Life Assessment and Life Extension of High Voltage Equipment in Transmission Substations

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A thesis submitted to the Faculty of Engineering, University of KwaZulu Natal Durban, in partial fulfilment of the requirements for the degree of Master of Science.

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DECLARATION

I declare that this thesis is my own, unaided work. It is being submitted for the degree of Master of Science at the University of kwaZulu Natal, Durban. It has not been submitted before for any degree or examination in any other university.

Omchand Singh

20 February 2004

ABSTRACT

In order to sustain transmission grid availability and reliability it is imperative that the condition of vital and costly high voltage equipment is ascertained on a continuous or regular basis. It is necessary to establish the effective diagnostic tools or surveillance devices that can be used to assess equipment condition.

Emphasis has been placed on refining well-established and more novel but developing condition assessment techniques. It is important to note that condition assessment of equipment also allows the opportunity to predict failure. Based on a complete and systematic assessment, the failure of defective equipment may be evident or predicted in time, thus preventing a forced outage and loss of valuable 'system minutes'. It has also become necessary to extend the life of existing equipment since most of them are reaching the end of their useful life. Replacement strategies have proven to be ineffective due to financial and resource constraints experienced by utilities.

Life extension is the work required to keep equipment operating economically beyond its anticipated life, with optimum availability, efficiency and safety. One of its principal components is condition assessment, with the possibility of predicting remnant life. As a result, refurbishment projects are then raised. Refurbishment by replacement, uprating, modifications or change of design of certain key components to extend the life usually requires a substantial amount of capital to be invested. These projects must be economically justified.

This thesis focuses on establishing condition assessment techniques for major power equipment such as power transformers. Assessment techniques for instrument transformers and circuit breakers are included, since these are commonly replaced or modified under refurbishment projects.

An experimental investigation was carried out to determine the effectiveness of integrating data of two diagnostic techniques i.e. dissolved gas analysis (on-line) and acoustic detection of partial discharges. It was found that there is a correlation between data obtained from an acoustic detection system and an on-line single gas (Hydrogen) analyser. By integrating the data of both on-line monitoring systems, the diagnostic process is further enhanced. In addition, the location of a fixed discharge source was verified by using an acoustic detection system. Further, the sensitivity of the acoustic technique to partial discharge inception voltage, relative to the established electrical detection technique was determined for the experimental arrangement used. The results obtained indicated that this is an effective technique for the evaluation of activity within a transformer structure.

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LIST OF SYMBOLS/ ABBREVIATIONS

LV	: Low Voltage
HV	: High Voltage
PD(s)	: Partial Discharge(s)
AE(s)	: Acoustic Emission(s)
CB(s)	: Circuit Breaker(s)
CT(s)	: Current Transformer(s)
VT(s)	: Voltage Transformer(s)
IT(s)	: Instrument Transformer(s)
CVT(s)	: Capacitive Voltage Transformer(s)
HVCT(s)	: High Voltage Current Transformer(s)
PDD	: Partial Discharge Detector
PDIV(s)	: Partial Discharge Inception Voltage(s)
PDEV(s)	: Partial Discharge Extinction Voltage(s)
Trfr(s)	: Transformer(s)
cct(s)	: Circuit(s)
V	: Voltage
kV	: Kilovolts
MV	: Medium Voltage
mV	: Millivolts
div	: Division
R	: Resistance
L	: Inductance
C	: Capacitance
F	: Farads
ac or AC	: Alternating Current
DC	: Direct Current

pC	: Coulombs
PC	: Personal Computer
yrs	: Years
s	: Seconds
m	: Metres
g	: Grams
mg	: Milligrams
mm	: Millimetres
cm	: Centimetres
p	: Pico
μ	: Micro
°C	: Degrees Celsius
/	: Or
&	: And
KOH	: Potassium Hydroxide
G(s)	: Gravitational Force(s) ($9.81 ms^{-2}$)
VA	: Volt-Amperes
kVA	: KiloVolt-Amperes
MVA	: MegaVolt-Amperes
W	: Watts
P	: Power
kW	: Kilowatts
MW	: Megawatts
LF	: Load Factor
Hz	: Hertz
kHz	: Kilohertz
MHz	: Megahertz

HF : High Frequency

kPa : Kilopascals

psig : Pounds per Square Inch (gauge)

ppm : Parts per Million

DGA : Dissolved Gas Analysis

SF_6 : Sulphur Hexaflouride

RVM : Recovery Voltage Method

DP : Degree of Polymerization

LVI : Low Voltage Impulse

FFT : Fast Fourier Transform

FRA : Frequency Response Analysis

IED(s) : Intelligent Electronic Devices

S1 : Acoustic Sensor 1

S2 : Acoustic Sensor 2

L1 : Location 1

L2 : Location 2

vs : Versus

EPRI : Electric Power Research Institute

IEEE : Institute of Electrical and Electronic Engineers

IEC : International Electrotechnical Commission

ASTM : American Society for Testing and Materials

SABS : South African Bureau of Standards

BS : British Standard

USA : United States of America

DSO : Digitizing Storage Oscilloscope

Δf : Change in Frequency

t : Transmission Time

t_S : Transmission Time of the Shortest Path

t_d	: Transmission Time of the Direct Path
t_c	: Charge Time
δ	: Delta
Φ	: Phi
Tan	: Tangent
Cos	: Cosine
Δt	: Difference in Time
$V_{l(Oil)}$	: Velocity of Longitudinal Wave in oil
$V_{l(Steel)}$	: Velocity of Longitudinal Wave in Plate Steel
P	: Actual Acoustic Wave Pressure
P_{ref}	: Reference Pressure
E_t	: Electric Field at Tip of Discharge
CRF	: Capital Recovery Factor
NPV	: Net Present Value
PV	: Present Value
DCF	: Discounted Cash Flow
kWh	: Kilowatt * hour
QOS	: Quality of Supply
EENS	: Expected Energy Not Supplied
BECOUE	: Break-even Cost of Unsupplied Energy
EACC	: Equal Annual Capital Charge
WACIC	: Weighted Average Customer Interruption Costs

CHAPTER 1: INTRODUCTION

1.1 Importance of High Voltage Power Equipment in Substations

An electrical power transmission system extends over the entire geographical area of a country to supply power in bulk as required to the regional distribution network. The availability of electric power to consumers within the various regions is of paramount importance to the maintenance and growth of the national economy. In order to ensure that electric power is securely available to consumers, the operational reliability of the transmission system must be assured at all times.

A transmission system comprises a complexity of subsystems and components, whereby redundancy techniques are widely employed in order to achieve the required overall system reliability. However, due to economic reasons, such redundancy cannot be applied in the case of major high voltage plant installed in the substations throughout the system. These costly plant items must therefore meet the reliability requirements by virtue of design, correct application, operation within design limitations and preventative maintenance over the plant lifetime.

During the operational lifetime of the high voltage equipment not only do maintenance requirements increase due to ageing, wear and change in operational duty as a result of transmission system growth and load flow adjustments. Therefore similar items of plant installed in different regions of the system will eventually exhibit widely differing condition. Some equipment may be in a condition to operate with the expected reliability for a further period of extended life due to being adequately maintained. Other equipment items will be unsuitable for continued operation thus requiring substantial refurbishment or complete replacement. For economic reasons, utility operators are forced to keep the equipment in service for as long as reasonably possible. In order to establish the risk of failure the condition of plant equipment may be determined through life assessment.

1.2 Life Assessment and Life Extension

Life assessment requires that condition monitoring techniques be employed to ascertain actual condition. Condition based evaluation is a means of assisting a utility to decide if and when equipment need to be replaced or refurbished, maintenance performed and life extension measures be implemented. Life extension is the measures taken to keep equipment operating economically beyond its anticipated life, with optimum availability, efficiency and safety. When the cost of life extension methods exceeds the cost of the equipment then replacement is necessary.

1.3 Economic Considerations in Condition Assessment

Through life assessment techniques the operational condition may be established. Based on the findings of the life assessment, equipment may then be considered for refurbishment (upgrade/modification) or replacement. Refurbishment projects may then raised with the intention of ensuring that the useful life is extended i.e. life extension. These projects usually require large amounts of capital that must be economically justified to ensure that the required funds are appropriated. These project proposals generally do not call for adding facilities but rather for an increase in the reliability of existing facilities. The business driver for capital expenditures is a positive real return within the shortest possible time. There are no exceptions and replacement due to ageing, modifications or uprating of equipment must be economically justified as well.

1.4 Aims of this Study

The object of this treatise is to present condition monitoring techniques (including condition diagnosis) for assessing the condition of the major high voltage plant equipment installed in transmission system substations and to provide recommendations for life extension. Various economic models to justify the capital expenditure required for refurbishment or replacement are proposed. The equipment items under consideration are:

- Power transformers (excluding bushings and tapchangers),
- Instrument transformers and circuit breakers

These equipment items of high voltage plant represent the most significant parts of capital expenditure in a substation. The operational lives of this equipment are most influenced by system operating conditions; therefore life assessment and refurbishment with the objective to extending life is relevant.

The subject is presented in four sections, namely:

- Life assessment techniques to establish the condition of equipment under consideration.
- Provide techniques or measures to extend the operational life of these items of plant.
- An experimental investigation that involves the combining of two monitoring techniques.
- Various methods to economically justify refurbishment and replacement of equipment items under study. Several case studies are included.

The sections that follow focus on power and instrument transformers. High voltage circuit breakers have not been investigated or explored in this study with the same depth as was explored for transformers.

1.5 Structure of Thesis

This thesis has nine chapters. Chapter 1 (this chapter) is an introduction and defines the scope of this study. Chapter 2 provides an overview of the failure mechanisms and diagnostic techniques for power transformers, instrument transformers and circuit breakers. Chapter 3 describes various condition monitoring techniques that may be performed on power transformers, instrument transformers and circuit breakers. Condition diagnostics (interpretation of monitored data) and the evaluation of equipment condition (condition assessment) to determine whether each equipment item is acceptable for continued operation, is presented as well. Chapter 4 provides techniques or practices in brief to extend equipment life. Chapter 5 provides a literature review and theory on electrical breakdown and partial discharges in liquids. Chapter 6 presents the results of a laboratory experimental investigation that was carried-out to:

- Determine the sensitivity of the electrical and acoustic detection system to partial discharge inception voltage; and the corresponding partial discharge magnitude;

- Detect and verify the location of a single partial discharge source (in a fixed position), by acoustic technique;

- Determine if a correlation exists between gas-in-oil measurements (on-line) and acoustic emission data.

Chapter 7 proposes financial methods that may be used to economically justify replacement or refurbishment of defective or aged equipment under study. The technical and economic aspects associated with condition assessment are explored in the form of case studies. Chapter 8 discusses the various developing and available condition monitoring techniques for power transformers, instrument transformers and circuit breakers. The application of financial methods for the refurbishment and replacement of equipment items is discussed as well. As a conclusion, chapter 9 summarises the methodology of the experimental investigation and conclusions drawn. Lastly, comments are made with regard to the implementation of financial models in the case studies presented.

CHAPTER 2: FAILURE MODES AND DIAGNOSTIC METHODS FOR TRANSFORMERS AND CIRCUIT BREAKERS

This chapter provides an overview of the failure mechanisms and diagnostic techniques for power transformers, instrument transformers and circuit breakers. The various stresses that these equipment items are subjected to while in-service are presented as well. The definitions below are referred to throughout this document:

On-line monitoring of equipment refers to equipment, which is employed on a continuous basis, providing surveillance while the primary unit is in-service.

Off-line monitoring is regarded as that equipment which is utilised for condition assessment on a periodic basis, with the primary unit out of service.

In-service in this study refers to techniques that may be utilised whilst the primary unit is energised.

Firstly, a review of the failure modes and diagnostic methods for power transformers are presented. Thereafter, a similar literature review with regards to instrument transformers and circuit breakers follows respectively.

2.1 Power Transformers

Power transformers are the most critical and costly single item of equipment in the distribution of electrical power; therefore, above all other plant equipment and systems, they should be either effectively monitored or have their in-service condition assessed. Failures may and do occur without warning, resulting in interruptions in service. The failures of these large transformers are sometimes catastrophic. If incipient or developing failures are detected before leading to a fault condition, then the transformer may be refurbished or repaired in a controlled fashion. Early detection of incipient faults may eliminate a forced outage, prevent possible damage to adjacent equipment and/or loss of life.

The insulation used in power transformers is generally based on oil-impregnated paper in the form of kraft paper as a turn-to-turn insulation, or as cotton-and/or kraft-based transformer board used for winding spacers and as major insulation between windings and from windings to earth. Mineral insulating oil is used as an impregnant for dielectric and cooling purposes.

Graine et al [1] stated that predictive and preventative measures have been the normal procedures for many utilities for cost effective equipment maintenance. As power transformers age in the network, assessing or monitoring their condition becomes more important. There are a number of diagnostic techniques, test and surveillance devices that may be implemented. A study of power transformer failures by various utilities over an extended period has yielded valuable information as to the most common failure modes. Ongoing research in the area by the Electric Power Research Institute (EPRI), Doble Engineering Company, IEEE, CIGRÉ and many utilities aims to establish the most effective tools with which to diagnose and safeguard against catastrophic failures of power transformers, which are coming under increased risk of failure as the plant ages beyond 25 to 30 years.

There is ongoing development of techniques and methods for preventative failure prediction. On-line monitoring of the condition of power transformers has not been implemented by many utilities due to the unavailability and unreliability of certain sensing or measuring devices of continuous surveillance equipment.

Graine et al [1] stated that power transformers that are correctly maintained should not need refurbishment in their expected life. The same researchers also reported that there are other factors that have an effect on expected life. Refurbishment of a unit should be based on the outcome of its condition evaluation. Kogan et al [2] concluded that the expected life of a typical transformer is approximately 30 to 40 years, depending on its utilization. For example, at 50% load a transformer may be expected to last longer than a transformer loaded to 90% of its rating. In Europe, the mean transformer lifetime was reported to be 38 years, with the most common cause of failure being ageing [2]. Beyond a certain age, both internal insulating systems and external components deteriorate rapidly. De Klerk [3] reported that in South Africa, transformers have a more onerous short circuit exposure than transformers elsewhere in the world and thus seldom fail of age only. The cause of this exposure is due to the low impedance transmission network. Myers et al [4] stated that the decision to refurbish a transformer may not necessarily extend a unit's designed operational life, but may ensure that the expected life is achieved. The terms 'designed operational life' and 'expected life' are considered to have the same meaning.

2.1.1 Deterioration Factors and Failure Mechanisms

The decision to refurbish a transformer should be based on one or more parameters that are indicative of condition such as short circuit withstand capability, insulation condition and moisture content. These parameters are discussed below.

2.1.1.1 Short Circuit Withstand Level

Power transformers are specified and designed for certain short circuit withstand levels. These values are an estimate of the short circuit levels in-service for the application of the particular transformer. When these levels are computed, future network growth is taken into consideration. However, the growth cannot be accurately predicted over a long period of time, and the fault levels in certain locations of the network may increase more rapidly than initially expected due to network expansion. It is possible that the fault level in a particular location may exceed the transformer design fault level in that location, especially towards the end of the expected transformer lifetime.

De Klerk [3] reported that throughout the service duty of a transformer, short circuits which occur are reported to have an accumulative degrading effect on the short circuit withstand strength. In order to establish the integrity of a specific unit, the short circuit history of that unit would therefore need to be analyzed. The information required with regard to the short circuit capability is the amplitude of the current, the duration and the type of fault. The original design withstand level of the transformer is also required.

It may be difficult to determine the serviceability of a transformer with regard to short circuit withstand capability. Schmidt and Malewski [5] reported that a visual inspection of each individual winding and the measurement of actual winding clamping pressure is one possible method of confirming the serviceability of a transformer for short circuit withstand. In order to do this the transformer has to be dismantled in a workshop environment. There are other off-line diagnostic methods that may provide an indication of winding movement/deformation. Refurbishment motivated based on short circuit withstand is therefore very difficult. Elovaara et al [6] stated that when the actual fault levels at a substation exceeds the design levels, then the movement of that particular transformer to a location of lower fault levels should be considered.

2.1.1.2 Insulation Degradation

The insulating system of a transformer consists of solid and liquid insulation. The liquid (oil) also serves as a cooling medium. Both the solid and liquid insulation age during operation. Kogan et al [2] reported that the factors that may influence the rate of the ageing process include high temperatures (>98 °C), high levels of moisture content and oxygen. The deterioration of the solid insulation produces by-products such as sludge, furfurals and acids. These acids may reduce the dielectric strength of the oil [2]. The reduction in electrical breakdown strength of the oil is caused mainly by the combined presence of moisture and foreign particles. This will be addressed as part of "wet insulation" (section 2.1.1.3 below).

The acidity of the oil is expressed as mg KOH/g and the suggested limits for in-service oils vary by group and voltage class [7]. Relevant IEEE standards [7,8] specify that for voltage classes less than 288 kV, an acidity limit of 0.2 is recommended. IEEE standard 62 [7] and Cardwell [9] specify for in-service oils in transformers of voltage class greater than or equal to 345 kV, the suggested limit is 0.1 mg KOH/g. The oil may be processed on site (regeneration) or alternatively the oil can be drained and replaced with new oil. Old oil may be regenerated by static plant at a workshop or refinery. It is however important to note that the solid insulation ages together with the oil and the paper ageing process is irreversible.

Another by-product of ageing, namely sludge, is deposited in the cooling ducts of the windings and radiators. This may cause the transformer to operate at higher temperatures due to poor circulation. The operating conditions would have to be the same in order to compare the difference in operating temperatures. These operating conditions are system voltage, tap position, ambient temperature, loading and cooling status. However, all other possible causes would have to be eliminated prior to concluding that the higher operating temperatures are caused by sludge deposits.

Myers et al [4] stated that the desludging of transformers is done at elevated temperatures (greater than 80 °C). The sludge is dissolved by the hot oil and then filtered out. On site desludging of transformers is limited to smaller units (40 MVA and less). Myers et al also reported that the heating of the transformer active parts to temperatures in excess of 80 °C makes this process impractical for large transformers [4]. Desludging of large transformers may be performed in a workshop environment (where the transformer may be de-tanked).

2.1.1.3 Wet Insulation

All oil filled power transformers contain moisture, which is distributed in the solid insulation and the oil. Myers et al [4] stated that the solid insulation contains the major percentage of moisture, but the equilibrium depends on the actual temperature of the insulating oil. IEEE standard 62 [7] specifies a moisture content of 2% or less in the solid insulation to be acceptable for new transformers.

As mentioned previously, moisture is one of the contributing factors to insulation degradation. There is therefore a limit to the levels that are acceptable. The acceptable in-service limits of moisture content are contained in international specifications [7,8]. These limits are 20 ppm and 3% for the oil and solid insulation respectively. These specifications also specify that moisture levels in excess of 4.5% impose an unacceptable risk of failure. Beyond 20 ppm of moisture content, the dielectric strength of the oil may deteriorate rapidly. Allan and Corderoy [10,11] reported that when the dielectric strength of the oil as determined by ASTM D-1816 reduces to 50 kV the unit is not suitable for continued operation. ASTM D-1816 [12] specifies the procedure for the breakdown voltage test. The moisture content in the oil may be an indication of the moisture content in the solid insulation. By using a set of curves (Piper Chart) contained in IEEE standard C57.106 [8] the moisture content in the solid insulation may be obtained for a specific moisture level in the oil, at various equilibrium temperatures. At any given time the total amount of moisture in a unit does not change, but the distribution thereof in the oil and the solid insulation depends on the temperature of the unit. At higher temperatures the moisture migrates from the solid insulation to the oil. IEEE standard C57.106 [8] states that the moisture content of a transformer may be correlated at different operating temperatures for varying voltage classes.

The sampling of solid insulation for the testing of moisture may be done when the transformer is de-energized and the oil is drained to a level of access where a small piece of insulation may be removed without placing the unit at risk. The moisture extracted and the calculation of the percentage moisture in the insulation is usually done in a laboratory

2.1.1.4 Generic Defects

Certain units may show similar problems relating to their particular specification, design, manufacture or operation. Graine et al [1] reported that such a batch or generation of identical units are generally addressed together when decisions are made to refurbish (modify) them. Examples of generic problems are loose magnetic shunts, low short circuit withstand, insufficient cooling, local overheating, part winding resonance, tapchanger design, bushing design and magnetic shunt design. Depending on the location and the severity of the problem, some modifications may be done on site.

2.1.1.5 Oil Leaks

Oil leaks may occur on welded seams, gasketted seals and even through the casings of components such as valves. An oil leak may be an indication of moisture ingress that may increase the rate insulation ageing.

2.1.1.6 Unreliable Fittings

Power transformer fittings include temperature indicators, pressure relief devices, Buchholz relays, dehydrating breathers, current transformers, fans, pumps, cabling and tapchanger protective devices. When these devices operate incorrectly, replacement or repairs are required. This is a process that is usually done in situ, but some of these devices require the oil to be drained to a level that would allow their safe removal. An outage would have to be arranged in most cases.

2.1.1.7 Incipient Faults

Internally developing faults in power transformers are termed incipient faults. Incipient faults are detected by gas-in-oil analysis. Different failure modes produce different ratios of hydrocarbon gasses. By analysing the concentration of each of these gasses, the type and possible severity of the fault can be suggested. Important factors to note are:

- The total case history of the unit i.e. all work that has been done on the unit including maintenance;
- Similar units that have had failures;
- Ratio and key gas analysis may only be effective when significant quantities of dissolved gasses are present i.e. total gas content greater than 300 ppm [8].
- The stability of the gas levels may also be an indication of the severity of the fault i.e. trending gas levels is important.

On-site inspection may provide limited success in the actual location of the indicated problem due to limited access within transformers, however some important external parts may be inspected i.e. bushing connections and tap leads.

2.1.1.8 Deteriorated Bushings

The condition of the bushings is generally established through visual inspection and a leakage current test. The leakage current test, better known as Tan (delta) or loss angle measurement provides an indication of the condition of the bushing insulation. A test voltage is applied between the main insulation and the bottom flange of the bushing. The loss angle is then measured. At the same time the bushing capacitance is measured. These values are then compared with the original values given by the manufacturer. Myers et al [4] stated that a variance of 5% may be acceptable, otherwise the bushing should be repaired or replaced.

An outage is not required for visual inspections. Any leak on the bushings is considered serious. Bushings are sealed units and any leaks would mean that moisture ingress into the insulation is possible with catastrophic results. The bushing would have to be replaced or repaired urgently. The replacement of bushings may be done on-site however; the actual refurbishment requires a workshop environment. It may be cost effective to replace a faulty bushing with a new bushing rather than to remove and repair it.

2.1.1.9 Faulty Tapchangers

The transformer accessory that fails the most frequently is tap changers, followed by bushings [4]. On load tap changers (OLTC) are the only moving parts in the transformer. They require regular maintenance. When tap changer contacts start to malfunction, carbon forms on the contacts surfaces that contaminate the oil. Tap changers of older generation transformers have insulating cylinders of resin bonded paper. Myers et al [4] reported that they have a tendency to leak after being in operation for several years. The same researchers also reported that leaks from the arcing chamber to the main tank could contaminate the main transformer oil and distort the dissolved gas analysis results.

2.1.2 Diagnostic Methods

Diagnostic or monitoring techniques have been introduced mainly to detect the presence of small local faults, and to monitor their development over a period of weeks or months. They provide evidence to plan for further investigation to take place on a planned basis, rather than as an emergency. These important diagnostic techniques listed in Table 2.1 below form an integral part of the condition monitoring and assessment that is described in Section 3.

PROBLEMS	DIAGNOSTIC METHODS	ON/OFF LINE	REFERENCES
Dielectric	**OIL ANALYSIS**		
	1. Oil tests: Moisture, dielectric strength, acidity, dissipation factor, etc	OFF	[4,7,8,12]
	2. Moisture (Polarisation spectrum)	OFF	[44]
	3. Furfural analysis	ON	[3,46,50,115,117-120]
	PD MEASUREMENT		
	4. Ultrasonic method	ON	[58,60]
	5. Acoustic method	ON	[3,56,58,59,62]
	6. Electrical Method	OFF	[57,61,64,124]
	7. Insulation Power factor	OFF	[4,7,8,64,124]
Thermal	**GAS-IN-OIL ANALYSIS**		
	8. Sampling (analysis, interpretation)	ON	[7,8,9,14,15,23-25,51,52]
	9. Gas chromatography	ON	[3,13,53,64,124]
	10. Equivalent hydrogen method	ON	[30,79,114]
	PAPER DETERIORATION		
	11. Degree of polymerization	OFF	[3,45,48-50]
	12. Liquid chromatography - DP method	ON	[47,121]
	HOT-SPOT DETECTION		
	13. Invasive sensors	ON	[63-65]
	14. Infra-red / thermal scanning	ON	[3,29]
Mechanical	**WINDING DISTORTION**		
	15. Vibration analysis	ON	[3,68,70,122,123]
	16. Hydraulic load cell /transducers	ON	[5,69,70]
	17. Low voltage impulse tests	OFF	[71,72]
	18. Frequency response analysis	OFF	[73-76]
	19. Leakage inductance measurement	OFF	[5,64]

Table 2.1: Diagnostic methods used for power transformers (paper-oil).

The advantages and/or disadvantages of each of the methods tabulated above (Table 2.1) are listed below.

Method 1 (oil tests) – Myers et al [4] commented that the analysis of the transformer oil to determine water content, electric strength, dielectric loss angle, volume resistivity, interfacial tension and acidity is the conventional and most successful approach to the diagnosis of insulation deterioration.

Method 2 (polarisation spectrum) – Mogiba and Moore [44] concluded that he diagnosis of the total insulation condition by the polarisation spectrum may be traced from the results of recovery voltage measurements, without the need for specimens to be extracted from the transformer.

Method 3 – Furfural analysis is the measurement of cellulose (insulating paper) breakdown products (called furanic compounds) present in the oil specimen. International specifications such as IEC 1198 [46] contain the methods for determining the furfural and related compounds It is however an indirect method of determining the degree of polymerization. Various researchers [3,50] commented that technically, the age of a transformer is mainly determined from the condition of the insulating paper. Shroff and Stannett [50] have reported that by analysing the furfural content in the oil specimen the useful life of the transformer may be estimated. Degradation of the cellulose is advanced by heat, moisture, oxygen and acids, leading to a decrease in the quality of insulating medium. These results are trended and continually analysed.

Methods 4, 5 and 6 (partial discharge measurement techniques) are powerful tools used to determine incipient faults. Various researchers [3,56,58,59,60,62] have reported that acoustic and ultrasonic systems may be used both for the on-line detection and localisation of the sources of internal discharges. Researchers [57,61,64,124] have reported that electrical partial discharge measurements have been used on-line in a number of case, however, the tendency is to apply this method as an off-line occasional check using a mobile power supply.

Method 7 (tan delta) is used as a simple technique to determine the general overall condition of transformer insulation. IEEE standards [7,8] and various researchers [4,64,124] have stated that this measurement may be sensitive to moisture and other conditions that can cause increased dielectric loss.

Method 9 - Gas-in-oil analysis using gas chromatography, is a routine and most widely used diagnostic tool for transformers: much experience is available, together with an adequate level of standardisation [13,53]. The limitations concern its poor capacity to detect fast developing dielectric problems; moreover, a rigid interpretation of the limit values of gas content, without a precise knowledge of the relevant source, may lead to erroneous evaluations.

Method 10 (on-line gas-in-oil) – Various researchers [30,79,114] have reported that a low-cost, simplified system for on-line hydrogen gas analysis have been developed and successfully implemented.

Method 11 (DP method) – Various researchers [3,45,48,50] have concluded that the determination of the Degree of Polymerization (DP) of insulating paper (cellulose) due to thermal deterioration provides an indication of the quality of the insulating medium. The disadvantage of this technique is that the transformer would have to be taken out of service for a paper sample to be extracted. Cellulose consists of fibre chains, made up of a string of glucose molecules. The average length of these strings is called DP

Method 12 (liquid chromatography) – Researchers [47,121] have reported that the examination of oil samples, by High Performance Liquid Chromatography (HPLC) to measure the furanic component, assists in determining the cellulose condition. This technique allows for on-line analysis and an estimate of useful life.

Method 13 (invasive sensors) - Hot-spot detection in windings may be performed using variety of devices or sensors. Various researchers [63-65] have reported that optic and acoustic sensors may be fitted on transformer windings to obtain the hot-spot temperature. These researchers stated that this may only be possible for new units or for units that are being rewound. The reason for this is that it may be difficult to retrofit a transformer with optical and acoustic sensors in the windings. Winding temperature indication provides valuable information on the service condition of a transformer. Ageing and loading capabilities, affecting overall reliability, can be determined with the aid of accurate temperature measurements. Most importantly, management of emergency overloading can be confidently undertaken, when it is based on true winding temperature.

Other means of early fault detection are infra-red scanning, vibration, audible noises and operating temperatures. Moja [29] stated that with infra-red scanning, relative temperatures are more important than actual temperatures i.e. compare bushings, etc. Vibration measurements could be used to detect changes, alerting the user of any possible movement inside the transformer. Abnormal noises may also indicate a requirement for further investigation. Visual inspections are important in detecting leaks, cracked bushing housings, low fluid levels, broken gauges showing high temperatures, etc.

Method 14 (infrared scanning) is an apparatus used to measure the relative temperature (externally and internally) of components of any equipment. Hot spots and areas of uneven cooling may be located on the tank, connections and other areas. Various researchers [5,64,69-76] have reported that methods 15 to 19 (winding distortion detection) are considered very important to evaluate the potential risks of dielectric failure consequent to mechanical movements, distortion or displacement

2.2 Instrument Transformers

2.2.1 Introduction

Instrument transformers in a high voltage power system form part of the instrumentation and protection system used for detecting, locating and initiating the removal of a fault from the power system. The instrument transformer is therefore critical for efficient management and control of a power transmission network.

Insulation deterioration within these instrument transformers may take place over a long period. Transients resulting from breaker operations or faults in the network may increase the rate with which deterioration takes place. System conditions and the mishandling of such equipment may lead to effects such as partial discharges that degrade insulation properties and eventually lead to breakdown. The effect of these actions may remain undetected for years, in some cases.

An EPRI report [17] stated that several utilities have experienced problems with exploding free-standing high voltage current transformers (HVCTs) endangering personnel and damaging nearby equipment and facilities. Although the capital cost to replace these high voltage current transformers are relatively low compared to other substation equipment, the financial consequence of the catastrophic failure mode may result in the loss of generation, loss of supply to customers, poor quality of supply to customers, damage to adjacent plant and risk of injury to personnel.

2.2.2 Instrument Transformer Design

The construction and service duty of instrument transformers is different from power transformers. This characteristic can be seen in manufacturers datasheets. Voltage or potential transformers have small volt-ampere ratings so that the conductors are quite small compared to distribution and power transformers. The volts per turn are kept low so that the magnetic circuit will be small. The total losses are quite low so that cooling is not a problem, and the insulation is frequently made from paper tape without built in oil ducts. Conducting layers are sometimes used within the insulation to improve the voltage distribution. The oil volume around the outside of the assembly is relatively small.

Free-standing current transformers used for metering and control are constructed in a similarly manner to bushings. The primary conductor is either a copper or aluminum tube or a cable. Solid insulation made from paper tape is used between the high-voltage portions and the shielded ring type transformers. Conducting layers are used within the stressed insulation region to improve the distribution of voltage in the insulation. There are two types of free-standing current transformers i.e. hairpin and through-type. The hairpin type has a primary conductor that is U shaped with the core and secondary terminals located at the bottom of the U. In the through-type, the primary conductor at the top end of the unit is straight. The core is located on the conductor with the terminals housed in a tube leading to the bottom of the unit. In both the hairpin and the through-type free-standing transformers, there is very little oil volume around the assembly. In both voltage and current transformers, the only oil within the insulation assembly is used for impregnation of the paper and spaces at the edges of the paper.

Current transformer designs are based on hermetically sealed oil-paper insulation. For external insulation, the oil-paper systems are installed in a hollow porcelain post insulator attached to the head and the foot sections to house the cores and terminal box. The combination of hermetically sealed oil-paper, porcelain and the galvanised metal or epoxy resin containers at the top and bottom ends, are designed to nominally eliminate the need for maintenance and to ensure maximum service life.

2.2.3 Hermetic Sealing

General acceptance of hermetic sealing for achieving long, reliable and maintenance free operation required that the pressure variations in the oil-paper insulation system had to be controlled. These variations resulted from a range of specified ambient and load related temperatures that cause oil expansion or contraction in the sealed environment.

2.2.3.1 Gas Cushions

Initially, hermetically sealed solutions were based on a gas (typically nitrogen) or simply an air cushion at the top of the unit. Nitrogen was favoured for its inert characteristic, which maximises insulation life by eliminating oxidisation. Gas filling at a slight over pressure biases the system to avoid negative pressure during low load and low ambient temperature. Avoiding the occurrence of a negative pressure condition under all specified operating conditions is a fundamental requirement in preventing moisture ingress. Such a condition may lead to the reduction of the voltage withstand capability of the insulating system. Any successful re-filling procedure must take into account the temperature at that point in time. A slow leakage of the gas cushion has the potential to aid in the development of under pressure condition when the load or ambient temperature drops suddenly.

2.2.3.2 Expansion Bellows

Due to failures being attributed to inadvertent excessive pressure variation and the possible formation of bubbles in the oil a bellow system for controlling pressure is normally implemented. Bellows take several forms, and can, for example, be external concertina type stainless steel bellows, or rubber membranes floating on the top of the oil surface. Some systems that have been employed also contain gas filled rubber bags. The objective of these systems is to keep the oil free of gas and oxygen and to minimise the pressure variations. Initially, rubber-based bellow systems had a very limited lifespan compared to the technically more challenging stainless steel bellows. However, rubber technology has drastically improved over the recent years.

2.2.4 Stresses In-Service

The internal insulation of instrument transformers is subjected to combinations of stresses that may result in the deterioration of the mechanical and dielectric properties of paper and other insulating materials. An international specification such as IEC 185 [18] states that in terms of dielectric stresses, the insulation strength lies in the instrument transformer's capability to withstand service voltage, temporary overvoltages at power frequency, switching and lightning overvoltages. In general, the design of internal insulation of an instrument transformer mainly depends on the service voltage and lightning overvoltages while external insulation is more sensitive to switching overvoltages and polluted environmental conditions.

Mechanical stresses may be severe during transportation and during the occasional occurrence of seismic activity. Electrodynamic stresses such as short circuits cause damage due to failures on the system. CIGRÉ work group 23.07 [19] reported that thermal stresses due to the heat produced inside the windings are more important for current transformers than for the other instrument transformers. Since current transformers form part of the power transmission circuit, a failed current transformer would result in the interruption of supply.

2.2.5 Deterioration Factors and Failure Mechanisms

The sensitivity of oil-impregnated cellulose to the combination of heat and voltage stresses is of special significance to high voltage current transformers. In the absence of oil circulation, heat transfer takes place mainly by conduction; therefore, any local concentration of contaminants may be relieved by slow diffusion processes. The heat transfer process is started either by local overheating or by permanent or transient enhancement of the field strength.

In current transformers for high voltage systems, a significant part of the total losses is represented by dielectric losses. An EPRI report [17] stated that moisture and soluble polar contaminants are the most common causes of increased dielectric losses at elevated temperatures. Sometimes the contamination may be traced back to the manufacturing process, either to incorrect selection of materials or inadequate processing or quality control.

The proceeding of an EPRI workshop [17] reported that high dissipation factors associated with wax-like residues (x-wax) of polymerised oil molecules have been observed in current transformers known to have undergone extensive ionisation phenomena.

A second deterioration process is associated with partial discharges. While occasionally the discharges may be initiated by lightning or switching overvoltages, more often they originate due to local enhancements of the electric field. Discontinuities in the dielectric typically consist of gas filled voids within which discharges are initiated.

Four mechanisms are generally recognised by which gas bubbles may be generated:

- Poor impregnation of paper;
- Thermal decomposition of cellulose;
- Supersaturation of the oil with air or blanket gas;
- Local breakdown of the impregnating oil by electrical discharges.

The performance of current transformers depends on the design of its capacitive grading shields. In the event of uneven distribution of the current field along the shields and their connecting leads, dangerous voltage stresses may arise at particular locations. According to EPRI [20] these phenomena acquire critical importance for electric systems at and above 400 kV. Most current transformers are not protected by surge arresters that are closer to transformers.

The deterioration of the dielectric of capacitive voltage dividers is mainly due to partial discharges initiated by overvoltages at the edges of the capacitor regarding sections. Research conducted by EPRI [20] concluded that moisture or negative pressure inside the porcelain insulators, and manufacturing defects are usually the causes for this phenomenon.

2.2.6 Diagnostic Methods

Allan et al [21] stated that condition monitoring systems should be based on diagnostic methods that do not interfere with operation, leaving off-line tests to periodic and special maintenance or situations. Information obtained from these condition monitoring systems will then be used to determine the maintenance schedule and replacement (end of safe, useful life) date. The on-line concept is to obtain every possible service minute from instrument transformers by retiring them to avoid in-service failures. Table 2.2 highlights diagnostic methods most widely used for instrument transformers, together with references.

PROBLEMS	DIAGNOSTIC METHODS	ON/ OFF LINE	APPLICATION TO:			REFERENCES
			CTs	VTs	CVTs	
Mechanical	1. Pressure inside enclosure	ON	X	X	X	[26]
	2. Pressure valve	ON	X	X	X	[26]
	3. Bellow position	ON	X	X	X	[26]
	4. Oil level indicator	ON	X	X	-	[26]
	5. Inspection for oil leakage	ON	X	X	X	[26]
	6. Water content in the oil	ON	X	X	-	[52]
Thermal	7. Inspection of contacts	ON	X	-	-	[26]
	8. Gas-in-oil chromatography	ON	X	X	-	[13,17]
	9. Thermal scanning	ON	X	-	X	[26,27,29]
Chemical	10. Oil testing (neutralization value, corrosive sulphur, oxidation, viscosity, etc.)	ON	X	X	-	[30]
Dielectric	11. Gas-in-oil chromatography	ON	X	X	-	[13,27]
	12. H_2 detection	ON	X	X	-	[19,26,79]
	13. Oil dielectric strength	ON	X	X	-	[12,27,30]
	14. PD measurement	ON	X	X	X	[19,21,26-28]
	15. Zero sequence checking	OFF	-	-	X	[27]
	16. Tan (delta) measurement	ON	X	-	X	[18,21,22,27,80]

Table 2.2: Diagnostic methods used in instrument transformers (paper-oil).

In order to facilitate the monitoring of the instrument transformer condition, the installation of a low cost monitoring system should be economically justified in the case of high voltage systems. CIGRÉ reported [19] that these types of devices used depend on the sealing and oil compensation systems adopted and that they may include pressure sensors, pressure valves, bellow position indicators and gas detection systems.

Visual checks are generally performed to identify traces of oil originating from hair-line cracks on the porcelain and for connection discolouration indicating overheating of poor or loose contact. Depending on the circumstances the following diagnostic techniques are usually applied:

2.2.6.1 Tan (delta) or Loss Angle Measurement

The tan (delta) or loss angle measurement is a measure of the power loss in the insulating material and therefore a general indication of the quality of the dielectric. Some types of current transformers are provided with a connection point at the lowest capacitive grid in order to measure the loss angle. Therefore, it is possible to measure the loss angle of the main insulation between this terminal and the bottom flange of the current transformer.

In the case of voltage transformers, it is possible to measure the loss angle of the insulation between the shielding grid and the secondary winding. However, this is not common practice. The value of the loss angle depends on a number of factors such as voltage, temperature and design features. IEC 358 [22] recommends that measurements be carried out at higher temperatures (about 90 °C) at which the presence of contaminant may be detected as a function of the voltage.

2.2.6.2 Analysis of Gases Dissolved in Oil

Most types of instrument transformers are provided with an oil valve from which it is possible to take samples of oil. International standard IEC 567 [23] states that oil sampling must be done with caution if performed while the unit is in service. This is due to the fact that air bubbles created during sampling may cause failure. For gas analysis and their interpretation, the same methods as with power transformers are in use [24,25].

Precautions may be taken during oil sampling, because the volume of oil is small and may require refilling. The presence of a large amount of hydrogen is an indication of partial discharge activity in the oil between the paper layers. According to EPRI research [17] the formation of x-wax in these areas is typical.

Various researchers [19,26,79] have reported that voltage transformers have been provided with hydrogen detection probes. These researchers stated that the hydrogen concentration in oil is checked after diffusion from the oil through a membrane by a thermal conductivity detector.

2.2.6.3 In-Service Partial Discharge Detection

Various researchers [27,28] reported that some utilities employ this in-service partial discharge detection to detect discharge activity in instrument transformers by means of acoustic sensors fixed with magnets on the outer tank surface. Gabriel et al [27] stated that this method is reliable for detecting the presence of large partial discharges (more than 1000 pC). High intensity partial discharges may result in rapid violent failure of equipment.

2.2.6.4 Thermal Scanning

Thermal scanning may be used systematically in substations. Moja [29] stated thermal scanning reveals overheating at the level of the connecting contacts and that it might be possible to detect the oil level within the sealed apparatus.

2.2.6.5 Other Oil Checks

International specification IEC 422 [30] states that an inspection of the internal insulation should be performed every 3 to 5 years. In the case where there are 'leak-free' cable terminations, ageing may occur and result in the formation of moisture from the paper or of other substances that may have adverse chemical effects on the insulating oil.

This, in turn, influences the breakdown strength or the thermal stability of the insulation in an unfavourable manner. As all these phenomena can result in physical and chemical changes of the insulating oil, certain basic measurements are important. These are breakdown strength, water content, neutralisation value, dielectric interfacial tension, dielectric loss angle, etc.

Presently, the condition of instrument transformers may be monitored systematically. The application of computer-based techniques with advanced procedures for data acquisition and processing favours on-line methods. However, the extensive application of these techniques depends on the availability of simple and reliable diagnostic and surveillance sensors. According to EPRI research [20] internal pressure, gas detection and bellow position sensors can now be mounted on instrument transformers for extra and ultra high voltage systems.

2.3 Circuit Breakers

2.3.1 Background

Failures of high voltage circuit breakers may have direct impacts on network stability, availability of supply and may cause extensive damages to connected equipment. The associated replacement costs of damaged equipment may be significant.

Traditionally, maintenance of circuit breakers has been preventive i.e. according to fixed maintenance schedules or based on the accumulated number of operations. Apart from regular inspections the circuit breaker may be removed from site, opened and overhauled. It is commonly known that over-maintaining carries the risk of introducing new failures, especially in complex equipment. The reliability of the equipment may well be decreased following a major overhaul or periodic maintenance. As a result, there are additional disadvantages such as excessive labour costs, unnecessary planned outages and equipment actually needing maintenance may be overlooked. CIGRÉ working group 13.08 [31] reported that circuit breakers represent 40% of operations and maintenance related substation expenses of utilities in North America. Various research groups [31,32] state that there is a trend (or necessity) to reduce operating and maintenance expenditure. However, the same reliability and availability of supply is demanded on a reduced budget. Thus it appears that maintenance philosophies require a re-examination.

A CIGRÉ report on life management on circuit breakers [31] commented that in Europe and North America, maintenance philosophies are focusing on predictive maintenance where maintenance is performed only when required. The ability to assess the condition of a circuit breaker by non-invasive methods is a useful tool in the maintenance and refurbishment of breakers. EPRI [32] and Noack et al [33] reported that sophisticated condition monitoring systems are commercially available. IEEE standard C37.10.1 [34] and IEEE standard C37.10 [35] provides various diagnostic methods for the condition assessment of circuit breakers. In essence, these systems are able to provide an indication on (1) the status (open/close position) and (2) excessive wear or an impending failure of the circuit breaker. In this way circuit breakers are logically prioritised for maintenance and the overall reliability of the network is thus enhanced.

According to the CIGRÉ publication on the life management on circuit breakers [31] many utilities still have a large number of oil and air blast breakers in-service, a number of which are over 30 years old. In the same publication it was stated that in some utilities air blast breakers represent a significant portion of the circuit breaker population. Maintenance on both types of circuit breaker may be costly because the technology may be outdated and spare parts are unavailable. It is financially and logistically difficult to replace old breakers with the more modern SF_6 type all at once on a planned refurbishment or replacement program. EPRI [32] reported that older breakers reaching the end of their useful lives could be refurbished, where the decision-making should depend on condition monitoring systems or the results of a combination of diagnostic techniques. Diagnostic techniques may be used to evaluate condition and where possible detect failure of apparatus and systems.

2.3.2 Stresses In-Service

Circuit breakers in-service are subjected to various stresses that may cause the insulation to fail. These stresses summarised from the work of CIGRÉ [31] are listed below.

2.3.2.1 Electrical

The expected electrical stresses in a circuit breaker include rated ac and temporary overvoltages, lightning impulses, switching impulses fast transients overvoltages with disconnector or circuit breaker operation.

2.3.2.2 Mechanical

This type of stress is caused by normal operating (switching) as well as due to external apparatus. These include forces consequent to driving operations (rods, pipes) and forces created by the short circuit currents, gas shock waves and hot gas streams from power arcs, tension from internal gas pressure and subsonic oscillations caused by earthquakes.

2.3.2.3 Environmental

Environmental stresses are due to extreme temperatures, humidity, rain and pollution. Temperature rises cause by high currents and high ambient temperature differences between inside and outside of the breaker.

2.3.3.4 Chemical

These stresses are caused during and after switching operations that form by-products, dust and powder. As a result the insulation dielectric strength may be reduced. During switching operations a hot gas-stream of by-products may be formed. After switching operations there may be a high concentration of by-products. Dust and powder may be produced by arc-erosion during switching operations.

2.3.3 Deterioration Factors and Failure Mechanisms

The withstand voltage of a breaker's insulation can be reduced in service due to the effects discussed below.

According to EPRI [32] insulation failures inside the breaker can be caused by:

(1) Chemical by-products,

(2) Conductive particles,

(3) Defects in solid dielectrics (e.g. voids, poor adhesion, cracks, humidity and conductive particles).

The first two items produce conductive areas on insulator surfaces or protrusions on conductors, leading to local field enhancement and finally to a flashover. The third item creates partial discharges, which are activated from service stresses and may lead to breakdown.

For SF_6 insulated circuit breakers, the dielectric quality of the gas may be reduced. Small amounts of air or moisture in SF_6 do not strongly affect the gas withstand values, as long as there are no additional quantities of by-products. EPRI [32] reported that the combination of moisture and SF_6 by-products causes a high reduction of the dielectric strength of insulator surfaces. The same source also stated that the dielectric properties of compressed air and oil breakers may be reduced by moisture as well.

The wear of contacts in the circuit breaker interrupting chamber produces rough electrode surfaces, which may reduce the breakdown voltage across the contact gap. The melted contact material may produce dust, metallic particles and conductive layers on the surfaces of insulators.

Abnormal operations of mechanical elements are not generally classified as deterioration factors, but they may cause subsequent dielectric failures. As one example, a slow movement of the driving components, which cause an increasing arcing time with higher amounts of hot by-products, may cause breakdown during switching operations. If the switching contacts are not in 'full' open position, this reduced insulation gap gives a lower breakdown voltage. In this sense, the mechanical conditions are related to the dielectric aspects.

Overheating may also be the origin of a dielectric breakdown. An abnormal increase of temperature usually indicates defects on the contacts. This may be caused by a loose metallic component.

2.3.4 Field Experience of Failures

Koert and Schenk [36] stated that the reliability of aged circuit breakers are reduced due to the high number of operations and excessive maintenance to which they have been subjected. These researchers also stated that most circuit breaker problems relate to the operating mechanism and not the interrupter (arc contacts and quenching) portion of the circuit breaker. Additionally the auxiliary systems of especially the more modern breakers have had a negative influence on overall reliability.

Major failures in the interrupting units comprise mostly of electrical breakdowns whilst major failures in the operating mechanism comprise "breaker does not open or close on command" and relate to components such as compressors, pumps, motors and pipework. Wear in SF_6 circuit breakers occurs mainly in the arc quenching parts and the operating mechanism. Koert and Schenk [36] reported that this is due to either ageing or actual operation of the breaker.

2.3.5 Diagnostic Methods

EPRI [32] reported the following with regard to maintenance and diagnostic methods of circuit breakers. Preventative maintenance for circuit breakers is carried out after periodic intervals or after a specified number of switching operations. With the introduction of diagnostic techniques, the maintenance activities are adapted according to the circuit breaker conditions. Under good operating conditions maintenance intervals become less frequent, while dangerous conditions could indicate the necessity of an earlier intervention, in order to avoid failures in service.

Table 2.3 below is a summary of diagnostic techniques widely used for SF_6 circuit breakers, together with references. Other types of diagnostics may be performed for the assessment of bulk oil and air blast breakers.

PROBLEMS	DIAGNOSTIC METHODS	ON/ OFF LINE	REFERENCES
Insulation defects	Measuring:		
	- Gas pressure	ON	[31,33-38]
	- PD at coupling capacitor	ON	[35,36,40]
	- HF current probe	ON	[37]
	- HF capacitive probe	ON	[35,36,41]
	- Ultra-sonic	ON	[34]
Dielectric gas-quality	SF_6 Quality Control:		
	- Dielectric check	ON	[31,40]
	- Gas analysis:		
	* gas chromatography	ON	[31,37]
	* infra-red spectroscopy	ON	[31,37]
	* colour detector	ON	[31,37]
	* air contents	ON	[31,35-37]
	* moisture contents	ON	[31,35-37]
Wear of circuit-breaker	Measuring:		
	- Location of shaft position	OFF	[31,37,41]
	- Contact wear	ON	[31,35,36,39]
	- Dust and powder contents in SF_6	ON	[31,35,36,39]
Abnormal mechanical operation	Measuring:		
	- At potentiometer on moving contact	OFF	[31,33,34,37-41]
	- Optical markers on moving parts	OFF	[31,40]
	- Friction of driving elements	OFF	[31,40]
	- Tripping time	ON	[35,36,39]
Overheating	Measuring:		
	- Infra-red camera	ON	[31,33-41]
	- Contact resistance	OFF	[31,33,35-38,40,41]

Table 2.3: Diagnostic methods used for SF_6 circuit breakers.

Each of the above problems and diagnostic methods indicated in Table 2.3 are briefly discussed below.

Insulation defects may result in rapid and catastrophic failures. It is important that any method used is sensitive enough to ensure that serious defects are detected. A number of small defects inside the breaker, for example, metallic particles may be detected by partial discharge measurements. During on-site commissioning, partial discharge measurements are not always effective, as background noise considerably reduces the sensitivity. Various researchers [35,36] reported that there are different types of sensors available for partial discharge detection in service. These researchers also stated that these sensors detect the partial discharge high frequency signal either by current measurements or by voltage measurements via a capacitive pick-up probe. Various researchers [31,33-38] commented that reductions in the insulation strength caused by a very low gas pressure could be detected by monitoring the gas-pressure. This may be a simple and essential measurement.

Dielectric gas quality is related to insulation but may not be diagnosed using the more traditional partial discharge measurement techniques described above. Direct measurements of the SF_6 gas characteristics (i.e. breakdown voltage) may be a valid quality control dielectric check. Gas analysis by means of gas chromatography or infrared spectroscopy may provide accurate composition results. Jeanjean et al [37] stated that devices and procedures for detecting air contents in SF_6 are available and a measurement of moisture in SF_6 gas and air may be possible by taking a sample for analysis.

Wear of circuit breaker internal mechanical components such as the operating shaft and contacts are important to measure in order to establish condition. Several researchers [31,36,39] commented that the wear of the contacts in the interrupting chamber is difficult to measure. Setsuta et al [39] stated that the measurement of the location of the operating shaft position corresponding to the moment of closing provides imprecise information, as contact erosion can be distributed very differently on the contact surface. The amount of by-product concentration may not indicate the contact wear, because absorbers in the breaker may neutralise and reduce the by-products. Kawada et al [37] concluded that the general law for contact wear, which gives information about the total deterioration of a breaker chamber, is:

$$\sum n_i * I_i^{\propto} = K$$

Comments made by the same researchers with regard to the above equation are summarised briefly. The cumulative effect of interrupted currents may be evaluated in order to estimate the lifetime of the circuit breaker that has been consumed. Values of the parameters in the above equation are available from the breaker manufacturers. It is emphasised, that this equation is related to the switching performance of the circuit breaker, and not to the integrity of the dielectric. The maintenance interval for the switching chamber may be determined by the electrical ageing, i.e. by the reduction of switching performance through contact wear.

Abnormal mechanical operation could be measured by a few diagnostic methods that are available. Barkan et al [40] reported that contact movement, longer than normal operating times, and contacts, which are not fully separated in the open condition, can be detected by a space-time diagram of the moving contacts. The operating time for open or close condition may be easily measured for the auxiliary contacts by means of the tripping signal. Various researchers [34,35,38] reported that abnormal friction, which causes low contact speed, could be detected by resistance sensors

Overheating of the circuit breaker may result in the deterioration of the circuit breaker insulation. Various researchers [33-41] stated that overheating of breakers may be observed with the breaker in-service by an infrared camera, which may detect an abnormal temperature outside the breaker. This gives indirect information of the temperature of the inner conductors

2.3.6 Assessment of Diagnostic Methods

2.3.6.1 Power Transformers and Instrument Transformers

Based on the review above, it has been established thus far that there are a number of techniques available or currently under development that may be used to assess the condition of power transformers, instrument transformers and circuit breakers. The techniques for power transformers and instrument transformers (oil-paper filled equipment) are similar to a certain extent, but those techniques applicable to the assessment of circuit breakers tend to be different e.g. the focus is on the mechanical integrity of circuit breaker mechanism..

Power transformer condition assessment is possible through well-established off-line techniques such as several standardised oil tests. Off-line testing techniques are still relied upon as the most dependable methods. Off-line gas-in-oil analysis is widely implemented but requires careful management of sampling intervals. Although sampling is performed on-line, the analysis of the oil is performed in a laboratory. Since the results of the analysis are historical, it may become difficult for operational personnel to make a decision under emergency conditions. However, the research and development emphasis is on on-line gas-in-oil analysis. On-line monitoring of gas levels and concentrations is now possible. The development and commercial availability of on-line fault gas monitoring systems or sensors is encouraging however, their reliability is questionable.

Partial discharge detection and localisation by acoustic means is available commercially and is being implemented with some success. However, significant improvements need to be made to the continuously operating monitoring system for a commercial system. A major problem with electrical partial discharge detection on-line are the high levels of background noise that may be found in a substation environment. This technique may be ideally implemented under laboratory conditions.

Methods of determining the condition of the transformer paper insulation without the need to extract samples are available and may become an extremely valuable means of approximating the unit's remaining operational lifespan. Techniques that fall into this category are recovery voltage measurement (polarisation spectrum) and furfural content in oil. Although, recovery voltage measurements taken to determine the moisture content in the paper insulation may be a reliable technique the transformer would have to be de-energised. In order to determine the furfural content an oil sample may be taken on-line and analysed in a laboratory. The remnant of the transformer may then be inferred.

The detection of transformer winding displacement or deformation may be established via out of service methods such as frequency response analysis. Conductors and clamps connecting the transformer to the overhead busbar may have to be disconnected. It appears that the accuracy of the measurement instrumentation employed for this monitoring technique may be of concern to researchers and users. The interpretation of frequency response results may pose a challenge to researchers as well. A means of performing this technique on-line is currently under development. On-line techniques to detect winding displacement continue to be researched. On-line vibration monitoring and infrared scanning, although not new, have been successfully implemented.

Most of the monitoring or diagnostic techniques for power transformers may be applied to instrument transformers. In some instances, where instrument transformers are not fitted with a test tap to obtain an oil sample for analysis other measurements such as tan delta, capacitance, leakage current, power factor and partial discharge detection (either performed on-line or off-line) may be relied upon to establish insulation condition. Commercial systems to measure tan delta, leakage current and power factor off-line are available. These measurements provide an indication of insulation deterioration. On-line systems are being developed.

As a result of a large number of catastrophic failures occurring in a number of high voltage free-standing current transformers, there has been some experimentation with sensors for on-line monitors. It appears that the development of various sensors listed below for on-line monitoring have provided encouraging results. These sensors may be applied to voltage transformers as well.

Leakage current sensors were used to determine if changes occurred in the insulation capacitance. The tan delta is obtained from this measured quantity as well.

Acoustic sensors to detect partial discharges may be attached to the lower end of the porcelain. Improvements need to be made to this detection system.

Hydrogen-in-oil sensors connected to a monitor determine the hydrogen content.

2.3.6.2 Circuit Breakers

Most networks comprise of old technology breakers (airblast, bulk oil and minimum oil). Financial and logistic constraints forestall the immediate upgrading of these breakers to the extent that some means of condition monitoring or assessment is sought. Continuous, on-line condition monitoring will yield returns only on breakers which operate relatively frequently, otherwise inspections and off-line monitoring methods of breakers will have more meaning. The on-line and off-line condition assessment techniques appear to be well established with commercial systems readily available. This is probably due to the key role that circuit breakers play in the power system.

2.3.6.3 Conclusions

Condition monitoring is regarded as the ideal diagnostic tool to identify imminent failures in the equipment under study to enable prioritisation of maintenance, refurbishment or replacement. In some cases where the off-line testing is still relied upon as the most dependable means of establishing condition, imminent or catastrophic failure would be unavoidable. On-line monitoring enhances early warning and diagnosis of sporadic or rapidly developing faults that may cause violent failure. In this way, damage to surrounding substation equipment and loss of life may be prevented. While some feasible techniques to monitor equipment on-line are being enhanced and made available, off-line methods may no longer be relevant.

CHAPTER 3: CONDITION MONITORING, CONDITION DIAGNOSTICS AND CONDITION ASSESSMENT APPLIED TO TRANSFORMERS AND CIRCUIT BREAKERS

The failure modes discussed in chapter 2 may be prevented by applying the diagnostic methods also covered in chapter 2. From a utilities perspective, the techniques available need to be applied in a co-ordinated way. Hence, the methods discussed in chapter 2 need to provide operational staff with information on both past and current status of the equipment condition. Where trends are established these may be used to predict the remaining life of the equipment or when maintenance should be performed. This co-ordinated approach is referred to as condition monitoring, condition diagnosis and condition assessment. Each of these concepts is briefly defined and then each technique is discussed for power transformers, instrument transformers and circuit breakers.

Breen [42] stated that life assessment maps condition assessment to a failure risk assessment. Technical, financial and strategic issues may be included when performing the assessment. Breen also stated that life assessment is an integral part of asset management, allowing control of lifetime costs, maintenance needs, effectiveness of expenditure and a means to identify incipient failure process.

Various researchers [42,43] stated that there are three factors that may impact on the useful life of equipment i.e. technical, economic and strategic. Technical factors such as ageing, mechanical and electrical overstressing, and insulation contamination may impact on the life expectancy of equipment.

A financial or economic factor is a measure used to quantify asset value in company accounts. According to CIGRÉ [43] the normal practice is to depreciate the capital cost over 35 years, just short of the designed operational life of the asset. There are other aspects that also influence the financial value of costly equipment e.g. transformers. By virtue of their design, there are costs associated with load and no-load losses. At some future time, energy conservation measures may cost-justify replacement with lower loss cores and this may be sufficient to fully depreciate the cost of a transformer in-service against the purchase of a new unit. As transformers age, maintenance costs may increase, but this may be less of a factor than for circuit breakers where the maintenance costs may increase substantially with age. Finally, there may be a financial cost associated with increasing failure risk. A catastrophic failure of a transformer may result in other equipment in close proximity being damaged, environmental pollution due to oil spillage and loss of supply to industrial and residential customers. The net cost of failure in the end may turn out to be far more expensive than the capital cost of a much larger unit embedded in the transmission system.

The strategic factor relates the equipment's ability to meet load and fault rating requirements, etc. The consequences of failure may have a capital cost of the current asset value, but the failure may have other negative effects. It may have a negative impact on the community, fuelled by adverse media reporting that could probably cause a decrease in share value. Much of system design and operation revolves about maintaining system security in the event of one or two faults (n - 1 or n – 2 criteria). The risk of failure of key equipment in a system requires ongoing assessment and the condition of a unit may become an unacceptable risk.

Various researchers [42,43] stated that life assessment is therefore a process of reviewing the risks of failure from technical, strategic and financial considerations. According to CIGRÉ [43] there are various types of evaluation techniques that may be applied to assess equipment condition. These are:

- Condition monitoring is any repetitive observations or data taken that is related to the condition of the equipment for the purpose of detecting developing faults. Monitoring is aimed at detecting changes in the equipment insulation or any other component, over a period of days, weeks or months, so that sufficient evidence may be available to make further investigations or take remedial action on a planned rather than an emergency basis.

- Condition diagnostics is the interpretation of that data to indicate the onset of a malfunction.

- Condition assessment is where a single or a range of condition monitoring or diagnostic techniques may be applied to evaluate the technical condition of equipment. Other relevant information such as routine maintenance and inspection data may be taken into account to establish condition.

This chapter describes various condition monitoring techniques that may be performed on power transformers, instrument transformers and circuit breakers. Condition diagnostics (interpretation of monitored data) and the evaluation of equipment condition (condition assessment) to determine whether each equipment item is acceptable for continued operation, is presented as well. The focus of this thesis is on power and instrument transformers. High voltage circuit breakers have not been explored in this study with the same depth. Circuit breakers are included because of two case studies that are presented in chapter 7 on economic considerations in condition assessment.

3.1 Power Transformers

There are various monitoring that may be used to assess the condition of a power transformer. These monitoring techniques are either used on- or off-line. Several monitoring techniques together with condition diagnosis are described for power transformers. For some monitoring techniques, only on-line measurements are possible. Some of these techniques are applicable to both power and instrument transformers.

3.1.1 Insulating Oil Analysis

3.1.1.1 Condition Monitoring

3.1.1.1.1 Oil Sampling (On-Line)

Periodic oil sampling and analysis is the most widely used tool for condition monitoring. An oil sample may be taken once or twice a year and tested in an accredited laboratory. International standards [7,8,15,23] stipulate the preparation technique of the oil sample and also the manner in which the tests are carried out. The test results provide key performance characteristics and may provide an indication of the condition. For the purpose of accurately recording and monitoring the test results of all sampling undertaken, all data are may be logged onto a database system. The test results are trended and analysed on a continuous basis. Standardised tests (section 3.1.1.2 below) may be performed on the oil sample taken.

3.1.1.2 Condition Diagnostics

3.1.1.2.1 _Moisture in Oil_: Moisture is introduced into the oil by various means such as the degradation of the paper insulation, through the breathing system and damaged gaskets. This test is a measure of the moisture content in a known quantity of insulating oil. Myers et al [4] stated that the limit for moisture content is 20 ppm.

3.1.1.2.2 _Acidity_: This test is a measure of the presence of organic acids in the oil. These organic acids will promote the degradation of the insulation and may also cause rusting. The test consists of mixing a known quantity of the sampled oil with a suitable solvent and an indicator, and then neutralising with Potassium Hydroxide (KOH). The end point is noted using a colour indicator. The quantity of KOH used to neutralise the acid is the measure of the acid content. An increase in the acid number indicates a deterioration of the oil. The disadvantage of this technique that is unable to detect colour changes in dark oils. This problem is overcome through the use of potentiometric titration. IEEE standards [7,8] specify 0.1 mg KOH/g as the limit for acidity.

3.1.1.2.3 _Interfacial Tension (IFT)_: IFT is a measure of the tension at the interface between two immisible liquids, oil and water. The tension is influenced by the property of oil decay products and contaminants from the insulating materials used in the transformer. The surface tension is measured due to a vertical linkage being formed between oil and water molecules caused by the contaminant. IEEE standards [7,8] specify clean oil to yield values around 40 – 50 dynes/cm, while contaminated oil may produce results in the range of 20 to 30 dynes/cm.

3.1.1.2.4 _Dielectric Strength_: The dielectric strength of oil is measured in terms of the breakdown voltage. A high moisture content in oil is one of the factors that lowers the dielectric withstand capability. Other impurities such as particles may further exacerbate the deterioration in dielectric strength of the oil. An international standard [12] describes the test procedure to be an application of an alternating voltage at a controlled rate, to a set of spherical electrodes (either 1.0 or 2.5mm apart), immersed in the oil specimen or sample. The voltage at which electrical breakdown (visible arc observed between electrodes), is the breakdown voltage. The limits for service aged oil by voltage class is suggested in IEEE standard [8]:

Test Gap at Minimum Voltage	Voltage Class	Breakdown Voltage
1mm	230 kV and above	30 kV
2mm	230 kV and above	50 kV

3.1.1.2.5 _Furfural Analysis (FFA)_: FFA is a measure of 2-furfurals compounds in transformer oil. Furfural is a by-product of the ageing process of the paper used in the insulation of transformers. This ageing will result in the chain scission of the cellulose and a reduction in the Degree of Polymerization (DP) or strength of the insulating paper. There exists a relationship between the Furanic content in the oil and DP. FFA is preferred to a direct measure of DP since the test gives an indication of the DP and is non-invasive. International standards [7,8] stipulate that a DP value of around 1200 is expected for new insulating paper, while values around 200 are regarded as end of life criteria for insulation material. Due to the difficulties in obtaining a cellulose sample from a transformer in operation, another technique of measuring furans has been developed. This may be accomplished in a laboratory using High Performance Liquid Chromatography (HPLC). The interpretation of the results is done using trend analysis.

3.1.1.2.6 *Dielectric Dissipation Factor (or Tan delta)*: This test is performed to check the deterioration and contamination of the insulating oil. This is achieved by measuring the leakage current when an alternating voltage is applied between the electrodes in a sample of oil. This leakage current is displaced by an angle of 90 degrees from the voltage due to capacitance. Since the capacitance is not ideal, an angle exists between the perpendicular current axis. The tangent of this angle is a representation of this loss current i.e. tan delta of oil. In the ideal situation the tan delta would be zero. For transformer oil, 0.5% is the accepted limit specified in IEEE standards [7,8].

3.1.1.2.7 *Colour of Oil*: The oil sample is compared to a reference chart contained in IEEE standard [7], which indicates the condition of the oil based purely on the colour of the oil. This is probably the easiest means of evaluating the condition of the oil, but is very subjective.

3.1.1.2.8 *Percentage Saturation of Water in Oil*: The possibility of free water forming in the oil may be calculated. Reference [8] provides a method for calculating the percentage water saturation in the oil and gives a table that relates it to the condition of the paper insulation. The presence of free water may lead to unacceptable dielectric withstand capability of the oil.

3.1.1.2.9 *Gas Analysis*: Various faults in a transformer will be exhibited in the breakdown products of the oil and paper insulation as dissolved gasses. The primary method for determining the nature of problems within the transformer, is gas in oil analysis. The gases present in the oil are indicative of different types of fault conditions that have either occurred or are evolving. The Total Dissolved Combustible Gas (TDCG) is measured against the limits stipulated in international standards [14,15].

3.1.2 Estimate of Moisture in Paper Insulation

Moisture in insulating systems adversely affects the transformer performance and, ultimately, service life. There are numerous reasons for the presence of moisture in oil and paper insulating systems. These include ingress of water via breathers, poorly gasketted bushings, inspection ports, etc. This situation is normally contained by the application of air dehydrating devices. In addition to the normal moisture developing mechanism, ageing of the cellulose accelerates moisture production.

Insulating paper contains hydrogen and oxygen molecules and a certain amount of moisture. Ageing or degradation of the cellulose causes water to be evolved, which either migrates into the oil or is present in various parts of the insulation itself. Cellulose may hold a far greater quantity of moisture than oil (this is temperature dependant). The useful life of a transformer may be determined by establishing the amount of moisture present in paper insulation. In addition to moisture content in the oil and paper, the calculation of possible formation of free water or percent saturation of water in the oil may be of greater significance. Percentage water saturation indicates the possibility of water formation in the oil. Free water in the oil leads to unacceptable dielectric strength values of the oil. IEEE Standards [7,8] gives a method for calculating the percentage saturation of water in oil and provides a table that relates it to the condition of the cellulosic insulation. Among other techniques there are two proven reliable techniques to determine moisture content in paper. These techniques are explained below.

3.1.2.1 Condition Monitoring

3.1.2.1.1 Oil Sampling (On-Line)

The presence of moisture in a thermally and electrically stressed cellulosic insulation system will ultimately lead to failure. Moisture causes the insulation strength to degrade, accelerates the ageing/oxidation process and causes the formation of bubbles that may further reduce the insulation strength by discharge activity. The objective would be to maintain the moisture level to a minimum and in order for this to be attained, a means of measuring this component is imperative. Detecting moisture concentration levels may be an important condition factor.

In order to provide good electrical characteristics, transformer insulation (oil and paper) is dried during manufacture or refurbishment. The amount of moisture present (i.e. where it will reside) in either the oil or paper insulation is dependant on temperature (see figure 3.1).

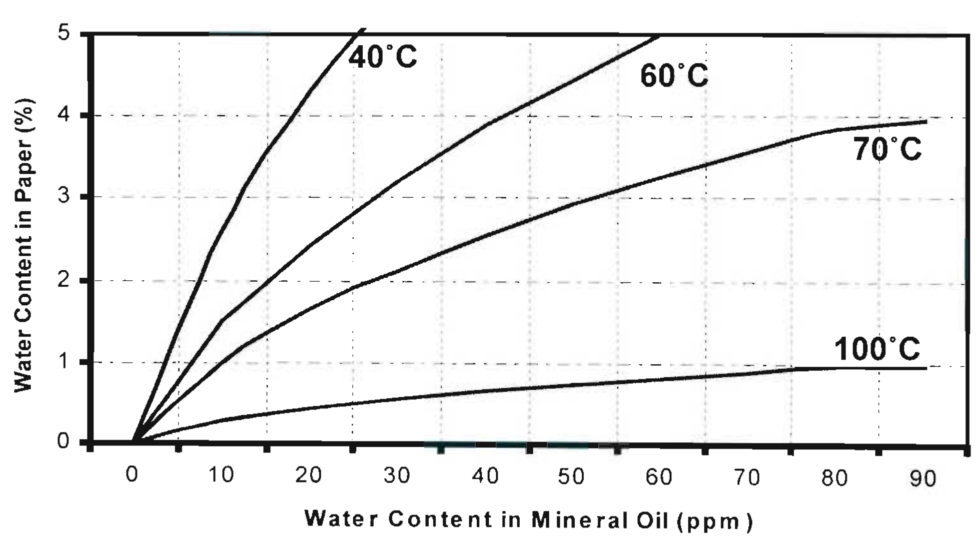

Figure 3.1: Equilibrium or Water Absorption Curves for paper-oil transformers [4,7,8].

Various researchers [4,7,8] stated that when applying these curves an estimate of moisture content in the paper is obtained when the top oil steady state temperature and the moisture content in the top oil have been measured. The same researchers also stated that the moisture in the transformer oil migrates back and forth between the cellulose insulation and the oil at varying operating temperatures.

An increase in temperature causes moisture to migrate from the paper to the oil and during cooling, the possibility of saturation of the oil exists. Solubility of the moisture in the oil affects the amount of water that can be carried by the oil (cold oil absorbs less water). At some point the oil becomes saturated and free water is formed. The insulation medium may be weakened, with a high probability of the transformer failing.

3.1.2.1.2 Polarisation Spectrum (Off-Line)

Mogiba and Moore [44] concluded that without the need for specimens to be extracted from the transformer, the diagnosis of the total insulation condition by Polarisation Spectrum can be traced from the results of recovery voltage measurements. Mogiba and Moore explained that paper and oil combinations exhibit a space charge polarisation effect, where molecules of hydrogen and oxygen are affected by an applied electric field stress. This effect may be influenced by the properties of the materials and their dielectric state. Ageing bi-products and moisture content alter the dielectric state and hence the polarisation process. Dielectric dissipation factor, or tan delta, is frequency dependent. To detect moisture, it may be necessary to observe the lower end of the frequency spectrum. A direct current (DC) excitation source may be required for this time variable field application. This technique involves electric stress and time for charging (dipole orientation), discharging and recovery (dipole depolarisation) periods. Mogiba and Moore reported that during this recovery the voltage across the insulation is monitored, providing the necessary information required in the analysis process.

Bassetto and Mak [45] reported that when the transformer is disconnected, the oil and paper insulation between the transformer HV and LV windings and ground is charged with a DC voltage source produced by an instrument, utilising the Recovery Voltage Method (RVM) principle. The charging process may temporarily halted and a discharge effected (short-circuited) for a predetermined period. When the short circuit is removed a recovery voltage will appears at the test terminals due to the internal electrical characteristics (see figure 3.2).

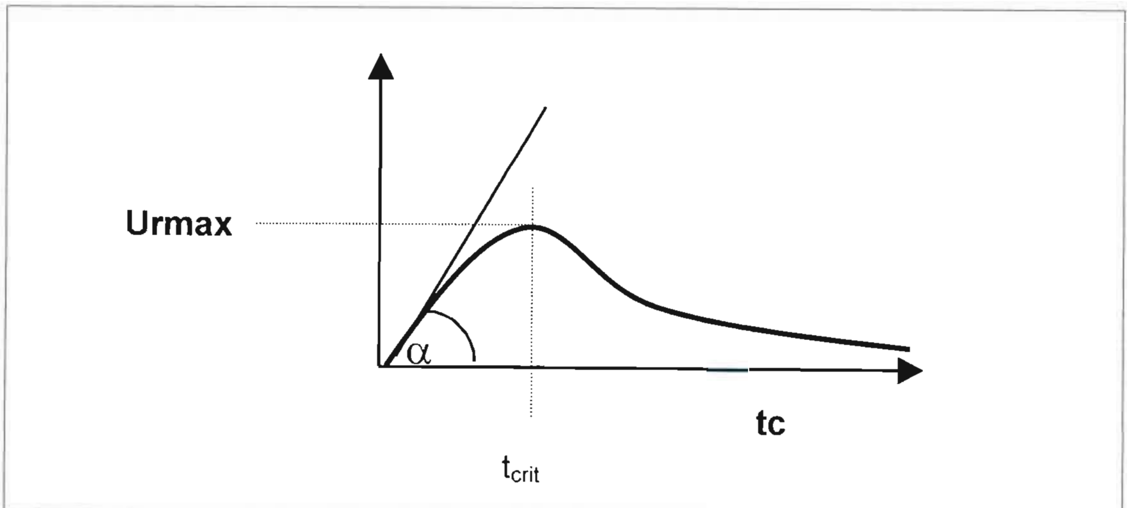

Figure 3.2: Recovery voltage (Ur) as a function of charge time (tc) [44].

This voltage and its initial slope are then measured, during that which is termed the recovery period. This process may continue over many cycles during which the charging time may be increased. Different values of Maximum Voltage and Initial

Voltage are obtained for each charge/discharge cycle. Mogiba and Moore [44] stated that when each residual voltage (U_{max}) is plotted logarithmically against its corresponding charge time (tc), an indication of the dielectric quality (ageing and water content) of the paper insulation is deduced, from U_{rmax} at tc(dominant) on the Polarisation Spectra Curve shown in figure 3.3.

Bassetto and Mak [45] stated that the RVM instrument is a micro-processor controlled device that allows for complete automation of the tests required to determine polarisation spectra. Setting of test parameters (Excitation Voltage, Charge Time and Charge/Discharge Time Ratio) and automatic logging of test data may be accomplished.

The increased sensitivity level and information content of this technique compared to other methods such as absorption and dispersion factors have made this a useful testing method. In addition, the tests can be carried out using a portable measuring instrument that is fully automated.

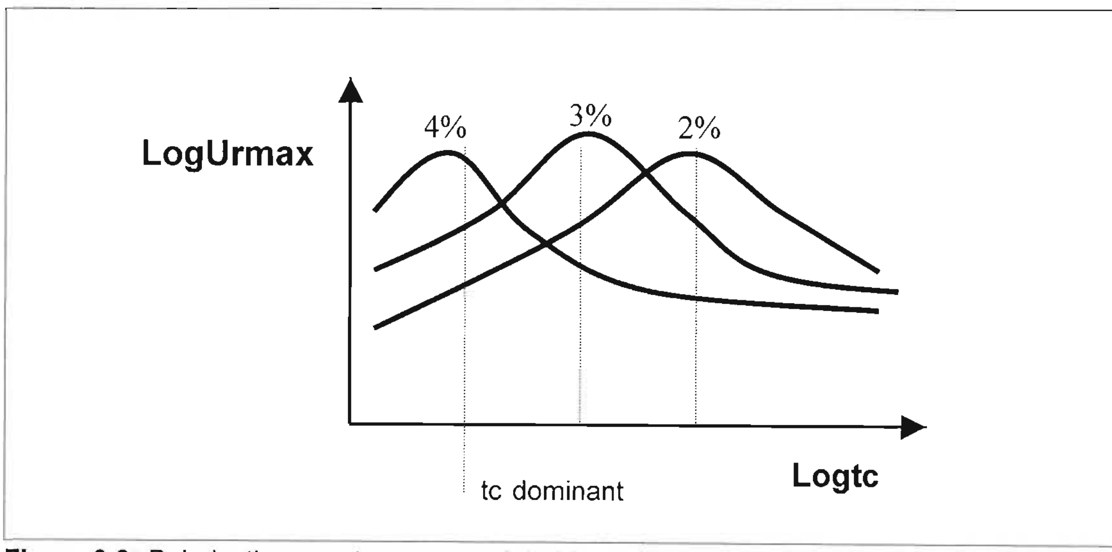

Figure 3.3: Polarisation spectra curves related to moisture content of paper [44].

3.1.2.2 Condition Diagnostics

Once the moisture content of the oil is determined for a given temperature, the corresponding moisture content for the paper may be estimated from either on or off-line methods. IEEE standards [7,8] provide the limits for moisture in paper content together with an interpretation of the condition. These are as follows: 0 – 2% (Dry paper), 2 – 4% (Wet paper) and >4.5% (Excessively Wet Paper) [7,8].

3.1.3 Paper Insulation Condition

Various researchers [45,46] stated that the analysis of a paper or cellulose sample, together with oil infers the condition of the insulating system. Cellulose consists of fibre chains made up of a string of glucose molecules held together by glycosidic bonds. Reference [45] stated that the average length of these strings is called the Degree of Polymerization. The length is expressed as the polymerization number of molecules, which form the average chain. Mogiba and Moore [45] stated that new paper has long chains of between 1000 - 1500, compared to a few hundred for aged paper. These researchers also stated that the shortening of the chains is associated with diminished mechanical properties (tensile strength, burst strength, elongation to rupture), so it is possible to relate DP to mechanical properties. Degradation of the cellulose may be advanced by heat, moisture, oxygen and acids, leading to a decrease in the integrity of the insulating medium.

Degradation of cellulose under the influence of heat is observed by the breaking down of the glycosidic bonds, which leads to the production of free glucose, further forming water, carbon monoxide and carbon dioxide. Cellulose may be susceptible to oxidation, while by hydrolytic (water and acid) degeneration, free glucose is yielded. Cataldi and Griot [47] reported that this free glucose degrades under the influence of water and acids, to produce furanic compounds (Furfuraldehydes), the principal one being 2-furfuraldehyde. These researchers also stated that different types of cellulosic insulation seem to generate furans at different rates when heated and the generation rate may be influenced by moisture content. A measurement of furanic compounds may provide an indication of cellulose degradation.

3.1.3.1 Condition Monitoring

3.1.3.1.1 Oil Sampling (On-Line)

Essentially furans are breakdown products of cellulose (insulating paper). Insulating paper may be readily dissolved in the transformer oil. Examination of oil samples, by Cataldi and Griot [47] also reported that High Performance Liquid Chromatography (HPLC) to measure the furanic component may lead to the determination of the cellulose condition. The major advantage of furanic analysis is being able to determine the cellulose condition without the removal of the transformer from service.

3.1.3.1.2 Removal of Paper Sample (Off-Line)

This method requires the removal of one or more specimens of insulating paper. Whilst oil sampling may be routine, obtaining insulating paper for laboratory testing and evaluation requires that the transformer be taken out-of-service. The oil is drained and the unit undergoes a degree of dismantling for access to the internal leads. Samples of cellulose are removed and later analysed in a laboratory to determine the Degree of Polymerization.

Bassetto and Mak [48] reported that the hottest and most aged conductor insulation may be located at the top of the transformer, where the oil may be the hottest. These researchers also stated that the most convenient and least hazardous location from which to sample, is a lead at the top of the transformer. Typically leads are sized to have a hot-spot temperature that may be comparable to that of the windings. Bassetto and Mak also stated that the lead hot spot is deep within the insulation, at the conductor surface, so an appropriate sample may be taken. Researchers Bassetto and Mak concluded that the thin paper insulation on winding conductors will be at relatively uniform temperature at the given location in the winding, so an outer wrap would be satisfactory.

Viscometric measurement performed in the laboratory is the technique used to determine the length of these fibre chains. This technique is performed in accordance with an international standard [49]. Briefly, the standard requires that a sample of paper be pulverising and then dissolved in a solvent. Viscosity readings are then taken and converted to a DP value.

3.1.3.2 Condition Diagnostics

Shroff and Stannett [50] concluded that a correlation between furanic and DP measurements on transformer oil have been found to be accurate. An indication of transformer condition based on furfural analysis is given in Table 3.1.

Furfural Content	Condition
< 2.5 ppm	Normal
2.5 – 5.0 ppm	Uncertain
> 5.0 ppm	Abnormal ageing

Table 3.1: Typical furfural analysis [50]

These researchers also concluded that if any set of ageing data is plotted with DP on a logarithmic scale and time on a linear scale, a straight-line results for the portion of the data after the initial rapid drop-off. The zero time intercepts for the straight lines range from DP = 700 to 900 for sets of test data at different temperatures. All of the data can be grouped by normalising, based on the time required for the DP to reduce to 200 (the life end-point). The resultant graph of normalisation life versus DP is shown in figure 3.4. The application of the curve may be understood by looking at a few examples extracted from reference [50].

A very aged transformer should have an insulation DP = 200. Figure 3.4 says that the normalisation life = 1, or total insulation life has been consumed i.e. useful mechanical properties of the paper is lost. Typically, moderately aged transformers have insulation with DP = 500. Figure 3.4 shows that the normalisation life (or consumed life) is about 0.33, with a possible range of from 0.27 to 0.39. This means that the insulation is still useful. Transformers of moderate age, but with histories of being lightly loaded would have DP = 800. According to figure 3.4 the normalised life (or consumed life) is zero. This means that the insulation is still very good.

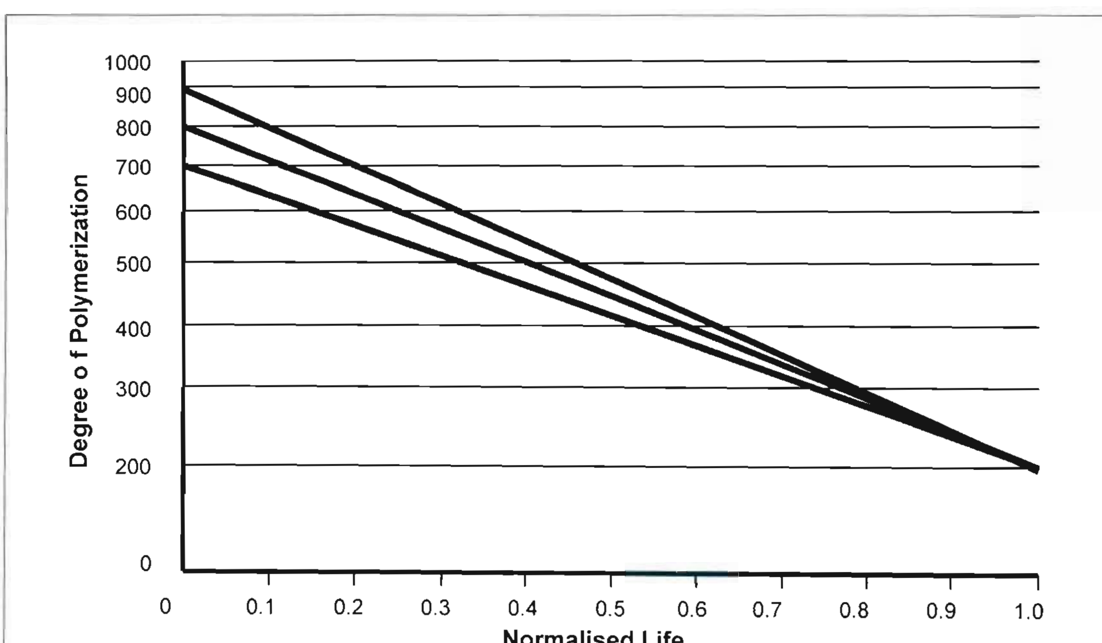

Figure 3.4: Normalised insulation life consumption versus degree of polymerization [50].

3.1.4 Dissolved Gas Analysis

When the insulating oil used in transformers breakdown as a result of abnormal conditions (such as overheating of paper and oil, partial discharges and arcing) gases appear in the oil. Gas-in-oil analyses are made to determine the presence of such gases. Gas-in-oil analysis or dissolved gas analysis is a widely used condition assessment technique that involves sampling and analysing gases dissolved in the oil of operating transformers. This technique may be sensitive to a wide range of malfunctions, both thermal and electrical, which could eventually lead to failure of a transformer if corrective measures are not taken.

3.1.4.1 Condition Monitoring (On-Line)

3.1.4.1.1 Oil Sampling

The objective of the sampling process is to collect a representative sample, while avoiding entrance of contaminants, and to preserve the integrity of the sample until it is analysed. Lombard [51] reported that sampling intervals are typically from 1 to 3 years depending on the size and voltage of the transformer, with more frequent sampling for large, critical units and less frequent sampling for smaller, less critical units. The same researcher also stated that should an abnormal condition be detected the frequency of sampling may be increased. There are a international standards [8,52] that address the sampling procedure for oil.

For example, ASTM D-3613 [52] suggests that samples be taken from a convenient valve at the bottom of the tank, which may be equipped with a sampling adapter. The same standard recommends that samples may be taken from energised apparatus provided it is certain that a positive pressure exists at the sampling point. It could be disastrous if the pressure were negative, causing an air bubble to be drawn into the unit. Normally the same samples are used for dissolved moisture and dissolved gas analyses.

Three possible styles of sampling containers are mentioned in ASTM D-3613 [52], namely glass hypodermic syringes, stainless steel sampling cans, and flexible-sided metal cans, all of which must be thoroughly cleaned prior to use. In all cases, the sampling technique involves pre-cleaning of the sampling connection and flushing of one to two parts of oil through the connection and sampling container to assure the absence of contaminants. Each sample container should have provision for a tight seal to avoid loss of gas during transportation and storage prior to analysis.

Each sample should be tagged to identify the apparatus sampled, the date sampling, and the oil temperature. Sample containers are forwarded to the laboratory for analysis. The process involves separation of the gas from the oil, introduction of the gas into a gas chromatograph, and calculation of the composition of the gas sample from the resultant chromatogram. This laboratory technique is described in ASTM D-3612 [13].

Research by CIGRÉ [53] recommended the repeatability of gas analysis between reputable laboratories. Much information may be derived from comparative data over a period of time. CIGRÉ also recommended that a periodic check of results between the customary laboratory and another laboratory of known reliability be performed especially when an unusual break in the trend of data is noted. An analysis error may generate concern leading to unnecessary action being taken. The result could be the irrecoverable loss of valuable time and money.

3.1.4.1.2 Fault Gas Monitors

Increasing demands on system reliability has led to the development of on-line measuring systems. A fault condition produces gases that dissolve in the oil, and form oil bubbles that reach the surface where it is finally detected in the blanket. The major advantage of on-line monitoring systems is their ability to detect faults as they evolve. There are at present several suppliers that provide continuous on-line dissolved gas monitoring systems such as Micromonitors [54], Hydran [55] and other on-line continuous sensors.

3.1.4.2 Condition Diagnostics

Various key gases that may be identified and their presence or combinations thereof, are used to interpret the oil condition, leading to fault determination. International standard [13] specifies the procedure for the separation and quantification of the gasses by Gas Chromatography. Various methods for interpretation are utilised. These include the Key Gas Method, Rogers Ratios and Doernenburg Ratio technique. The methods are described in IEEE Standard C57.104 [14] and IEC 60599 [15].

3.1.4.2.1 Interpretation of Dissolved Gas Results (IEEE Std C57.104)

IEEE Standard C57.104 [14], is an invaluable aid for the interpretation of gas-in-oil analysis results. The standard offers advice on both a simple qualitative interpretations based on certain key gases, as well as detailed quantitative diagnosis based on absolute levels and ratios of gases. In addition, it provides a rational step-by-step action plan to carry the user from the first recognition of abnormal gas generation and trending through an increased surveillance period to possible removable from service. Briefly, the methodology the calculation of the total dissolved combustible gases (TDCG). The transformer condition is classified according to each gas. The rate of change of the gas values in ppm is monitored. When these values become high a course of action should be decided.

The presence of the fault gases listed below, may be interpreted as follows:

- Carbon monoxide and Carbon dioxide (CO and CO_2)

  Thermal decomposition of cellulose, even at normal operating temperatures, produces these carbon oxide gases. Thus, low rates of production are not a cause for alarm. However, production of such gases at an abnormally high rate is associated with overheated insulation. Both the rate of production and the ratio of the two gases may be indicative of the severity of the overheating.

- Hydrogen and Hydrocarbon Gases

  Thermal breakdown of mineral oil generates this family of gases, with certain ratios of the gases indicating the severity of the overheating. Little or no acetylene and a broad spectrum of the other gases usually is the result of metallic parts being overheated by stray flux or circulating currents. These metallic parts are not covered by cellulose.

- Hydrogen

  Low intensity electrical discharges in oil, sometimes referred to as corona, produce principally hydrogen, with some methane, but lesser quantities of the other hydrocarbon gases.

- Acetylene (C_2H_2)

  High-density electrical discharges or electrical arcs produce very high temperatures (over 800 to 2000 °C), which causes the generation of small but significant quantities of acetylene [14]. Acetylene is absent for other types of faults. There is reason for major concern when it is detected.

Since all normally operating transformers will have some levels of the above mentioned gases dissolved in the oil with the exception of acetylene, it is important to identify concentration levels for which the user should have some concern. This is tabulated in IEEE Standard C57.104-1991 [14]. Table 3.2 has been extracted from this source.

Status See Notes	H_2 Hydrogen	CH_4 Methane	C_2H_2 Acetylene	C_2H_4 Ethylene	C_2H_6 Ethane	**CO** Carbon Monoxide	CO_2 Carbon Dioxide	**TDCG** See Notes
Cond 1	100	120	35	50	65	350	2 500	720
Cond 2	101-700	121-400	36-50	51-100	66-100	351-570	2 501-4k	721-1 920
Cond 3	701-1800	401-1k	51-80	101-200	101-150	571-1.4k	4001-1k	1921-4630
Cond 4	> 1 800	> 1 000	> 80	> 200	> 150	> 1 400	> 10 000	> 4 630

Notes:		
Cond	=	Condition
TDCG	=	Total Dissolved Combustible Gas (Excludes CO_2).
Cond 1	=	Dissolved gas in this range indicates normal operation.
Cond 2	=	Dissolved gas in this range indicates greater than normal generation. Begin analysis.
Cond 3	=	Dissolved gas in this range indicates a high level of insulation decompostion. Sample frequently to establish the trend of gas evolution and apply gas ratio analysis for diagnosis.
Cond 4	=	Dissolved gas in this range indicates excessive decomposition. Continued operation could result in failure.

Table 3.2: Dissolved gas concentration limits in ppm [14].

Gas ratio analysis may be helpful in determining the source of abnormal gas generation. Ratios of the hydrocarbon gases and hydrogen may indicate the temperature range of the heat source. Refer to reference [14] for more details of ratio methods, but note that significant levels of dissolved gas must be present before this technique may be practised (gas levels beyond Condition 1).

3.1.4.2.2 Interpretation of Dissolved Gas Results (IEC 60599)

It has been established that various faults in a transformer will be exhibited in the breakdown products of the oil and paper insulation as dissolved gases. The rates of production of these gases will indicate the severity of the problem. The yearly acceptable limits of gas production are specified in IEC 60599 [15]. These limits are:

- Hydrogen < 5 ppm
- Methane < 2 ppm
- Ethane < 2 ppm
- Ethylene < 2 ppm
- Acetylene < 0.1 ppm

3.1.5 Partial Discharge Detection

Partial discharge (PD) is the phenomena of the deterioration or partial breakdown of a dielectric under electrical stress. It may be similar to small explosions producing pressure waves that are emitted as high frequency electrical pulse discharges or corona. PD may be caused by faults such as, surface degradation, delamination of paper insulation, cavities or foreign bodies entrapped in the insulation and loose components. Some dielectric failures may be caused by damage from through faults, short-circuits and other causes. This PD activity within a transformer may eventually lead to irreparable damage, in the form of total breakdown of the insulation. The challenge is to detect partial discharges in the incipient stages in order to prevent catastrophic failures. It may be prudent to perform partial discharge detection tests after such events rather than wait for an indication that partial discharges are present.

Various researchers [56,57] have demonstrated that PD is detectable via various means. These researchers reported that the PD measuring techniques are well established under laboratory conditions, but many problems exist if these techniques are applied for on-line diagnosis. Therefore, various researchers [56,58,59,60] have concentrated efforts on on-line PD measurements. The main research goals were to improve the sensitivity of PD detection to the small signal levels presented against higher amplitude background noise levels.

3.1.5.1 Condition Monitoring

3.1.5.1.1 Acoustic Detection (On-Line)

Acoustic emission (AE) sensing may be more effective at localisation of PD associated with high voltage connections, exposed segments of windings and core stress shield faults. Various researchers [58,59] reported that by utilising a number of AE sensors simultaneously with specialised filtering, signal processing and software, the PD source may be located within the transformer. Various researchers [58-62] reported that when partial discharges occur in oil, acoustic signals are generated in the oil and transmitted in all directions throughout the transformer. Research by EPRI [59] concluded that these signals may be detected using special acoustic sensors.

Studies performed by various researchers [58-60] reported that such sensors have a frequency response band in the range of 20 - 300 kHz.

Piezo-electric sensors may be used to convert the acoustic signals to electrical signals that are transmitted to detector circuits. The sensors are placed at different locations on the tank wall to determine if acoustic signals are present. Various researchers [58,59] stated that if such signals are detected, then by triangulation an approximate location of the discharge may be obtained.

3.1.5.1.2 Audible Discharges (On-Line)

EPRI [59] reported that partial discharge activity inside the transformer could be heard. EPRI also stated that different individuals use different terms to describe such noise. Terms such as "frying sound", "popping noise" or "spitting noise" are used. If such noises are heard, immediate action should be taken to investigate the noise since only high pitched discharges may be heard by the human ear.

3.1.5.1.3 Oil Sampling for DGA (On-Line)

Hydrogen gas may evolve from partial discharges under oil. It may take appreciable discharges to produce sizeable quantities of hydrogen in the large volumes of oil that are used in power transformers. If there are appreciable amounts of hydrogen in the oil without corresponding amounts of other gases, there is a good probability that partial discharges may exist.

3.1.5.1.4 Electric Detection (Off-Line)

Conventional PD monitoring devices measure the current pulses at the earth side of the object. In order to obtain a certain sensitivity, the return path for the PD may be a low impedance e.g. a coupling capacitance. This is normally applicable in the laboratory. The standard for PD measurements (IEC 270) presents definitions, requirements for circuits and measuring devices, calibration methods, disturbances and test procedures. The main measuring quantity is the apparent charge of a PD pulse, additional quantities are its phase position, the repetition rate n, and integrated quantities such as the cumulative apparent charge 'q', the discharge power or the average current.

The apparent charge may be determined in the frequency domain or in the time domain. The commonly used PD instruments determine the charge in the frequency domain. According to CIGRÉ [61] two types of basic circuits may be used, the narrow-band ($\Delta f \cong 10$ kHz) and the wide-band ($\Delta f \cong 100 - 500$ kHz) measuring instruments. CIGRÉ also reported that radio interference voltmeters may be used and are of the narrow band type. The frequency response is determined by tuned band-pass filters having a variable response frequency and a narrow band-width. The instrument does not directly indicate the apparent charge, but gives a general indication of the PD magnitude. The peak value may increase or decrease with the repetition rate n, because of superposition pulses.

Hilder [57] reported that newly developed PD instruments extend the frequency range to more than 1 MHz. In this case the integration of the current pulse to get the apparent charge may be done in the time domain after the amplification of the current pulse.

EPRI [59] recommended the following process (figure 3.5) for detecting partial discharges in in-service transformers.

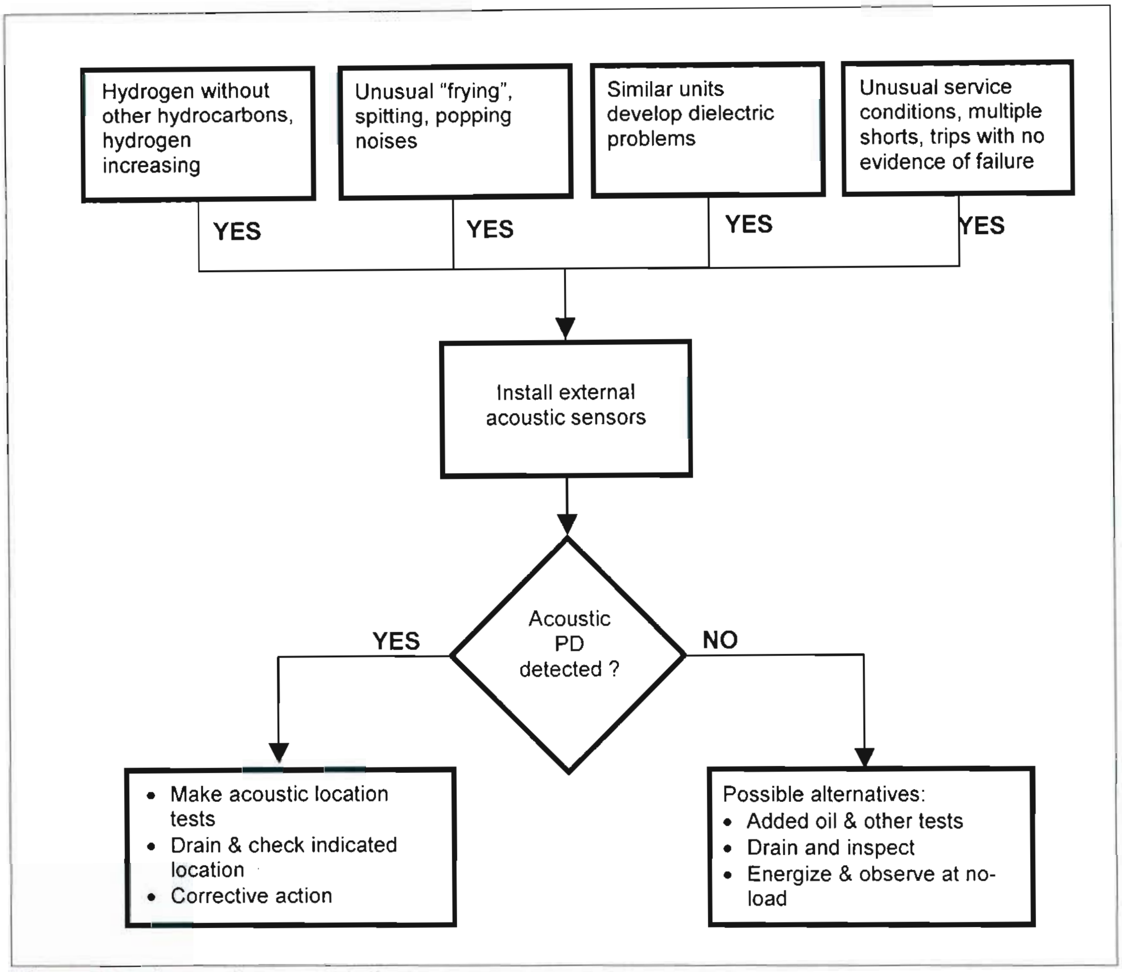

Figure 3.5: In-service partial discharge detection [59].

Research and investigation by EPRI [59] demonstrated that portable acoustic detection equipment for the isolation of corona noise sources in the substation environment is possible. An instantaneous indication of the relative level of discharge activity from in-service equipment may be provided.

3.1.5.2 Condition Diagnostics

IEEE standard C37.127 [62] suggests guidelines on discharge activity in power transformers. These are:

- 10 – 50 pC may be regarded as normal.
- < 500 pC = normal deterioration (ageing insulation).
- > 500 pC = questionable.
- > 1000 pC = defective.

IEEE standard C57.104 [14] states that a transformer having 300 ppm hydrogen with only very low levels of other gases, probably has a source of partial discharge that should be investigated. The standard also suggests that more investigations be conducted if such trends continue. The next step would be to perform an internal inspection. If the transformer has a history of dielectric problems and the hydrogen levels start to increase, action may have to be taken to determine if partial discharges are present.

3.1.6 Temperature Monitoring

The thermal behaviour of a transformer is an important element taken into consideration in its design and utilisation. From a manufacturer's perspective, knowledge of a transformer's thermal performance allows for improved quality and competitiveness of product. The operator now has the ability to manage emergency loading without compromising life expectancy, overall reliability or any performance guarantees of the transformer. The main reason for monitoring the thermal behaviour of transformers is to ensure reliable operation and long-life. A transformer outage means loss of potential revenue to the power utility and high maintenance costs.

The life of a transformer may be directly related to its insulation condition. Lampe et al [63] reported that the ageing process is minimal provided that the oil and paper is kept dry, the oxygen content is nominal, and the hot-spot temperatures are not above standard allowances. The same researchers reported that it may be possible to load the transformer at or above its rating depending on the ambient temperature, without significant loss of life if the transformer temperature does not exceed the rating of the paper. There may be specific areas of the insulation that have relatively high temperatures in comparison to the surrounding oil. These are hot spot locations that seriously affect the life expectancy of a unit.

3.1.6.1 Condition Monitoring (On-Line)

3.1.6.1.1 Indirect Method – Thermocouple

Oil temperature may be monitored, to determine loading effects, abnormal heating, oil cooler malfunctioning, arcing, stray flux, etc, via various means. Thermocouples are used to provide indications, such as direct top oil temperature and indirect winding temperature (which is simulated by the passing of current derived from a load measuring current transformer via a heating element utilised to heat a pocket of oil which in turn is monitored).

Various researchers [63-65] reported that direct measurement of temperature at the windings may be achieved with the use of single-point sensors. Although these sensors have been available for many years, technique developers [63-65] have been faced with the dilemma of isolation from high electric stresses. Further research and development has led to the introduction of acoustic [64] and optic sensors [63,65]

3.1.6.1.2 Acoustic Sensors

Pratt [64] reported that the acoustic sensor is a device operated on the principle of resonant frequencies, i.e. a variation in temperature would, in effect, vary the resonant frequency of the sensor. The same researcher reported that the results of the tests carried out on this device were encouraging, but the sensors exhibited severe problems with seals and waveguide attachments even though electron beam welding was used. In addition, sensors were susceptible to fibre damage during assembly when installed on heavy transformer coils. The fibres were damaged during the manufacturing, handling and transportation of the heavy transformer coils. Many of these sensors, however malfunctioned while in operation. These manufacturing problems of the sensor and the waveguide system have therefore prevented implementation of this device.

3.1.6.1.3 Optical Sensors

The second direct measurement method of winding temperature sensing uses optical fibre sensors with a fluroptic thermometer. Saravolac [65] reported that the performance of the thermometer is based on the fact that certain chemical compounds (e.g. phosphors), when excited by ultraviolet light emit fluorescence, the intensity ratio of which varies with temperature. Saravolac also reported that the optical fibre device combined with phosphor, is temperature sensitive. The device may be embedded in the windings at manufacture and provided that the correct positioning of the sensor is determined or estimated at the design, an accurate measurement of the hottest area may be obtained. However, there are concerns about the accuracy of predicting the hot spot area. Myers et al [4] stated that the area is estimated to be approximately two thirds of the way up the coil stack and one third of the way into the HV winding. This device provides an efficient means of measuring winding temperature directly without requiring any insulation as in the case of thermocouples.

According to Lamp et al [63] the use of optical fibre devices, have provided excellent results, their application has its disadvantages. Firstly, they were susceptible to mechanical damage and their long-term reliability is yet to be proven. Secondly, they require precise installation to prevent them from being damaged by high electric stresses. Also, the sensors have to be installed during manufacture or at open-tank maintenance.

3.1.6.1.4 Infrared Scanning

Moja [29] reported that infrared thermography and thermal imagery techniques have been developed and have now found their application in the overall substation environment. Optical ports located around the transformer monitor individual internal components. It appears that the major advantage of these techniques is that they are non-invasive providing satisfactory measurements obtained by external monitoring apparatus. For example, blocked cooling radiators may be identified using infrared thermography techniques. The disadvantage, however, is that the inner winding temperatures cannot be easily obtained. For the optical port method, it may be installed during the manufacturing or refurbishment.

3.1.6.2 Condition Diagnostics

With reference to Table 3.3 IEEE standard 57.91 [66] state that the useful life of transformer oil is halved for every 10 °C increase above 60 °C of top oil temperature.

Oil Temperature (°C)	Oil Life Expectancy
60	20 years
70	10 years
80	6 years
90	2.5 years
100	1.25 years
110	7 months

Table 3.3: Temperature effects on transformer oil [66].

Another international standard IEC 354 [67] stated that the relative rate of ageing of insulation is doubled for every 6 °C rise above 80 °C (hot-spot temperature). Reference [67] also stated that for a hot-spot temperature of 92 °C, one per unit life of a transformer will be consumed.

3.1.7 Mechanical Condition

In the transformer design process, mechanical forces are considered very carefully, and allowances are made for most type of events throughout the transformer's life. Winding clamping pressures are set to accommodate the range of forces that could be applied during short circuit fault conditions. Compensation, by the application of opposing forces on the same plane may be employed within the structural design, to ensure minimal effect during fault conditions. For example, hydraulic assisted spring systems (adjustable coil clamping) may be installed, to compensate for nominal winding movement under fault conditions. During manufacture, windings may be tightened during the drying out (vapour phase) process.

Kogan et al [2] reported that transformers are usually very reliable equipment, with an average lifespan of 38 years. The same researchers also reported that there are units that have a longer technical lifetime than initially assumed by the designers, and some units are still operational after 40 and even 50 years of service. However, when faults occur they may have catastrophic results with excessive repair costs. In addition to electrical and thermal failure mechanisms, a transformer may be subjected to high through fault currents during short-circuits, the mechanical structure and the windings may be subjected to large mechanical stresses. Transformers may be designed to withstand the effects of short duration through fault currents. Stresses of mechanical origin may be capable of causing transformer failure due to secondary effects, such as insulation breakdown.

The paper insulation of transformers that are seldom loaded to rated capacity may not age by the effect of thermal stresses. However, paper may lose its initial elasticity after many years of service. An initial compression of the winding that may ensure its mechanical integrity is reduced since the compressed paper does not spring back, and the winding may be prone to displacement or deformation. For example, a short-circuit in the transmission system may draw a heavy current from the transformer for a few cycles before the current is interrupted by the breaker. Such short-circuit current may be as high as ten to twenty times the rated current. A dynamic force induced in the transformer windings by the short-circuit current tends to deform or displace the winding. A new transformer may be designed to withstand the dynamic force resulting from the short-circuit current. However, some of the older transformer windings lose their initial winding compression and the winding discs are kept in position just by gravity. A resulting short-circuit current may then shift the coils or buckle their outer turns or displace other components. Aged or brittle paper insulation may be crushed and a bare copper conductor exposed. The dielectric strength of the bare metal electrodes immersed in oil may be lower than of the electrodes wrapped in paper. These changes unnoticed would eventually lead to unit failure in time. A possible overvoltage condition could follow causing breakdown of the weakened insulation, leading to failure in service. To reduce the probability of a costly failure there are several on- and off-line monitoring techniques that may be employed to assess winding displacement or deformation. Monitoring or measurement of certain mechanical parameters could assist in the early detection of incipient failure.

3.1.7.1 Condition Monitoring

3.1.7.1.1 Vibration Monitoring (On-Line)

Displacement of windings may be detected by monitoring vibrations on the tank. These patterns emanating from loose windings, connections and core clamping components in a transformer may be analysed and imminent failure could be predicted. According to Drake [68], sophisticated sensors such as accelerometers have been developed to measure vibration in varying degrees of sensitivity.

The same researcher also reported that the G-Force Recorder was developed to measure vibrations on the tank wall of suspect and even significant units on a network. Single-plane accelerometer modules, developed specifically for this application, are attached to the transformer tank at up to eight positions. Drake [68] reported that these modules are connected to a data logging system, monitoring vibration levels (with a pre-programmed maximum recording level of 2.5Gs) for up to a period of three months is possible, before download. The monitoring system is mains powered (with battery backup for the logging facility) and has the option of remote communication with control, included.

3.1.7.1.2 Winding Tension (On-Line)

Loosened windings or core clamping structures inevitably begin to vibrate, further increasing the likelihood of insulation failure with sometimes-catastrophic results. While off-line testing procedures such as frequency response analysis (FRA) and impedance measurement are utilised to assess winding integrity, continuous monitoring of winding slackness has also been undertaken. De Klerk [69] reported that direct measurement of winding movement or change in winding tension (loss of clamping pressure) has been applied successfully. In another source De Klerk [70] stated that with strain gauge technology, monitoring these parameters is possible, with the employment of sensors in various positions. The same researcher also stated that with the development of a hydraulically coupled force measuring system (Hydraulic Load Cell) the winding tension or slackness can be measured.

3.1.7.1.3 Impulse Testing (Off-Line)

The impulse strength of a transformer relates to its ability to withstand surge voltages (lightning and switching surges), without being damaged while in-service. Myers et al [4] stated that a transformer is nominally designed to withstand 2.5 times the normal operating voltage under impulse conditions. During the operational life of a transformer, primarily moisture, oxygen and elevated temperatures may influence ageing of the insulating system. These three factors may play a role in the reduction of the impulse strength characteristics as well, rendering the unit vulnerable to fault conditions that may lead to failure. These changes contribute to a decrease in the impulse strength.

To ensure that the transformer may withstand an impulse of 2.5 times the nominal operating voltage, various tests may be carried out at time of manufacture (acceptance testing). Myers et al [4] stated that these tests include the application of artificially induced lightning and switching impulses, and induced overvoltage tests. While the application of a pure high voltage impulse at full or reduced levels could indicate deteriorated insulation characteristics, the goal to accurately assess the mechanical aspects (especially winding clamping pressure or distortion/movement) of the transformer are equally important. This objective has driven the emphasis toward methods of measuring changes in the transformer impedance. Various researchers [71-76] reported that techniques such as low voltage impulse (LVI) method or frequency response analysis (FRA) may be utilised to obtain the impulse transadmittance function of a transformer. These researchers stated that the transfer function is given as the amplitude and phase shift of a sine wave, for each frequency of the applied signal in the frequency domain.

3.1.7.1.4 Low Voltage Impulse (Off-Line)

Researchers [71,72] stated that this method consists of an application of a microsecond duration LVI to the winding and recording the winding response. The relative geometry of the windings may then be ascertained and compared with initial ("fingerprint") readings on the same unit. Wang et al [71] reported that the initial fingerprint, or signature, may be determined by the unit's natural resonant frequencies within the range reaching approximately 1 MHz.

Voltage impulse application with a view to observing the transfer function of the transformer may be regarded as a significant condition-measuring tool. The interaction of the distributed capacitance and inductance of the windings generate a particular frequency response for a specific winding geometry. This provides the fingerprint for that particular transformer winding, which may be referenced during subsequent diagnostic testing. Any changes to the winding geometry i.e. the inductance and capacitance of the winding, may cause a change in the frequency response of the transformer or the winding itself. This impulse response waveform is transformed into the frequency domain using the Fast Fourier Transform (FFT) that may be used as a reference (an initial "fingerprint") for future tests.

3.1.7.1.5 Frequency Response Analysis (Off-Line)

Frequency response analysis is a technique used to detect winding movement and looseness. This subsection briefly describes the use of two known excitation techniques used to test the internal winding condition. e

A transformer winding consists of many winding turns that are inductively and capacitively coupled to each other. A capacitive coupling also exists between the windings and the earthed core and tank. Mechanical changes influence the equivalent circuit (inductance and capacitance) of a transformer, hence the transfer function/impedance under impulse conditions will provide an indication of a change in winding geometry. Faults such as HV winding shift relative to LV winding, short-circuited turns, earth faults between core and windings and some tapchanger faults, etc, would possibly bring about the mechanical changes.

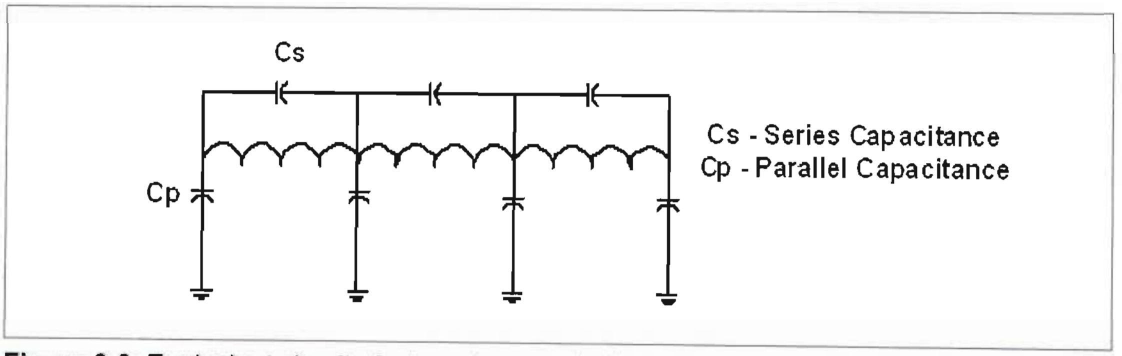

Figure 3.6: Equivalent circuit of a transformer winding.

The transfer function of a transformer is a frequency domain measurement, which provides the amplitude amplification and phase shift (for a range of frequencies) of a sine wave at each particular frequency. Vaessen and Hanique [74] reported that the transfer function is mainly influenced by the inductive impedance of the coils and not the capacitance's which at low frequencies (e.g. 50 Hz) present a very high impedance.

Vets and Leite [75] reported that two excitation methods are used to conduct FRA measurements. They are the Low Voltage Impulse and the Sweep Frequency method. In the low voltage impulse excitation, a source voltage/current is applied to HV terminal of the transformer and the voltage/current response is measured on the LV terminal of the transformer. In the sweep frequency excitation method a frequency source, connected to a particular winding, is swept over a range of frequencies and the frequency response of that winding is measured.

3.1.7.2 Condition Diagnostics

Vandermaar et al [76] published the results of FRA tests carried out on a 300 MVA transformer by using LVI excitation technique. In order to facilitate understanding of the transfer impedance technique, it is briefly described.

The test transformer was firstly isolated from the power system. A short duration, low voltage impulse was then injected on the HV terminal of the transformer with the neutral end of the winding earthed. The output voltage/current signal was measured on the LV terminal. The applied voltage and output secondary voltage/current were measured with the aid of a digitizer. A Fourier Transform was applied to the digitally recorded time data to obtain the frequency response. The transfer function was obtained by dividing the transformed output voltage/current by the transform of the input voltage. Changes in the winding were detected by comparing the results obtained with previous recorded results of the transformer under test or results recorded on an identical transformer. Figure 3.7 shows the FRA tests carried out this 300 MVA, 345/138 kV unit. The response of the transformer before re-clamping is compared with the results of a reference transformer.

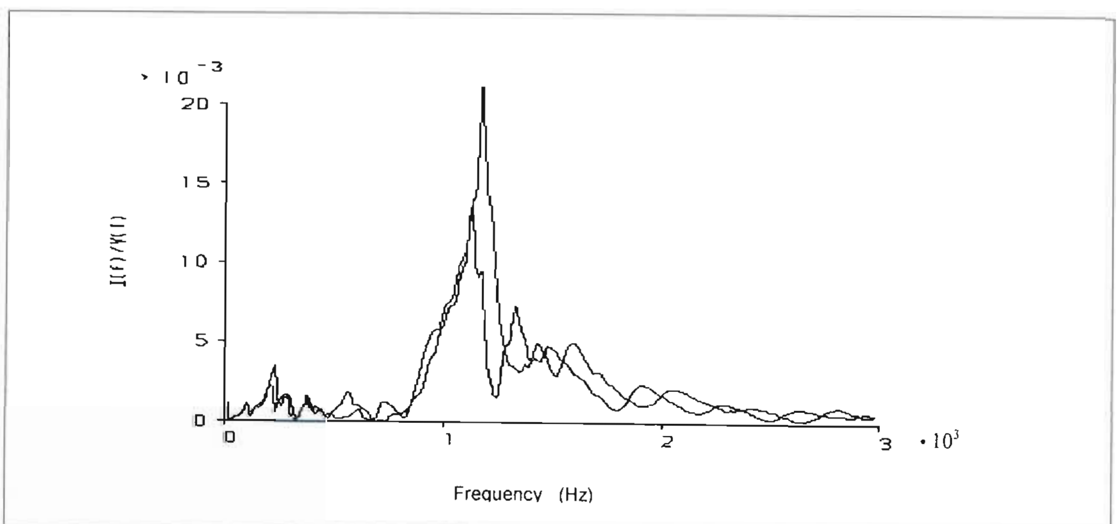

Figure 3.7: Frequency response analysis comparison of a reference and a re-clamped transformer [76].

The trace with the larger peak is from the transformer with a loose winding and the trace with the lower peak is from the reference transformer. Figure 3.8 shows the results of the FRA tests carried out on the same transformer before and after re-clamping. The trace with the larger peak is before re-clamping and the lower trace is after re-clamping.

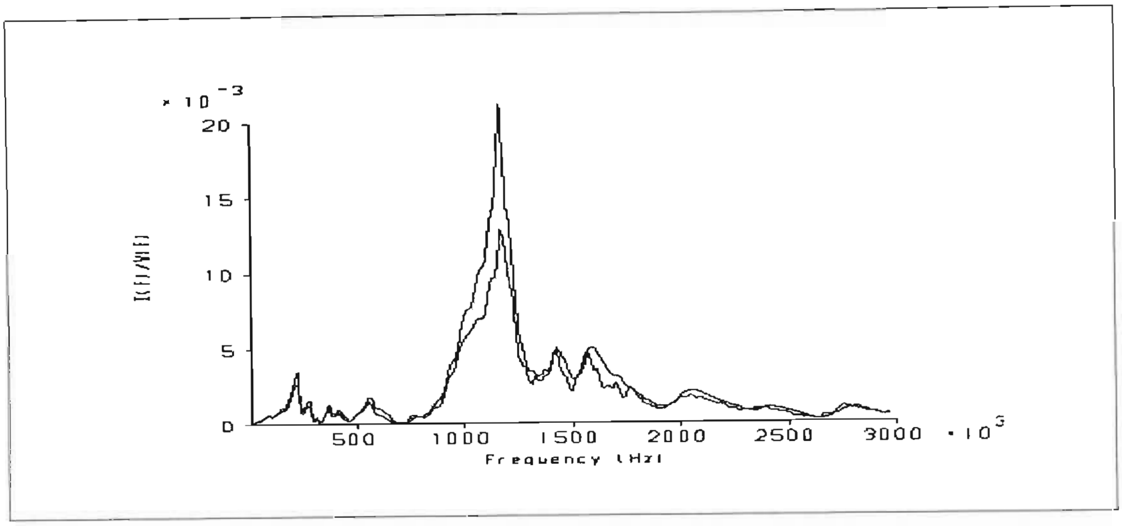

Figure 3.8: Frequency response analysis comparison before and after re-clamping [76].

Low voltage impulse test results should conform to the limits contained in international standards such as IEC 76-5 [77]. The standard specifies that a change in impedance of 1% is regarded, as an impending problem while the transformer will necessitate opening and stripping for detailed examination for an impedance change exceeding 2%. It appears that the accuracy of the measurement instrumentation that may be employed should be of concern to researchers and users of this monitoring technique. A phase shift or change in amplitude of the impulse response peaks caused by an inaccurate measurement device would lead to the incorrect interpretation of results.

3.2 Instrument Transformers

High voltage instrument transformers in a power system are intended to transmit information signals to meters and protective or control devices. They provide the information to discriminate and quickly isolate faulty equipment or system components in order to minimize equipment damage and to limit the disruption of the power system operation. These signals may be necessary for calculating and regulating power flows.

EPRI [17] reported that there have been a number of catastrophic failures in service involving instrument transformers. Most of the failures have involved high voltage current transformers. EPRI also reported that all manufacturers of current transformers have experienced some failures, but most of the failures have involved four manufacturers. Apparently, these four manufacturers also produced more units than the others because they were supplied with breakers. According to EPRI the causes for all of the failures were not identified.

This section focuses on performance, impact and assessment procedures related to current transformers since the number of voltage transformer problems to date has not been significantly large enough to initiate the same sort of action taken for current transformers. Some of the results from current transformer investigations also applies to voltage transformers (VTs).

3.2.1 Condition Monitoring

3.2.1.1 Current Transformers (Off-Line)

With reference to EPRI [17] research and investigation, the following is a brief summary of tests that may be performed on current transformers. The testing of current transformers may depend to a large extent on the history of the manufacturer's product line in service. The lower voltage class current transformers such as 138 kV and below are seldom tested in service unless there has been a record of problems on a specific brand. However, some utilities perform power factor tests on all oil filled current transformers at some interval. The experience in service with high voltage breaker current transformers indicates that periodic testing may be required although the manufacturer's instructions may state that such testing is not needed. The type of tests and frequency of testing depends on the history of performance. If there has been no history of problems in service, it may be advisable to perform insulation power factor tests and oil tests after being in service for 10 years. If there has been a history of problems including failures, the test frequency may be decreased. EPRI sponsored accelerated ageing tests on current transformers concluded that periodic oil testing is a useful technique for detecting certain forms of insulation degradation. The following tests are typically performed.

3.2.1.1.1 Oil Tests

- Gas in oil analysis to determine if hydrogen or acetylene is present indicating partial discharges or arcing respectively.
- Moisture in oil content to determine if there are any leaks.
- Dielectric tests.

3.2.1.1.2 Insulation Power Factor or Tan Delta (Dissipation Factor)

It is usually difficult to get free standing current transformers out of service to make power factor tests since they are a part of the breaker set-up. It may be performed if oil tests indicate a possible problem. Prasad et al [78] stated that the power factor (cos Φ) or the dissipation factor (tan δ) is a measure of the power loss in the insulating material. This measurement is an indication of the dielectric quality. The presence of contaminants, moisture and oxygen may result in the degradation of the insulating oil. Prasad et al [78] reported that power factor may increase due to an increase in following conditions:

- Temperature
- Metallic corrosion
- Mechanical and electrical insulation degradation
- Water solubility
- Oxidation

IEEE standard 62 [7] specifies the power factor of new oil to be less than 0.001. According to Prasad et al [78], the power factor or dissipation factor of a dielectric may be obtained as follows. When a voltage source is applied across a perfect dielectric, there is no loss i.e. the power factor is zero. At zero power factor the induced capacitive current (I_c) leads the applied voltage (V) by 90 degrees. This relationship is shown in figure 3.9 on the following page. Practical dielectrics may have a degree of conductivity. When these dielectrics are subjected to an alternating or direct current voltage source a small current (I_e) is in phase with the applied voltage (V). As a result the vector sum of the two currents (I_t) leads the voltage by less than 90 degrees as shown in figure 3.9. The cosine of the angle Φ by which the current (I_t) leads the voltage (V) is the power factor of the dielectric. The angle δ or ($90° - \Phi$) is designated as the dielectric loss angle, if the angle δ is small, then cos Φ is equal to tan δ. Alternatively, the power factor of an insulation is given by the ratio: Loss in dielectric (Watts)/ Apparent power (Volt-Amperes). Typically, a Scheuring bridge is used to generate an applied voltage up to 10 kV.

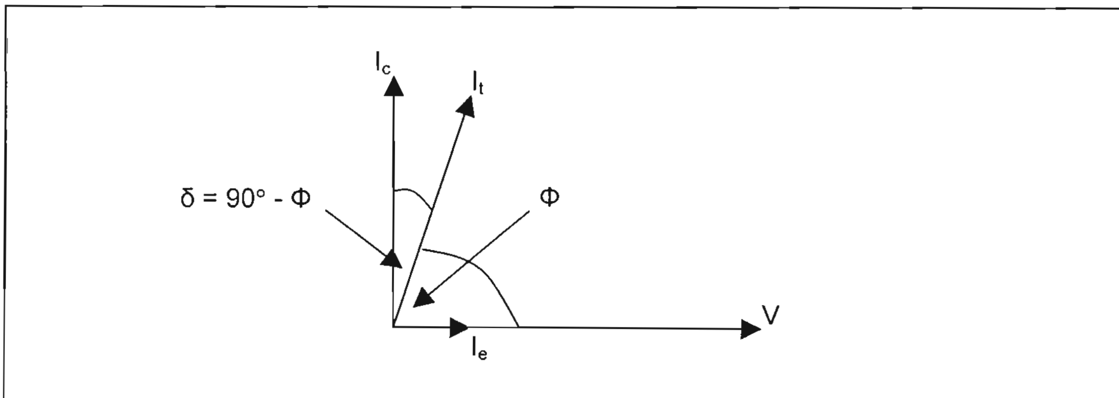

Figure 3.9: Vector relationship of voltage and current in a practical dielectric [78].

3.2.1.2 Voltage Transformers (Off-Line)

If the manufacturer's manuals do not contain instructions for testing or maintenance, Gabriel and Bradley [27] reported that the following tests may be performed. A complete set of oil evaluation tests are advisable for 220 kV voltage classes and above after 3 years in service. If there is no indication of problems, samples at intervals of 5 years are advisable. The oil tests should include:

- Gas in oil analysis. This may be an important test in that many of the problems in voltage transformers have involved partial discharges, which are indicated by the presence of hydrogen.

- Moisture in oil content if there are any leaks due to deteriorated gaskets.

If the oil test indicates a high moisture content, power factor tests could be made to check if the insulation is wet. Researchers Gabriel and Bradley also stated the testing of voltage transformers may be a function of the history in service.

3.2.2 Current Transformers (On-Line)

After performing various tests, EPRI [20] reported that current transformer failures may occur very. EPRI suggested that the number of failures could be reduced by more frequent off-line testing, but getting equipment out of service frequently to perform such tests is difficult to schedule. Even if the testing frequency could be increased to once a year, failures may occur because of the rapidity of some failure modes. EPRI also reported that on-line monitoring is needed to effectively reduce the number of erratic and sometimes rapid nature current and voltage transformer failures.

During testing EPRI [20] used various monitoring devices to determine which were the most effective in detecting a current transformer failure. The parameters monitored on-line were:

- Capacitance
- Power factor
- Leakage current
- Surface temperature
- Moisture in oil content
- Oil pressure (hermetically sealed units only)
- Partial discharge (acoustic and electrical)
- Hydrogen-in-oil content

The tests indicated that the most effective parameters to monitor may be partial discharge, capacitance and dissipation factor. EPRI [20] reported that a commercial product manufactured by Doble Engineering Company for effective on-line monitoring of dissipation factor and capacitance is available. According to EPRI a suitable product for field application to detect partial discharges on-line is not presently available. Balanger and Duval [79] reported that a sensor for monitoring hydrogen-in-oil has been successfully implemented. Researcher [80] reported that encouraging results were obtained after installing leakage current sensors at several Eskom sites in South Africa.

3.2.3 Condition Diagnostics

An instrument transformer may be either removed from service or considered suspect when the measured or monitored parameters discussed below indicate changes.

Leakage current trend begins to increase over a period of time. The primary voltage together with the leakage current may be recorded or logged at the same time since fluctuations in the voltage cause the leakage current to change proportionately. Any increase in the leakage current may imply that the capacitance of the insulation has changed.

A sustained increase in capacitance may imply that there is a reduction in capacitive layers as a result of one or more layers deteriorating. The voltage stress across the remaining layers of capacitance may be increased. An increase in electric stress could result in the onset of partial discharges especially where there are areas of weakness due to contamination or voids. Eventually the entire insulation or remaining capacitive layers may fail.

Gas in oil analysis or hydrogen-in-oil sensors indicates an increase in hydrogen content. The presence of hydrogen is associated with partial discharge activity. Oil analysis may indicate the presence of acetylene gas. Arcing is generally associated with acetylene. Discharge activity or arcing may be confirmed by acoustic or electrical means.

Boshoff [81] suggested that the following action be taken based on the insulation power factor results. For a value of 1% and greater the unit should be taken out of service immediately. Units having a power factor of 0.3 to 0.5% is acceptable for continued operation. A unit is considered to be suspect when the power factor falls within the range of 0.6 to 1%.

While in service, an increase in the trend of oil the moisture content over a period of time could imply moisture ingress due to leaking gaskets. During routine maintenance and inspection intervals, the presence of oil leaks may confirm the increases in moisture levels.

3.3 Circuit Breakers

A power circuit breaker is a device for closing, maintaining and interrupting an electrical circuit between separable contacts under both load and fault conditions.

Interruption of electrical circuits has been a necessary part of electric utility systems since the first use of electricity. Initially, this interruption was achieved simply by separating the contacts in air. Wright et al [82] reported that as current levels became higher, arcing between the opening contacts presented greater problems that required the development of methods to deal with plasma arcs that may occur during the opening process. The problem may be severe during faults or short-circuits at which times practically instantaneous interruption of current may be necessary as a protective measure for the connected apparatus.

By the late 1920s, all principal methods of arc interruption had been developed with the exception of the SF_6 types, which came into being in the late 1950s. Oil, air-magnetic, air-blast and vacuum methods were all in use by 1930. Many of the principles of these first modern breakers are still used in today's breaker designs.

In this era of deregulation, the focus is to maintain the level of reliability of existing circuit breakers and to predict with some level of confidence their future reliability. A circuit breaker may be replaced when it does not meet system reliability requirements or when the cost of life extension measures exceeds the cost of replacement. On the other hand, when the circuit breaker continues to operate reliably, the focus should be on extending the life of the circuit breaker through condition assessment. However, the basic functionality of the circuit breaker must be preserved during its extended life.

The intent of condition assessment is to identify the factors that contribute to an overall reduction in the reliability of a circuit breaker so that its life may be extended. The age of circuit breakers at many utilities has already exceeded design life so programs for life extension are very necessary to defer capital costs. Good circuit breaker maintenance practices may provide for the repairs needed to return the equipment to service. Diagnostic testing is a key component for the proper condition assessment.

3.3.1 Condition Monitoring (On-Line)

A preferred on-line condition monitoring system may employ sensors to obtain information concerning the functionality of the circuit breaker. These sensors employed may be non-invasive. CIGRÉ [31] reported that these sensors may not interfere with the insulating properties and surface insulation of the breaker, and may not decrease the reliability of the breaker by causing inadvertent or sporadic tripping. This meant that the part of the condition monitoring system that directly interfaces with the breaker requires a level of reliability greater than that of the breaker itself.

With regard to circuit breaker condition monitoring CIGRÉ [31] reported the following. A sophisticated condition monitoring system should monitor all possible parameters and store these in a database for each circuit breaker. Each time the breaker operates, the operational data may be stored and compared to previous operations. Once the variations in breaker parameter values become too large, an indication is may be given to initiate maintenance. Essentially a "fingerprint" or "signature" of the breaker may be compiled through the monitoring system and compared to a reference signature obtained at commissioning and subsequently directly after maintenance. In addition, mechanical-monitoring methods such as vibration sensors and accelerometers may be utilised. Some of these on- and off-line monitoring parameters are described briefly below.

3.3.1.1 Monitoring Parameters (On/Off-Line)

Various researchers [31-34] reported that circuit breaker parameters that may be monitored, are categorised into the following :

a) Gas or oil which refers to the insulating and arc quenching medium.

b) Electrical which refers to the main (and arcing) contacts and components in the breaker head directly affected by the arc (such as SF_6 nozzles).

c) Mechanical - referring to the operating mechanism.

d) Auxiliary systems which refer to compressors, motors, trip and close coils, hydraulic oil, etc. The parameters depend entirely on the individual design of the breaker e.g. spring operated versus hydraulic.

Additionally the parameters may be classified as suitable for off-line or on-line monitoring, or both. Off-line monitoring requires that the breaker be de-energised and may be periodic (or inspectional) whilst on-line monitoring means the breaker is in-service and may be continuous or periodic depending on the condition monitoring philosophy adopted. Table 3.4 on the following page shows the typical parameters that various researchers [31-34,36-40] highlight as suitable for condition monitoring.

In my opinion condition monitoring is necessary to identify imminent failures in circuit breakers and to enable prioritisation of condition based maintenance and refurbishment. Also continuous, on-line monitoring may yield returns on breakers which operate relatively frequently; otherwise, inspections of breakers may have more meaning. Inspection of breakers may necessitate their operation that may have an advantage for seldom operated breakers in preventing the clogging of grease in mechanical parts for instance.

PARAMETERS	AIR BLAST	OIL	SF_6	ON/ OFF-LINE	COMMENTS
GAS/OIL					
Temperature	X	X	X	ON	arc energy
Pressure	X		X	ON/OFF	gas tightness
Moisture content	X	X	X	ON/OFF	measure of dielectric strength
Arc products	X	X	X	ON/OFF	measure of dielectric strength and contact wear
Oil level		X		ON/OFF	oil leaks
Dielectric strength test	X	X	X	OFF	measure of dielectric strength
ELECTRICAL					
$I^2 t$	X	X	X	ON	contact and nozzle wear
Temperature	X	X	X	ON	contact wear
Re-strike	X	X	X	ON	contact opening speed
Pre-strike	X	X	X	ON	contact closing speed
Dynamic resistance	X	X	X	OFF	contact quality
Main contact timing	X	X	X	OFF	contact wear
MECHANICAL					
Contact travel	X	X	X	ON/OFF	linkage wear; clogged grease
Contact position	X	X	X	ON/OFF	pole and break synchronisation
Vibration	X	X	X	ON/OFF	misalignment damage; loose parts
Auxiliary contacts	X	X	X	ON/OFF	contact speed and timing
Number of operations	X	X	X	ON	operational ageing
AUXILIARY SYSTEMS					
Compressors	X		X	ON/OFF	gas tightness
Motor currents/hydraulic oil			X	ON/OFF	reliability
Trip/close coil currents			X	ON/OFF	breaker timing
Heating			X	ON/OFF	breaker slower at low temperature
AC/DC supply voltage			X	ON/OFF	reliability

Table 3.4: Circuit breaker condition monitoring parameters.

3.4 Condition Assessment

On- and off-line monitoring techniques to establish the condition of power transformers, instrument transformers and circuit breakers have been presented. By using a single or a combination of available techniques it may be possible to determine whether these items of equipment may be acceptable for continued operation with required reliability. Other relevant information such as routine maintenance and inspection data may be taken into account to establish condition as well. A means to establishing the condition of power transformers, instrument transformers and circuit breakers by the use of monitored data is discussed.

3.4.1 Power Transformers

Oil sampling and analysis may yield valuable information on power transformer condition. Several tests performed on a sample of oil taken may reveal the condition of the transformer's insulation. However, furanic analysis may provide a good indication of remnant life of the transformer. A DP value of 200 is an indication of end of useful life. Allan and Corderoy [10] reported that a transformer with insulation DP = 300 should be considered for a partial rewind, because about 70% of the insulation life has already been consumed. This is an appropriate technique for assessing the condition of the solid insulation.

Moisture within oil-paper insulating systems is detrimental to the life expectancy of power transformers. According to IEEE standards [7,8] transformers in-service having moisture levels in paper of up to 3% are considered to be acceptable. Recovery voltage measurements used to determine the condition of the transformer insulation without the need to extract samples is possible and may become an extremely valuable diagnostic technique.

The presence of fault gases may infer the condition of the insulating system. Sharp increases in hydrogen or acetylene content that is associated with partial discharge activity and arcing respectively, is cause for concern. However, other diagnostic tests such as partial discharge detection (by electric or acoustic means) may have to be performed to confirm the presence of discharge activity. International standard [14] suggested that a sudden change in the total gas content by approximately 300 ppm. would require further investigating and action to be taken to remedy the fault condition. Dissolved gas analysis remains a key technique for assessing the condition of the internal insulating system

Partial discharge detection and localisation by acoustic means is available commercially and is being implemented with some success. International standard [62] suggested a guideline for partial discharge detection in power transformers which is as follows. The integrity of a unit is considered to be questionable if the discharge intensity is found to be greater than 500 pC. If the discharge magnitude is greater than a 1000 pC the transformer should be taken out of service. Early warning and diagnosis may be enhanced when acoustic emission and gas-in-oil (on-line) data may be used in conjunction. If it may be possible, on-line or conventional gas analysis results may be taken into account when interpreting partial discharge measurements.

It is evident that thermal stress plays a significant role in the overall life of the transformer. Myers et al [4] reported that the useful life of transformer oil is halved for every 10 °C increase above 60 °C of top oil temperature. Reference [67] stated that a hot-spot temperature of 92 °C in the winding would cause a one per unit loss of life. Based on these findings, constant monitoring of transformer temperature (winding and oil) is of major importance. It appears that the objective of utility operators would be to maintain the hot-spot temperature below 90 °C. Various researchers [4,67] reported that loading of transformers having oil and hot-spot temperatures in excess of the suggested limits should be avoided, otherwise the useful life may be drastically reduced. In order to maintain the life of a power transformer, managing the loading of a unit may be extremely important.

There are several techniques that may be used to establish winding displacement of deformation in transformers. The detection of abnormalities in windings may be established by off-line transfer impedance methods such as frequency response analysis and low voltage impulse testing. Vibration monitoring and direct measurement of winding movement or change in winding tension (loss of clamping pressure) may be possible.

3.4.2 Instrument Transformers

Various monitoring devices may used to determine the most effective way in detecting a current transformer failure. These devices may be applied to voltage transformers as well. EPRI [20] concluded that the most effective parameters to monitor on-line were partial discharge, capacitance and tan delta (dissipation factor).

Sokolov et al [83] reported that imminent failure of may be caused by thermal runaway or electrical origin. These researchers also stated that for a unit to be regarded as defective (prior to failure) changes in certain monitored parameters were observed and recorded. For each cause of failure the observed changes in parameters were as follows. When thermal runaway caused failure; rapid rise in Tan δ or dissipation factor in the range of 0.58% to 1.6% occurred. The partial discharge intensity was greater than 250 pC. An increase in capacitance occurred (5 to 15%). A rapid rise in surface temperature was noted. In the case were failure occurred due to electrical origin; a rapid rise in partial discharge intensity of greater than 3000 pC occurred. The Tan δ increased rapidly from 4 to 6%. A high generation of fault gases (hydrogen and carbon dioxide predominantly) was recorded. The in capacitance increased due to short-circuiting between layers

3.4.3 Circuit Breakers

While the present condition of a circuit breaker may be evaluated on the basis of on-line monitoring, a complete out-of-service inspection and series of diagnostic tests may be performed. CIGRÉ [31] reported that there are also other factors discussed below, that may be considered for dependable long-term service use.

- **Inspections, diagnostic tests and maintenance records**

  Historical records of the individual circuit breaker may be reviewed in complete detail and compared with records for other breakers of the same manufacturer, type, and voltage/current ratings. This comparison may be helpful in highlighting conditions that may be common to any particular breaker group or family. Additional data available from other utilities and from the manufacturer may be used to corroborate the conclusion. This data could emphasise inherent areas of concern and help to determine whether these may be economically correctable.

- **Does the circuit breaker's design and rating fits its application?**

  As substations age, and as system short-circuit currents increase with larger loads to the point where the older breaker design and capability may be exceeded, the possibility of in-service failure of the circuit breaker increases. Accordingly, an important part of assessing the condition of a breaker is to make sure that its rating is capable of handling any anticipated future system expansion at that location. If not, it may be important to know if modification kits are available to uprate this breaker.

- **Does the circuit breaker pose an environmental problem?**

  If the circuit breaker or attached bushings were initially filled with or were subsequently contaminated with an environmentally hazardous material (such as Polychlorobiphenyls), corrective action may be considered.

This process discussed above is illustrated in figure 3.10 on the following page.

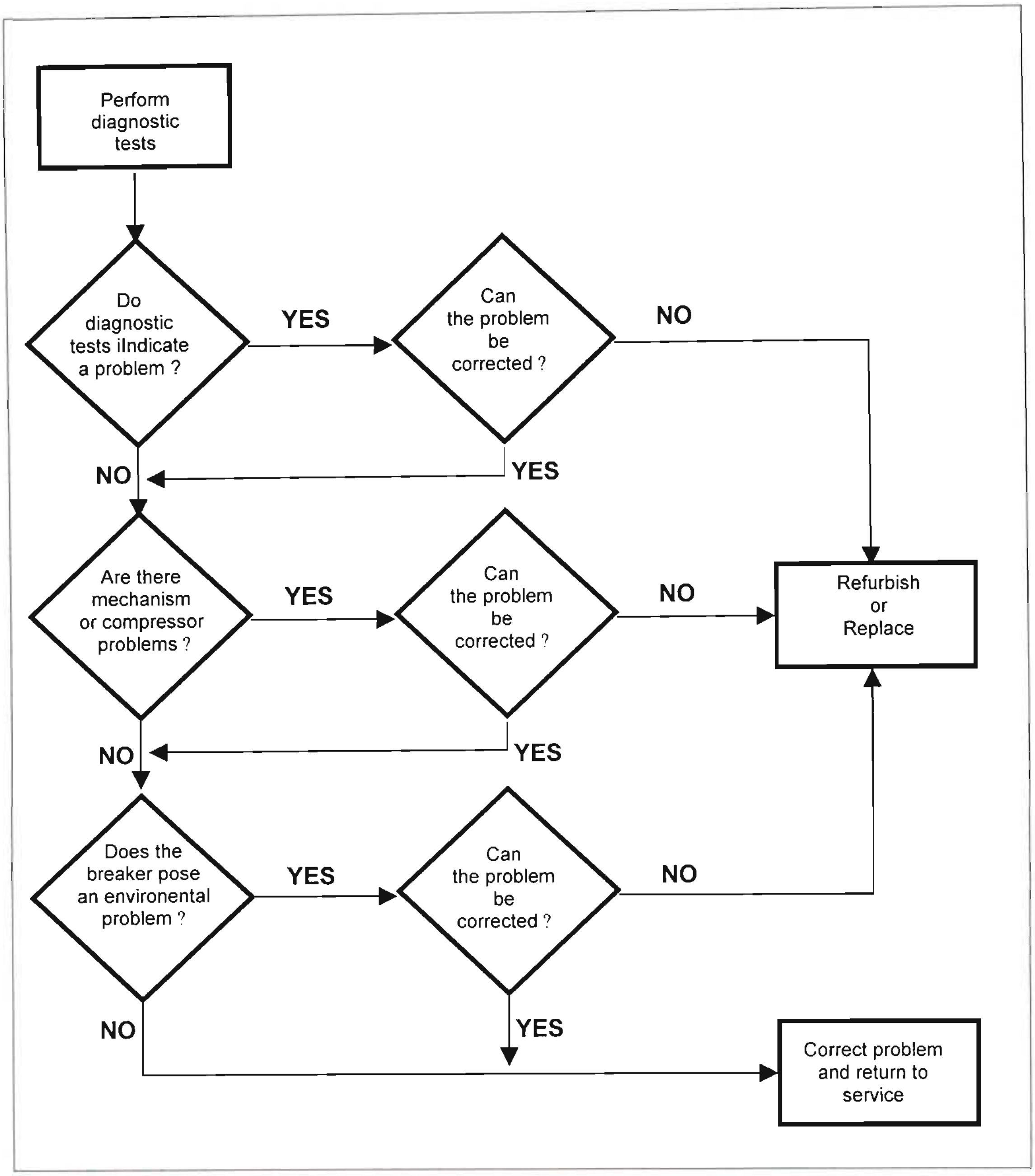

Figure 3.10: Condition assessment process of circuit breakers [31].

With regard to circuit breaker condition assessment the following comments were made by Sargent and Lundy [84]. In order to make a fairly accurate assessment on the present condition of an individual circuit breaker for continued service, present inspection maintenance and test data, along with service history, inspection, maintenance and test results should be available for review. If the information available is insufficient to support a valid judgement as to its condition for future service, other industry experience should be obtained to assist in the analysis. The basic information should include complete inspection, test and maintenance data. The same researchers also suggested that diagnostic tests be carried out. In summary, these diagnostic tests may include overall power factor, dielectric loss and capacitance tests on the circuit breaker. The grading capacitors associated with the interrupters should be tested as well. Additional tests may include contact resistance measured across each phase, a complete analysis of the insulating fluid and gas mediums, circuit breaker timing and motion checks, DC insulation resistance tests and an inspection and operational tests on the mechanism and compressor(s).

Sargent and Lundy [84] reported that available history on inspection, maintenance and diagnostic data may be carefully reviewed for any indication of negative trends that may cause the reliability to be questioned. These researchers suggested that the following aspects discussed below be considered.

Overall in-service inspection and tests. The record of past in-service visual inspections and tests may be reviewed to note the extent and frequency of corrective work.

Inspections and diagnostic tests for interrupters. While there are certain tests that may be applied to the breaker externally to reveal interrupter problems, it might be better to perform an internal inspection so that checks may be performed directly on each interrupter assembly.

Auxiliary interrupter components. It may be important that the auxiliary interrupter components be checked whenever there is a complete inspection or cleaning process.

Maintenance of mechanisms. There are certain in-service and out-of-service inspections and tests that may be performed on some schedule that includes the number of switching and fault operations, elapsed time, or absence of any operations over an extended time period.

Maintenance of compressor(s). There are particular items to be checked, both in-service and out-of-service, to ensure that the compressor(s) may functioning properly.

Maintenance of the insulating fluids systems. There are specific items to be checked to ensure that the gas system may be functioning properly.

3.5 Conclusions

The intent of life assessment is to identify the factors that contribute to an overall reduction in the reliability of equipment. These factors are obtained through condition assessment. Condition monitoring by on- and/or off-line techniques is a key component for condition assessment. Condition monitoring may be necessary to identify imminent failures in power equipment and to enable prioritisation of maintenance i.e. condition based maintenance. Condition based evaluation is a means of assisting a utility to decide if and when equipment need to be replaced or upgraded, to maximise operation and optimise expenditure. The emphasis on reduced maintenance costs, and life extension make it desirable to have monitoring systems that will provide information for determining when maintenance should be performed and life extension measures or practices implemented. Equipment may be replaced when it does not meet system reliability requirements or when the cost of life extension measures exceeds the cost of replacement.

The objective of maintenance and condition monitoring is to maintain the level of reliability of existing equipment and to determine the necessary measures that may be taken to extend life. At Croydon substation in Eskom (South Africa) a 500 MVA 400/132 kV transformer failed after being in service for 38 years. After 27 years of being in service, dissolved gas analysis results indicated a high moisture content in oil of approximately 25 ppm and oil dielectric strength of 52 kV. Three years later (i.e. after 30 years of service) the oil was reprocessed, an on-line dry-out system and a rubber bag were retrofitted to prevent further moisture ingress through the conservator tank. It may be evident that through regular maintenance (tapchanger only) and condition monitoring the transformer at Croydon was identified as being critical and measures to extend life were taken. However, the unit failed catastrophically eight years later.

Based on the discussion above, the best approach would be to utilise condition monitoring techniques to identify imminent failure, enable prioritisation of maintenance and to assist utilities when deciding to refurbish (life extension) or replace equipment. In this way operations are maximised and expenditure (either operational or capital) is optimised.

CHAPTER 4: LIFE EXTENSION

Life extension is the work required to keep substation equipment operating economically beyond its anticipated life, with optimum availability, efficiency and safety. A principal component of life extension is condition assessment, which allows failure of defective equipment to be predicted before causing a forced outage [43,84].

It has become necessary for power utilities to increase their competitiveness in the global market place. This may be achieved by providing electricity at the lowest cost and the highest expected reliability. Most may then prefer to defer substantial amounts of capital expenditure for new equipment by extending the life of existing equipment. The report by Sargent and Lundy [84] contains a comprehensive description of the life extension practices for substation equipment. The short description of the life extension measures or practices below is summarised largely from this source. Sargent and Lundy reported that utilities are undertaking life extension projects (refurbishment) based on condition or economic evaluation. The same researchers also stated that some utilities consider life extension to be the result of a well-founded, consistently applied maintenance program.

Detailed below are recommendations to extend the life of equipment under discussion. These recommendations have been extracted from various sources referenced.

4.1 Power Transformers

Transformer life may be shortened by a number of events. Taking actions to prevent failure from any of these causes may be a method for extending life. Briefly, discussed below may be possible methods to substantially extended the life of a transformer.

Controlling the characteristics of the internal system such as the oxygen and moisture contents.

Maintaining the condition of the paper insulation by improving the utilization of the transformer capacity. International standards such as IEEE Std C57.91 "IEEE Guide for Loading Mineral Oil Immersed Transformers", 1995 [66], IEC 354, "Loading Guide for Oil – Immersed Power Transformers", 1991 [67] and The Transformer Loading Calculation Method [84] may be considered good guidelines for the application and loading of oil-immersed transformers.

Maintaining the condition of external components, internal components and insulating systems.

4.1.1 Internal Insulating System and Components

A general summary of recommended operations that may be performed to extend the life of the internal insulation system and components is outlined in this subsection. In some cases, the reference document in which the relevant information can be found is stated. A summary of the processes to extend the life of the internal insulating system and components is presented in figure 4.1 on the following page.

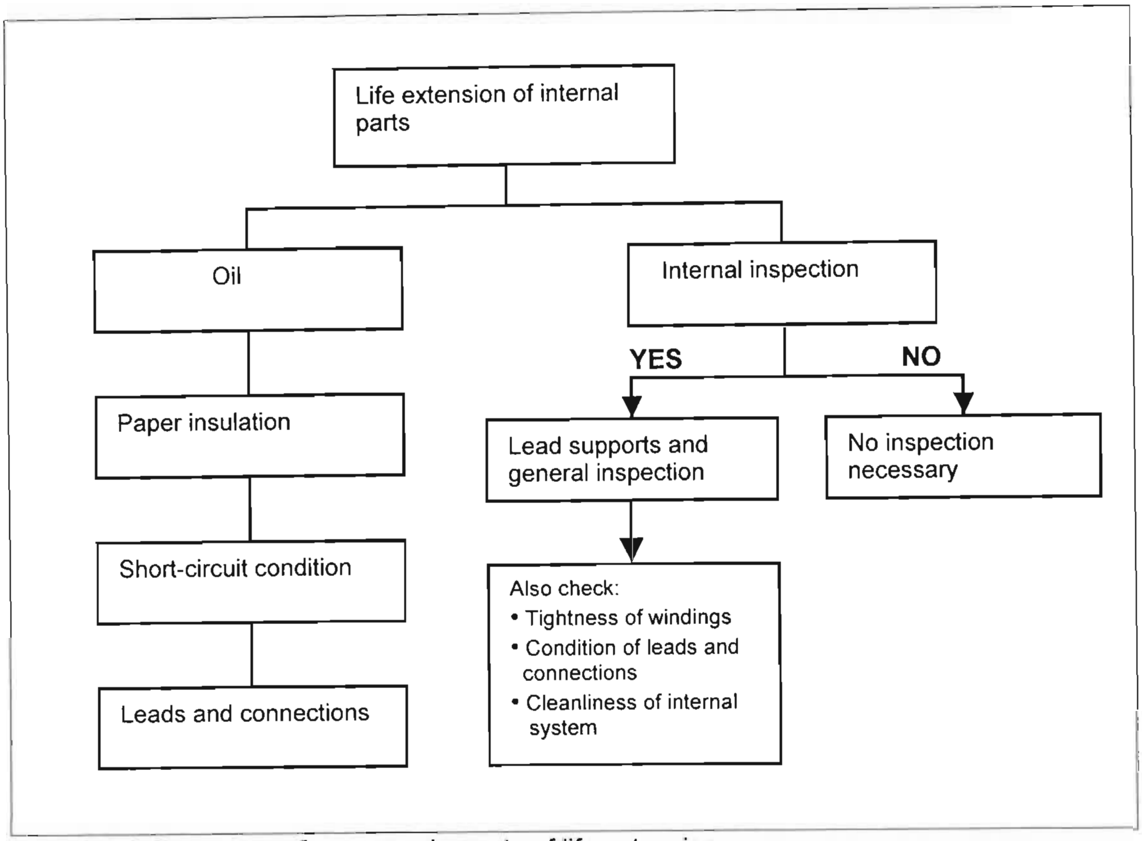

Figure 4.1: Power transformers - elements of life extension.

4.1.1.1 Oil

The oil properties may be maintained as outlined in references 4, 12, 51 and 52.

4.1.1.2 Paper Insulation

The most important elements of life extension for the paper insulation would be to keep it dry and to prevent excessive deterioration either by high temperatures or by high oxygen and moisture contents. The importance of these factors has been outlined in section 3.1.3 - *Paper Insulation Condition.*

4.1.1.3 Short-Circuit Condition

4.1.1.3.1 Condition of the Conductor Insulation

Based on the review presented in the previous chapters it is evident that the condition of the conductor insulation be maintained since embrittlement of the paper by thermal ageing or deterioration with excessive oxygen and moisture may result in the shearing of the paper under short-circuit forces. The installation of an on-line dry-out system and a rubber bag in the expansion tanks could be considered for both old and new transformers. However, Van Wyk [85] stated in the case of older transformers having a moisture in paper content exceeding 3% and an oil dielectric strength of less than 60 kV, the installation may be not justifiable.

4.1.1.3.2 Maintaining Tightness of the Windings

Loose windings are not the only important variable in maintaining short-circuit condition in-service. However, from a practical point of view this may be the only defect that may be corrected in-service. Frequency response analysis is a diagnostic method that may be used to determine winding looseness or deformation.

Sargent and Lundy [84] reported that a possible means of obtaining data on specific transformer designs that have a record of becoming loose in service would be to contact other utilities and industry sources. These researchers also stated that transformers may not be internally inspected to determine the tightness of the windings unless available historical information indicates that there may be a potential problem or some serious cause for concern.

4.1.1.3.3 Tightening of Windings In-Service

Before attempting to retighten the clamping of the windings, an attempt could be made to appraise the condition of the insulation. If the paper insulation appears to have lost its resilience and shows some indication of brittleness, retightening may not be attempted. Insulation that may be in a satisfactory condition with windings that may be loose, the task to contract a transformer manufacturer to retighten them may be simple.

4.1.1.4 Leads and Connections

Gas-in-oil results may indicate that an internal inspection may necessary. However, the ideal or good practice would be to check these component items when an internal inspection is undertaken. Below is a summary of comments made by Sargent and Lundy [84] when deciding to make such inspections and for making life extension improvements with regard to leads and connections. These comments or suggestions may be used as a guide.

4.1.1.4.1 Leads

Inspect all paper-taped leads and supports. If the tape has been damaged or found to be loose, it could be replaced with new crepe paper tape since it may be easier to apply, and stays in position once applied. The new tape should be dried and oil impregnated prior to its use in the transformer. The taping must be applied tightly on the leads with all or most of the stretch pulled out of the crepe paper. Experienced personnel could perform re-taping of tapered joints or any joint. Incorrect re-taping may cause oil voids on the surface of the conductor or spongy areas in the tape. These voids or spongy areas may be the source of partial discharges that may be the cause of failure. The same thickness of tape applied in the original design may be used. Shielding of sharp points should be replaced.

4.1.1.4.2 Connections

Bolted connections usually remain tight for the lifetime of the transformer. Those not covered by insulation may be inspected using a wrench to check the tightness. Insulated joints could be checked for darkening of the paper, indicating overheating.

4.1.1.5 Miscellaneous

4.1.1.5.1 Lead Supports

Lead supports are made from laminated pressboard, wood and other electrical-grade laminates. Lead supports are usually bolted together using fibre or plastic bolts and nuts. These bolts may become loose. During an electrical inspection the condition of the supports including the tightness of the bolts may be checked.

Damaged bolts could be replaced with electrical grade type. Researchers [84] stated that almost all hardware considered for use should be of electrical grade that is suitable for use under hot oil; and the nuts may be locked using materials approved by the transformer manufacturer for use in transformer oil.

4.1.1.5.2 General Inspection

The remainder of the internal assembly may be inspected for loose parts or contamination. Any loose parts may be repaired. Contamination that could be found including paper particles or pieces may be cleaned.

Sargent and Lundy [84] reported the following with regard to the use of materials. The use of approved materials should be considered for the repair of internal parts since transformer oil reacts with many materials that may cause major problems. These researchers also stated that many synthetics or plastics are not compatible with transformer oil that either become soft or disappear in hot oil.

4.1.2 Particles, Oxygen and Moisture in Insulating System

It has been established that excessive oxygen and moisture are factors that contribute to the deterioration of paper insulating properties in service. High oxygen levels in the transformer system results in oxidation of the oil, which produces sludge, etc. The presence of moisture adds to the deterioration process. The oxygen and moisture contents of oil in transformers having expansion tanks with rubber bags or nitrogen blankets above the oil may be low, if the oil preservation systems are maintained. Conditions that may result in high oxygen contents in transformers having nitrogen blankets are as follows:

- Incomplete purging of the gas space when the transformer may be opened.
- Gasket or other leaks above the oil level. When nitrogen bottles are not replaced promptly when empty, the pressure in the gas space may be negative resulting in air being pulled in through defective gaskets.

Particles may be detractors from dielectric strength particularly in combination with moisture in the oil. Particles may reduce the dielectric strength of the oil and the surface (creepage) strength of the solid insulation. Therefore, it may be important to keep the insulation system free of excessive particles as part of life extension.

Higher than normal dielectric loss may be an indication of excessive water in the solid insulation, contamination or dielectric breakdown in the insulation. If the periodic insulation power factor tests indicate higher than normal values, action could be taken to determine the cause and to remedy the situation.

4.1.2.1 Control of Oxygen Content

International standard [8] recommended that the oxygen content of the oil be controlled to a maximum of 2000 ppm. It may be easy to contaminate the gas in oil sample with air while taking the oil sample or when making the gas extraction from the oil. Extreme care may be taken to prevent air contamination when making tests to determine the oxygen content of the oil.

4.1.2.2 Control of Moisture Content in Paper

International standard [8] specify the limits for moisture content in insulating paper. According to voltage class, Table 4.1 shows these values to which the moisture content may be controlled.

Voltage Level	% Moisture in Paper
525 and 800 kV	1.0
230 and 345 kV	1.0
115 and 230 kV	1.5
Less than 115 kV	2.0

Table 4.1: Power transformers - acceptable levels of moisture in the paper insulation [8].

Since there may be high costs to maintain these oxygen and moisture contents, some judgement may be exercised when using this information since the cost may not be justified for transformers with small kVA ratings.

4.1.2.3 Methods for Controlling Oxygen and Moisture Contents

The oxygen and moisture contents in the insulating system may be controlled by the application certain devices such a rubber bag(s). Their use may depend on the importance of the transformer, replacement cost of the unit and the cost to implement these devices. These costs would be used to justify the total expenditure required for the device.

4.1.2.3.1 Older transformers with Oil Expansion Tanks without Rubber Bags

The oil expansion tank may be retrofitted with a rubber bag to prevent or exclude the ingress of oxygen and moisture into the oil.

4.1.2.3.2 Transformers with Nitrogen Gas Blankets

Allan and Corderoy [10] reported that some utilities have fitted expansion tanks having rubber bags to these transformers to control the oxygen and moisture ingress. These researchers also stated that the sources of oxygen and moisture ingress in this type of transformer are due to one or more of the following reasons. The first reason is the failure to adequately purge the gas space of air after the gas space has been opened to perform maintenance operations. Secondly, not replacing the nitrogen bottle correctly when it becomes empty and lastly, there may be gasket or other leaks above the oil level.

Elimination of the cause usually requires care when performing maintenance operations.

4.1.2.3.3 Transformers with Expansion Tanks having Rubber Bags

The rubber membrane may permit oxygen and water vapour to leak through the rubber during the years of service. The oxygen level in the gas-in-oil samples may be checked periodically to determine whether the levels are increasing over a number of years. If so, one possible solution could be to drain and refill the transformer with degassed oil.

4.1.2.3.4 Transformers with Forced Oil to Air Radiators

Negative pressures may occur on the intake side of the pump and at the top of radiators. This situation may result in leaks from gaskets and dresser couplings.

4.1.2.4 Control of Particle Content

All types of particles including paper may reduce the dielectric strength of oil, and metal particles may reduce the surface (creepage) strength of the solid insulation. Paper particles absorb moisture from the oil and may become conducting, reducing the breakdown strength of the oil.

The particle content should be controlled to ensure that the dielectric strength is within limits specified in international standards [7,8]. Allan and Corderoy [10] recommended that particle count tests be made when making tests to determine life extension actions that should be taken.

Sargent and Lundy [84] reported that most manufacturers have different limits for particle control in their transformers. These researchers also stated that the limit for transformers that have been in service for several years is somewhat subjective, but recommended that action be taken to clean transformers if the particle count is greater than 50 000 particles in 100 ml of oil. Sargent and Lundy also concluded that if the number of particles greater than 100 microns exceed 1 000 in 100 ml of oil, cleaning operations should be considered. When performing the oil cleaning operation the oil may be dehumidified and degassed at the same time.

4.1.3 External Components and Systems

External components and systems may be considered for life extension. Some of these components and systems include cooling equipment, coolers or radiators, instruments and gauges and oil preservation equipment. The recommendations provided in this subsection are basically maintenance-related practices. Various researchers [4,84] have documented detailed transformer maintenance procedures. These procedures are concerned with life extension only. These practices may impact on the life of the transformer system as well as the components.

4.1.3.1 Cooling Equipment

4.1.3.1.1 Pumps

Bearing wear and other mechanical failures in oil pumps could be the cause of failure in some power transformers. The particles generated from pumps found in areas of high electric field stress may cause failure. There is no effective way to test pumps in-service for such conditions. However, Sargent and Lundy [84] suggested that the following actions discussed below, be considered.

Change-out of the oil pumps on a regular basis. The time interval depends on the time that the pumps are in operation and the experience with each pump design. All bearings, either sleeve or ball, that may eventually wear need to be replaced.

Some pumps may have a history of problems while in service. These pumps may be replaced when they may have been in service for a long period of time.

When pumps are replaced on transformers that are in-service or repaired units, these pumps may either be replaced with new pumps that may be reliable or be rebuilt with improved bearing systems.

For important applications such as large generator step-up transformers and system tie auto-transformers, install of pumps with bearing monitoring systems so that any problem may can be detected early, before harmful particles get into the transformer system.

The operation of pumps (and fans) on coolers could be rotated on a regular basis. They are usually arranged in-groups that may be activated by the cooler temperature controls. Rotating the groups may assist in balancing the wear on the pumps.

4.1.3.1.2 Forced Oil to Air (FOA) Radiators

Some types of radiators may be subjected to clogging. When this occurs, the transformer may operate at higher than normal temperatures. The temperature trends on such transformers may be checked and corrective action taken to ensure that insulation deterioration resulting from excessive temperatures does not occur. It may be neccessary to replace the radiator to save on maintenance costs.

4.1.3.1.3 Plate Fin Radiators

Sargent and Lundy [84] reported that these radiators may last for many years, essentially trouble free. It may be necessary to check the temperature trends on these transformers at pre-determined intervals and to clean these radiators if there may be an increase in the trend due to the radiators being dirty.

4.1.3.2 Instruments and Gauges

Kogan et al [2] reported that a number of transformer failures occur each year because instruments and gauges that control the transformer are inoperative. Such failures included overheating due to loss of cooling and the low oil level that may have not been detected by a defective gauge. Critical instruments may be checked periodically to ensure correct operation. During the substation inspections gauges may be checked.

4.1.3.3 Oil Preservation Equipment

It may be important that oil preservation equipment function properly so that oxygen and moisture are prevented (to an extent) from entering the paper and oil insulating system.

4.1.3.3.1 Expansion Tanks with Rubber Bags

Sargent and Lundy [84] reported that such equipment requires little maintenance. The oxygen and moisture contents from the periodic oil tests may be checked periodically for trends to determine whether the levels are increasing. A possible cause may be gasket leaks, but such trends may indicate that the bag has a leak or that air may be slowly permeating the rubber.

The system may not be operating properly, if the oil level gauge does not indicate the correct level and/or there may be a rupture in the bag, which may require replacement.

4.1.3.3.2 Insulation Dry Out Systems

Van Wyk [85] reported that there are a number of effective transformer insulation off-line dry-out techniques may be used. These techniques are briefly discussed below.

The vapour phase dry-out system requires that the transformer be de-tanked in a workshop environment and inserted into a vapour phase autoclave. The tank is then washed with kerosene vapour heated to 180 °C, before drawing a vacuum. At this temperature the impregnated oil is moves out of the solid insulation, thus enabling moisture to be extracted from the paper in a period of approximately three days.

The conventional site dry-out system is a mobile plant that circulates, treats and heats the oil (and therefore the transformer insulation) to a temperature of 80 °C. Thereafter, the oil is drained. A vacuum is then drawn on the drained transformer tank at approximately 4000 m^3 per hour at a pressure of 10^{-3} kilopascals. The elevated temperature and reduced pressure on the paper insulation causes the moisture in the insulation to boil off and is removed by the vacuum plant. The complete process may take up to six weeks.

The low frequency heating (LFH) system for site or workshop dry-out of power transformers uses a solid-state low frequency converter, a controlled (pulsed) three phase current that is injected into the transformer primary, with the secondary short circuited. At the same time a conventional dry-out plant described above is used to circulate, treat and heat the oil. By heating the transformer insulation from within by the LFH plant and circulating oil, the heating time is significantly reduced. Thereafter, the transformer oil is drained and a vacuum is drawn on the tank, exactly as previously described, to remove moisture from the paper insulation. This process may take 4 weeks to complete.

These off-line dry-out systems require that the transformer be taken out-of-service. It may be for this reason that an on-line insulation dry-out system may be favoured. The developer [86] reported the following with regard to an on-line dry-out system i.e. The Dry Keep. The Dry Keep is a device that is fitted in the transformer oil-circulating path. It comprises of two passive cartridges containing a high technology sponge with the ability of removing dissolved moisture continuously from the oil. The device is capable of reducing moisture levels from 50 ppm to 10 ppm in transformer oils. The continuous extraction of moisture from the oil ensures the removal of the moisture in the paper as well. This process may occur as a result of the diffusion of moisture from the paper insulation to the oil to maintain the associated equilibrium as moisture may be removed from the oil.

4.1.3.3.3 Gas Cushion Oil Preservation

These systems may result in supersaturating of the oil with nitrogen when the temperature of loaded transformers may be decreased rapidly by dropping the load in cold weather and/or during rain. Sargent and Lundy [84] reported that most utilities have replaced the pressure controls that allowed the pressure to increase up to 6 psig before the system started to release the nitrogen into the atmosphere. The pressure controls that were changed released nitrogen at around 3 to 3.5 psig. Sargent and Lundy also reported that for some critical power transformers, the nitrogen system has been replaced with expansion tanks having rubber bags. The reason for this change was due to the following concerns, briefly discussed below.

If the nitrogen cushion designs are not properly maintained, this could result in the failure of the transformer. If the nitrogen bottle becomes empty and not replaced, the pressure in the gas space may become negative causing gas bubbles to evolve from the saturated oil.

4.2 Instrument Transformers

This section focuses on certain maintenance and life extension practices for instrument transformers. There may be very little that could be done to extend the life of the internal components of instrument transformers. The required maintenance and life extension practices differ for different brands of instrument transformers. The following is presented for guidance on such transformers.

4.2.1 Current Transformers

Sargent and Lundy [84] reported that manufacturers of current transformers state in their instruction manuals that oil samples are not to be taken. However, EPRI [20] concluded that the history of current transformer operation indicated that the oil deteriorated in some current transformers, which would mean that the oil should be tested at predetermined intervals. EPRI also concluded that the deterioration would cause an increase in the power factor of the oil particularly at elevated temperatures after being in service for several years. This deterioration is believed to be related to the use of oils that were not suitable for HV application.

EPRI [17] reported that oil power factor's as high as 15% at 100 °C were measured in some experimental high voltage current transformers. The same researcher concluded that if the power factor is as high as this value, it would be difficult to remove all of the contaminated oil from the insulation. Based on the review presented in chapter 2, x wax is known to be a polymer formed by partial discharges in oil-paper systems. EPRI [17] reported that if such polymers formed, it may be impossible to remove the wax from the insulation and that the presence of the wax may contribute to higher partial discharge levels.

EPRI [17] concluded that there is a high probability that the x wax exists in the insulation, if the following conditions exist:

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

4.2.1.1 Free Standing Hairpin Current Transformers

The central current carrying conductor is made in the form of a U. The paper tape is then applied over the U shaped conductor. Conducting layers are applied within the insulation to distribute the voltage from the central U to the ground shield on the outer circumference of the paper.

Sargent and Lundy [84] reported that there have been a number of problems with this configuration. The problems involved quality of work and design. Some of these problems are as follows.

- Ground lead not properly connected to the outer ground layer, which could cause discharge between the ground lead and the shield;
- Excessive oil spaces within the insulation that result in partial discharges in the oil gaps;
- Excessive amounts of adhesive used within the insulation causing partial discharges in the air spaces within the adhesive;
- Discharges at the ends of the shielding layers caused by improper location of the shield layers;
- Poor quality of oil; and
- Some of the shield materials have resulted in conducting particles within the insulation contributing to partial discharges.

There is nothing that can be done to correct any of the problems in service with the possible exception of the oil. Sargent and Lundy [84] suggested possible actions that may be taken. These are discussed below.

Drain and refill the oil, but this may not solve the problem. The oil impregnated in the paper may be an appreciable percentage of the total oil. This oil in the paper may not be removed when the transformer is drained. After some period of time in service the old oil in the paper may contaminate the new oil causing the power factor to increase. Therefore, draining at the site and refilling under vacuum may not solve the problem. Some current transformers may contain approximately 100 gallons of oil.

Draining and refilling at the site may be approached with caution. Current transformers contain many kilograms of paper insulation that may be from 4 to 6 thick depending on the manufacturer and the type of design. Therefore, it may be critical to start the vacuum operations as soon as the oil is drained to prevent moisture re-entering the paper. In fact, the oil may be followed down with dry air or nitrogen to reduce moisture re-entrance. The refilling could be done with hot oil so that the oil gets into the spaces between the paper. Failure may occur if all the air is not removed when refilling operations are performed.

Processing in a workshop may be more effective. The following operations may be performed. Drain the transformer by following the oil down with dry air or nitrogen. Immediately pull vacuum on the current transformer for approximately 8 hours. Fill the transformer with clean degassed and dehumidified oil. As soon as the current transformer is filled, start circulation of the oil from the bottom of the current transformer through an oil processor (where the oil may be filtered, degassed and dehumidified) and back to the top of the current transformer. The oil temperature may be maintained at 60 to 75 °C during the circulation period. This circulation could continue for approximately 4 hours. At the end of the 4 hour period, stop the circulation and perform any operations needed to complete the assembly for operation, including pressurisation of the head, preparation of any bellows in the head, etc. The current transformer may then be tested for partial discharges. If the transformer does not pass this test, it may not be returned to service.

4.2.1.2 Free Standing Pedestal-Type Current Transformers

Sargent and Lundy [84] reported the following with regard to these type of transformers. These transformers have been found to have the same oil problems as the hair-pin type, therefore oil processing may be the same. Some of these current transformers have rubber bellows in the head to allow for oil expansion. After several years in operation, these bellows developed leaks due to deterioration of the rubber by sunlight that enters through the sight glass. According to researcher [84], when oil leaks occurred, it meant that moisture, air and oxygen were entering the unit and the only way a leak could be detected is when oil is seen on the head of the current transformer. Sargent and Lundy also sated that it may be some time before the leak is detected depending on the frequency of station walkdown and the ability to observe a small amount of oil on the head of the current transformer, that may be 15 to 20 feet above the ground. At this stage a considerable amount of oxygen and moisture may have already entered the system. The maintenance and life extension practices suggested by reference [84] in this case are discussed below.

When such leaks are detected, the moisture and oxygen contents of the oil may be checked when intending to replace the rubber. A sample of oil from the top, at least 6 inches below the normal level should be taken. Take a second sample from the bottom of the drain valve. If the moisture content detected is greater than 15 ppm or the oxygen content is greater than 2000 ppm in either sample, draining and refilling the oil is recommended.

When the oil is being drained to change the bellows, ensure that there is still at least 2 inches of oil above the top of the 'donut' structure. Any oil added after the refurbishment must be degassed to less than 1% gas by volume and dehumidified to less than 10 ppm of water. The additional oil should be filled from the top of the current transformer in a manner that will not create bubbles.

4.2.2 Voltage Transformers

The recommended maintenance procedures could be found in the manufacturer's instruction manuals. In general, the maintenance may be similar to that of current transformers, but also has some elements of power transformers. There may be more oil volume in voltage transformers that allow for samples to be taken for analysis.

In cases where the manufacturer's instruction manuals do not contain procedures for testing or maintenance, Sargent and Lundy [84] suggested that oil tests be performed. The oil tests may include gas in oil analysis (to detect partial discharge activity) and moisture in oil content. The presence of moisture could suggest leaking gaskets. If the oil test indicates a high moisture content, power factor tests may be made to check if the insulation is wet.

4.3 Circuit Breakers

4.3.1 Analysis of Various Factors

When the results of a circuit breaker's assessment indicates that there may be a need of extensive maintenance, researcher [84] suggested that the next step be to review other factors and any further options for refurbishment that may include uprating, repair or modifications to extend the units life. These factors reported by Sargent and Lundy [84] are discussed briefly below, and further options under subsection 4.3.2.

Manufacturer's recommendations. The manufacturer's recommendations on the availability of modification and uprating kits may be reviewed. When a manufacturer has modification and uprating kits available for an older circuit breaker, confidence in terms of improving the unit's reliability may be restored.

Availability of reliable spare parts at reasonable cost. Most breaker manufacturers written manuals may be clear with regard to replacement instructions of certain components or parts. Some manufacturers may not provide enough in-depth instructions to enable users to make repairs adequately or to refurbish the breaker without extensive research into methods, techniques, tools and parts or materials.

There are some manufacturers that may attempt to replace components in a modular way as wear occurs, e.g., a complete blast valve or closing valve. A user may interpret this approach as the replacement of individual pieces. In the case of older breakers the parts may be locked together in ways that discourage attempts at disassembly, because in most instances the attempt could cause irreparable damage to the parts, requiring replacement of the entire component anyway.

In many cases, special tools were designed to disassemble (without destroying) the interlocked parts. Methods and procedures have been created to enable rebuilds to be accomplished in a manner that could be cost effective. Quality vendors may be selected for the manufacturing of parts and may in some cases if possible perform the rebuild work under the direction and supervision of the utility staff.

This method allows refurbishment of breakers that otherwise could have been replaced because of extremely high costs to rebuild. Utilizing the manufacturer's spare parts, could be the most economically viable option instead of replacement. There may be a high probability that a breaker could be far more trouble free after rebuild, because replacement parts are made of higher quality materials than when the breaker was manufactured.

4.3.2 Review of Options

Circuit breaker technology has advanced considerably to the point where newer SF_6 puffer or self-blast breakers may often provide improved service at reduced maintenance cost. This technology may be considered in the analysis of all the factors in a judgement decision on repair, refurbishment or replacement.

It may be possible to refurbish or uprate older breakers with acceptable service histories. As power networks continue to expand, it may be possible for older circuit breakers to be used at less critical locations where their service duty could be less severe. In such cases, safety to personnel and to the substation must be taken into consideration.

Can the older, refurbished breaker be made reliable for the foreseeable future? Consider the following example that illustrates how the major factors may be used in the analysis of whether to repair, refurbish or replace a specific circuit breaker.

4.3.2.1 Repair

Consider repairing the breakers when (a) the modification kits to improve the circuit breaker's operation may be available and (b) uprating kits may improve the circuit breaker's rating to more closely match that of a new breaker.

4.3.2.2 Refurbish

The condition assessment may provide an idea of the cost to repair, refurbish or uprate the breaker. Refurbishment could reduce maintenance costs initially, but it may be prudent to assume that maintenance costs could rise drastically in the future in comparison to having a new circuit breaker.

4.3.2.3 Replace

When replacing a circuit breaker with a new unit, costs may be obtained for a new SF_6 puffer or self-blast circuit breaker. Besides the cost of the new breaker itself, the following possible costs summarised below may be considered.

Removal of the existing circuit breaker. However, if there are other breakers of the same type and rating, this breaker may be a valuable asset as a source of spare parts.

The present foundation may not be adequate. If this may the situation, then it could be replaced or altered.

Associated isolators, bus arrangement and clamps. These items of equipment may have to be altered or replaced to accommodate the new breaker?

New control and signal cabling may have to be installed and tested. As a result, applications and labour costs could be incurred.

These considerations may be examined carefully and costs compared for the various options.

4.4 Conclusions

The life of a power transformer may be substantially extended by controlling the characteristics of the internal system i.e. controlling the oxygen and moisture contents. These characteristics may be controlled by employing on-line dry-out systems and retrofitting rubber bags. On-line dry-out systems may be extremely effective when installed on new transformers such that the level of the moisture in the oil and paper insulating system is maintained. When fitted on older or more aged transformers the moisture content in the insulating system maybe reduced or maintained as well. Care should be taken when installing the rubber bags in the conservator tanks. If the bag is ruptured or lacerated during installation, the benefit of the measure taken to extend the life of the transformer would be defeated. By improving the utilization of the transformer capacity the condition of the paper insulation can be maintained.

There is very little that can be done to extend the life of the internal components of instrument transformers. However, during station walk downs or inspections, it is important to check for oil leaks and hot connections. When oil leaks are identified bellows and gaskets may have to be changed. After the installation of the new bellows and gaskets, care should be taken during the oil draining and refilling process (section 4.2.1.1). The ingress of moisture and the introduction air bubbles during refilling may contribute to the possible failure of the instrument transformer rather than extending life.

With regard to extending the life of circuit breakers, various factors need to be taken into consideration. These are inspection, maintenance, service history, failure of similar breakers in service, and the availability of uprating and modification kits. However, the decision to modify or uprate the breaker must be financially justified.

CHAPTER 5: ELECTRICAL BREAKDOWN AND PARTIAL DISCHARGES IN LIQUIDS

5.1 Introduction

This phenomenon may be described as an electrical pulse or discharge, in a gas-filled void or on a dielectric surface of a solid or liquid insulation, which partially bridges the gap between two high potentials. There are several possible causes of partial discharges, but generally they may occur as a result of an insulation discontinuity creating a region of high electrical stress. The localised dissipation of energy may cause insulation damage and breakdown products. The resultant damage may extend the partial discharge process and cause rapid deterioration. In the case were PD activity may be intense, this could most likely lead to catastrophic failure.

Partial discharges are recognised as having a potentially significant impact upon the life of most types of high voltage insulation systems. Within electrical equipment, failure modes may relate to particle contamination, bubble generation and partial discharges. The breakdown mechanisms are briefly reviewed. In order to examine the electrical stress limitations of insulating liquids an overview of the breakdown mechanism is presented as well.

5.2 Literature Review

The electrical insulating properties of materials are degraded under the influence of partial discharges. As this degradation mechanism may lead to eventual failure and even the catastrophic loss of equipment, much effort has been devoted to the development of detection methods [14,87-92]. Other aspects related to measurement and interpretation [87,93-96], localisation techniques [89,91,95,97-101] and acoustic wave propagation within the confines of the transformer tank [60,90,91] have been researched and documented. In order to generate discharges during experimentation, researchers have utilised various electrode/model geometries that closely represent defects within transformers [60,94,95,102].

When the results of a periodic gas-in-oil analysis indicate a rise in key fault gases such as hydrogen or acetylene, discharge detection techniques are employed to assess the severity. Based on the assessment, corrective action is taken to prevent possible failure. On-line single gas and multi-gas fault analysers have been developed with the intention of enhancing the diagnostic process [103,104]. Earlier detection and screening of internally developing faults in power transformers is possible. The theoretical and mathematical aspects of the breakdown mechanism in solid, liquid and gas dielectrics are detailed in reference [105].

5.2.1 Detection Methods

The current methods utilized for the detection of partial discharges fall into three general categories, which may be summarized as follows:

5.2.1.1 Electrical Detection

Partial discharges cause high frequency, low amplitude perturbations in the applied voltage and current waveforms. Electrical discharge detection techniques are intended to detect these perturbations. At least two standard circuits exist (as well as several variations) which enable detection of either Radio Interference Voltage (RIV) or PD level (pico-coulombs) associated with the phenomenon [87,88]. Unfortunately these techniques are not very effective, typically as a result of excessive interference signals (electromagnetic interference) or excessive test object capacitance. A further limitation of this technique is that it is generally not possible to indicate the location of a detected partial discharge source.

5.2.1.2 Chemical Detection

In a transformer the insulation is primarily oil impregnated cellulose and it is usually submerged in a dielectric liquid. In the majority of cases the liquid is mineral oil. Consequently, partial discharges cause the formation of degradation products from both the effected insulation and oil. These products are principally gaseous and are absorbed into the surrounding volume of oil. Above this oil is usually a blanket of nitrogen and those gases absorbed in the oil that would eventually appear in the head space as they reach an equilibrium situation with the liquid.

Detection of partial discharges then involves the analysis of oil for specific absorbed gases. The presence of hydrogen and/or acetylene gas is an indication of PD activity and arcing respectively [14]. This technique is free of the noise associated with electrical detection methods. This is an accepted and recognised technique in the field.

Problems associated with chemical methods are due to the fact that a PD source evolves a small volume of gas as compared to the large volume of oil present in the system. Consequently there can be a long time delay between the initiation of a PD source and the evolution of enough gas for it to be detectable. For this reason the information tends to be historic. Oil analysis would indicate that a problem exists, but does not allow for an evaluation of the instantaneous condition of a transformer. As the gas and oil samples are taken from large reservoirs, there is also little information regarding the physical location of the source.

5.2.1.3 Acoustic Emission Sensing

Partial discharges are pulse like phenomenon, which cause mechanical stress waves to exist in the material involved. These stress waves propagate through the surrounding transformer oil and can be detected by sensors attached to the tank wall. Much work has been done in the detection of these high frequency signals [89-92] but transformers are mechanically noisy, there has been considerable difficulty in differentiating between partial discharge produced signals and others.

One of the advantages of the acoustic method is its ability to locate a source provided its presence can first be detected. The success of this method is based on the sensitivity of the acoustic sensor [91]. This method is less sensitive for sources inside the winding structure [92].

5.2.2 Measurement and Interpretation

The technique of measuring and analysing partial discharges occurring in insulation structures or assemblies can be used to detect weaknesses before they lead to catastrophic failure. In a transformer, partial discharges cause transient changes of voltage to earth at every available winding terminal.

Commercially available detectors are used to detect radio interference voltage, or radio influence voltage [87], or measure the intensity of partial discharges expressed in pico-coulombs [88]. Partial discharge magnitude expressed in pico-coulombs is now established in IEC and various other documents [93-96]. There exists well-documented literature [87,95,96] on partial discharge patterns, their evaluation of results and determination of origin, etc, to assist practitioners in the interpretation of results.

5.2.3 Localisation Techniques

The possibility of partial discharge location determination is a major features of acoustic discharge detection. Location can be based on either measurement of the time of signal arrival at a sensor [89,91,95,97-101] or on the measurement of a signal level [88], provided that the discharge source is at a fixed position. In practical situations, localisation is based on time-of-flight measurements requiring two or more simultaneous measurements in order to facilitate triangulation to determine the source location. With the use of two or three sensors (all-acoustic system) an accuracy margin of ± 10 cm is possible [95].

Locating the position of a discharge is also possible when used in conjunction with electrical sensing systems. Here an electrically detected pulse is recorded on one channel of the measurement equipment and the outputs of several acoustic sensors recorded on other channels. This technique is often used at a factory or laboratory due to the problems inherent in electrical detection methods. It has been reported that a precision better than ± 5 cm may be obtained with the use of a combined electrical and acoustic system [91]. By employing advanced signal processing techniques to this system, the accuracy can be improved by 60% [99]. Provided that it may be possible to differentiate the partial discharge signals from other noises, the time delays associated with sensor locations may be used to calculate the source location.

5.2.4 Acoustic Wave Propagation

Acoustic signals produced by a partial discharge can be divided into two waves i.e. longitudinal and shear waves. In power transformers, the mediums in concern are liquid (oil) and solid (steel wall of tank). The speed of the longitudinal wave in oil is approximately 1400 m/s [99]. Corrections to speed of sound for temperature and moisture content are not generally made to increase accuracy because the uncertainties due to material propagation are usually much larger [101]. However, in the steel wall of the transformer tank, both longitudinal and shear waves propagate with velocities of 5200 m/s and 3200 m/s respectively [101].

5.2.5 Discharge Inducing Defects – Model Geometries

In order to analyse discharge activity patterns and other important characteristics, researchers have performed experimental investigations based on a range of electrode or model geometries [95]. These geometries represent various types of discharge defects, which can be present in oil filled transformers. Discharge sources have also been activated under oil by the use of simple gapped electrode arrangements such as a point-to-hemisphere [94], sphere-to-sphere [60] and point-to-plane [102]. The point is usually a stainless steel needle with a tip radius ranging from 20 to 50 microns and a sphere diameter ranging from 12.5 to 25mm.

5.2.6 On-Line Fault Gas Monitoring

Analyzing fault gases to diagnose problems in power transformers is universally accepted and has been used for many years. Dissolved Gas Analysis remains a key technique in establishing fault mechanisms. The introduction of in-situ on-line analysis brings new possibilities. Real-time gassing, including trends, can be associated with specific events, even on a daily basis, and yield information closely related to the unit's problems. On-line gas analysis offers the ability to make an assessment of the transformers operating condition close to real time.

Several on-line gas detection devices have been evaluated to establish their performance [103]. Based on this evaluation, one monitoring system (Hydran 201i) has proven to be reliable in the field. This system monitors only one key fault gas (Hydrogen) [104] – necessary for detecting discharges in transformers. The manufacturer of Hydran specifies the analytical performance in terms of accuracy to be ±10% of reading ±25 ppm of dissolved hydrogen gas.

5.3 Breakdown in Insulating Liquids

There are two main types of insulating liquids that are commonly used in high voltage applications. These are petroleum and synthetic based insulating oils [105]. Other oils used are synthetic hydrocarbons and halogenated hydrocarbons. For very high temperature applications silicone oils and fluorinated hydrocarbons are generally used.

5.3.1 Petroleum Oils

Petroleum insulating oils are mainly used in transformers (oil-immersed), circuit breakers, capacitors, bushings and power cables. In transformers the oil impregnates the paper insulation and provides insulation between the live and grounded parts. The oil is also used for cooling by convection.

The oils are obtained by fractional distillation of crude oil. The oils are divided into two main classes based on their chemical compositions.

- Paraffin base (or methane series) characterised by the formulae C_nH_{2n+2} [106]
  - Due to oxygen in the air the paraffin-based hydrocarbons are liable to deteriorate by oxidation [106].

- Naphthene base, characterised by the chemical formulae C_nH_{2n} [106]
  - The naphthene hydrocarbons are more stable since they have a higher oxidation resistance [106].

Before application, the oil has to be purified, dried and free of acid (acid increases the oil conductivity). Highly purified oils are of lighter colour while oxidised oils are darker. Oxidised oil forms sludge that settles on the windings and hampers effective cooling and results in overheating and ageing of the solid insulation.

5.3.2 Synthetic Oils

Synthetic oils are obtained by chlorinating diphenyl ($C_{12}H_{10}$) - a mixture of diphenyl and various degrees of chlorination e.g. $C_{12}H_5C_{15}$. Such dielectrics commonly known as askarels, are mainly used in capacitors and special transformers [106]. The askarels have a higher viscosity than transformer oil and are non-flammable. They have a higher breakdown strength. Use of askarels is discouraged because they are highly toxic and difficult to dispose.

Silicone liquids have also been developed for use in capacitors and transformers. They have a lower viscosity than transformer oil and a higher flash point.

5.3.3 Breakdown Process

The breakdown mechanism in insulating liquids is strongly dependent on the purity of the liquid. Liquid purity may be categorised as follows:

(a) Contaminated liquids - contain dissolved water and solid particles.

(b) Technically or commercially pure liquids – these liquids are almost free of or contain very small amounts of moisture and solid particles.

(c) Pure (or highly purified) liquids - completely free from moisture, solid particles and any dissolved gases.

Breakdown in commercially pure and contaminated liquids is a result of foreign substances (dissolved gases, metallic/fibrous particles and moisture) contained in the liquid. In pure liquids, breakdown is thought to be 'electronic' in nature. It is assumed that electrons are released from the cathode into the liquid by either a field emission or by the field enhancement thermionic effect [105].

5.3.3.1 Technically Pure Liquids

Breakdown in these liquids occurs mainly due to dissolved water and gases. The presence of moisture in the oil greatly reduces the breakdown strength. Discharges are initiated in the water globules because of the lower permittivity of the water compared to the insulating liquid. The presence of dissolved gases leads to breakdown due to ionisation in the gas bubbles.

The liquid may contain bubbles due to:

- The presence of dissolved gases e.g. air.
- Microscopic particles or electrode surface imperfections.
- Local heating (places of higher conductivity) or corona discharges.
- Dissociation of products by electron collisions give rise to gaseous products.

When the field in the bubble becomes equal to the gaseous ionisation field (i.e. in the bubble), discharges may occur leading to liquid decomposition and eventual breakdown. The equation for the bubble breakdown field is given by [105]

$$E_{ob} = \frac{1}{(\epsilon_1 - \epsilon_2)} \left\{ \frac{2\pi\sigma(2\epsilon_1 + \epsilon_2)}{r} \left[\frac{\pi}{4} \sqrt{\left(\frac{V_b}{2rE_0} \right) - 1} \right] \right\}^{\frac{1}{2}} \qquad \text{.......}\mathbf{5.1}$$

Where,	E_{ob}	=	bubble breakdown field
	σ	=	liquid surface tension
	ε_1	=	liquid permittivity
	ε_2	=	bubble permittivity
	r	=	initial bubble radius
	V_b	=	voltage drop across the bubble
	E_0	=	field in the liquid in absence of the bubble

The expression (equation 5.1) indicates that in a given liquid, the critical field is mainly dependent on the initial size of the bubble, which is affected by external pressure and temperature [105].

5.3.3.2 Highly Purified Liquids

In practical engineering applications high levels of purity are difficult to maintain. Breakdown is thought to be mainly due to collisional ionisation initiated by electrons released from the cathode by field emission and field enhanced thermionic emission. The field emission is enhanced (locally) by positive ions returning to the cathode. When an electron is released into the liquid, it acquires energy from the applied field. It is then accelerated and ionises the liquid molecules, setting-up avalanches.

The condition for avalanches to be initiated is when [105]

$$eE\lambda = ph\nu \qquad \text{........}\mathbf{5.2}$$

Where,	e	=	electronic charge (1.6×10^{-19} C)
	E	=	applied field
	k	=	electron mean free path
	$h\nu$	=	quantum energy lost in ionising the molecule
	p	=	an arbitrary constant

Table 5.1 below depicts the typical breakdown strength of highly purified fluids.

Liquid	Strength (MV/cm)
Hexane	1.1 – 1.3
Benzene	1.1
Good oil	1.0 – 4.0
Silicone	1.0 – 1.2
Oxygen	2.4
Nitrogen	1.6 – 1.88

Table 5.1: Dielectric strengths of highly purified fluids [105].

The intrinsic breakdown strength of 1×10^8 V/m or more tends to indicate that partial discharges within the transformer would generally be related to voids or bubbles.

5.4 Mechanism of Hydrogen Generation

Transformer oil decomposes at elevated temperatures and emit hydrocarbons such as methane, ethane and ethylene. Ethylene is produced when the heat in the discharge is above 150 °C [103]. At much higher temperatures acetylene is also produced, usually from arcing (high intensity discharges). Hydrogen gas is not usually detected below 250 to 300 °C [103]. Predominantly hydrogen generation with or without some hydrocarbons, particularly methane, is generally associated with corona activity. It is believed that in a strong electric field, the hydrogen atoms are stripped off from the hydrocarbon chain of the oil molecules. Such activity may be influenced by the oil-metal/oil-paper interface [103].

5.5 Partial Discharge Sources

Partial discharges may result from problems associated with the transformer design, construction, maintenance or general ageing effects. Insulation defects or potential sources that may lead to initiation of PD in transformers include [95]:

- *Delamination* – may occur where two or more pieces of pressboard are glued together to form thicker barriers.

- *Voids* – may occur in glue, connections with enamelled thread or in places with insufficient impregnation.

- *Gas Bubbles* – may be created by discharges that cause vaporization of oil and moisture.

- *Free particles* – may be present due to the manufacturing process of the transformer.

- *Fixed metallic particles* – these may be found in "wood details" or fixed in paper on windings.
- *Moisture* – formed by the ageing of the transformer or may be introduced into the system during the manufacturing process.
- *Bad connections of electrostatic shields* – due to the large capacitance involved, these discharges are normally large.
- *Static electrification* – results from excessive velocities of cooling causes charges to be deposited in certain areas causing electric field enhancement.
- *Surface tracking* – occurs on barrier surfaces on the boundary between different insulating materials.

5.6 Electrical Measurement of Partial Discharges

In a transformer, partial discharges cause transient changes of voltage to earth at every available winding terminal. The electric pulse generated at every terminal due to the voltage collapse at the discharge site can be measured using techniques set out in the relevant standards [93]. A corona detector measures the component of the pulse in the frequency range of 20 kHz to 300 kHz [93]. Problems of harmonic and radiated interference are thus avoided. Precautions must be taken to eliminate interference from discharge sources in the surrounding area, the power supply source and the terminal bushings [94].

The pulses are displayed on an ellipse, which represents the power cycle. This visual display provides information regarding the magnitude and polarity of the pulse as well as the position of the pulses in the power cycle.

The actual charge transferred at the location of a partial discharge cannot be measured directly. The preferred measure of the intensity of a partial discharge is the apparent charge 'q' as defined in IEC Publication 270 [93]. The apparent charge that surrounds the discharge site. is not equal to the true magnitude at the discharge site but is less, depending upon the capacitance's of the discharge site and the insulation

Before any measurements are taken, the measuring circuit must be calibrated. The measuring equipment is connected to the terminals by matched coaxial cables. The measuring circuit should always present an almost constant impedance to the test terminals. This is achieved by matching the cable impedance to that of the input impedance of the measuring instrument.

When measuring partial discharges between the line terminal of a winding and the earthed tank, a measuring impedance Z_m is connected between the bushing tap and the earthed flange. Calibration of the measuring circuit is carried out by injecting a series of known charges at the terminals and measuring its magnitude at the detector. Subsequent measurements can then take into account the attenuation of the measurement circuit.

Figure 5.1 shows a measurement and calibration circuit of this type where the calibration circuit consists of a pulse generator and a series capacitor C_0 of approximately 50 pF [93]. Where the calibration terminals present a capacitance much greater than C_0 the injected charge will be $q_0 = U_0{*}C_0$, where U_0 is the voltage step.

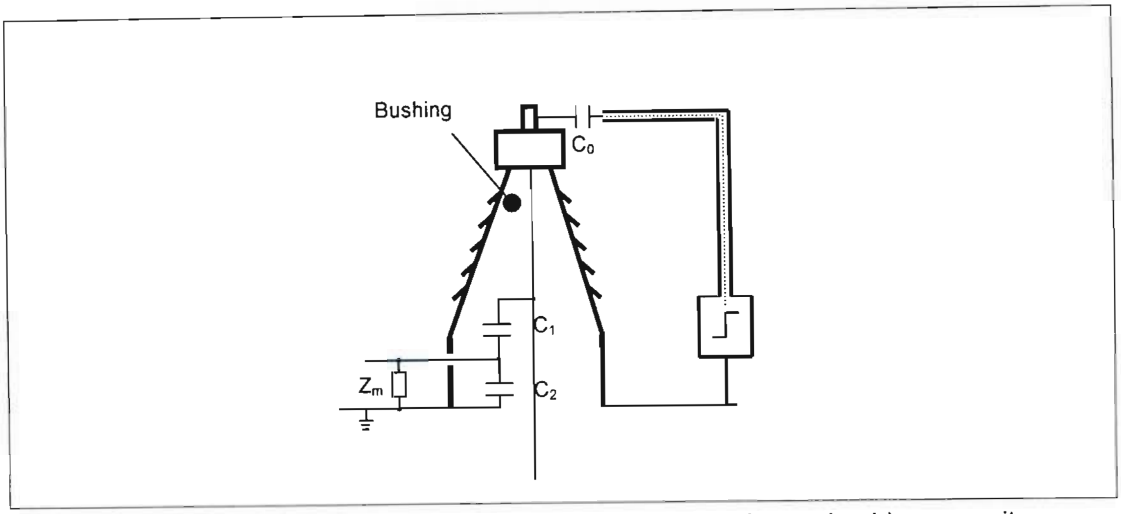

Figure 5.1: Measurement and calibration circuits using a condenser bushing capacitance tap [93].

Figure 5.2 illustrates an arrangement where a bushing tapping is not available. The measuring impedance is connected to the HV terminal of a partial discharge free HV coupling capacitor C. Commercial partial discharge detectors must be calibrated in terms of the method specified in IEC 270 [93]. These detectors also have a built-in impedance matching functionality. There are two types of measuring instruments in use: (a) narrow-band and (b) wide-band.

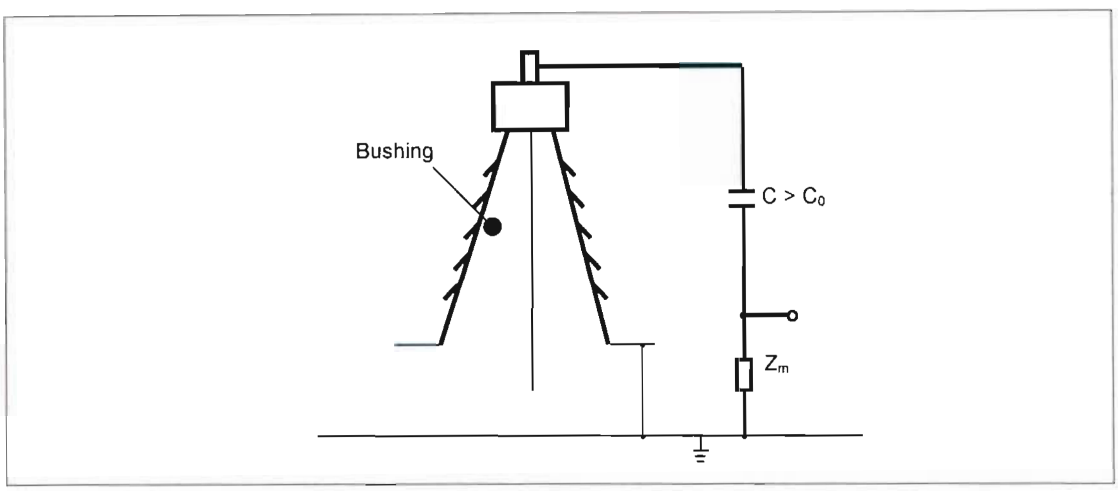

Figure 5.2: Calibration and measurement circuits using a HV coupling capacitor [93].

Measurements are made for the following reasons [93]:

- To verify that the test object of concern does not exhibit PD greater than a specified magnitude, at a specified voltage;
- To determine the voltage amplitude at which PD inception and extinction occurs;

- To determine the magnitude of the specified discharge quantity at a specified voltage.

Guidelines on discharge activity in power transformers have been suggested [62]. These are:

- 10 – 50 pC may be regarded as "normal"
- < 500 pC = normal deterioration (ageing insulation)
- > 500 pC = questionable
- > 1000 pC = defective

5.6.1 Recognition of Corona in Oil

In oil, corona produces discharges symmetrically displaced about the voltage peaks on both half cycles of the power frequency waveform [90]. The different patterns that are obtainable with electrical detection techniques are depicted in figure 5.3.

The discharges on one half cycle are greater in magnitude and the larger discharges may have equal magnitude, or vary in magnitude (figure 5.3(a) and (b) respectively). Erratic discharges may appear at a voltage below the inception voltage with the number of discharges increasing rapidly above the inception voltage. Discharges with a much larger magnitude begin at first.

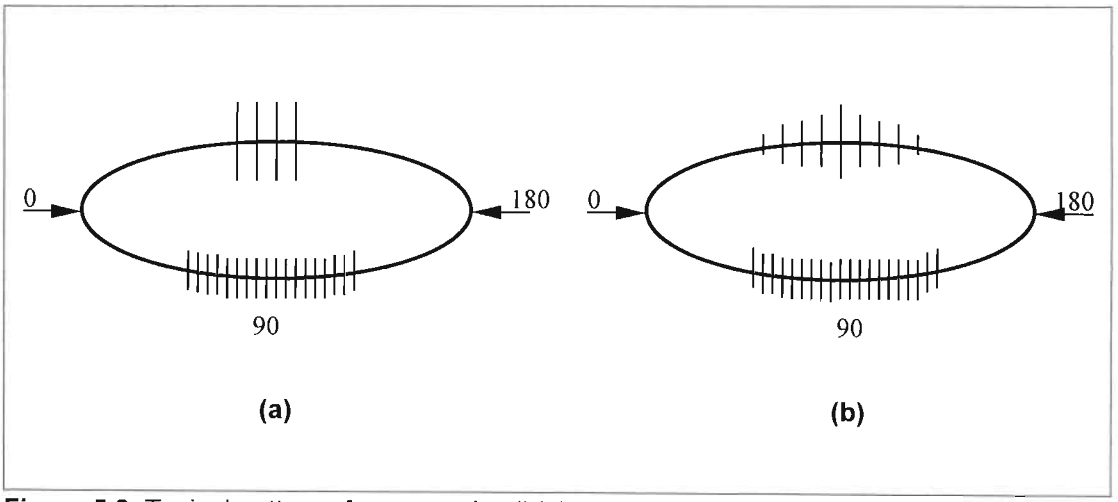

Figure 5.3: Typical patterns for corona in oil (a) and (b) [90].

5.7 Acoustic Detection of Partial Discharges

5.7.1 Definitions

Couplant:

A substance used at the structure-to-sensor interface to improve the transmission of acoustic energy across the interface during acoustic emission monitoring. All liquids and many gels meet this criterion. Couplants commonly used are glycerine and silicone grease.

Acoustic impedance:

The decisive factor for determining reflection and transmission properties when passing from one acoustic medium to another. The acoustic impedance is denoted Z and defined as (density) x (propagation velocity), Z = r v.

Sensor, Transducer or Sensing transducer:

A detection device, generally piezo-electric, that transforms the particle motion produced by a shock wave into an electrical signal.

Attenuation:

Acoustic waves attenuate as they travel through the media. Attenuation is due to a combination of wave diffusion and losses due to molecular collisions, as well as reflection/ transmission at media interfaces.

Magnetostriction Noise:

Noise associated with the flipping of magnetic domains in the core of a transformer; generally occurs at twice the power frequency. The amplitude of this signal as measured during each half cycle is about the same.

Critical angle:

The largest incidence angle (from normal) for which a wave can enter a medium with a higher propagation velocity. This angle is given by sin (f)=V_{in}/V_{out}; for an oil-steel interface. V_{in} and V_{out} corresponds to the velocity of sound in oil and steel respectively.

Decibels:

The decibel scale is a logarithmic scale commonly used to express sound pressure or energy levels. The conversion between decibel level and linear scale is [101]:

$$\text{Sound Pressure Level (dB)} = 20 \log (P/P_{ref}),$$

where the reference pressure, P_{ref}, is typically 1 Pascal. Sound energy, which is proportional to the square of the pressure, increases by 26% for each decibel increase [101]. This means that the sound energy doubles for each 3-dB increase [101].

where the reference pressure, P_{ref}, is typically 1 Pascal. Sound energy, which is proportional to the square of the pressure, increases by 26% for each decibel increase [101]. This means that the sound energy doubles for each 3-dB increase [101].

Diffraction:

The distortion of an acoustic wave front by an object in the sound field. It is characterized by the "bending" of sound waves around the obstruction.

Direct acoustic (oil-borne) path:

Propagation of the PD acoustic signal through the oil directly to the sensor located on the tank wall.

Longitudinal waves or Pressure waves:

The particle motion in the medium is purely in the direction of propagation. Normally this is the only kind of wave that propagates in liquids and gases.

Reflection:

Scattering of propagating waves back in the direction of origin by an obstruction or discontinuity in the propagation path.

Sensors:

Damped acoustic emission piezo-electric sensors were used in the experiment. These were mounted externally on the transformer tank.

Structure-borne path:

Propagation of the PD acoustic signal through the transformer structure.

Transverse or Shear waves:

The particle motion is perpendicular to propagation direction similar to a vibrating string. They occur only in solids such as cellulose.

5.7.2 Introduction

A partial discharge results in a localized, nearly instantaneous release of energy that acts as a point source for acoustic waves [88].

"A discharge creates a disturbance that sets a mechanical wave that propagates through the insulation medium surrounding it. The disturbance causes rarefaction and compression of the surrounding medium, resulting in changes of density and displacement of molecules within the medium. This is called '*particle displacement*' where a 'particle' refers to a small volume of the bulk material" [90].

5.7.3 Acoustic Signal Transmission Characteristics

Active PD sources in oil-filled transformers produce acoustic emissions that propagate away from the source in all directions [90]. The acoustic signals travel through pressboard, clamps and other intervening material to eventually arrive at the transformer tank wall. The distance travelled by the acoustic signal may be approximated as follows [88]:

Distance travelled = acoustic wave speed x *time* **5.3**

The principle of acoustic PD source location assumes that the acoustic signal travels a direct, straight-line route from the source to the sensor [98]. Unfortunately, this is not always the case, as the acoustic field inside the tank is very complex due to wave reflection, diffraction and transmission [98]. For example, if there is an obstruction blocking the line of sight between the source and the sensor location, the sound may (a) Travel around the obstruction - this leads to a longer propagation time that would imply a greater distance between the source and the sensor or (b) The sound may travel directly through the obstruction at a wave speed that is faster than its speed through oil. The resulting arrival time would be earlier, which would imply a shorter distance between the source and the sensor.

Structure-borne propagation paths within the tank wall present a further technical challenge. As the acoustic wave hits the tank wall, its frequency characteristics remain the same, but its mode of propagation, and the speed at which it propagates, does change [107]. Take the example in figure 5.4 in which the sensor is located on the far side of the tank, away from the source.

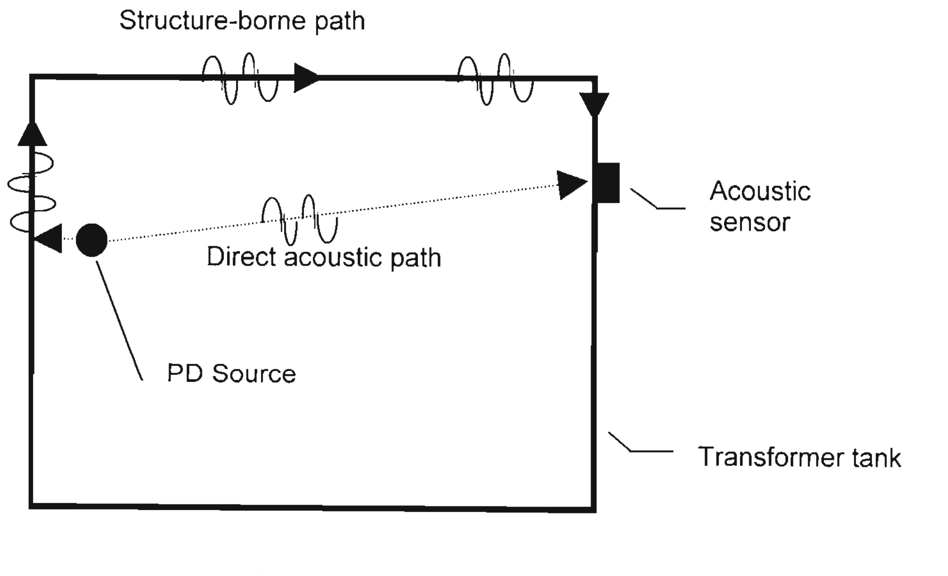

Figure 5.4: Illustration of alternate propagation paths for the acoustic partial discharge signal.

Acoustic waves hitting the tank wall will set up an alternate propagation path via the steel tank to the sensor on the other side [107]. The wave speed in steel is faster than in the oil and the wave travelling this structure-borne path may arrive at the sensor earlier than the wave travelling the direct acoustic path [107]. If the distance calculations were based on the arrival time of the structure-borne wave, with the wave speed in oil, this would imply a shorter distance between the source and the sensor when compared to the actual distance the signal travelled. It is crucial that distance calculations are based on the direct acoustic path. Corrections to speed of sound for temperature and moisture content are not generally made to increase accuracy because the uncertainties due to material propagation are usually much larger [101].

5.7.4 Acoustic Signal Propagation

Another way to distinguish the structure-born waves from the oil-borne waves is to look at the mode of vibration [107]. Fluids, such as oil will only support pressure waves. Solids, such as steel can support many types of wave motion. A PD event creates a spherical pressure wave in the oil similar to that of a point source generating longitudinal/pressure waves only, travelling at a velocity of approximately *1400 m/s* ($V_{l(Oil)}$) [99]. Pressure waves in the oil become both pressure waves and shear waves in the tank wall [107].

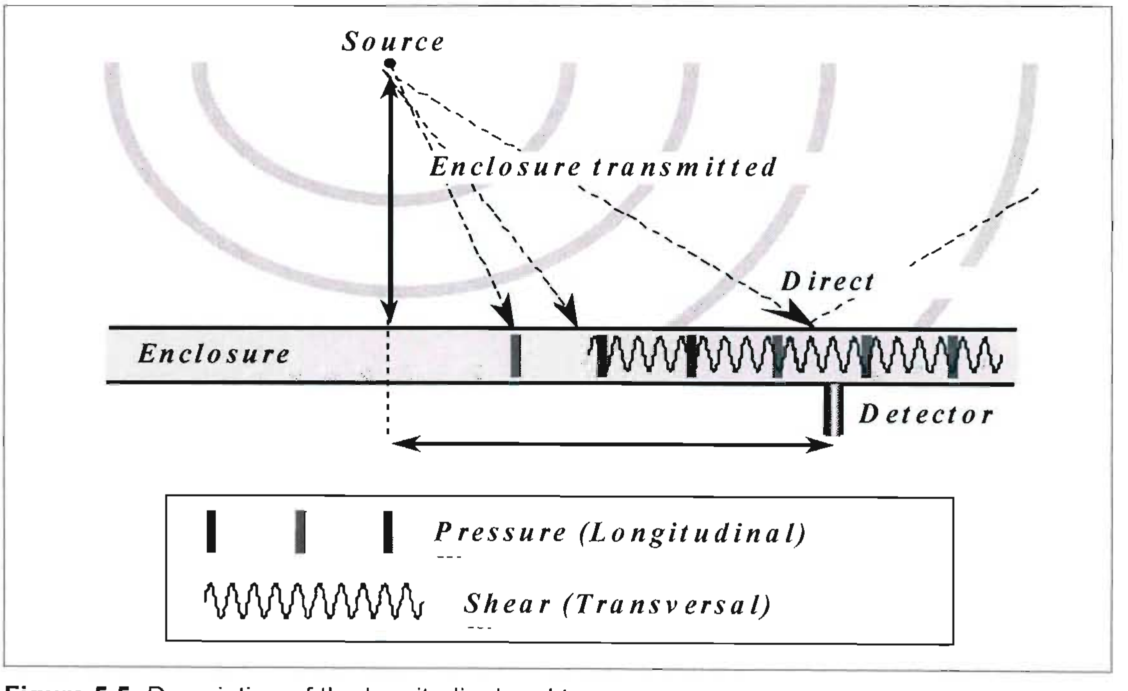

Figure 5.5: Description of the longitudinal and transverse waves.

Two wave fronts (longitudinal and shear) will be seen in the steel plate enclosure as illustrated in figure 5.5. In a steel plate the longitudinal ($V_{l(Steel)}$) and transversal ($V_{s(Steel)}$) wave velocities are approximately *5200* and *3200 m/s* respectively [101].

These waves hit the transformer wall at different incident angles (θ). Two critical angles θ_l and θ_s are formed according to 'isotropic acoustic Snell's law' [107] since $V_{l(Steel)}$ and $V_{s(Steel)}$ are greater than $V_{l(Oil)}$.

$$\theta_l = \sin^{-1}(V_{l(Oil)} / V_{l(Steel)}) \sim 13{,}7^{\circ}$$
$$\theta_s = \sin^{-1}(V_{l(Oil)}/ V_{s(Steel)}) \sim 25{,}9^{\circ}$$

The tank surface can thus be divided into three regions. Both the shear and longitudinal waves can be transmitted for $\theta < \theta_l$. Where $\theta_l < \theta < \theta_s$, only shear waves are transmitted. In the region $\theta > \theta_s$ the incident is completely reflected [107].

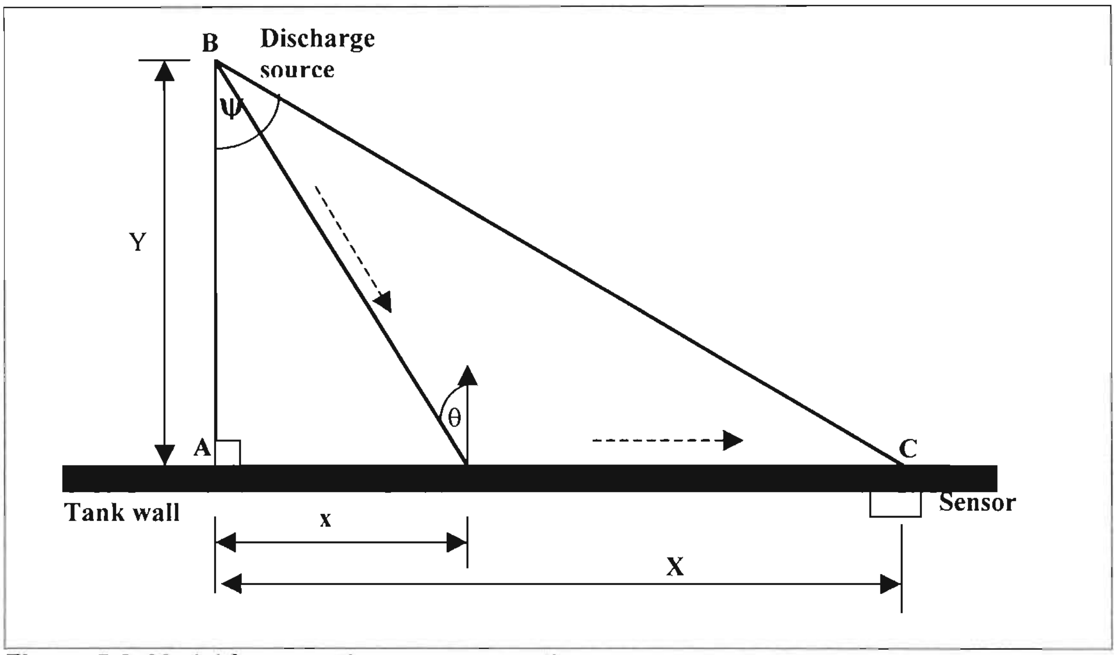

Figure 5.6: Model for acoustic wave propagation.

The shear and the longitudinal waves propagate internally along the wall due to multiple reflections at the interfaces of the steel and the oil, shown in figure 5.5. It can be seen from figure 5.6 that an angle **ψ** is formed between the sensor and the source **B**. It is obvious to find a general solution for the quickest path, however the solution should correspond to a path with an incident angle **θ** not exceeding **α**. The transmission time (t) can thus be found by [107]:

$$t = \frac{\sqrt{(x^2 + Y^2)}}{v_0} + \frac{(X - x)}{v_m} \qquad \text{.......5.4}$$

where $v_o = V_{l(oil)}$ and $v_m = V_{l(steel)}$ or $V_{s(steel)}$. The transmission time of the shortest (t_s) path corresponds to the point where $\theta = \alpha = v_o / v_m$.

$$t_s = \frac{Y}{v_0 \cdot \cos(\alpha)} + \frac{X - \tan(\alpha)}{v_m} \qquad \text{.......5.5}$$

However this is only true if $\alpha < \psi$, else the time for the direct path (t_d) is found using $\theta = \psi$.

$$t_d = \frac{\sqrt{(X^2 + Y^2)}}{v_0} \qquad \text{.......5.6}$$

5.7.5 Signal Absorption and Reflection

When dealing with acoustic signals, 'acoustic impedance' and 'signal intensity' are two important units. The ratio between the sound pressure and the velocity of the particle is called the 'specific acoustic impedance, z which is analogous to electrical impedance Z is given by:

$$\vec{z} = \frac{\vec{p}}{\vec{v}} \qquad \text{.......5.7}$$

where p = peak pressure and v = peak velocity. In the case of planar waves, this acoustic impedance becomes a scalar quantity ($z = p_0 c$), which is then referred to as the characteristic impedance, Z_c, of the material [90]. Note that the relationship between the propagation of the wave and the individual particle movement is determined by the parameters of the material.

The time average of the acoustic energy flow through a specific medium is the 'acoustic intensity', I, expressed below in terms of its peak pressure and velocity, p and V respectively, and its characteristic impedance [90]:

$$I = \overline{\vec{v}\vec{p}} = -\frac{p}{2p_0 c} = \frac{Vp_0 c}{2} \qquad \text{...... .5.8}$$

Several mechanisms e.g. spreading of the acoustic wave, acoustic absorption and scattering of the wave front cause the intensity of a wave to decrease as a function of the distance from the source, as it propagates through a medium [90]. For lossless media, the intensity of a spherical wave decreases inversely to the area of the wave front, and in a cylindrical wave the intensity of the wave decreases inversely with the distance from the source. This reduction in intensity is termed 'spatial attenuation'.

When an acoustic wave propagates from one medium to another, the wave is partly refracted and the rest is reflected. The energy of the transmitted wave is thus reduced [90]. The intensity of the transmitted wave depends on the transmission coefficient, α, of the two media given by the term [90]:

$$\alpha_{Transmission} = \frac{I_t}{I_i} = \frac{4Z_1 Z_2}{(Z_1 + Z_2)^2} \qquad \text{.......5.9}$$

where I_t and I_i are the transmitted and incident wave intensities and Z_1 and Z_2 the acoustic impedances of the two media. Large differences of the acoustic impedances of the two media result in a small portion of the incident wave being transmitted. For a given pressure wave the transmission coefficient between the oil and the steel is 0.11, while the transmission coefficient between air and steel is 0.0016 [90]. The signal is thus greatly attenuated.

When the incident wave strikes the boundary obliquely, the angle of the transmitted wave is governed by the required coincidence between the incident and transmitted wave along the interface [90]. Snell's Law describes this as:

$$\sin(\frac{\phi_t}{c_t}) = \sin(\frac{\phi_i}{c_i}) \qquad \text{.......5.10}$$

5.7.6 Locating the Source of the Discharge

Partial discharge detection and location by acoustic means are carried out in the factory and in the field, the latter with the transformer either connected or disconnected to the grid.

Two general categories of location systems have been developed:

- The all-acoustic system and
- The acoustic system with an electrical PD trigger.

Typical implementations of each of these types of systems are described below.

5.7.6.1 The All-Acoustic System

The first category, the all-acoustic system consists of an array of acoustic transducers that are sensitive to the acoustic emissions generated by a PD event [91]. The location of the PD source is determined solely by the relative arrival times of the acoustic signals at each of the sensors. This makes the all-acoustic system suitable for source location on operating transformers in the field.

The acoustic transducers can be mounted on the exterior of the transformer tank to detect the signal from PD noise impinging on the tank wall, or inside the transformer to detect the PD signal in the oil. Both of these set-ups can be used for long term, unattended monitoring.

5.7.6.2 The Acoustic System with Electrical PD Trigger

The acoustic system with an electrical PD trigger, pairs the array of acoustic sensors described above with a current or voltage measurement device that detects the PD signal electrically [91]. Since the electric signal is detected instantaneously, the arrival time of the electric signal can be used as time zero for the PD event. The difference in arrival times of the electric signal and an acoustic signal is the propagation time between the PD source and that sensor location. Thus PD location in this type of system is based on the absolute arrival time at each sensor, as opposed to the all-acoustic system described above which uses the difference in arrival time between sensors.

PD location is one of the major features of acoustic discharge detection. As previously mentioned, location can be based on either measurement of the time of signal arrival at a sensor or on measurement of signal level. In practical situations, location based on a time-of-flight measurement requires two or more simultaneous measurements in order to facilitate triangulation to determine the source location [91]. The simplest approach is to measure the electrical signal simultaneously with the acoustic signal (figure 5.7). If the acoustic propagation velocity is known, then the source location is easily determined.

Using this approach an estimate of the spatial location of the discharge can be obtained using a minimum of three sensors placed externally on the transformer tank [101]. Firstly, a three dimensional layout should be constructed by using a convenient corner of the tank for zero co-ordinates (figure 5.8). For tanks with rounded corners, consider squaring them off for reference [101].

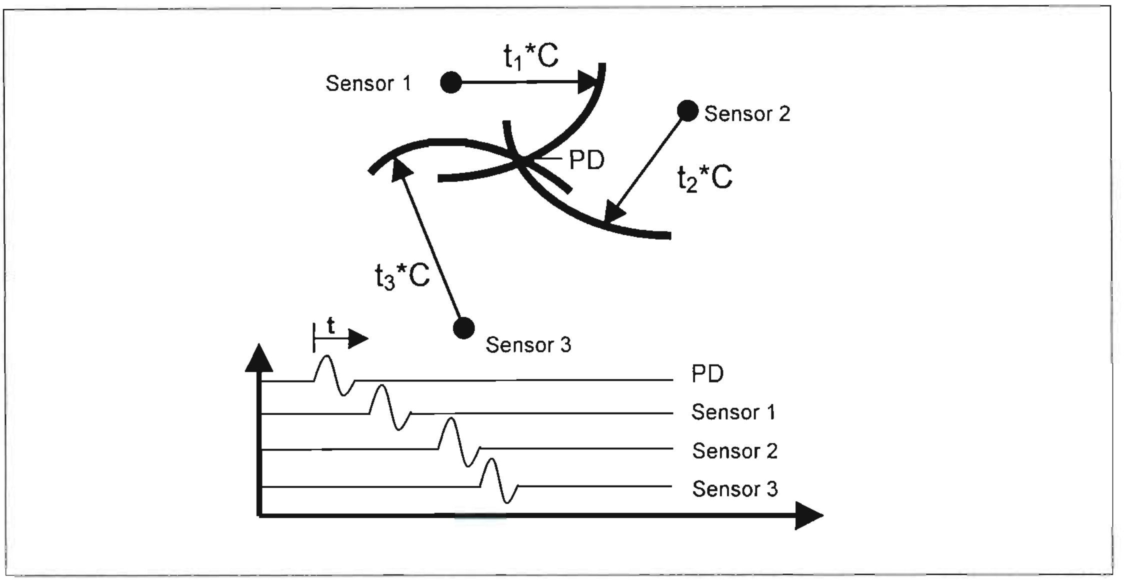

Figure 5.7: Triangulation of source location based on time of flight measurements for an acoustic system with electrical partial discharge trigger [91].

Consider figure 5.8 as a representation of a transformer tank with three sensors located at different positions as indicated. The PD source is located as shown.

If the speed of sound in oil is ***C*** *m/s* and $\boldsymbol{t_i}$ is the time taken for the acoustic signal to arrive at sensor $\boldsymbol{S_i}$, then the distance from S_i to the partial discharge source is given by [91]:

$$(x-x_i)^2+(y-y_i)^2+(z-z_i)^2=C^2t_i^2 \quad \text{.......}\mathbf{5.11}$$

For $i=3$ in this case, the location of the PD source (x, y, z) can be easily estimated by solving the *simultaneous equations*.

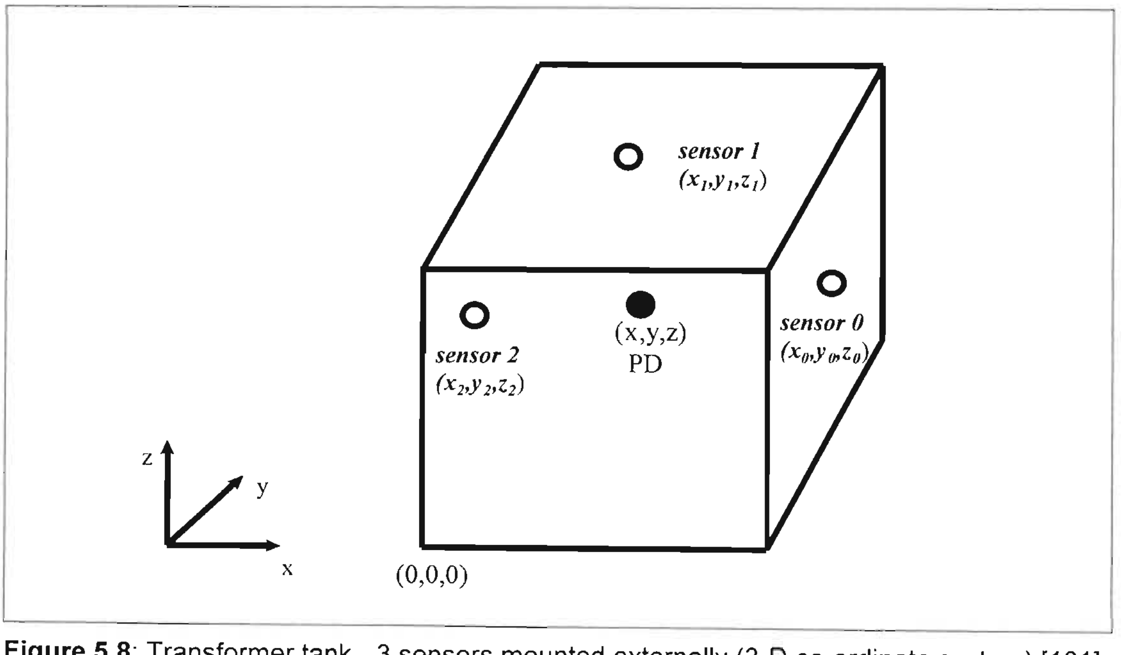

Figure 5.8: Transformer tank - 3 sensors mounted externally (3-D co-ordinate system) [101].

If the electrical signal cannot be detected, triangulation can be carried out as a simultaneous measurement with two or more acoustic sensors. The source can be located on a hyperboloid between the two sensors, which can be determined from analysis of time lag of the signal (figure 5.9). This method can be used during tests, where time is limited. Alternatively, the distance from the PD source to the sensor is approximated by multiplying the acoustic speed in oil *(C)* and the time difference between the two signals (**Δt**) [91].

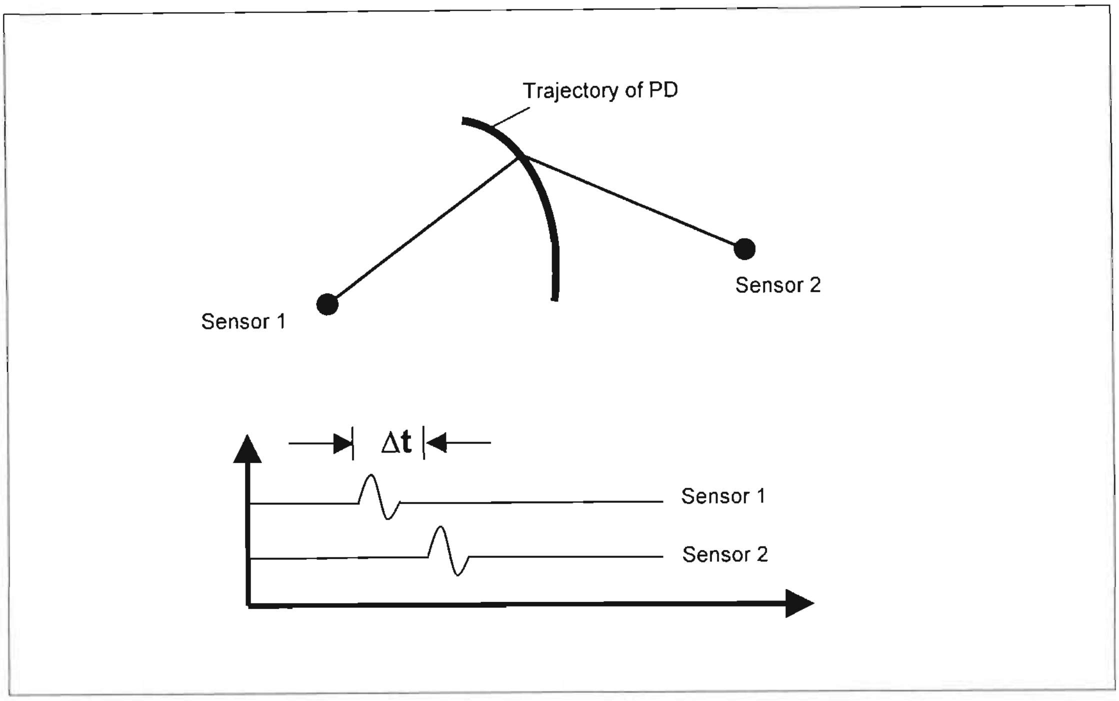

Figure 5.9: Triangulation of source location based on time of flight measurements for an all-acoustic system [91].

5.7.7 Acoustic Emission Testing: General Considerations

Transducer placement and mounting is critical to obtaining good results. Aspects to consider as discussed briefly below [98]:

The contact between the transducer and the transformer tank is critical. Simply placing a transducer on the transformer tank surface often produces a very weak signal. It is advisable to wipe the area free of contaminants and polish it with a mild abrasive or abrasive cloth before installing the transducer.

An acoustic couplant is essential for enhancing the mechanical and acoustical coupling between the transducer and the tank surface. It should be evenly applied to the clean mounting surface of the transducer before placement.

Transducers should be mounted on the tank walls. Mounting on a bolted cover or other gasketted surface can distort or dissipate the signal.

Avoid locations where magnetic or non-magnetic tank shielding, exists since this will cause additional signal attenuation.

For transformers built with double wall construction, transducers should be located on the welded ribs that span between the two tank walls to provide a strong signal. The air in the cavity between the walls attenuates acoustic signals.

Avoid locations above nitrogen blankets. This adds impedance in the transmission path, which produces additional attenuation. Locating sensors in close proximity to high voltage sources for safety reasons should also be avoided. There may be sufficient spacing between sensors to insure independent signals.

Verify sensor operation, for the entire system and for each sensor. This may be accomplished by tapping on the tank with a screw driver.

CHAPTER 6: PARTIAL DISCHARGES - EXPERIMENTAL ASPECTS

6.1 Introduction

Although acoustic emission data is useful in its own right, it becomes even more useful when used in conjunction with other information such as dissolved gas in oil data. Assuming that an incipient fault has been present for some time within a transformer, as is typical of situations that develop in the field, good correlation should be expected between the results of gas-in-oil analysis and acoustic emission data.

Dissolved gas analysis is a proven technology and is a key technique in establishing fault mechanisms in transformers. The reader is referred to the following references - IEEE Std C57.104-1991 [14], "Guide for the Interpretation of Gasses Generated in Oil Immersed Transformers" and IEC 60599-1990 [15], "Interpretation of the Analysis of Gases in Transformers and other Oil-Filled Electrical Equipment ", for more information. The new technology (Acoustic Emission Sensing) is a valuable diagnostic technique that can be used to detect and locate discharges in transformers.

The acoustic emission technique provides essentially real time information. Oil analysis, on the other hand, is to an extent historical in nature due to the fact that test samples are taken on a periodic basis. Most transformers become candidates for acoustic emission sensing provided that the trended data of the gas in oil analysis indicates a rapid rise in the hydrogen content. It then becomes necessary for oil samples to be taken on a more frequent basis. The decision to keep the transformer in-service becomes extremely difficult since the information at dispose is historical.

A discharge has to be active for some time before sufficient gas (hydrogen) is generated and detectable in the large volume of oil present. However, with the development and commercial availability of reliable on-line analysers, it is now possible to obtain fault gas data that is almost real-time. These analysers are seen as invaluable condition monitoring tools that provide an indication of gas concentrations, and therefore trends, closer to real-time as is possible. The ability to detect an evolving fault gas such as Hydrogen (on-line) in transformers can enhance early warning and diagnosis. On-line monitoring of dissolved hydrogen gas is therefore a tool by which more confidence can be attained in diagnosing developing problems.

This chapter presents the results of a laboratory experimental investigation that was carried-out to:

- Determine the sensitivity of the electrical and acoustic detection system to partial discharge inception voltage (PDIV); and the corresponding PD magnitude;
- Detect and verify the location of a single PD source (in a fixed position), by acoustic technique;
- Determine if a correlation exists between gas-in-oil measurements (on-line) and acoustic emission data.

The test object was an oil-immersed distribution power transformer that had to be modified to perform the experiment.

6.2 Test Set-Up

An experimental set-up was established in a laboratory consisting of a de-energised 11-kV/400 V oil-filled distribution transformer. A point-to-sphere electrode configuration was fitted on the internal ends of the high voltage terminals (figure 6.1), to create a discharge source when a test voltage is applied to the point electrode. The spacing between electrodes could be manually set from 0 to 100mm. The internal components of the transformer consisting of the tapchanger mechanism, laminated core and windings were not removed from the tank. Both HV and LV terminals were disconnected from the windings during testing.

Two piezo-electric acoustic sensors S1 and S2 (Appendix A) were placed in locations L1 or L2 on the transformer tank. The positioning of the sensors is illustrated in figure 6.2. These sensors were held in place by magnets. A sketch of the magnet and acoustic sensor coupled can be seen in figure 6.3.To improve acoustic coupling, a thin layer of silicone grease was applied to the face of the sensors. Methanol was used to clean the surface of the transformer tank prior to attachment.

The transformer tank was modified to create an external oil-circulating path. Oil circulation at a rate of 100 litres/hr was achieved by installing a small capacity in-line pump that had to be fitted with viton 'o' rings for the oil application. A gauge valve was fitted to take oil samples when necessary during the experiment. An on-line hydrogen in oil sensor was also installed in the oil circulation path. During testing, the oil temperature was measured by using a hand held meter connected to a 300mm long thermocouple that was fitted onto the top tank cover. A sketch of the piping, pump (P), gas sensor, ball valves, gauge valve and thermocouple installation is shown in figure 6.2.

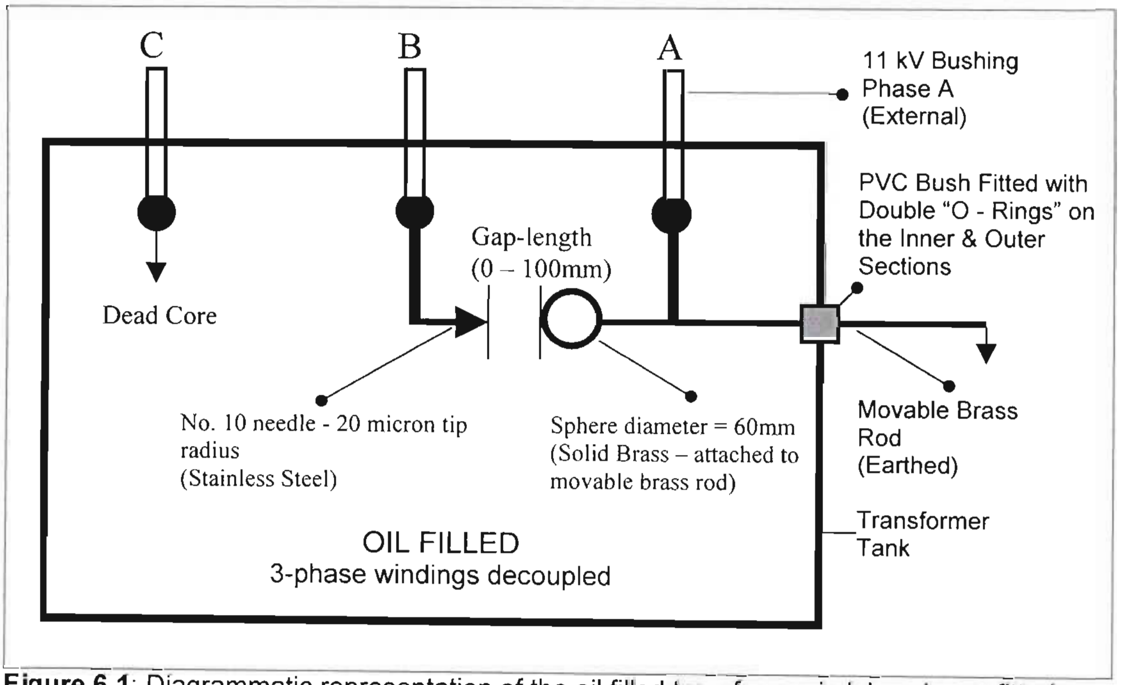

Figure 6.1: Diagrammatic representation of the oil filled transformer in laboratory – fitted with point and sphere electrodes on the internal ends of HV terminals A and B.

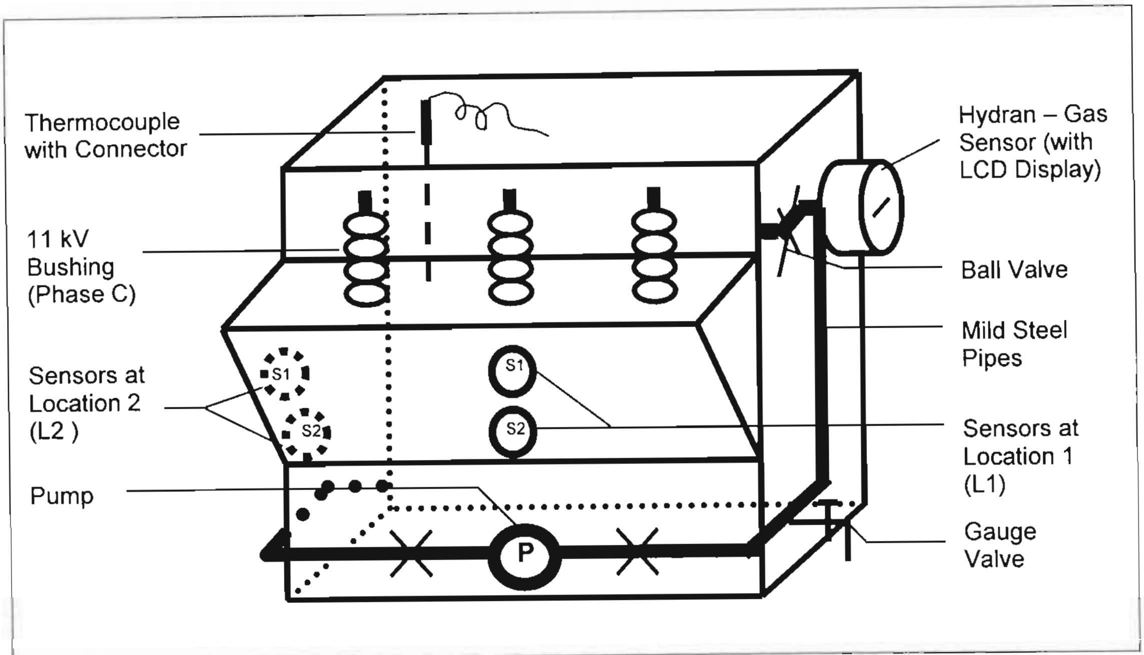

Figure 6.2: Illustration of oil circulating path - gas sensor, pump and piping mounted externally.

A PD free transformer was used to supply the voltage necessary to generate a discharge from the gapped point-to-sphere electrode geometry within the transformer. The supply transformer is rated at 40 kVA with an output voltage range of 0 to 100 kV.

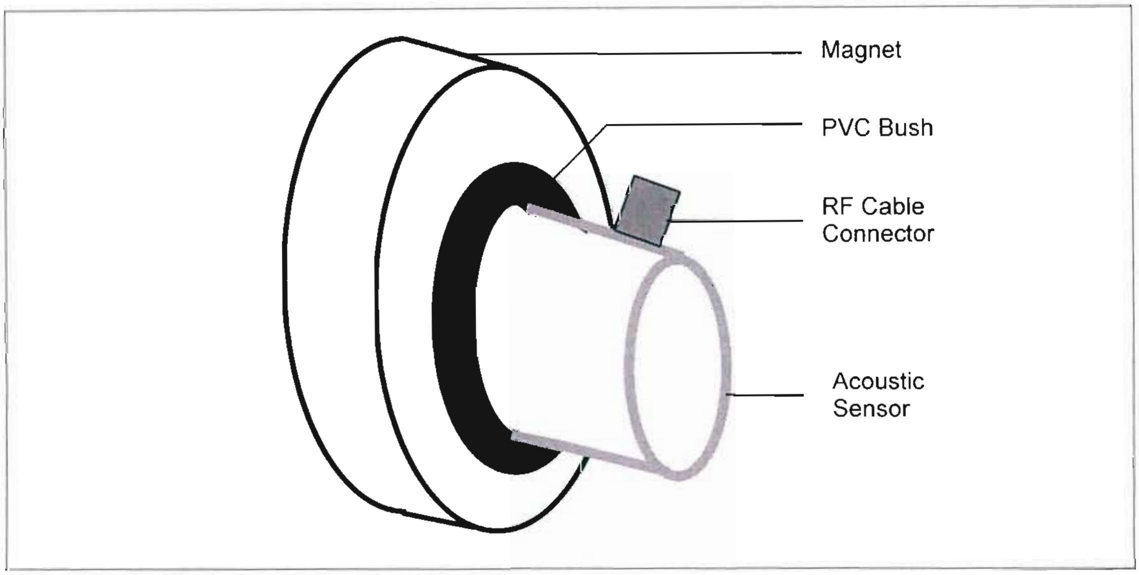

Figure 6.3: Sketch of a magnet and acoustic sensor coupled.

Figures 6.4 and 6.5 represent the measurement system and equipment used to:

- Observe discharge activity by electrical and acoustic means.
- Determine apparent charge magnitude using a Corona Detector (Appendix B).
- Verify the location of the discharge source.
- Take measurements to determine the sensitivity of both detection systems.

The HV supply transformer was energised by a single-phase autotransformer in order to supply a variable ac voltage to the point anode or test gap. A voltmeter connected to the tertiary winding of the supply transformer provided an indication of the output voltage. Apparent PD magnitude was measured using a 3 nF HV coupling capacitor (C_k). The input impedance (Z_m) of the detector is automatically set to match the measurement cable impedance. The instantaneous electrical signal or measurement was obtained from the Corona Detector that has a built-in RLC ringing circuit.

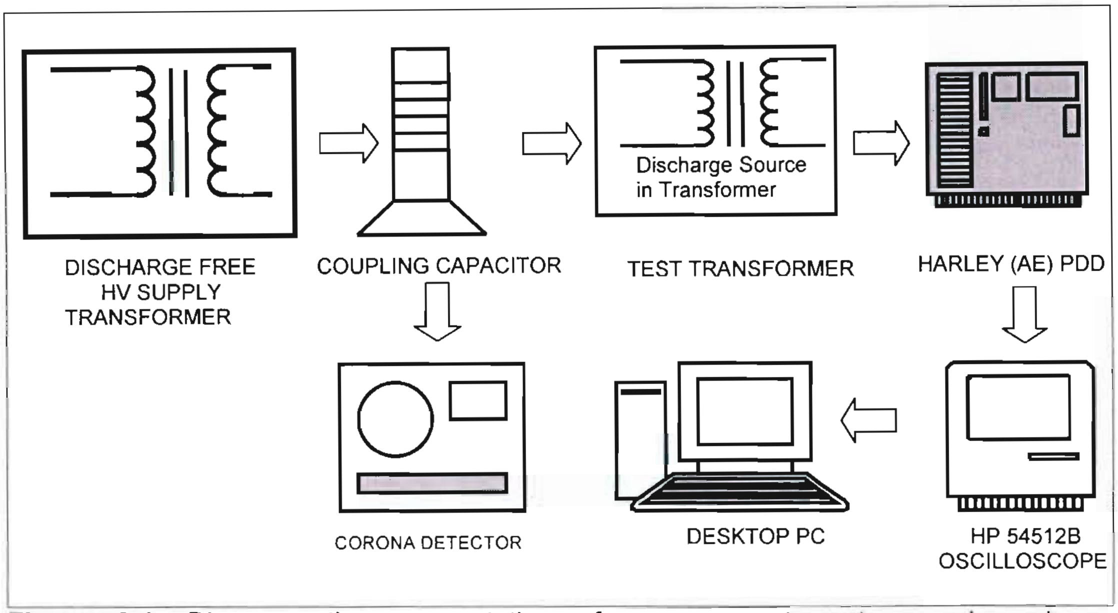

Figure 6.4: Diagrammatic representation of measurement system and equipment configuration.

Acoustic sensors placed on the tank wall were connected to a commercially available acoustic monitoring system by 50-ohm co-axial or measurement cables. The system was manufactured by JW Harley, Inc. Output signals from the monitoring system were filtered and amplified and then fed into HP 54512B digitising oscilloscope, which has a maximum sampling rate of 300 MHz or 1 Giga Sample/second. A desktop PC was used to acquire and store captured waveforms from the 4-channel oscilloscope for subsequent analysis.

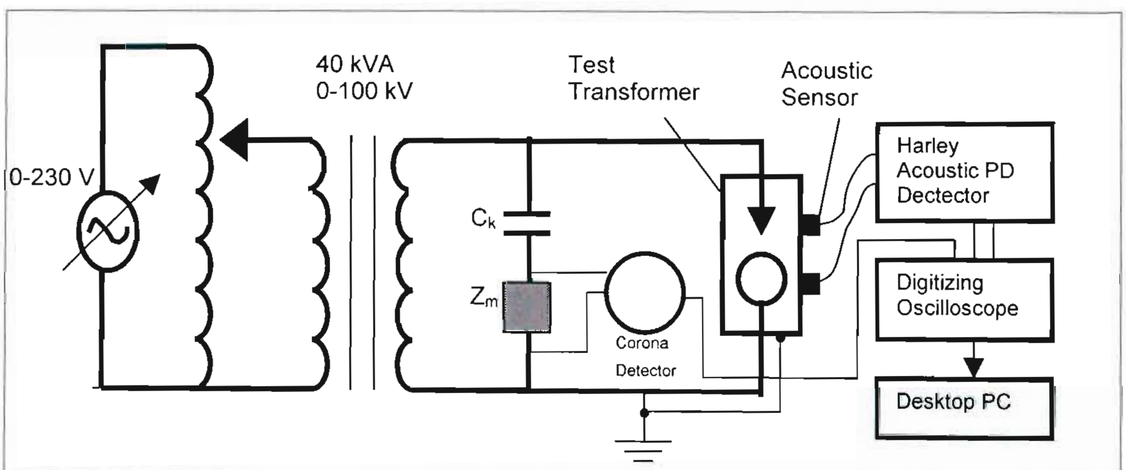

Figure 6.5: Equivalent electrical circuit - experimental test.

6.3 Test Procedure

6.3.1 Part 1: Measurement Instrumentation and Equipment Testing

Prior to performing the experimental investigation, laboratory work related to the use of (1) measuring instrumentation and equipment, (2) understanding and interpreting acoustic waveforms were carried-out. At this stage the transformer was not modified. The work in brief, entailed:

(a) Calibrating electrical PD detection equipment (Corona Detector) according to the method outlined in IEC 270. The procedure followed to calibrate the detector was as follows:

- The transformer (test object) was disconnected from the power supply. A 100 pF calibrating capacitor was then connected to phase B (point anode terminal). The detector 'calibration mode switch' was moved to the 'on' position. Next the 'sensitivity' selector switch was set to 50 pC. Thereafter, the 'gain' and 'attenuator' controls on the amplifier were adjusted to give not more than 2 divisions on the screen. The 'calibration mode switch' was then returned to the 'off' position.

(b) By energising the test transformer as described below, the magnitude of the peak PD pulse was then determined (in pico-coulombs) for the following configurations:

- One phase-to-neutral on the LV side.
- The HV side between two phases A and B, with one phase connected to neutral. The LV terminals were short-circuited and earthed.

The supply used in both cases was a 10 A, 0 - 230 Vac autotransformer. At this stage, only the gas sensor (Hydran) was installed.

(c) Heating the circulating transformer oil from an external source in contact with the tank (since energising one phase could not generate sufficient heat from the core). The external source was a 2000 W hot plate positioned beneath the tank. During this period of testing and experimentation, the gas sensor response was monitored in order to ensure correct operation of the device.

Later the transformer was moved to the workshop and modified as described in section 6.2. When the transformer was returned to the laboratory, the following tests were performed:

(a) A record of the gas sensor measurement was taken 24 hours after installation. An oil sample was then taken for dissolved gas analysis. When the results of the DGA were obtained, the accuracy range of the gas sensor reading was then calculated. It was then established that the device was providing an instantaneous reading within the manufacturer's specification.

(b) The acoustic detection system was tested in order to ensure proper operation. Tapping on the tank with a screwdriver was the method used to cause a test event. The signals from various sensors/transducers were recorded and stored for further interpretation and analysis.

6.3.2 Part 2: Experimental Testing

6.3.2.1 Determination of the Sensitivity of Electrical and Acoustic Detection Systems

In order to determine the sensitivity of the electrical and acoustic detection system, the following steps or procedure were undertaken:

1. The electrical circuit, measurement and signal processing instrumentation, as illustrated in figure 6.5, were connected.
2. The digitizing storage oscilloscope (DSO) was set to trigger above the noise level of 150 millivolts/division (noise level established by trial and error).
3. The acoustic sensors were placed in location L1 as indicated in figure 6.2.
4. The oil circulation pump operation was verified.
5. The point-to-sphere electrode gap length was set to 20mm.
6. The Hipotronics Corona Detector was calibrated (1 vertical division on the display corresponded to an apparent PD magnitude of 1000 pC).
7. The supply transformer primary voltage was supplied by an autotransformer that was slowly raised until the first sign of corona activity was observed on the detector.
8. The test voltage reading (*Partial Discharge Inception Voltage (PDIV)* by electrical means) and corresponding PD magnitude were recorded.
9. The supply voltage was further raised until the DSO triggered.
10. The applied voltage reading (PDIV by acoustic means) and corresponding PD magnitude were recorded.
11. The applied voltage was further raised to a maximum of 15 kV.
12. The test voltage was decreased until the oscilloscope stopped triggering.
13. The applied voltage measurement was then recorded (*Partial Discharge Extinction Voltage (PDEV)* by acoustic means).
14. The test voltage was further reduced until no PD activity could be observed on the corona detector display.
15. The applied voltage reading was then recorded (PDEV by electrical technique).
16. The test voltage was reduced to zero. The supply transformer was then earthed.

Steps 6 to 15 were performed five times, the PDIV and PDEV for both the detection techniques were reported as the mean of the five voltages obtained. The above procedure was also carried out for gap lengths of 25, 30, 35 and 50mm. The results obtained were tabulated and plotted.

6.3.2.2 Detection and Verification of the Location of a Fixed PD Source

To detect and verify the location of a fixed PD source, the following steps were carried-out:

1. The electrical circuit, measurement and signal processing instrumentation, as illustrated in figure 6.5, were connected.

2. The test gap length was set to 25mm.

3. The acoustic sensors were placed at L1 as indicated in figure 6.2. At L1 the sensors are vertically in-line, but directly below the internal discharge source.

4. The DSO was set to trigger above the noise level of 150 mV/div.

5. The applied voltage was slowly raised to 15 kV.

6. Three waveforms were captured (electrical and two acoustic) on the DSO.

7. The captured waveforms were then stored on the desktop PC.

8. The test voltage was reduced to zero and the supply transformer was earthed.

The above procedure was carried out again, only this time the acoustic sensors were placed at L2. When the sensors were attached to the opposite side of the transformer tank with respect to L1, no discernible waveforms could be observed.

6.3.2.3 Combination of Two Real Time Diagnostic Techniques

The following steps or procedure were undertaken to establish if the diagnostic process is enhanced when two techniques are combined:

1. The electrical circuit, measurement and signal processing instrumentation, as illustrated in figure 6.5, were connected. S1 and S2 were placed at L1.

2. A hand held temperature meter was connected to the thermocouple.

3. An oil sample was then taken. While the circulation pump was switched off, the oil was drained from the gauge valve and stored in a 1 litre metal can.

4. Immediately after the oil sample was taken, the oil temperature was recorded.

5. The reading on the hydrogen sensor was recorded (the date, time and oil temperature as well).

6. The test voltage was raised to 15 kV and a peak discharge of approximately 1400 pCs was initiated. The discharge was allowed to occur for an hour before the gas sensor and oil temperature readings were recorded. These readings were taken on average 5 times a day for a duration of 4 days. Acoustic signals were observed on the DSO.

7. After a period of 4 days, another oil sample was taken and the oil temperature recorded at the same time.

6.4 Results and Observations

6.4.1 Oil Sample (Verification of Gas Sensor Accuracy)

Prior to energising the transformer, an oil sample close to the point of the senor (Hydran) installation was taken and stored in a one litre metal can that was sent to the laboratory for analysis. The results of the dissolved gas analysis (Appendix C) and comparison with the reading obtained simultaneously from the Hydran unit, is presented in Table 6.1.

The Hydran 201i system uses membrane technology and a sensor that is sensitive to essentially four gases in the following quantities: Hydrogen (100%), Carbon Monoxide (18%), Acetylene (8%) and Ethylene (1.5%). Accuracy is stated as ± 10% of reading and ±25 ppm for Hydrogen. The unit is coupled directly to the oil circulation path. Refer to Appendix D for Technical Specifications.

Gases		Hydran (ppm)	DGA_1 (ppm)
H_2	(Hydrogen)	21	0
O_2	(Oxygen)		22 209
N_2	(Nitrogen)		39 641
CO_2	(Carbon Dioxide)		367
CO	(Carbon Monoxide)		4
C_2H_2	(Acetylene)		0
C_2H_4	(Ethylene)		0
C_2H_6	(Ethane)		0

Table 6.1: Dissolved gas analysis sample comparison – test transformer.

The accuracy of the sensor is determined as follows:

(1) Sensor reading = 21 ppm

(2) Laboratory DGA $= (100\%*H_2) + (18\%*CO) + (8\%*C_2H_2) + (1.5\%*C_2H_4)$
$= (100\%*0) + (18\%*4) + (8\%*0) + (1.5\%*0)$
$= 0.72$ ppm

(3) Accuracy = (0.72 ppm*10%) ±25 ppm = 0 – 25 ppm

The gas sensor reading is regarded as being within specification.

6.4.2 Sensitivity of Electrical and Acoustic Detection Systems

The PDIVs measured for various gap lengths together with the discharge intensity are summarised in Table 6.2.

Gap Length mm	Detection Technique	PDIV kV (rms)	PD Magnitude pC (peak)
20	Electrical	8.6	400
	Acoustic	10.9	1000
25	Electrical	9.5	500
	Acoustic	11.3	1000
30	Electrical	9.7	800
	Acoustic	10.5	1000
35	Electrical	9.6	600
	Acoustic	10.6	1000
50	Electrical	9.6	800
	Acoustic	10.6	1100

Table 6.2: Electrical and acoustic detection systems - PDIV and PD magnitude for mineral oil.

The measured partial discharges occurred on both positive and negative half cycles of the applied waveform. A number of discharges occurred simultaneously on both cycles. An approximate value of the peak partial discharge magnitude that occurred on the positive cycle of the applied waveform is recorded in Table 6.2. The magnitude of the partial discharges at onset for mineral oil is of the same order of magnitude published elsewhere [108]. Figure 6.6 is a plot of the point-to-sphere gap lengths versus partial discharge inception voltages (PDIVs) for both detection techniques.

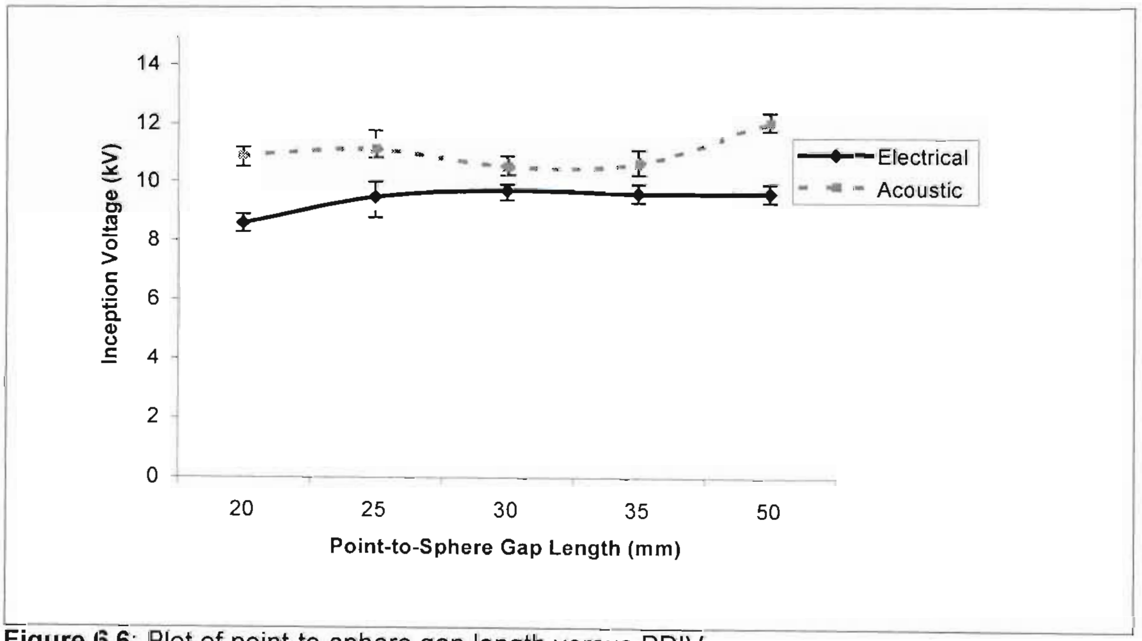

Figure 6.6: Plot of point-to-sphere gap length versus PDIV.

From figure 6.6 it can be seen that for a gap length greater than 30mm, the partial discharge inception voltage is constant for the electrical technique. This finding can be explained in terms of understanding the changes or variation in field strength between the point anode and sphere.

If a point-to-plane geometry is considered with a discharge or streamer extending from the point into the liquid (assuming that the tip of the streamer is hyperbolic) then the equation for the electric field produced by the streamer tip at potential V and distance to the plane d is given by [102]:

$$E_t = \frac{2V}{r_p \ln\left(\frac{4d}{r_p}\right)} \qquad \text{.....}\mathbf{6.1}$$

where

r_p = radius of the streamer tip.
d = distance from the streamer tip to the plane electrode.

This equation applies for the condition $r_p \ll d$ i.e. for many experimental conditions utilised in partial discharge and pre-breakdown studies in liquids.

For an r_p = 20 μm (tip radius of a stainless steel needle), the electric field at the tip of the discharge is calculated using equation 6.1 for the various PDIVs achieved at the predetermined test gap lengths. The calculated values are summarised in Table 6.3

Gap Length (d) **mm**	**PDIV** (V) **kV (peak)**	**Normalized Electric Field per Applied V V/m**	**Electric Field at Inception**(E_t) **V/m**
20	12.16	11.66×10^3	1.47×10^8
25	13.44	11.74×10^3	1.58×10^8
30	13.72	11.49×10^3	1.57×10^8
35	13.58	11.29×10^3	1.54×10^8
50	13.58	10.86×10^3	1.51×10^8

Table 6.3: Calculated values of E_t at inception (electrical method).

It can be seen from Table 6.3, that the field strength at onset remains almost unchanged for point-to-plane gap lengths greater than 30mm. Therefore, the PDIV achieved for the electrical technique remains almost constant for gap lengths greater than 30mm. This characteristic is depicted in figure 6.6. Table 5.1 specifies the dielectric strength range for 'good oil'. The calculated values of electric field strength at inception fall within this range. For the acoustic measurement technique the mean value for PDIV achieved is 10.78 kV. These measured values were all within 600 V of the mean for all five measurements.

A summary of the PDEVs achieved is presented in Table 6.4.

Technique	PDEV (kVrms)				
Electrical	7.5	7.5	7.5	7.8	7.5
Acoustic	10.2	10.4	10.3	9.7	10.3

Table 6.4: PDEV for the electrical and acoustic technique.

For the electrical and acoustic technique the mean values for the PDEV are 7.56 and 10.18 kV, respectively. These values are within 134 V (electrical) and 278 V (acoustic) of the mean for all five measurements taken. The five measurements obtained for both methods seem to be consistent, with a very small standard deviation. However, the difference in the mean values can be attributed to the limitations of the measurement equipment i.e. the DSO.

6.4.3 Detection and Verification of Location (Fixed PD Source)

The sensors were initially placed at location 1 to achieve acoustic signals in close proximity to the discharge site, and at the same time maintain a safe clearance to the high voltage test supply (phase B bushing terminal). The instantaneous electrical and acoustic signal waveforms obtained at both locations on the tank surface are plotted in figure 6.7(a).

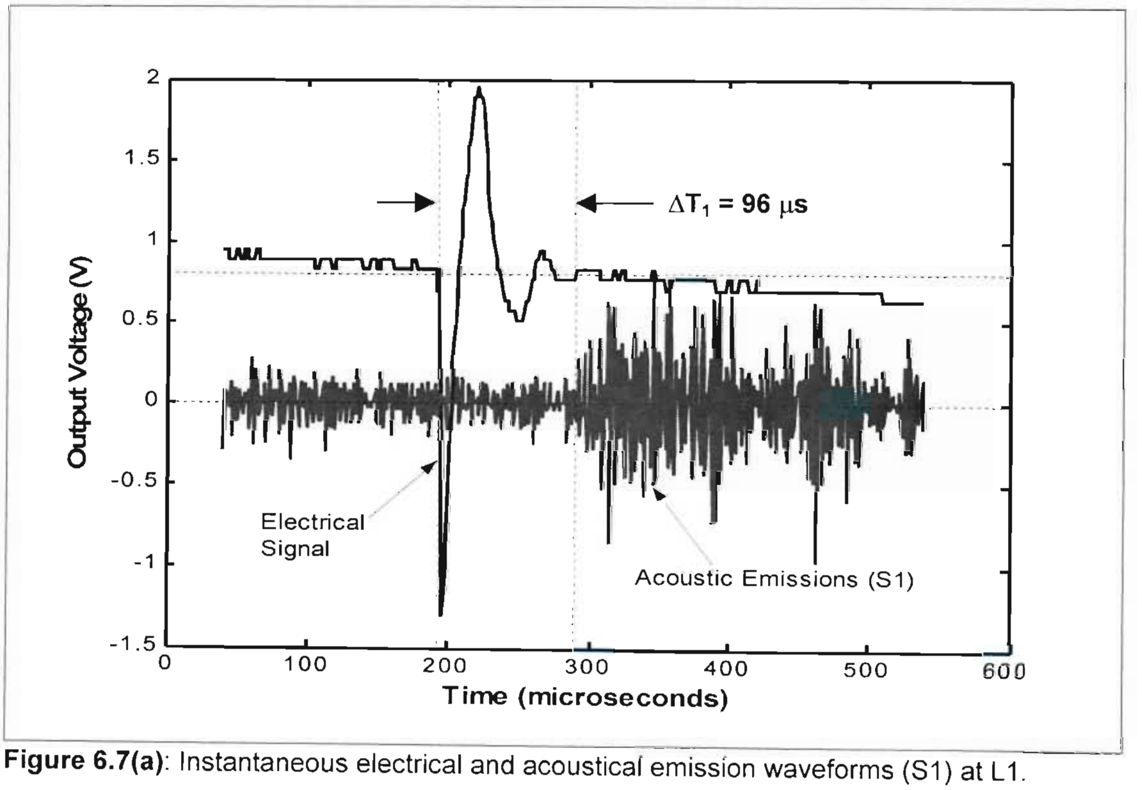

Figure 6.7(a): Instantaneous electrical and acoustical emission waveforms (S1) at L1.

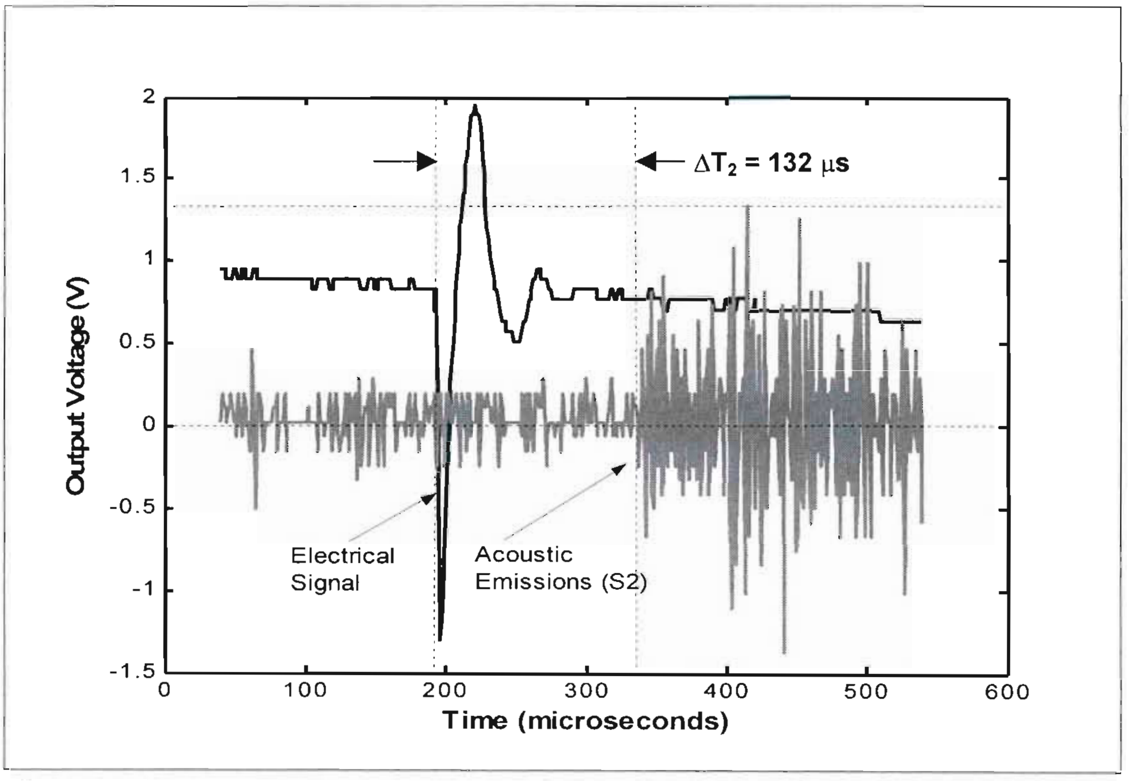

Figure 6.7(b): Instantaneous electrical and acoustical emission waveforms (S2) at L1.

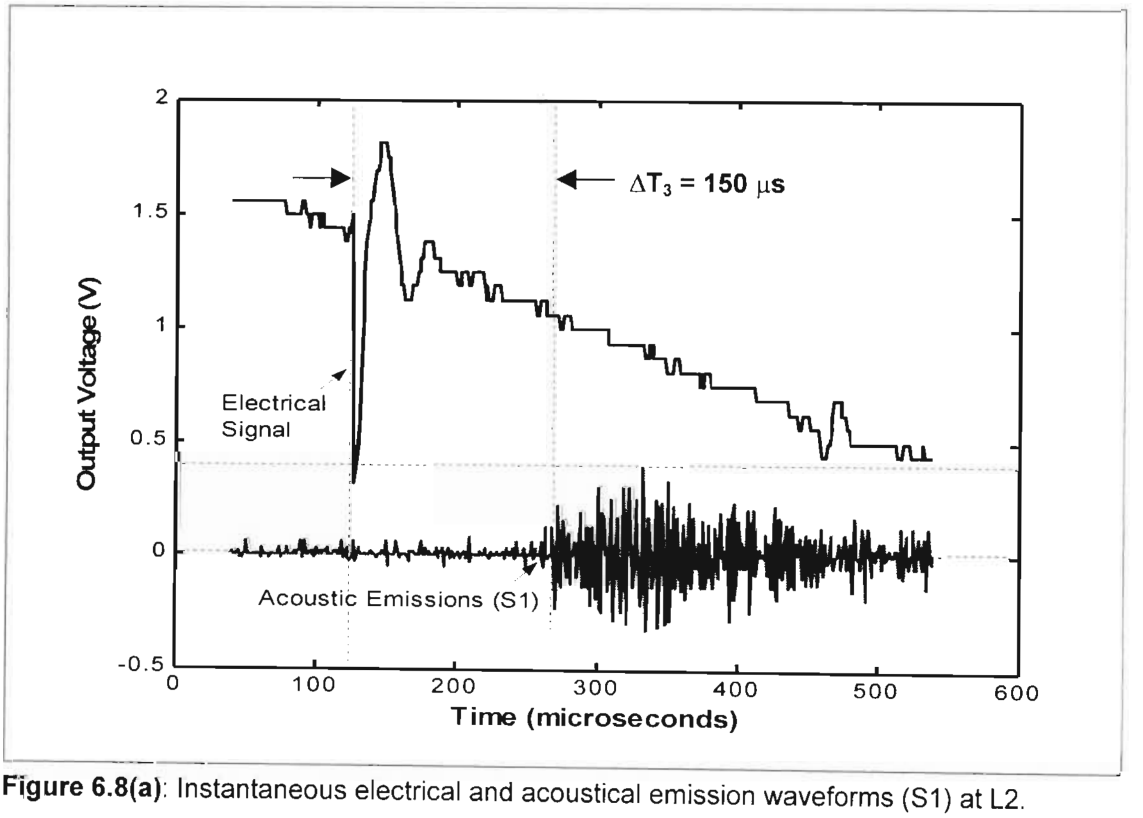

Figure 6.8(a): Instantaneous electrical and acoustical emission waveforms (S1) at L2.

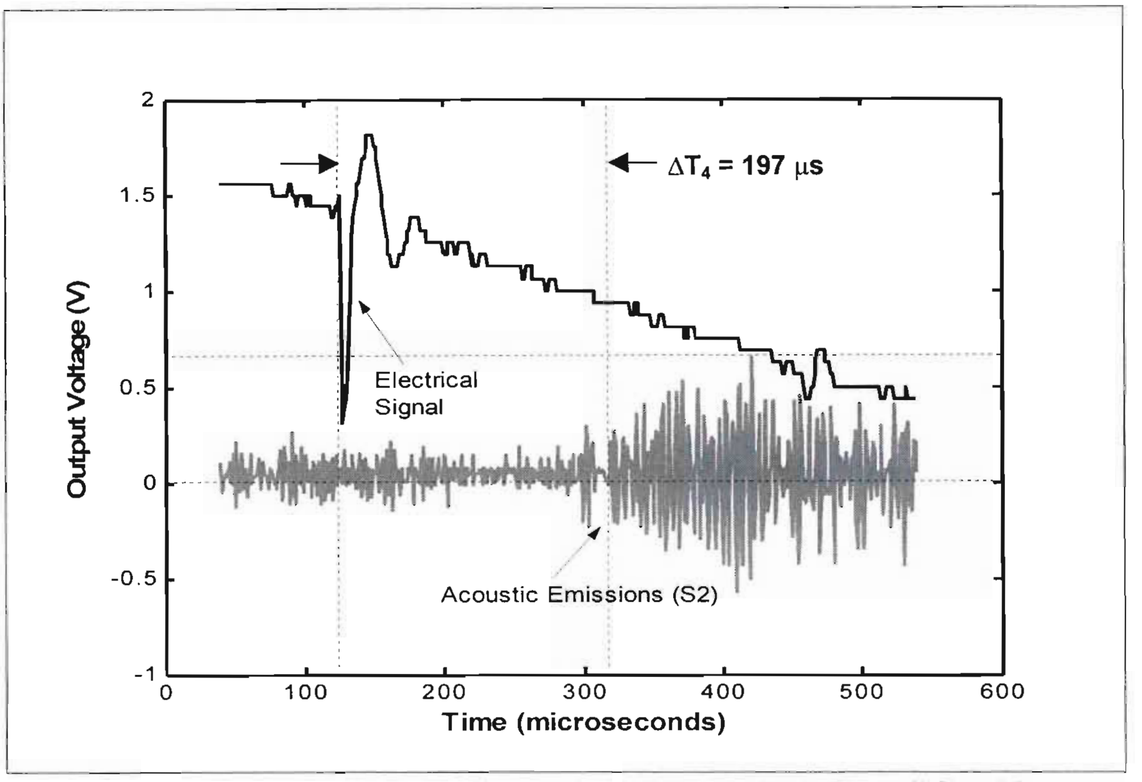

Figure 6.8(b): Instantaneous electrical and acoustical emission waveforms (S2) at L2.

When comparing the characteristics of the waveforms in figures 6.7(a) and (b) to figures 6.8(a) and (b) respectively, they differ in terms of amplitude and absolute arrival times. At location 1, the sensors are closest to the fixed partial discharge source, therefore they exhibit signals with much larger amplitudes and shorter duration's of arrival times. In figures 6.8(a) and (b) the signal is attenuated and the arrival times are slightly longer in duration. Based on the internal arrangement of the transformer core and coil structure, the sensors at location 2 are not in line of sight of the discharge source. Therefore, subsequent attenuation of the signal is most likely due to propagation of the acoustic waves by the tank wall that have welded seams or joints i.e. structure-borne propagation path. The signal arrival times for each sensor at the different locations on the tank wall are summarised in Table 6.5.

Acoustic Sensor	Position on Tank	Absolute Arrival Time
S1	L1	96 μs
S1	L2	132 μs
S2	L1	150 μs
S2	L2	197 μs

Table 6.5: Measured arrival times of acoustic signals.

With reference to the measured arrival times tabulated above, it is evident that when the sensors are placed at a distance from the fixed PD source (at L2) the signal arrival is delayed since the travelling wave can not traverse a direct path. The difference in arrival times of the acoustic signal for each sensor is almost insignificant since the acoustic waves travel in the tank wall at much higher speeds than in the oil. Furthermore, in terms of the physical dimensions of the experimental transformer, it is relatively small.

6.4.4 Combination of Two Real Time Diagnostic Techniques

The hydrogen gas sensor readings taken on:

12/08/2003 was 132 ppm;

and on 15/08/2003 it was 137 ppm.

Therefore, the net increase in dissolved hydrogen is 5 ppm.

Refer to Appendix E for sensor readings recorded for the duration of this part of the experiment.

For an oil sample taken before PD was initiated (12/08/2003) and after experimental testing (15/08/2003), the laboratory analysis of the constituent gases present can be found in Appendix F and G, respectively.

After carefully examining the results, changes in hydrogen and acetylene levels were noted. The hydrogen and acetylene contents taken before and after PD activity are highlighted in Table 6.6 below.

Gases Generated		DGA_2 (ppm)	DGA_3 (ppm)
		Sample Date: 12/08/2003	*Sample Date*: 15/08/2003
		Oil Temperature: 22.2 °C	*Oil Temperature*: 24.8 °C
H_2	(Hydrogen)	64	68
C_2H_2	(Acetylene)	3	10

Table 6.6: Dissolved gas analysis – test transformer.

According to IEEE Std C57.104-1991, the presence of hydrogen is commonly associated with partial discharges, and acetylene with arcing. Discharges on the order of several thousand pC in magnitude were produced under oil for a short period (approximately 21 hours). The increase in the hydrogen content by 5 ppm (on-line monitoring) and 4 ppm (DGA) was noted. During the testing period, the discharges were detected by both acoustic and electrical means. Acoustic waveforms were captured and stored on an hourly basis.

A trace increase in the acetylene level was also observed and noted. This probably due to sparking that may have occurred. If the discharge developed into an arc, the test circuit supply would have tripped. There was certainly no evidence of arcing having occurred during the experiment.

6.5 Discussion

The partial discharge inception voltages achieved and peak discharge magnitudes measured for both electrical and acoustic techniques are reasonable. Discharge intensity measurements could only be taken once the electrical detection system was calibrated according to the method outlined in IEC 270. Calibration of the Corona Detector was successfully performed. With electrical detection, the response to changes in gap lengths can be predicted with a greater degree of accuracy. In the case of the acoustic technique the same degree of accuracy is not possible. However, it seems that the predicted response to changes in test gap lengths would lie within a certain range or bandwidth. It would be important to note that the results obtained and presented for the acoustic technique are within the limitations of the signal processing and measurement instrumentation. It is however, an effective technique for the evaluation of activity within a transformer structure.

It has been demonstrated that it is possible to detect and locate a discharge source within a transformer by acoustic means. By placing the acoustic sensors at various locations on the tank surface and observing the signal amplitude and arrival times, the position of the source can be approximated. Acoustic signals with the highest amplitude and an arrival time of the shortest duration would mean that the discharge site is in close proximity. Further, the use of a combined electrical and acoustic method, using an array of sensors, would be extremely useful in practice since the absolute signal arrival times can be calculated. Then, by triangulation the approximate location can be determined. With regard to the laboratory experiment, triangulation was not possible due to the complex structure of the tank.

When acoustic emission and gas-in-oil (on-line) data are integrated, the diagnostic process is further enhanced. The two sources of data can supplement each other in yet other ways. For instance, sometimes the breakdown of constituents in a conventional gas analysis is so complex that, although it is obvious that a significant problem exists, it is not possible to determine whether the cause is due to partial discharges or is thermal in origin. The acoustic emission system responds only to signals produced by partial discharges or arcs. Purely thermal phenomena do not produce such signals. Therefore, the existence of any acoustic (or electrical) emission signal together with an on-line single or multi-gas analyser may confirm the existence of partial discharges. Conversely, the absence of acoustic emission activity in this case may indicate that the problem is basically thermal in origin. The integration of information of these two techniques is encouraging, it is recommended that on-line, if possible or conventional gas analysis results be taken into account when interpreting acoustic and electrical emission data.

6.6 Conclusions

From the laboratory experiment the following conclusions can be drawn:

- The detection threshold (partial discharge inception voltage) for the acoustic technique is 20% higher than the established electrical detection technique for the particular experimental arrangement used in this work.

- For the acoustic measurement technique the mean value for the partial discharge inception voltage achieved is 10.78 kV. This voltage corresponds to a partial discharge magnitude of approximately 1000 pC.

- The partial discharge sensors are more sensitive than gas sensing technology, either on-line (hydrogen) or off-line (DGA).

- Although the acoustic sensors operated correctly, one type was found to be more sensitive. However, partial discharge detection and localisation by a combined electrical and acoustic system is effective. The acoustic signal received with the highest amplitude and shortest duration arrival time would mean that the discharge is in close proximity.

- A correlation between gas-in-oil measurements (on-line) and acoustic emission data could not be established. A small increase in dissolved hydrogen was observed at the end of the experiment therefore, no conclusion could be drawn.

6.7 Recommendation for Future Work

An item for further investigation would be to determine how long it may take for the hydrogen sensor and dissolved gas analysis measurements to detect increases in hydrogen while the same discharges are generated continuously (developing fault condition) within the experimental transformer.

CHAPTER 7: ECONOMIC CONSIDERATIONS IN CONDITION ASSESSMENT

7.1 Introduction

Based on the findings of a condition assessment, plant equipment may then be considered for refurbishment. Refurbishment may include modifications, uprating/upgrading or replacement due to ageing. In response to these findings, refurbishment projects are then raised with the intention of ensuring that the expected life of plant equipment is achieved or extended. These projects usually require large amounts of capital that must be economically justified to ensure that the required funds are appropriated.

These project proposals generally do not call for adding facilities but rather for an increase in the reliability of existing facilities or the reduction in operating (maintenance) costs. Justifying a project especially on a reliability basis can be difficult. There are no exceptions and replacement due to ageing must also be economically justified.

This section discusses in detail some of the approaches that can be used to justify refurbishment or replacement projects. Several case studies are included.

7.2 Justification Methods

Four types of methods are proposed. These are:

- Positive Net Present Value (NPV),
- Statutory Requirements,
- Operating Cost Reduction and
- Least Economic Cost

The application of any of the above justification methods requires the use of certain parameters that are current. These parameters include financial rates such as interest, inflation and taxation that could be provided annually by the Corporate Body of the power utility [109]. Technical statistics, maintenance costs, etc, could be obtained from the relevant technical departments (e.g. HV plant and equipment systems) within the utility.

7.2.1 Positive Net Present Value

This method is used for investment decisions that are related to system expansion required to supply large amounts of new loads, with which significant incremental energy sales are associated. The investment justified on net present value (NPV) is the result of discounted cash flow calculations over the expected duration that the new proposed asset(s) will be in service (typically 25 years for transmission high voltage equipment) [109]. Discounted cash flow (DCF) methods can be briefly described as follows.

Envisage all future cash flows as positive (all income) and negative (expenses) on a time scale (years 0 to 25). The present value (PV) of the future cash flows can be determined by means of the following equation:

$$PV_n = \text{Cash Flow}_{n\,(+\text{ or }-)} \div (1 + (r \div 100))^n \qquad \text{.....7.1}$$

Where

PV_n = Present Value of Cash Flow_n
n = number of years
r = real discount rate in %
= $[((1 + (i \div 100)) \div (1 + (e \div 100))) - 1] \times 100$

and

i = nominal interest rate in %
e = escalation or inflation rate in %

Equation (7.1) must then be applied to all future cash flows, which stem from the proposed investment:

$$NPV_{investment} = PV_{revenue} - PV_{expenses} \qquad \text{......7.2}$$

7.2.2 Statutory Requirements

Capital investment, based on this criterion may include the following [110]:

- Investments to meet National Electricity Regulator requirements.

- Projects necessary to meet environmental legislation, organisational policy or in-house specifications.

- Expenditure to satisfy the requirements of the statutes of the applicable country. This classification is intended to ensure the safety of the utility operating and maintenance personnel who are exposed to possible danger when engaged in activities related to electrical power transmission.

- Possible compulsory commitments.

It must be known that this investment criterion should not be used for justifying projects that are not of economic benefit. An economic evaluation exercise for these projects should be completed, as less costly capital or operational solutions may exist. The financial impact (NPV) of the proposed solution should also be determined, which should include all operational costs and savings associated with the investment.

7.2.3 Operating Cost Reduction

The proposed capital expenditure that is intended to reduce the utility's transmission operating costs should be justified by this method. Firstly, it is necessary to calculate the NPV of the proposed investment using the DCF methods explained in section 7.2.1. This should be done by considering all cost reductions as positive cash flows, off-setting the required capital expenditure. A resulting positive NPV would indicate that the investment is justified over the expected life of the proposed new asset.

However, a positive NPV does not always indicate the optimal timing for the investment. Indeed, the issue is not so much if the money should be spent but rather, when the money should be spent. The pertinent question in an increased maintenance cost environment is therefore to pinpoint the optimal time to invest in network changes. It is possible to provide an indication of the correct time to invest using this justification methodology.

The recommended method to calculate the cost to commission an asset in the required year, as opposed to delaying it by one year, uses the Equal Annual Capital Charge (EACC) of the investment [110]. The EACC is calculated by determining the capital recovery factor (CRF) or annuity payment over a pay-back period equal to the book life of the asset at the real discount rate [110]:

$$\begin{aligned} \text{CRF} &= r \div [1 - (1 + r)^{-n}] \\ &= 0{,}06 \div [1 - 1{,}06^{-25}] \\ &= 7.82\% \end{aligned} \qquad \ldots\ldots \mathbf{7.3}$$

If the first annuity payment is made one year after the commissioning or capital expenditure date then:

$$\begin{aligned} \text{CRF} &= [r \div [1 - (1 + r)^{-n}]] \div (1 + r)] \\ &= 7.82 \div 1.06 \\ &= 7.38\%) \end{aligned} \qquad \ldots\ldots \mathbf{7.4}$$

where

r = Real Discount Rate = 6% per annum for this example.
n = Number of years (book life) = 25 years for this example.

and

$$\text{EACC} = \text{CRF x CAPITAL EXPENDITURE} \qquad \ldots\ldots \mathbf{7.5}$$

The project is justified and an Operating Cost Reduction is achieved when:

$$\text{EACC} < \text{Expected Annual Cost Reduction (Year 1)} \qquad \ldots\ldots \mathbf{7.6}$$

Where the Annual Cost Reduction is calculated as follows:

(i) the savings in operational costs due to the existing installation(s);

less (ii) the extra operational costs caused by the new installation(s);

If this relationship is not satisfied then it means that it is cheaper for the utility to incur increased operating costs than to invest in the proposed asset. It would then be logical to delay the investment until operating costs have increased to such an extent for example, system losses have increased due to load growth that equation (7.6), together with a positive NPV is satisfied.

7.2.4 Least Economic Cost

When investments are made in terms of improving supply reliability and/or quality, this would be the preferred method to use. This methodology should also be used to determine and/or verify the desired level of network or equipment redundancy.

This type of economic justification is based on the least-cost planning concept [110]. Not simply least-cost to the utility is considered, but also to the entire community of consumers. This concept is consistent with social welfare economic theory [110]. The criterion minimises the total cost of electricity to the partnership consisting of the utility plus the consumers who benefit from the new installation or proposed network change. In other words, the criterion says that "a new installation(s) should continue only when (a) the extra annual costs incurred by the utility for owning and operating the asset are less than (b) the annual savings to the consumers because of that project(s)" [110].

(a) The extra costs incurred by the utility for owning and operating the assets are as follows:

The *sum* of (i) EACC (the equal annual capital charge)
(ii) the extra operating and maintenance costs caused by the new installation(s);

less (iii) the savings in transmission losses due to the new installation(s);

(b) The annual savings to the consumers because the new installation(s) is part of the system include:

(i) all the cost reductions resulting from the improved quality of supply.

The extra costs incurred by the utility are not difficult to calculate. The benefits derived by the consumers are more difficult to assess. The first step would be to calculate the reduction in energy not supplied due to the improvement in quality of supply i.e. the reduction in interruptions, voltage depressions, harmonics, etc. Thereafter the value of this energy not supplied to consumers is calculated i.e. the cost of unserved energy.

The cost of unserved energy is a function of the type of loads, the duration and frequency of the interruptions, the time of the day they occur, whether notice is given of the impending interruption, the indirect damage caused and the start-up costs incurred by the consumers, the availability of customer back-up generation and many other factors [110]. Since the people who know this best are the consumers themselves, this information can only be obtained via surveys [110].

7.2.4.1 Least Cost Investment Criteria Equations

The least-cost investment criterion equation to be satisfied can also be expressed as follows [110]:

Value of Improved Quality of Supply to Customers > *Cost to Utility to provide the Improved Quality of Supply* **7.7**

From equation (7.7) it may evident that if the value of the improved quality of supply to the customer is less than the cost to the utility, then the utility may not invest in the new asset or other proposed network changes.

Equation (7.7) can be stated differently as;

Value (in Rand/kWh) x Reduction in Amount of Energy Not Supplied to Consumers (kWh) > Cost to the Utility to Reduce EENS (Rands) **7.8**

with the reduction in EENS relating to all aspects of improved QOS. The reduction in EENS is calculated on a probabilistic basis [110].

$$\text{EENS} = \text{EEAR} \times P(f) \qquad \text{.....}\mathbf{7.9}$$

where

EEAR = Expected Energy at Risk (that will no longer be at risk after the network change or new installation(s).

P(f) = Probability that the system is constrained through one or more components (primary or secondary equipment) being out of service. This probability is a function of the performance of the plant.

An alternative and recommended approach is to calculate the break-even cost of unsupplied energy (BECOUE) for the proposed capital expenditure [110]. This can be done by taking the ratio of the above mentioned components as follows:

BECOUE (R/kWh) = Annual Cost of having Asset "X" in commission in Year 1 ÷ Reduction in EENS in Year 1 due to Asset "X" being in service (kWh) **7.10**

The BECOUE is that value which equates the left and right hand sides of equations (7.7) and (7.8). A preliminary judgement can then be exercised on this break-even value. Projects can be motivated when the BECOUE has been less than the estimated Weighted Average Customer Interruption Costs (WACIC). The WACIC can also be estimated for a mixture of different types of load by adding the costs in a weighted manner, proportional to the percentages of that type of load. If the break-even cost is too high, it indicates that insufficient load is at risk. The project should therefore be postponed and re-evaluated at a later stage once the load has grown or reliability has further decreased.

7.3 Case Study 1 - Circuit Breaker Replacement

The 275 kV Impala 2 (minimum oil ASEA HLR) feeder circuit breaker at Avon substation is stressed severely due to the number cane fire and pollution fault operations. Maintenance costs have increased in the last three years and spares are difficult to obtain. There have been a number of ASEA HLR breakers that have exploded due to the high duty cycles. The project proposal is to replace this breaker with a spare SF_6 breaker located at another substation. Changing this breaker will reduce the maintenance costs and supply interruptions to customers, improve system performance, and most importantly the safety of the operating personnel.

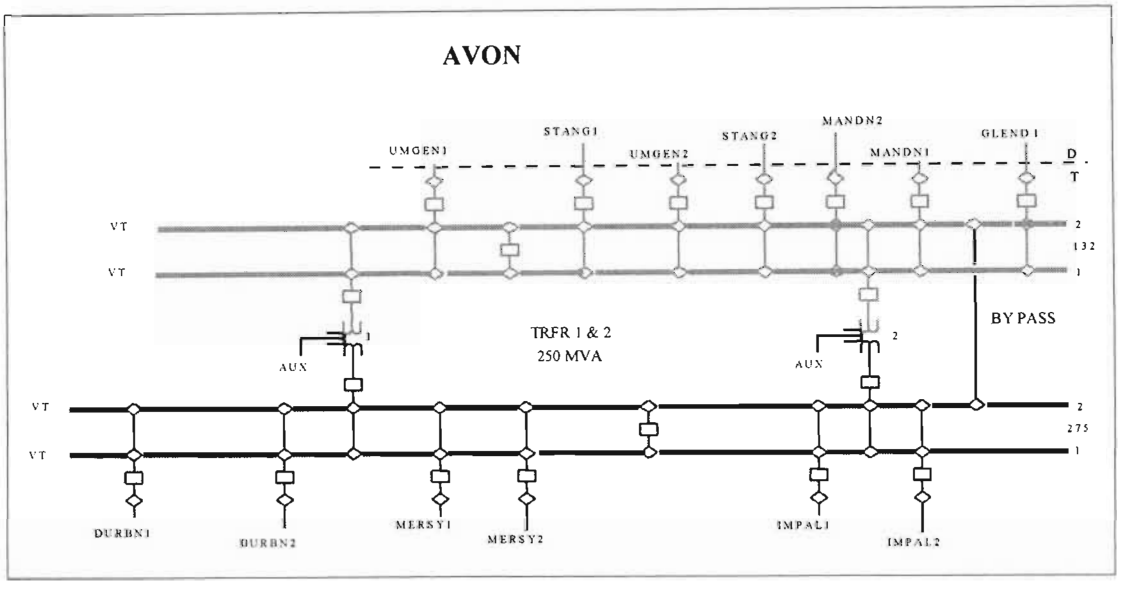

Figure 7.1: Avon substation electric diagram.

The economic justification for the replacement of the ASEA HLR breaker follows.The station electric diagram in figure 7.1 shows the location of the ASEA HLR 275 kV breaker, as well as the linking of the station under normal operating conditions. The impact of a failure is dependent on the linking of the substation at the time of the failure, and it is assumed that under normal operating conditions the station is linked as shown in the electric diagram. The impact of the breaker failing is summarised in Table 7.1.

Asea HLR Breaker	Zones Possibly Impacted By Failures	Circuits Effected Under Normal Linking
Impala 2	B	Mersey 2, Durban North 2 and Transformer 2
	A and B (if protection operates incorrectly)	Mersey 1 and 2, Durban North 1 and 2, Transformer 1 and 2 or the entire 275 kV yard.

Table 7.1: Impact of the 275 kV Impala 2 breaker failure.

7.3.1 Station Loading and Type of Loads

Customers	Load (MW)	Cost of EENS (R/kWh)[2]	Type of Load
Durban North 1 275 kV	120	7.00	Municipality
Durban North 2 275 kV	120	7.00	Municipality
Umgeni 1 132 kV	12	3.00	Rural
Umgeni 2 132 kV	8	3.00	Rural
Stanger 1 132 kV	25	7.00	Municipality
Stanger 2 132 kV	25	7.00	Municipality
Mandini 1 132 kV	45	8.00	Mandini, Sappi
Mandini 2 132 kV	40	8.00	Mandini, Sappi
Glendale 1 132 kV	5	2.00	Rural
Total	**400**	**6.95** *(Total Average Weighted Value)*	

Table 7.2: Station loading, type of loads and calculation of EENS.
[2] Typical values for this power utility.

7.3.2 Probabilities Used

The impact of a breaker failure is dependent on the layout and status of the busbars in the substation as well as the availability of the protection. In assessing the impact, both the effects of power outages and dips are considered. The figures calculated below are used in determining the impact of various possibilities of failures, with regard to the breaker:

- Service experience has shown that the reliability of the breaker is dependent on its duty-cycle. If the network performance is similar to that experienced between 1990 and 1992 then field staff estimate that out of a population of four Asea HLR breakers, there would probably be three catastrophic failures in a period 3 years. However, due to other work that has been done on the network, the performance has improved significantly. On the Avon-Impala 2 line the average number of faults has been reduced from 30 to 5 faults per year. This reduction indicates that the reliability that is dependent on the number of faults would increase by six times. However, the breaker on the Impala 2 has been exposed to the high duty cycle and for this reason the expected improvement on the reliability will only be 4 times. Thus from these estimates the probability of the Impala 2 breaker at Avon failing catastrophically is, approximately 0.012, (25 failures out of a total population of 589 in 3.5 years for this utility):

  $P_{\text{Bkr Failure}} = (3/4)*(1/3)*(1/4) = 0.0625$ per annum

- Busbar isolator maintenance requires that the affected circuit and the relevant busbar zone be removed from service for the duration of the procedure. The remaining circuits in the effected zone will obviously have to be linked to the adjacent bar creating a non-standard arrangement and security of supply will therefore be reduced during maintenance. Isolator maintenance takes 8 hours per set. At Avon there are 18 isolators.

  $P_{\text{Non-standard Config}} = (18 \text{ isolators} * 8 \text{ hrs shift}) / 3 \text{ years} = 48 \text{ hrs/ year}$

$P = (48 \text{ hrs/yr}) / (8760 \text{ hrs/yr}) = 0.00548$

- In the event of a breaker clearing a fault, the bus strip protection will operate and strip the bus-zone to which the faulty circuit is connected. If this does not clear the fault then the fault is cleared through the protection back-up system (remote ends trip, etc.). This will cause the whole yard to be switched-out. Records of the transmission voltages indicate that from January 1988 there have been 161 bus-zone operations to clear faults (these figures do not include incidents related to human intervention). Of these bus-zone operations 25 have malfunctioned and failed to clear the fault or cleared the incorrect zones. Thus the probability of the bus-strip protection failing is:

  $P_{\text{Protection Fail}} = 25/161 = 0.155$

- The Richards Bay/Empangeni load centre (industrial) is electrically coupled to the Durban load centre (CBD) via the Avon-Impala lines. Under normal operating conditions these lines provide voltage support to both load centres with little real power being transferred over these two lines. However, in the event of a line outage in either network, real power will flow towards the weakened network to compensate for the line outage. Avon substation has two infeeds from Mersey and two from Impala under normal operating conditions. The majority of the real power requirements is supplied from Mersey substation. The two Avon-Mersey lines often have to be switched out to accommodate cane burns under the lines. There were on average 150 cane burns a year under these lines and each outage lasting approximately 1 hour. The number of line outages on the Avon-Mersey lines have been reduced to approximately 20, as the line servitude was recently cleared and is now cane free. While the Avon-Mersey lines are out of service, Avon substation is supplied from Impala substation. Thus the probability of the Avon-Mersey lines being out of service is:

  $P = (20 \text{ hrs}/ 8760 \text{ hrs}) = 0.00228$

7.3.3 Scenario Identification

7.3.3.1 Scenario 1

Breaker failure under normal conditions: The breaker fails while operating under normal load or trying to clear a fault. This failure will initiate a bus trip, disconnecting the portion of busbar to which the breaker is connected. The bus strip operation will result in the isolation of the zone to which the breaker is connected. Under normal conditions it will mean the loss of a Mersey feeder, a Durban North feeder and a transformer. With catastrophic breaker failure there is the possibility of causing damage to adjacent equipment in that bay or neighbouring bays, as well as injury to staff if they are working in the yard. In this case there will be no loss of supply but there will be a severe dip on the system in the vicinity of Avon, affecting sensitive customers. The probability of a severe dip on the system is $P = 0.0625$.

7.3.3.2 Scenario 2

Breaker failure during a busbar outage: The breaker fails or explodes resulting in the isolation of the zone of the busbar to which the breaker is connected. During maintenance the feeders and the transformers are all connected to one busbar. This arrangement is equivalent to losing two zones in the event of a bus-strip. The result will be the loss of the two transformers (Transformer 1 and 2).

During isolator or busbar maintenance the breaker is linked to a non-standard arrangement and this reduces the security of supply. A breaker failure will effectively cause the loss of two zones. The probability of this occurring is:

P = (0.00548* 0.0625) = 3.43 E-4

7.3.3.3 *Scenario 3*

Breaker failure and protection malfunction: The breaker fails which results in a bus strip operation. If there is a protection malfunction such as a sticky contact, the result will be the isolation of the entire 275 kV yard. The probability of the breaker failing and the protection not operating, causing the entire station to be disconnected from the network is:

P = 0.0625 * 0.155 = 0.00969

7.3.3.4 *Scenario 4*

Breaker failure on the Impala feeder during cane burns: During an outage on the Avon-Mersey lines, Avon substation is supplied from Impala substation. A voltage collapse will occur at Avon if one of the Avon-Impala lines are out of service, resulting in the shedding of load. If this occurs, 100 MW of load would have to be shed to restore voltage stability at Avon.

P = 0.00228 * 0.0625 = 1.43 E-4

Table 7.3 summarises the impact of the feeder breaker failing.

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
Condition	**Normal condition**	**During maintenance**	**Protection failure**	**Avon/Mersey outage**
Circuits Effected	Zone B	Zone A & B 275 kV Yard	Zone A & B 275 kV Yard	Part of the Avon Load
Security of Supply	Station abnormal	Station Black-out	Station Black-out	Voltage Collapse
Effect on customers	Severe Dip	Supply Loss	Supply Loss	Load Shed
Load interrupted (EEAR) MW	None	400 MW 0.75 LF	400 MW 0.75 LF	100 MW
Event Probability	0.0625	3.43E-4	0.00969	1.43 E-4
Duration of the Interruption	-	1 hr	1 hr	1 hr
EENS (kWh)	-	103	2 907	14
Customers Cost (R150 000 / Dip)	9 375	-	-	-
Customers Cost (R 6.95 / kWh)	-	716	20 204	146

Table 7.3: Summary of possible conditions for which feeder breaker failure occurs.

7.3.4 Break-Even Cost of Unsupplied Energy

The total capital cost to replace the breaker is R 297 000. The annual cost of capital is thus

$$\text{Cost}_{\text{Refurbishment Project}} = \text{R } 297\,000 * 0.0738 = \text{R } 21\,980 \text{ per annum.}$$

The total savings on maintenance costs, that is the reduction in the maintenance of the spare breaker relative to the maintenance expenditure of the ASEA HLR presently in service on the Impala 2 bay, is then calculated. The average annual cost of maintaining the ASEA HLR is R 31 000, and the average cost of the SF_6 breaker is R 3 500 per annum. Records indicate that every time one of these breakers failed, the pole and some of the adjacent equipment had to be replaced at an average cost of R 300 000. If the breaker is replaced, then this is a saving since no capital will be spent on repairing damaged equipment. This portion of the saving amounts to (R 300 000 * 0.0625 = R 18 750 per annum).

$$\text{Cost}_{\text{Savings}} = (\text{R } 31\,000 - \text{R } 3\,500 + 18\,750) = \text{R } 46\,250 \text{ per annum.}$$

The total energy not supplied due to the constraints of the existing HLR breaker (summation of all the EENS from the Table 8.3 above)

$$\text{EENS} = (103 + 2\,907 + 14) = 3\,024 \text{ kWh per annum.}$$

The break-even cost of unsupplied energy (BECOUE) is calculated as

$$\text{BECOUE} = \text{R } (21\,980 - 46\,250) / 3\,024 \text{ kWh}$$
$$= -\text{ R } 8.03 \text{ /kWh}$$

The value obtained is negative in comparison to the value calculated in Table 7.2 (average cost to the customer for energy not supplied). This comparison should be interpreted as improvements made to the plant by the utility are justified based on the least economic cost principal.

7.3.5 NPV Calculations

In order for the project to be finally accepted, significant savings in terms of operational cost had to be verified. The NPV calculations are done for each option to determine which of the two options is the most suitable for improving of the reliability of the Avon breaker. The results for installation of the spare breaker compared with the old breaker presently in service are given in Table 7.4. See Appendix H for NPV calculation.

	Option 1 Do Nothing	**Option 2** Replace
Net Present Value R ' (000)	446	326

Table 7.4: Net present value comparison of breaker replacement versus no replacement.

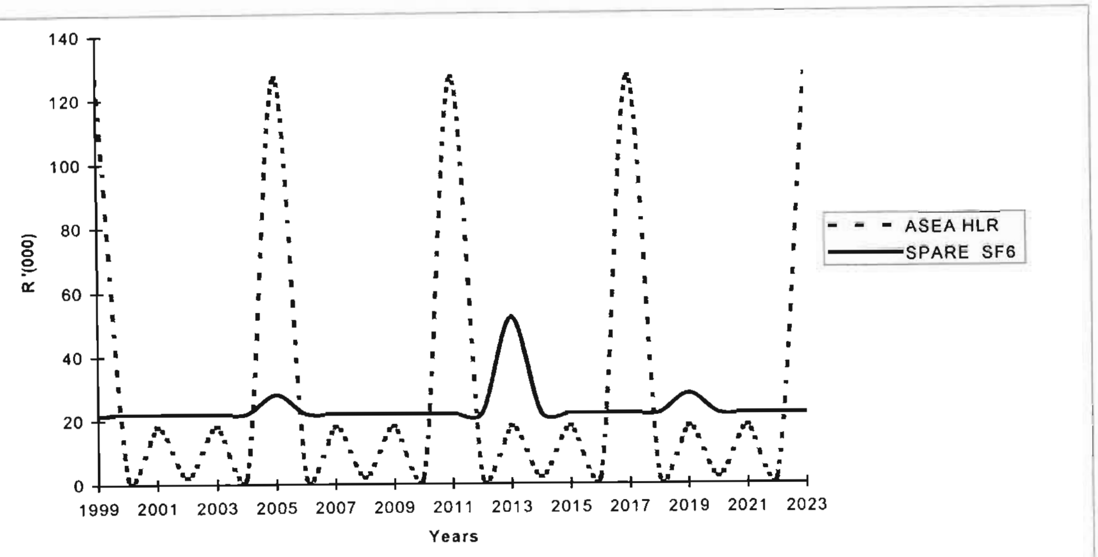

Figure 7.2: Plot of cash flow: ASEA HLR versus spare SF_6 breaker over the next twenty-year period.

Figure 7.2 is a plot of expenditure that would be required to maintain the breakers (existing and spare). The plot allows comparisons to be made in terms of cash flows. The periods just before the points of intersection would be the ideal times for the refurbishment project to take place. It is important to note that capital expenditure should be appropriately timed. In some instances the project would have to be deferred due to lack of sufficient funds. A plot of the cash flow over the write-off period would be useful when making such a decision.

For option 1 (existing HLR breaker) the expenditure is solely for maintenance of the breaker while in option 2 (spare SF_6) there are the finance charges to service the capital as well as maintenance that will be required. From these results the preferred option is to replace the Impala 2 breaker immediately in order to avoid any further expenditure to maintain the existing HLR breaker. The breaker replacement is thus justified.

7.4 Case Study 2 – Current Transformer Refurbishment

During 1998, selective inspections on the 275 kV Balteau CTs at Avon substation highlighted serious signs of deterioration and perishing of the rubber bellows. The bellows consist of two components that are made out of different rubber compositions. The first bellow is an oil side bellow for oil sealing, while the second is an airside bellow for preventing moisture ingress. After a final inspection, it was established that the rubber bellows will not last the expected service life of the CTs and the replacement is essential to maintain the integrity of the hermetically sealed system for the remaining life of the CTs. These CTs have been known to fail on the system and cause damage to adjacent plant, supply interruptions to customers and risk injury or endanger the life of operational staff. A refurbishment project was proposed to replace the bellows of these 18 units.

The least economic cost method was used to justify the capital expenditure required for refurbishing the CTs. All calculations pertaining to this technique follows.

7.4.1 Probabilities Used

The impact of a CT failure is dependent on the layout and status of the busbars in the substation as well as the availability of the protection.

- The number of 275 kV Balteau CTs that have failed on the system is 5 out of the 230 units installed. These failures have occurred over a period of nine years. The probability of a failure occurring is:

  $P_{CT\ Failure}$ = (5/ 230) * (1/9) = 0.00241 per annum

- By refurbishing the bellows the probability of failure will not be eliminated. However, the probability of failure would most likely improve by an estimated value of 0.001, giving an improvement of 0.00141.

  $P_{Improvement}$ = 0.00141

7.4.2 Scenario Identification

7.4.2.1 Scenario 1

A CT failure on the bus coupler: This will cause a severe dip but not necessarily an interruption. Due to the construction of these units, there is a fifty-percent (P=0.5) chance that the fault will be reflected on the P1 (primary) side as apposed to the P2 (secondary) side of the transformer. If the fault is reflected by the protection instrumentation as a P1 fault, then both zones will be stripped. If it is seen to be on the P2 side then only zone 1 is isolated and there will be no interruption to the supply. There are a total of 6 CTs on the bus coupler.

The probability of a severe dip on the system is P = 6*0.00141 = 0.00846, the corresponding probability of an interruption is P = 0.00846 * 0.5 = 0.00423

7.4.2.2 Scenario 2

A CT failure on one of the feeders: If the CT fails and the fault is reflected on the P2 side, then this will be seen as a line fault. There will only be an interruption in the event of a protection failure. The probability of the line protection including all the back-ups failing is very low, therefore, in this case it is ignored. However, if the fault is reflected as a P1 fault then the protection will isolate that zone and interruption to supply will only occur in the event of a protection failure. The probability of the protection failing is not calculated rather it was obtained from the performance history database of this power utility.

The statistics indicate that the probability of the bus zone protection failing is 0.155. The probability of a severe dip on the system is P = 18 * 0.00141 = 0.0253, while the probability of an interruption is P = 0.0253 * 0.5 * 0.155 = 0.00197

Table 7.5 summarises the impact of the possible current transformer failures.

	Scenario 1	Scenario 2
Condition	**Bus Coupler CT failure**	**Feeder CT failure**
Security of Supply	Station Black-out	Station Black-out
Effect on Customers	Supply Loss	Supply Loss
Megawatts Interrupted (EEAR)	400 MW 0.75 LF	400 MW 0.75 LF
Event Probability	0.00423	0.00197
Duration of the Interruption	1 hr	1 hr
EENS (kWh)	1 269	591
Cost to Customers (R150 000 / Dip)	1 269	3 795
Cost to Customers (R 6.95 / kWh)	8 820	4 107

Table 7.5: Impact of current transformer failures.

7.4.3 Break-Even Cost of Unsupplied Energy

The capital required to purchase a CT is R 185 500. The annual cost of capital is

$$\text{Cost}_{\text{Refurbishment Project}} = \text{R } 185\,500 * 0.0738 = \text{R } 13\,690 \text{ per annum}$$

Every time one of these CTs failed, the CT and some of the adjacent equipment had to be replaced at an average cost of R 160 000 per event. If the CT is refurbished then there will be a saving of (R 160 000 * 0.0625 = R 18 750).

$$\text{Cost}_{\text{Savings}} = (\text{R } 160\,000 * (0.00846 + 0.0253)) = \text{R } 5\,402 \text{ per annum}$$

The total energy not supplied due to the constraints of the existing CT (summation of all the EENS from the Table 7.4 above).

$$\text{EENS} = (1\,269 + 591) = 1\,860 \text{ kWh per annum}$$

The break-even cost of unsupplied energy (BECOUE) is calculated as:

$$\begin{aligned}\text{BECOUE} &= \text{R}(13\,690 - 5\,402) \,/\, 1\,860 \text{ kWh} \\ &= \text{R } 4.46 \text{ /kWh}\end{aligned}$$

Since the BECOUE (R 4.46 /kWh) < Cost incurred to the customer (R 6.95 /kWh) in the event of a failure, the replacement of the CT bellows is justified.

7.5 Case Study 3 – Power Transformer Replacement

At Everest substation the maintenance costs for the 500 MVA 400/132 kV transformer has doubled over the last three years. Acid level tests, dissolved gas and furanic analysis were carried out to determine ageing and condition of the paper insulation. After 25 years of service, the results indicate that there is a need to replace the existing transformer with two new 250 MVA units in order to reduce operating maintenance costs and enhance station reliability.

Due to operating and maintenance cost records being mislaid, experienced field staff were consulted to obtain an estimate of average annual values that can be used in the justification calculations. The necessary data required and obtained is given below.

Expected energy at risk	= 400 MW
Average maintenance $Cost_{old\ trfr}$ per year	= R 750 000
Average maintenance $Cost_{new\ trfrs}$ per year	= R 11 000/ transformer
$Cost_{New}$ transformers	= R 10 million
Cost of unserved energy (Industrial load)	= R 17/ kWh

Performance data and component populations surrounding the transformer in this utility is tabulated in Table 7.6.

Item	Average No. of Occurrences [3] *(per annum)*	Component Population	Probability of Occurrence *(% per annum)*
Severe Failures	5.34	328	1.628
Other Failures	12.67	295	4.295
Protection Trips	58.0	295	19.661
Busbar Isolations	38.4	207	18.569

Table 7.6: Probability of occurrence - power transformer failure.
[3] Average number of occurrences calculated over a recent 3-year period.

7.5.1 Probabilities Used

Firstly, the various scenarios for which the in-service transformer may be out of service is established based on following information:

- Severe failure which requires that the unit be removed from site for possible repairs or to be replaced by a strategic spare unit (6 to 9 weeks).
- Failure which involves an on-site repair (7 to 10 days).
- Transformer protection trip with no permanent fault detected (1 to 2 hours).
- Transformer maintenance (9 hours for a diverter switch and 15 hours for the transformer bays each year).
- HV or MV/LV busbar isolation (1 hour)

With the performance data given, it is possible to calculate the probability of the power transformer being out of service. This probability is calculated as follows.

$$P_{\text{out of service}} = [((1.628 \div 100) * 1008 \text{ hrs}) + ((4.295 \div 100) * 168 \text{ hrs}) + ((19.661 \div 100) * 1 \text{ hr}) + ((18.569 \div 100) * 1 \text{ hr}) + (9+15 \text{ hrs}) \div 8760 \text{ hrs}] = 0.005481$$

The probability of the old transformer being out of service per annum is 0.5481% or 48.013 hrs.

7.5.2 Break-Even Cost of Unsupplied Energy

The capital required to purchase the two transformers is R 10 000 000. The annual cost of capital is

$$\text{Cost}_{\text{Refurbishment Project}} = \text{R } 10\ 000\ 000 * 0.0738 = \text{R } 738\ 400 \text{ per annum}$$

If the single unit is replaced, the cost to maintain the new transformers (R 22 000 per annum) are far less in comparison to the existing unit (R 750 000). The corresponding savings is

$$\text{Cost}_{\text{Savings}} = (\text{R } 750\ 000 - 22\ 000) = \text{R } 728\ 000 \text{ per annum}$$

The total energy not supplied as a result of any possible failure discussed above is

$$\text{EENS} = 400 \text{ MW} * 0.005481 = 2\ 192 \text{ kWh per annum}$$

The break-even cost of unsupplied energy (BECOUE) is calculated as

$$\text{BECOUE} = \text{R } (738\ 000 - 728\ 000) / 2\ 192 \text{ kWh} = \text{R } 4.56 \text{ /kWh}$$

The investment of R 10 million is thus justified since the cost to the customer (R17/kWh) in the event of a failure is greater than the calculated BECOUE value of R 4.56 /kWh. However, operational cost savings need to be verified for final acceptance.

7.5.3 NPV Calculations

The Net Present Value (NPV) calculations were done for each option to determine which of the two options is the most suitable in terms of operational cost. The results for the installation of the new transformers and the old transformer presently in service are presented in Table 7.7. See Appendix I for NPV calculation.

	Option 1 Do Nothing	**Option 2** Replace
Net Present Value R ' (000)	10 338	10 303

Table 7.7: Net present value comparison of transformer replacement versus no replacement.

From the above results it is clearly evident that option 2 (to replace) is preferred. In this case the operational cost savings were not significantly high enough to obtain final acceptance.

7.6 Case Study 4 – Circuit Breaker Refurbishment

At Pegasus substation two 400 kV minimum oil restriking feeder circuit breakers need to be replaced. The option to replace the oil feeder breakers with existing SF_6 bus section and bus coupler breakers located at Pegasus was accepted after carefully evaluating various solutions. Two spare minimum oil breakers located at a station in close proximity would then replace the bus section and bus coupler breakers. These spare oil breakers have no history of restriking while being in service for 34 years. Both the breakers would have to be transported to the new site and then overhauled. The total capital cost of the project is approximately R 1.55 million.

By substituting and overhauling the breakers as proposed, substantial savings in terms of operational costs were foreseen. The economic justification was based on operational or maintenance cost reduction. This was determined as follows.

7.6.1 Operational Savings

The minimum oil feeder breakers are being replaced with existing SF_6 type, therefore, all future expenditures that would be required to maintain these breakers is considered as savings. A summary of these costs are given in Table 7.8.

Activity	**Maintenance Cost/ breaker**	**Maint. Cost/ 2 Breakers/ yr**
PMT	R 35 000 / 3yrs	R 23 500 /yr
MOT	R 75 000 /12yrs	R 12 500 /yr
	TOTAL (1)	**R 36 000 /yr**
PMT = Periodic Maintenance & Testing		MOT = Major Overhaul & Testing

Table 7.8: Breakdown of maintenance costs for the 400 kV minimum oil feeder breakers.

In the event of an oil breaker failing violently, there would be damage to surrounding plant equipment. Possible equipment that may be damaged and the cost to replace these items are listed in Table 7.9. However, the total approximate cost of a catastrophic failure is based on the probability of such an event occurring.

The probability of failure P(f), was calculated using the following performance data obtained:

Total number of restriking breakers in the entire network = 7,

Number of violent failures = 3 in 8 years.

Probability of failure – P(f) = (3/7)*(1/8) = 0.05357 /yr

Quantity	Equipment Item	Cost of Equipment
1	400 kV Circuit Breaker	R 1500 000
3	Single Phase CTs	R 600 000
3	Motorised Isolators	R 100 000
1	Labour	R 100 000
	TOTAL	**R 2300 000**
Breakdown Cost due to Restriking (Violent Failure)		***R 2300 000 * P(f)***
	TOTAL (2)	**R 123 211 /yr**
	TOTAL COST (1) + (2)	**R 159 211 /yr**

Table 7.9: Cost of a breakdown in the event of a 400 kV minimum oil feeder breaker failing catastrophically.

7.6.2 Operational Expenses

The cost to maintain the existing SF_6 breakers are not taken into consideration since they remain unchanged. The planned maintenance cycle of the spare oil breakers differs from the installed oil feeder breakers. These costs shown in the Table 7.10 would be regarded as the only additional expenses as a result of the changes being made. The cost to maintain these breakers would not change and is on-going.

Activity	Maintenance Cost/ breaker	Maint. Cost/ 2 Breakers/ yr
PMT	R 35 000 / 4yrs	R 17 500 /yr
MOT	R 75 000 / 12yrs	R 12 500 /yr
	TOTAL EXPENSES	**R 30 000 /yr**
PMT = Periodic Maintenance & Testing		MOT = Major Overhaul & Testing

Table 7.10: Breakdown of maintenance costs for the spare minimum oil feeder breakers.

7.6.3 Capital Expenditure (Justifiable Amount)

- For an NDR of 6% and the write-off period being 25 years, the **CRF** = 0.0738.
- **Net Savings** = Total Savings – Total Expenses
  = R 159 211 – R 30 000
  = R 129 211 /yr
- **Justifiable Amount** = Net Savings/CRF
  = R 129 211 / 0.0738
  = R 1 750 826

The project is thus justified since the capital amount required is estimated to be 1.55 million Rands.

7.7 Case Study 5 –Replacement of a Failed Power Transformer

At Croydon substation (near Johannesburg) a 500 MVA 400/132 kV transformer failed catastrophically after being in service for 38 years. After 27 years of operating, gas-in-oil tests indicated a high moisture content in oil of approximately 25 ppm (c.f. 20 ppm limit as defined by IEEE [7,8]. The dielectric strength of the oil was reduced to 52 kV (as determined by international standard [12]; a technique using a 2.5mm gap spacing). Three years later (i.e. after 30 years of service) the oil was reprocessed, an on-line dry-out system and a rubber bag was retrofitted to prevent further moisture ingress through the conservator. This led to a further 8 years of service before failure. The transformer was replaced at total cost of R 10million.

The replacement of the transformer was justified based on operational cost savings. An estimate of average annual maintenance cost values was used in the justification calculations. These values together with the energy at risk and the cost of un-served energy for an industrial load are presented in Table 7.11.

Expected energy at risk	= 400 MW
Average maintenance $Cost_{existing\ trfr}$ per year	= R 740 000
Average maintenance $Cost_{new\ trfrs}$ per year	= R 10 000
Cost of unserved energy (Industrial load)	= R 17/ kWh

Table 7.11: Maintenance costs (existing and new transformer), energy at risk and cost of unserved energy.

7.7.1 Probabilities Used

The probability of the transformer being out service is 0.005481 per annum. See 7.5.1 for an explanation.

7.7.2 Break-Even Cost of Unsupplied Energy

The capital required to purchase the new transformer is R 10 000 000. The annual cost of capital is

$$Cost_{Refurbishment\ Project} = R\ 10\ 000\ 000 * 0.0738 = R\ 738\ 400 \text{ per annum}$$

If the single unit is replaced, the cost to maintain the new transformers (R 10 000 per annum) is far less in comparison to the existing unit (R 740 000). The corresponding savings is

$$Cost_{Savings} = (R\ 740\ 000 - 10\ 000) = R\ 730\ 000 \text{ per annum}$$

The total energy not supplied as a result of any possible failure discussed above is

$$EENS = 400\ MW * 0.005481 = 2\ 192\ kWh \text{ per annum}$$

The break-even cost of unsupplied energy (BECOUE) is calculated as

BECOUE = R (738 000 – 730 000) / 2 192 kWh
= R 3.64 /kWh

The investment of R 10 million is thus justified since this value it is lower than cost of un-served energy specified in Table 7.11. However, operational cost savings had to be verified for final acceptance.

7.7.3 NPV Calculations

The Net Present Value (NPV) calculations were done for each option to determine which of the two options is the most suitable in terms of operational cost. The results for the installation of the new transformer and the existing transformer presently in service are presented in Table 7.12. See Appendix J for NPV calculation.

	Option 1 Do Nothing	**Option 2** Replace
Net Present Value **R ' (000)**	10 337	10 137

Table 7.12: Net present value comparison of transformer replacement versus no replacement.

With reference table 7.12 it is clearly evident that option 2 (the replacement) is justified.

CHAPTER 8: DISCUSSION

There is an increasing need for power utilities to increase the utilisation of their assets while maintaining system reliability. Asset or equipment reliability not only affects the availability of power to the customers, but also affects the economic operation of the utility. Substantial economic benefits can also be realised by maintaining and repairing equipment based on condition and operating them beyond their expected life. Because of this economic incentive, condition assessment of plant equipment and associated systems is essential. Key components of condition assessment are condition monitoring or diagnostic techniques that are employed as a means of verifying the condition for replacement/refurbishment or identifying failure or malfunction modes.

It has been established thus far that there are a number of techniques available or currently under development that can be used to assist in performing equipment assessment. However, the emphasis on special test and monitoring techniques for transformers and circuit breakers differ.

Power transformer condition evaluation is possible through some unique methods that are still being refined; however, the emphasis is being placed on more established means. Off-line testing techniques are still relied upon as the most dependable methods. It is also evident that some feasible techniques to monitor units while in-service and on-line are being made available.

There are several factors such as dielectric strength, acidity, colour of oil, dissipation factor, etc, that may reveal the condition of the transformer windings. This may be obtained via oil sampling and analysis.

Dissolved gas analysis remains the key assessment technique in determining the condition of power transformers. On-line gas analysers are available and need to be considered for application on high risk and transformers exhibiting unhealthy signs, requiring constant surveillance and nursing to a planned intervention levels and concentrations is now possible.

Partial discharge detection and localisation by acoustic means is available commercially and is being implemented with some success. The experimental results obtained in chapter 6.0 is confirmation thereof.

Experimental findings (chapter 6.0) show that when acoustic emission and gas-in-oil (on-line) data are used in conjunction, early warning and diagnosis is enhanced. As the combination of information produced by these two techniques is advantageous, it is recommended that on-line, if possible or conventional gas analysis results be taken into account when interpreting partial discharge measurements.

Techniques such as recovery voltage measurement and furfural content in oil will become an extremely valuable means of approximating the unit's remaining operational lifespan. Furanic analysis from oil samples is one test that should be conducted on all transformers to ascertain the present state of health of the insulating paper. Subsequent tests will allow the projection of remaining insulation life.

The detection of abnormalities in transformer windings is being established by off-line techniques such as frequency response analysis. On-line techniques to detect winding displacement continue to be researched. Vibration monitoring has proven to be a useful tool in determining the mechanical integrity of windings. which may be infrared scanning, although not new, are being further enhanced.

As a result of a large number of catastrophic failures occurring in a number of high voltage free-standing current transformers, there has been some experimentation with sensors for on-line monitors. Leakage current sensors (to measure capacitance and dissipation factor), acoustic sensors (to detect partial discharges) and hydrogen sensors (to detect hydrogen in oil levels) have been developed:

It may be difficult to financially justify the replacement of old technology breakers such as airblast, bulk oil and minimum oil types. However, refurbishment (life extension) or replacement decision may be achieved by some means of condition monitoring to determine condition. Condition monitoring is regarded as the ideal diagnostic tool to identify imminent failures in circuit breakers.

Key questions asked are: Do circuit breakers generally require a sophisticated condition monitoring system monitoring every possible parameter? A vast amount of data would need to be processed and there is the law of diminishing returns. The meaning of too much of data may become obscure. Continuous, on-line condition monitoring may yield returns only on breakers which operate relatively frequently, otherwise inspections of breakers may have more meaning.

The life of a transformer can be substantially extended by controlling the characteristics of the internal system i.e. controlling the oxygen and water contents. By improving the utilization of the transformer capacity the condition of the paper insulation can be maintained.

There is very little that can be done to extend the life of the internal components of instrument transformers. However, certain maintenance practices and techniques may contribute to extending life.

With regard to extending the life of circuit breakers, various factors need to be taken into consideration. These are inspection, maintenance, service history, failure of similar breakers in service, and the availability of uprating and modification kits. However, the decision to modify or uprate the breaker must be financially justified.

Five case studies have been presented in detail to demonstrate the financial techniques that can be applied to justify the refurbishment or replacement of HV plant equipment in concern. Only four of the five were economically feasible projects.

CHAPTER 9: CONCLUSIONS

A literature review was carried out to establish the available and developing monitoring or diagnostic techniques to determine the condition of major high voltage plant equipment. Power transformers were the focus of this study. The findings of the study were as follows:

- The age of plant equipment is a poor indicator of condition.
- Diagnostic tests are required to accurately assess condition to decide on refurbishment or replacement.
- No single technique exists that would guarantee the condition of equipment; however, a combination of reliable techniques would allow for vastly improved prediction of failure and decision taking.

An experiment was developed to examine issues related to condition assessment of electrical power equipment. These issues included investigating:

(1) The sensitivity of the electrical and acoustic detection to partial discharge inception voltage, and the corresponding measured PD magnitude;

(2) The detection and verification of the location of a fixed PD source; and

(3) The correlation between gas-in-oil measurements (on-line) and acoustic and electric emission data. A small scale experimental arrangement that is representative of power transformers in the field was used to investigate these issues. The test object was a small distribution transformer fitted with a point-to-sphere electrode geometry within the tank. The point anode comprised a stainless steel needle with a tip radius of 20 microns and the cathode; consisting of a 60mm brass sphere. The point-to-sphere gap lengths were varied from 20 to 50mm. When a test voltage was applied to the point anode, partial discharges were produced under oil and measurements were taken for different gap lengths. The electrical detection and measurement system was calibrated according to the method described in IEC 270. Electrical PD detection is a well-known and established technique. From the experiment the following conclusions can be drawn:

  - The detection threshold (partial discharge inception voltage) for the acoustic technique is 20% higher than the established electrical detection technique for the particular experimental arrangement used in this work.
  - For the acoustic measurement technique the mean value for the PDIV achieved is 10.78 kV. This voltage corresponds to a PD magnitude of approximately 1000 pC.
  - The partial discharge sensors are more sensitive than gas sensing technology, either on-line (hydrogen) or off-line (DGA).
  - Partial discharge detection and localisation by a combined electrical and acoustic system is effective. By placing the acoustic sensors at various locations on the transformer tank, the position of the discharge can be

estimated by measuring the signal amplitude and absolute arrival time to the sensors. The acoustic signal received with the highest amplitude and shortest duration arrival time would mean that the discharge is in close proximity.

- A small increase in dissolved hydrogen was observed at the end of the experiment therefore, a correlation between gas-in-oil measurements (on-line) and acoustic emission data could not be established.

Plant items requiring substantial amounts of capital for refurbishment/replacement or life extension can be economically justified based on the application of proposed justification methods. In order to demonstrate the use of the financial justification techniques and to enhance understanding, five case studies were presented and explained in detail. These methods were applied successfully.

CHAPTER 10: REFERENCES

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APPENDIX A: SPECIFICATION FOR PIEZO-ELECTRIC ACOUSTIC SENSORS

Model	R15
Manufacturer	Physical Acoustics Corporation
Supply Voltage	12VDC
Dimensions	29x31mm (diameter x height)
Operation Temperature	-45 °C to 177 °C
Connector Type	BNC
Case Material	Stainless Steel
Face Material	Ceramic
Frequency Range	70 to 300 kHz
Seal Type	Epoxy

APPENDIX B: SPECIFICATION FOR CORONA DETECTOR SYSTEM

Model	CDO 77A3.
Manufacturer	Hipotronics Inc.
<u>Scope</u>:	
Input	115 Vac/220 V, 1 Amp, 50/50 Hz.
Display	Straight line flat faced circuit class "C" amplified trace-locked to input frequency.
Graticle	Illuminated with centimetre divisions.
Sensitivity	Greater than 5 microvolts/cm.
Band Pass	Position 1: ±30 kHz – slot filter in amplifier. Position 2: ±70 kHz – slot filter in amplifier. Position 3: ICEA – approximately 20 – 200 kHz.
<u>Pulse Calibrator</u>:	
Input	220 Vac, 30 mA, 50/60 Hz.
Output	1, 2, 4, 10, 20, 40, 100, 250 Pico-coulombs when coupled to a 100 pF coupling capacitor.
Pulse Shape	200 μs wide, 50 ns rise time variable phasing.

APPENDIX C: DISSOLVED GAS ANALYSIS – SAMPLE 1

Submission No.: 100104469

Sampled on: 30-SEP-2001
Logged on: 10-OCT-2001
Reported on: 15-OCT-2001
Oil samples taken from transformers at UNIVERSITY OF NATAL on 30-SEP-01

Sample Id	200272942
Description	20011010-942
Position	ELECT LAB
Sampling Point	BOT DRAIN VALVE
Unit Make	NOT GIVEN
Serial Number	NOT GIVEN
Plant Voltage kV	NOT GIVEN
Capacity Mva	NOT GIVEN
Kks Number	23309
Component:	Value:
RESAMPLE DATE	N/A
ACTION	N/A
HYDROGEN	0
OXYGEN	22209
NITROGEN	39641
METHANE	1
CARBON MONOXIDE	4
CARBON DIOXIDE	367
ETHYLENE	0
ETHANE	0
ACETYLENE	0
TOP OIL TEMP (deg C)	NOT GIVEN
%GAS v/v AT N.T.P.	6.28

APPENDIX D: TECHNICAL SPECIFICATION FOR HYDRAN 201I

HYDRAN® 201 *i* INTELLIGENT TRANSMITTER

The HYDRAN® 201Ti continuous on-line intelligent Transmitter is a small, cylindrical, thermally controlled enclosure that attaches to the valve of the transformer to be monitored. It contains the HYDRAN® sensor with its microprocessor based electronics. It is used in conjunction with the HYDRAN® 201 Ci-1, HYDRAN® 201Ci-4 or the HYDRAN® 201 Ci-C controllers. It is housed in a NEMA-4X instrument enclosure.

HYDRAN® products meet the intent of Directive 89/336/EEC for Electromagnetic Compatibility.
EN 50082-1 Immunity:
IEC 801-3 RF Radiated
IEC 801-4 Fast Transients

GENERAL

Instrument Components	Sensor and micro-electronic transmitter in single cylindrical enclosure
Responds to	H_2, CO, C_2H_2, C_2H_4 (Hydrogen, Carbon Monoxide, Acetylene, Ethylene)
Medium	Electric insulating oil
Application	Transformer monitoring: specifically, detection of failure conditions in oil-filled electrical equipment; Upgrading or expansion of existing HYDRAN® 201R installations or similar cases that require the advanced capabilities of the HYDRAN® 201T*i*.

ANALYTICAL PERFORMANCE

Sensor Principle	Selective gas permeable membrane and combustible gas detector
Measurement Method	Flooded port with Dynamic Oil Sampling System
Sampling/Bleeding Port	Allen screw, 5/32", fits glass syringe with Luer stopcock
Range	0 - 2000 ppm (Volume/Volume, H2-Equivalent)
Accuracy	±10% of reading ±25 ppm for hydrogen
Relative Sensitivity to H_2	Reading = 100% of concentration
.. to CO	Reading = 18% ±3% of concentration
.. to C_2H_2	Reading = 8% ± 2% of concentration
.. to C_2H_4	Reading = 1,5% ± 0,5% of concentration
Response Time	10 minutes (to 90% of step change)

ELECTRONIC UNIT (Overview)

Hardware	Microprocessor, watchdog and time-of-day clock
Software	Real-time operating system and menu-driven interface
Functions	Gas level; hourly and daily trends (adjustable); gas level, gas trends and fail alarms; history logging; periodic sensor test; calibration, configuration and self-test; networking, modem control; remote software upgrading
Communications	One port, user selectable as RS-232 (DB-9) or isolated supervisory link
External Display	Back lit LCD, 2 lines by 16 characters
Internal Keypad	6 keys (Enter, Up, Down, Change, Escape, End)
Alarm Contacts	Gas Hi, Gas Hi-Hi, Fail; SPDT, 125VA @ 250VAC, 60W @ 220 VDC
Standard Analog Output	0-1 mA non-isolated output , 0-2000 ppm scale; 2V max. output
Output Option	Available as 4-20 mA isolated output, 1500 V RMS; 10V max. output

MISCELLANEOUS

External Enclosure	NEMA-4X (IP-66) 7" diam. x 7 1/8" white cylindrical aluminium housing
Electronic Modules	CPU and I/O modules totally encased; swappable and weather-proof
Enclosure Heating / Cooling	325 Watts heating plate plus convection cooling maintains sensor and electronics within temperature range of 15°C to 65°C (59°F to 149°F)
Enclosure to Valve Mounting	Brass adaptor with 1 1/2" male thread screws to customer valve (standard) 1" and 2" adaptors and a 1 1/2" Finned High Temperature adaptor are optional
Operating Temperature Range	Oil at the valve: -50°C to +90°C (-58°F to + 194°F); +105°C (+ 221°F) with optional finned high temperature brass adaptor Ambient: -50°C to +55°C (-58°F to +131°F)
Oil Pressure Range	0 to 700 kPa (100 PSI) gauge pressure; no vacuum allowed
Power Requirements	100 / 115 / 230 VAC, ±15%, 50 / 60 Hz, 350 VA maximum
EMI / RFI / ESD Compatibility	Meets IEEE C37.90 and IEC 255-4, 801-2, 801-4 standards
Weight	Installed: 13 lbs (6 kg) Shipping: 16 lbs (7.3 kg)

APPENDIX E: GAS SENOR READINGS

Applied Voltage = 15 kV			Gap Length = 25 mm		
DATE	TIME	HYDRAN (ppm)	PD MAG (pC)	TEMP (DegC)	
11-Aug-03	13h20	132	1300	23.9	
11-Aug-03	14h20	132	1300	23.9	
11-Aug-03	15h20	132	1300	24.2	
12-Aug-03	10h05	132	1300	23.8	
12-Aug-03	11h05	132	1300	23.9	
12-Aug-03	12h05	132	1300	24.0	
12-Aug-03	13h05	132	1300	24.0	
12-Aug-03	14h05	132	1300	24.5	
12-Aug-03	15h05	132	1300	24.6	
13-Aug-03	10h05	134	1400	21.6	
13-Aug-03	11h05	134	1400	22.3	
13-Aug-03	12h05	134	1400	22.8	
13-Aug-03	13h05	134	1400	23.4	
13-Aug-03	14h05	134	1300	23.6	
13-Aug-03	15h05	134	1300	23.9	
13-Aug-03	16h05	134	1300	24.3	
14-Aug-03	10h00	134	1300	21.3	
14-Aug-03	11h00	135	1300	22.3	
14-Aug-03	12h00	135	1300	22.8	
14-Aug-03	13h00	135	1300	22.8	
14-Aug-03	14h00	135	1300	23.2	
14-Aug-03	15h00	135	1300	23.4	
14-Aug-03	16h00	135	1300	23.6	
15-Aug-03	09h45	136	1400	21.3	
15-Aug-03	10h45	137	1400	22.3	
15-Aug-03	11h45	137	1400	23.1	
15-Aug-03	12h45	137	1400	24.2	

APPENDIX F: DISSOLVED GAS ANALYSIS – SAMPLE 2

Submission No.: 100129301

District: PINETOWN
Sampled on: 12-AUG-2003
Sampled by: R SINGH
Logged on: 01-SEP-2003
Printed on: 01-SEP-2003
Oil samples taken from transformers a UNIVERSITY OF NATAL on 12-AUG-03

Sample Id	200342449
Description	NOT GIVEN
Position	NOT GIVEN
Sampling Point	NOT GIVEN
Unit Make	NOT GIVEN
Serial Number	NOT GIVEN
Plant Voltage kV	12
Capacity Mva	0.5

Component:	Value:
RESAMPLE DATE	N/A
ACTION	N/A
HYDROGEN	64
OXYGEN	18346
NITROGEN	46030
METHANE	6
CARBON MONOXIDE	114
CARBON DIOXIDE	2140
ETHYLENE	4
ETHANE	4
ACETYLENE	3
TOP OIL TEMP (deg C)	22
%GAS v/v AT N.T.P.	6.18

APPENDIX G: DISSOLVED GAS ANALYSIS – SAMPLE 3

Submission No.: 100129303

District: PINETOWN
Sampled on: 15-AUG-2003
Sampled by: R SINGH
Logged on: 01-SEP-2003
Printed on: 01-SEP-2003
Oil samples taken from transformers a UNIVERSITY OF NATAL on 15-AUG-03

Sample Id	200342451
Description	NOT GIVEN
Position	NOT GIVEN
Sampling Point	NOT GIVEN
Unit Make	NOT GIVEN
Serial Number	NOT GIVEN
Plant Voltage kV	12
Capacity Mva	0.5
Component:	Value:
RESAMPLE DATE	N/A
ACTION	N/A
HYDROGEN	68
OXYGEN	18385
NITROGEN	45909
METHANE	7
CARBON MONOXIDE	113
CARBON DIOXIDE	2177
ETHYLENE	5
ETHANE	4
ACETYLENE	10
TOP OIL TEMP (deg C)	25
%GAS v/v AT N.T.P.	6.19

CIRCUIT BREAKER REPLACEMENT

Description of Income/Expenditure	Year	n	Value (R' 000)	PV(Cost) OLD	Description of Income/Expenditure	CASH Flow	Value (R' 000)	PV(Cost) NEW	Capital COST	
MOT, replace turbulators	1999	0	127	127.00	Annual inspection, capital cost of new bkr	320.755	0.5	297.50	297.00	
Annual Inspection and breakdown	2000	1	2	1.89	Annual inspection	23.727	0.5	0.47		
PMT, breakdown & inspections	2001	2	18	16.02	Annual inspection	23.700	0.5	0.44		
Annual Inspection and breakdown	2002	3	2	1.68	Annual inspection	23.675	0.5	0.42		
PMT, breakdown & inspections	2003	4	18	14.26	Annual inspection	23.651	0.5	0.40	1.06	
Annual Inspection and breakdown	2004	5	2	1.49	PMT and annual inspection	28.112	6.5	4.86	446.16	NPV(OLD)
MOT, replace turbulators	2005	6	127	89.53	Annual inspection	23.608	0.5	0.36	326.02	NPV(NEW)
Annual Inspection and breakdown	2006	7	2	1.33	Annual inspection	23.588	0.5	0.33		
PMT, breakdown & inspections	2007	8	18	11.29	Annual inspection	23.569	0.5	0.31		
Annual Inspection and breakdown	2008	9	2	1.18	Annual inspection	23.551	0.5	0.30		
PMT, breakdown & inspections	2009	10	18	10.05	Annual inspection	23.534	0.5	0.28		
Annual Inspection and breakdown	2010	11	2	1.05	Annual inspection	23.518	0.5	0.26		
MOT, replace turbulators	2011	12	127	63.12	Annual inspection	23.504	0.5	0.25		
Annual Inspection and breakdown	2012	13	2	0.94	MOT and annual inspection	37.555	30.5	14.30		
PMT, breakdown & inspections	2013	14	18	7.96	Annual inspection	23.476	0.5	0.22		
Annual Inspection and breakdown	2014	15	2	0.83	Annual inspection	23.464	0.5	0.21		
PMT, breakdown & inspections	2015	16	18	7.09	Annual inspection	23.452	0.5	0.20		
Annual Inspection and breakdown	2016	17	2	0.74	Annual inspection	23.441	0.5	0.19		
MOT, replace turbulators	2017	18	127	44.49	PMT and annual inspection	25.532	6.5	2.28		
Annual Inspection and breakdown	2018	19	2	0.66	Annual inspection	23.420	0.5	0.17		
PMT, breakdown & inspections	2019	20	18	5.61	Annual inspection	23.411	0.5	0.16		
Annual Inspection and breakdown	2020	21	2	0.59	Annual inspection	23.402	0.5	0.15		
PMT, breakdown & inspections	2021	22	18	5.00	Annual inspection	23.394	0.5	0.14		
Annual Inspection and breakdown	2022	23	2	0.52	Annual inspection	23.386	0.5	0.13		
MOT, replace turbulators	2022	24	127	31.37	PMT and annual inspection	24.860	6.5	1.61		
Annual Inspection and breakdown	2023	25	2	0.47	Annual inspection	23.372	0.5	0.12		
TOTALS				446.16				326.02		

Note:

MOT - Major overhaul

PMT - Period maintenance

TRANSFORMER REPLACEMENT

Description of Income/Expenditure	Year	n	Value (R' 000)	PV(Cost) OLD	Description of Income/Expenditure	CASH Flow	Value (R' 000)	PV(Cost) NEW	Capital COST	
Inspection and routine maintenance	1999	0	750	750.00	Inspection, capital cost of new trfr	10805.000	22	10022.00	10000.00	
Inspection and routine maintenance	2000	1	750	707.55	Inspection and routine maintenance	803.755	22	20.75		
Inspection and routine maintenance	2001	2	750	667.50	Inspection and routine maintenance	802.580	22	19.58		
Inspection and routine maintenance	2002	3	750	629.71	Inspection and routine maintenance	801.472	22	18.47		
Inspection and routine maintenance	2003	4	750	594.07	Inspection and routine maintenance	800.426	22	17.43	1.06	
Inspection and routine maintenance	2004	5	750	560.44	Inspection and routine maintenance	799.440	22	16.44	10338	NPV(OLD)
Inspection and routine maintenance	2005	6	750	528.72	Inspection and routine maintenance	798.509	22	15.51	10303	NPV(NEW)
Inspection and routine maintenance	2006	7	750	498.79	Inspection and routine maintenance	797.631	22	14.63		
Inspection and routine maintenance	2007	8	750	470.56	Inspection and routine maintenance	796.803	22	13.80		
Inspection and routine maintenance	2008	9	750	443.92	Inspection and routine maintenance	796.022	22	13.02		
Inspection and routine maintenance	2009	10	750	418.80	Inspection and routine maintenance	795.286	22	12.28		
Inspection and routine maintenance	2010	11	750	395.09	Inspection and routine maintenance	794.589	22	11.59		
Inspection and routine maintenance	2011	12	750	372.73	Inspection and routine maintenance	793.933	22	10.93		
Inspection and routine maintenance	2012	13	750	351.63	Inspection and routine maintenance	793.314	22	10.31		
Inspection and routine maintenance	2013	14	750	331.73	Inspection and routine maintenance	792.731	22	9.73		
Inspection and routine maintenance	2014	15	750	312.95	Inspection and routine maintenance	792.180	22	9.18		
Inspection and routine maintenance	2015	16	750	295.23	Inspection and routine maintenance	791.660	22	8.66		
Inspection and routine maintenance	2016	17	750	278.52	Inspection and routine maintenance	791.170	22	8.17		
Inspection and routine maintenance	2017	18	750	262.76	Inspection and routine maintenance	790.708	22	7.71		
Inspection and routine maintenance	2018	19	750	247.88	Inspection and routine maintenance	790.271	22	7.27		
Inspection and routine maintenance	2019	20	750	233.85	Inspection and routine maintenance	789.860	22	6.86		
Inspection and routine maintenance	2020	21	750	220.62	Inspection and routine maintenance	789.471	22	6.47		
Inspection and routine maintenance	2021	22	750	208.13	Inspection and routine maintenance	789.105	22	6.11		
Inspection and routine maintenance	2022	23	750	196.35	Inspection and routine maintenance	788.760	22	5.76		
Inspection and routine maintenance	2022	24	750	185.23	Inspection and routine maintenance	788.434	22	5.43		
Inspection and routine maintenance	2023	25	750	174.75	Inspection and routine maintenance	788.126	22	5.13		
TOTALS				10337.52				10303.23		

Note:

MOT - Major overhaul

PMT - Period maintenance

REPLACEMENT OF FAILED TRANSFORMER

Description of Income/Expenditure	Year	n	Value (R' 000)	PV(Cost) OLD	Description of Income/Expenditure	CASH Flow	Value (R' 000)	PV(Cost) NEW	Capital COST	
Inspection and routine maintenance	1999	0	750	750.00	Inspection, capital cost of new trfr	10793.000	10	10010.00	10000.00	
Inspection and routine maintenance	2000	1	750	707.55	Inspection and routine maintenance	792.434	10	9.43		
Inspection and routine maintenance	2001	2	750	667.50	Inspection and routine maintenance	791.900	10	8.90		
Inspection and routine maintenance	2002	3	750	629.71	Inspection and routine maintenance	791.396	10	8.40		
Inspection and routine maintenance	2003	4	750	594.07	Inspection and routine maintenance	790.921	10	7.92	1.06	
Inspection and routine maintenance	2004	5	750	560.44	Inspection and routine maintenance	790.473	10	7.47	10338	NPV(OLD)
Inspection and routine maintenance	2005	6	750	528.72	Inspection and routine maintenance	790.050	10	7.05	10138	NPV(NEW)
Inspection and routine maintenance	2006	7	750	498.79	Inspection and routine maintenance	789.651	10	6.65		
Inspection and routine maintenance	2007	8	750	470.56	Inspection and routine maintenance	789.274	10	6.27		
Inspection and routine maintenance	2008	9	750	443.92	Inspection and routine maintenance	788.919	10	5.92		
Inspection and routine maintenance	2009	10	750	418.80	Inspection and routine maintenance	788.584	10	5.58		
Inspection and routine maintenance	2010	11	750	395.09	Inspection and routine maintenance	788.268	10	5.27		
Inspection and routine maintenance	2011	12	750	372.73	Inspection and routine maintenance	787.970	10	4.97		
Inspection and routine maintenance	2012	13	750	351.63	Inspection and routine maintenance	787.688	10	4.69		
Inspection and routine maintenance	2013	14	750	331.73	Inspection and routine maintenance	787.423	10	4.42		
Inspection and routine maintenance	2014	15	750	312.95	Inspection and routine maintenance	787.173	10	4.17		
Inspection and routine maintenance	2015	16	750	295.23	Inspection and routine maintenance	786.936	10	3.94		
Inspection and routine maintenance	2016	17	750	278.52	Inspection and routine maintenance	786.714	10	3.71		
Inspection and routine maintenance	2017	18	750	262.76	Inspection and routine maintenance	786.503	10	3.50		
Inspection and routine maintenance	2018	19	750	247.88	Inspection and routine maintenance	786.305	10	3.31		
Inspection and routine maintenance	2019	20	750	233.85	Inspection and routine maintenance	786.118	10	3.12		
Inspection and routine maintenance	2020	21	750	220.62	Inspection and routine maintenance	785.942	10	2.94		
Inspection and routine maintenance	2021	22	750	208.13	Inspection and routine maintenance	785.776	10	2.78		
Inspection and routine maintenance	2022	23	750	196.35	Inspection and routine maintenance	785.618	10	2.62		
Inspection and routine maintenance	2022	24	750	185.23	Inspection and routine maintenance	785.470	10	2.47		
Inspection and routine maintenance	2023	25	750	174.75	Inspection and routine maintenance	785.330	10	2.33		
TOTALS				10337.52				10137.83		

Note:

MOT - Major overhaul

PMT - Period maintenance