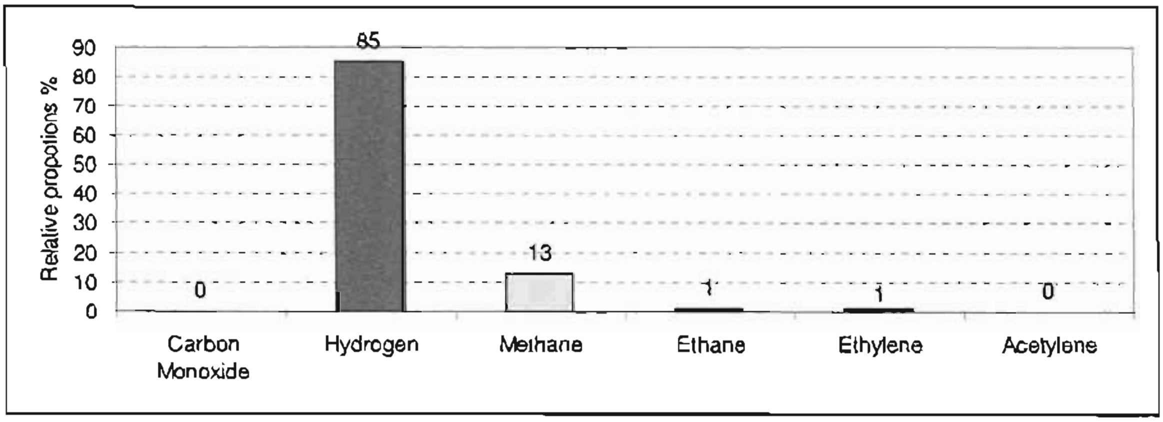


Figure 3-11: Corona in oil

Low energy electrical discharges produce hydrogen and methane, with small quantities of ethane and ethylene. Comparable amounts of carbon monoxide and dioxide may result from discharges in cellulose. The principal gas is Hydrogen.

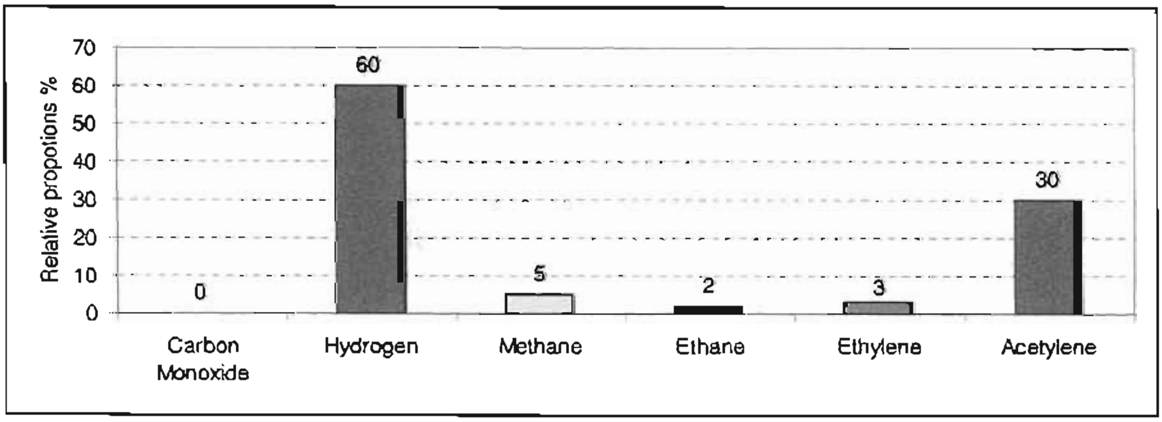


Figure 3-12: Arcing in oil

Large amounts of hydrogen and acetylene are produced, with minor quantities of methane and ethylene. Carbon dioxide and carbon monoxide may also be present if the fault involves cellulose. Oil may be carbonized. The principal gas is Acetylene.

3.5.6.7. Production per day

When analyzing a transformer, the maintenance of oil history is very important. The rate at which gas is produced in a transformer is very important. The rate of gas production per day [38] serves as an indication that the fault is serious. Once a fault condition is established a replacement transformer may not be available, thus highlighting the proper management of the existing asset based on the production per day analysis. This method relies on the previous sample result being available. The difference between the current and previous combustible gas result is calculated and divided by the number of days between the testing of the two samples.

The volume of oil affects the production per day results. In large transformers a small change in results may indicate that the fault is developing quickly, but in a smaller transformer large changes may indicate a minor change, in the progress of the fault, is taking place. Table 3-10 [38] shows values that serve as a guideline.

Table 3-10: Values of gas component for 50 m^3 of oil

Gas component	Normal (ppm/Day)	Serious (ppm/Day)
Hydrogen	< 0,1	>2
Methane	0,05	6
Ethane	0,05	6
Ethylene	0,05	6
Acetylene	0,05	1
Carbon Monoxide	2	10
Carbon Dioxide	6	20

3.5.6.8. Dissolved Gas Guidelines

The first pass filter is to check the individual combustible gases [38], specifically hydrogen.

- The hydrogen value should not be over 50 ppm.
- If hydrogen is over 50 ppm check the methane, ethane and ethylene gases.
- If these are over 10 ppm the then there may be a fault developing.
- At this point it may be necessary to carry out a Key Gases identification analysis or use the total dissolved combustible gases analysis.
- The TDCG value should not be above 720 ppm.
- If this limit is exceeded, use the TDCG table of production per day is used to determine the frequency of sampling.
- It is advisable to initiate taking another sample to check the production per day. The sample must be taken from the same sampling point.
- Check the previous sample.

To determine the type of fault it is useful to use the Key Gas graphs. Understanding the temperature of the fault helps understand the type of fault. Due to the fact that the transformers at Eskom are only sampled yearly, if a bad result is noticed then action needs to be taken. In this case it would advisable to:

- Initiate a re-sample as soon as possible.
- Check the production per day of the individual gases.
- Check the production per day of the TDCG.

Once the results of the sample are available re-check the TDCG production per day. If the transformer exceeds the TDCG of 30 ppm per day then it is advisable to request a spare and contact the operational staff and notify them of the impending failure. Under fault conditions i.e. buchholz tripping or differential relay operation, an oil sample must be taken. To minimize the risk of mechanical failure careful consideration must be given to the interpretation of the oil results. With any sign of flashover (high concentrations of acetylene and hydrogen or substantial insulation damage, carbon monoxide) the risk of causing further mechanical damage is high. The unit must under go electrical tests.

3.6. Electrical testing

Electrical testing of power transformers provides an indication of the extent of the transformer to comply with loading capability, dielectric withstand, and further operating characteristics. The requirements of tests are combined and published in national and international standards. The primary standards organizations are IEC and ANSI.

Tests are divided into three categories i.e. Routine tests, Type tests, and Special tests. The tests done on site are routine and will be discussed briefly, to illustrate its purpose and to show the type of electrical test to be performed on a power transformer for elevated gas levels.

3.6.1. Turns ratio

This test only needs to be performed if a problem is suspected from the DGA Tests. The turns ratio test detects shorted turns which indicate insulation failure. Shorted turns will result from short circuits or dielectric failures. Measurements are made by applying a known low voltage across the high voltage winding and measuring the induced voltage on the low voltage winding. The voltage ratio obtained by the test is compared to the nameplate voltage ratio. The ratio obtained from the field test should be within 0.5% of the nameplate. New transformers of good quality normally compare to the nameplate within 0.1% [68] [69].

3.6.2. Leakage reactance

This test is performed to verify the nameplate percent impedance. A 3% difference from the nameplate is acceptable. However, after the initial onsite test, the percent impedance should not vary more than 2%. As the transformer ages or is subjected to through faults, induced lightning strikes, and switching surges, this test is used to detect winding deformation. Winding deformation can lead to immediate transformer failure after a severe through fault, or a small deformation can lead to a failure years later. Percent leakage reactance testing is performed by short circuiting the low voltage winding, and applying a test voltage to the high voltage winding [68] [70].

3.6.3. Bushing tan delta

This test is performed on bushings that have a potential tap point .The capacitance between the top of the bushing and the bottom tap and the capacitance between the tap and ground are measured. To determine bushing losses, power factor tests are also performed. Tap and ground capacitance is much greater than the capacitance between the top of the bushing and the bottom tapping point [71].

3.6.4. Winding tan delta

This test determines the state of dryness of the windings and insulation system and to determine a power factor for the overall insulation, including bushings, oil, and windings. It is a measure of the ratio of the power losses to the volt-amperes applied during the test. The power factor obtained is a measure of watts lost in the total transformer insulation system including the bushings. The power factor should not exceed 0.5% [72].

3.6.5. Magnetizing current/excitation

This test is used to detect short-circuited turns, poor electrical connections, core de-laminations, core lamination shorts, tap changer problems, and other possible core and winding problems. On three-phase transformers, results are also compared between phases. This test measures current needed to magnetize the core and generate the magnetic field in the windings [69].

3.6.6. Frequency response analysis

This test shows, in trace form, the winding transfer function of the transformer and is used to determine if any damage has occurred during shipping or during a through fault. Core grounds, core displacement, and other core and winding problems can be revealed by this test. These tests should be conducted before and after the transformer has been moved or after experiencing a through fault. Results should be compared to initial tests performed at the factory.

For a delta/star transformer, a test voltage of variable frequency is placed across each phase of the high voltage winding. With this set of tests, low voltage windings are isolated with no connections on any of the bushings. An additional set of tests is performed by short circuiting all the low voltage windings and again placing the test voltage on each phase of the high voltage winding. A third set of tests is done by isolating the high voltage winding and placing the test voltage across each low voltage winding [73].

3.6.7. DC winding resistance

If there is generation of ethylene, ethane, and methane in the DGA's, this indicates a poor connection, winding resistances should be checked. Winding resistances are tested in the field to check for loose connections on bushings or tap changers, broken strands, and high contact resistance in tap changers. Results are compared to other phases in star connected transformers or between pairs of terminals on a delta-connected winding to determine if a resistance is too high. Resistances can also be compared to the original factory measurements or to sister transformers. Agreement within 5% for any of the above comparisons is considered satisfactory [69].

3.6.8. Core insulation test

Core insulation resistance and core ground tests are used if an unintentional core ground is suspected; this may be indicated by the DGA. Key gases that are present ethane and-or ethylene and possibly methane. These gases may also be present if there is a poor connection at the bottom of a bushing or a bad tap changer contact. Therefore, this test is only necessary if the winding resistance test above shows that all the connections are good and if tap changer contacts are in good condition.

The core ground connection must be disconnected. This may be difficult, and some oil may have to be drained to accomplish this. On some transformers, core grounds are brought outside through insulated bushings and are easily accessed. A standard dc insulation tester is then attached between the core and ground. The insulation tester is used to place a dc voltage between these points and the resistance is measured. A new transformer should read greater than 1 gigaohms. A service-aged transformer should read greater than 100 megohms. Ten to one hundred megohms is indicative of deteriorating insulation between the core and ground. Less than 10 megohms is sufficient to cause destructive circulating currents and must be further investigated [74].

3.6.9. Audible transformer sound level

The 100hertz noise that's created by the 50hertz system frequency comes from the steel core [75]. The sound level of a typical transformer should not exceed 58dB. The dB value is an indication of the effectiveness of the core clamping. This is illustrated in Table 3-11 [76].

Table 3-11: Effects of load change on the sound levels of a power transformer

Decibels	Power change	Decibels	Power change
1	1.25	10	10
2	1.58	11	12.6
3	2	12	15.8
4	2.5	13	20
5	3.15	14	25.1
6	4	15	31.6
7	5	20	100
8	6.3	30	1000
9	7.9	40	10000
1 db = lowest sound that can be heard, 70 db = human voice, 30 db = whisper 100 db = loud radio, 58 db = average office noise level, 120 db = ear discomfort			

3.7. Eastern Region transformer condition analysis

The oil of power transformers at Eskom Distribution (Eastern Region) were sampled and tested for Electric Strength, Moisture Content, Predicted DP, Ethane, Ethylene and Acetylene. The results of the tests are presented below, highlighting the transformer fleets condition.

3.7.1. Electric strength profile

The existing transformer base has been tested for dissolved gasses, electric strength, moisture content, predicted DP, and acidity. Figures 3-13 to Figure 3-19 provides an indication of the condition of the power transformers.

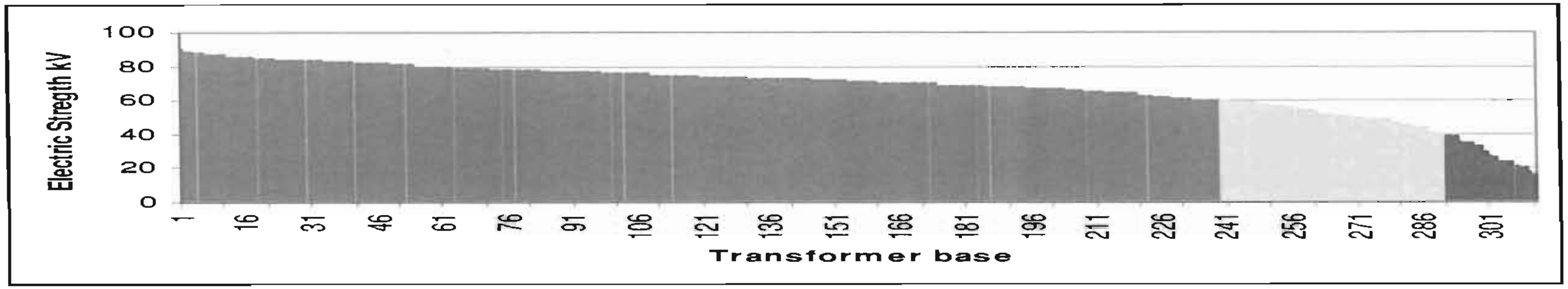


Figure 3-13: Electric strength profile

3.7.2. Water content & pipers chart profile

The electric strength is divided into three sections. The green area shows transformers that are within acceptable limits. The yellow area requires monitoring and may lead to filtering of the oil. The red area requires the transformers to be removed form service and a detail investigation conducted. The core may require a dry out and re-clamping of the windings.

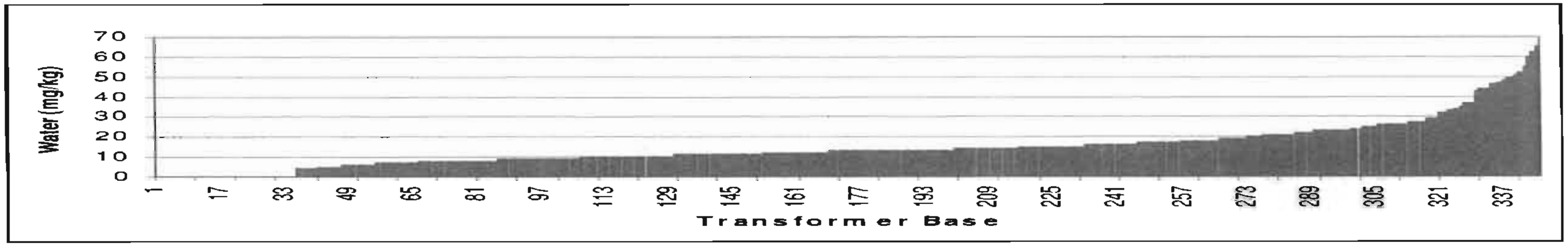


Figure 3-14: Water content profile

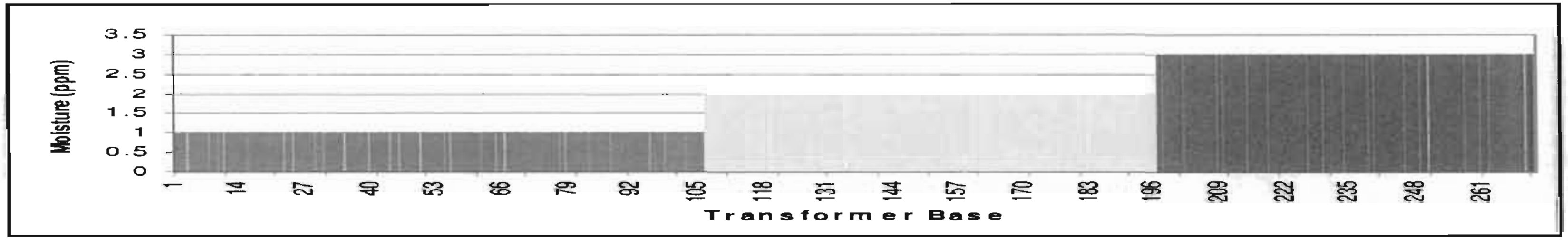


Figure 3-15: Pipers chart profile

The area in green indicated that no action is required. The area in yellow indicates that the oil requires filtering. The area in red indicates that specialist action is required since filtering cannot remove the water from the paper and oil due to the large concentration.

3.7.3. Predicted DP profile

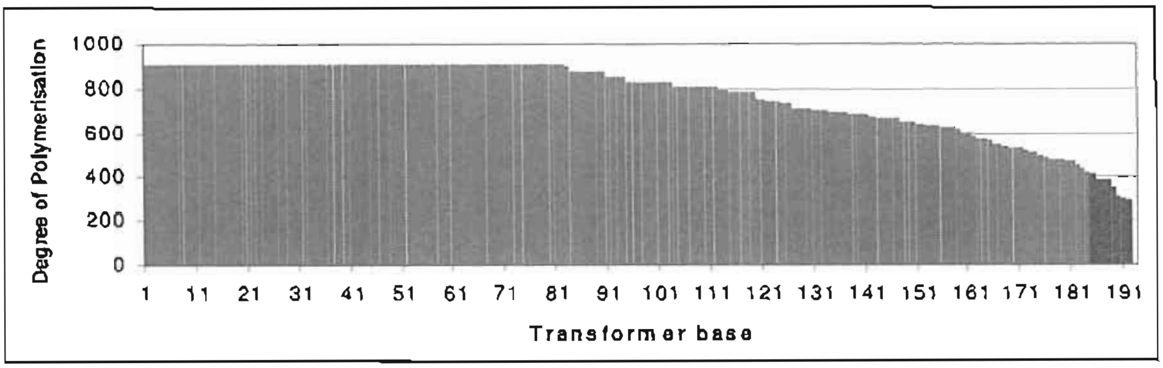


Figure 3-16: Predicted DP profile

The predicted DP shows the condition of the paper. Only a small number of transformers (in red) have a DP of less the 400.

3.7.4. Ethane profile

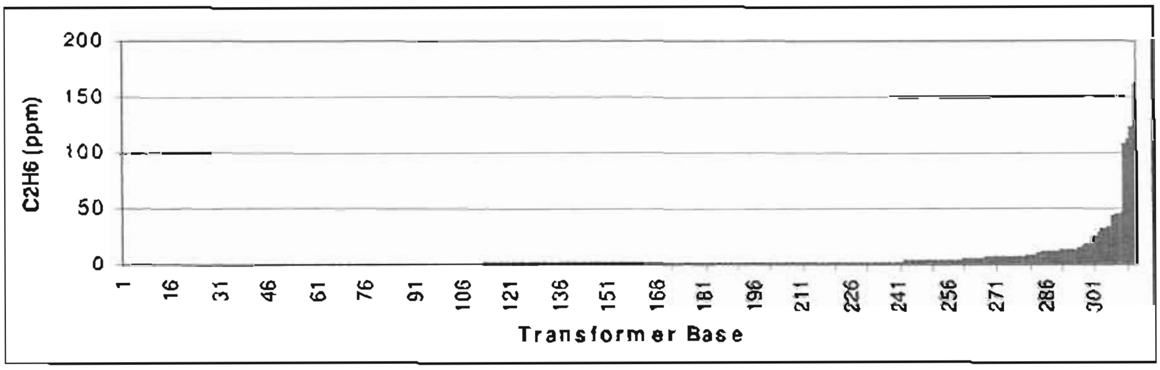


Figure 3-17: Ethane profile

Figure 3-17 shows the concentration of ethane in the transformers during normal operation, indicating local overheating within the transformer.

3.7.5. Ethylene profile

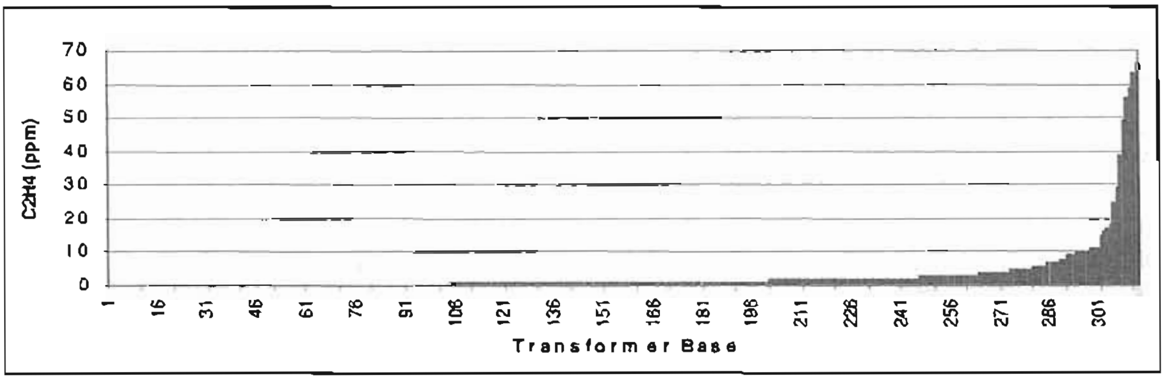


Figure 3-18: Ethylene profile

The above graph shows the concentration of ethylene in the transformers during normal operation, indicating severe overheating within the transformer.

3.7.6. Acetylene profile

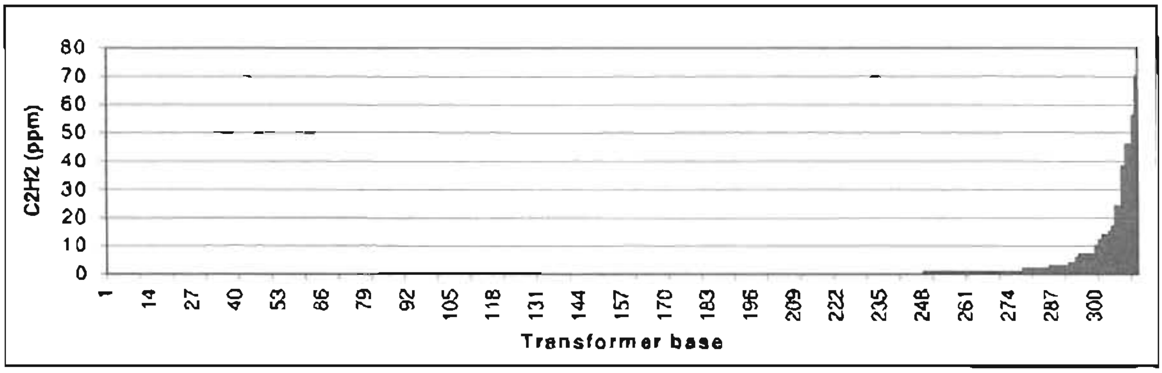


Figure 3-19. Acetylene profile

The above graph shows the concentration of Acetylene in the transformers during normal operation, indicating that arcing has occurred inside the transformer.

3.8. Case study – Failed 20MVA transformer analysis

Oil sampling and analysis of transformers are done yearly at Eskom Distribution. The case study is based on a sample that was taken in January 2007. High levels of fault gases were present in the sample. The previous samples were uses to establish that there was a substantial increase in fault gases. This called for frequent sampling to the daily production rate of the gases. The results of the daily production rate calculations showed that a serious fault was developing. The transformer was then removed from service and replaced with a strategic spare. The transformer details for this case study are given below:

Transformer details:

MVA rating:	20 MVA
Voltage ratio:	132/11kV
Make:	ABB
Serial number:	29691
Tapchanger:	UZRN
Cooling:	ONAN
Percentage loading:	56.8MVA
Year of manufacture:	1996
Age at failure:	10 years

Table 3-12 tabulates the oil sample history from 1996 to 2007.

Table 3-12: Case study - Oil samples of failed 20MVA transformer

No.	Sampled	O2	N2	CO	H2	CH4	CO2	C2H4	C2H6	C2H2	H2O	ES	ACID	TEMP
1	14-Oct-96	22752	48831	11	0	1	246	0	1	0	13	70	0.01	48
2	14-Oct-96	21866	47330	14	0	1	217	0	1	0	7	69	0.01	48
3	04-Feb-97	19067	54512	70	11	3	520	0	6	0	10	79	0.01	50
4	27-Jan-98	18485	50917	48	10	3	768	1	13	0	12	73	0.01	54
5	04-Mar-99	22640	54332	80	69	5	1007	1	18	1	15	71	0.01	52
6	19-Jan-00	12102	49759	103	150	3	1022	0	13	1	13	73	0.01	50
7	03-Mar-00	12224	52975	130	181	3	1319	0	15	1	13	78	0.01	48
8	05-Jan-01	21453	53348	107	68	2	1519	0	9	0	10	68	0.02	51
9	29-Apr-04	23246	51378	30	2	1	204	0	0	0	6	64	0.02	35
10	25-May-04	20363	44156	33	2	1	227	0	0	0	10	72	0.01	42
11	11-Jan-05	21043	42448	42	2	1	451	0	0	0	6	70	0.02	36
12	12-Jan-06	23401	57746	39	13	25	656	59	12	3	11	70	0.02	40
13	02-Feb-07	14763	43773	40	12	97	730	365	79	7	12	85	0.02	44
14	14-Feb-07	13878	41970	39	10	78	710	347	73	6	8	85	0.02	44
15	19-Feb-07	14442	42696	47	10	89	832	392	88	11	8	78	0.02	46
16	21-Feb-07	14234	41962	47	10	89	851	398	90	12	8	78	0.02	56

3.8.1. Oil result analysis

The tests from Table 3-12 was analysed using the following oil analysis methods:

(a) CSUS Guideline Diagnosis
(b) Rogers Ratio Method
(c) Dornenberg Method
(d) Key Gas Analysis
(e) TDCG Analysis

3.8.1.1. DGA findings

(a) CSUS Guideline Diagnosis
Sample 13, 15, and 16 shows signs of sparking.
Sample 13, 14 and 15 shows local overheating and severe overheating.

(b) Rogers Ratio Method
Sample 3 and 4 shows heat present at a temperature of between 100 to 200 ^{0}C.

(c) Dornenberg Method
Sample 5 shows that corona is present.
Sample 12, 13, 14, 15, 16 shows hot spots.

(d) Key Gas Analysis
Sample 1 to 12 shows that the cellulose is overheated.
Sample 5, 6, 7, 8 shows that corona is present.
Sample 12 to 16 shows severe overheating.

(e) TDCG Analysis

The TDCG shows that the total dissolved combustible gas level is below the acceptable 720 limit.

From the above analysis methods results it is deduced that a fault was developing from sample 12 onwards. The daily gas production rate increased on successive samples. This supported the decision to remove the transformer from service and replace it with a strategic spare before the power transformer failed in service

3.8.2. Electric strength & moisture

The electric strength results of the samples taken range from 64 to 85kV. This is within Eskom's acceptable limits. The moisture in oil results range from 6 to 15 ppm. This is also within Eskom's acceptable limits.

3.8.3. DP analysis

The predicted DP of the transformer is 827 and the transformer is still considered to 100% remaining life. Table 3-2 indicates that the transformer is aging normally and has 100% useful remaining life.

3.8.4. Percentage Trending Method

Trending the results of several samples is not very useful as the "X-scale" of the plot has values in the thousands of ppm for some gases and others are in minute quantities. The Percentage Trending Method was developed to plot the results on a normalized scale. This was achieved by converting the results of each sample to a percentage of the individual gases.

The ppms of each gas taken in the 16 samples were converted to a percentage. For example, all 16 of the CO results were summed obtaining a total of 880. The first result converted to a percentage is then $\frac{11}{880} x100\%$. This is 1% of the 800 base.

The same methodology is used to convert all results to a percentage. The results are tabulated in Table 3-13.

Table 3- 13: Case study - Percentage representation of gases

Sampled	O2	N2	CO	H2	H2	CH4	CO2	C2H4	C2H6	C2H2
14-Oct-96	8%	6%	1%	0	0%	0%	2%	0%	0%	0%
14-Oct-96	7%	6%	2%	0	0%	0%	2%	0%	0%	0%
04-Feb-97	6%	7%	8%	11	2%	1%	5%	0%	1%	0%
27-Jan-98	6%	7%	5%	10	2%	1%	7%	0%	3%	0%
04-Mar-99	8%	7%	9%	69	13%	1%	9%	0%	4%	2%
19-Jan-00	4%	6%	12%	150	27%	1%	9%	0%	3%	2%
03-Mar-00	4%	7%	15%	181	33%	1%	12%	0%	4%	2%
05-Jan-01	7%	7%	12%	68	12%	0%	13%	0%	2%	0%
29-Apr-04	8%	7%	3%	2	0%	0%	2%	0%	0%	0%
25-May-04	7%	6%	4%	2	0%	0%	2%	0%	0%	0%
11-Jan-05	7%	5%	5%	2	0%	0%	4%	0%	0%	0%
12-Jan-06	8%	7%	4%	13	2%	6%	6%	4%	3%	7%
02-Feb-07	5%	6%	5%	12	2%	24%	6%	23%	19%	17%
14-Feb-07	5%	5%	4%	10	2%	19%	6%	22%	17%	14%
19-Feb-07	5%	5%	5%	10	2%	22%	7%	25%	21%	26%
21-Feb-07	5%	5%	5%	10	2%	22%	8%	25%	22%	29%
TOTAL	100%	100%	100%	550	100%	100%	100%	100%	100%	100%

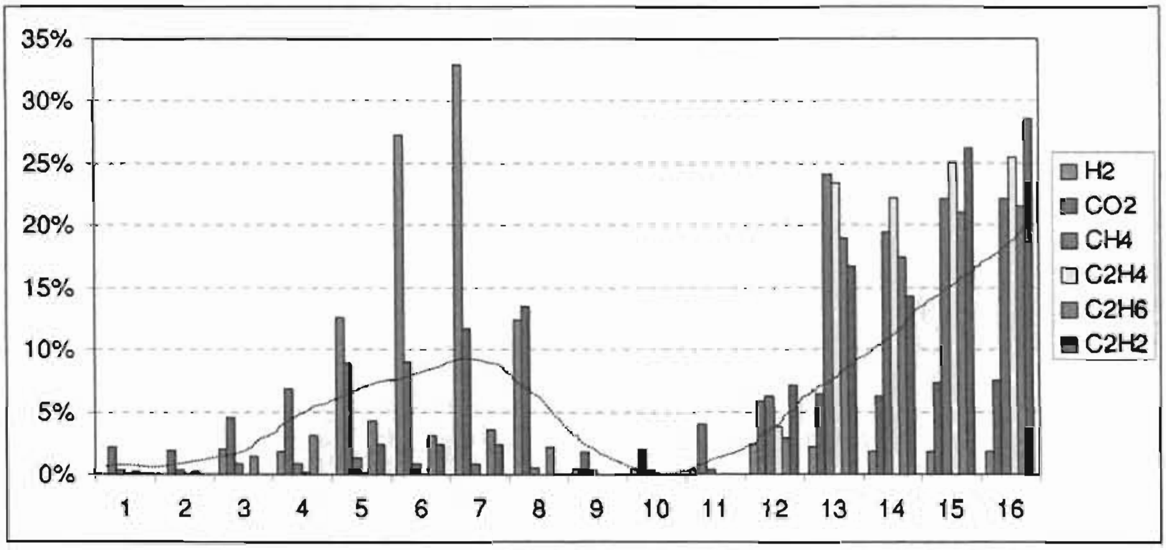


Figure 3-20: Case study - Percentage ratio of gases - Percentage Trending Model

Figure 3-20 is a graphical representation of Table 3-12. Only the fault gases are plotted to illustrate the percentage trending method. It can be observed that a developing fault occurred between sample 6 and 7. This is due to the sharp increase in H_2, CO_2 and a small increase in C_2H_2.

Samples 13 to 16 show a large increase in fault gases. The dotted line is an average of the samples and shows the trend of the sample.

The presence of H2 between sample 5 and 8 was also investigated. It was established that in the year 2000, the transformer experienced a fault after tap changer maintenance and was sent to the manufacture for repairs.

3.9. Chapter summary

Eskom Distribution conducts routine inspects of transformers on a monthly basis to identify any visual defects, not all defects are found due to low skill levels. Not all defects are cleared due to network constraints.

DP tests are done on a five yearly interval. Oil samples are taken and tested annually. They are used to trend the production of gasses to determine if a fault is developing. Any reduction in electric strength or increase in moisture is investigated.

There are several analysis methods that are used to trend a fault and to check or verify the results of one method against another. Eskom has the most confidence with the CSU method and the Key Gas Method of Analysis.

Electrical testing is done prior to commissioning and on a 5 yearly cycle. The tests done are limited. Only insulation resistance, magnetizing current, impedance tests and calibration of oil and temperature probes are done. In the recent years, due to network constraints and lack of skilled staff, transformers are not tested on a 5 yearly cycle.

A conditional analysis of the transformer fleet at Eskom was conducted. 10% of transformers have critically low electric strength. 6% of transformers have DP's below 400. The DGA results indicate that 23% of transformers have Ethane present in the oil, 68% have Ethylene present, 21% have acetylene present.

The case study developed a Percentage Trending Model to convert the gasses in the oil sample to a percentage value and plotting all gasses on a percentage graph. This method clearly illustrates a deviation from the norm, without any detailed knowledge of oil sampling. The case study shows a developing fault using the oil analysis methods discussed in this chapter.

CHAPTER 4: Reliability Analysis of Power Transformers

Case Study: At a component level and how it affects the system

4.0. Chapter overview

This chapter illustrates the reliability of a series and parallel network using actual reliability data. The network configuration is analysed and the percentage firmness of the system is determined. The fault levels at the substations were modelled using DigSilent. The breaker through faults at substations is then categorized into the breaker through fault range to determine the impact of breaker through faults. A reliability model of a transformer is developed. Actual failure data of components is used to calculate the reliability of the model. Power transformer failures from 1999 to 2006 were collected and verified and were then used to calculate the failure rate of transformers for Eskom Eastern Region. The power transformer failure rate is used to calculate the mean time to failure per transformer. Maintenance defects were collected from 2003 to 2006 to determine the physical condition of the transformer fleet. The impact of transformer reliability on system performance is determined. The impact of power transformer failures to performance indices such as CAIDI, SAIFI, SAIDI, RSLI and DSLI is calculated. The major impact performance index is calculated for failed transformers. A statistical analysis of power transformer using transformer failure data is used to highlight failures per year, age, voltage, MVA, manufacturer, failure triggers and transformer components. The cost of a transformer failure to Eskom is quantified. The cost of unserved energy per MVA hour is determined.

4.1. Reliability of a simple network

4.1.1. Reliability of radial systems

A radial system requires that all components operate in a satisfactory manner for proper performance. A radial system with two components is shown in Figure 4-1. The system will function only if all components are working. The reliability of the system is expressed as:

$$R_{system} = (R_a)(R_b)(R_c)(R_d)(R_e) \qquad \text{Eq 4-1}$$

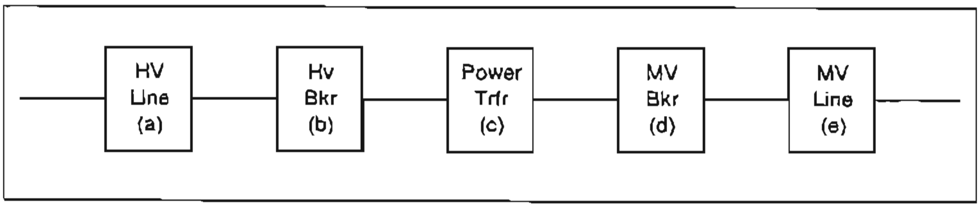


Figure 4-1: Radial system network model

The actual reliability of the components is:

$R_{HV\ Line\ (a)}$ = 0.999
$R_{HV\ Breaker\ (b)}$ = 0.998
$R_{Power\ Transformer(c)}$ = 0.970
$R_{MV\ Breaker\ (d)}$ = 0.995
$R_{MV\ Line\ (e)}$ = 0.985

using Eq 4-1,

$$\begin{aligned} R_{system} &= (R_a).(R_b).(R_c).(R_d).(R_e) \\ &= (0.999)(0.998)(0.970)(0.995)(0.985) \\ &= 0.947822 \\ &= 94.78\% \end{aligned}$$

This illustrates that in a radial system, the reliability is lower than the lowest components reliability. The reliability of the system with the lowest transformer reliability is 94.78%. If the reliability of the transformer changes from its worst case value of 0.970 to its best case value of 0.985, then the reliability of the radial system changes to:

$$\begin{aligned} R_{system} &= (R_a).(R_b).(R_c).(R_d).(R_e) \\ &= (0.999)(0.998)(0.985)(0.995)(0.985) \\ &= 0.962479 \\ &= 96.25\% \end{aligned}$$

The radial systems reliability changes to 96.25%. This calculation shows that a 1.4% improvement is achieved in system reliability for a change in transformer reliability from 97% to 98.5%

4.1.2. Reliability of a parallel system

A parallel system has several identical components in parallel and all components must fail to cause total system failure. A parallel system with two components is shown in Figure 4-2. The system will function if either A or B, or both are working. The reliability of the system is expressed as:

$$R_{system} = R_A + R_B - (R_A)(R_B) \qquad \text{Eq 4-2}$$

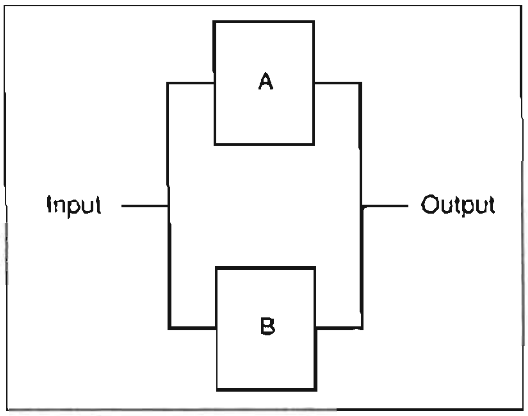


Figure 4-2: Parallel system reliability model

Using the calculation based on Figure 4-1 and the results obtained by Eq 4-2, the system can be represented as follows:

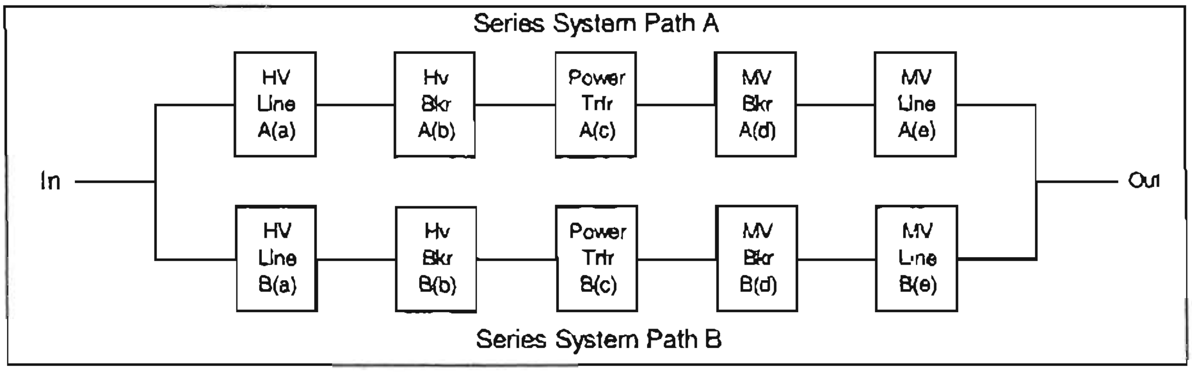


Figure 4-3: Typical parallel reliability model in Eskom

From Equation 4-2, the reliability of Series Path A and B is 0.947822. Substituting these values in Figure 4-2 and using Equation 4-3, the reliability of the parallel system is:

$$\begin{aligned} R_{system} &= R_A + R_B - (R_A)(R_B) \\ &=(0.947822) + (0.947822) - (0.947822)(0.947822) \\ &= 0.997277 \\ &= 99.73\% \end{aligned}$$

This shows that the overall system reliability increases with identical components in parallel. When the reliability of the transformer changed from 0.970 to 0.985, the systems reliability changes to 0.998592, i.e 99.86%. The change in transformer reliability from 97% to 98.5%, increases the parallel systems reliability by 0.13%.

4.1.3. Reliability of a jericho system

A Jericho system has an HV breaker connected to two motorized auto trip switches. Each switch protects a power transformer. In the event of a transformer failure, the HV breaker opens, the trip switch that protects the faulted transformer opens. The HV breaker then closes and restores supply to the healthy transformer and supply back to the customer. Path A is in series with the parallel Path BC and then in series with Path D

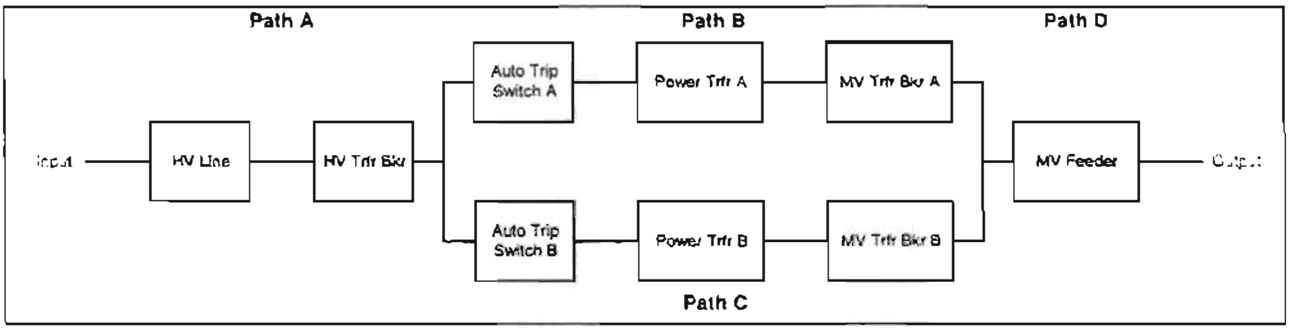


Figure 4-4: Typical series-parallel-series- Jericho system in Eskom

The reliability of the system is expressed as:

$$R_{system} = (\text{Path A})(\text{Path B//Path C})(\text{Path D})$$
$$=(R_{PathA})\ (R_{PathB}+R_{PathC}-(R_{PathB})(R_{PathC}))\ (R_{PathD})$$

The actual reliability of the components is:

$R_{HV\ Line}$ = 0.999
$R_{HV\ Trfr\ Breaker}$ = 0.998
$R_{Power\ Trfr}$ = 0.970
$R_{MV\ Trfr\ Breaker}$ = 0.995
$R_{MV\ Line}$ = 0.985
$R_{Auto\ Trip\ Switch}$ = 0.900

Using the Eq 4-1, the reliability of Path A can be calculated:

R_{PathA} $= (R_{HVLine})(R_{HV\ Trfr\ Bkr})$
$= (0.999)(0.998)$
$= 0.997002$

R_{PathB} $= (R_{AutoTripSwitch})(R_{PowerTrfr})(R_{MVTrfrBkr})$
$= (0.900)(0.970)(0.995)$
$= 0.868635$

R_{PathC} $= R_{PathB}$
$= 0.868635$

R_{PathD} $= 0.985$

Therefore,

$$R_{system} = (\text{Path A})(\text{Path B//Path C})(\text{Path D})$$
$$= (R_{PathA})\ (R_{PathB}+R_{PathC}-(R_{PathB})(R_{PathC}))\ (R_{PathD})$$
$$= (0.997002).(\ 0.868635 + 0.868635 - (0.868635)(\ 0.868635)).(0.985)$$
$$= (0.997002)(\ 0.982743)(0.985)$$
$$= 0.965099$$
$$= 96.51\%$$

The Reliability of the Jericho system is 96.51%. The least reliable system is the Series system at 94.78%, followed by the Jericho system at 96.51%. The Parallel system has the greatest reliability of 99.73%.

4.1.4. Power system reliability targets

Eskom Eastern Region's Electricity network supplies 632298 customers. The Distribution network voltages are 132kV, 88kV and 33kV. The lines length for these voltages are 6159km. The reticulation network voltages are 22kV and 11kV. The combined line length for these two voltage levels are 39587km. The substations are divided into Substation with transformers, Switching Stations and Traction substation. There are 289 substations with 428 installed transformers, 45 switching stations and 111 traction stations. This is a total of 379 stations. The installed MVA at the 289 substations is 6066MVA.

The reliability targets for Eskom are set based on past performance and by workgroups and the National Energy Regulator of South Africa (NERSA). The reliability indices are an IEEE standard [83]. Eskom Distribution has published its own standard (DISASACT3) "Distribution network performance KPI definitions standard". The Eskom standard aligns with the IEEE P1366 document, revises the existing network reliability indices, cleans up certain existing definitions and introduces a set of new reliability indices for Eskom Distribution [84]. The targets that affect the power system reliability and performance indices are:

- Distribution Supply Loss Index (DSLI)
- Reticulation Supply Loss Index (RSLI)
- Customer Average Interruption Index (CAIDI)
- Supply Average Interruption Index (SAIDI)
- Supply Average Interruption Frequency Index (SAIFI)

Table 4-1 shows Eskom's the reliability figures for 2005 and 2006 and the targets for 2007 to 2009.

Table 4-1: Eskom's power system reliability targets

KPI	2005	2006	2007 Target	2008 Target	2009 Target
DSLI (minutes)	7.995	7.128	6.6	6.6	6.6
SAIFI	24.94	22.44	20.2	19	19
SAIDI (hours)	49.58	44.62	40.16	38	38
RSLI (minutes)	149.445	132	132	132	132
CAIDI (hours)	2	2	2	2	2

The values in Table 4-1 are 12 month moving averages. The base figures used in calculating the targets are:

Total MVA:	6066
DSLI 12MMA MVA Base:	93264
RSLI 12MMA MVA Base:	59960
Customer Base:	632298

The RSLI and DSLI 12MMA base is the sum of the total MVA base per month over the 12MMA period for Reticulation and Distribution respectively. An interruption in supply caused by a transformer failure will result in customers being interrupted for a certain duration. The MVA base of the customers affected and the duration is used to calculate the MVA hours lost.

4.2. Network sensitivity

4.2.1. Substation firmness

Eskom Eastern Region has 428 transformers with an installed power transformer base of 6066MVA. Table 4-2 tabulates Eastern Regions transformer firmness [77] [78].

Table 4-2: Eskom's parallel and switched transformer firmness study

Parallel transformer firmness

2007 Trf Base Qty	Qty of Trfr Firmness	% of Trfr Firmness	MVA Firmness	% MVA Firmness
428	66	15%	1760	29%

Switched Transformer Firmness

2007 Base Qty	Qty of Trf Switched Firmness	% of Switched Firmness	MVA Switched Firmness	% MVA Switched Firmness
428	46	11%	1286	21%

Parallel & Switched Transformer Firmness

2007 Base Qty	Qty of Trfr Total Firmness	% of Total Firmness	MVA Total Firmness	% MVA Total Firmness
428	112	26%	3046	50%

Sixty six of the 428 transformers have firmness from parallel transformers. The parallel firmness MVAs total is 1760MVA, 29% of the installed transformer base. If one of the 66 transformers fails, there should be no interruption in supply to the customer due to the parallel transformer arrangement at the substation.

Forty six of the 428 transformers have switched firmness. The switched transformer firmness MVAs total is 1286MVA, 21% of the installed transformer base. If one of the 46 transformers fails, the customer will experience a momentary interruption in supply. During this time, the supply will be restored via switching operations on the Distribution network.

The total firmness (parallel and switched) caters for 112 transformers or 26% of the 428 transformers. The MVA represented by the 26% is 3046MVA. This is 50% of the installed MVA base. The customers supplied by the remaining 311 transformers and 3022MVA will experience an extended outage when a transformer fails.

4.2.2. Substation fault levels and breaker through faults

The fault levels at each transformer on the network were calculated used DIGsILENT Power Factory software. The results were placed in kA ranges and quantified. The number of breaker through faults from 1999 to 2006 was summed and linked to a corresponding kA profile. Table 4-3 shows the results.

The intention of this exercise was to determine the number of through faults experienced by each transformers and the impact it would have on the short circuit withstand capability of the transformer and the level of stress imposed on the transformers insulation. However, 30 of the through faults occurred in the 0 to 5kA range and 3 in the 6 to 10kA range. The fault current is considered to have minimal impact on the transformer as its magnitude is very low and the duration did not exceed 400milli-seconds.

Table 4-3: Simulated three phase fault - substation fault levels

Simulated kA Profile	Qty of kA Profile	No of Breaker Through Faults
(0 - 5)kA	286	30
(6 - 10)kA	99	3
(11 - 15)kA	31	0
(16 - 20)kA	5	0
(21 - 25)kA	7	0

4.3. Reliability of transformer and its components

4.3.1. Transformer reliability model

Figure 4-5 shows a typical reliability model for a power transformer. The series path contains the Bushing, HV/LV winding, Insulation, Tapchanger Winding and the Tapchanger. Failure of any series component will result in a transformer failure. An "unknown" component is added for failures that could not be traced to a known component.

A series model has a dependency from one component to another for the transformer to perform its desired output. The undesirable event being modelled is the ability of the transformer to transform voltage from one level to another at a constant MVA. If this does not occur, then the transformer has failed to perform its function and the undesirable event has occurred. There are no parallel paths in the model. The only parallel path in the model will be an identical parallel power transformer to prevent the undesirable event in-case one transformer fails.

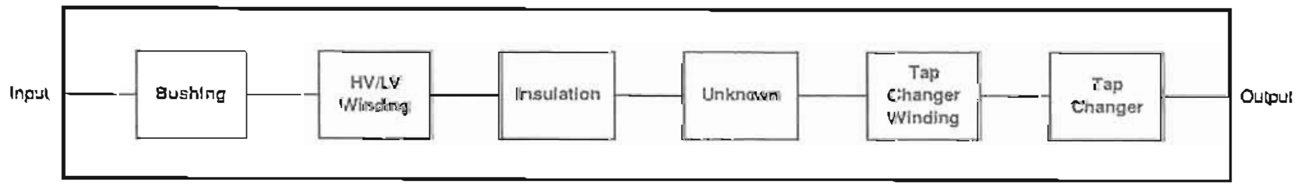


Figure 4-5: Transformer reliability model - series dependency

The failure rate and reliability per component is tabulated in Table 4-4. The equivalent failure rate per component is calculated per year and averaged. The failure rate formula is used as a check [79].

Failure Rate per year

$$\lambda = \frac{\sum Failures}{(TrfrBase)(YearOf\ RecordedData)} \ldots \qquad \text{Eq 4-3}$$

Table 4-4: Eskom's component reliability and failure rates - 1999 to 2006

Component that Failed	No of Failures	Percentage	Failure Rate	Reliability
HV/LV Winding	47	48%	1.433%	0.98567
Bushing	16	16%	0.488%	0.99512
Unknown	11	11%	0.335%	0.99665
Tapping Winding	10	10%	0.305%	0.99695
Insulation	7	7%	0.213%	0.99787
Tapchanger	6	6%	0.183%	0.99817
Total	**97**	**100%**	**2.957%**	**97.07%**

The reliability of the transformer is the series product of the components. Using the data from Table 4-4, the reliability of the series transformer model can be calculated as follows:

Transformer Reliability

= (HV/LV Winding)(Bushing)(Unknown)(Tapping Winding)(Insulation)(Tapchanger)

= (0.98567)(0.99512)(0.99665)(0.99695)(0.99787)(0.99817)

= 0.970734

= 97.07 %

Based on the failure rate of each component from 1999 to 2006, the series model of the transformer shows that the reliability of transformers in Eskom Eastern Region is 97.07 percent. The transformer failure rate is calculated to be 2.957%. Winding related failures contribute to 47% of all failures. The failure rate per region is summarized in Table 4-5. Eastern Region has the highest failure rate. The average failure rate within Eskom Distribution is 2.0876%. The median for the region is 2%. Eastern Regions failure rate is 0.9256% higher than the Distribution Groups average.

Table 4-5: Failure rates per Region in Eskom Distribution

Regions	Failure Rate
Eastern Region	2.957%
Southern Region	2.0%
Northern Region	2.2%
North West Region	1.7%
Western Region	1.3%
Regional Average	2.0314%

International failure rates vary from 0.4% to 1%. MV/MV transformers have a failure rate of 1% to 1.3%. HV/MV transformers have a failure rate of 1.4% to 2.5% [80]. The failure rate of power transformers at Eskom is higher than the international average.

4.3.2. Transformer failure rate calculation

The percentage failure rate from 1999 to 2006 is tabulated in Table 4-6 below. The average of the eight years of failure data is 3.43%. Using equation 4-3, the failure rate per year was calculated to be 3.45%. The difference is 0.02%. The failure rate equation can then be used to determine the failure rate of a given transformer base. The failure rate equation shows that the higher the transformer base, the lower the failure rate.

Table 4-6: Eskom's transformer failure rate per year

Year of Failure	Installed Trfr base	No of Failures	Failure Rate	Failure Rate Equation Test
1999	311	13	4.18%	3.90%
2000	326	13	3.99%	3.72%
2001	334	4	1.20%	3.63%
2002	341	7	2.05%	3.56%
2003	353	19	5.38%	3.43%
2004	371	19	5.12%	3.27%
2005	397	15	3.78%	3.05%
2006	401	7	1.75%	3.02%
Average Failure Rate per Year			**3.43%**	**3.45%**

4.3.3. Failure rate versus age – bathtub curve

Figure 4-6 shows the number of failures against age at failure. The failure pattern is a typical bath tub curve [81] [40]. The initial 3 year period shows a high number of failures. These failures can be attributed to manufacturing defects. The period 3 to 20 years is the useful life period. Random transformer failures occur during this period. From year 21 onwards, high transformer failures are experienced due to wear out and end of useful life being reached. A total of 97 failures occurred from January 1999 to December 2006. 12% of failures occurred in the infant mortality stage. 39% of random failures occurred during the useful life period. 49% of failures occurred at the end of useful life period. The average age of all 97 transformers that have failed is 18.9 years. Attention needs to be given to the 39% of random failures to reduce the failure rate. This is an area of concern.

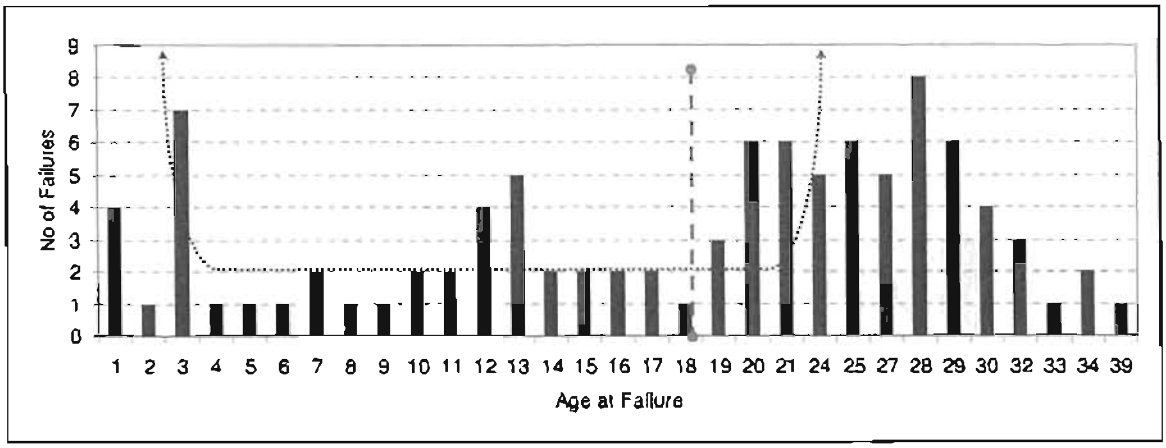


Figure 4-6: Bath tub curve - Eskom's transformer failures

4.3.4. Mean Time to Failure

The mean time to failure in years is calculated using the equation:

$$MTTF = \frac{1}{FailureRate}$$

The average failure rate from Table 4-6 is 3.43% i.e. 0.0342

Therefore the $MTTF = \frac{1}{0.0342} = 29$ years

This implies that based on a failure rate of 3.43%, the mean time between failures is 29 years.

4.4. System to mitigate un-reliability

4.4.1. System design and operating options

Transformer and system reliability is controlled by adopting the following methodology within Eskom's Power System:

- N-1 contingency
- Firm Transformer Substation
- Use of rings in cable networks and loop-in-out arrangements on lines
- Refurbishment of aging assets
- Preventative Maintenance Programs and Strategies (RCM, CBM)
- 80% transformer loading limits
- Installing system spares at single transformer substations
- Adequate strategic stock levels

Annual oil sampling is used to asses the condition of the transformer. The results indicate the percentage moisture in the oil, the electric strength and the concentration of gases. They are used to diagnose any developing faults. Controlling the reliability of a power transformer ensures that it does not result in a failure and there is no impact to the customer and the performance KPI's.

4.4.2. Factors contributing to failures

Failure refers to the condition of loss of use of a transformer. This has an impact on performance KPI's when there is a loss of supply. Factors that contribute to the failure of a power transformer at Eskom were determined to be:

- Lack of and inadequate transformer maintenance
- Failure after commissioning due to errors. Attributed to insufficient skill.
- Inadequate protection systems, incorrectly commissioned protection schemes
- Uncontrolled overloading of transformers
- Un-calibrated winding and oil temperature gauges resulting is large errors for alarm and trip settings.
- Incorrect design review applied to a transformer for re-rating.
- Low DP transformer being moved resulting in insulation failure, when first energized.
- Lack of staff to test and interpret transformer test results
- Lack of properly trained drivers for transporting transformers to site
- Monthly transformer inspections done by in-experienced staff and hence defects not identified.
- Planned maintenance on a 4 yearly cycle for protection systems not been done adequately due to lack of staff.
- Bushing flashovers caused by wildlife in environmentally sensitive areas, resulting in transformer fires.
- Failures occur after planned maintenance on tap changers due to errors during minor and major services.
- Transformers with design flaws e.g. smaller than required cores – overheating
- Breaker through faults due to aging breakers
- Long fault clearing times of bulk oil breakers (~300msec)
- Increased system fault levels due to new injection points for transmission system expansion
- Lightning surges
- Stolen transformer earths at substations
- Depleted or damaged substation earth mats – high earth mat resistance
- Floating star points on partially graded transformer designs
- Failure of condenser type GOB bushings

4.4.3. Categories of failures

Failures are classified into the following three categories:

- Failures that cause outages
- Failures that do not cause outages (but are recorded by system operations)
- Failures that are identified during routine inspections and maintenance

The failure rates in Table 4-6 uses information on transformers that have caused outages.

4.4.3.1. Maintenance defects contribution to reduced reliability

Table 4-7 shows all the maintenance defects that were identified over a four year period, specific to transformers. A total of 855 defects were identified over a four year period. This is an average of 213 defects per year.

Table 4-7: Maintenance defects identified between 2003 and 2006 at Eskom

DEFECT	2003	2004	2005	2006	Total
Oil Leak	79	137	112	63	391
Silica Gel	16	10	6	4	36
Gauge	16	27	13	15	71
Rust	2	7	7	9	25
OLTC	17	26	41	24	108
Bushing	9	29	25	15	78
Low Oil	16	26	37	30	109
Cyclo meter	7	5	6	2	20
Breather	2	4	0	1	7
Fans	2	6	0	2	10
Total	**166**	**277**	**247**	**165**	**855**

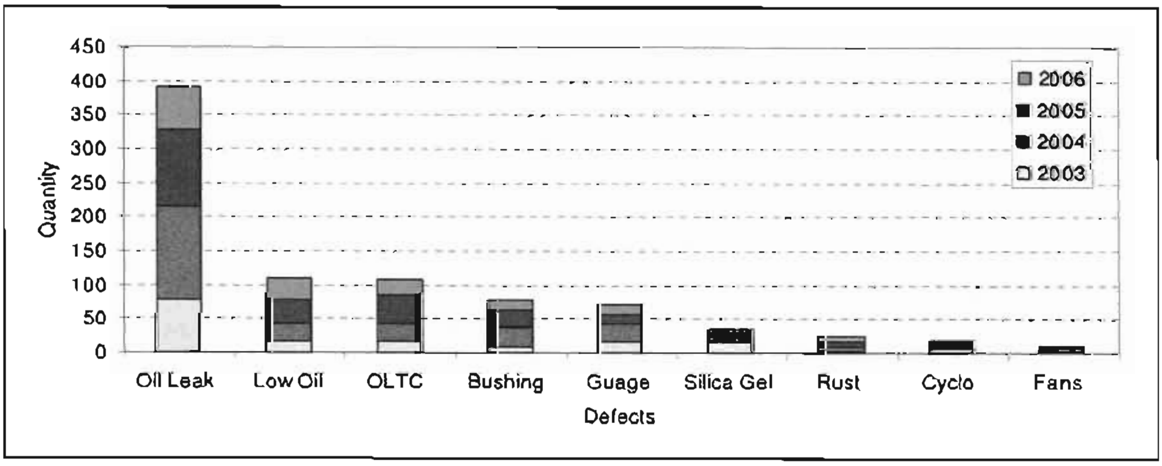


Figure 4-7: Maintenance defects identified between 2003 and 2006 at Eskom

Table 4-8: Percentage of defects identified compared to the installed base

Year	Installed Base	Defects Found	Percentage Defects to Installed Base
2003	355	166	47%
2004	371	277	75%
2005	397	247	62%
2006	401	165	41%
Average Defects per Transformer per Year			56%

The average of percentage defects identified to the installed base is 56%. More than half of all transformers in the system have at least one defect that could ultimately lead to a transformer failure.

4.5. Design reliability

Manufactures design transformers in accordance to specifications. They are tested to comply. The reliability of modern designed transformer is almost 99.9%. This is achieved during the design and manufacturing stages [82] by concentrating on the following key elements:

- Maximizing short circuit strength – improved clamping methods
- Sealed tanks
- Nitrogen blanket systems
- Vacuum tapchangers
- Digital winding and oil temperature gauges
- Use of virgin oil
- Heat run tests
- Modern design software
- Laboratory testing of completed transformers
- Type and impulse testing of new designs
- ISO accredited manufacturing process
- Thermally improved kraft paper
- Maintenance free breather
- Vacuum sealed manufacturing facilities

However, the power transformers are designed for a 35 year lifespan and the designs are optimized to the extent that there is no 'fat' in the design. The power transformers at Eskom have traces of combustible fault gases during normal operations.

4.6. The impact of reliability on system performance

4.6.1. Reliability evaluation criteria

Customers on the network are connected to a feeder. A feeder is the connection from a sub-station through wires, transformers etc. to a customer. The electric utility industry uses the reliability indices [83] like CAIDI, SAIFI, SAIDI to track and benchmark reliability performance. Key Performance Indicators (KPI) are needed for the following reasons:

- Manage network performance at some acceptable level.
- Acceptable level will ensure customer satisfaction.
- Will serve as a trigger for performance and refurbishment investigations.
- Reporting to the National Energy Regulator South Africa (NERSA)
- Corporate requirement – balance scorecard.
- Serves as an indication of planned and unplanned event management.

KPI's are divided into two broad categories:

- Frequency
- Duration

Frequency KPI's are represented by SAIFI and CAIFI. Duration KPI's are represented by CAIDI, SAIDI, RSLI and DSLI. SAIFI, CAIFI, CAIDI and SAIDI are affected by customer numbers. RSLI and DSLI are affected by the installed MVA.

The meaning and example of each KPI follows [84]:

(a) **CAIDI (Customer Average Interruption Duration Index):** The CAIDI of a network indicates the average duration of a sustained interruption that only the customers affected would experience per annum. It is commonly measured in customer minutes or customer hours of interruption.

$$\text{CAIDI} = \frac{\text{Sum customer interruption durations p.a.}}{\text{Total number of effected customer}}$$

A CAIDI of 3 indicates that, 3 hours on average, was taken, to restore supply to customers that were interrupted over the past 12 months, for planned and unplanned outages.

(b) **CAIFI (Customer Average Interruption Frequency Index):** The CAIFI of a network indicates how often on average, only the customers affected by an interruption experience a sustained interruption per annum.

$$\text{CAIFI} = \frac{\text{Total number of customer interruptions p.a.}}{\text{Total number of customers interrupted}}$$

A CAIFI of 10 indicates that for the past 12 months customers experienced 12 interruptions.

(c) **SAIFI (System Average Interruption Frequency Index):** The SAIFI of a network indicates how often on average the customer connected would experience a sustained interruption per annum.

$$\text{SAIFI} = \frac{\text{Total number of customer interruptions p.a.}}{\text{Total number of Customers served}}$$

A SAIFI of 15 indicates that every customer was interrupted 15 times for the past 12 months.

(d) **SAIDI (System Average Interruption Duration Index):** The SAIDI of a network indicates the average duration of a sustained interruption the customer would experience per annum. It is measured in customer minutes or customer hours of interruption.

$$\text{SAIDI} = \frac{\text{Sum customer interruption duration's p.a.}}{\text{Total number of Customers served}}$$

A SAIDI of 45 indicates that for the past 12 months every customer in the system was without supply for 45 hours.

(e) **DSLI (Distribution Supply Loss Index):** The DSLI of a network indicates the average network loss duration by the HV plant installed due to sustained interruptions caused by Distribution. It is measured as hours. This index provides a KPI to measure network performance due to Distribution interruptions only.

$$\text{DSLI} = \frac{\text{Sum of MVA.Hours Lost per month}}{\text{Installed MVA Base}}$$

A DSLI of 6.45 (12MMA) indicates that for the past 12 months the sub transmission network was not available for 6.45 minutes.

(f) **RSLI (Reticulation Supply Loss Index):** The RSLI of a reticulation network indicates the average network loss duration by the MV and LV plant installed due to sustained interruptions. It is measured in hours. Only the MV transformers are used as part of the calculation. The index only includes events due to Distribution. This index provides a KPI to measure network performance due to Distribution interruptions only.

$$\text{RSLI Reticulation} \quad = \frac{\text{Sum of MVA.Hours Lost per month}}{\text{Installed MVA Base}}$$

A RSLI of 1.94 (12MMA) indicates that for the past 12 months the reticulation network was not available for 1.94 hours.

4.6.2. Reliability Calculations of Failed Transformers

The failure of a distribution transformer will affect the DSLI for the region. The DSLI refers to the number of minutes the entire transformer base has being off in a year. The target set for Eskom Eastern Region by the National Energy Regulator is shown in Table 4-1. The target for 2007 is 6.6 minutes per year. The DSLI 12MMA MVA base for Eastern Region is 93264.

The total MVA base for Eastern Region is 6066 MVA. The current customer base is 632298 customers. Using these two bases, the average MVA per customer can be calculated:

Average MVA per customer $= \frac{MVAbase}{CustomerBase}$

$= \frac{6066}{632298}$

= 0.0095935777 MVA per customer

or expressed in kVA = 0.009593 *1000

= 9.593 kVA per customer

4.6.2.1. 1.25MVA 22/11kV Transformer Failure

A failure of a 1.25MVA 22/11kV transformer will impact the following performance KPI's:

- CAIDI
- SAIFI
- SAIDI
- RSLI

The DSLI will not be impacted because it is a Distribution KPI. The 22kV and 11kV voltage levels affect the Reticulation KPI's. Using the average kVA per customer of 9.593, the average number of customers connected to the 1.25MVA transformer can be calculated as follows:

Average Number of customers $= \frac{FailedTransformerMVA}{Average(kVA)perCustomer} x1000$

$= \frac{1.25MVA}{9.593kVA} x1000$

= 130 customers

When a failure occurs on the system, the power is restored to the customer using N-1 contingency or the customer will be without supply for several hours. This is the time taken to replace a failed transformer. The average time to replace a failed 1.25MVA transformer is 17 hours.

(a) CAIDI Calculation

CAIDI = Sum customer interruption durations p.a. / Total number of effected customer

$$= \frac{(17 hours)(130 customers)}{(130 customers)}$$

= 17 hours

The CAIDI of 17 indicates that it has taken 17 hours to restore supply to the 130 customers, which were affected by the transformer failure. The CAIDI of 17 has to be normalized to the regions target of 2 hours using the regional customer base of 632298. The current CAIDI target is 2 hours. This is based on the performance of all the components making up the system, such as lines cables, breakers, power transformers, reticulation transformers. This target means that the entire customer base of 632298 will be switched off for 2 hours in a 12MMA period.

Therefore the percentage contribution to the CAIDI target for every 1.25MVA transformer failure is:

$$\text{Percentage contribution to CAIDI} = \frac{\frac{130}{632298}}{\frac{17}{2}} x100\%$$

$$= 0.000024\%$$

The calculated CAIDI is considered to be insignificant for a 1.25MVA transformer failure.

(b) SAIFI Calculation

The customers will be interrupted once, for the transformer failure.

$$\text{SAIFI} = \frac{\sum Interruptions}{TotalCustomersBase}$$

$$= \frac{130}{632298}$$

$$= 0.000206 \text{ interruptions}$$

The current SAIFI target is 20.2 interruptions per customer for the system. The calculated SAIFI has to be normalised using the systems target to determine the impact to systems target. Therefore the percentage contribution to the SAIFI target for every 1.25 transformer failure is:

$$\text{Percentage contribution to SAIFI} = \frac{0.000206}{20.2} x100\% = 0.001018\%$$

The calculated SAIFI is considered to be insignificant for the 1.25MVA failure.

(c) SAIDI Calculation

SAIDI for a transformer failure will have the same value as SAIFI. However, the unit of measure will be hours.

$$\text{SAIDI for the failures} = \frac{\sum Interruptions}{TotalCustomersBase}$$

$$= \frac{130}{632298}$$

$$= 0.000206 \text{ hours}$$

The current SAIDI target is 40.16 hours for the system. The calculated SAIDI has to be normalized using the systems target to determine the impact to systems target. Therefore the percentage contribution to SAIDI for every 1.25MVA transformer failure is:

$$\text{Percentage contribution to SAIDI} = \frac{0.000206}{40.16} x100\% = 0.000513\%$$

The calculated SAIDI is considered to be insignificant for a 1.25MVA failure.

(c) RSLI Calculation

The average time to replace the 1.25MVA transformer is 17 hours.

MVA Hours Lost = 17hours x 1.25MVA = 21.25MVA hours

The 12MMA transformer base is 93264MVA. Therefore,

$$\text{RSLI} = \frac{MVAhoursLost}{SystemMVAbase}$$

$$= \frac{21.25}{93264}$$

$$= 0.000228 \text{ hours or}$$

$$= 0.01368 \text{ minutes}$$

The current RSLI target is 132 minutes for the system. . The calculated RSLI has to be normalised using the systems target to determine the impact to systems RSLI target.

$$\text{Percentage contribution to RSLI} = \frac{0.01368}{132} x100\% = 0.0103\%$$

Therefore, every 1.25MVA transformer failure impacts the RSLI by 0.0103%

4.6.2.2. 80MVA 132/88kV transformer failure

A failure of an 80MVA 132/88kV transformer only impacts the DSLI. The time to replace a failed 80MVA power transformer is 72 hours. The RSLI will not be impacted because it is a Reticulation KPI.

Failure MVA = 80 MVA
Outage Duration = 72 hours
= 4320 minutes
12MMA System base = 93264

$$DSLI = \frac{FailureMVAx\,RestorationTime}{SystemBaseMVA} \text{ minutes}$$

$$= \frac{80x4320}{93264}$$

= 3.706 minutes

The current DSLI target is 6.6 minutes for the system. The calculated DSLI has to be normalised using the systems target to determine the impact to systems DSLI target.

$$\text{Percentage contribution to DSLI} = \frac{3.706}{6.6} x100\% = 56.14\%$$

Therefore, every 80MVA transformer failure impacts the DSLI target by 56.14 %. The impact to the DSLI is considered to be significant. This is the major impact KPI for power transformer failures.

4.6.2.2. Summary of transformer failure's and impact to system reliability

Table 4-9 and Figure 4-8 shows the impact to the performance KPI's for the various MVA ratings of transformers that have failed. Figure 4-8 shows that the contribution to CAIDI, SAIFI and SAIDI is almost zero and has no impact on the performance KPI's. The RSLI is not impacted for transformer rated 1.25MVA to 10MVA. Transformers greater than 20MVA do not impact the RSLI as it is a reticulation KPI. The major impact KPI is DSLI.

Table 4-9: MVA failure versus performance KPI impact

MVA	1.25	2.5	5	10	20	40	80
CAIDI (hours)	0.002%	0.005%	0.01%	0.01%	0.01%	0.03%	0.04%
SAIFI	0.001%	0.002%	0.004%	0.01%	0.02%	0.03%	0.07%
SAIDI (hours)	0.001%	0.0010%	0.002%	0.004%	0.008%	0.02%	0.03%
RSLI (minutes)	0.0002%	0.0003%	0.001%	0.003%	0.008%	0.02%	0%
DSLI (minutes)	0%	0.4%	1.2%	3.5%	9.4%	18.7%	56.1%
No Customers	130	261	521	1042	2085	4169	8339
kVA per customer	9.6	9.6	9.6	9.6	9.6	9.6	9.6
Average Restoration hours	17	17	24	36	48	48	72
MVA Hours Lost	21.25	42.5	120	360	960	1920	5760
Total Customer base	632298	632298	632298	632298	632298	632298	632298
System MVA Base 12MMA	93264	93264	93264	93264	93264	93264	93264
RSLI System MVA base 12MMA	93264	93264	93264	93264	93264	93264	93264

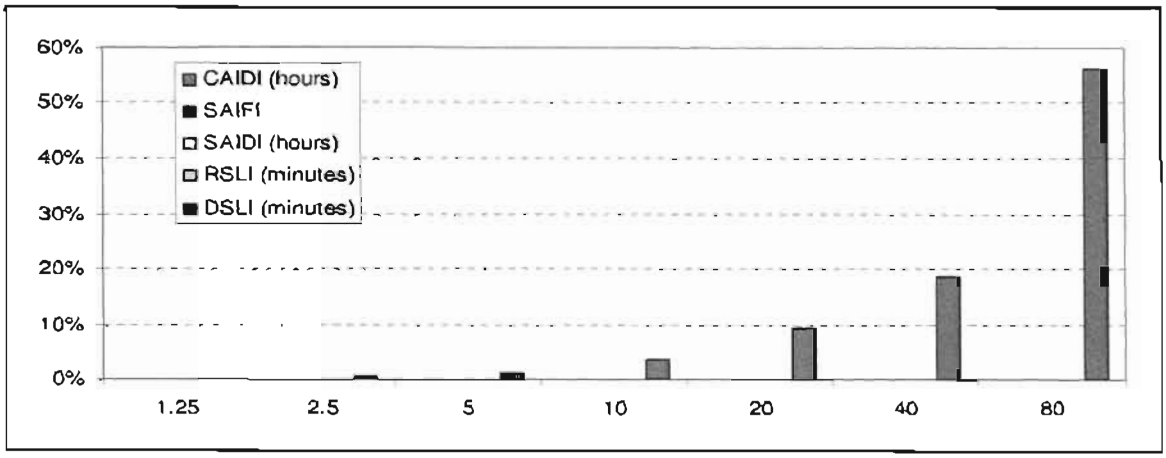


Figure 4-8: MVA failure versus performance KPI impact

4.6.3. Failure rate versus impact to performance KPI's

Failure of 97 transformers in 8 years is an average of 12.125 transformer failures per year or roughly one per month. The average time taken to replace failed transformers at Eskom is: 1.25MVA is 17hours, 5 MVA is 24hours, 10MVA is 36hours, 20MVA and 40MVA is 48 hours, 80MVA is 72 hours.

The MVA sum (i.e. 1MVA to 80MVA) of all 97 failures = 1241MVA

The average MVA per failure = $\frac{1241}{97}$ = 12.79MVA

The average restoration time to replace a failed transformer is 37 hours. The average MVA hours lost = 37hours x 12.79MVA = 473 MVA hours. Using the failure rate equation,

Failure rate per annum = $\frac{12.125}{428} x100\ \%$ = 2.833%

If one transformer fails per annum the failure rate is ($\frac{1}{428} x100\ \%$) = 0.234%

Therefore, for every failure that does not occur, or for every failure that is prevented, the average failure rate will reduce by 0.234%. The impact to the Performance KPI's per averaged transformer failure can be calculated with the following average values:

Average MVA per Failure:	12.29MVA
Average Duration:	37 Hours
Average MVA hours lost:	473MVA hours
System Customer Base:	632298
12MMA System Base:	93264

The result of the Performance KPI's impact by a transformer failure is summarized in Table 4-10.

Table 4-10: KPI's impacted by single average transformer failure

MVA	Targets	Impact to Target - Value	Impact to Target - %
CAIDI (hours)	2	0.0001	0.011%
SAIFI	20.2	0.0001	0.010%
SAIDI (hours)	40	0.0001	0.0053%
RSLI (minutes)	132	0.0000	0.0038%
DSLI (minutes)	6.6	0.0461	4.6%
No Customers	1333		
kVA per customer	9.6		
Average Restoration hours	37		
MVA Hours Lost	473.23		
Total Customer base	632298		
System MVA Base 12MMA	93264		
RSLI System MVA base 12MMA	93264		

Table 4-10 shows the savings to the Performance KPI's per transformer failure saved. The saving to the DSLI will be 2.7 seconds. The saving to the RSLI will be 0.138 seconds. The power transformer s failure will have negligible impact on CAIDI, SAIFI and SAIDI. The major impact performance KPI for transformer failures is DSLI. The other KPI's (RSLI, CAIDI, SAIFI, and SAIDI) have almost no impact to the targets for transformer failures.

4.6.4. Measures to improve transformer reliability

The following are suggested measures to improve transformer reliability and improve performance KPI's

- Perform Adequate maintenance
- Adoption of preventive maintenance rather than break down maintenance
- Better control of transformer/system operation
- Avoid over loading of transformers
- Employ better quality equipments
- Minimisation voltage transformations
- Ensure coordinated protection settings
- Human Resource Development – Skills
- Replace porcelain bushings with composite type
- Improved transport systems with monitoring
- Replace bulk oil and small oil volume breakers
- Create system redundancy
- De-rate and de-load older transformers

Reliable service is directly associated with the proper asset utilization, adequate and timeous maintenance, power availability, and redundancy in the system and fixing of performance targets for improvement in years to come.

4.7. Transformer failure analysis

This analysis provides an insight into the power transformer failures at Eskom Distribution Eastern Region from January 1999 to December 2006. The failures analysed are transformers with a secondary voltage greater than 3kV, the primary voltage less than 133kV, and MVA rating greater than 1MVA. The intent of this analysis is to highlight areas of risk by statistical analysis.

Historically power transformer failure information was not stored in any software system at Eskom. Hence hard copy archives were analysed in an attempt to identify the number of failures, asset information of the failed plant, and root cause of failure. The archives were limited to an eight year history, and hence the information analysed is based on failures that occurred within the last eight years. In the statistical analysis, asset information was also obtained from both Maximo and Eskom's oil sample database (LIMS).

4.7.1. Failure analysis per year

The greatest number of failures occurred in 2004. Figure 4-9 illustrates a total number of 19 failures in the years 2003 and 2004, which accounts for 41% of the total number of failures in eight years.

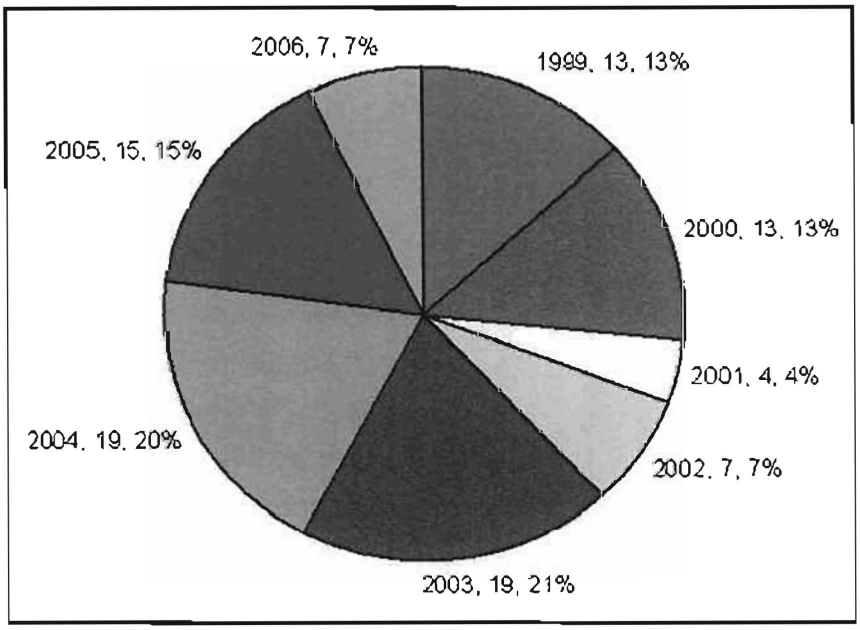


Figure 4-9: Transformer failures per year

4.7.2. Failure analysis per age category

The designed life of a transformer under normal, manufacturer specified conditions is 35 years. The regions power transformers have been categorised into 5 year age groups, in an attempt to identify the high risk age groups. The greatest number of failures occurred in the 26-30 years age category.

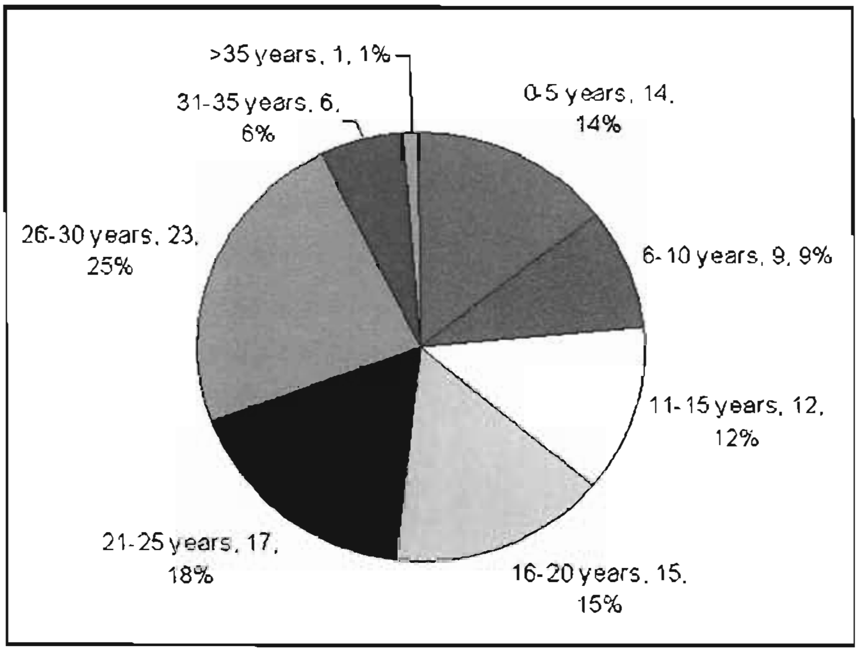


Figure 4-10: Transformer failures per age category

4.7.3. Failure analysis per voltage category

Figure 4-11 illustrates the distribution of failures across the various voltage categories and shows that in the 22/11kV voltage range, there were 42 failures in eight years, which amounts to 44% of the total number of all failed transformers in eight years.

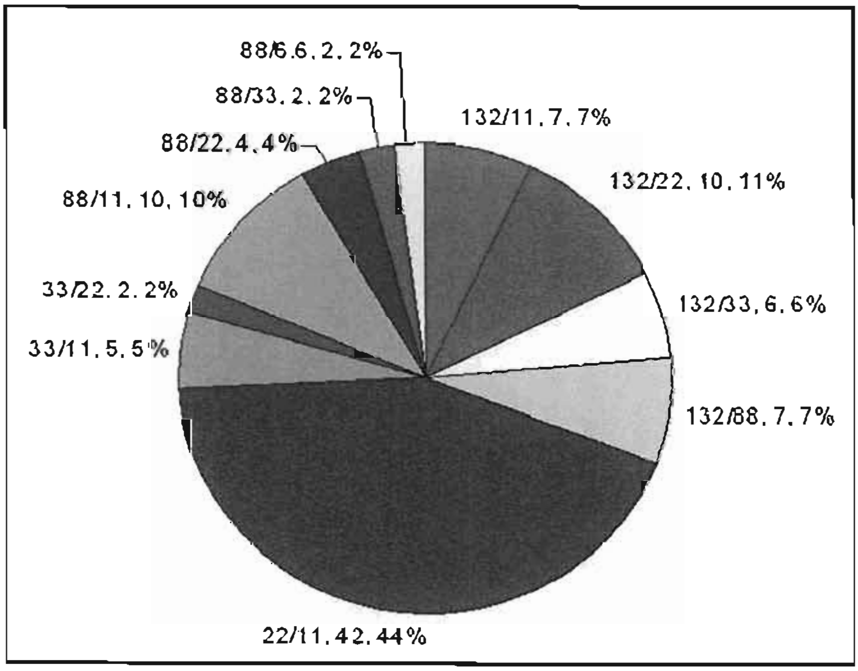


Figure 4-11: Transformer failure per voltage category

4.7.4. Failure analysis per MVA category

Figure 4-12 illustrates the distribution of failures across the various MVA categories and shows that in the 1.25 MVA range, there were 27 failures in eight years, which amounts to 29% of the total number of all failed transformers in eight years. The second highest is the 2.5MVA, 16% and followed by 20MVA range, 15%.

The root cause of the 22/11kV failure was attributed to no surge protection on the transformers and no or inadequate transformer protection. An evaluation of the 22/11kV sites was conducted and projects were raised within Eskom to install surge protection on the 11kV and 22kV sides of the 1.25MVA transformers, install 11kV and 22kV breakers, and to install or upgrade the protection and telecontrol.

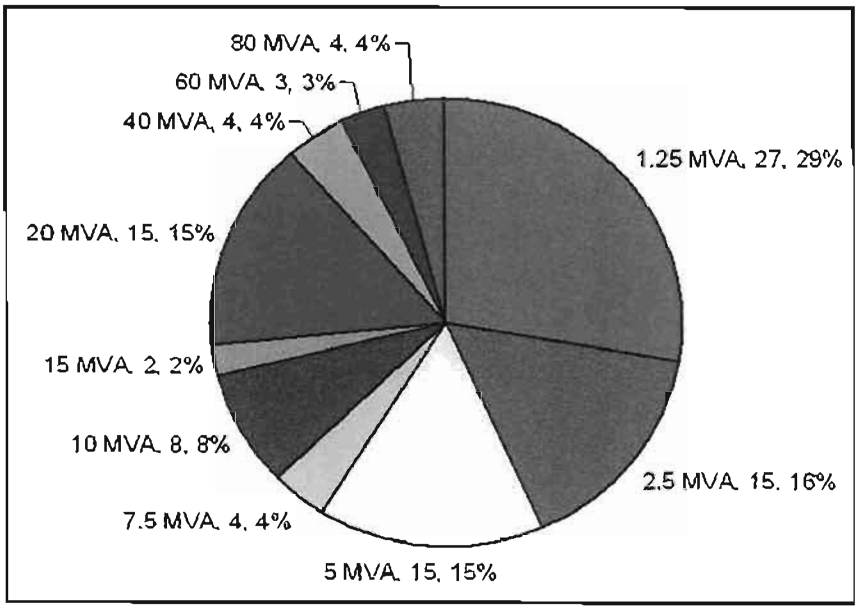


Figure 4-12: Transformer failure per MVA category

4.7.5. Failure analysis per manufacturer

Figure 4-13 illustrates the distribution of failures across transformers designed by different manufacturers. Figure 4-13 shows that the maximum number of failures was of the Asea make, which is 28%, followed by Desta which is 27%.

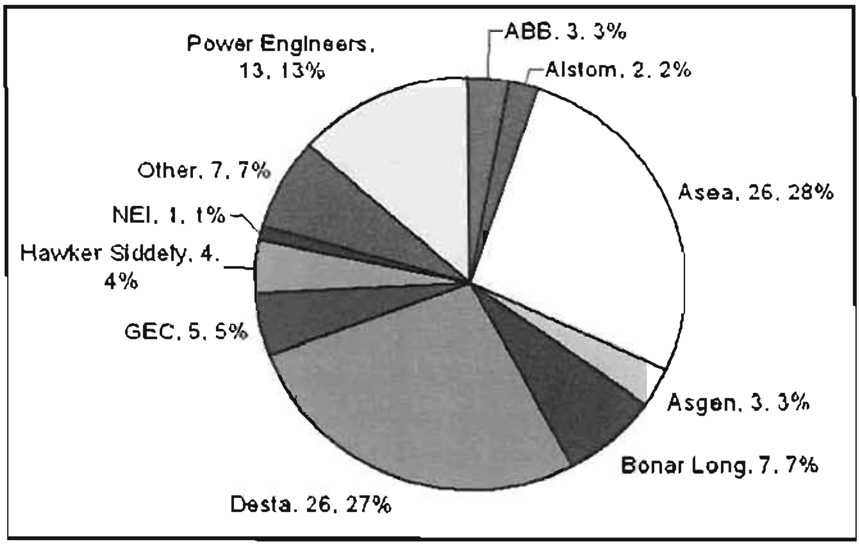


Figure 4-13: Transformer failures per manufacturer

4.7.6. Failure analysis per failure triggers

Failure triggers commonly know as event triggers are events that lead to a failure. It is not necessarily the root cause e.g. a lightning event triggered insulation breakdown within a transformer. Here the lightning is the trigger to the failure event; insulation breakdown is the mode of failure. The root cause can be attributed to a surge arrestors not operating, or not present. From Figure 4-14, it is evident that the majority of failures are triggered by mechanical related activities.

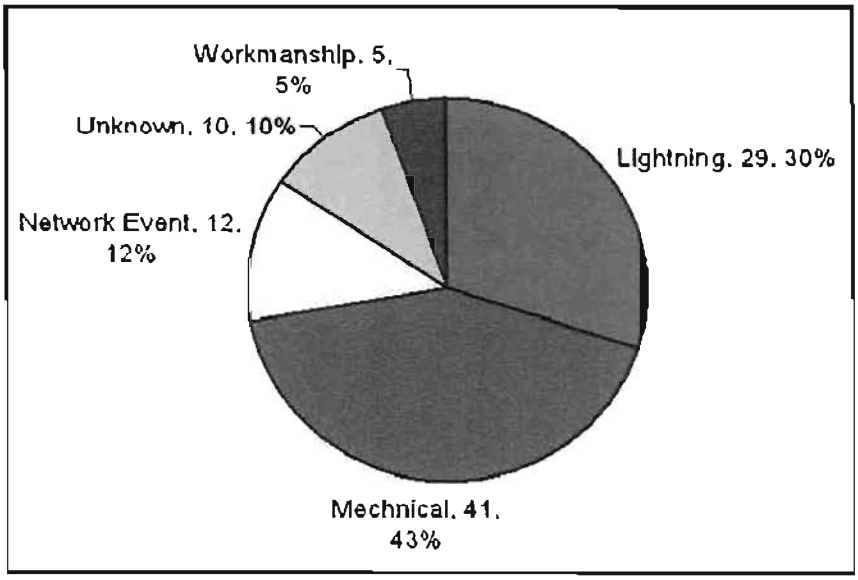


Figure 4-14: Transformer failures per failure triggers

4.7.7. Failure analysis per transformer component

A transformer failure is attributed to component failure within the transformer. The majority of failures are winding related as illustrated in Figure 4-15. 49% of all failures are related to HV/LV windings and 10% to tapping windings. The second major cause of failures is bushings, in most cause, resulting in transformer fires.

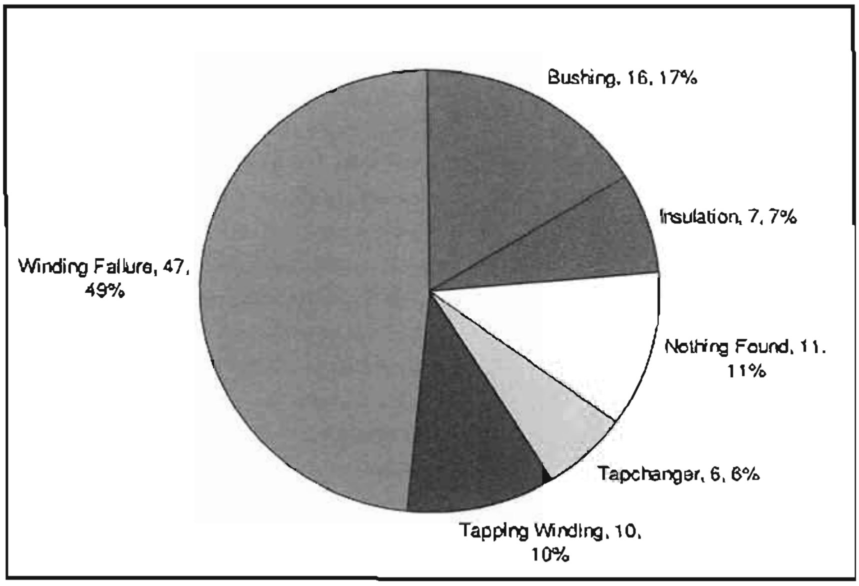


Figure 4-15: Failure per transformer component

4.8. The cost of a transformer failure

A transformer failure results in two categories of financial losses. The first loss is to the transformer and surrounding equipment, material, transport and labour associated with the replacement and any impact to the environment that needs to be rectified. The second loss is the cost of unserved energy. This refers to the loss of revenue for the duration of the outage to the customer.

4.8.1. Equipment failure loss

The cost to replace each failed transformer and the costs that were paid from the insurance department is tabulated in Table 4-11 from 1999 to 2006. The costs are in millions of rand [85] [86].

Table 4-11: Replacement and Insurance costs for failed transformers at Eskom

MVA	Qty	Insurance Payout (R million)	Total Replace value (R million)	Total Shortfall (R million)	Shortfall Per Trfr (R million)
1.25	27	R7.05	R15,20	R8,14	R0.30
2.5	15	R4.87	R15,00	R10,12	R0.68
5	15	R14.73	R27,00	R12,26	R0.82
7.5	4	R3,21	R8,70	R5,48	R1.37
10	8	R5,57	R20,40	R14,83	R1.85
15	2	R2,92	R6,15	R3,23	R1.62
20	15	R14,31	R54,00	R39,69	R2.65
40	4	R9,12	R23,00	R13,88	R3.47
60	3	R19,72	R20,77	R1,06	R0.35
80	4	R5,25	R32,60	R27,35	R6.84

The shortfall per transformer is represented in Figure 4-16. The average shortfall across the MVA range is shown in red.

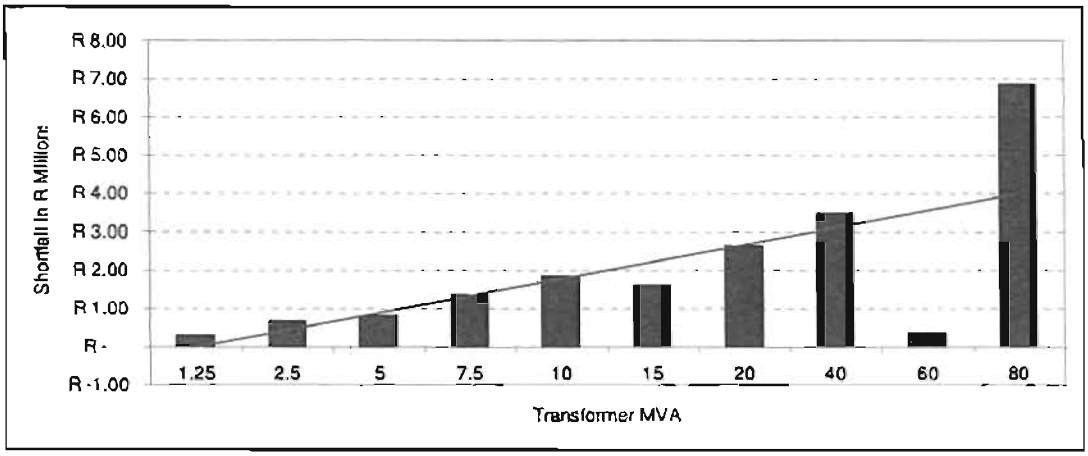


Figure 4-16: Shortfall per transformer failure

The average shortfall for the failed transformers range from R0.3 million for a 1.25MVA transformer to R4 million for an 80MVA transformer

4.8.2 Cost of unserved energy

Table 4-12 provides an indication of the unserved energy cost calculated at a peak kWh rate [42]. Unserved Energy refers to the loss of income or damages sustained by a customer during an outage. There are six categories of customers as shown in Table 4-12.

Table 4-12: Unserved energy costs per kWh lost

Commercial/Industrial Customer	Cost in Rand's per kilo Watt Hour lost
Industry	R 19.40
Mining	R 19.40
Commercial	R 14.85
Agricultural	R 4.55
Rural	R 4.55
Residential	R 2.22

Table 4-13: Unserved energy costs for transformer failures

MVA	Outage Duration (hours)	MVA Hours Lost	Average Unserved Energy Cost MWh	Loss Per MVA
1.25	17	21.25	R 3,773	R 64,147
2.5	17	42.5	R 3,773	R 64,147
5	24	120	R 3,773	R 90,560
7.5	24	180	R 6,543	R 157,020
10	36	360	R 6,543	R 235,530
15	48	720	R 14,550	R 698,400
20	48	960	R 17,883	R 858,400
40	48	1920	R 17,883	R 858,400
60	72	4320	R 17,883	R 1,287,600
80	72	5760	R 17,883	R 1,287,600

Table 4-13 tabulates the MVAs that have failed, the outage duration per MVA failure and the MVA hours lost. The average unserved energy cost has being converted to MW hours. The customer mix varies for the MVA size. The MW hour loss for a 1.25MVA transformer failure is 80 thousand rand. The MVA loss for an 80MVA transformer failure is as high as 103 million rand.

Therefore, from Table 4-13, it can be established that a transformer failure has a major impact to the end customer. The customer suffers major loss of income and damages to materials in the industrial, mining and commercial sectors.

4.9. Chapter summary

The average rate of transformer failures was calculated to be 3.4%. The transformer failure pattern resembles a typical bath tub curve. However 39% of transformer failures occur during the useful life period, and is an area of concern.

Using the failure rate of 3.4%, the reliability of transformers was calculated to be 96.6%. Therefore the mean time to failure for transformers at Eskom is 29 years. The major contribution to transformer failures as a result of maintenance related defects was found to be oil leaks at 25%.

The impact of transformer failures on Eskom's system performance was calculated. The performance KPI's CAIDI, SAIDI, SAIFI have negligible impact to the performance targets i.e. they range from 0.001% to 0.03% impact. The RSLI also has negligible impact to the RSLI target, i.e. they range from 0.002% to 0.001%. The major impact KPI was determined to be DSLI. The percentage impact to the target ranges from 3.5% for a 10MVA transformer failure to 56.% for an 80MVA transformer.

The top two components that contribute to the highest unreliability, of power transformers is HV/LV winding failures and bushing failures.

A transformer failure statistical analysis was conducted and the following was established:

- 20% of failures occurred in 2004
- 25% of failures occurred in the 26 to 30 year category
- 44% of failures occurred in the 22/11kV range. The second most is the 132/22kV and 88/11kV (10%).
- 29% of failures occurred in the 1.25MVA category, second is 2.5MVA at 15%, third is the 20MVA and 5MVA at 15%. Projects were raised to install adequate protection on transformers within Eskom.
- 43% of failures occurred due to mechanical events.
- The component to fail is the winding failure (49%), second is bushings failure at 17%.

The shortfall from insurance payouts, for a transformer failure was calculate to range from R0.3 million to R6.84 million for a 1.25MVA and a 80MVA.

The cost of unserved energy for a transformer failure was calculated to range from R64 thousand to R1.2 million per MVA hour lost. The difference in loss is determined by the load type.

CHAPTER 5: Transformer Risk Ranking and Associated KPI's

5.0. Chapter overview

This chapter illustrates a risk ranking matrix to be used when identifying high risk transformers. The matrix uses the condition and priority of the transformer in the system to perform the ranking. The methodology for elements to be used, in the weighted conditional and priority exercises, is performed. The methodology is used to evaluate Eskom's transformers and identify the high risk transformers. International KPI benchmarking is discussed, including the infrastructure and reliability of Eskom and International utilities. Eskom Distribution's Regional performance is compared with each other. The faults that affects Eskom's performance is analysed and the highest contributor to the KPI's is indicated. The causes and mitigation of poor reliability is discussed.

5.1. Transformer risk ranking

Power Transformers are extremely important in the power supply industry as transformer failures have a direct impact on continuity of supply to the customer, and results in both loss of revenue to Eskom and loss in production and income to the customer. Most electric utilities are using condition based strategies to manage their aging fleet of transformers. Effective management of transformers requires understanding the condition of transformers, and identifying highly loaded units.

Ranking of transformers is required to prioritize maintenance and capital expenditure. Risk optimization using limited capital and maintenance intervention, coupled with increased loading poses a challenge, and ultimately impacts on system performance and customer satisfaction. A risk ranking matrix will allow for prioritising capital reinvestment and maintenance of transformers. The model will aid in identifying units for replacement in the short term, hence reducing the risk of failure and increasing the reliability of the aging transformer fleet.

5.1.1. Risk ranking methodology

Historical failure models cannot be used to identify the condition of system transformers. Existing evaluation methods used in Eskom are limited by the availability of maintenance records and manufacture data. A detailed risk ranking system [87] requires that transformers undergo onsite inspections and routine testing. Ranking the condition of individual transformers, in comparison to other transformers is done by conducting a Data and Design analysis, energized and de-energized testing, and external inspections.

Evaluation of the transformer's condition is subjective and is dependent on the quality of the information used. The results of an evaluation method have to be weighted to obtain a realistic result. Condition evaluation methods are subjective and are generally based on the quality of information, requiring the results to be weighed depending on each of the factors that have been selected. Table 5-1 shows factors such as design, operating environment, usage and routine tests, that can be used for a transformer evaluation.

Table 5-1: Typical factors for calculating Weighted Condition Factor

Design		Operating Environment	Usage	Routine Tests & Diagnostics
Main unit	Ancillary	Source	Historical	DGA-Dissolved Gas analysis
Manufacrure	Equipments	Impedance	Loading	Oil Quality
Age	Oil	Protection		Power Factor
Winding	OLTC	Lighting Level	Prior Through	Insulation Resistance
Configuration	Cooling	Ambient	Fault Levels	Maintenance Records
		Load Power		
Materials	Bushings	factor		Predicted DP
		Tapchanger		
Short Circuit		range	Maintenance	
BIL				

As a preliminary process, elements selected in the data and design analysis can be used to evaluate the transformers condition, create a priority level and provide an overall ranking. Table 5-1 shows that many factors have to be considered and weighted, to provide a realistic conditional evaluation score, for the transformer. The condition of internal insulation condition is very important for the transformer to function adequately. The transformers loading, number of system faults, moisture in oil results and degree of polymerisation results are also required to evaluate the condition of transformers.

5.1.2. Establishing risk ranking and Priority Index

Knowing the probable condition of a transformer is not an adequate measure to make satisfactory decisions on maintenance and capital expenditure. In some cases, different maintenance strategies are used whereby one transformer is maintained regularly and another is run to failure. Therefore, a risk matrix is required to rate a transformer based on both its condition and priority. The condition factor must be weighted (WCF) against the level of the transformers importance in the system.

Table 5-2 [88] shows typical factors that can be used. The Transformers Priority Index (TPI) is calculated by scoring the available data for the transformer being evaluated against scoring table for each of the selected factors.

Table 5-2: Transformer Priority Index- Factors crucial for future use

Maintenance	Planning	Operations
Application	Growth Areas	Load Served
Voltage	System Location	Contingency
MVA	Capital Budget	Customer Contracts
Type	Available Spares/ Risk	System Impact
Age	Load Limits	Risk Level
Historical Problems	Population Density	
Fault Levels		
Physical Condition		

The combination of the individual unit's WCF and TPI can be used to make decisions about the extent to which the transformer should be operated and maintained. A transformer rated in poor condition, and in a position vital to the system's operation would require a high level of attention. A transformer rated in similarly poor condition but not crucial to future system operation, may be operated with a minimum of attention.

Table 5-3 shows a typical risk matrix [88] that allows for transformers to be ranked in order of condition and priority. The transformers are ranked into four groups: Red, Yellow, Blue and Green, indicating the level of risk associated with operating older units, and can be used as decision matrix.

Table 5-3: Risk matrix for WCF and TPI ranking

Weighted Condition Factor	Transformer Priority Index									
	Vital			Critical			Important			
	1	2	3	4	5	6	7	8	9	10
15										
14										
13										
12										
11										
10										
9										
8										
7										
6										
5										
4										
3										
2										
1										

5.1.3. Weighted Condition Factor methodology

The weighted condition factor (WCF) [89] will use the following elements from Table 5-1 to evaluate the condition of a transformer:

- Dissolved Gas Analysis (DGA) : 30% weighting
- Moisture in oil : 10% weighting
- Degree of Polymerisation (DP) : 60% weighting

The WCF score for Eskom's transformer fleet will be weighted using the formula below:
WCF = 0.30*(DGA) + 0.10*(Moisture) + 0.60*(DP)

The result will be used to rank the entire power transformer fleet according to its conditional factor.

5.1.3.1. DGA ranking

This method is used simply evaluate the dissolved gasses in oil and is based on IEEE C57.104-1991. To calculate the Total Dissolved Combustible Gases (TDCG) all the combustible gases found in the analysis are summated.

TDCG $= H_2 + CO + CH_4 + C_2H_6 + C_2H_4 + C_2H_2$

= Hydrogen + Carbon Monoxide + Methane + Ethane + Ethylene + Acetylene

Table 5-4 provides the score to be used for the calculated TDCG.

Table 5-4: TDCG scoring table

DGA (30 % weighting)	Score
TDCG >1200	5
TDCG > 720 and CO2 less 50%	4
TDCG > 720	3
TDCG > 430	2
Low TDCG	1

Example: If the TDCG is greater than 430 ppm, then the score is 2.

5.1.3.2. Moisture ranking

Water is harmful in power transformers because the water is attracted to places of the greatest electrical stress where it has the greatest damaging effect. Water accelerates the deterioration of both the insulating oil and the insulating materials used inside the transformer.

With only a small amount of water present in the insulation paper there is a greater fall in the electric strength. As an example, with 4 % water content in paper there is a 10 % fall in the electric strength of oil impregnated paper but with 8 % water content the value of the electric strength falls by 40 %. The scoring for moisture will be done in consultation with a pipers chart. Table 5-5 provides the score to be used for the values obtained from a pipers chart.

Table 5-5: Moisture scoring table

Moisture (10 &% weighting)	Score
Result above upper limit – High moisture	4
Result between lower and upper limit – Medium moisture	2
Result below lower limit – Low moisture	1

Example: If the result is above the upper limit, the score is 4.

5.1.3.3. DP ranking

The DP values in Table 5-6, can be used for the assessment of the paper and cellulose condition and useful remaining life of the power transformer [47].

Table 5-6: DP, percent of life used

Estimated Degree of Polymerization (DP)	Estimated Percentage of Remaining Life	Interpretation
800	100	Normal Aging Rate
700	90	
600	79	
500	66	Accelerated Aging Rate
400	50	
380	46	
360	42	
340	38	Excessive Aging Zone
320	33	
300	29	
280	24	High Risk of Failure
260	19	
240	13	End of Expected Life of Paper Insulation and of the Transformer
220	7	
200	0	

The scoring for DP will be done in consultation with Table 5-6. Table 5-7 provides the score to be used for the power transformers DP values.

Table 5-7: DP scoring table

DP (60% weighting)	Score
End of Expected Life of Paper Insulation and of the Transformer	4
High Risk of Failure	3
Excessive Aging Zone	2
Accelerated Aging Rate	4
Normal Aging Rate	1

Example: If the DP of the transformer is 280, then the score is 3.

5.1.3.4. Weighted Condition Factor example

Using the examples from 5.2.3.1 to 5.2.3, the WCF can be calculated using the weightings from 5.2.3.

TDCG Score	= 2
DP Score	= 3
Moisture Content Score	= 4

The weighted score is then:

$$WCF = (0.30)(2)+(0.10)(4)+(0.60)(3)$$
$$= 2.8$$

This score is out of a maximum of 4.3. The WCF in the risk model has a scale of 0 to 15. The calculated value of 2.8 is normalised as follows:

$$\text{Normalised value} = \frac{15}{4.3} x2.8 = 9.77$$

The value is then rounded of to the next decimal figure i.e. 10. Therefore the WCF for the example, to be used on the risk matrix is 10.

5.1.4. Transformer Priority Index

The following elements with its associated weightings will be used to determine the TPI for the transformer fleet:

Table 5-8: TPI elements and weighting

TPI Elements	Weighting
a) MVA rating	15
b) Voltage level in kV	10
c) Percentage loading of transformer	20
d) Substation fault level	5
e) Maintenance defects and physical condition	20
f) Lightning density level in strikes per square km per year	5
g) On load tap changer	10
h) Cooling System	15

The priority of a typical transformer is dependent on its condition and importance in the network and the maintenance strategy adopted. Hence, the above selection of elements will provide a transformer priority index that is realistic.

5.1.4.1. MVA ranking

Table 5-9 provides the score to be used for the MVA ranking. The larger MVA transformers are given a higher score because they are either located at coupling substations or are supplying a very high customer base.

Table 5-9: MVA ranking

MVA Rating	Score
1.25	1
5	2
7.5	3
15	4
20	5
40	6
60	8
80	10

Example: If a power transformer is rated 60MVA, then the score is 8.

5.1.4.2. Voltage ranking

Table 5-10 provides the score to be used for the kV ranking. The highest kV from, for example, a 132/33kV transformer will have a score of 10.

Table 5-10: Voltage ranking

Voltage Rating	Score
11 & 22	2
33	5
88	8
132	10

Example: If a power transformer has a voltage ratio of 132/88kV, then the score is based on the higher voltage i.e. 132kV. Therefore the score is 10.

5.1.4.3. Percentage loading ranking

Table 5-11 provides the score to be used for percentage loading rating. The greater the transformer loading, the higher will be the score.

Table 5-11: Percentage loading ranking

Percentage Loading Rating	Score
0-20%	1
21-40%	2
41-60%	4
61-80%	6
81-100%	8
>100%	10

Example: If the power transformer is loaded to 90%, it will have a score of 8.

5.1.4.3. Fault level ranking

Table 5-12 provides the score to be used for the fault level at the substation. The high fault levels will cause stresses within the transformer for close-on faults.

Table 5-12: Fault level ranking

Fault Level Rating	Score
0-5kA	1
6-10kA	4
11-15kA	6
16-20kA	8
21-25kA	10

Example: If a power transformer is installed in a substation that has a fault level of 11-15kA, then the score will be 6.

5.1.4.4. Physical condition ranking

Table 5-13 provides the score to be used for the conditional assessment of the transformer. The assessment is conducted onsite and the physical condition of the transformer is scored.

Table 5-13. Physical condition ranking

Conditional Assessment	Score
Good Condition	1
Medium Condition	6
Bad Condition	10

Example: If the transformer is in medium condition (this is subjective), then the score will be 6.

5.1.4.5. Lightning density ranking

Table 5-14 provides the score to be used for the lightning density of the substation location.

Table 5-14: Lightning density ranking

Lightning Density	Score
0-3	1
3-6	6
6-9	8
9-12	10

Example: If the transformer is located in an area with a lightning density of 7 strikes per square km per year, then the score will be 8.

5.1.4.6. Load tapchanger ranking

Table 5-15 provides the score to be used for the tapchanger ranking. Transformers with on load tapchangers are given a score of 10 and those without, a score of 0.

Table 5-15: Load tapchanger ranking

Load Tapchanger Rating	Score
No On Load Tapchanger	0
Has On Load Tapchanger	10

Example: If the power transformer has an on-load tapchanger, then the score is 10.

5.1.4.7. Cooling system ranking

Table 5-16 provides the score to be used for the cooling system ranking. The transformers with ONAN cooling are not subjected to the same heat stresses as transformers with ONAF cooling.

Table 5-16: Cooling system ranking

Cooling System Ranking	Score
ONAN	0
ONAF	10

Example: If the power transformer has ONAF cooling, then the score is 10.

5.1.4.8. TPI example

Using the examples from 5.2.1.1 to 5.2.4.7, the TPI can be calculated using the weightings from Table 5-8.

MVA Ranking score	= 8
Voltage Ranking score	= 10
Percentage Loading score	= 8
Fault Level score	= 6
Physical Condition score	= 6
Lightning Density score	= 8
Load tapchanger score	= 10
Cooling System score	= 10

The weighted score is then:

$$\begin{aligned} TPI &= (0.15)(8)+(0.1)(10)+(0.2)(8)+(0.05)(6)+(0.2)(6)+(0.05)(8)+(0.1)(10)+(0.15)(10) \\ &= 8.2 \end{aligned}$$

The value is then rounded of to the next decimal figure i.e. 9. Therefore the TPI for the example, to be used on the risk matrix is 9.

5.1.4.8. Risk Matrix WCF and TPI example

The WCF for this example is 10. The TPI for the example is 9. These values are plotted on the risk matrix on in Table 5-3. The plotted value is in the yellow area. The yellow area is considered as critical. The appropriate action can then be taken to address this critical transformer, using the elements of concern in the WCF and TPI.

5.1.5. Eastern Region's transformer risk matrix

The elements of the TPI were used to rate each transformer and obtain a score. The elements of the WCF were also used to rate each transformer and obtain a score. The TPI and WCF score were plotted on Table 5-17 to create the Transformer Risk Matrix for Eskom's Transformer at Eastern Region.

Table 5-17: Eastern Regions transformer risk matrix

Weighted Condition Factor	Transformer Priority Factor									
	Vital			Critical			Important			
	10	9	8	7	6	5	4	3	2	1
15										
14										
13										
12			2							
11			2	1						
10			1		3					
9		1	2	2	6	3	1			
8		1	2	1	15			2		
7		1	4			4	1	1		
6			2	1	3		1	1		
5										
4		8	6	7	117	15	11	29		
3	1	7	4	2	100	7	41	9		
2										
1										

Number of transformer at Risk		Risk Percentage
Vital	4	1%
Critical	15	4%
Important	26	6%
Good Condition	383	89%
Total transformer base: 428		**100%**

The risk matrix indicates that 4 transformers or 1% of the transformer base are in critical condition and require immediate attention. The details of the four high risk transformers are:

a. Desta, 40MVA, 132/33kV, 21years old
b. BBT, 40MVA, 132/33kV, 24 years old
c. BBT, 40MVA, 132/33kV, 24 years old
d. Desta, 40MVA, 132/33kV, 19 years old

Transformer (a) supplies a municipality. Transformer (b) and (c) supplies a key customer that has a firm supply contract. Transformer (d) is a coupling substation for the 132/33kV network. As a result of this study, the four transformers identified as high risk are being replaced as capital projects within Eskom [90] [91] [92]. Fifteen transformers are at a high risk and require investigation in the short term. The remainder of the transformers are in acceptable condition.

5.2. International KPI benchmarking

International utilities participate in a network reliability benchmark program. The benchmarking program looks at network reliability indices [93] [94]. Eskom Distribution has participated in the international PA Consulting benchmarking since 2000, with utilities from Argentina, Australia, Chile, Brazil and Sweden. The intention of the program is to certify the reliability data capture, processing and reporting systems to align the metrics with international measures and best work practices.

5.2.1. Influence of key factors for network reliability benchmarking

The following key factors are taken into account, when conducting a reliability benchmark exercise [94] [95]:

- Step restoration methodology
- Geographic area
- Lightning ground flash density
- Network exposure and design
- Degree of outage management and system automation
- Completeness and accuracy of data connectivity
- Performance measurement methodology
- Cost of domestic electricity price

Each key factor could increase or decrease the reliability figures, obtained for use in the benchmarking exercise, and could ultimately distort the reliability figures.

5.2.2. Comparison of Eskom and international utilities network infrastructure

Table 5-18 [94] [96] provides a summary of international countries and the extent of their distribution infrastructure compared to Eskom.

Table 5-18: International countries distribution infrastructure

Country	No Of Distribution Companies	Energy (GWh)	No of MV customers	Area (sq km)	Line Length (LV & MV)	Percentage Overhead Line
Italy	195	188 00	11 000	301 000	1 030 900	38%
Netherlands	21	70 818	18 284	33 939	247 257	0%
Norway	200	71 000	N/A	386 958	277 183	64%
Portugal	15	28 426	18 140	88 797	174 208	81%
Spain	450	128 290	65 733	506 000	571 246	80%
UK	14	276 006	N/A	228 705	750 360	39%
Eskom	2	32733	632 298	1 219 909	45 746	97%

5.2.3. Comparison of Eskom and international utilities reliability figures

Table 5-19 [97] tabulates the reliability figures for various countries. Eskom has the highest SAIFI and SAIDI figures. The CAIDI figures are in line with international utilities. The performance of Eskom can be compared to that of Indonesia and Thailand. For Eskom, the SAIFI of 22 indicates that each customer experiences 22 interruptions in a year. The SAIDI of 2640 indicates that each customer will be without supply for a total of 2640 minutes in a year.

Table 5-19: Eskom and International utilities reliability target comparison

Country	SAIFI (interruptions)	SAIDI (minutes)	CAIDI (hours)
Japan	0.05	6	2.00
Singapore	0.05	2.2	0.73
Netherlands	0.51	29	0.95
United Kingdom	0.77	70	1.52
France	1.21	53	0.73
Iceland	1.34	170	2.11
Ireland	1.34	236	2.94
United States	1.35	214	2.64
New Zealand	2.00	128	1.07
Australia	2.22	182	1.37
Canada	2.41	220	1.52
Norway	2.73	218	1.33
Spain	3.30	179	0.90
Italy	3.83	203	0.88
Finland	4.06	183	0.75
Argentina	6.00	480	1.33
Philippines	6.50	1200	3.08
Portugal	7.51	531	1.18
Brazil	17.64	1101.6	1.04
Indonesia	18.50	794	0.72
Thailand	18.85	1496	1.32
South Africa (Eskom)	22.00	2640	2

5.2.4. Analysis of Eskom Distribution performance

The performance of each region within Eskom is tabulated in Table 5-20. The percentage contribution to the SAIFI, SAIDI and CAIDI, to Eskom Distribution's total performance is shown.

Table 5-20: Percentage contribution to Eskom performance

Region	% SAIFI	% SAIDI	% CAIDI
Western	1.5	7.4	11.9
Eastern	2.3	4	15
Central	14.7	16.5	10.9
North West	14.7	1.3	21.8
Southern	16	22.6	16.1
Northern	22.9	23.5	12.4
North East	27.9	24.7	11.9
Total		100	

Eastern Regions contribution to SAFI and SAIDI is 2.3% and 4% respectively. This is the second lowest contribution within Eskom Distribution.

5.2.5. Comparison of faults that effect Eskom's performance KPI's

Figure 5-1 illustrates the various faults that contribute to Eastern Regions performance.

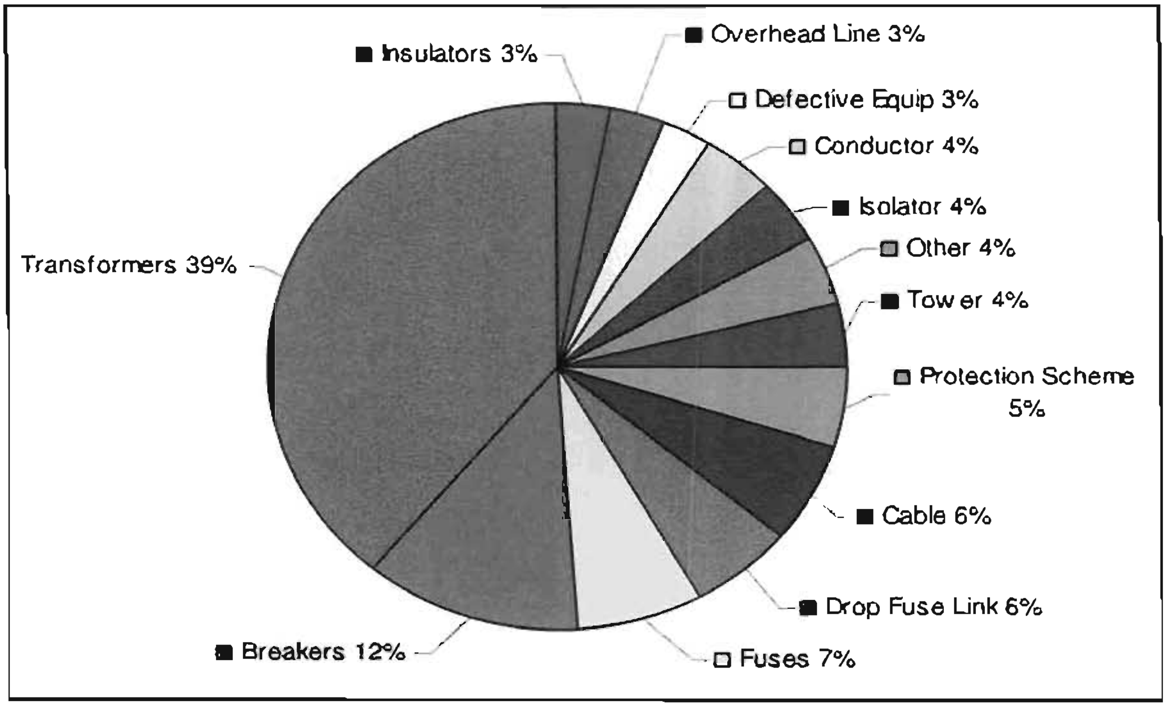


Figure 5-1: Fault contribution to regional performance

Transformer faults contribute to 39% of the regions performance. The second highest contributor to the performance is breakers at 12%. This again, highlights the impact transformer failures have to system performance.

5.3. Causes and mitigation of poor reliability

Maintenance is performed at regular intervals, e.g. the 100 thousand service intervals for a tapchanger and is referred to as Time Based Maintenance (TBM). The basic assumption with TBM is that the probability of failure increases with age. These intervals are based on detailed knowledge of the typical performance of transformers. For example, transformer oil degrades at a certain rate, and cleaning or replacement of the oil before too much degradation will prevent damage to both the transformer and surrounding equipment. Further, an outage due to a failure will be prevented, since outages due to failures may take a long time to repair.

In the 1960's and 1970's, it was found that certain failure types cannot be reduced by preventative TBM, even if the maintenance period is reduced. Negative aspects of TBM transformers that operates in harsher conditions than the average may still fail before the normal maintenance was scheduled, resulting in an unacceptably long outage for repairs and transformers that operates in better conditions than the average don't have to be maintained at the average intervals. Outage time can therefore be saved by scheduling maintenance of transformers at longer intervals.

Reliability Centered Maintenance (RCM) [98] focuses on the function of the transformer and the severity of a failure. Preventative maintenance is therefore scheduled to minimise the risks of severe failures, rather than all failures. A subset of RCM is Condition Based Maintenance (CBM), where the maintenance is scheduled based on the condition or wear of the transformer. A pre-requisite for CBM is detailed knowledge of the condition of the transformer, as well as methods to track the condition with time. Maintenance will be scheduled as and when it appears necessary. Additionally, only the required maintenance will be performed, which may reduce the maintenance period and hence the outage duration.

5.3.1. Causes

Causes for transformer failure and interruptions [99] can be classified into the following categories:

- Weather-related, e.g. lightning, wind, ice/snow storms.
- Pollution; dirty bushings increase the risk of flash-over during bad weather and switching transients in the network.
- Animals, e.g. bird streamers, large bird's wing span touching between phases, rodents or monkeys.
- Physical failures, e.g. vandalism.
- Fire; normal veld-fires may cause flash-over, but this risk is increased with vegetation overgrowth.
- Protection philosophies and failures, e.g. sympathetic tripping of breakers
- Overloading; the overloading may be caused by too much load growth or due to a failure elsewhere in the system.
- Human error; equipment is accidentally switched out, or in onto protective earth connections during maintenance.
- Unknown; unfortunately not all faults can be classified, since no indication of the fault location or mechanism can be found.

5.3.2. Mitigation

There are many causes for interruptions on the power system and many possible solutions for many of these causes. The performance of a power transformer can be improved by reducing the number of transformer failures or by reducing the duration of the interruptions.

The main failure reduction method is to improve or implement maintenance strategies, e.g. RCM and CBM. Frequent inspection of transformers may reveal possible risk situations that may be corrected before a failure occurs. In high lightning areas, it is useful to use dual, station class surge arrestors and mount them on the transformer [100]. Surge arrestors should be verified after lightning storms to determine if they are still functional. Animal related transformer failures can be prevented by the use of bird and animal guards on bushings. These prevent phase to phase or phase to ground faults.

Network topology and protection philosophies should help reduce the duration of interruptions. Different protection philosophies may positively impact the reliability by clearing faults downstream and not subjecting the transformer to high fault currents. The substation may be upgraded to increase number of transformers or loop-in-out arrangements can be created to increase switched firmness capabilities. Additional lines or substations will reduce the duration of interruptions and decrease the number of customers affected by a single transformer failure.

Distribution automation is aimed at increasing the speed of restoring power to customers. This is done by using available switching points. Distribution automation will allow the supply to be restored in a shorter time.

5.4. Chapter summary

A risk risking methodology for identifying high risk transformers was established. The results of the matrix showed that 1% of the transformer base (4) is at high risk. Capital projects were raised within Eskom to replace these high risk transformers.

The electrical systems infrastructure of international utilities was compared to that of Eskom. Eskom has 97% overhead line and 3% cable infrastructure. The energy produced by Eskom in comparable with Spain (~33GW).

The comparison of Eskom's and international utilities performance showed that Eskom has the worst SAIFI (22 interruptions per customer per year) and SAIDI (2640 minutes of no supply per customer in a year).

The analysis of Eskom's performance against the regions showed that Eastern Regions performance is the second to that of Western Region. The faults that effect Eskom's performance were analysed. The largest contributor to the performance KPI's is transformers failures (39%). The second highest contributor to the performance KPI's is breaker faults (12%).

CHAPTER 6: Conclusion and Recommendations

This dissertation analysed the reliability of power transformers and its impact of failure on system performance. Eskom Distribution, Eastern Region, is used as a practical case study, which has an installed transformer base of 6066MVA comprising of 428 transformers ranging from 1MVA to 80MVA with voltage levels of 6.6kV to 132kV.

6.1. Transformer reliability impacted by design evolution

The evolution of transformer designs by manufacturers has reduced the reliability of transformers by decreasing both the oil volume per kVA and the short circuit strength of the windings, and by increasing the volts per turn, hot spot temperature rise, ambient temperature constants and hot spot temperature of the windings. These design changes allows for more compact transformers to be manufactured, however at a reduced reliability level and increased risk of failure. The downside is that there is no "fat" in the design. Any form of overloading will decrease the anticipated 35 year lifespan.

6.2. Transformer reliability impacted by maintenance and operation

This study included a conditional assessment and an oil analysis review of power transformers at Eskom. The assessment showed that 10% of transformers have critically low electrical strength, 6% have low DP's, 23% have ethane present, 68% have ethylene present and 21% have acetylene present. The low electric strength indicates that the cellulose is wet and the transformers short circuit withstand capabilities are compromised. The low DP values indicate that the 6% of transformers are nearing their end of useful life. The area of concern is the combustible gases that are present under normal operating conditions. This indicates that the cellulose is overheating and that temperatures of up to 1000^0C are present inside the transformer during "normal" operating conditions. This is not the norm, and requires further investigation.

6.3. Transformer failure mode analysis

A parallel and switched firmness study was conducted to establish the degree of network firmness. Only 50% of the distribution system at Eskom Distribution Eastern Region has firmness. The power transformer failure rate was calculated to be 3.4%. The component that contributed to the highest unreliability is HV/LV windings (48% of failures). The second contributor is bushing failure (16% of failures). The power transformer failures were shown to be characteristic of a bathtub curve, however 39 percent of failures occurred during the useful life period. The design life of power transformers is considered to be 25 years. The mean time to failure of power transformers at Eskom is calculated to be 29 years. This is 4 years greater than the desired 25 years of service. However, the average age of all transformers that failed between 1999 and 2006 is 18 years.

6.4. The impact of transformer failures on system reliability

The study showed that power transformer failures have minimal impact to system performance KPI's such as SAIDI, SAIFI, CAIDI, and RSLI. The major impact KPI is DSLI and ranges from 3.5% impact for a 10MVA power transformer failure to 56% impact for an 80MVA power transformer failure.

The failure details of each power transformer over eight years was analysed and an insight to power transformer failures using statistical analysis methods was presented. 20% of failures occurred in the year 2004. 35% of failures occurred in the 26 to 30 year age category. 44% of failures occurred in the 1.25MVA and 2.5MVA category. The root cause of these failures were no or inadequate surge protection, transformer protection and lack of 11kV and 22kV breakers. Projects were raised within Eskom to install or upgrade surge protection, install transformer protection, install new breakers and to install telecontrol at these substations.

5% of failures were due to poor workmanship. This refers to failures that occurred after a major tapchanger inspection or service. The reason for the failure is attributed to lack of skill transfer because of the high staff turnover that Eskom is experiencing.

Maintenance defects for the period 2003 to 2006 was collected and analysed from the on site inspection sheets for power transformers, at Eskom. This exercise revealed that 46% of all defects are oil leaks. This correlated to the moisture results showing that 10% of transformers have critically low electric strength values and 34% of transformers require dry out due to the cellulose being wet. The study also revealed that 56% of all transformers in the system have defects such as oil leaks, low oil, pink silica gel, faulty fans, rust, etc.

International KPI Benchmarking was investigated to establish the criteria for network reliability indices and to compare the network infrastructure and performance of international utilities and Eskom. It was established that transformer faults have the major impact to Eskom Distribution's regional performance. 39% of the regional KPI is impacted by transformer failures. The second highest contributor is breakers failures at 12%.

6.5. Financial impact of transformer failures

The cost of a power transformer failure both to Eskom and the customer using actual insurance claim data, power transformer replacement values and unserved energy costs was determined. The shortfall for a transformer failure was calculated to range from R0.3 million to R6.84 million for a transformer rating of 1.25MVA to 80MVA. The cost of unserved energy was calculated to range from R64 thousand to R1.2 million per MVA hour lost, based on the type of load (domestic or industrial).

6.6. Identification of high risk transformers using a risk matrix

The later part of the study involved the analysis of a risk ranking methodology to establish a risk ranking matrix. The matrix used two elements to establish criteria's for the evaluation. A weighted conditional factor (WCF) was used, focusing only on DGA, DP, and Moisture levels. This weighted valued were plotted against a Transformer Priority Index (TPI). The TPI used factors such as MVA rating, % loading, physical condition, cooling system, lightning density, tapchanger and fault levels to obtain a weighted TPI score. The power transformers were ranked in the matrix using the WCF and TPI values to identify the high risk focus areas. The risk matrix indicates that 4 transformers or 1% of the transformer base are in critical condition and require immediate attention. Projects were raised within Eskom to replace the identified critical risk power transformers. Fifteen transformers are at a high risk and require investigation in the short term. The remainder of the transformers are in acceptable condition.

6.7. Research objectives

The objective of the research was to determine the following:

- Determine the reliability and impact of transformer failures.
- Demonstrate this for the Eskom Eastern Region transformers.
- Establish a risk ranking matrix for the transformers within the system.
- Recommendations for improvements in operations and maintenance practices and transformer procurement specifications.

The above four major objectives of this research study was achieved and the high risk transformers that were identified using the risk matrix are being replaced as a result of this study.

The hypothesis of this dissertation is "Analyzing the existing state of the power transformers and the determination of the dominant cause of failure will help identify the high risk focus areas allowing a plan of action to reduce these risks, hence minimizing future transformer failures". The hypothesis proved to be valid.

6.8. Recommendations

The following are recommendations, to increase the reliability of power transformers and increase customer satisfaction:

- The design criteria of transformers must be evaluated in detail. The new transformer in the system shows signs of fault gases from the first day of service. This cannot be acceptable as there is an increased risk of transformer failure.
- The BIL of the transformer should be increased for the 11/22kV 1.25MVA and 2.5MVA transformers in an attempt to reduce winding related failures. Improve insulation co-ordination by installing station class surge arrestors close to the 11kV and 22kV transformer bushings.
- The creepage of the bushing should be of a level that caters for the highest pollution level in the region. This can be achieved by applying silicon spray coating with creepage extenders on existing bushings.
- The procurement specification for transformers should allow for the GOB porcelain bushings to be replaced with composite bushings.
- A plan of action is required to address the power transformers that fall in the critical section of the risk matrix, i.e. 15 transformers relating to 4% of the system base. And the 26 important transformers (blue) that account for 6% of the system base.
- Increase distribution automation and substation visibility via SCADA. Transformer oil and winding temperatures can be monitored remotely and appropriate action can be taken to minimise transformer ageing.
- The transformer procurement specification be changed to purchase 120MVA transformers to be used as 80MVA. This practice is used in other regions with Eskom Distribution but not implemented in Eastern Region.
- Introduce a transformer de-rating philosophy for the high impact DSLI transformers i.e. 20, 40, 60 and 80MVA to increase overall system reliability.
- Implement Reliability Centred Maintenance within the region to elevate maintenance defects.
- Replace oil breakers that are susceptible to through faults and do not operate when given a trip signal.
- Establish service contract with Original Equipment Manufactures (OEM's) to maintain and service tapchangers and refurbish transformers. This will also help with lack of skill and staff shortages and prevent tapchanger failures after routine sevices.
- The risk evaluation method from this dissertation should be used Nationally at Eskom.

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Appendix A: Power Transformer Failure Data

No	Year of Failure	kV Ratio	Size (MVA)	YOM	Manufacturer	Component that Failed	Event of Failure
1	1999	22/11	5	1998	ABB	Winding Failure	Network Event
2	1999	22/11	1.25	1998	Desta	Winding Failure	Network Event
3	1999	33/22	2.5	1996	Desta	Tapchanger	Mechanical
4	1999	22/11	1.25	1993	Other	Winding Failure	Lightning
5	1999	132/33	20	1991	Desta	Winding Failure	Lightning
6	1999	22/11	2.5	1989	Desta	Winding Failure	Mechanical
7	1999	22/11	1.25	1984	Asea	Winding Failure	Lightning
8	1999	22/11	1.25	1983	Power Engineers	Winding Failure	Network Event
9	1999	132/88	80	1982	Asea	Insulation	Mechanical
10	1999	22/11	1.25	1979	Power Engineers	Winding Failure	Lightning
11	1999	132/33	20	1979	Other	Bushing	Lightning
12	1999	88/11	15	1970	Asea	Nothing Found	Unknown
13	1999	88/11	2.5	1969	Other	Winding Failure	Lightning
14	2000	132/22	20	1999	Desta	Winding Failure	Network Event
15	2000	132/22	20	1999	Desta	Tapping Winding	Lightning
16	2000	22/11	5	1997	Bonar Long	Tapping Winding	Mechanical
17	2000	22/11	2.5	1986	Power Engineers	Tapchanger	Workmanship
18	2000	88/11	5	1982	Bonar Long	Bushing	Mechanical
19	2000	22/11	1.25	1982	Power Engineers	Bushing	Lightning
20	2000	132/88	80	1981	Asea	Nothing Found	Unknown
21	2000	88/11	10	1981	Bonar Long	Bushing	Workmanship
22	2000	22/11	1.25	1976	Hawker Siddely	Winding Failure	Network Event
23	2000	132/88	80	1973	Asea	Bushing	Mechanical
24	2000	132/11	20	1973	GEC	Tapchanger	Mechanical
25	2000	88/33	40	1971	Asea	Bushing	Mechanical
26	2000	88/11	2.5	1970	Other	Winding Failure	Network Event
27	2001	132/22	20	1999	Desta	Tapping Winding	Mechanical
28	2001	22/11	2.5	1998	Desta	Winding Failure	Workmanship
29	2001	132/33	40	1976	Asea	Bushing	Mechanical
30	2001	132/22	10	1974	Asea	Tapping Winding	Mechanical
31	2002	132/11	20	1998	ABB	Tapping Winding	Mechanical
32	2002	22/11	1.25	1993	Desta	Winding Failure	Mechanical
33	2002	22/11	2.5	1991	Asea	Winding Failure	Mechanical
34	2002	22/11	5	1990	Bonar Long	Nothing Found	Unknown
35	2002	132/11	20	1977	GEC	Tapping Winding	Mechanical
36	2002	33/11	5	1977	Hawker Siddely	Nothing Found	Workmanship
37	2002	88/33	40	1974	Asea	Bushing	Lightning
38	2003	22/11	1.25	2000	Alstom	Winding Failure	Mechanical
39	2003	22/11	1.25	2000	Alstom	Winding Failure	Mechanical
40	2003	22/11	1.25	2000	Desta	Winding Failure	Mechanical
41	2003	132/33	15	1991	Other	Bushing	Mechanical
42	2003	88/22	20	1988	Asea	Tapchanger	Mechanical
43	2003	33/11	5	1984	Power Engineers	Tapping Winding	Mechanical

44	2003	33/11	5	1983	Power Engineers	Tapping Winding	Mechanical
45	2003	33/11	5	1983	Power Engineers	Tapchanger	Workmanship
46	2003	132/33	20	1983	Desta	Bushing	Mechanical
47	2003	22/11	1.25	1983	Power Engineers	Winding Failure	Lightning
48	2003	88/11	5	1982	Asea	Winding Failure	Mechanical
49	2003	22/11	1.25	1982	Power Engineers	Winding Failure	Mechanical
50	2003	22/11	1.25	1982	Power Engineers	Insulation	Lightning
51	2003	88/22	5	1978	GEC	Nothing Found	Mechanical
52	2003	132/22	10	1975	Asea	Winding Failure	Mechanical
53	2003	132/22	10	1975	Asea	Tapping Winding	Network Event
54	2003	88/11	20	1973	Asea	Bushing	Mechanical
55	2003	132/22	7.5	1971	Asea	Winding Failure	Network Event
56	2003	132/88	60	1969	Other	Tapchanger	Mechanical
57	2004	132/11	20	2001	Desta	Winding Failure	Mechanical
58	2004	22/11	2.5	1999	Desta	Winding Failure	Mechanical
59	2004	22/11	1.25	1997	Desta	Winding Failure	Lightning
60	2004	22/11	2.5	1997	Desta	Nothing Found	Unknown
61	2004	22/11	2.5	1995	Desta	Winding Failure	Mechanical
62	2004	22/11	1.25	1993	Desta	Winding Failure	Mechanical
63	2004	132/11	10	1992	Bonar Long	Nothing Found	Unknown
64	2004	132/88	60	1991	Asea	Winding Failure	Mechanical
65	2004	22/11	2.5	1983	Asea	Nothing Found	Unknown
66	2004	132/88	80	1983	Asea	Insulation	Mechanical
67	2004	132/22	10	1980	Asea	Winding Failure	Network Event
68	2004	88/11	5	1980	GEC	Insulation	Lightning
69	2004	132/22	10	1977	GEC	Nothing Found	Unknown
70	2004	132/33	40	1977	Asea	Bushing	Lightning
71	2004	22/11	2.5	1976	Desta	Winding Failure	Lightning
72	2004	22/11	2.5	1976	Desta	Insulation	Lightning
73	2004	22/11	2.5	1976	Desta	Winding Failure	Lightning
74	2004	22/11	1.25	1972	Other	Nothing Found	Unknown
75	2004	132/22	7.5	1971	Asea	Nothing Found	Unknown
76	2005	22/11	1.25	1995	Bonar Long	Winding Failure	lightning
77	2005	88/11	5	1992	Bonar Long	Winding Failure	Network event
78	2005	88/22	20	1992	NEI	Winding Failure	lightning
79	2005	88/22	5	1991	Desta	Winding Failure	Network Event
80	2005	22/11	1.25	1989	Hawker Siddely	Winding Failure	Lightning
81	2005	33/11	5	1988	Asea	Winding Failure	Network Event
82	2005	22/11	1.25	1984	Desta	Winding Failure	Mechanical
83	2005	132/11	20	1981	Desta	Winding Failure	Lightning
84	2005	132/11	20	1981	Desta	Bushing	Lightning
85	2005	22/11	1.25	1977	Power Engineers	Winding Failure	Lightning
86	2005	22/11	1.25	1976	Desta	Winding Failure	lightning
87	2005	88/6.6	7.5	1976	Asgen	Insulation	Mechanical
88	2005	88/6.6	7.5	1976	Asgen	Insulation	Mechanical
89	2005	22/11	1.25	1976	Asea	Winding Failure	Lightning
90	2005	88/11	10	1971	Asea	Bushing	Lightning
91	2006	22/11	5	1998	ABB	Winding Failure	Mechanical
92	2006	22/11	1.25	1981	Power Engineers	Bushing	lightning

93	2006	22/11	1.25	1981	Asea	Winding Failure	lightning
94	2006	22/11	1.25	1978	Power Engineers	Winding Failure	lightning
95	2006	22/11	1.25	1976	Hawker Siddely	Winding Failure	Mechanical
96	2006	33/22	2.5	1974	Desta	Tapping Winding	Mechanical
97	2006	132/88	60	1967	Asgen	Bushing	unknown