CONDITION MONITORING OF TRANSFORMER OIL AND PAPER

A THESIS

SUBMITTED FOR THE AWARD OF THE DEGREE OF

DOCTOR OF PHILOSOPHY

BY

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CERTIFICATE

This is to certify that the thesis entitled **"Condition Monitoring of Transformer Oil and Paper"** which is being submitted by Mr. Piush Verma in fulfilment of the requirements for the award of the degree of Doctor of Philosophy in the Department of Electrical and Instrumentation Engineering, Thapar Institute of Engineering & Technology (Deemed University) Patiala, is a record of candidate's own work carried out by him under our supervision and guidance from March 2001 to December 2004. The matter presented in this thesis has not been submitted in part or full for the award of any degree in any other University or Institute.

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* Based on the studies carried out for this doctoral work, neural network study has been carried out separately which is not a part of the thesis.

PREFACE

Like other machines, transformer too has limited life. However, unlike other machines, it does not have any moving parts, except tap changers or cooling fan or pump motors. The outages, therefore, is not due to wear out. The transformers die because of deterioration of insulation over time. Generally, cellulosic paper and mineral oil form bulk of insulation in the transformer. The insulation is subjected to a variety of stresses, such as thermal, mechanical, electromagnetic, etc. Under the influence of the said stresses and in the presence of oxygen and moisture, the insulation deteriorates continuously over a period of time, eventually leading to failure. If these failures can be predicted with some degree of confidence, sudden failures can be minimized.

In view of the above, efforts are being made to understand and analyze factors responsible for determining the life of a transformer. Broadly, ageing of insulating material can be looked upon as a chemical reaction, which takes place at a rate that is influenced by thermal, electrical and mechanical stresses. All chemical reactions lead to product(s), which have physical and chemical characteristics different from the parent material. Therefore, chemical and physical characterization of the reaction product(s) may assist in monitoring the health of the insulation and hence transformer. For instance, cellulose undergoes degradation under thermal stress: the Degree of Polymerization (DP) of cellulose is reduced due to thermal ageing. Besides, it leads to the formation of reaction products, such as carbon monoxide, carbon dioxide, water, furan, etc. Furans are a family of organic compounds like 2-furfuraldehyde, 2–acetylfuran, 5-methyl-2-furfuraldehyde, furfurylalcohol, 5-hydroxymethyl -2- furfuraldehyde, etc. It is therefore, possible to estimate the extent of insulation damage by monitoring reaction product(s). Moreover, these changes in cellulose, at molecular level manifest in change of physical properties. Tensile strength, dielectric breakdown voltage, tan-δ of Kraft paper are the physical properties affected by these changes. For example, breakage of cellulose chain at microscopic level may lead to microscopic voids, which may influence the partial discharge behaviour of the material.

Over the years a number of studies, involving monitoring of one or more of above parameters, have been carried out to predict the impending death of transformer. However, the results are far from complete. Laboratory studies have been carried out to study ageing behaviour of cellulose paper and oil. Mostly the studies are confined to thermal ageing and thus do not simulate the real life situation. Alongside the aging studies, efforts have been directed to develop sensors and instrumentation for on-line monitoring of some of the mentioned properties. But, a holistic approach to the problem is somehow missing.

In the present study an accelerated aging study involving combined application of thermal and electrical stress is carried out on cellulosic paper and mineral oil. All possible properties, which are likely to be affected by degradation i.e. such as Viscosity, Moisture, Breakdown voltage, Tan-delta, Dielectric Constant, Interfacial tension, Resistivity, Acidity and Flash point of oil and paper properties like Tensile Strength, Degree of Polymerization (DP), etc. are periodically measured. A few properties, which are related to the degradation of both paper and oil, like Partial Discharge (PD) and Dissolved Gas Analysis (DGA), have also been studied. In some cases a few reaction products are formed due to combined stresses like, different gases (CO_2, H_2, C_2H_2, C_2H_4, C_2H_6, CH_4) and furanic derivatives which are dissolved in oil. The analysis of these reaction products have provided very useful information about the paper insulation system.

The dissolved gas analysis (DGA) is carried out on the aged samples to predict the incipient faults. Though there is no direct method to detect these incipient faults, it is known that these faults, especially in the form of overheating, arcing or partial discharge, develop certain gaseous hydrocarbons, that are retained by the insulating oil as dissolved gases. Thus the evaluation of these gas compositions and their interpretation, known as Dissolved Gas Analysis (DGA), seems to be one of the life saving diagnostic tests on condition monitoring of transformers.

A wide range of techniques is available for pattern recognition of PD signatures. The first significant system developed for analyses of PD signatures, as observed on an oscilloscope, was published by CIGRE in 1969. In the late 1980s computerized data acquisition became commonly available, facilitating acquisition, storage and digital processing of discharge patterns. Earlier the integrity and quality of insulation was checked by various tests like power frequency voltage withstand test, loss angle measurement, insulation resistance measurement, impulse voltage withstand test etc. But with above measurements, the minor insulation flows and improper/inefficient processing of insulation was not identified. Many cases were found where the material having a very high insulation resistance failed within an unexpected short duration. Many experiments were carried out to understand the phenomena and after various experiments and research on the progressive deterioration of the insulation, it was found that such a failure is only due to the phenomena named Partial Discharge. If there is an air gap or void in the solid insulation, the localized electrical discharge in the insulating media, which are restricted to a small part of the dielectric under test partially, bridges the insulation between the electrodes. Because of this, progressively large leakage current path develops in the insulation and results in an ultimate failure of the object. The early detection of partial discharge present in a transformer is very important to avoid/reduce the losses to the catastrophic failure of transformer. Also, once the PD is detected, the location of the same is very important so that the defects can be pinpointed and solved effectively.

The furanic compounds analysis reveals the rate of insulating paper degradation of the equipment and it directly projects the expected life. As this degradation is not observable by any other means, it is one of the essential tests to diagnose the equipment. Cellulose insulation has a structure of long chains of molecules. The cellulosic paper contains about 90% cellulose, 6-7% of hemi-cellulose and 3-4 % of lignin. Cellulose is a natural polymer of glucose and it degrades slowly as the polymer chains breakdown during service, releasing degradation products into the oil. The paper eventually degrades to such an extent that it loses all its mechanical strength and becomes susceptible to mechanical damage, which puts the electrical integrity of the equipment at risk.

Efforts have been made to identify the most sensitive properties with respect to ageing and to establish a correlation between various properties. Eventually, this knowledge data base will help in evolving a condition monitoring strategy and instrumentation for actual transformers.

Chapter 1 describes the basic construction of the transformer. The chapter also summarizes the types and properties of insulation oil and paper required for a healthy transformer. The importance of condition monitoring of transformer and its possible benefits are discussed. Historical background of transformer along with literature pertaining to life assessment of transformers is reviewed. Various conventional and innovative techniques like Dissolved Gas Analysis (DGA), Frequency Response Analysis (FRA), Furfural Analysis (FFA), Recovery Voltage Measurement (RVM), Partial Discharge (PD) and Moisture Analysis etc. for predicting transformer's life based on state of insulation are summarized. The various models and expert system for predicting life of the transformer is also discussed. Finally, scope of the study for condition monitoring of transformer oil and paper is mentioned.

Chapter 2 describes design and fabrication of test cell and oven for carrying out the accelerated ageing studies on transformer oil and paper. The accelerated ageing study is carried out under combined thermal and electrical stresses. The test cell is kept in the air-circulated oven for accelerated thermal stress at 120^0C, 140^0C and 160^0C and electrical stress from normal 1.0 kV to maximum 2.5 kV. The samples are taken out periodically at an interval of 360, 720, 1080 and 1440 hrs. The sample preparation and the various electrical, chemical and mechanical properties to be measured are described along with standard methods used.

Chapter 3 outlines the effect of accelerated thermal and electrical stress on oil and paper properties. Oil properties, such as Viscosity, Moisture, Breakdown voltage, Tan-delta, Dielectric constant, Interfacial tension, Resistivity, Acidity and Flash point and paper properties like Tensile Strength, Degree of Polymerization (DP) and BDV have been monitored periodically. The combined effect of thermal and electrical stress on the above mentioned properties are discussed. The activation energy for each parameter is found out to predict the life of the insulation. Finally, an effort is made to develop a mathematical function between the various properties and the independent variables like temperature, time, electrical stress, etc.

Chapter 4 discusses the results of Dissolved Gas Analysis (DGA), Partial Discharge (PD) and High Pressure Liquid Chromatography (HPLC). Gases like Hydrogen (H-H), Methane (CH_3-H), Ethane (CH_3-CH_3), Ethylene (CH_2=CH_2) or Acetylene (CH≡CH) evolved following thermal and electrical aging are estimated by DGA. The test cell insulation system is tested for PDs. The results of PD are correlated with dissolved gas analysis. The concentration of Furan compounds in transformer oil is evaluated by HPLC. The most common compounds like 2-furfuraldehyde, 2–acetylfuran, 5-methyl-2-furfuraldehyde, furfurylalcohol, 5-hydroxymethyl –2- furfuraldehyde are produced due to paper degradation. The results of HPLC estimation are discussed.

Chapter 5 discusses monitoring degradation of transformer cellulose paper by Scanning Electron Microscope (SEM), X-Ray Diffractometer (XRD), Fourier Transformer Infrared (FT-IR) and Differential Scanning Calorimeter/Thermo Gravimetric Analysis (DSC/TGA) techniques. The aged oil samples are also characterized by FT-IR and Nuclear Magnetic Resonance (NMR). SEM study on aged sample shows morphological changes in the paper after aging. XRD study indicates the change in crystallinity of cellulose. FT-IR study on oil and paper monitors the changes in carbonyl and hydroxyl groups in oil and paper after aging. DSC/ TGA is used to find out the phase transition of virgin and aged samples. NMR technique has been used on aged oil sample to capture the information of structural changes at the molecular level. The test results from these findings are discussed in details.

Chapter 6 is a compilation of the test data collected from the various tests and an attempt is made to establish the possible correlations between them. In the end, conclusions are made based on the study and the scope of the future work in this area is proposed.

Chapter 1

INTRODUCTION

Overview

Present chapter describes the basic construction of the transformer. The chapter also throws light on the types and properties of insulation oil and paper required for healthy transformer. The importance of condition monitoring of transformer and its possible benefits are discussed. Historical background of transformer along with literature pertaining to life assessment of transformers is reviewed. Various conventional and innovative techniques like dissolved gas analysis (DGA), frequency response analysis (FRA), furfural analysis (FFA), recovery voltage measurement (RVM), partial discharge (PD), moisture analysis etc. for predicting transformer life based on state of insulation are summarized. The various models and expert system for predicting life of the transformer is also discussed. Finally, scope of the study for condition monitoring of transformer oil and paper is mentioned.

1.0 Transformer

A transformer is essentially a static electromagnetic device consisting of two or more windings which link with a common magnetic field. The main purpose of power or distribution transformer is to transfer electric power from one voltage level to another. It works on the principal of electromagnetic induction. The main components of the transformer are core, winding, insulation (solid or liquid) and tank. The purpose of the transformer core is to provide a low reluctance path for the magnetic flux linking the primary and secondary windings. The primary and secondary windings are so arranged as to reduce the leakage flux in the transformer. In doing so the core experiences iron loss due to hysteresis and eddy currents flow, which manifest themselves as heat. Research and development in the material used for transformer core has resulted not only the losses but also reduction of the noise.

Power Transformer windings have mostly been made from hard half drawn annealed copper, but aluminum is also used depending upon the rating and the cost involved. Normally multiple layer-winding system is used because the impulse voltage is shared between the layers. This gives a much better distribution of voltages than a disc winding where a large part of the voltage is across the first few coils.

Transformer insulation is provided mainly through mineral oil and Kraft paper. Ferranti recognized their benefits for the transformer as far back as 1891. The mineral oil is still being used with better refining and selection.

Transformer tanks in nineteenth century were generally of the cast iron type. Since then transformers have almost invariably been constructed from welded plates. For cooling the transformer, different methods are used subject to its capacity and requirement as condition of operation, overall size limitation, capitalization of losses, etc. Suitable bushings are used for insulating and bringing the terminals of the windings out of the case.

1.1 Historical Background of Transformer

In 1831, Faraday induced a voltage pulse across the secondary terminals of his experimental apparatus by interrupting the flow of direct current. In 1836, G.J.Page repeated the experiment in his open-core device that would today be called an auto transformer. In 1838, N.J.Callon again repeated the experiments of Faraday.

At the GANZ Factory in Budapest, (originally an iron foundry established by the successful Swiss iron-founder, Abraham Ganz in 1884), the first closed core transformer was built on 16th September 1884 under the guidance of M. Dery, O.Blathy and K.Zipernovsky. The capacity of this transformer was 1400 VA, its frequency 40 Hz and its voltage ratio 120/72 V. The GANZ inventors were the first to use the term “transformer” in their patent application, a name created from the Latin. M.O. Dolivo-Dobrowolsky, an engineer working with AEG in Germany, invented the three-phase transformer in 1890 and in the same year the first oil-cooled, oil–insulated transformer was constructed by Brown. The oil-cellulose two-phase insulation system opened the way to higher capacities and voltage levels. At present, transformer designers are aiming at 2000 MVA capacity or more and units of 1500 kV voltage rating are now at the experimental operation.

With growing capacities, an ever-increasing reliability of products in service is demanded of power transmission systems. The design of transformers is based on the expected sustained and short-term power-frequency voltage stresses originating on the network and those caused by lightning and switching surges. Besides, the growing geometrical dimensions, disposal of heat losses and the determination of local hot spots resulting from stray magnetic fields are factors of increasing concern in the design.

International standardization is trying to establish a basis for proving compliance with the requirements of service reliability by specifying up-to-date test methods, but progress in this field is by no means complete. Thus the partial discharge tests specified for judging the state of insulation give insufficient information for either the location of internal discharges or the degree of hazard associated with them; no measuring or computing methods are yet known for locating hot spots, and only very few short-circuit laboratories are available which are capable of performing the required tests on power transformers of high ratings.

Technological advances in recent decades have accustomed the development engineer to rapid changes, a phenomenon that will have to be taken into account when considering the future of transformers. It seems that in near future, the transformer will still remain an important element of power systems. It is not easy to predict what new requirements will be raised in the years to come. In any case, the present state of the art is surely an important link in the chain leading into the future.

1.2 Insulating Materials

These are the materials, which permit only a negligible current (order of pA) to flow in phase with the applied voltage. Insulating materials or insulants are extremely diverse in origin and properties. They are essentially non-metallic, organic or inorganic; uniform or heterogeneous in composition; natural or synthetic. Many of them are of natural origin as, for example, paper, cloth, paraffin wax and natural resins. Wide use is made of many inorganic insulating materials such as glass, ceramics and mica. Many of the insulating materials are man-made products manufactured in the form of resins, glass, ceramics, etc. In the recent years wide use is made of new materials whose composition and properties place them in an intermediate position between inorganic and organic substances. These are the synthetic organo-silicon compounds, generally termed as silicones.

1.2.1 Properties of insulating materials

There are many properties, which characterize the insulating materials, e.g. resistivity, breakdown voltage, permittivity and dielectric loss, etc. An ideal insulating material should have:

- High dielectric strength sustained at elevated temperature
- High resistivity
- Good thermal conductivity
- High tensile and shear strength of solid insulation
- High degree of thermal stability

In addition to the above properties, the material should have good other mechanical properties such as ability to withstand moisture (it should be non-hygroscopic), vibration, abrasion and bending. Also, it should be able to withstand chemical attack, heat and other adverse conditions of service.

1.2.2 Transformer Oil

Oil used for insulation in transformers is mineral oil and it is obtained by refining crude petroleum. Animal oils and vegetable oils are not used for this purpose as these form fatty acids on heating which are corrosive for the cellulosic paper used in insulation. Mineral oils were in use as liquid dielectrics in electrical equipment for over hundred years now. Despite the availability of a variety of synthetic oils, with far more superior properties, mineral oils held its way, due to their abundant availability and economy.

Three properties that are fundamental to use of mineral oil as dielectric are:

- High insulating property,
- Good oxidative and ageing stability and good heat transferability.

The reliable performance of mineral insulating oil in an insulation system depends upon certain basic oil characteristics, which can affect the overall performance of the electrical equipment:

- High electric strength to withstand the stresses in service
- Sufficiently low viscosity so that its ability to circulate and transfer heat is not impaired
- Adequate low temperature properties down to the extreme of climatic conditions expected at the installation site
- Proper oxidation resistance to ensure long life in service
- Good resistance to emulsion to prevent holding water in suspension in it
- Free from inorganic acid, alkali and corrosive sulphur which causes corrosion of metal parts and insulation and accelerate the production of sludge
- Free from sludging under normal separating conditions
- High flash/fire points
- Low pour point

- Low water content

The main requirements of transformer oil as listed in various national and international standards only state the minimum requirements for transformer oil (table 1.1), whereas many transformer producers and electricity companies and boards have their own stringent specifications based on the required conditions. With advanced refining techniques, it is possible to produce transformer oil tailor-made to suit the exact requirements for such specification.

Table 1.1 Characteristic requirements of IS, IEC, and BS specification for uninhibited transformer oil

S. No.	Characteristics	IS-335 (1993)	IEC-296 (Class I)	IEC-296 (Class II)	BS-148 (Class I)
1.	Appearance	The oil shall be clear, transparent and free from suspended matter or sediments.			
2.	Density (g/cm^3)	0.89 @ 29.5°C(max)	0.895 @ 20°C(max)	0.895 @ 20°C(max)	0.895 @ 20°C(max)
3.	Kinematic Viscosity (cSt)	27 max. @ 27°C	16.5 max. @ 40°C 800 max. @-15°C	11.0 max. @40°C	16.5 max. @40°C 800 max. @ 15^{o}C
4.	Interfacial tension N/m (min.)	0.04	-	-	-
5.	Flash point ^{o}C (min.)	140	140	130	140
6.	Pour point, ^{o}C (max)	-6	-30	-45	-30
7.	Electric Strength (BDV), kV i. New unfiltered oil ii. After filtration	30 (min.) 60 (min.)	30 (min.) 50 (min.)	30 (min.) 50 (min.)	30 (min) (As delivered)
8.	Tan delta @ 90^{o}C	0.002 (max)	0.005 (max)	0.005 (max)	0.005 (max)
9.	Resistivity @ 90^{o}C @ 27^{o}C, Ω cm	35x10^{12} (min) 1500x10^{12} (min)	-	-	-
10.	Oxidation stability 164 hrs. i. Neutralization	0.4 (max.)	0.4 (max.)	0.4 (max.)	1.5 (max.)

	value, mg. KOH/gm ii. Sludge content % by wt.	0.1 (max.)	0.1 (max.)	0.1 (max.)	1.0 (max.)
11.	Neutralization value i. Total acidity mg. KOH/gm ii. Sludge content % by wt.	0.03 Nil	0.03 -	0.03 -	0.03 -
12.	Corrosive sulphur	Non-corrosive	Non-corrosive	Non-corrosive	Non-corrosive
13.	Oxidation inhibitor	0.05% max. is treated as absence of inhibitor	Non detectable	Non detectable	Non detectable
14.	Water content (ppm)	50 (max.)	40 (max.)	40	-
15.	S.K. Value	Under consideration	-	-	-
16.	Accelerated Ageing Test (open beaker method with copper catalyst) i. Resistivity @ 27°C ii. Resistivity @ 90°C iii. Tan Delta at 90°C iv. Total Acidity mg. KOH/gm v. Total Sludge	 2.5×10^{12} Ωcm. (min) 0.2×10^{12} Ωcm. (min) 0.2 (max.) 0.05 (max.) 0.05% by wt. (max.)	-	-	-
17.	Gassing tendency	-	-	-	+5 (max.)

1.2.2.1 Insulating Oil Quality

The condition of the oil greatly affects the performance and the service life of transformers. A combination of electrical, physical and chemical tests is performed to measure the change in the electrical properties, extent of contamination, and the degree of deterioration in the insulating oil.

The results are used to establish preventive maintenance procedures, to avoid costly shutdowns and premature equipment failure, and extend the service life of the equipment. There is a multitude of tests available for insulating oil. Threshold levels for these tests are specified in ASTM D3487 for new oils and IEEE Guide 637-1985 for service oils. As paper degrades, a number of specific furanic compounds are produced and dissolved in the oil. The presence of these compounds is related to the strength of the paper as measured by its degree of polymerization (DP). Furan and phenol measurement in oil is a convenient, noninvasive method to assess the condition of the paper insulation. Transformer oil samples should be analyzed for furans and phenols when one or more of the following conditions exist:

- Overheating or overloading of the transformer,
- High levels of carbon monoxide or carbon dioxide,
- Rapid decrease of interfacial tension without a corresponding increase in acid number,
- Sudden darkening of the oil
- Sudden increase of the moisture content of the oil, transformers over 25 years old.

1.2.3 Paper Insulation

Insulation grade paper is made by the delignification of wood pulp by the Kraft process. It contains about 90% cellulose, 6-7% lignin and, the balance is hemicellulose. The natural humidity of paper is 4-5% by weight and the insulation is dried after winding to less than 0.5%. The dried paper is impregnated with insulating oil, which increases its dielectric strength and also serves to cool the windings. Table 1.2 represents the specification of electrical grade paper. The major constituent of paper is cellulose, which is a natural polymer of glucose. Power transformer conductor windings are insulated by paper impregnated with insulating oil, which is expected to last the life of the transformer (25 years minimum at an operating temperature of 65-95^{o}C). A typical 600 MVA transformer contains 12 t of paper, 30-120 μm thick (density 0.7-0.8 g/cm^3), and 45 t

(40,000 l) of oil. Heat, water and oxygen degrade (depolymerise) the cellulose, reducing the polymer molecular chain length and with it the mechanical strength of the material. Local mechanical failure could lead to short the turns or paper fragments or fibers in the oil ducts and hence to dielectric or thermal failure of the insulation system. Changes in the compliance and tension of the windings with time may result in distortion and an increased susceptibility to short-circuit force failure of the aged insulation or even of the winding itself. Water is a product of ageing. Its presence in the insulation increases conductivity and the likelihood of gas bubble formation, reducing the thermal stability of the insulation system during overload conditions.

In order to serve as a good insulant, paper should have the following properties:

- Good breakdown voltage
- High resistivity
- Low dissipation factor
- Low conductivity of extract
- Good tensile strength
- High degree of polymerization
- Low cost

Table 1.2 Electrical grade papers specification as per IEC 554-3-5 1984 (Rev. 3)

S.No.	**Properties**	**Specifications**
1.	Substance (g/m^2)	30.4-40.0 ± 10%
2.	Thickness (Micron)	38-50 ± 10%
3.	Apparent Density (g/cc)	0.80 ±0.05
4.	Tear Index (MNm^2/g) Min MD CD	 5 6
5.	Tensile Index (Nm/g) Min MD CD	 93 34
6.	Water Absorption (mm) MD CD	 8 8
7.	Electric strength (In Air at 90^{o}C) min. (kV/mm)	7.0
8.	Air permeability (μm/Pa.Sec.)	0.5-1.0
9.	Ash content Max (%)	1.0
10.	Conductivity of Aqueous Extract Max. (mS/m)	10.0
11.	pH of Aqueous Extract	6-8
12.	Moisture content Max. (%)	8.0
13.	Heat Stability Max. % (mS/m) At 120^{o}C, 168 Hours) 1. Decrease in Burst Strength 2. Increase in Conductivity	 20 23

1.2.4 Recent Advances in Transformer Insulation

The most important insulating materials of optimum dielectric strength properties that have been used in large high-voltage transformers through almost a century are the oil-impregnated, cellulose-based products: primarily paper and pressboard. The bushings used for taking out the ends of transformer windings from the tank oil-impregnated paper, or resin-bonded or resin-impregnated paper, are also employed as insulation in the inside of ceramic shell. In the internal insulation, mainly where high mechanical strength is also required, phenol-based paper is still employed. However the dielectric strength of this material, mainly its creep-age strength, is much poorer than that of the pressboard. Parts of laminated wood are used to bear only mechanically stressed. The low electric stress that may arise in these parts is insignificant, if they are carefully processed (i.e. with all voids of air eliminated). In recent designs, oil resistant enamel is also employed as inter-turn insulation, although it is less capable of withstanding mechanical stresses (caused by thermal displacements and short – circuit forces) than oil –impregnated paper insulation.

In recent years, the use of high-pressure (5 bar) SF_6 gas has been proposed instead of oil as an insulating medium of transformers. The most significant advantage of SF_6 insulation for large transformers is the much higher inter-turn dielectric stress that may be imposed on the inter-turn insulation. Thereby, a considerable decrease in the dimensions of windings can be achieved. Also the thermal stress of insulation may be much higher, permitting the application of significantly increased current densities with unchanged conditions of cooling. Thus, the quantity of materials built into the transformer also decreases, resulting in a reduction of weight for transport. A further advantage of SF_6 gas insulated transformers is that hardly any ageing of pressboard insulation occurs in SF_6 gas.

A problem is imposed, however, in designing the tank that has to withstand an internal pressure exceeding 5 bar. In addition, certain operating experiences indicate that a transformer of such design is not necessarily the optimum solution from an economical point of view. Nevertheless, it has been concluded from model tests that even 500 MVA, 500 kV transformers could be realized by this insulation system.

In smaller power transformers, silicon oil is also used as an insulating medium instead of mineral oil and Kraft paper can be replaced by “nylon-paper”(a synthetic sheet material). Such nylon-papers are made by a process similar to that employed in the manufacture of Kraft paper, but use of aromatic polyamide fibers and flakes (e.g. NOMEX Aramid paper) are reported. Since aromatic cyclical elements are introduced into the polymeric ring, several properties of the materials thus obtained will be superior to those of linear polycondensates, such as polyamides. The most important property of these materials is their high thermal stability. Their dielectric strength is excellent, being above that of Kraft paper, and they retain this property for a sustained period even at 180- 200°C for short periods of time. In such cases it may prove more economical to install, instead of a transformer of higher rating, a smaller transformer provided with “nylon-paper” inter-turn insulation. Because of the higher costs involved, as in the case of silicon oil, this type of insulation is seldom adopted, and even then is used mainly in transformers of smaller rating.

In any case, the manufacture of large power transformers, no kind of plastic insulation has so far succeeded in superseding the oil-impregnated paper and oil-impregnated pressboard insulations. Due to their high dielectric strength, their excellent cooling properties and the possibility of their easy regeneration, these insulation systems are being used even in transformers of presently highest voltage ratings, and it is most improbable that any other kind of insulation system could take over their place in the near future. Therefore, only the oil-impregnated paper seems to be the best option even till date.

1.3 Condition Monitoring of Transformers

Considerable amounts of money have been invested in the installed power equipment in the electrical energy systems. Power transformers are an important part of it. They represent a valuable asset for the utilities, and are expected to be functional over tens of years. In earlier days it could happen that power transformers with long operational years and considerable ‘weak’ or a potential source of trouble were ‘simply’ replaced. Money was ‘no problem’ and the final energy customer had to pay the bill in the end. Today the paradigm has changed and considerable efforts are directed into finding new approaches using transformer monitoring, diagnosis and life assessment [1].

The stronger constraints that have faced transformer users stem from two major factors: The deregulation of the energy market and advances in science and technology. The deregulation pressures are reflected in efforts for:

- Costs reduction, which is affecting maintenance, replacement, repair and upgrade philosophies
- Increase power transformer availability, in order to assure power quality and customer satisfaction
- Handling unprecedented power flow patterns in the system

Consequences of the changing situation on the market have been a trend to allow higher transformer overloads, to work power transformers longer and to take all necessary additional measures to achieve that. These two facts imply that the transformer user accepts a higher risk in operation but at the same time a high availability is required. However, the operation of power transformer units is desired to occur with as low as possible costs and by many utilities there is a continuous reduction in staff and repair facilities. These aspects bear an intrinsic contradiction! This cannot be solved without improved means of transformer life assessment and condition evaluation, monitoring and diagnosis.

Another important aspect influencing the need for condition evaluation is that there is an ageing population of transformers installed at the industries and in the transmission and distribution networks. Several of these were installed during a fairly narrow time span, 20-30 years ago, when large investments were made in the electric infrastructure. These transformers have been exposed to various accumulative deterioration stresses and will eventually attain a higher risk of failure and will approach their expected end-of-life. This fact may cause the owner of the population to see an increased number of transformers being in the need of refurbishment, repair or replacement if not jeopardizing the reliability or availability of power. The life assessment and condition evaluation techniques thus take on the task of assessment of the transformer on a broader basis in a holistic view.

1.3.1 Benefits of Condition Monitoring

- Timely filled measurements
- Confirmation, on the spot, of the presence of the faults gases in the event of alarms
- On time proactive decision making
- Reducing unplanned outages
- More predictable and reliable maintenance schedules
- Prevention of catastrophic failure and destruction of peripheral equipment
- Reduced maintenance costs

- The results provide a quality control feature, limiting the probability of destructive failures

This leads to improvements in operator safety and quality of supply, limiting the severity of any damage incurred, elimination of consequential repair activities and identifying the root causes of failures. Information is provided on the plant operating life enabling business decisions to be made either on plant refurbishment or replacement, safer work environment.

As transformers age, their internal condition degrades, which increases the risk of failure. Failures are usually triggered by severe conditions, such as lightning strikes, switching transients, short-circuits, or other incidents. When the transformer is new, it has sufficient electrical and mechanical strength to withstand unusual system conditions. As transformers age, their insulation strength can degrade to the point that they cannot withstand system events such as short-circuit faults or transient over voltages.

To prevent these failures and to maintain transformers in good operating condition is a very important issue for utilities. Traditionally, routine preventative maintenance programs combined with regular testing were used. With deregulation, it has become increasingly necessary to reduce maintenance costs and equipment inventories. This has led to reductions in routine maintenance. The need to reduce costs has also resulted in reductions in spare transformer capacity and increases in average loading. There is also trend in the industry to move from traditional time-based maintenance programs to condition-based maintenance. These changes occur at a time when the average age of the transformers in service is increasing and approaching the end of nominal design life.

The change to condition-based maintenance has resulted in the reduction, or even elimination, of routine time-based maintenance. Instead of doing maintenance at a regular interval, maintenance is only carried out if the condition of the equipment requires it. Hence, there is an increasing need for better nonintrusive diagnostic and monitoring tools to assess the internal condition of the transformers. If there is a problem, the transformer can then be repaired or replaced before it fails.

Many testing and monitoring techniques have been used by utilities. This chapter reviews the existing monitoring and diagnostic methods and future trends.

1.4 Literature Review

1.4.1 Power Transformer Failures and Problems

Transformer failure can occur as a result of different causes and conditions. Generally, transformer failures can be defined as follows [1,2].

- Forced outage due to transformer damage in service (e.g., winding damage, tap-changer failure).
- Trouble that requires removal of the transformer for return to a repair facility, or which requires extensive field repair (e.g., excessive gas production, high moisture levels).

Transformer failures can be broadly categorized as electrical, mechanical, or thermal. The cause of a failure can be internal or external. Table 1.3 lists typical causes of failures. In addition to failures in the main tank, failures can also occur in the bushings, in the tap changers, or in the transformer accessories.

Table 1.3 Typical causes of transformer failures

Internal causes	External causes
Insulation deterioration	Lighting strikes/temperature
Loss of winding clamping	System switching operations/thermal
Overheating	System overload
Oxygen	System faults (short circuit)
Moisture	
Solid contamination in the insulating oil	
Partial discharge	
Design & manufacture defects	
Winding resonance	

The failure pattern of transformers follows a “bath-tub” curve, as shown in figure 1.1. The first part of the curve is failure due to infant mortality; the second part of the curve is the constant failure rate; and the last part of the curve is failure due to old age. In addition to normal ageing, a transformer may develop a fault that results in faster-than-normal ageing, resulting in a higher probability of failure.

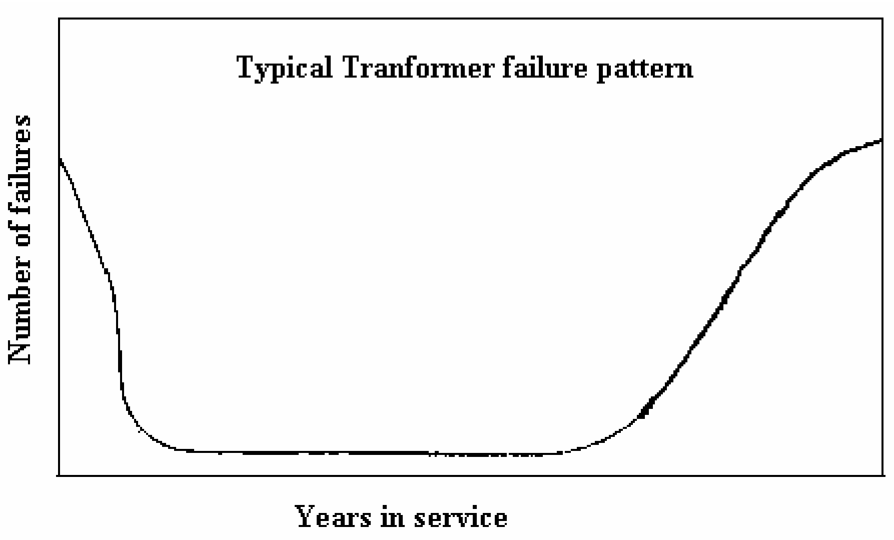


Fig. 1.1 Bathtub failure curve

Power transformers have proven to be reliable in normal operation with a global failure rate of 1-2 percent per year. The large investment in generating capacity after the Second World War continued into the early 1970’s has resulted in a transformer population that, in theory, is fast approaching the end of life [3]. The end of life of a transformer is typically defined as the loss of mechanical strength of the solid insulation in the windings. These power transformers are at the last stage of the “bathtub” curve. They are expected to have an increasing failure rate in the next few years.

A survey [4] indicates that the main causes (51 percent of transformer failures in a five-year period) are due to the following problems:

- Moisture, contamination and ageing which causes the transformer’s internal dielectric strength to decrease,
- Damage to the winding or decompression of the winding under short circuit forces, or

- Damage to the transformer bushings caused by loss of dielectric strength of the internal insulation.

An American utility reported four single-phase EHV autotransformer failures due to transformer winding resonance [5]. All of the failures involved the breakdown of the no-load tap changers immediately after the transmission system was energized. The utility also experienced three 25/765 kV, 500 MVA generator step-up transformer failures and two 765 kV, 80 MVA reserve auxiliary transformer failures; all of the failures were dielectric in nature [6].

Another survey done by a CIGRE working group on failures in large power transformers [1] found that about 41% of failures were due to on-load tap changers (O.L.T.C) and about 19 % were due to the windings. Figure 1.2 shows the percentage failure distribution for power transformers with on-load tap changers.

The failure origins were 53 percent mechanical and 31 percent dielectric. On transformers without on-load tap changers, 26.6 percent of failures were due to the windings, 6.4 percent were due to the magnetic circuit, 33.3 percent were due to terminals, 17.4 percent were due to the tank and dielectric fluid, 11 percent were due to other accessories, and 4.6 percent were due to the tap changer.

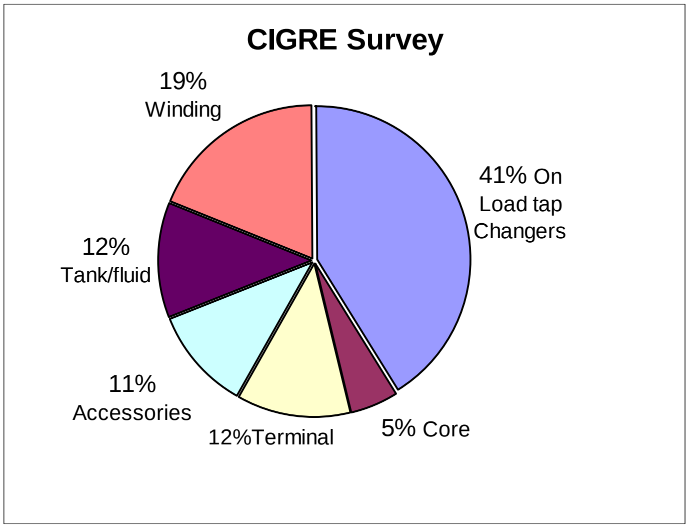


Fig. 1.2 Percentage failure of power transformers with on-load tap changers.

Another report presents transformer failure data in South Africa [7]. This failure analysis was based on 188 power transformers in the voltage range of 88 kV to 765 kV with ratings from 20 to 800 MVA. Failure statistics for large transformers that had been in service between 15 and 25 years are shown in figure 1.3 [4]. The above surveys and research results indicate that load tap changers, windings, insulation ageing, and contamination are the key sources of transformer failures. Another report [8] indicates that the average number of failures over a four-year period (1975 to 1979) was 2.6 failures per year per 100 transformers. The cost and time to repair and replace a power transformer is very high. The repair and replacement of a 345/138 kV transformer normally requires about 12-15 months. If a spare is available, the time needed for replacement of a failed unit is in the range of 8-12 weeks.

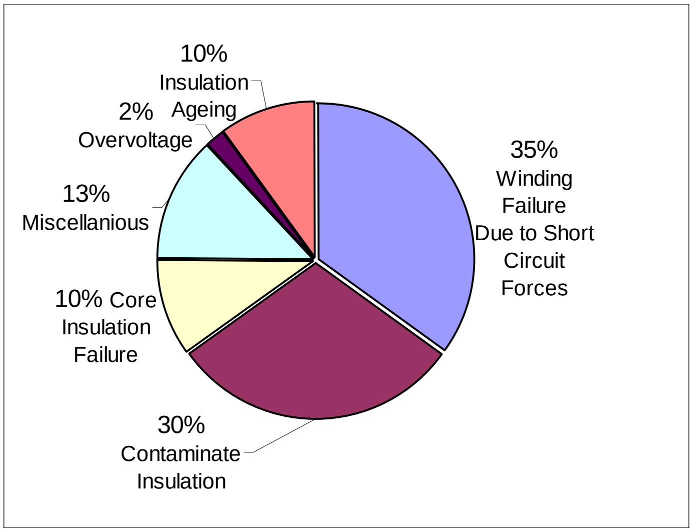


Fig. 1.3 Failure statistics for large transformers in service between 15 and 25 year

1.4.2 Transformer Life Management

Transformer life management has gained an increasing acceptance in the past 10-15 years, due to economic and technical reasons. The fundamental objective is to promote the longest possible service life and to minimize lifetime operating costs. The importance of this issue [9-15] has led to a lot of research in this area. In general, transformer life is equal to the insulation life, which depends on mechanical strength and electrical integrity.

Insulation degradation consists of hydrolytic, oxidative and thermal degradation. The ageing and life of a transformer has been defined as the life of the paper insulation [10]. Several ageing mechanisms were identified as follows:

- Applied mechanical forces
- Thermal ageing (chemical reactions)
- Voltage stresses
- Contamination

The transformer is subjected to mechanical forces due to transportation, electromagnetic forces caused by system short circuits, and inrush current. Vibration and thermal forces, generated by different thermal expansion rates in different materials, cause long-term degradation of the paper. The eventual dielectric failure may occur when the mechanical forces rupture the insulation. The compressive mechanical forces on the cellulose paper can cause material flow and cause clamping pressure to reduce. Thus the ageing of paper insulation determines the ultimate life of the transformer, although other factors may contribute to earlier failure.

Thermal ageing of transformer insulating materials is associated with the chemical reactions occurring within the materials. These chemical reactions are caused by pyrolysis oxidation and hydrolysis, and are accelerated by increased levels of temperature and of the oxygen and moisture contents. Apart from the chemical reaction, there is a reduction in the mechanical properties of cellulose paper. The paper insulation becomes brittle to the point of almost falling apart, but it still retains an acceptable level of dielectric strength.

The temperature of a transformer has a major impact on the life of the insulation. Continuous on-line monitoring of the transformer oil temperature along with a thermal model of the transformer can give an estimate of the loss of life of the transformer due to overheating. Current industry standards limit maximum allowable hot spot temperatures in transformers to 140°C with conventional oil/paper insulation.

The accelerated electric stress is an important factor considered in the oxidation of the oil. The weight and dimension restrictions of the transformer lead to a decrease in insulation clearances. Consequently, the oil ducts also become narrower and hence the strength of the electrical field increases which exerts a great effect on the oxidation process. Essentially, the electric stress supplies the energy (approximately 4 eV) required for the cleavage of a covalent bond. Forster describes the mechanism by which the high voltage field interacts with the chemistry of insulating oil. His extensive research in this field reveals the hidden source of energy capable of breaking covalent bonds. It consists of the electrons that escape from the conduction band and manage to leave the surface of the metal conductor, especially during very short but frequent communication voltage surges. The collision of these free electrons, injected into the liquid insulation, is inevitably followed by the electronic excitation of hydrocarbon molecules.

$$M \xrightarrow{h\nu} M^*$$

Whereas M is molecule, M* excited molecule, h is plank's constant and ν is the frequency of light.

While a stable molecule that reaches its singlet excitation level usually releases the absorbed energy as a quanta of light,

$$M^* \longrightarrow M + h\nu$$

The molecule decomposes and generates a pair of free radicals. Both of these fragments have an unpaired electron and is an important factor affecting the stability of oil. While the hydrogen atom can couple its electron with another similar low molecular weight fragments evolving as a gas, the rest of chain left in the oil may catch a free electron. Such a large segment may then become a charge carrier, or it may combine with another free radical of the same size to generate an insoluble colloidal suspension.

$H + H \longrightarrow H_2$ that detected by DGA

$R + e^- \longrightarrow R^-$

Charge carrier causing an increase in the dissipation factor of the oil.

$R + R \longrightarrow R\text{-}R$

Insoluble suspension having a molecular weight between 500 & 600.
The accumulation of the colloidal suspensions is of particular interest in sealed transformers, especially when DGA indicates the existence of a hot spot or an incipient electrical failure.

End of life may be dictated by any one factor or by a combination of factors. Much attention has been given to a paper ageing as a cause of transformer failure. While it is undoubtedly a factor in reducing life, it does not automatically lead to failure; some other influence is normally required, such as mechanical shock. In industry loadings guides (e.g., IEC, ANSI and IEEE) the principal factor for end of life relates only to transformer's thermal factor. A classical method of calculating the remaining life of a transformer has been the Arrhenius-Dakin formula:

$$\text{Remaining life} = Ae^{-B/T}$$

Where, A: initial life; B: constant, depending on the properties of the material studied; and T: absolute temperature in K.

A more comprehensive approach is clearly needed to evaluate the remaining life of a transformer as a whole. The other factors affecting the probability of failure are not as easily quantified as thermal ageing. To assess the overall condition of a transformer reliably, several monitoring techniques are used and are under investigation. The most common monitoring/testing methods used for transformer condition assessment are discussed by M. Darveniza et.al., G. Breen et.al. and Z. Wang et.al. [11,16,76].

The traditional routine tests are: transformer ratio measurement, winding resistance, short-circuit impedance and loss, excitation impedance, and dissipation factor and capacitance, as well as applied and induced potential tests. These tests usually give information on faults in windings, winding conductor and joint problems, winding deformation, oil moisture and contamination, and dielectric problems. Special tests include partial discharge measurement, frequency response analysis, vibration analysis, infrared examination, voltage recovery, and degree of polymerization. These detect problems such as local partial discharge, winding looseness and displacement, slack winding and mechanical faults, hot spot on connection, moisture in paper and ageing of paper, as well as insulation degradation.

Oil tests are used extensively. They consist of dissolved gas analysis (DGA) with ratio analysis, furan analysis, water content, resistivity, acidity, interfacial tension (IFT), and dissipation factor (DF). These detect oil incipient faults, overheating, ageing of paper, and dryness of oil-paper and ageing of oil.

Life assessment of large transformers may be performed for the following reasons [12]:

- To monitor the condition of transformers and provide an early warning of faults.
- To diagnose problems when transformers exhibit signs of distress or following the operation of protection equipment.
- To determine whether a transformer is in suitable condition to cope with unusual operating conditions.
- To obtain reference results to assist in the interpretation of subsequent tests.
- To assist in planning the replacement strategy for a population of transformers
- To satisfy the requirements for insurance coverage.

1.4.3 Monitoring and Diagnostic Methods

Generally speaking, the term “monitoring” describes a basic parameter measurement with threshold alarms. The term “diagnostics” indicates the addition of sophisticated analysis, such as an expert system capable of providing an assessment of equipment condition and suggested actions.

There are a variety of tools available to evaluate the condition of transformers [25, 55, 64, 65, 77-81]. They can be separated into traditional diagnostic methods that have seen widespread use for many years and nontraditional methods that range from methods that are starting to be used to methods that are still in the research stage.

1.4.4 Traditional Diagnostic Methods

Testing of the winding insulating oil is one of the most common tests used to evaluate the condition of transformers in service. Thermal and electrical faults in the oil lead to degradation of the oil. The dissolve gas analysis test is one of the important techniques for condition monitoring of transformers.

1.4.4.1 Dissolved Gas Analysis

Insulating oils under abnormal electrical or thermal stresses break down to liberate small quantities of gases. The composition of these gases is dependent upon the type of fault. By means of dissolved gas analysis (DGA), it is possible to distinguish faults such as partial discharge (corona), over-heating, and arcing in a great variety of oil filled equipment. A number of samples must be taken over a period of time to discern trends and to determine the severity and progression of incipient faults. The gases in oil tests commonly evaluate the concentration of hydrogen, methane, acetylene, ethylene, ethane, carbon monoxide, carbon dioxide, nitrogen, and oxygen. The relative ratios and the amount of gas detected in the sample are used to detect problems with the insulation structure [82-90].

Cellulosic Decomposition – The thermal decomposition of oil-impregnated cellulose insulation produces carbon oxides (CO, CO_2) some hydrogen and methane (H_2, CH_4) due to the oil.

Oil Decomposition **–** Mineral transformer oils are mixtures of many different hydrocarbon molecules, and the decomposition processes for these hydrocarbons in thermal or electrical faults are complex. Heating the oil produces ethylene (C_2H_4) as the principal gas.

Information from the analysis of gasses dissolved in insulating oil is one of the most valuable tools in evaluating the health of a transformer and has become an integral part of preventive maintenance programs. Data from DGA can provide:

- Advanced warning of developing faults
- Monitoring the rate of fault development
- Confirm the presence of faults

- Means for conveniently scheduling repairs
- Monitoring of condition during overload

DGA data by itself does not always provide sufficient information to evaluate the integrity of a transformer system. Information about its manufacturing details and the history of a transformer in terms of maintenance, loading practice and previous faults are an integral part of the data required to make an evaluation.

Generally, there are three steps involved to determine the transformer condition. The first step is to establish whether or not a fault exists. In-service transformers always have some fault gases dissolved in their oil. Only when these levels exceed some threshold value, a fault is suspected. Several recommended safe values have been published. Some of these are listed in table 1.4 [85].

The second step is to determine the type of fault. Two methods most commonly used are the key gases and their ratios [17, 18, 21- 23, 27, 29, 30, 36, 39, 45, 56, 58, 60, 76]. The first involves plotting all the total dissolved combustible gas (TDCG) as a percentage of their total in a histogram. Each fault type will give a distinctive pattern characterized by a key gas, generally the most abundant. For example, high levels of hydrogen with low levels of other gases are characteristic of partial discharge. The ratio method requires the calculation of ratios of gases among each other, such as methane to hydrogen. Three or four such ratios are used for diagnosis. The most widely used are Roger’s ratios; the severity of the fault is established by comparison of the levels of gases with threshold levels and their rate of generation. At least two consecutive samples are needed to calculate rates of fault generation.

A list of key gases and their related faults are shown in table 1.5. This has been discussed in detail in IEEE Std. C57, 104-1991, “IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers.”

Table 1.4 Recommended Safe Value of Various Gases in (ppm)

Transformer Type	**H_2**	**CO**	**CO_2**	**CH_4**	**C_2H_6**	**C_2H_4**	**C_2H_2**
Power Transformer (No OLTC)	60-150	540-900	5100-13000	40-110	50-90	60-280	3-50
Power Transformer (Communicating OLTC)	75-150	400-850	5300-12000	35-130	50-70	110-250	-270
Industrial Transformer (Furnace)	200	800	6000	150	150	200	-
Industrial Transformer (Distribution)	100	200	5000	50	50	50	5
Instrument Transformers (CT)	6-300	250-1100	800-4000	11-120	7-130	3-40	1-5
Instrument Transformer (VT)	70-1000	-	-	-	-	20-30	4-16

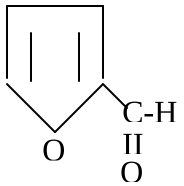
Table 1.5 Key Gases Generated by Particular Fault

Material	**Condition**	**Key Gases**
Cellulose	Overheated >150°C	Carbon Monoxide (CO), Carbon Dioxide (CO_2), water (H_2O)
Oil	Overheated>110°C	Methane (CH_4) Ethane (C_2H_6) Ethylene (C_2H_4) Organic acids
Oil	Electrical stress (Partial discharge and arcing to 1000°C)	Hydrogen (H_2) Acetylene (C_2H_2) Waxes and water

1.4.4.2 Furan Analysis

Cellulose is a natural polymer of glucose and it degrades slowly as the polymer chains breakdown during service, releasing degradation products into the oil. The paper eventually degrades to such an extent that it loses all its mechanical strength and becomes susceptible to mechanical damage, which puts the electrical integrity of the equipment at risk. The kinetics of cellulose deterioration are important for the prediction of insulation life, and are generally monitored by the change of degree of polymerization (DP) of the paper, which can be estimated from the viscosity of the paper in solution [108]. However, this requires removal of paper from the transformer. Moreover, the paper at different locations in the transformer undergoes ageing at different rate, as temperature gradients exist in the transformer. In order to know the fastest ageing, the hot spot locations in the transformer shall be accurately known. Thus, the DP measurement has not found favours with the people interested in monitoring the extent of damage.

Thermal degradation of cellulosic materials present in electrical equipment with oil-paper insulation systems yields different amounts of furanic derivatives, the most common being 2-furfuraldehyde [109-111].



The other furanic derivatives which have been identified are 5-hydroxy-methylfurfuraldehyde, acetylfuran, 5-methylfurfuraldehyde, furfurylalcohol and furoic acids, but these are produced in much smaller quantities when transformer paper degrades thermally.

Furans are currently detected by manually extracting oil samples from the transformer, their concentration is then determined by High Performance Liquid Chromatography (HPLC) [112]. The concentration of these furans gives an indication of the condition of the paper in terms of the degree of polymerization, while the rate of change of furan concentration can indicate the rate of ageing of paper. The main advantage of using this technique of furan analysis as a diagnostic tool is that these compounds are degradation products specific to paper, and cannot be produced by oil.

It has been estimated that new paper, under normal running conditions will generate furfural at the rate of 1.7 ng/g of paper/hour. The rate of production increases with increasing degree of degradation and a total yield of 0.5 mg of furfural per gram of paper is expected in 100000 hours or 15-20 years. Elevated temperatures or the presence of oxygen or water increase this rate. The limits of detection of furfural are about 0.02 mg/l of oil. Suggestions have been made to the acceptable levels of furfural in transformer oil, which can be summarized as: <0.1 mg/l, acceptable; >0.1 mg/l, questionable; and 0.25 mg/l, unacceptable [113].

S.D. Myers Inc, Ohio, USA has conducted a massive survey of the furanic compounds in the dielectric fluid of operating transformers [114]. They have found the most useful single parameter to be furan total which is the total of the concentrations in ppb (μg/kg) for the five furans. For the computation of the percentage remaining life, the following formula has been suggested

$$\% \text{ Remnant life} = \frac{(DP - 200)}{(1200 - 200)} \times 100$$

Where, DP is the degree of polymerization

Needless to say, the new transformer paper has the DP of 1200 and end of life DP is found to be 200. Based on large-scale survey they have concluded a correlation between the furan concentration and DP. The finding is summarized in table 1.6.

Table 1.6 Correlation between furan concentration and DP

Total furan level (ppb)	Range of DP	Recommended retest period (Months)
100	444-1200	12
101-250	333-443	6
251-1000	237-332	3
1001-2500	217-236	1
>2500	<217	Failure likely

1.4.4.3 Thermography

Infrared emission testing is used to check the external surface temperature of the transformer on-line. It is useful for detecting thermal problems in a transformer, such as cooling system blockages, locating electrical connection problems, and for locating hot spots [32, 39, 42]. Infrared imagers "see" the surface heat radiation from objects. It cannot look "inside" the transformer tank. Black and white thermograms (heat pictures) show hot areas in white and cold areas in black, unless stated otherwise. For color thermograms, white and red areas are usually hotter, while black and blue areas are colder. Infrared thermography provides the heating patterns for the load that was on the equipment at the time that the scan was performed. Any abnormal conditions can be located from the scan. The severity of overheating from the scan can be categorized as follows:

Classification	**Temperature excess***
Attention	0-9°C
Intermediate	10-20°C
Serious	21-49°C
Critical	>50°C

*Temperature excess is defined as the difference in temperature between a reference point on the transformer at normal temperature and a higher temperature point.

1.4.5 Nontraditional Transformer Monitoring Techniques

There has been a great deal of new development in testing and monitoring techniques in recent years, and these are finding increasing use on transformers.

1.4.5.1 In-service PD Testing

PD in transformers degrades the properties of the insulating materials and can lead to eventual failures [23]. There are two commonly used PD detection methods: detection of the acoustic signals and measurement of the electrical signals produced by the PD [27]. PD can also be detected indirectly, using chemical techniques such as measuring the degradation products produced by the PD. The acceptable PD limits for new transformers are dependent on the voltage and size of the transformers and range from <100 to <500 pC.

PD pulses generate mechanical stress waves that propagate through the surrounding oil (in the range of 100 to 300 kHz) [35]. To detect these waves, acoustic emission sensors are mounted either on the transformer tank wall or in the oil inside the transformer tank in the oil. If multiple sensors are used, the PD can be located based on the arrival time of the pulses at the sensors. The sensitivity of test is dependent on the location of the PD, since the signal is attenuated by the oil and winding structure. This means that the deeper inside the winding the PD is located, the greater the attenuation. Piezoelectric sensors and fiber optic sensors can measure the PD. Recent research shows that optical sensors have a potential sensitivity much higher than normal external tank-mounted piezoelectric sensors for PD detection [93]. Fiber optic sensors also could potentially be placed inside the winding.

PD causes high-frequency low-amplitude disturbances on the applied voltage and current waveforms that can be detected electrically. Electrical PD signals can be measured at a number of different locations, including bushing tap current or voltage and neutral current [17,18, 23, 24, 26, 27, 35, 36, 39, 45, 50, 51, 55, 62, 68, 70, 73, 76]. Techniques using detection of ultra high frequency signals (typically 1-2 GHz) have been developed to detect PD in gas-insulated substations. The method has been applied to transformers and shows some promise [44, 61].

Acoustic methods of PD detection are limited by signal attenuation and electrical measurements are limited by electromagnetic interference problems. Equipment is commercially available to continuously monitor and evaluate internal PD on-line using both acoustic and electrical methods.

Investigations are also proceeding on improving acoustic detection of PD, as well as further work on electrical detection for in service monitoring [94]. The goal is to be able to detect and ideally locate PD levels with a minimum sensitivity of at least 100 pC.

1.4.5.2 Recovery Voltage Measurement

The recovery voltage measurement (RVM) [95-98] method is used to detect the conditions of oil-paper insulation and the water content of the insulation. The RVM relies on the principle of the interfacial polarization of composite dielectric materials; that is, the buildup of space charges at the interfaces of oil-paper insulation due to impurities and moisture. A dc voltage is applied to the insulation for a time. The electrodes are then short-circuited for a short period of time, after which the short circuit is removed to examine the rate of the voltage buildup or the polarization profile. The time constant associated with this peak recovery voltage gives an indication of the state of the insulation. The main parameters derived from the polarization spectrum are the maximum value of the recovery voltage, the time to peak value, and the initial rate of rise of the recovery voltage.

The test results give an indication of the state of the oil/paper insulation structure of the transformer. It requires a transformer outage to carry out the test [18, 23, 40, 45, 60, 66, 67, 99]. This method is very controversial as to its suitability for direct measurement of the moisture content in oil, due to the strong dependence of the results on the geometry, and construction of the insulation system of a transformer. Figures 1.4 and 1.5 show typical RVM curves for old transformers that are in good and poor condition respectively.

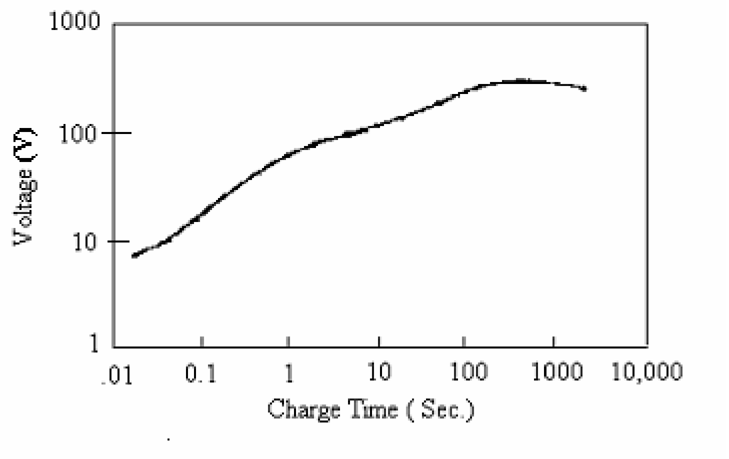


Fig. 1.4 RVM curve for good condition transformer

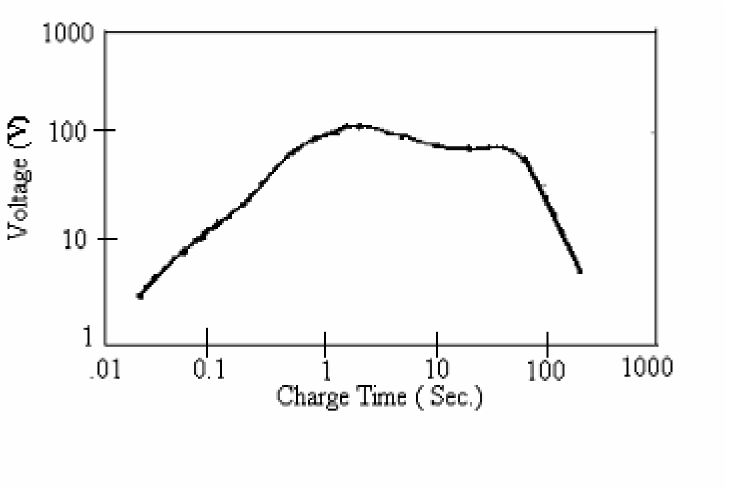


Fig. 1.5 RVM curve of poor condition of transformer

The drawbacks of this test are that a long outage may be required and the unreliability in the interpretation of the results.

1.4.5.3 Tap Changer/Motor Monitoring

The use of oil testing has been extended to the testing of the tap changer oil. The oil tests are used as an indicator of contact deterioration [19, 27, 35, 39, 42, 50, 51, 55, 59, 62-64, 100].

Monitoring of the tap changer temperature can be used to detect problems, such as contact overheating, while acoustic analysis of the switching operation can detect faults in the selector and diverter switches [99]. Tap changer motor currents can be monitored to obtain a signature every time the tap changer moves. Changes in this signature are used to detect problems in the tap changer. Bearing monitors are used to detect bearing wear on transformer oil pumps [26].

1.4.5.4 Winding Movement Detection

A very serious problem that is particularly difficult to detect is movement or distortion of the transformer winding. Forces on the winding during short circuits on the transformer can cause winding distortion. The other source of winding movement is reduction or loss of winding clamping. This can result in a transformer fault that will cause damage to the transformer and may result in explosive failure of the transformer. Traditionally, the only way to evaluate the winding condition of a large power transformer is to drain the oil from the transformer and carry out an internal inspection.

Some research work has focused on using the transformer vibration signal to detect winding looseness and on developing the analysis techniques for interpreting the vibration data [101-104]. The method is based on looking for changes in the transformer’s vibration signature to detect movement in the winding. This method is not used as widely as frequency response analysis tests for detecting winding movement.

In the frequency response analysis test (FRA), the transformer is isolated from the system and the impedance or admittance of the transformer is measured as a function of frequency (typically to at least 2 MHz). This gives a “fingerprint” of the transformer. The test is repeated over time and the “fingerprints” from two or more tests are compared.

There are two different test methods commonly used to carry out the FRA test: the swept frequency test and the pulse test. The swept frequency method applies a variable frequency voltage or a white noise voltage to the high-voltage winding and records the response in another winding or terminal. This technique is more widely used in Europe than in North America. A similar technique more commonly used in North America is the pulse FRA test. With this technique a pulse signal is applied to the high-voltage winding, and the response is recorded in another winding or terminal. Research indicates that the pulse method is more sensitive to detect small winding movement and winding clamping looseness [105]. Figure 1.6 shows an FRA test results comparison for a transformer with some movement compared to a transformer in good condition. In general, the greater the difference between the two "signatures", the greater movement in the transformer. The test requires experienced personnel to compare the two signatures and evaluate the severity of the movement.

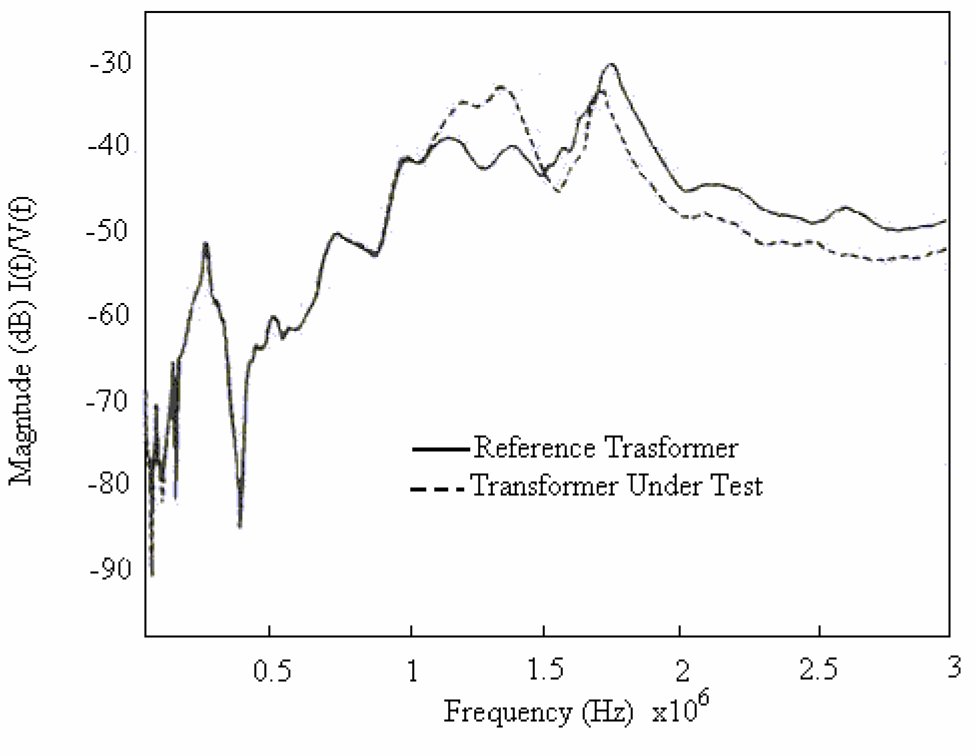


Fig. 1.6 Shows frequency response analysis test results

The conventional FRA test requires a transformer outage to carry out the test. Work has been carried out in Europe and North America to use the transient voltages generated during switching operations as the driving signal to measure the transformer admittance [75,106]. If the on-line FRA test could be developed, it could reduce or eliminate the need for outages to carry out an FRA test. The FRA test has been used extensively. The drawbacks of the test are that it requires an outage, an initial reference test with the transformer in good condition, greater consistency in the test setup from one test to the next, and it is required experienced personnel to interpret the data. Despite these drawbacks, this has been found to be the most effective test in detecting winding movement.

Another technique used to detect winding displacement is the frequency response of stray losses (FRSL). This test is done over a range of frequencies from 20 Hz to over 600 Hz [17-19, 21, 23, 25, 27, 34, 38, 45, 49, 52, 54, 56, 58, 72, 76, 107]. The FRSL test has not been extensively used or studied. It is thought not to be as sensitive to winding movement as the FRA test due to its lower measurement frequency range.

1.4.5.5 Diagnostic Software and Expert Systems

Diagnostic software, which gives more definite indications of transformer problems than conventional analysis, is under investigation by many researchers and utilities [63, 71, 76]. The use of software can improve the reliability and repeatability of the analysis of test data. It can also be used to extract information that is not available from the data directly.

A great deal of research has been done on software to interpret transformer oil test data such as gas, moisture content, dielectric strength and correlating the data with the transformer insulation condition. Expert systems have been developed that give an alarm signal to system operators. Some systems have been developed to detect PD signals in transformers [94]. Equipment using acoustic emission sensors and specialized software has been successful in detecting PD and locating the origin of the discharge. The sensors are mounted externally on the transformer tank wall and three-dimensional location techniques are applied to locate the source of the detected signals.

The present advancement in artificial intelligence (AI) modeling techniques has enabled power engineers and researchers to develop powerful and versatile AI software to diagnose transformer faults. The use of expert systems offers the potential of reducing the manpower and financial overhead required by utilities to assess transformer condition; however, this technique potential is yet to be realized in practice.

1.5 Discussion and Concluding Remarks

The most widely used tests to diagnose the condition of transformers are still oil tests and off-line power factor testing at reduced voltages. The use of other tests (both off-line and on-line) is increasing but is limited by a number of factors mentioned below:

- *Cost*: The high cost of testing and monitoring can make it difficult to justify the tests. The purchase price of the equipment is only one cost factor limiting their use. The cost of isolating the transformer and performing the test can be substantial for off-line tests. The long outage time required by tests, such as the recovery voltage method, can make them difficult to carry out. The installation costs for on-line monitoring equipment can be a major cost factor.
- *Data interpretation*: The interpretation of tests often requires experienced expert personnel. Incorrect interpretation of the data can lead to false conclusions about the transformer condition.
- *Reliability:* The degradation of a transformer occurs over several years. Sensors and electronic equipment installed on the transformers must be able to perform over many years with minimal maintenance.
- *Compatibility*: The compatibility of the many on-line monitoring systems now available is a major concern. Typically systems from one supplier are completely incompatible with those of other suppliers.

Use of nontraditional diagnostic and monitoring techniques is expected to increase on the ageing transformer population. The cost of the equipment will fall and reliability will increase with increased usage. The interpretation and understanding of the test data obtained from tests such as FRA, RVM and vibration testing will improve. In particular, standard analyses techniques are being developed that will enable field personnel to more easily use the test results and will reduce the need for interpretation by experts. Multiple test software that combines the results of different tests and gives an overall assessment of condition is expected to find increasing use. The use of continuous on-line monitoring of transformers is increasing. The cost of the equipment is decreasing and the sensors are improving. This makes it easier to justify the installation of sophisticated monitoring systems on transformers. Standardization will make it easier to integrate systems and data from different suppliers. The use of wireless technologies within the substation for communication between the transformer and control room will make it easier to install monitoring equipment.

The ultimate goal of transformer monitoring and diagnostic techniques is to have a set of devices/systems to monitor and anticipate the transformer failure, so that appropriate action can be taken before forced outage occurs. The organizational culture of a power utility significantly impacts on the operational practices in the use of condition-based maintenance.

1.6 Scope of Thesis

Like other machines, transformer too has limited life. However, unlike other machines, it does not have any moving parts, except tap changers or cooling fan or pump motors. The outages, therefore, is not due to wear out. The transformers die because of deterioration of insulation with time. Generally, cellulosic paper and mineral oil form bulk of insulation in the transformer. The insulation is subjected to a variety of stresses, such as thermal, mechanical, electromagnetic, etc. Under the influence of the said stresses and the presence of oxygen and moisture, the insulation deteriorates continuously over a period of time, eventually leading to failure. If these failures can be predicted with some degree of confidence, sudden failures can be minimized.

In view of above, efforts are being made to understand and analyze factors responsible for determining the life of a transformer. Broadly, ageing of insulating material can be looked upon as a chemical reaction-taking place at a rate that is influenced by thermal, electrical and mechanical stresses. All chemical reactions lead to product or products, which have physical and chemical characteristics different from the parent material. Therefore, chemical and physical characterization of the reaction product/products may assist in monitoring the health of the insulation and hence transformer. For instance, cellulose undergoes degradation under thermal stress: the degree of polymerization of cellulose (DP) is reduced due to thermal ageing. Besides, it leads to the formation of reaction products, such as carbon monoxide, carbon dioxide, water, furan etc. Furans are a family of organic compounds like 2- furfuraldehyde, 2-acetyl furan, 5 methyl 2-furfuraldehyde, furfurylalcohol, 5-hydroxymethyl 2 furfuraldehyde, etc. It is therefore, possible to estimate the extent of insulation damage by monitoring these reaction products. Moreover, these changes in cellulose, at molecular level are manifested in alteration of physical properties. Tensile strength, dielectric breakdown voltage, tan- δ, of Kraft paper are the physical properties affected by these changes. For example, breakage of cellulose chain at microscopic level may lead to microscopic voids, which may influence the partial discharge behaviour of the material.

A number of studies, involving monitoring of one or more of above parameters, have been carried out to predict the impending death of transformer. However, the results are far from complete. Laboratory studies have been carried out to study ageing behaviour of cellulose paper and oil. Most of the studies are confined to thermal ageing and thus do not simulate the real life situation. Alongside the ageing behaviour study, efforts have been directed to develop sensors and instrumentation for on line monitoring of some of the mentioned properties. But, a holistic approach to the problem is somehow missing.

It is therefore, proposed that an ageing study involving accelerated combined application of thermal and electrical stresses was undertaken on cellulosic paper and mineral oil. Accelerated ageing of paper and insulating oil were carried out, and all possible properties, which are likely to be affected by degradation, shall be periodically measured. A study of this kind will help in identifying the most sensitive properties with respect to ageing. It will also help in establishing a correlation between various properties. Eventually, this knowledge data base will help in evolving a condition monitoring strategy and instrumentation for actual transformers.

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Chapter 2

EXPERIMENTAL

Overview

This chapter describes designing, fabrication of test cell and oven to carry out the accelerated ageing studies on transformer oil and paper. The accelerated ageing study is carried out under combined thermal and electrical stresses. The test cell is kept in the air-circulated oven for accelerated thermal stress at 120^0C, 140^0C and 160^0C and electrical stress is applied from normal 1.0 kV to maximum 2.5 kV. The samples are taken out periodically at an interval of 360, 720, 1080 and 1440 hrs. The sample preparation and the various electrical, chemical and mechanical properties to be measured are described along with standard methods used.

2.0 Test Cell Design

The objective of this specially designed test cell to carry out the accelerated ageing study on oil-immersed transformer insulation system comprised of conductor insulation, which operates at a temperature significantly above oil temperature. To achieve this objective a model of a transformer winding consisting of a current carrying conductor supported by insulation spacers and separated from ground has been prepared. The whole assembly being immersed in an oil bath which is free to circulate by natural convection. The concept of this model is illustrated in cross-section in figure 2.1, and shown pictorially in figure 2.2, which shows the outer view of test cell while the details of the conductor assembly are shown in figure 2.3. Table 2.1 shows the description of test cell used in the present study.

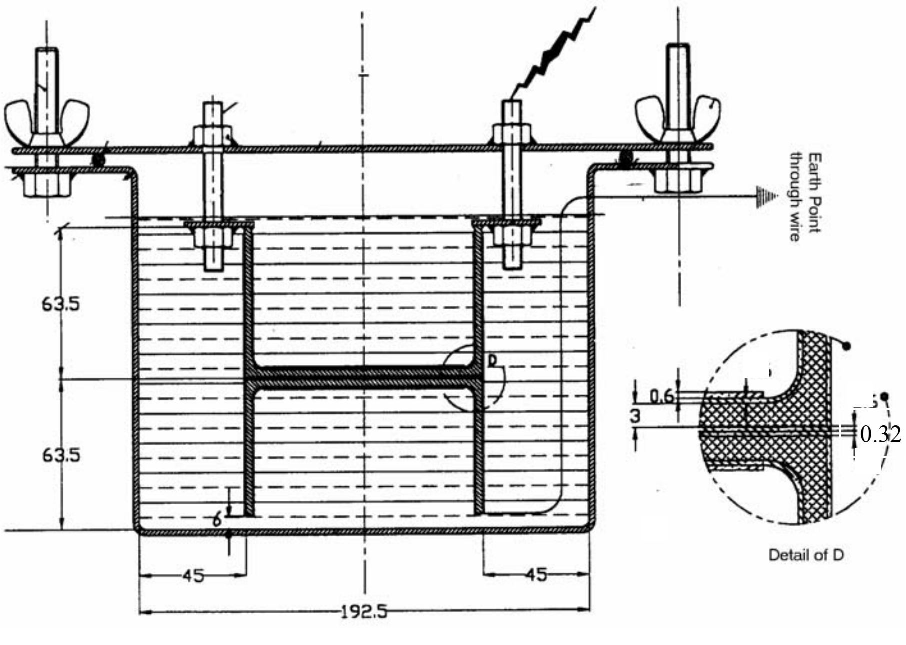

Figure 2.1 Test Cell set up

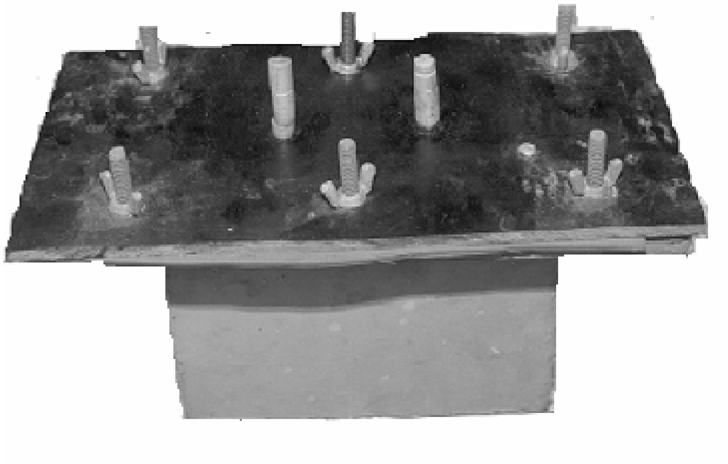

Fig. 2.2 Outer view of test cell

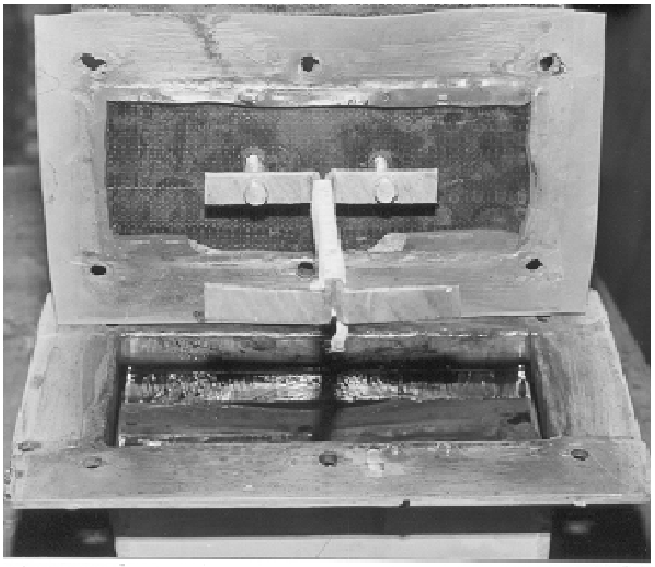

Fig 2.3 Details of the conductor assembly

Table 2.1 Description of test cell

Description	Material	Dimension/Thickness
Cover Plate	Mica Sheet	5 mm
Sealing Ring	Silicone Rubber	
Tank	M.S (Coated with Enamel Paint	192.5x152.4 mm
Round Stud &Nut	Copper	
Bolt	M.S.	
Transformer Oil	As per IS: 335-1993	
Copper Strip without paper wrapped	Copper	111x48.5x1.96 mm
Transformer Paper	As per IS: 9335-1993	0.16 mm

The copper conductor in the model had dimensions of (110 mm x 48 mm x 2.0 mm) with 0.32 mm two side's insulation. It was bent in U shape, with equal length legs.

The test cell was fabricated from steel plate of 3.5 mm thickness. The inner surface of the test cell has been polished with high temperature resistant enameled paint. The silicon sealing has been provided in between the top cover plate to prevent the leakage of gases at high temperature. The two copper strips covered with paper were joined together with cotton tape and placed in the test cell. The conductor assembly was mounted on the top plate of the cell, with threaded copper studs. Initially the test cell was heated at 70^0C for 24 hrs, so that paper should fully impregnated with oil. The oil and paper were put in the ratio 20:1 by weight. The oil taken conformed to the requirements of Indian National Standard specifications of IS: 335-1993[1] and unaged electrical grade paper was according to the Indian National Standard of IS: 9935(P: 3)[2]. The test cell was kept in the air-circulated oven for accelerated thermal and electrical stress studies on oil and paper. A pressure relief device on top of the cell assured that abnormal operation did not generate a safety hazard.

2.1 Model Preparation

The insulation oil and paper were chosen to be representative of those used in the present day production transformers. The conductors were insulated with six (6) layers of Kraft paper, wound in half- laps for total two side builds. Normal working stress on a single layer paper is 80V/ mil. The formula is given below to calculate the working stress on Kraft paper.

Normal stress = 80 x 40 x thickness of paper in mm.

Where 40 mil = 1mm.

For six (6) layers of paper, thickness was = 0.16 mm. As two strips of same insulation were joined together therefore, total thickness was 0.32 mm

According to above formula, Normal stress = 80 x 40x 0.32 = 1.024 kV.

2.2 Thermal and Electrical Ageing Facility

A specially designed oven was fabricated for thermal and electrical ageing studies of transformer oil and paper. The PID temperature controller was provided to control the temperature ± 2^0C. At the top of the oven, a bushing was provided along with conductor to pass through the accelerated electrical stress. The arrangement was tested with high voltage insulation tester to ensure that the oven insulation can withstand the required thermal and electric stress. The figure 2.4 (a) shows the front view of the oven in which at a time two cells were placed for ageing studies. The power supply with control panel is shown in figure 2.4 (b). An independent alarm scanner provided for over temperature monitoring and automatic shutdown. The equipment used was calibrated from reputed testing lab.

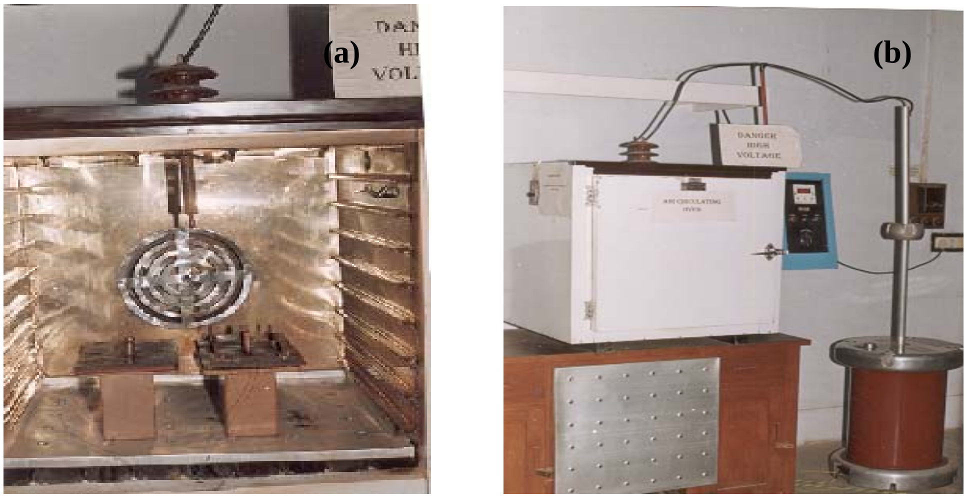

Fig. 2.4 Thermal and electrical aging set up

2.3 Ageing Test Plan & Procedure

Ageing temperatures and time were chosen to provide an adequate spread of the data points within the range of the anticipated half life of the materials being studied, based on prior test experience [3-4]

The ageing studies were carried out by applying accelerated thermal and electrical stress. Samples of both solid insulation and the mineral oil were tested prior to start up and after shut down of each cell. The test cell was kept in the air-circulated oven for accelerated thermal stress at 120^0C, 140^0C and 160^0C and electrical stress calculated above was applied from 1.0 kV to maximum 2.5 kV. The samples were taken out periodically at an interval of 360, 720, 1080 and 1440 hours.

At the completion of ageing, power to the cell was shut off and allowed the test cell to come down to room temperature i.e. 30^0C. The entire test assembly was removed from the oven. The samples were doubly wrapped in the plastic wrap and placed in plastic bags to prevent moisture migration. The insulated conductor was temporarily stored in a bucket of clear dry oil. The oil was removed from test cell for testing Viscosity, Moisture, Breakdown voltage, Tan-delta, Dielectric Constant, Interfacial Tension, Specific Resistance, Acidity, Flash point, Dissolved Gas Analysis (DGA), Fourier Transform Infrared Spectroscopy (FT-IR), Nuclear Magnetic Resonance (NMR), and Fur Furaldehyde Analysis (FFA).

The top layer of paper samples was removed from the conductor for Tensile Strength, Degree of Polymerization (DP), Scanning Electron Microscopy (SEM), X-Ray Diffractometer study (X-RD), FT-IR and Differential Scanning Calorimeter (DSC) and Thermal Gravimetric Analysis (TGA) studies. The paper samples were made free from oil by soxhlet extraction using hexane followed by chloroform.

The procedure followed for the measurement of above mentioned properties are explained briefly below:

2.4 Viscosity

Viscosity of oil is its resistance to flow. Viscosity of oil can be expressed in two ways - Dynamic viscosity and Kinematic viscosity. The definition of dynamic viscosity is given as the ratio between the applied shear stress and rate of shear of oil. Kinematic viscosity of the oil is its resistance of flow under gravity. Dynamic viscosity of oil can also be computed by multiplying kinematic viscosity by its density. Unit of dynamic viscosity is Poise and that of kinematic viscosity is Stokes. The kinematic viscosity of oil is generally expressed in centistokes. Kinematic viscosity is measured by determining the time required to flow a fixed volume of oil under gravity through standard capillary tubes. Viscosity of oil is very sensitive to its temperature. Because of this, the capillary tubes are kept in a special oil bath, the temperature of which is maintained very accurately. Ageing experiments were conducted on samples with initial moisture content of less than 0.5%. The measurement was done with Viscometer, Model LVID, Brookfield, (USA). The Kinematic viscosity was measured as per IS 1448-1976 [5].

2.5 Moisture

The Coulometric Karl Fischer instrument, Model AF7IC, Orion (USA) as shown in figure 2.5 was used to determine the moisture content. The sample was mixed with a base solution of iodide ion and sulphur dioxide. Iodine is generated electrolytically and reacts with water. It is generated in proportion to the quantity of electricity according to Faraday's law, as shown by the following reactions:

$2I^- — 2e \longrightarrow I_2$

Fig. 2.5 Moisture content determination set up

The sample was taken in clean amber coloured glass bottles of 500 ml capacity. Sample bottle was dried by heating in an oven for 24 hours at 115 ± 5^0C. While hot, the air content of each bottle was displaced by flushing dry nitrogen obtained by passing through concentrated sulphuric acid trap attached to the gas cylinder at internal pressure greater than 25 bar, and the bottle was capped immediately. After cooling to room temperature, the nitrogen flushing procedure was repeated and the bottle was re-sealed. Between the time of collection and analysis, the samples were kept in the dark and time between collection and analysis in any case was less than 7 days. The water content was calculated as per IS: 13567-1992[6].

Calculation of the result

Water content = m/M mg kg^{-1}

Where m = mean of displayed readings (μg of water)

M = mean mass in grams of insulating liquid discharged from 5 ml mark of syringe.

2.6 Breakdown Voltage (BDV)

The voltage at which the oil breaks down when subjected to an ac electric field with a continuously increasing voltage contained in a specified apparatus. The voltage is expressed in kV (rms).

The study was carried out in glass cell of 500 ml capacity. The electrodes were mounted on a horizontal axis having 2.5 mm gap. The gap between the electrodes was set to an accuracy of ± 0.01 mm by means of thickness gauges. The axes of the electrodes were immersed to a depth of approximately 40 mm. Before putting the oil for testing, the cell was thoroughly cleaned by rinsing with the test oil. Immediately after this, the sample was poured down slowly in the test cell to avoid air bubbles forming. The test voltage was applied at a rate of 2 kV/s as per IS: 6792-1982 [7]. The BDV tester Model OIT-100M, Sivananda (India) was used as shown in figure 2.6. After each breakdown, the oil was gently stirred so as to keep away the carbon particles between the electrodes

Fig. 2.6 BDV set up

2.7 Dielectric Dissipation Factor (Tan-delta)

It is also known as loss factor. It is a measure of imperfection of dielectric nature of oil. For a perfect dielectric when applied with a sinusoidal ac voltage, the current flowing through it should lead the voltage by 90 degrees. But it is not the case in reality. The angle by which it is short of 90 degrees is called the loss angle. The tan-δ measurements were done as per IS: 6262-71[8]. The Tan-delta Model MLO-1D, Sivananda (India) was used as shown in figure 2.7.

Fig. 2.7 Tan-delta set up

2.8 Dielectric Constant

The cleanliness of the test cell is paramount important when making dielectric constant measurement because of the inherent susceptibility of most insulating liquids to influences of the contaminants of most minute nature. For this reason, the cell was dismantled and all the components were washed thoroughly. After washing, the test cell components were placed in an oven maintained at 110^0C for one hour. At the end of drying, the test cell was assembled using clean glove as protection. The dielectric constant measurements were made on instrument Model MLO-1D, Sivnanda (India) as shown in figure 2.7. The calculations were carried out as per IS: 6262-1971[9].

Capacitance of the test cell was measured with air as the dielectric filled with liquid. The dielectric constant was calculated from the following equation

$K' = C_x / C_v$

Where K' = Dielectric constant of liquid

C_x = Capacitance of test cell with the liquid as the dielectric

C_v = Capacitance of test cell with air as the dielectric

2.9 Interfacial Tension (IFT)

Interfacial tension between the water and oil interface is the measure of molecular attractive force between the molecules of water and oil. It is measured using platinum ring tensiometer. The Interfacial tensiometer Model 4122, PDIC (India) was used to carry out the IFT study as shown in the figure 2.8. A planar platinum ring is first placed in the interface of water and oil and then it is lifted using a torsion wire into oil. The force required to lift the ring from the interface is proportional to interfacial tension. The test was carried out as per IS: 6104- 1971[10].

Fig. 2.8 Interfacial tension set up

2.10 Specific Resistance

It is the ratio of dc potential gradient in volts per centimeter paralleling the current flow within the specimen, to the current density in amperes per square centimeter at a given instant of time and under prescribed conditions. This is numerically equal to the resistance between opposite faces of a centimeter cube of the liquid. It is expressed in ohm-centimeter.

Resistivity measurements are carried out at 90^0C for monitoring purpose. New oil is tested both at room temp (27^0C) as well as 90^0C. Useful additional information can be obtained by measuring resistivity at both ambient temperature and at 90^0 C.

The study was carried out in a stainless steel three terminal test cell of capacity 40 ml. The Sivananda (India) make instrument, Model LS-3B as shown in figure 2.9 was used. The test cell was thoroughly cleaned and dried. The oil was poured in the test cell and an electric stress of 300V/mm is applied and tested at 90^0C as per IS: 6103-1971[11]

Fig. 2.9 Specific resistance set up

2.11 Total Acidity

It is the measure of free organic and inorganic acids present together and is expressed as milligrams of potassium hydroxide required to neutralize the total free acids in one gram of the oil. This is also called neutralisation number. The acidity is determined as per IS: 1448(P: 2,1967)[12]. Figure 2.10 shows the acidity measurement set up.

Fig.2.10 Acidity measurement Set up

2.12 Flash Point

Flash point of oil is the minimum temperature at which it gives enough vapors to form a flammable mixture with air under the standard test conditions. The flash point of oil is measured using Pensky-Marten's Closed Cup Flash Point apparatus of Model 04115, PDIC (India) as shown in figure 2.11. All parts of the cup and its accessories were thoroughly cleaned and dried before starting the test. The cup was filled with sample to be tested to the level indicated by the filling mark. The lid was on the cup and set the latter on stove. The locking device was properly engaged. A thermometer was inserted and the test flame was adjusted to 4 mm in diameter. The heat was supplied at a rate of 5^0 to 6^0C/ min. The stirrer speed was adjusted at 90-120 rpm. The flash point was recorded on the thermometer at the time of the test flame application, which causes a distinct flash in the interior of the cup.

IS: 1448(P: 21,1970)[13] was followed to measure the Flash point.

Fig.2.11 Flash Point measurement set up

2.13 Tensile Strength

Tensile tester Model 96124, L & W (Sweden) was used to perform tests on new and aged samples. Tensile strength is the force per unit width of test specimen. The tensile tester having two clamming jaws, each within a line contact for gripping the specimen, with the line of contact perpendicular to the direction of the applied load with means for controlling and adjusting the clamping pressure was used. While handing the test specimen, touching the test area between the jaws with the fingers was avoided. Clamping pressure was used so that neither slippage nor damage to the specimen occurred. The test was carried out as per TAPPI 494-1988[14].

2.14 Degree of Polymerization

For the measurement of DP, the impregnated paper was degreased with benzene and then allowed the solvent to evaporate in air at room temperature. The sample was cut into small pieces of 1 mm^2 with scissors and kept in a controlled humidity atmosphere. The paper samples were put in a flask with few glass balls and added 22.5 ml of distilled water to wet all paper. Added 22.5 ml of 1 M solution of cupriethylene-dimamine and the paper sample was stirred for 3 hrs. to dissolve in the solvent. The solution so obtained was allowed to stand for 1 hr. at 20^0C. Thereafter the solution was shifted in the viscometer reservoir. The measurement was taken for successive samples. The calculation was done as per IEC 60450-1974 [15].

2.15 Break Down Voltage of Paper

Breakdown voltage of paper was tested by BDV Tester, Model 2904, Tettex (Switzerland) as shown in figure 2.12. The test was conducted on virgin and aged samples. The BDV of paper was measured as per British Standard (BS-243) [16]. Before the BDV tests were performed, the Virgin and aged samples were dried in oven at 105^0C for 6 hours. For each sample, five test pieces of each 100 mm square were taken for the testing. The voltage source was calibrated before testing.

Fig. 2.12 BDV of Paper measurement set up

2.16 Dissolved Gas Analysis (DGA)

The incipient faults in the bulk oil equipment, generally undetected by the protection system, generates certain gases and because of the no escape construction of oil circulation system these gases are dissolved in the oil itself. The insulating oil being under convection or circulation gets these gases dissolved homogenously. A sample of about 200 ml of this oil is generally subjected to Multi Pass Gas Extraction and Gas Chromatography to evaluate the quantum of dissolved gases, individually and collectively.

The gases of interest are: hydrogen, methane, ethane, ethylene, acetylene, carbon monoxide and carbon dioxide. Most commonly used method to determine the content of these gases in oil is using a Vacuum Gas Extraction Apparatus and Gas Chromatograph. In the present study, the dissolved gas analysis was carried out using vacuum gas extraction system as shown in the figure 2.13. All the dissolved gases were first extracted from oil by stirring it under vacuum and total gas content in percentage was measured. These extracted gases were then introduced in Gas Chromatograph for measurement of each component. A standard gas mixture having known concentration was also injected in Gas Chromatograph to obtain standard peaks. Experience and experiments have evolved various interpretation techniques. Some of them are: Rojer's Ratio method, IEC-599 [17], key gas analysis etc. The samples were tested as IS: 9434-1992[18].

Fig. 2.13 Dissolved gas analysis set up

2.17 Furfuraldehyde Analysis (FFA)

The FFA has been carried out as per IEC-61198-1992 [19] as shown in figure 2.14, which employs the HPLC technique using UV detector.

The measurement was done in two steps. The furans were first separated from the oil by extraction with acetonitrile, followed by High Performance Liquid Chromatographic analysis (HPLC) on a Waters column (Spherical C18, 3.9x150mm). Depending on the concentration of the sample, 1to 5 ml of oil were diluted with 5 ml of hexane and injected on to the Sep-Pak, which was then washed with 10 ml of hexane to remove the oil. Nitrogen was applied for 5 minutes to evaporate the hexane, and the furans were eluted with 1.5 ml of acetonitrile (acn)/water solution (20%/80%). About 20 to 50 µl of eluent solution were injected into the HPLC, depending on concentration.

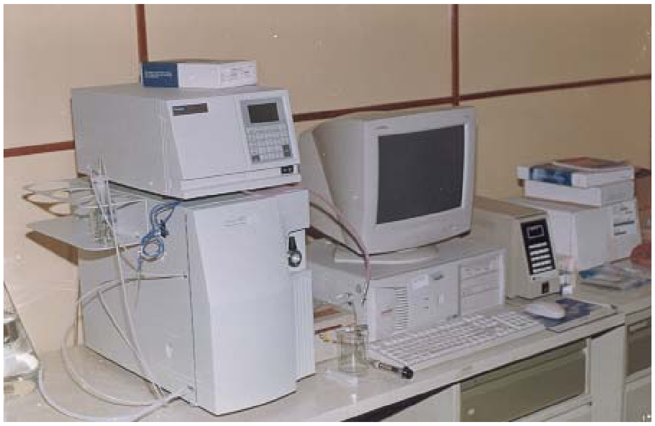

Fig.2.14 Furfuraldehyde analysis set up

2.18 Scanning Electron Microscopy (SEM)

Scanning Electron Microscopy study was carried in order to see the extent of degradation of aged paper sample under accelerated thermal and electrical stress. The samples were scanned at different magnifications. SEM study was conducted by using JEOL, Model JSM 840A (Japan) as shown in figure 2.15. The paper samples were sputter coated with gold for observation under SEM.

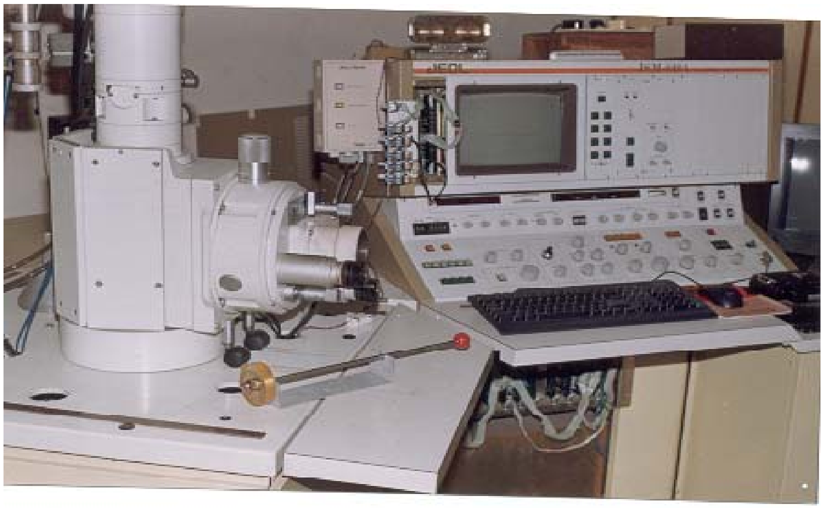

Fig.2.15 Scanning electron microscopy measurement

2.19 X-Ray Diffraction study

X-Ray Diffraction is a tool for the investigation of the fine structure of matter. Every atom in a crystal scatters an X-ray beam incident upon it in all directions. Even the smallest crystal contains a very large number of atoms, the chance that these scattered waves would constructively interfere would be almost zero except for the fact that atoms in crystals are arranged in a regular repetitive manner. The condition of the diffraction of a beam of X-rays from a crystal is given by Bragg equation:

$n\lambda = 2d\sin\theta$

Where n is the order of diffraction, d is the interplanar distance, θ is the angle of incidence of the beam and λ is the wavelength of the incident beam.

The position of the diffraction beam from a crystal depends only on the size and shape of the repetitive unit of a crystal and the wavelength of the incident X-ray beam, whereas the intensities of the diffracted beams depend on the type of atoms in a crystal and the location of the atoms in a fundamental repetitive diffraction pattern when one considers both the direction and intensity of all diffracted beams. The diffraction pattern is thus a fingerprint of a crystalline compound and the crystalline compounds of a mixture can be identified individually.

The aged samples were examined under X-ray diffractometer to see the change in 2θ values and crystallinity. X-RD study was done using Model Dmax IIIC, RIGAKU (Japan) as shown in figure 2.16. The diffraction patterns were recorded for 2θ of 10-40°, at a scanning speed of 5 degree per minute.

Fig. 2.16 X-Ray diffraction set up

2.20 Fourier Transform Infrared Spectroscopy

Fourier transform infrared spectroscopy (FT-IR) study was conducted on aged oil and paper samples. FT-IR observations were made by using FT-IR spectroscopy Model, MB series BOMEM (Canada) as shown in figure 2.17. The oil sample was dissolved in chloroform, carbon tetrachloride and the spectra were recorded. The paper sample was directly put in sample holder of the spectrophotometer after proper cleaning.

Fig. 2.17 FT-IR spectroscope

2.21 Partial Discharge Measurement

Partial discharge is an electrical discharge that only partially bridges the insulation between conductors. A transient gaseous ionization occurs in an insulation system if the voltage stress exceeds a critical value, and this ionization produces partial discharges. After each spell of accelerated ageing, the test cell was put for partial discharge measurement (PD). The magnitudes (pulse height) of a partial discharge were recorded at different voltages. The partial discharge magnitude and pulse rate are useful in estimating the rate, or change of rate, at which deterioration is produced. The PD levels were recorded using Model TE 571, HAEFELY (Switzerland) as shown in figure 2.18. The test was conducted as per ASTM D 1868-1993[20].

The test was conducted in the shielded room to reduce the interference of radiation and interference by suppressing conduction by means of a low- pass filter in the voltage supply circuit. The smooth leads surfaced and of a sufficient diameter, with spherical terminals were used to avoid corona on the connecting leads between the test voltage source and the specimen. The calibration procedure was carried out to establish a scale factor relating the response of the measuring device to the magnitude of a discharge pulse.

Fig. 2.18 Partial Discharge measurement set up

2.22 Nuclear Magnetic Resonance Study

Apart from traditional techniques for assessing these factors there are two obvious choices from a chemical viewpoint which are quick and non destructive to the sample, viz Nuclear Magnetic Resonance (NMR) and Infrared Spectroscopy. The NMR study was conducted on virgin and highly aged sample using NMR of Chemagnetics make, Model CMX-200.

2.23 Differential Scanning Calorimeter and Thermo Gravimetric Analysis Study

In order to determine precisely the water content, thermo analytical techniques such as Differential Scanning Calorimeter (DSC) and Thermo Gravimetric Analysis (TGA) were carried out on virgin and highly aged paper sample. The DSC/TGA investigations were made by using Model 821, Mettler Toledo.

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RESULTS
&
DISCUSSIONS

Chapter 3

EFFECT ON CHEMICAL, ELECTRICAL AND MECHANICAL PROPERTIES

Overview

The effect of accelerated thermal and electrical stresses are studied on Viscosity, Moisture, Break down voltage, Tan-delta, Dielectric constant, Interfacial tension, Specific Resistivity, Acidity and Flash point of oil and properties like Tensile strength, Degree of polymerization (DP) and Break down voltage (BDV) of paper. The effects of combined stresses on these properties are discussed. The activation energy of each parameter is found to predict the life of the insulation. The mathematical relationship is also developed for each property by Regression analysis.

Key words: Break down Voltage (BDV), Dielectric constant (ε_r), Degree of polymerization (DP), Electric Stress (E), Time (t), Thermal Stress (T).

3.0 RESULTS AND DISCUSSION

3.1 Properties of Oil

3.1.1 Kinematic Viscosity

Good oil should have less viscosity so that it offers less resistance to flow thereby not affecting the cooling of transformer adversely [1]. In addition, the viscosity of an insulating liquid is important for the impregnation process. It is a principal parameter in design calculations for heat transfer by either natural convection in smaller self-cooled transformers or forced convection in larger units [2]. A low value of viscosity and a good heat transfer capability are needed to achieve high performance. Low viscosity also assists initial penetration of the oil into narrow ducts and promotes circulation through the windings to overcome local overheating, which would result from more lengthy residence of the oil at any hot spots. Equally important is the fact that viscosity of oil should increase as little as possible with decrease in temperatures.

The results from the accelerated ageing experiments are graphically presented in figure 3.1(a-c). The figure 3.1(a) shows the variation of viscosity when the thermal stress varies from 120^{o}C to 160^{o}C under electric stress of 1.0 kV. The variation in viscosity is apparent in all the three different conditions. Figure 3.1(b) & (c) represent the change in viscosity under electric stress of 1.5 kV and 2.5 kV for the same thermal stress level of 120^{o}C to160^{o}C. The maximum increase in viscosity is for higher thermal stress i.e. 160^{o}C in all the cases. The higher thermal stress causes oxidation of oil and due to generation of oxidation products, the viscosity increases. Ageing of oil is due to the simultaneous action of molecular oxygen and temperature, which leads to oxidation of oil. Under maximum electrical stress of 2.5 kV, the variation is slightly higher. The possible reason for increase in viscosity under maximum electric stress, i.e. 2.5 kV, may be when an electrical stress acts on the oil, the process of oxidation is accelerated and the amount and the composition of the final oxidation products might be different [3]. Therefore, catalytic effects of various metal salts that are formed as a result of oxidation and accelerate the degradation of oil. The effect of temperature on the viscosity can be expressed in terms of reaction rate constant for the exponential portion of the production curve using the Arrhenious relationship. A classical method of calculating the remaining life of a transformer is the Arrhenious-Dakin formula:

$$\text{Remaining life} = Ae^{-B/T}$$

Where, A: initial life; B: constant, depending on the properties of the material studied; and T: absolute temperature in K.

Approximate rate constants of change in viscosity, calculated from the experimental data and assuming first order kinetics, plotted against reciprocal temperature and is shown in figure 3.2. The activation energy is calculated from the least squares fits to the data for 1440 hours.

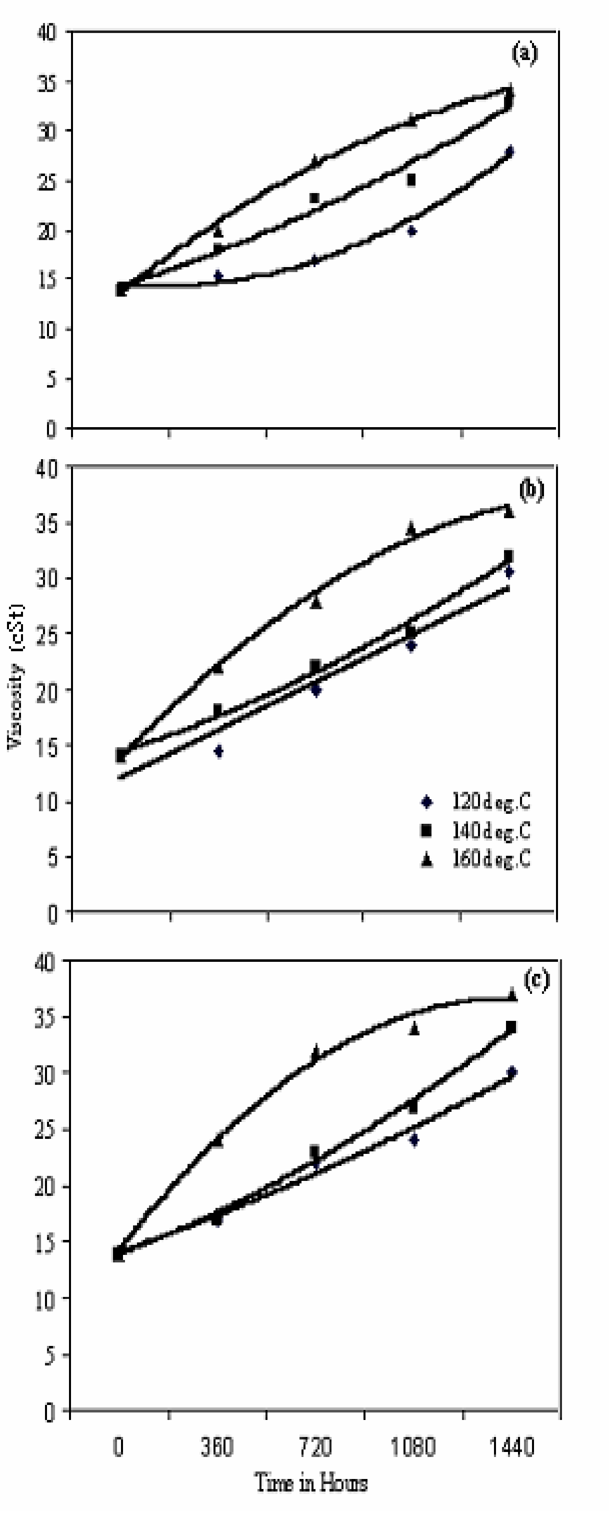

Fig. 3.1 Variation of viscosity with time at (a) 1.0 kV (b) 1.5 kV (c) 2.5 kV

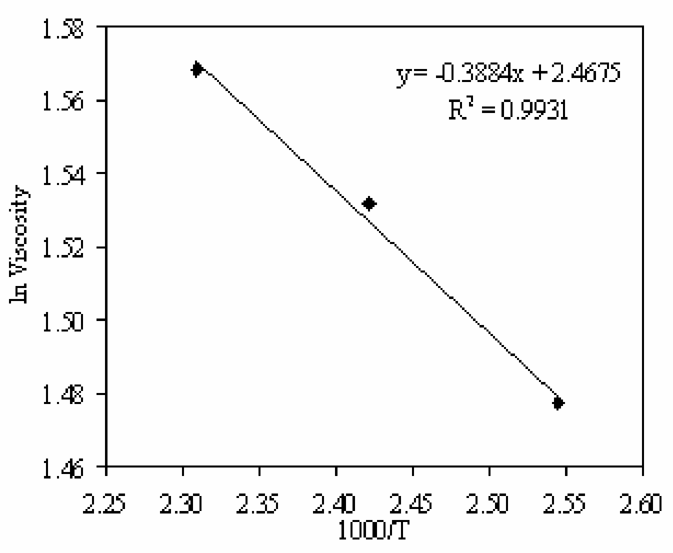

Fig. 3. 2 ln (Viscosity) vs. 1000/T (activation energy =0.033eV)

3.1.2 Regression Analysis for Viscosity

Multiple linear regression analysis is carried out for the Viscosity experimental data. The results revealed that time, temperature and electric stress are significant. The most effective prediction model is found with max R^2 = 94.38%. The mathematical function equation is as follows:

Viscosity = $-16.9484 + 0.01283 \times (t) + 0.2020 \times (T) + 1.5773 \times (E)$.

3.1.3 Moisture Content

Presence of water in oil is highly undesirable as it affects adversely the dielectric properties of oil. The water present in oil also affects the solid insulation of transformer. When transformer is filled with oil, the paper absorbs the moisture from oil, as the paper is highly hygroscopic in nature the insulation property is affected, thereby reduces its life.

The temperature of oil at the time of sampling from transformer is thus very important for determination of water content. In fact, it is now-a-days recommended to correct the water content measured to a standard temperature (20°C) before comparing with limiting values. The water present in oil is allowed at ppm levels. The accurate measurement of water content at such low levels requires sophisticated instrument like Automatic Coulometric Karl Fischer Titration.

The results from the accelerated ageing experiments are graphically presented in figure 3.3 (a-c). The figure shows the increase of water content under three different test conditions. The water content increases consistently at 120,140^0 and 160^{0}C under electrical stress of 1.0 kV, 1.5 kV, and 2.5 kV. Results indicate that water content increase is maximum at 160^{0}C after a period of 1440 hrs under electric stress of 2.5 kV. Formation of at least 4-5 times higher quantities of water is reported [3] than in the tests in which no electrical stress was applied. Hence the concentration of water in oil increases with increase in temperature and oxidation products of oil. When the oil is in service oxidises, acids are formed. These acids increase water concentration of oil. Acids coupled with water further decompose oil, forming more acids and water. Thus rate of deterioration of oil increases. The total water present in a transformer is distributed between paper and oil with paper having much high water content. As the temperature of transformer increases paper releases water thus increasing water content of oil. The water can be present in three different states: dissolved, emulsified or dispersed. Insulating liquids, such as transformer oil, have a low affinity for water, although the solubility increases markedly with increase in temperature High moisture content increases the electrical conductivity, dissipation factor and reduces the electric strength. Therefore, eventually it decreases the safety margin [4, 5]. The activation energy graph has been plotted between ln of moisture and 1000/T for 1440 hrs in figure 3.4.

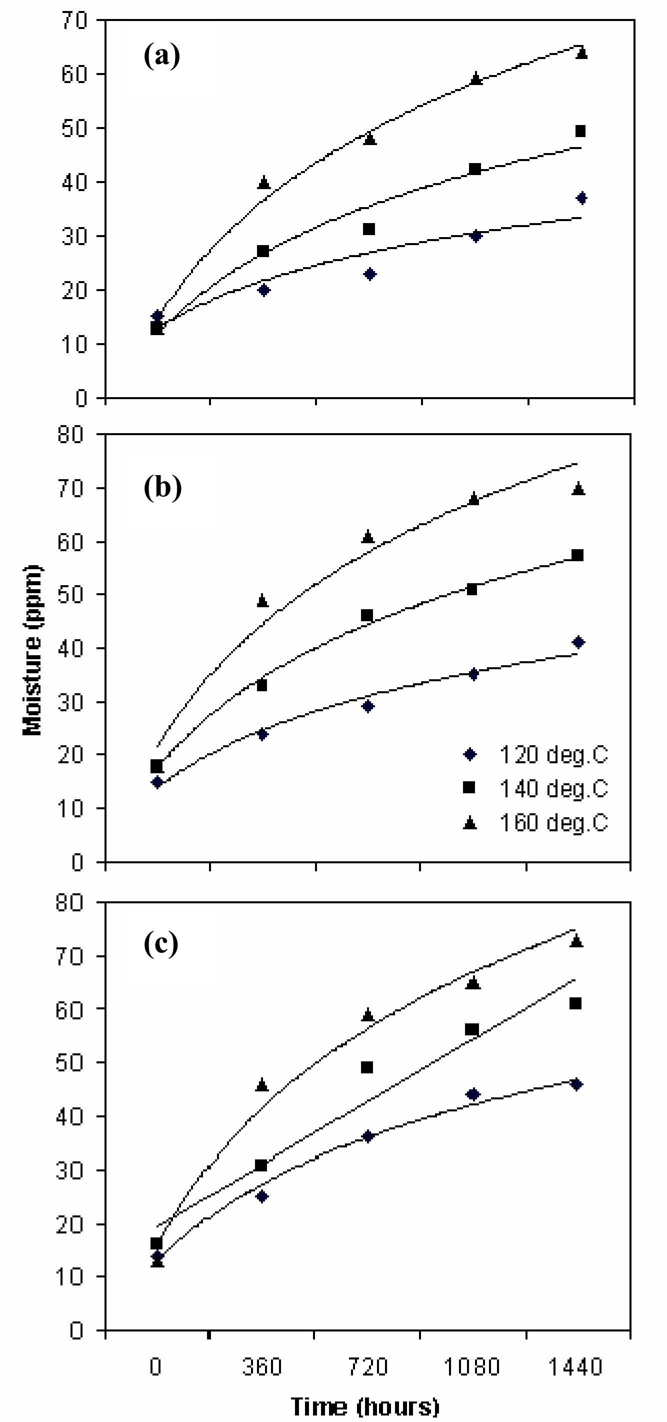

Fig. 3.3 Variation of moisture with time at (a) 1.0 kV (b) 1.5 kV (c) 2.5 kV

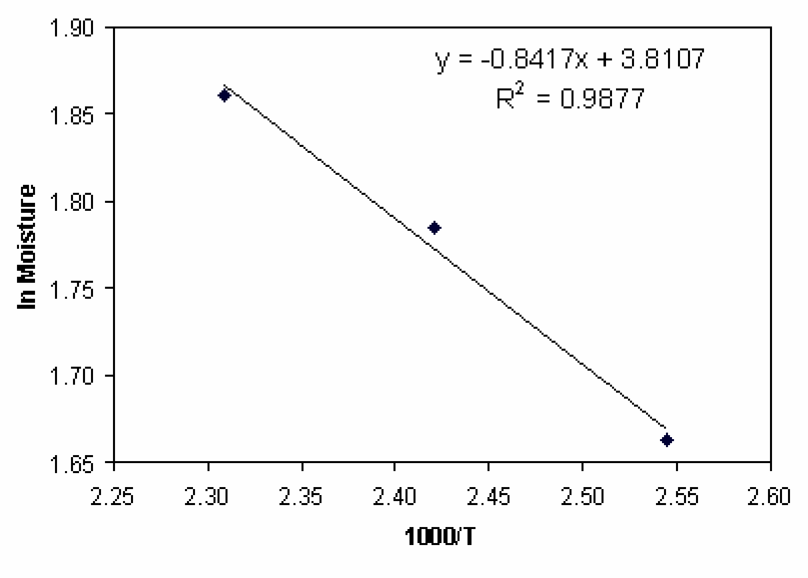

Fig. 3.4 ln (Moisture) vs. 1000/T (activation energy =0.072eV)

3.1.4 Regression Analysis for Moisture

Multiple linear regression analysis is carried out for the experimental data. The results revealed that time, temperature and electric stress are significant. The most effective prediction model is found with max R^2 = 94.31%. The mathematical function equation is as follows:

Moisture = $-74.8055 + 0.02089 \times (t) + 0.65 \times (T) + 6.0833 \times (E)$.

3.1.5 Breakdown Voltage of Oil (BDV)

The results of accelerated aged samples for breakdown voltage are shown in figure 3.5 (a-c). The BDV of oil decreases uniformly with rise in thermal and electric stress. The increase in moisture content in oil decreases BDV. Our study also indicates that the increase in moisture content decreases the BDV under electric and thermal stress. The similar findings have also been reported by other workers under thermal stress [6]. But under combined accelerated thermal and electrical stress, the decrease in BDV is more prominent. The BDV of the oil within transformer goes down slowly as the water content and conducting impurities increase as a result of oxidation of oil. The solid impurities released from within the transformer also reduce the BDV of oil.

BDV is the single most important and popular test to gauge condition of oil on site. It is indicative of solid impurities and water content present in the oil. Dry and clean oil exhibits normally high Breakdown voltage. However, high BDV does not necessarily indicate absence of all the above contaminants. The activation energy plot is shown in figure 3.6.

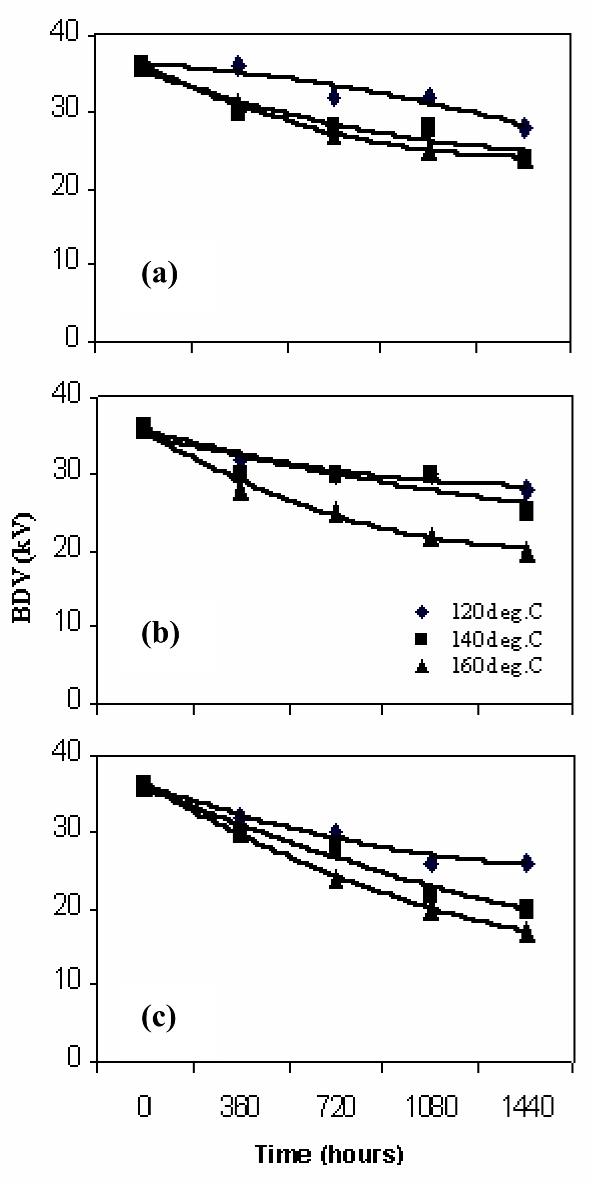

Fig. 3.5 Variation of BDV with time at (a) 1.0 kV (b) 1.5 kV (c) 2.5 kV

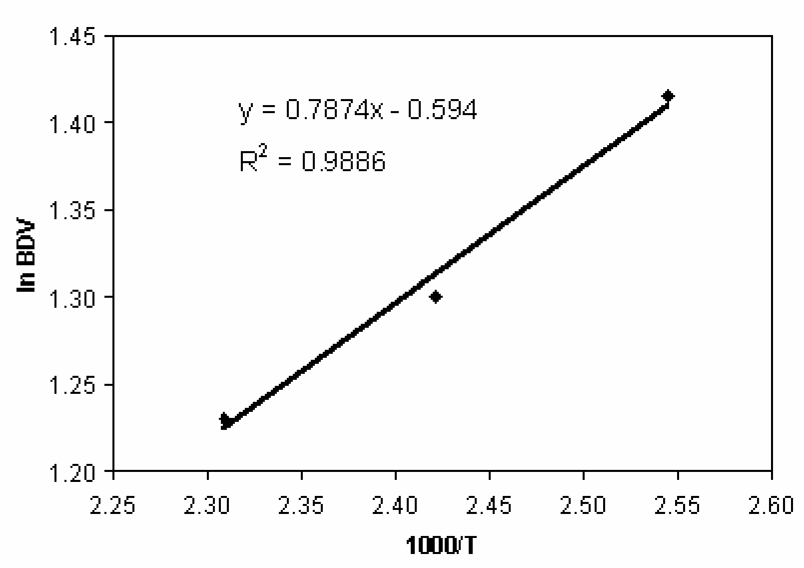

Fig. 3.6 ln (BDV) vs. 1000/T (activation energy = 0.067eV)

3.1.6 Regression Analysis for BDV of Oil

Multiple linear regression analysis is carried out for the experimental data. The results revealed that time, temperature and electric stress are significant. The most effective prediction model is found with max R^2 89.29%. The mathematical function equation is as follows:

$$BDV = 58.7837 - 0.0060 \times (t) - 0.1562 \times (T) - 2.6785 \times (E).$$

3.1.7 Dielectric Dissipation Factor (Tan-delta)

The tangent of the loss angle is called dielectric dissipation factor. A high tan-delta is an indication of presence of contaminants. Good oil should have 0.2 (max) tan-delta as per IS: 6262. A high tan-delta is an indication of presence of contaminants such as soluble varnishes, resins etc [7]. There is generally a relationship between tan-delta and resistivity, both being affected by same contaminants. A decrease in resistivity is coupled with an increase in tan-delta. Figure 3.7 (a-c) shows the variation of dissipation factor for the three different test conditions. It is evident from figure 3.7 that the dissipation factor increases 45% for the 160^0C at 2.5 kV electric stress. The other researcher also reported [8] that measurement of tan-delta without electric stress is meaningless. In actual condition due to accelerated electric stress, oxidation products significantly increases, which may further contaminate the oil. The activation energy graph is shown in figure 3.8.

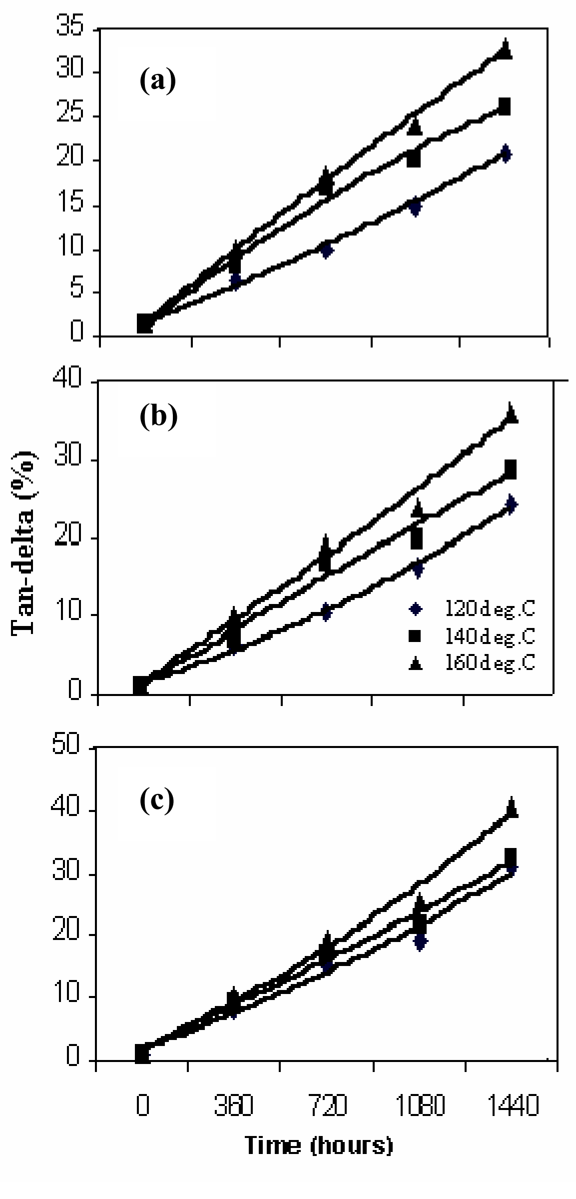

Fig. 3.7 Variation of tan-delta with time at (a) 1.0 kV (b) 1.5 kV (c) 2.5 kV

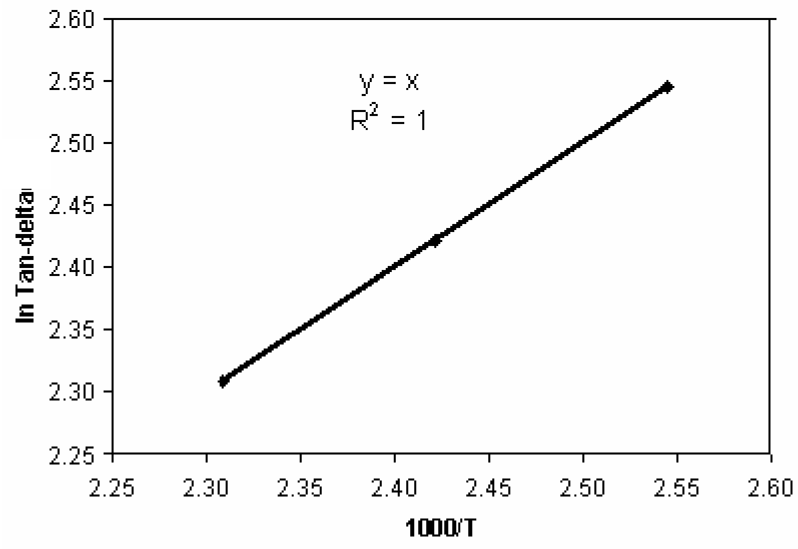

Fig. 3.8 ln (Tan-delta) vs. 1000/T (activation energy = 0.086eV)

3.1.8 Regression Analysis for Tan-delta

Multiple linear regression analysis is carried out for the experimental data. The results reveals that time, temperature, electric stress, are significant. It is also found from the analysis that interaction effect among time × temperature, time × electric stress, and $(\text{time})^2$ are also significant, whereas, interaction effect of temperature×electric stress is insignificant. The most effective prediction model is found with max R^2 = 97.66%. The mathematical function equation is as follows:

$$\text{Tan-delta} = -8.5915 - 0.01283 \times (t) + 0.103348 \times (T) + 5.55208 \times (E) + 0.00017 \times (t) \times (T) + 0.00371 \times (t) \times (E) - 0.0476 \times (T) \times (E) + 4.265 \times 10^{-6} \times (t)^2$$

3.1.9 Dielectric Constant

The results for the dielectric constants are shown figure 3.9 (a-c). The figure 3.9(a) shows that there is marginal change in dielectric constant between 120^0C and 140^0C under normal electric stress. However figure 3.9 (b) & (c) shows the countable variation in dielectric constant under accelerated electric stress of 1.5 kV and 2.5 kV. The dielectric constant value comes down from 2.5 to 1.8 for the maximum accelerated test conditions i.e. 160^0C and at 2.5 kV electric stress. I. Fosana and V.Wesserberg et.al [9] in his work reported that decrease in dielectric constant and increase in tan-delta was prominent under stress conditions. The activation energy graph has been plotted between ln of dielectric constant and 1000/T for 1440 hrs in figure 3.10.

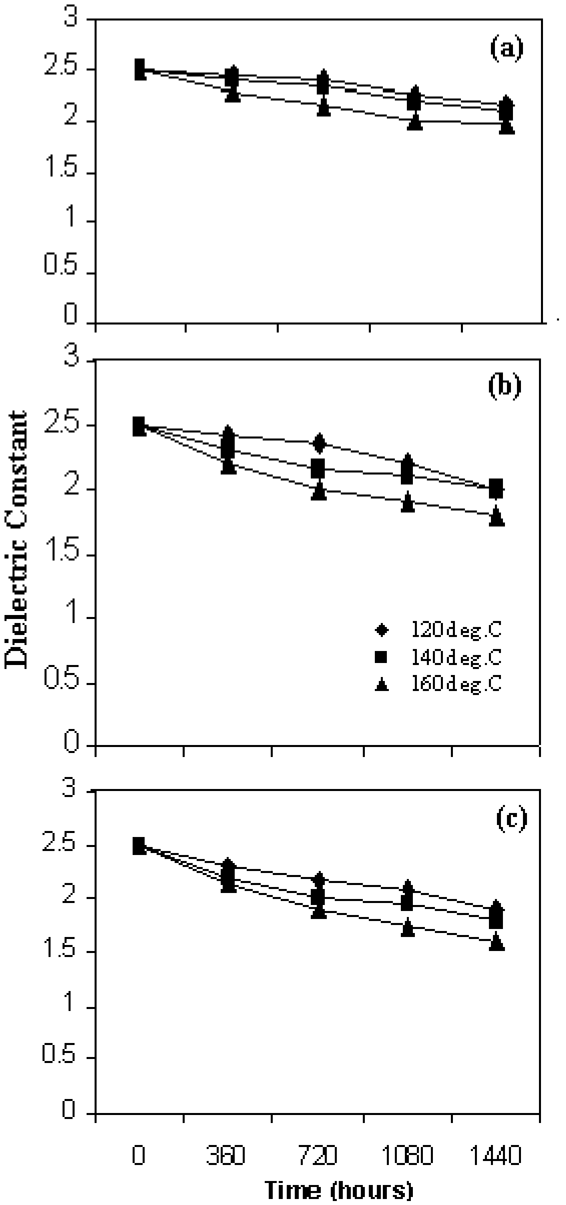

Fig. 3.9 Variation of dielectric constant with time at (a) 1.0 kV (b) 1.5 kV (c) 2.5 kV

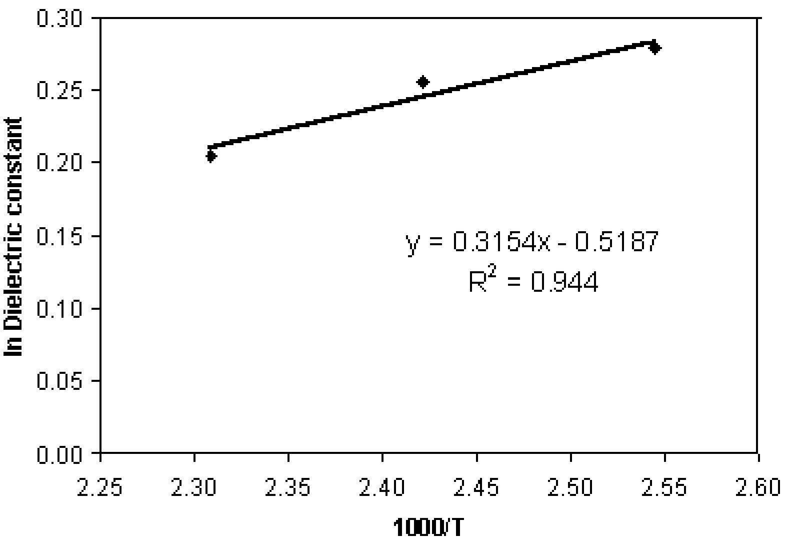

Fig. 3.10 ln (Dielectric constant) vs. 1000/T (activation energy = 0.027eV)

3.1.10 Regression Analysis for Dielectric Constant

Multiple linear regression analysis is carried out for the experimental data. The results revealed that time, and temperature are significant, however, electric stress is insignificant. The interaction effect of time×temperature, time×electric stress, time×temperature×electric stress, $(\text{temperature})^2\times$time, $(\text{time})^2\times$electric stress are also found significant, whereas, temperature×electric stress, $(\text{time})^2$, $(\text{temperature})^2$, $(\text{electric stress})^2$, $(\text{time})^2\times$electric stress, $(\text{electric stress})^2\times$time are insignificant. The most effective prediction model is found with max $R^2 = 90.16\%$. The mathematical function equation is as follows:

$$(\text{€r})^{\frac{1}{2}} = 2.4315 - 0.0.0036 \times (t) - 0.0102 \times (T) +1.4066 \times (E) + 4.5062 \times 10^{-5} \times (t) \times (T) + 0.000274 \times (t) \times (E) -0.01812 \times (T) \times (E) + 2.535 \times 10^{-7} \times (\text{time})^2 + 1.8162 \times 10^{-5} \times (T)^2 - 0.11984 \times (E)^2 - 30331 \times 10^{-6} \times (t) \times (T) \times (E) - 1.242 \times 10^{-7} \times (t)^2 \times E - 1.481 \times 10^{-7} \times (T)^2 \times t - 7.551 \times 10^{-5} \times (t)^2 \times E + 8.8211 \times 10^{-5} \times (E)^2 \times \text{time}.$$

3.1.11 Interfacial Tension (IFT)

Interfacial tension (IFT) is extremely useful for determining the presence of polar contaminants and oil decay products. Good, new oil generally exhibits high interfacial tension. The results for IFT are shown figure 3.11 (a-c). The interfacial tension variation is small, the trend is in expected direction. Oil oxidation contaminants lower the IFT. This is due to the reason that they have a high affinity towards water molecules (i.e. they are hydrophilic in nature) as well as the oil molecules [10]. At the interface they extend across to the water, thus a vertical force is exerted reducing the lateral tension. Increase in oxidation contaminants causes more reduction in IFT. Therefore, at accelerated test conditions i.e. 160^0C and at 2.5 kV electric stress, the oxidation of oil is faster in comparison with 120^0C and 140^0C. The activation energy is calculated by plotting the graph between ln of IFT and 1000/T as shown in figure 3.12.

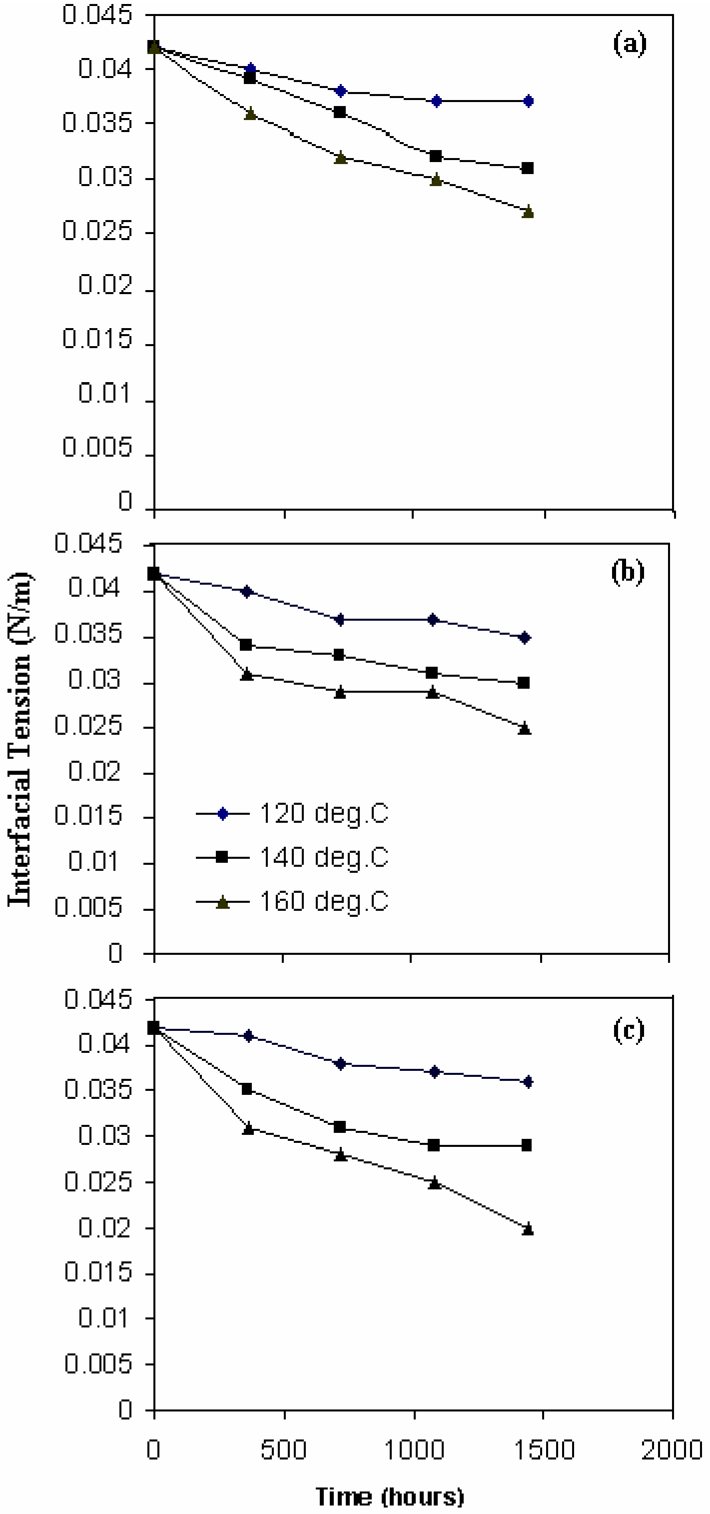

Fig. 3.11 Variation of interfacial tension with time at (a) 1.0 kV (b) 1.5 kV (c) 2.5 kV

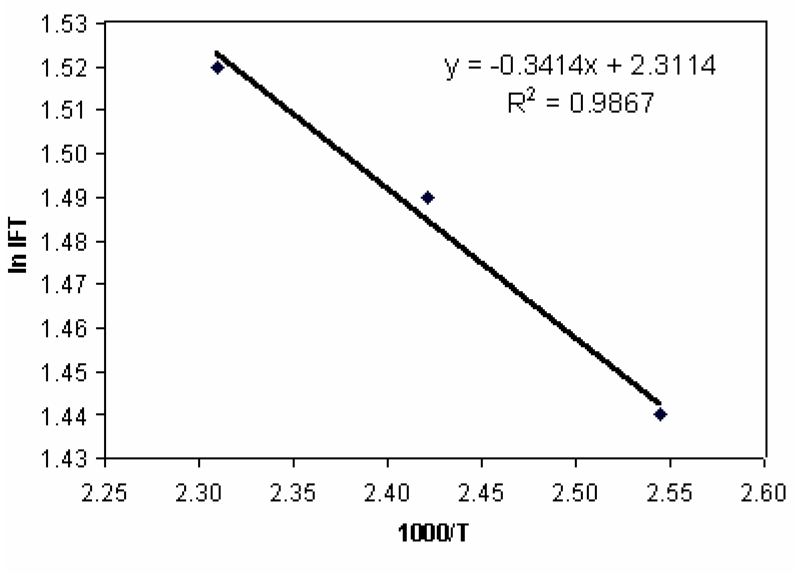

Fig. 3.12 ln (Interfacial tension) vs. 1000/T (activation energy =0.029eV)

3.1.12 Regression analysis for Interfacial tension

Multiple linear regression analysis is carried out for the experimental data. The results revealed that time and temperature, are significant, however electric stress is insignificant. Analysis also reveals that the interaction effect of time×temperature, time×electric stress, $(\text{time})^2$, $(\text{electric stress})^2$ have been also significant. The most effective prediction model is found with max $R^2 = 94.89\%$. The mathematical function equation is as follows:

$$IFT = 0.04328 + 6.1133 \times 10^{-6} \times t - 4.166 \times 10^{-6} \times T - 003412 \times E - 9.722 \text{ x } 10^{-8} \times t \times T - 1.362 \times 10^{-6} \times t \times E + 2.3577 \times 10^{-9} \times (t)^2 + 0.001388 \times (E)^2.$$

3.1.13 Specific Resistance/Resistivity

It is desirable to have specific resistance of oil as high as possible. A satisfactory value at 90^0 C and unsatisfactory values at room temperature is an indication of the presence of water or degradation products precipitatable in the cold but generally at a tolerable level. Unsatisfactory results at both temperatures indicate a greater extent of contamination and it may not be possible to restore the oil to a satisfactory level by reconditioning.

The test results are shown in figure 3.13 (a-c). Resistivity of oil varies greatly with temperature of oil. Uniform decrease in resistivity with respect to thermal and electric stress is observed in three different conditions. Resistivity of oil reduces considerably due to presence of moisture, acidity and solid contaminants [11, 12]. Contamination of oil, which would not otherwise be detected by acidity test, will immediately be indicated by changes in the value of resistivity. Therefore, decrease in resistivity strengthens our previous findings. The activation energy is calculated by plotting the graph between natural logarithm of resistivity and 1000/T as shown in figure 3.14.

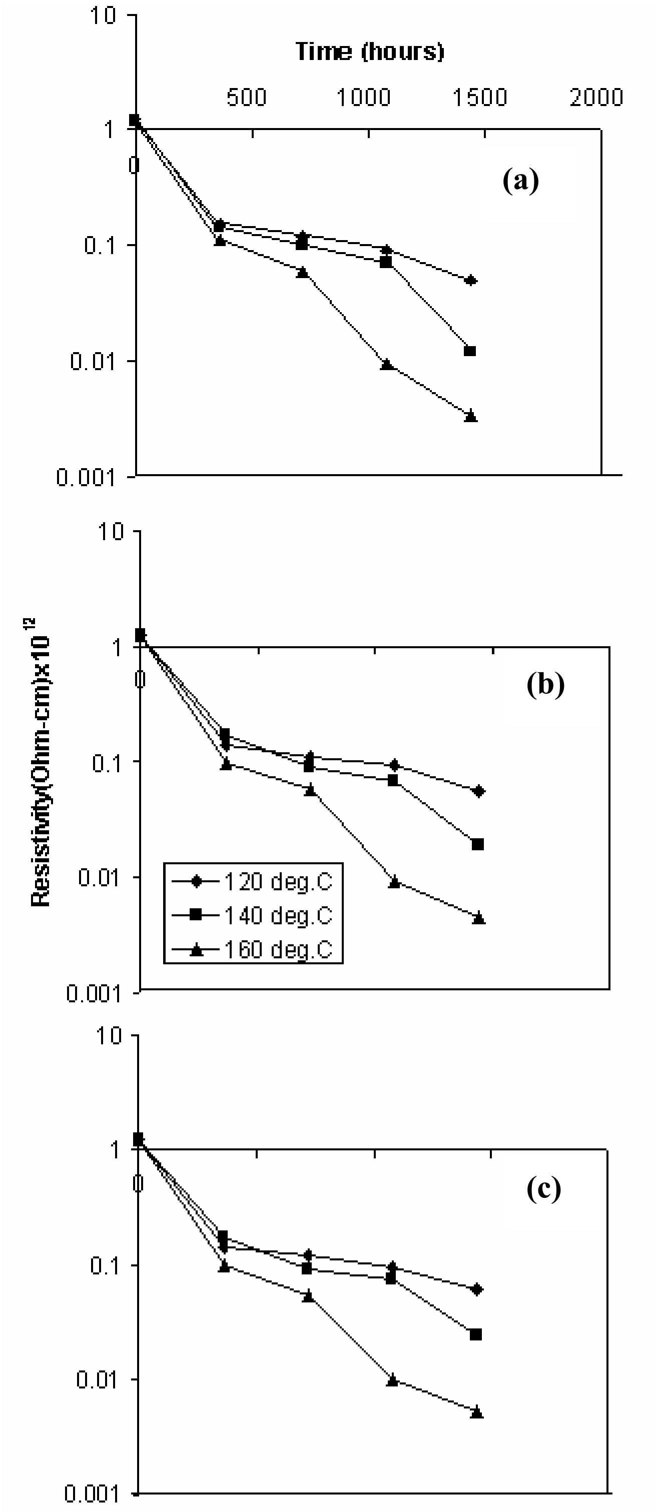

Fig. 3.13 Variation of resistivity with time at (a) 1.0 kV (b) 1.5 kV (c) 2.5 kV

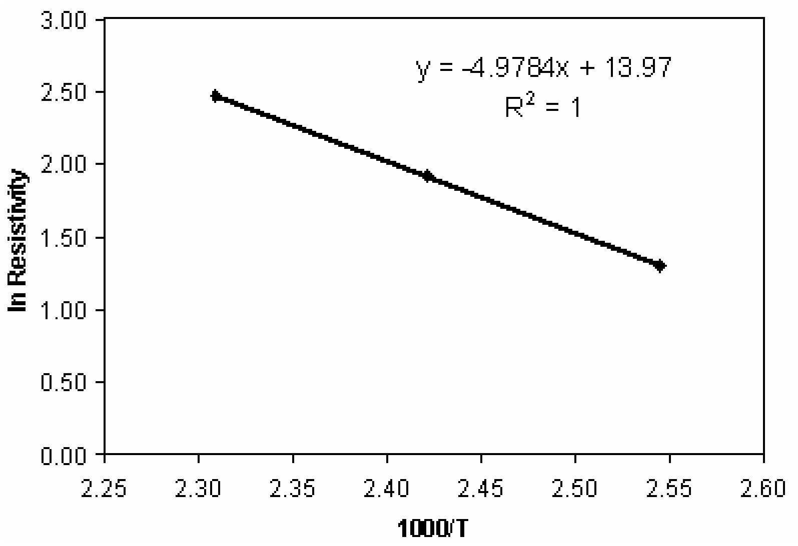

Fig. 3.14 ln (Resistivity) vs. 1000/T (activation energy =0.428eV)

3.1.14 Regression analysis for Specific Resistance/Resistivity

Multiple linear regression analysis is carried out for the experimental data. The results revealed that time, temperature are significant and electric stress is insignificant. The interaction among time×temperature, time×electric stress, temperature×electric stress, $(\text{temperature})^2$, time×temperature×electric stress, $(\text{time})^2\times$temperature, $(\text{time})^2\times$electric stress and $(\text{temperature})^2\times$time are significant, whereas, the interaction effect of $(\text{time})^2$, $(\text{electric stress})^2$, $(\text{electric stress})^2\times$time, $(\text{electric stress})^3$ and $(\text{time})^3$ are found to be insignificant. The most effective prediction model is found with max $R^2 = 97.62\%$. The mathematical function equation is as follows:

$$\text{Resistivity} = -2.504058 - 0.002479 \times t - 0.03860 \times T + 0.00150 \times E - 3.54 \times 10^{-5} \times t \times T - 0.000235 \times t \times E -+ 0.00037245 \times T \times E + 3.027 \times 10^{-8} \times (t)^2 - 0.00013 \times (T)^2 – 0.0688 \times (E)^2 + 1.8426 \times 10^{-6} \times t \times T \times E - 1.7506 \times 10^{-9} \times (t)^2 \times T - 5.648 \times 10^{-8} \times (t)^2 \times E + 1.0583 \times 10^{-7} \times (T)^2 \times t + 2.9678 \times 10^{-5} \times (E)^2 \times t - 0.0007469 \times (E)^3 - 6.308 \times 10^{-11} \times (t)^3.$$

3.1.15 Total Acidity

Acidity of new oil is normally very less. The figure 3.15 (a-c) shows the increase in acidity value with respect to thermal and electrical stress. The increase in acidity is maximum for the higher thermal and electrical stress, which is quite obvious as at higher stress level the oxidation of oil produces acids. Acidity of oil thus slowly increases with ageing of transformer oil [13]. The acids are harmful to the solid insulation. They can also induce rusting of iron in presence of moisture. Increase in acidity further reflects the interfacial tension, which is true in our findings. The activation energy is calculated by plotting the graph between natural logarithm of acidic value and 1000/T as shown in figure 3.16.

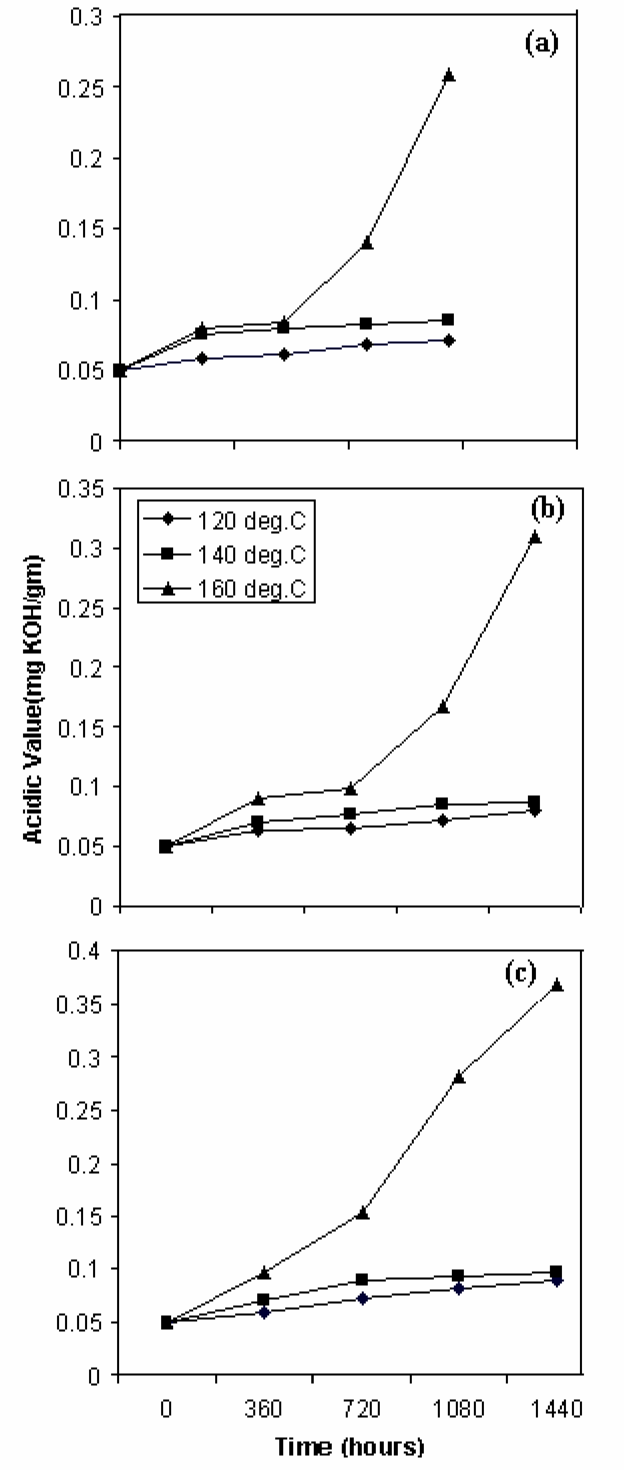

Fig. 3.15 Variation of acidic value with time at (a) 1.0 kV (b) 1.5 kV (c) 2.5 kV

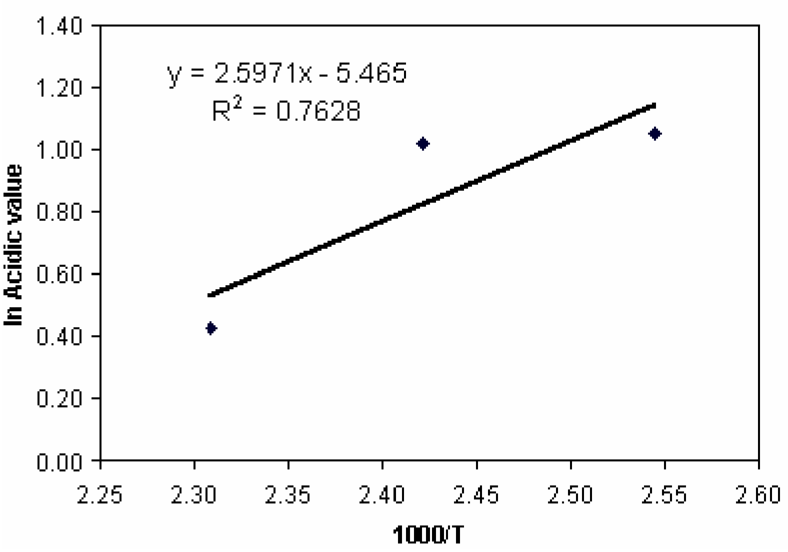

Fig. 3.16 ln (Acidic value) vs. 1000/T (activation energy =0.223eV)

3.1.16 Regression Analysis for Acidic Value

Multiple linear regression analysis is carried out for the experimental data. The results revealed that effect of temperature is significant, but there has been insignificant effect of time and electric stress. The interaction effect of time×temperature, temperature×electric stress, $(\text{time})^2$, $(\text{temperature})^2$, time-temperature×electric stress, $(\text{time})^2\times$temperature, $(\text{temperature})^2\times$time and $(\text{temperature})^2\times$electric stress are significant, whereas, and $(\text{time})^2\times$electric stress are found to be insignificant. The most effective prediction model is found with max R^2 = 98.16%. The mathematical function equation is as follows:

$$\text{Acidic value} = -4.4521 + 0.0.00527 \times t + 0.0651 \times T + 1.2632 \times E - 7.403 \text{ x } 10^{-5} \times t \times T + 0.01885 \times T \times E - 4.828 \times 10^{-7} \times (t)^2 - 0.00022 \times (T)^2 + 1.3214 \times 10^{-6} \times t \times T \times E + 4.4689 \times 10^{-9} \times (t)^2 \times T - 5.098 \text{ x } 10^{-8} \times (t)^2 \times E + 2.4491 \times 10^{-7} \times (T)^2 \times t + 6.75 \times 10^{-5} \times (T)^2 \times E$$

3.1.17 Flash Point

It is desirable that the oil should have very high flash point (>140°C). The figure 3.17 (a-c) shows the variation of flash point under combined thermal and electrical stress. The flash point of virgin sample was 146^0C, whereas after ageing for 1440 hrs at 160^0C/ 2.5 kV (thermal & electric stress), it comes down to 130^0C. It may be due to volatile combustible products present in oil, which reduce the flash point. Oil is exposed to very high temperatures under fault conditions for long duration. Therefore, lower molecular weight hydrocarbons may be produced. These low molecular weight hydrocarbons cause a lowering in the flash point of oil [14]. The activation energy is calculated by plotting the graph between natural logarithm of flash point and 1000/T as shown in figure 3.18.

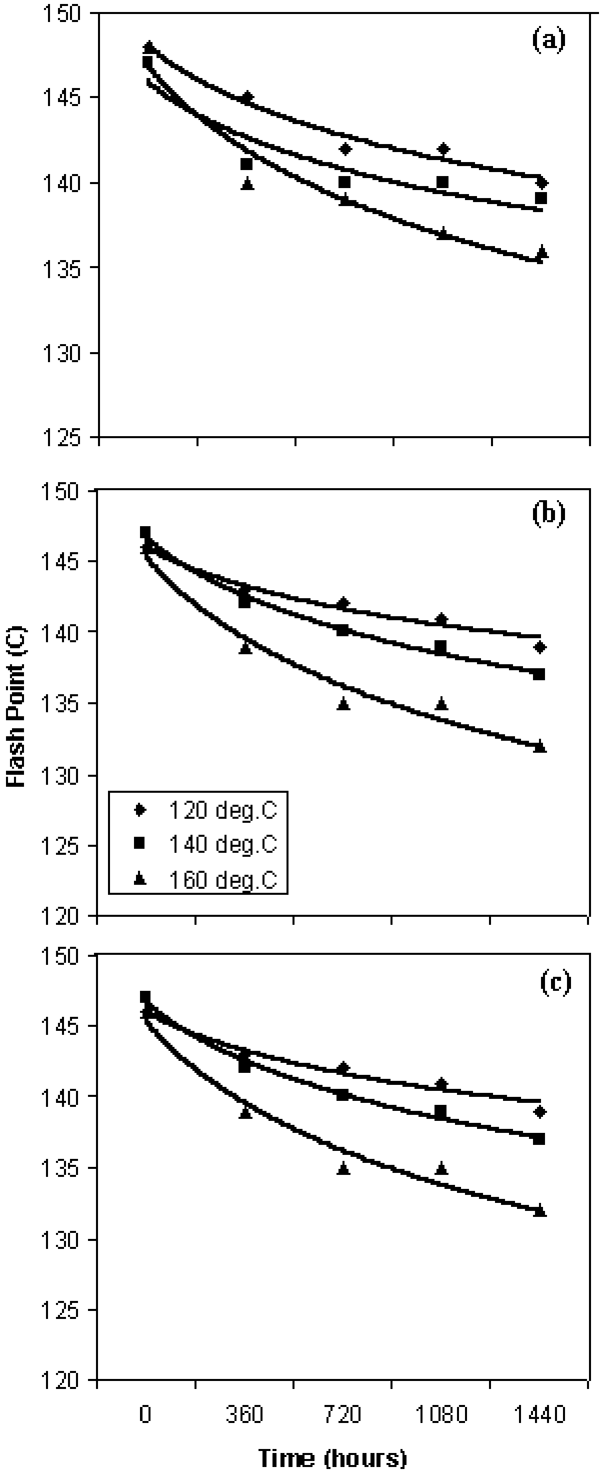

Fig. 3.17 Variation of flash point with time at (a) 1.0 kV (b) 1.5 kV (c) 2.5 kV

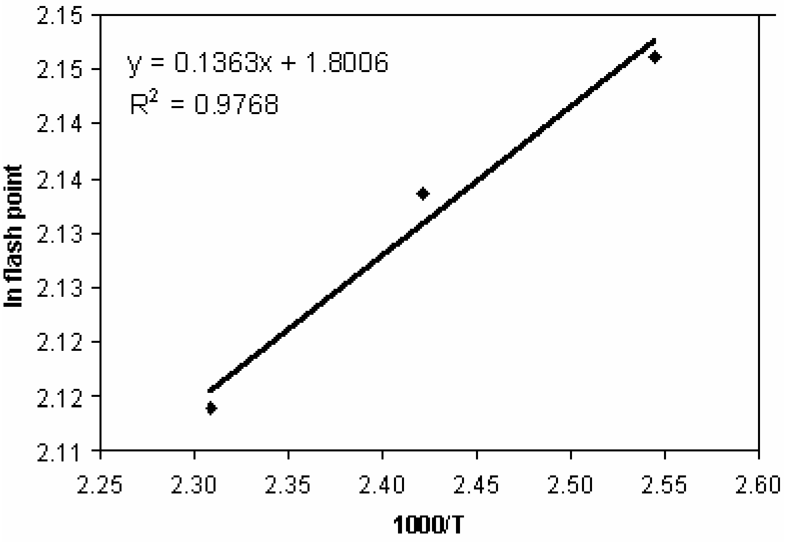

Fig. 3.18 ln (Flash point) vs. 1000/T (activation energy =0.011eV)

3.1.18 Regression Analysis for Flash Point

Multiple linear regression analysis was carried for the experimental data. The results revealed that time, temperature, electric stress and time×temperature are significant, whereas interaction of time×electric stress and temperature×electric stress are found to be insignificant. The most effective prediction model is found with max R^2 = 79.71%. The mathematical function equation is as follows:

Flash point = $0.007477 - 8.514 \text{ x } 10^{-7} \times t - 3.714 \times 10^{-6} \times T - 0.0003095 \times E + 7.0641 \times 10^{-9} \times t \times T + 8.4048 \times 10^{-8} \times t \times E + 2.1265 \text{ x } 10^{-6} \times T \times E$.

3.2 Properties of paper

3.2.1 Tensile Strength

It is the indicative of the serviceability of paper. The results of the tensile strength of the paper are shown figure 3.19 (a-c). Since paper is an aggregate of millions of pulp fibers, composed mainly of cellulose micro fibrils in a matrix of hemicellulose and lignin, the strength arises at different structural levels. Paper is a material with an enormously high degree of heterogeneity containing a seemingly infinite number of cracks of different dimensions [15,16]. With an increase in ageing time these micro cracks widen up and thus makes the strength to go down.

For samples tested at higher temperature the strength drops down drastically with ageing time as paper becomes brittle due to variation in structure of the paper. The strength of paper depends mostly on strength of fiber. During manufacturing of paper various types of stresses arises. Smith and other researcher in their work have reported that fibers in paper were permanently deformed by draws during the drying of paper [17-19]. At higher temperature a number of cracks appear at these fibers thus leading to catastrophic failure of the system**.** The figures 3.19 shows that at 120^0C and 140^0C the variation of paper strength is distinct, however, the maximum degradation in strength is visible for samples aged at 160^0C, where the strength of paper drops around to 16% after 1440 hrs ageing. The acceptable limit for a drop in strength up to 50% suggest that the paper ageing to such a high temperature for a long time leads to the catastrophic failure of the system [20, 21]. The activation energy is calculated by plotting the graph between natural logarithm of tensile strength and 1000/T as shown in figure 3.20.

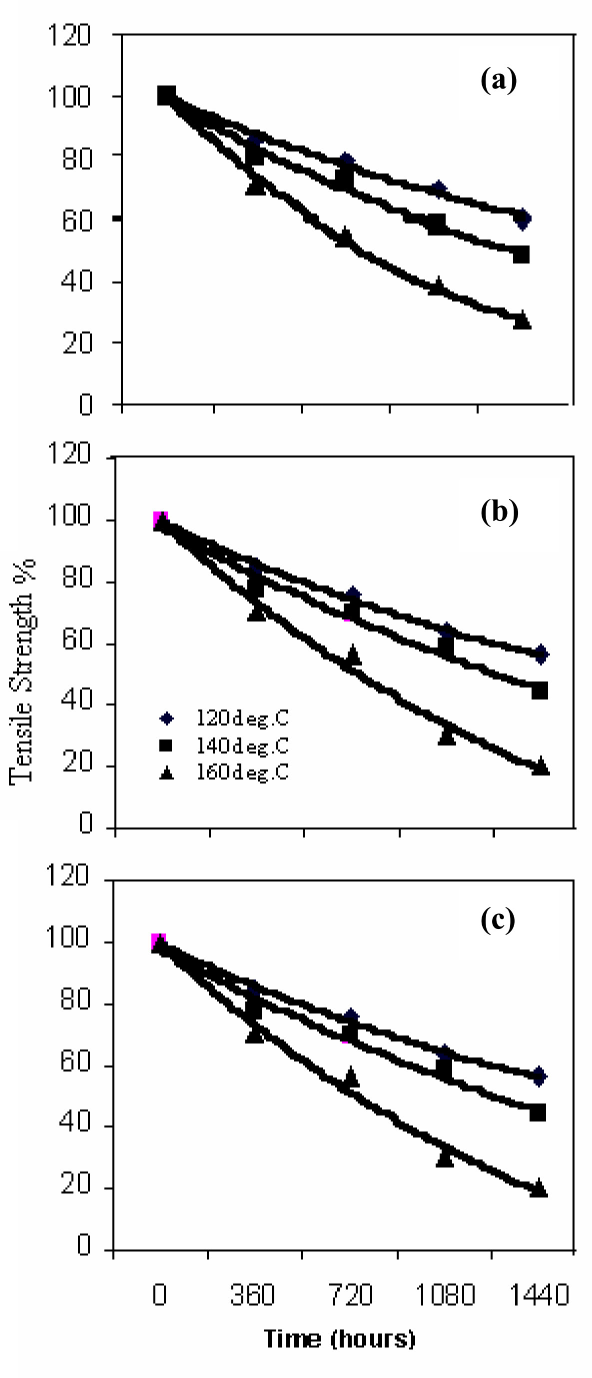

Fig. 3.19 Variation of tensile strength with time at (a) 1.0 kV (b) 1.5 kV (c) 2.5 kV

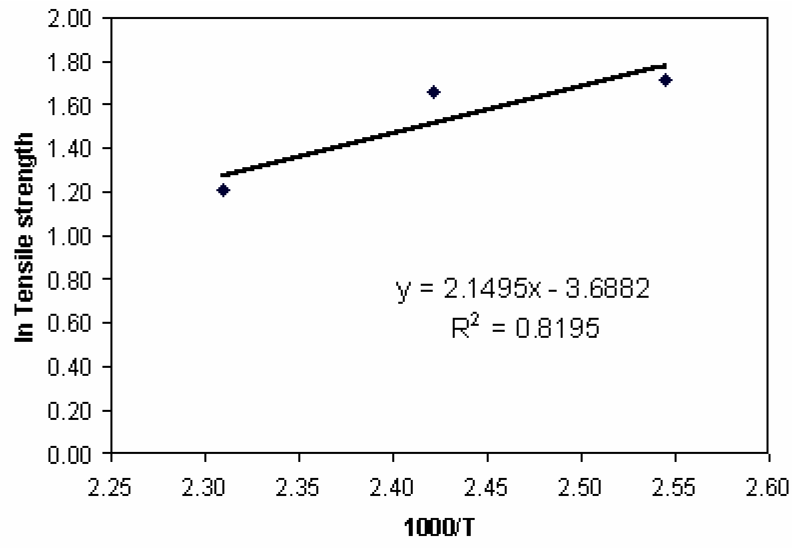

Fig. 3.20 ln (Tensile strength) vs. 1000/T (activation energy =0.184eV)

3.2.2 Regression Analysis for Tensile Strength

Multiple linear regression analysis is carried out for the experimental data. The results revealed that time, temperature and electric stress, are significant. The interaction of time×temperature, time×electric stress and $(\text{temperature})^2$ are significant, whereas, $(\text{time})^2$ is found to be insignificant. The most effective prediction model is found with max R^2 = 98.13%. The mathematical function equation is as follows:

$$\text{Tensile Strength (\%)} = -108.322 + 0.026816 \times t - 3.12916 \times T - 1.13095 \times E - 0.0004294 \times t \times T - 0.0044511 \times t \times E + 3.7509 \text{ x } 10^{-6} \times (t)^2 - 0.01203 \times (T)^2$$

3.2.3 Degree of Polymerization

The chemical and physical properties of the cellulose depend upon their molecular weight and molecular weight distribution. The molecular weight (M) is expressed as the degree of polymerization (DP=M/162) where 162 is molecular weight of an anhydroglucose unit. The M of cellulose is dependent on the technique used in its measurements. The degree of polymerization (DP) has traditionally been used as the primary indication of the condition of the insulation paper. Many workers have attempted to relate the strength of the paper with its DP. They have given some critical limit. The higher the DP, the better the mechanical properties of the paper. The initial value of DP of around 1200 is expected to last the lifetime of transformer for 25 to 40 years, but at DP 150-200 the mechanical strength of the paper is reduced to 20% of its initial value. Figure 3.21 (a-c) shows the results of DP at 120^0C to 160^0C under electric stress 1.0 kV, 1.5 kV and 2.5 kV. It is evident from these figures that the variation in DP value is significant even at temperature of 140^0C. However, at 160^0C for 1440 hrs, the DP value is drastically reduced. This is also true in the case of tensile strength for samples aged at 160^0C where its strength reduced to 20%. The decrease in DP with ageing time is because of reaction conditions inherent with the system. It decreases with action of air (oxygen) under alkaline conditions (ageing) [23]. The selective cleavage between C-2 and C-3 by oxidation leads to introduction of carbonyl groups at C-2 and or C-3 makes cellulose labile to alkali. An aldehyde group at C-6 considerably decreases the stability of cellulose towards acids and alkali, which comes due to thermal degradation [24].

Another factor that influences the DP is hydrolysis of cellulose. Presence of small amount of dilute acids and chloride ions can decrease the DP to a value of 300-350 with a weight loss of 4% at the beginning of hydrolysis [25]. This leads to change in cellulose structure partially from amorphous to crystalline. The part of cellulose is readily hydrolyzed to leave a fraction resistant to acid hydrolysis named as hydro cellulose. Under these circumstances where a variety of complexity is involved, no mathematical model can be fitted suitably to understand the kinetic of cellulose decomposition. Mathematical models developed to describe the kinetic of reactions by Ekenstam from the work of Kuhn and coworkers [26-28] followed by the work of Emsely and Steven [29] have shown that cellulose decomposition up to the value of DP = 200 can be fitted in their model. The natural logarithm of slope of the graph is shown to be directly related to reciprocal temperature via the Arrhenius relationship. Extrapolation of these lines to transformer temperature gives the lifetime of the paper to be predicted for these specific conditions. The activation energy is calculated by plotting the graph between natural logarithm of degree of polymerization and 1000/T as shown in figure 3.22.

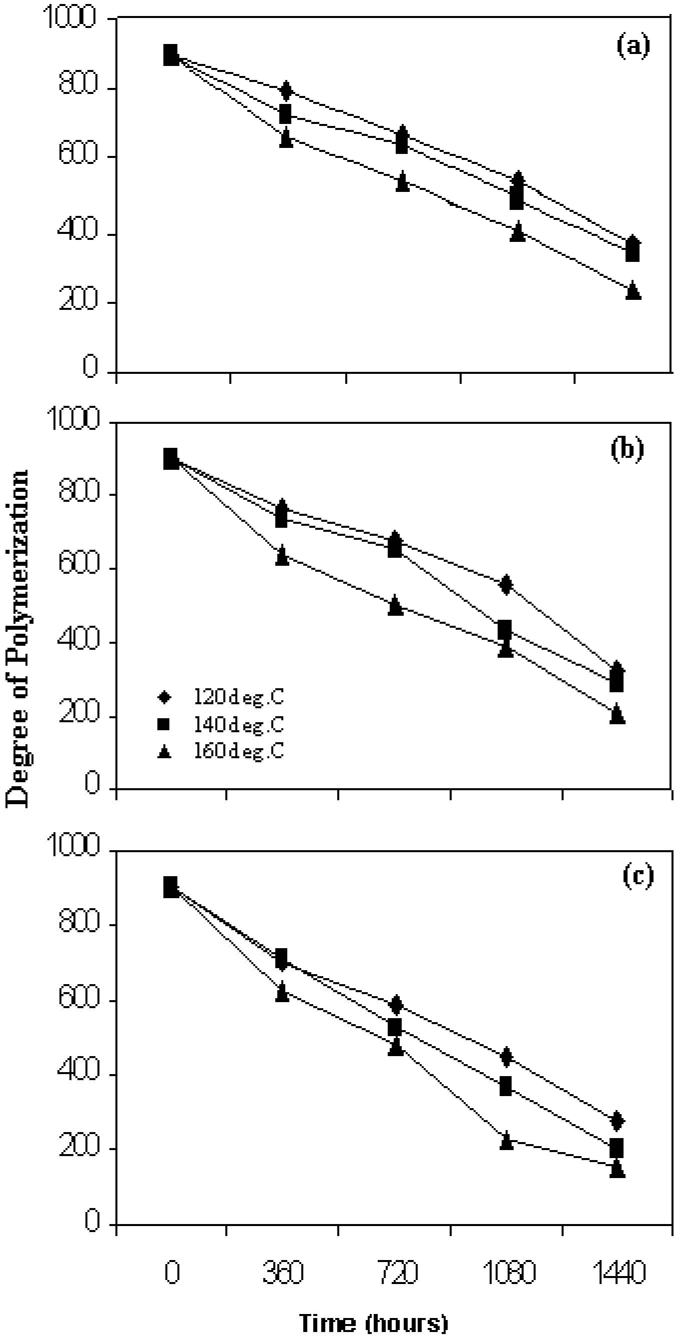

Fig. 3.21 Variation of degree of polymerization with time at (a) 1.0 kV (b) 1.5 kV (c) 2.5 kV

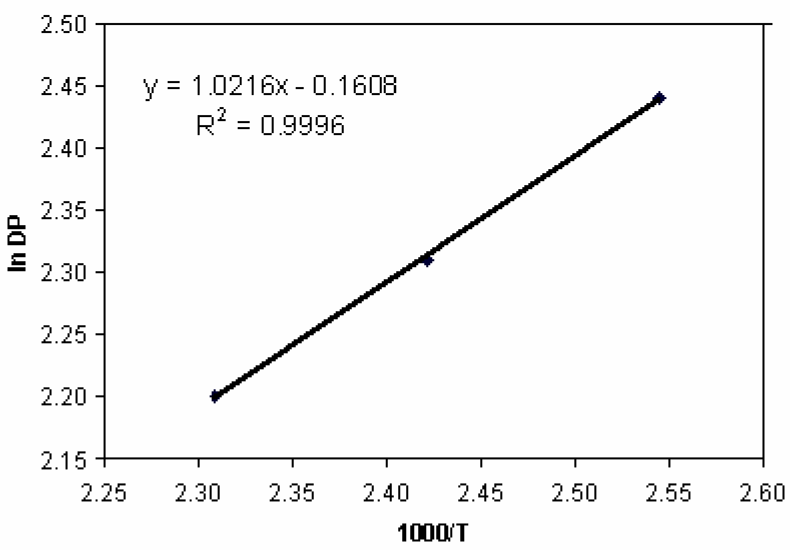

Fig. 3.22 ln (Degree of polymerization) vs. 1000/T (activation energy =0.087eV)

3.2.4 Regression Analysis for Degree of Polymerization

Multiple linear regression analysis is carried out for the experimental data. The results revealed that time, temperature and electric stress are significant. The interaction effect of time×electric stress, $(\text{time})^2$ and temperature^2 are significant, whereas $(\text{electric stress})^2$ is found to be insignificant. The most effective prediction model is found with max R^2 = 94.38%. The mathematical function equation is as follows:

Degree of polymerization = $528.5416 - 222.6428 \times t - 68.125 \times T - 45.4166 \times E - 14.7857 \times t \times E - 24.375 \times (t)^2 - 19.375 \times (T)^2 -12.5 \times (E)^2$.

3.2.5 Paper Break down Strength

The BDV of paper was measured on accelerated aged samples. The figure 3.23 (a-c) shows the variation of paper break down voltage (BDV) at 120^0C to 160^0C under three different electric stress levels. There is marginal change in BDV of paper at 120^0C and 140^0C. However, at 160^0C, the BDV comes down to half. A decrease in BDV with ageing temperature and time is because of decrease in bond strength due to thermal ageing. As discussed earlier the higher the mechanical stability of the paper, the better is the BDV of paper [30]. The activation energy is calculated by plotting the graph between natural logarithm of BDV of paper and 1000/T as shown in figure 3.24.

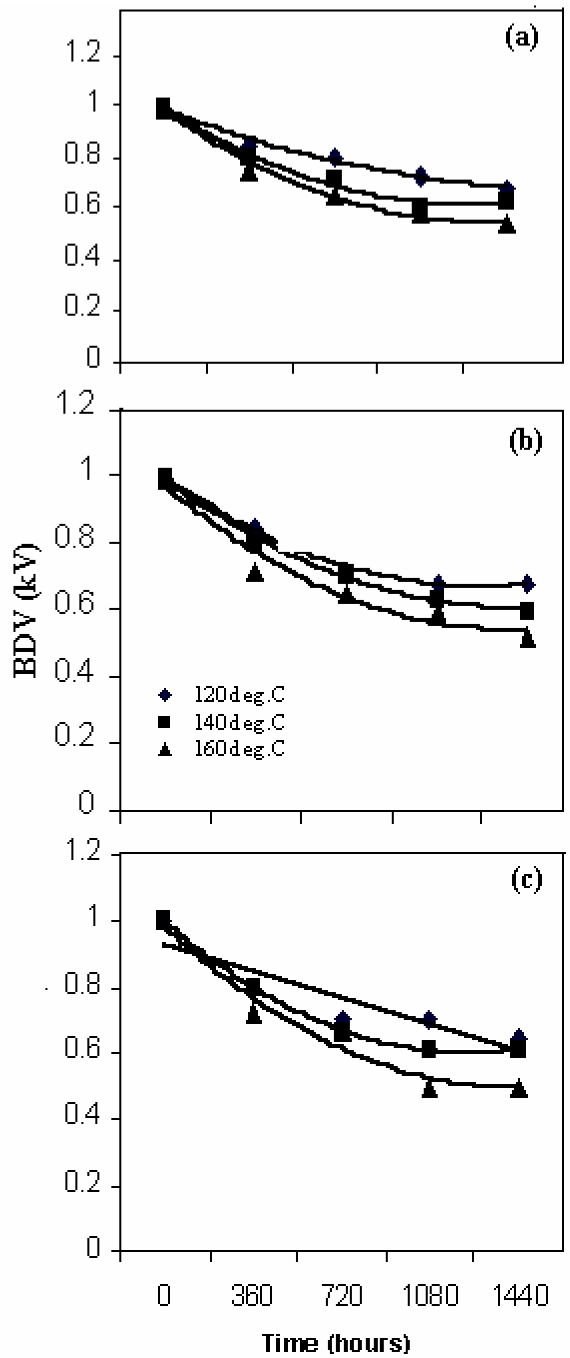

Fig. 3.23 Variation of BDV of paper with time at (a) 1.0 kV (b) 1.5 kV (c) 2.5 kV

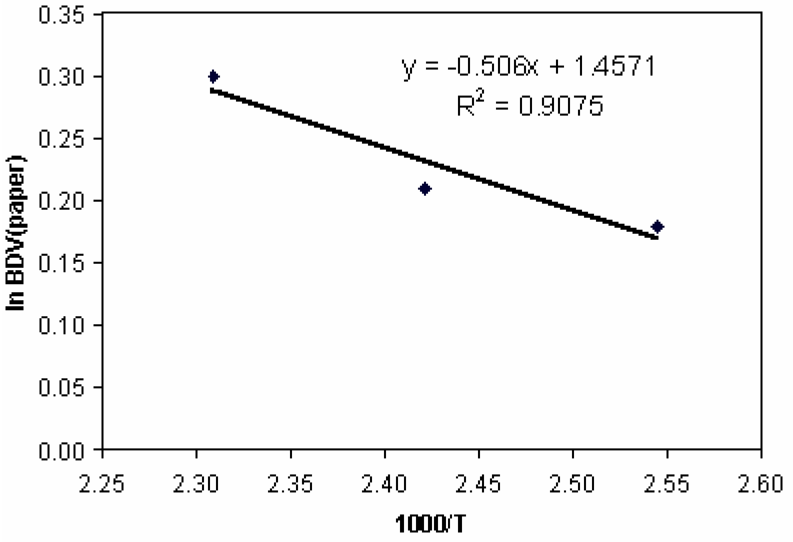

Fig. 3.24 ln (BDV of paper) vs. 1000/T (activation energy =0.043eV)

3.2.6 Regression Analysis for Paper BDV

Multiple linear regression analysis was carried out for the experimental data. The results could not find any transfer function for paper BDV.

3.3 Activation Energy Calculations

The activation energy for each parameter can be calculated from the above Arhennius plots as shown in table 3.1.

Table 3.1 Calculated activation energy for various parameter

Properties	**Activation Energy (eV)**	**Activation Energy kJ/mole**
Viscosity	0.03	2.89
Moisture	0.07	6.75
BDV of oil	0.07	6.75
Tan-delta	0.09	8.68
Dielectric constant	0.03	2.89
Interfacial tension	0.03	2.89
Specific resistance	0.43	41.48
Acidity	0.22	21.22
Flash point	0.01	0.96
Tensile strength	0.18	17.26
Degree of polymerization	0.09	8.68
BDV of paper	0.04	3.85

Conclusions:

From the above study following conclusions can be drawn:

1. The oil properties like Viscosity, Moisture, Breakdown voltage, Tan-delta, Dielectric Constant, Interfacial tension, Specific Resistance, Acidity and Flash point were measured under thermal stress of 120^0C to 160^0C and electric stress of 1.0 kV to 2.5 kV. The samples were taken out for testing after 360, 720,1080 and 1440 hours. It is evident that all the properties were affected under combined stress conditions and there is consistent change with respect to ageing time, temperature and electric stress. However, the maximum changes were at 160^0C at electric stress of 2.5 kV after 1440 hrs of ageing. Furthermore there is good correlation between Viscosity, Moisture, Breakdown voltage, Tan-delta, Dielectric Constant, Interfacial tension, Specific Resistance and Acidity i.e. increase in moisture content, acidity and solid contaminants of oil result in decrease in BDV, Resistivity, IFT and Dielectric constant whereas a decrease in resistivity is coupled with increase in tan- delta and viscosity.
2. The paper properties like Tensile strength, Degree of polymerization and Breakdown voltage have been affected under accelerated thermal and electrical stress. There is a good correlation between Tensile strength and Degree of polymerization.
3. The impact of thermal stress is significant as compared to electric stress, however electrical stress is an important factor to be considered in the oxidation oil.
4. The activation energy of each parameter has been calculated, the life of insulation can be predicted from activation energy.
5. The multiple regression analysis on the experimental data shows that R^2 value in most of the cases are more than 95% confidence level and function equation has been developed for each parameter.

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Chapter-4

STUDY OF AGED SAMPLES BY DISSOLVED GAS ANALYSIS, PARTIAL DISCHARGE AND HIGH PRESSURE LIQUID CHROMATOGRAPHY TECHNIQUES

Overview

In this chapter, the aged samples have been studied with techniques, such as Dissolved Gas Analysis (DGA), Partial Discharge (PD) and High-Pressure Liquid Chromatography (HPLC). Dissolved gas analysis is a very efficient tool and is like a blood test or a scanner examination of the human body. It can warn about an impending problem, give an early diagnosis, and increase the chances of finding the appropriate cure. Particular attention is given to DGA results related to PDs. The concentration of Furan compounds in transformer oil is evaluated by HPLC. The test results from the above studies are discussed.

Keywords: Dissolved Gas Analysis (DGA), Partial Discharge (PD) and High Pressure Chromatography (HPLC) Partial Discharge (PD).

4.0 RESULTS AND DISCUSSIONS

4.1 Dissolved Gas Analysis (DGA)

The protection systems being used in association with Bulk Oil Equipment are generally to operate on overloads and faults much beyond their loading capacities. Since this equipment are generally to handle very high quantum of energy, minor faults inside the equipment, called incipient faults, cannot be detected as faults by the protection system. If these faults are left undetected, they can aggravate themselves leading to irreparable damage to the equipment [1].

Though there is no direct method to detect these incipient faults, it is known that these faults, especially in the form of overheating, arcing or partial discharge, develop certain gaseous hydrocarbons, that are retained by the insulating oil as dissolved gases [2]. Thus the evaluation of these gas compositions and their interpretation, known as Dissolved Gas Analysis (DGA), became the only and life saving diagnostic test on bulk oil equipment.

Dissolved Gas Analysis is a very powerful technique to find out incipient faults within the transformer. Certain gases are produced by decomposition of oil or paper insulation when transformer undergoes abnormal thermal or electrical stresses [3]. These gases come out and get collected in buchholtz relay when their quantity is more. But when the fault is in very small area or if the severity of fault is insignificant these gases get dissolved in oil. As the composition and quantity of the gases generated is dependent on type and severity of the fault, regular monitoring of these dissolved gases reveals useful information about healthiness of a transformer and prior information of fault can be obtained observing the trend of various gas contents [4]. A number of methods are available for interpretation of DGA results [5]. The methods may be classified as those relying on characteristic of key gases, gas ratios and regression analysis. Key gas diagnostic criterion is qualitative in nature and gives an indication on the nature of fault in the transformer. The gas ratio is a semi-quantitative technique and helps identify the faults more specifically than the characteristic gases. Several ratio methods, such as Dornenberg ratio, Gas pattern, PEM ratio, O-C-H triangular plot, Rogers ratio method have been suggested. The ratio method applies generally to the relatively common conservator type units with expansion tank. Ratio codes and fault classification could be affected due to adjustment necessary in case of non-conservator type units with gas space. Regression method is a quantitative technique in which the rate of gas production is correlated with operation parameters, such as time on load, load current, load current squared, etc. [6,7,8]. Analysis using a computer generally shows that one of the faults is mainly responsible for excessive gas content.

Mineral insulating oils are made of a blend of different hydrocarbon molecules containing CH_3, CH_2 and CH chemical groups. Scission of some of the C-H and C-C bonds may occur as a result of electrical and thermal faults, with the formation of small unstable fragments, in radical or ionic form, such as H•, CH_3•, CH_2•, CH•, or C• (among many other complex forms), which combine rapidly, through complex reactions into gas molecules such as hydrogen (H-H), methane (CH_3-H), ethane (CH_3-CH_3), ethylene (CH_2=CH_2) or acetylene (CH≡CH). Low energy faults, such as partial discharges of cold plasma type (corona discharges), favour the scission of the weakest C-H bonds (338 kJ/mole) through ionization reactions and the accumulation of hydrogen as the main recombination gas [9]. Higher temperatures are needed for the scission of the C-C bonds and their recombination into gases with a C-C single bond (607 kJ/mole), C=C double bond (720 kJ/mole) or C≡C triple bond (960 kJ/mole). Ethylene is thus favoured over ethane and methane above temperatures of approximately 500°C. Acetylene requires temperatures of at least 800°C to 1200°C, and a rapid quenching to lower temperatures, in order to accumulate as a stable recombination product. Carbon particles form at 500°C to 800°C and are indeed observed after arcing in oil or around very hot spots [10]. Oil may oxidize with the formation of small quantities of CO and CO_2, which can accumulate over long periods of time into more substantial amounts.

The polymeric chains of solid cellulosic insulation contain a large number of anhydroglucose rings, and weak C-O bonds and glycosidic bonds which are thermally less stable than the bonds hydrocarbon in oil, and which decompose at lower temperature. Significant rates of polymer chain scission occur at temperatures higher than 105°C, with complete decomposition and carbonization above 300°C. Mostly carbon monoxide, carbon dioxide and water are formed in much larger quantities than by oxidation of oil at the same temperature.

Gases may be generated in some cases not as a result of faults in the equipment but through rusting or other chemical reactions involving steel, uncoated surfaces or protective paints. For example, hydrogen may be produced by reaction of steel with water, as long as oxygen is available from the nearby oil. Large quantities of hydrogen have thus been reported in some transformers that had never been energized. Internal transformer paints, such as alkyd resins and modified polyurethanes containing fatty acids in their formulation may also form gases.

The dissolved gas analysis was carried out on all the aged samples at 120^0C, 140^0C and 160^0C at 1.0 kV, 1.5 kV and 2.5 kV electric stress and samples were taken out after 360, 720, 1080 and 1440 hours.

In the present study the following gases in oil have been measured under different thermal and electrical stress:
CO_2, CH_4, C_2H_6, C_2H_4, C_2H_2 and H_2
The results of each are discussed below:

4.1.1 Carbon dioxide (CO_2)

The results (Figures 4.1- 4.3) indicate that CO_2 content remains low at lower thermal stress. As the temperature increases (120^0C, 140^0C and 160^0C), its concentration increases and at very high thermal stress, i.e. at 160^0C the concentration is maximum. Variation of electric stress does not cause any significant increase of CO_2 and at 160^0C the concentration of CO_2 remains almost same irrespective of electric stress. The presence of higher CO_2 is mainly due to decomposition cellulose in paper.

4.1.2 Regression Analysis for CO_2

Multiple linear regression analysis was carried out for the experimental data. The results revealed that time, temperature and electric stress, are significant. It is also found from the analysis that interaction effect among time×temperature and $(\text{temperature})^2$ are also significant, whereas, interaction effect of temperature×electric stress and $(\text{time})^2$ is insignificant. Hence the most effective prediction model with max $R^2 = 91.25\%$ was found to be in the following function equation.

$CO_2 = 463.621 - 0.0527 \times t - 7.0872 \times T + 32.1607 \times E + 0.00081019 \times t \times T + 0.19017 \times T \times E - 1.115 \times 10^{-5} \times (t)^2 + 0.02562 \times (T)^2$

4.1.3 Hydrogen (H_2)

The figures 4.4 – 4.6 show the hydrogen gas content at the above said temperature and electric stress. The study indicates that the hydrogen gas content increase with temperature and electric stress. Further the H_2 also increases uniformly at 120^0C/1.0 kV, 140^0C/1.5 kV and 160^0C/2.5 kV, however, the maximum increase is at higher thermal and electric stress i.e. 160^0C for 1440 hours at 2.5 kV.

4.1.4 Regression analysis for H_2

Multiple linear regression analysis was carried out for the experimental data. The results revealed that time, temperature, electric stress, are significant. It is also found from the analysis that interaction effect among time × temperature, time × electric stress, temperature × electric stress and $(\text{temperature})^2$ are also significant. Hence the most effective prediction model with max $R^2 = 83.24\%$ was found to be in the following function equation.

$H_2 = 101.657 - 0.0226 \times t - 1.2775 \times T - 12.3649 \times E + 0.00014 \times t \times T + 0.00362 \times t \times E + 0.081623 \times T \times E + 0.0004009 \times (T)^2$

4.1.5 Acetylene (C_2H_2):

The variation of C_2H_2 is shown in figures 4.7-4.9. The variation of C_2H_2 is within permissible range at 120^0C, 1.0 kV and at 140^0C, 1.5 kV but at 160^0C, 2.5 kV for 1440 hours it suddenly jumps to the level of 500 (ppm), which indicates the arcing occurs through high current and high temperature conditions.

4.1.6 Regression Analysis for C_2H_2

Multiple linear regression analysis was carried out for the experimental data. The results could not find any transfer function for C_2H_2.

4.1.7 Methane (CH_4), Ethane (C_2H_6) and Ethylene (C_2H_4)

The variation of Methane (CH_4), Ethane (C_2H_6) and Ethylene (C_2H_4) gas content is shown in figures 4.10- 4.12 at 160^0C and at 1.0 kV, 1.5 kV & 2.5 kV. CH_4, C_2H_6 and C_2H_4 content also increases uniformly under the various thermal and electric stress level. The results also indicate that C_2H_4 (C=C formation) content is much higher compared to CH_4 and C_2H_6 (C-C formation) at higher temperature. These gases are generated mainly due to overheating.

4.1.8 Regression Analysis for CH_4

Multiple linear regression analysis was carried out for the experimental data. The results revealed that time, temperature and electric stress are significant. It is also found from the analysis that interaction effect among time× temperature and $(\text{temperature})^2$ are also significant, whereas, interaction effect of temperature×electric stress and $(\text{time})^2$ is insignificant. Hence the most effective prediction model with max R^2 = 91.25% was found to be in the following function equation.

$$CH_4 = 463.621 - 0.0527 \times t - 7.0872 \times T + 32.1607 \times E + 0.00081019 \times t \times T + 0.19017 \times T \times E - 1.115 \times 10^{-5} \times (t)^2 + 0.02562 \times (T)^2$$

4.1.9 Regression Analysis for C_2H_6

Multiple linear regression analysis was carried out for the experimental data. The results could not find any transfer function for C_2H_6.

4.1.10 Regression Analysis for C_2H_4

Multiple linear regression analysis was carried out for the experimental data. The results revealed that time, temperature and electric stress are significant. It is also found from the analysis that interaction effect among time × temperature is also significant, whereas, interaction effect of time × electric stress, $(\text{temperature})^2$ and $(\text{electric stress})^2$ are insignificant. Hence the most effective prediction model with max $R^2 = 87.73\%$ was found to be in the following function equation.

$$C_2H_4 = 325.32 - 0.1609 \times t - 4.8708 \times T + 25.38095 \times E + 0.00096 \times t \times T + 0.008373 \times t \times E + 0.01697 \times (T)^2 - 7.5 \times (E)^2$$

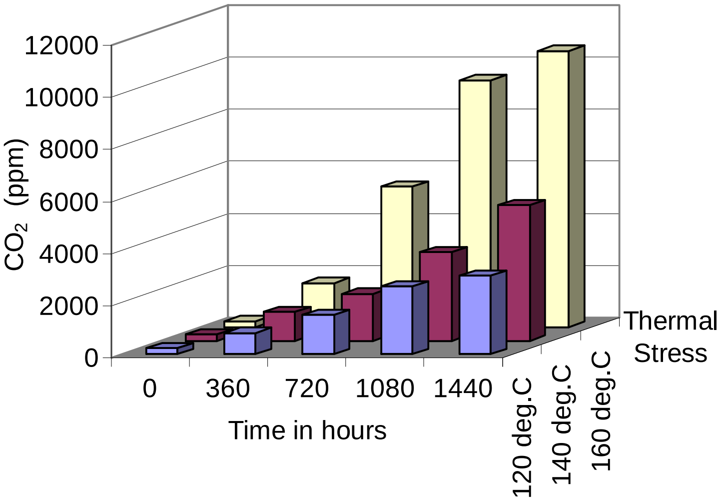


Fig. 4.1 Variation of CO_2 at electric stress 1.0 kV

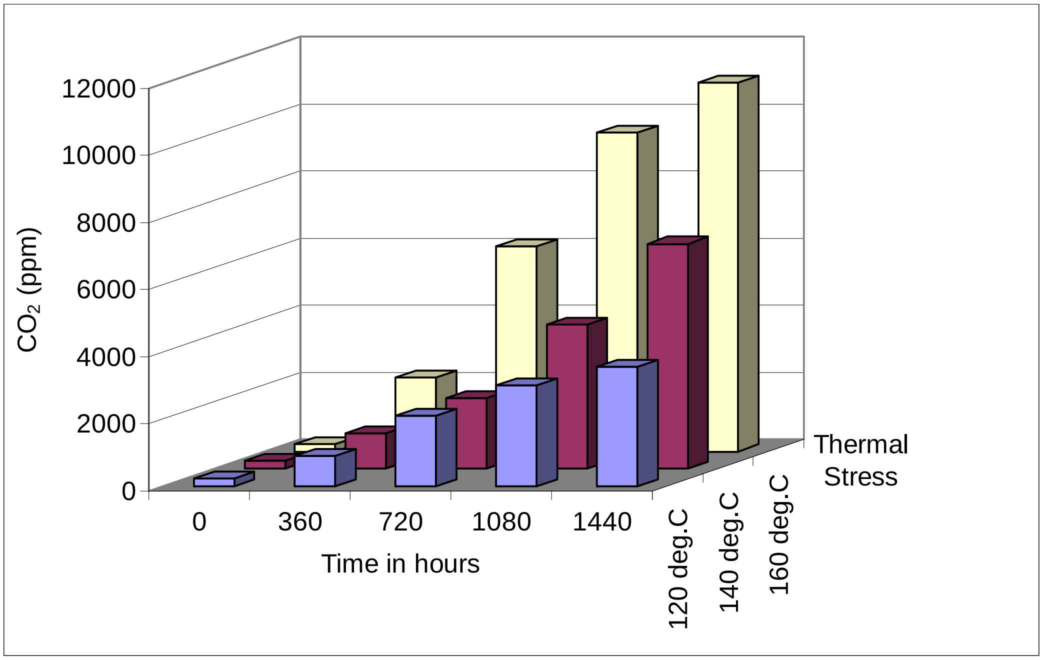


Fig. 4.2 Variation of CO_2 at electric stress 1.5 kV

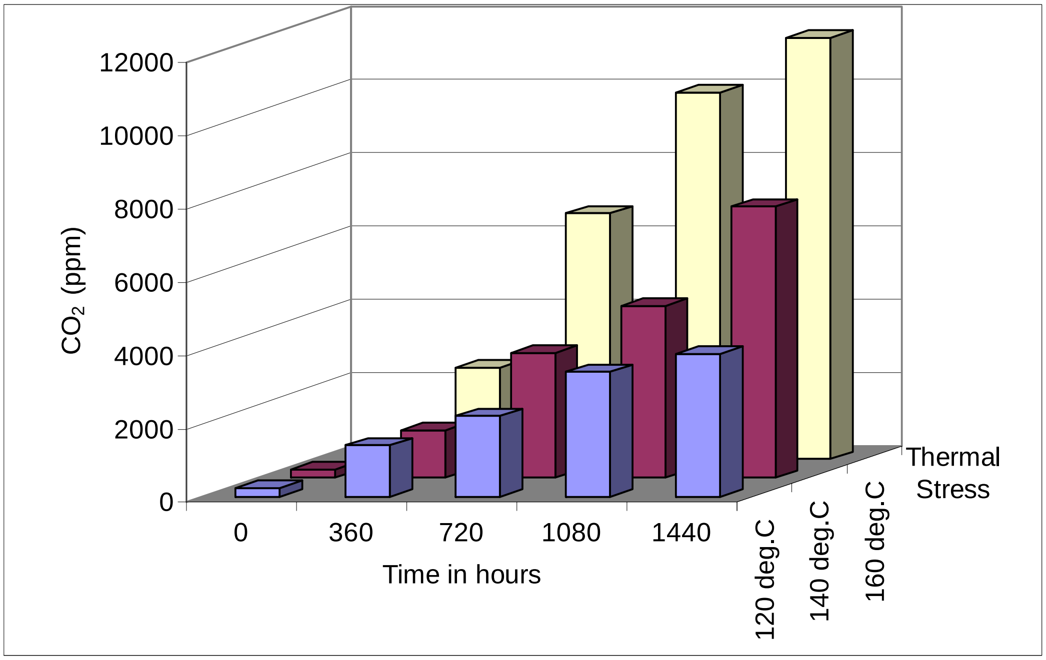


Fig. 4.3 Variation of CO_2 at electric stress 2.5 kV

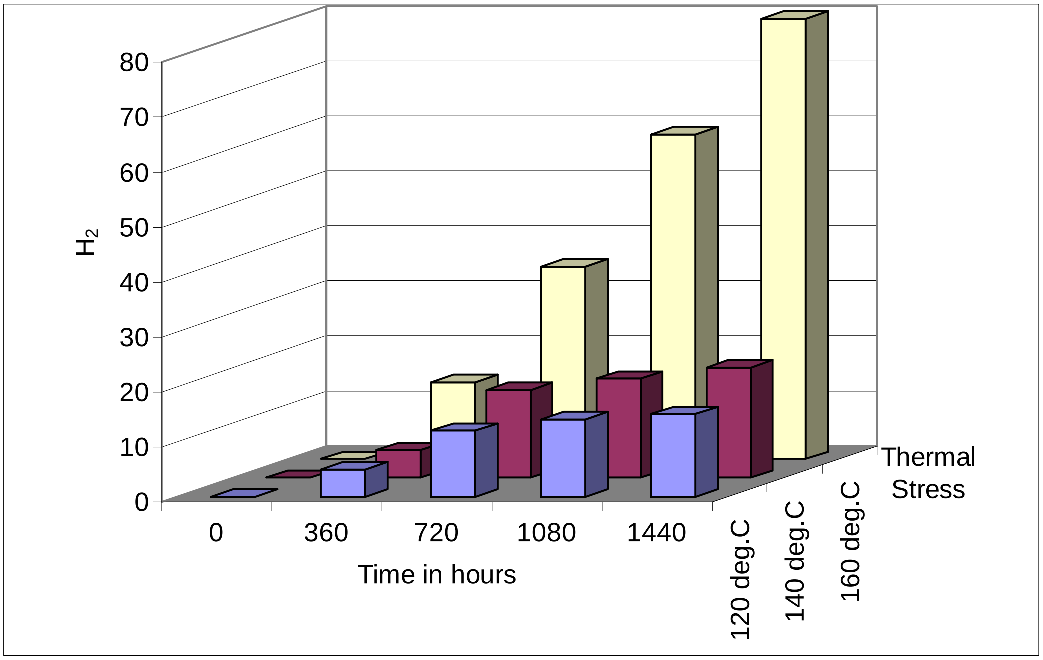


Fig. 4.4 Variation of H_2 at electric stress 1.0 kV

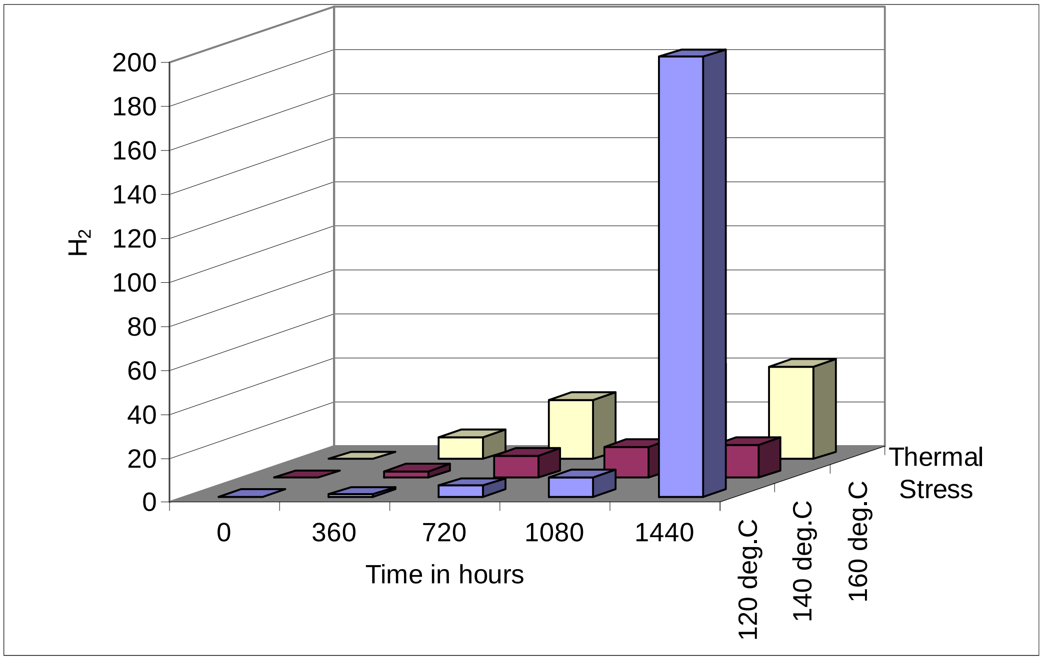


Fig. 4.5 Variation of H_2 at electric stress 1.5 kV

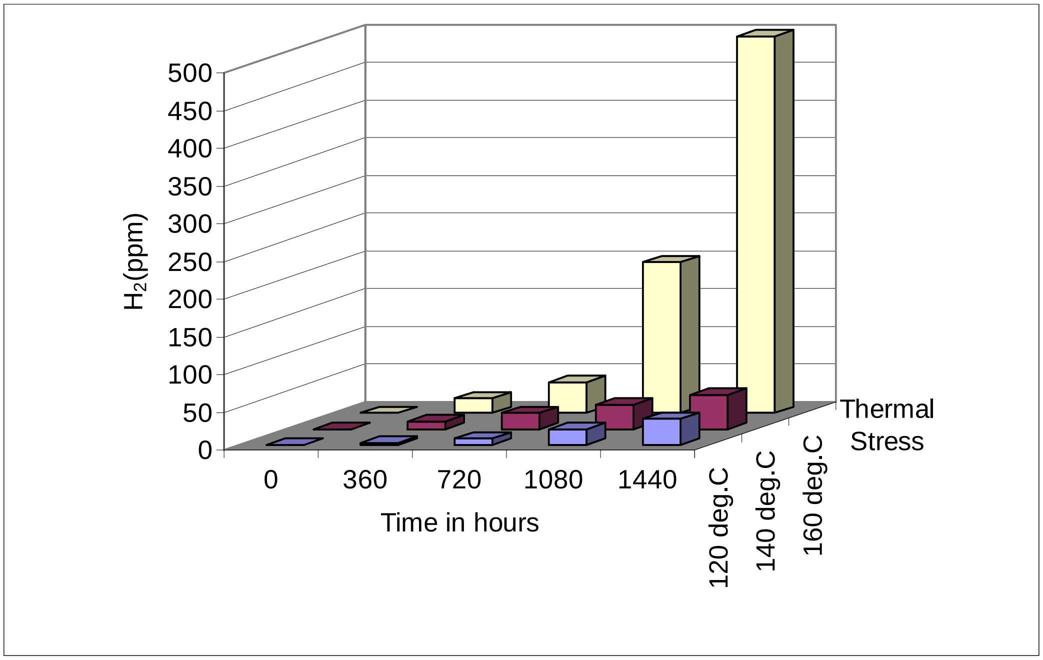


Fig. 4.6 Variation of H_2 at electric stress 2.5 kV

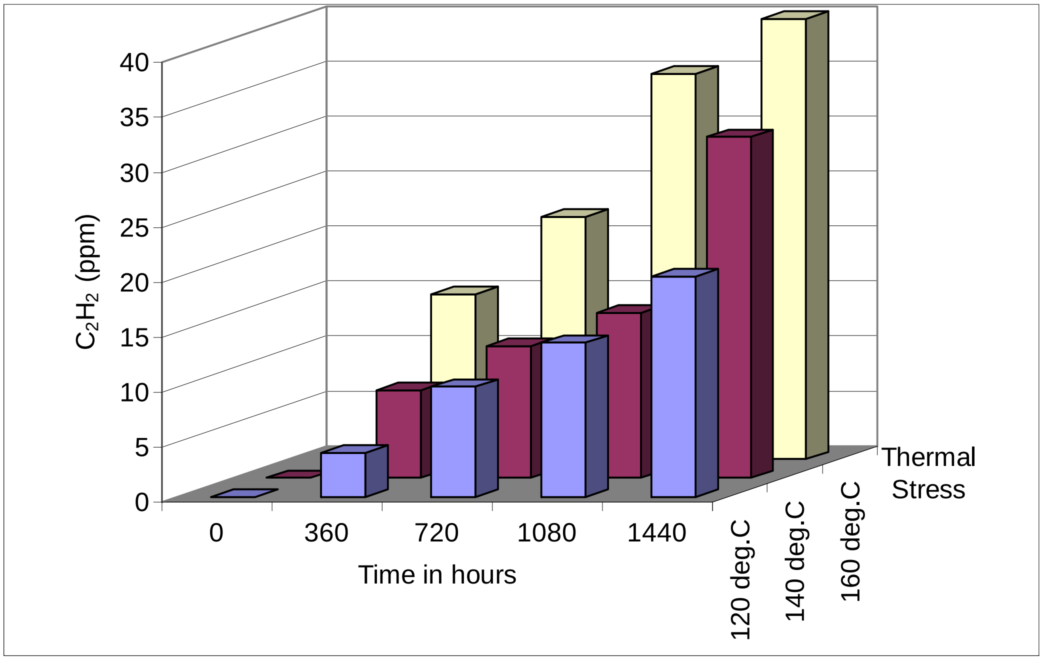


Fig. 4.7 Variation of C_2H_2 at electric stress 1.0 kV

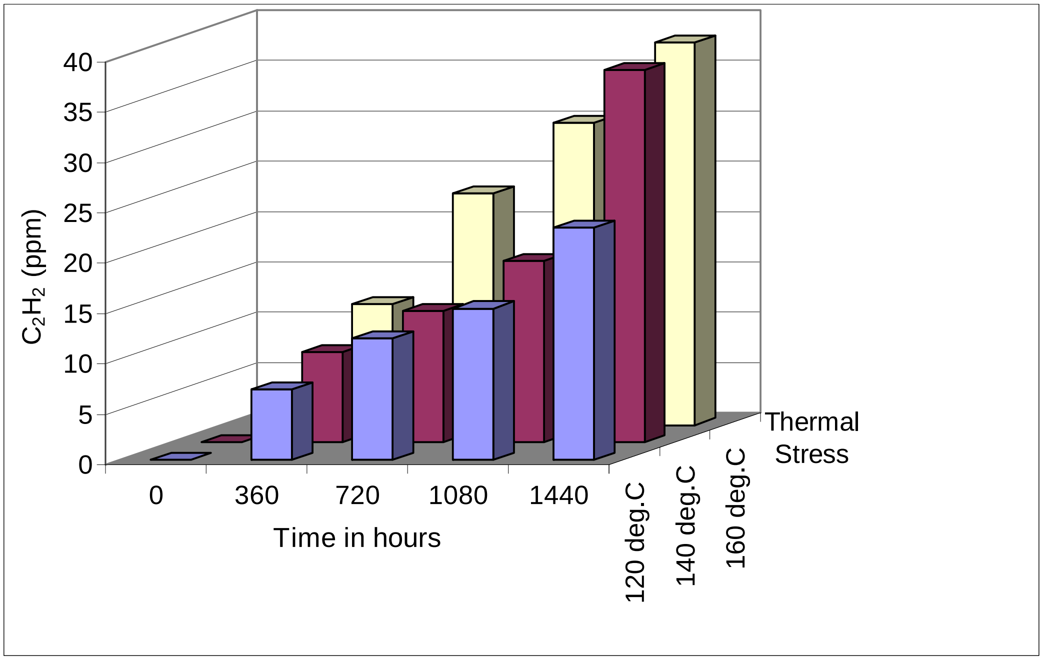


Fig. 4.8 Variation of C_2H_2 at electric stress 1.5 kV

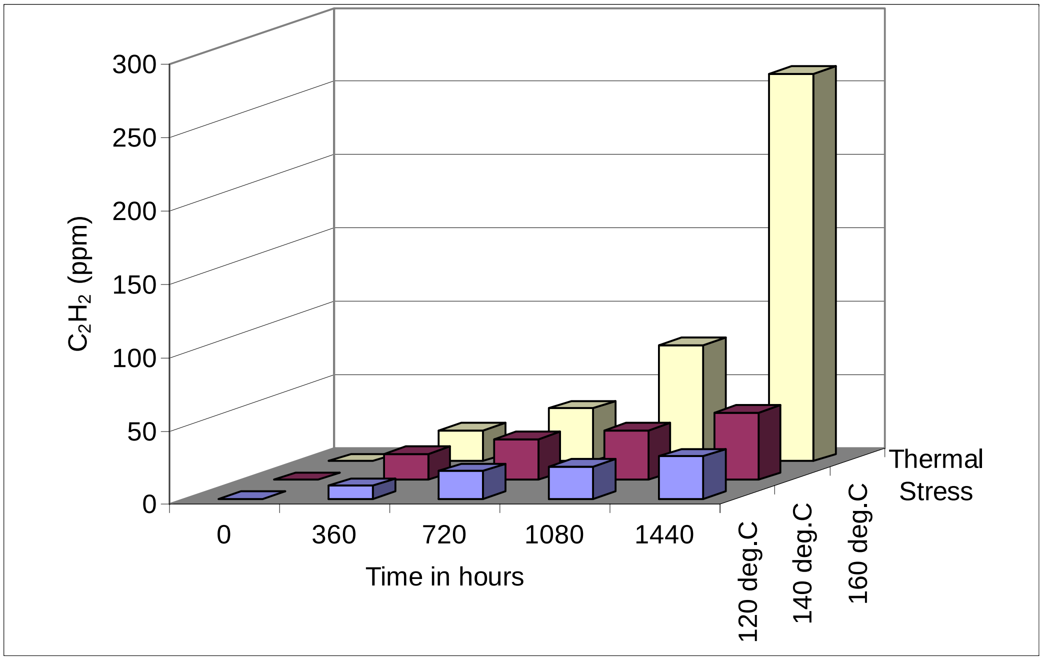


Fig. 4.9 Variation of C_2H_2 at electric stress 2.5 kV

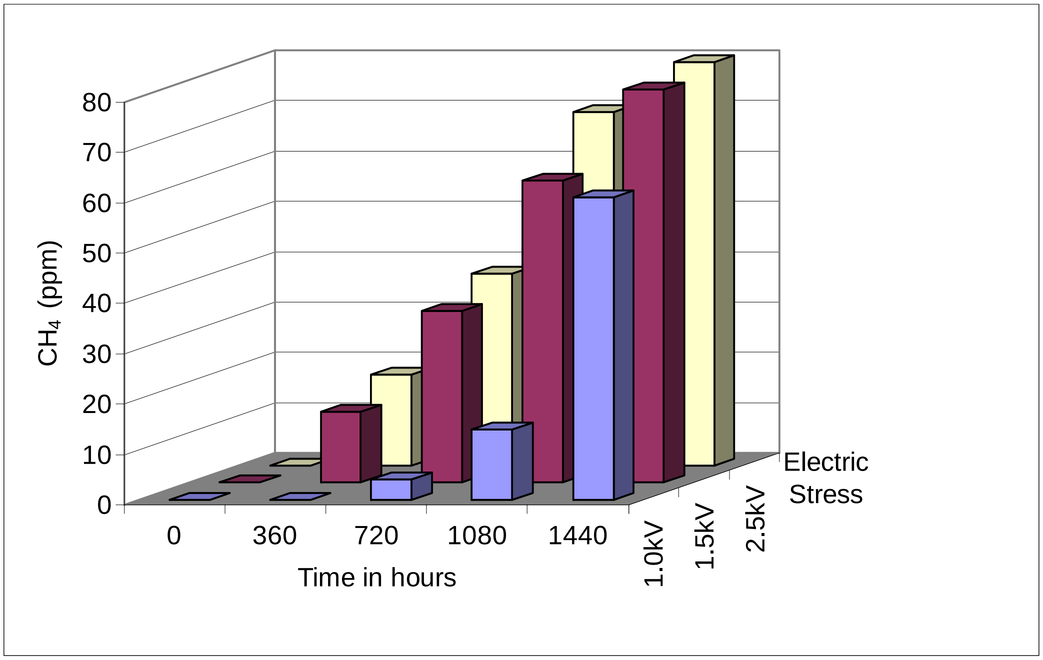


Fig. 4.10 Variation of CH_4 at 160^0C/1.0 kV, 1.5 kV& 2.5 kV.

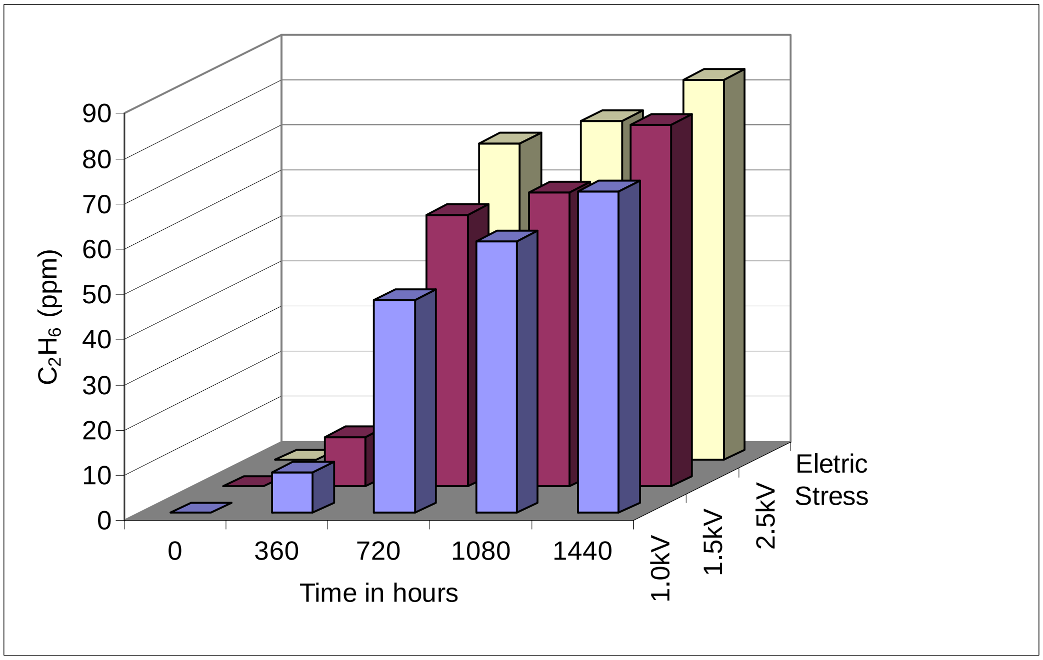


Fig. 4.11 Variation of C_2H_6 at 160^0C/1.0 kV, 1.5 kV& 2.5 kV

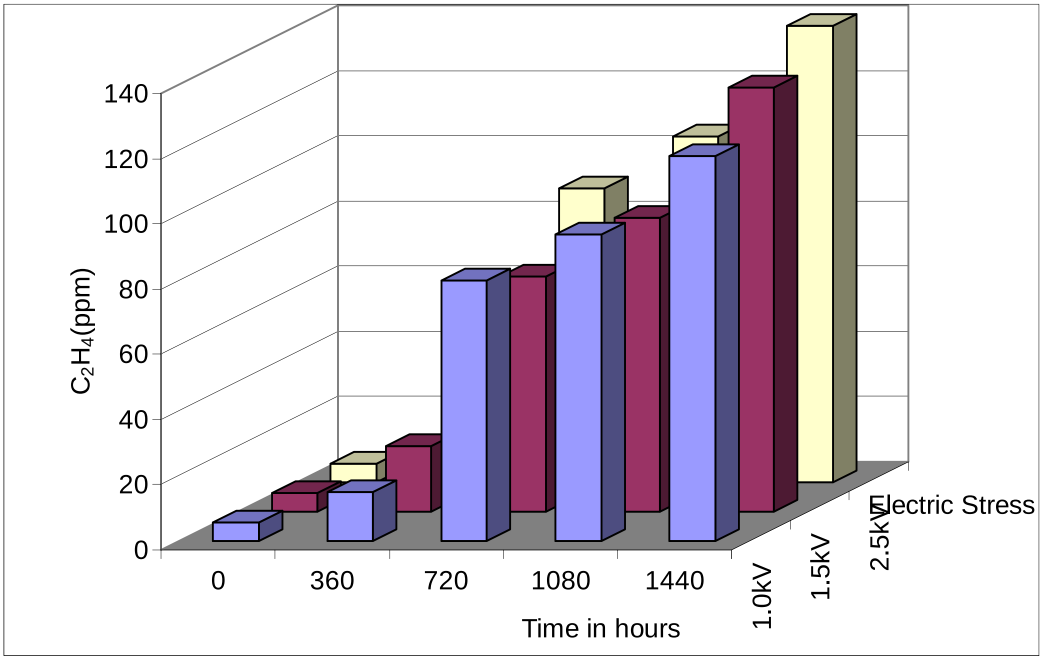


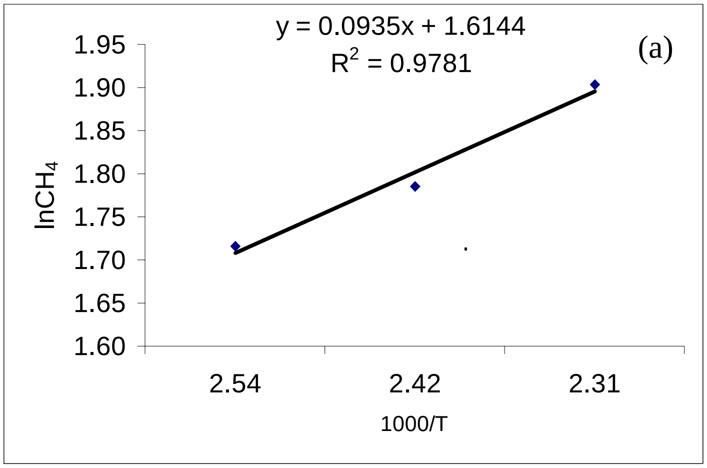
Fig. 4.12 Variation of C_2H_4 at 160^0C/1.0 kV, 1.5 kV& 2.5 kV

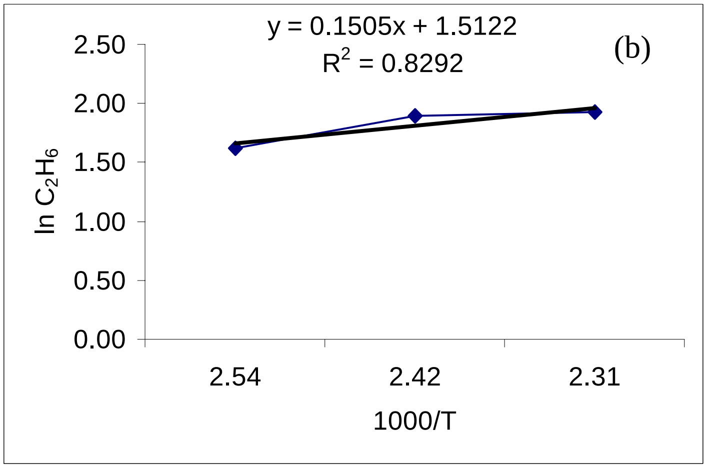
4.1.11 Activation Energy Calculations

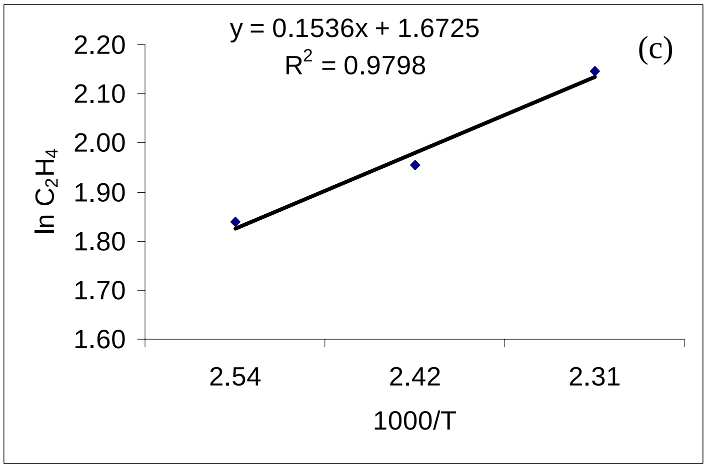
The Arhenius plots for various gas content at 160°C/2.5kV for 1440 hours is shown in figure 4.13 (a-f). The activation energy is calculated from Arhenius-Dankin formula is shown in table 4.1.

Table 4.1 Calculated activation energy for various gas content

Gas	Activation Energy (eV)	Activation Energy kJ/mole
CH_4	0.008	0.811
C_2H_6	0.013	1.245
C_2H_4	0.013	1.274
C_2H_2	0.412	39.790
CO_2	0.021	1.988
H_2	0.049	4.786


y = 0.0935x + 1.6144
R^2 = 0.9781
(a)
$\ln CH_4$
1.95
1.90
1.85
1.80
1.75
1.70
1.65
1.60
2.54
2.42
2.31
1000/T


y = 0.1505x + 1.5122
R^2 = 0.8292
(b)
$\ln C_2H_6$
2.50
2.00
1.50
1.00
0.50
0.00
2.54
2.42
2.31
1000/T


y = 0.1536x + 1.6725
R^2 = 0.9798
(c)
$\ln C_2H_4$
2.20
2.10
2.00
1.90
1.80
1.70
1.60
2.54
2.42
2.31
1000/T

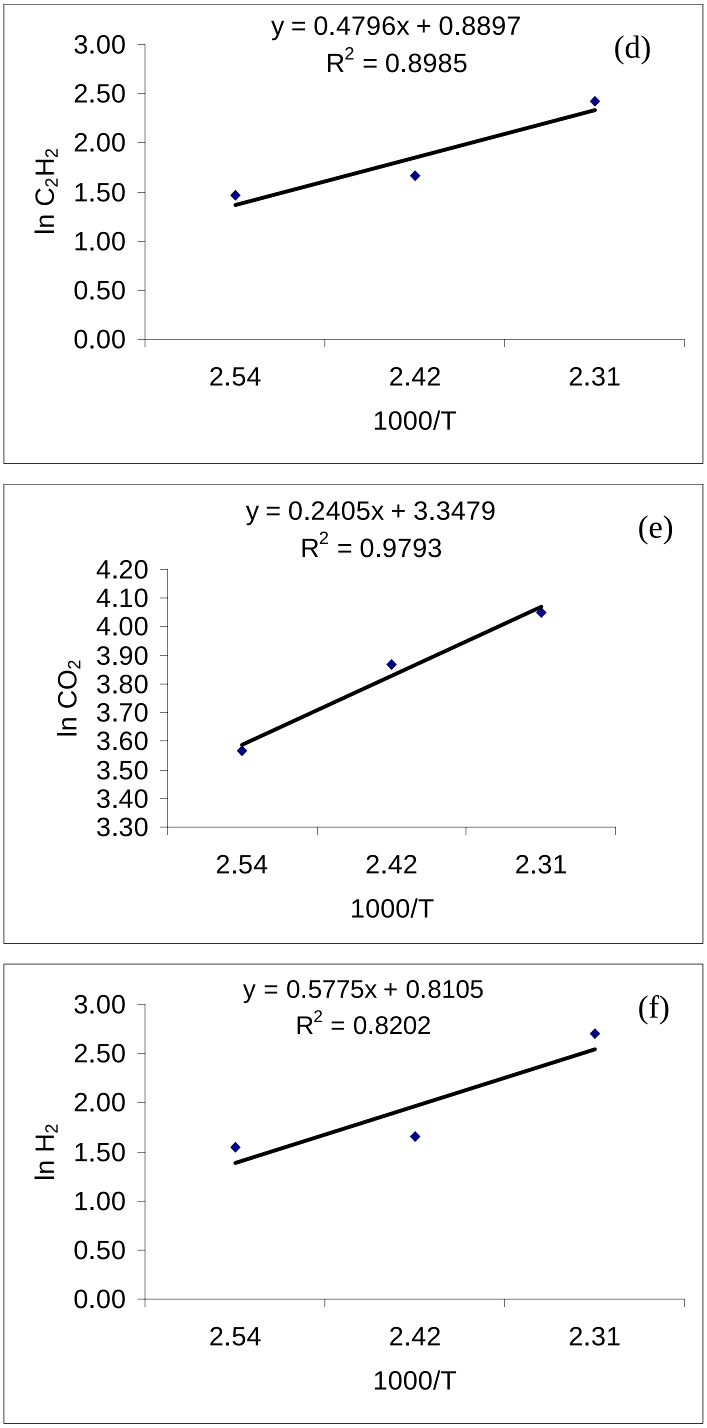


Fig. 4.13 Arhenius plots for (a) CH_4 (b) C_2H_6 (c) C_2H_4 (d) C_2H_2 (e) CO_2 and (f) H_2 gas content at 160°C/2.5kV for 1440 hours

4.2 Partial Discharge Measurement (PD)

The partial discharge test was conducted on all the samples at 150% of rated voltage i.e. 15 kV and the magnitude of partial discharge was measured. The partial discharge magnitude of virgin sample and aged sample at 120^0C/ 2.5 kV for 1440 hours was in the range of 7 pC to 20 pC as shown in figure 4.14 (a & b). The partial discharge magnitude was found to have increased and was in the range of 70-450 pC. The sample aged at 140^0C and at 160^0C at electric stress 1.5 kV and 2.5 kV respectively for 1440 hours are shown in figures 4.14 (c, d, e & f). The maximum increase in partial discharge at 160^0C at electric stress 2.5 kV is found 450 pC, which strengthen our dissolved gas analysis results i.e. at the same stress level the acetylene (C_2H_2) gas content is found 500 (ppm) which is only due to partial discharge. The Scanning Electron Microscopy study, which is discussed in the next chapter, also shows that the cellulose fiber bonding is totally broken due to arcing.

A wide range of techniques is available for pattern recognition of PD signatures. One popular approach is given in [11]. The first significant system developed for analyses of PD signatures, as observed on an oscilloscope, was published by CIGRE in 1969[12]. In the late 1980s computerized data acquisition became commonly available, facilitating acquisition, storage and digital processing of discharge patterns. Earlier the integrity and quality of insulation was checked by various tests like power frequency voltage withstand test, loss angle measurement, insulation resistance measurement, impulse voltage withstand test etc. But with above measurements, the minor insulation flaws and improper/inefficient processing of insulation was not identified. Many cases were found where the material having a very high insulation resistance failed within an unexpected short duration [13-14].

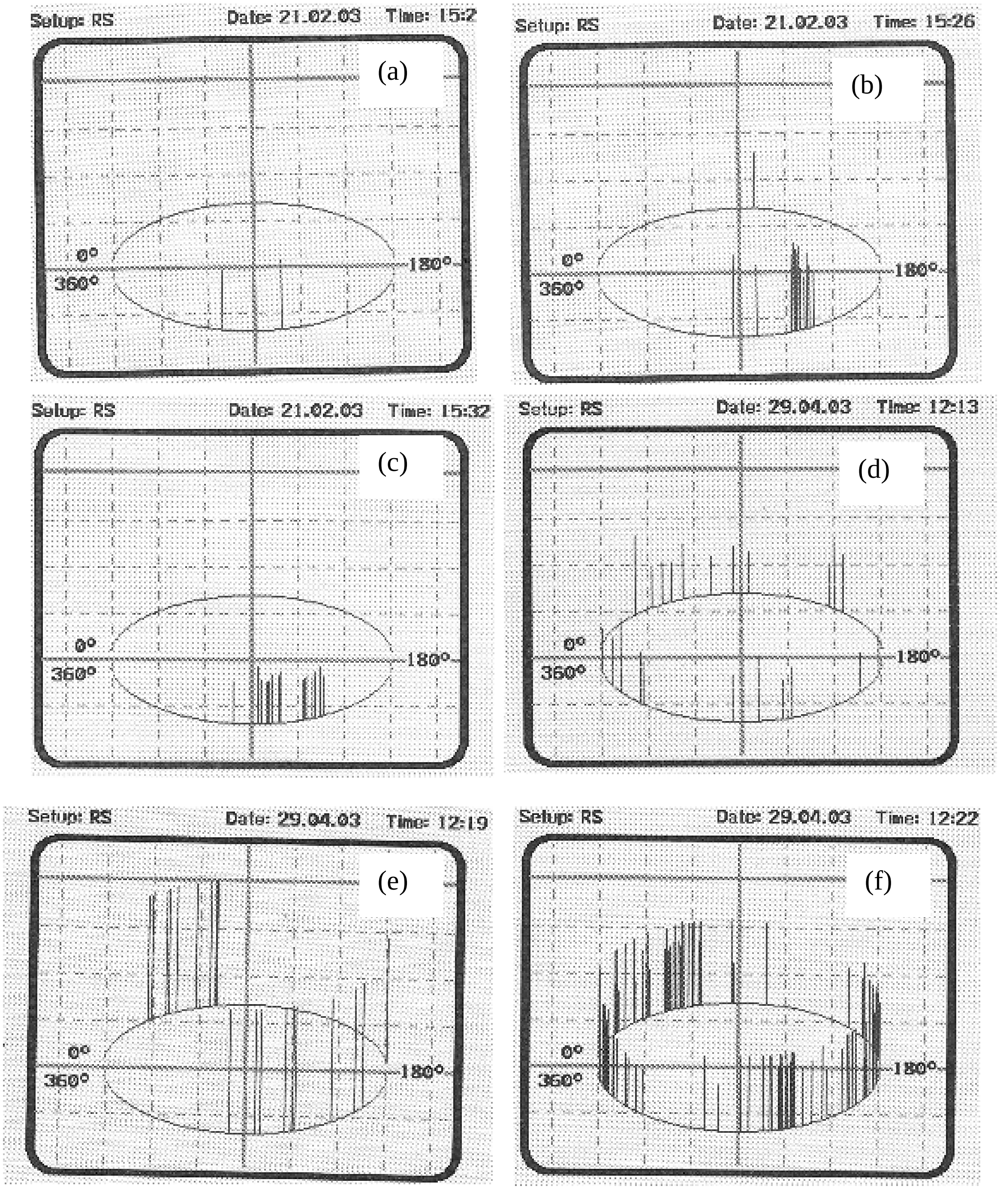


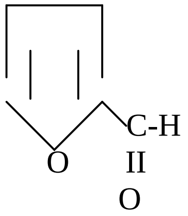
Fig. 4.14 Discharge pattern of (a) virgin at rated voltage (b) 120^0C/2.5kV (c) 140^0C/1.5kV (d) 140^0C/2.5kV (e) 160^0C/1.5kV and (f) 160^0C/2.5kV after 1440 hours

Many experiments were carried out to understand the phenomena and after various experiments and research on the progressive deterioration of the insulation, it was found that such a failure is only due to the phenomena named Partial Discharge. If there is an air gap or void in the solid insulation, the localized electrical discharge in the insulating media, which are restricted to a small part of the dielectric under test partially bridges the insulation between the electrodes. Because of this progressively large leakage current path develops in the insulation and results in an ultimate failure of the object [15]. The early detection of partial discharge present in a transformer is very important to avoid/reduce the losses to the catastrophic failure of transformer. Also, once the PD is detected, the location of the same is very important so that the defects can be pinpointed and solved effectively [16-17].

4.3 Furfuraldehyde Analysis (FFA)

Generally, bulk oil equipment are using impregnated paper as the solid insulation between their windings. Over the years of use, the paper insulation degrades and level of that degradation can be monitored by analyzing the content of furanic derivatives present in the oil. Like DGA, FFA also is the diagnostic test on the Bulk oil equipment [19].

The FFA reveals the rate of insulating paper degradation of the equipment and it directly projects the expected life. As this degradation is not observable by any other means, it is one of the essential tests to diagnose the equipment. Cellulose insulation has a structure of long chains of molecules [19]. The cellulosic paper contains about 90% cellulose, 6-7% of hemicellulose and 3-4 % of lignin. Cellulose is a natural polymer of glucose and it degrades slowly as the polymer chains breakdown during service, releasing degradation products into the oil. The paper eventually degrades to such an extent that it loses all its mechanical strength and becomes susceptible to mechanical damage, which puts the electrical integrity of the equipment at risk. Thermal degradation of cellulosic materials present in electrical equipment with oil-paper insulation systems yields different amounts of furanic derivatives, the most common being 2-furfuraldehyde [20-21].



Therefore, monitoring the concentration of 2-furfuraldehyde of the aged sample might be a useful tool for the condition monitoring.

The other furanic derivatives which have been identified are 5-hydroxy-methylfurfuraldehyde, acetyl furan, 5-methylfurfuraldehyde, furfurylalcohol and furoic acids, but these are produced in much smaller quantities when transformer paper degrades thermally [22-25].

The concentration of these furans gives an indication of the condition of the paper in terms of the degree of polymerization, while the rate of change of furan concentration can indicate the rate of ageing of paper. The main advantage of using this technique of furan analysis as a diagnostic tool is that these compounds are degradation products specific to paper, and cannot be produced by oil.

As per the study carried out by NGC, UK, with the information obtained from in- service transformers and failed transformers, it was noted that when there is some overheating of the cellulose insulation in addition to damage from partial discharge and arcing, then significant quantities of CO_2 and 2-furfuraldehyde generated with smaller quantities of carbon monoxide [26]. When the faults are associated with PD and arcing at higher temperature, the increases in carbon dioxide content is accompanied with increase of 2-furfuraldehyde [27-28] .We have also observed that higher 2-furfuraldehyde is associated with higher PD level and higher value of CO_2 due to degradation of paper under accelerated thermal stress.

In our study, the furanic compounds present in the aged oil samples have been analyzed by HPLC, after extraction with solvent mixture as per IEC 61198 [29]. The samples are tested at 120^{0}C, 140^{0}C and 160^{0}C and at electric stress 2.5 kV for 360,720 and 1440 hours. The results are shown in table 4.2.

Table: 4.2 Furfural compound formation under accelerated thermal and electric stress.

Aging condition	2-Furfural dehyde (ppb)	2-Acetyl furan (ppb)	5-Methyl furfuraldehyde (ppb)	5-hydroxy methyl furfural-dehyde (ppb)
120^{o}C, 2.5 kV, 360hrs	41	12	16	22
120^{o}C, 2.5 kV, 720hrs	54	19	23	29
120^{o}C, 2.5 kV, 1440hrs	76	27	38	51
140^{o}C, 2.5 kV, 360hrs	106	41	54	82
140^{o}C, 2.5 kV, 720hrs	116	42	57	90
140^{o}C, 2.5 kV, 1440hrs	150	48	59	97
160^{o}C, 2.5 kV, 360hrs	480	154	135	265
160^{o}C, 2.5 kV, 720hrs	4920	155	140	267
160^{o}C, 2.5 kV, 1440hrs	5600	162	151	290

The results indicate that at same temperature and electrical stress, the concentration of furanic compounds increases with time. These compounds also increase with temperature and ageing time and at 160^{0}C, the concentration of 2-furfuraldehyde is very high. The results indicate that among the furanic compounds, generation of 2-furfuraldehyde is much more compared to the other furan derivatives. Therefore, monitoring the concentration of 2-furfuraldehyde of the aged sample might be a useful tool for the condition monitoring.

Conclusions:

1. From the Dissolved gas analysis (DGA), it is clear that there is significant increase in individual gases with accelerated ageing. The increase in CO_2 gas is mainly due to paper degradation at higher thermal stress. The sudden increase of H_2 gas at 120^0C indicates that, it is a low energy fault. The maximum increase of C_2H_2 along with H_2 gas is associated with arcing and it is mainly due to higher electric stress.

2. The partial discharge test results reveal that the magnitude of PD is increased with ageing. The virgin sample shows the PD level of 7 pC at the rated voltage whereas at the maximum thermal and electric stress, the PD level increases to 450 pC. The PD results may be correlated with dissolved gas analysis as the maximum acetylene (C_2H_2) gas content at 160^0C/2.5 kV is mainly due to partial discharge. Hence there is strong correlation between dissolved gas analysis and partial discharges and arcing is the most severe of all the fault processes. Large amounts of hydrogen and acetylene are produced with minor quantities of methane and ethylene. Arcing occurs through high current and high temperature conditions.

3. Furfuraldehyde Analysis (FFA) results indicate that at same temperature and electrical stress, the concentration of furanic compounds increases with time. These compounds also increase with temperature and at 160^0C, the concentration of 2-furfuraldehyde is very high. The results indicate that among the furanic compounds, generation of 2-furfuraldehyde is much more compared to the other furan derivatives. Therefore, monitoring the concentration of 2-furfuraldehyde of the aged sample might be a useful tool for the condition monitoring. The increase in furan content is mainly due to higher thermal stress as evident from the present study, however the impact of accelerated electric stress can not be ignored.

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Chapter-5

CHARACTERIZATION OF AGED OIL AND PAPER SAMPLES BY SEM, XRD, FT-IR, DSC/TGA AND NMR TECHNIQUES

Overview

In this chapter, the degradation of Kraft insulating cellulose paper has been characterized using SEM, XRD, FT-IR and DSC/TGA techniques. The aged oil samples were also subjected to FT-IR and NMR investigations. The SEM study of aged sample shows the extent of degradation of paper after aging. XRD study indicates the change of crystallinity with aging. FT-IR study on oil and paper shows the change in carbonyl and hydroxyl groups after ageing in case of paper. Differential Scanning Calorimeter (DSC) on paper revealed about the transition temperature. Thermo Gravimetric Analysis (TGA) shows the temperature at which weight loss of paper takes place. Nuclear Magnetic Resonance (NMR) technique has been used on aged oil sample to probe the structural changes with aging.

Key words: Scanning Electron Microscopy (SEM), X-ray Diffraction (XRD), Fourier Transform Infrared Spectroscopy (FT-IR), Differential Scanning Calorimeter (DSC), Thermo Gravimetric Analysis (TGA), Nuclear Magnetic Resonance (NMR) technique.

5.0 RESULTS AND DISCUSSION

5.1 Microstructural Analysis with SEM

Microstructural studies were conducted on the fresh and also on aged cellulose paper to compare the extent of degradation of paper. Figure 5.1 (a and b) shows the SEM micrographs of fresh paper at magnifications 50x and 400x. SEM photographs of the fresh paper indicate closely packed cellulose fibers with dense interwoven network having no deformation [1]. The higher magnification micrograph figure 5.1(b) clearly indicates that the fibers have ribbon like morphology, which is a typical characteristic of paper produced by thermo chemical pulping (TMP) process [2].

The micrographs of the paper corresponding to ageing temperature of 120^0C for 1440 hrs with electric stress of 1.0 kV, 1.5 kV and 2.5 kV are shown in Fig.5.2 (a), (b) & (c) respectively. The figures show the start of deformation of fibers but there is no evidence of breakages of fibre. In all the three micrographs, the deformation looks the same, therefore, higher electric stress does not have much effect here.

The figures 5.3 (a), (b) & (c) have been taken for the paper aged at 140^0C for 1440 hrs under electric stress of 1.0 kV, 1.5 kV and 2.5 kV. The fiber deformation from the matrix is clearly visible in all the three conditions. Figure 5.3 (c) at 2.5 kV electric stress indicates the pinhole in the paper in some of the locations.

The figures 5.4 (a), (b) & (c) shows the micrographs of paper aged at 160^0C for 1440 hrs under electric stress of 1.0 kV, 1.5 kV and 2.5 kV. The figure 5.4 (a) shows the pinhole type morphology on all around the fiber. In figure 5.4 (b) shows the fiber breakage in different places of the paper, whereas figure 5.4 (c) shows the complete rupturing of paper and seems that after a pinhole rupture, the discharge current flow through it under the influence of higher voltage and finally burn the paper.

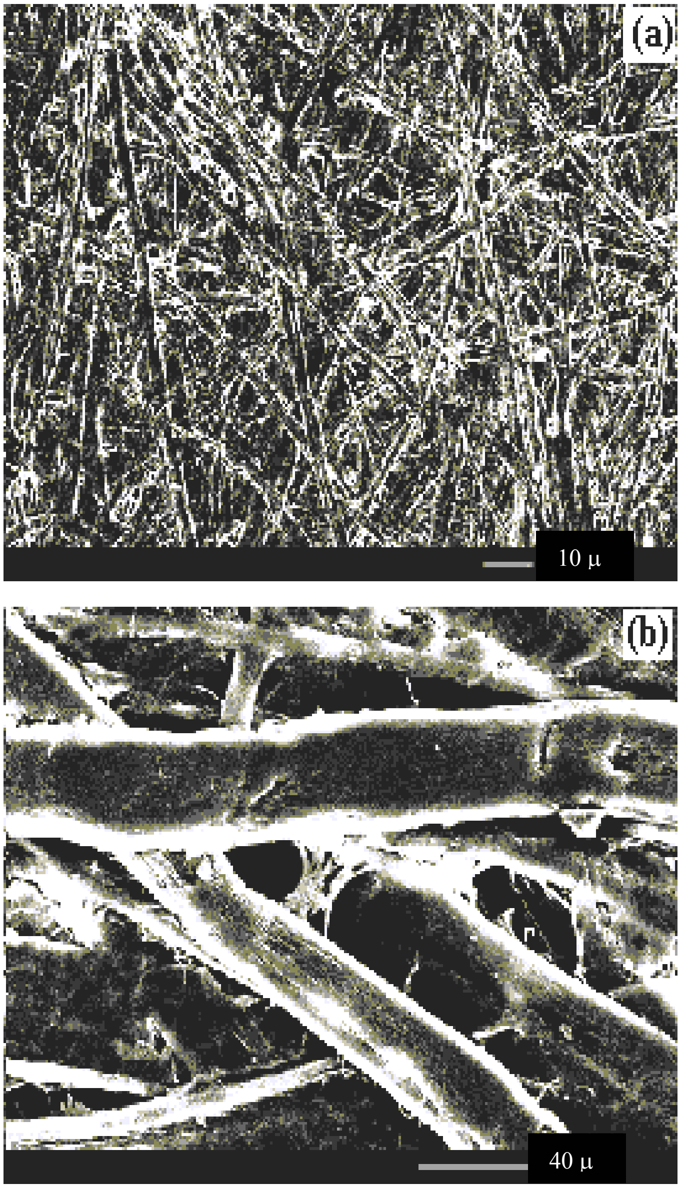

Fig. 5.1 SEM micrograph of fresh paper at different magnifications (a) 50x (b) 400x

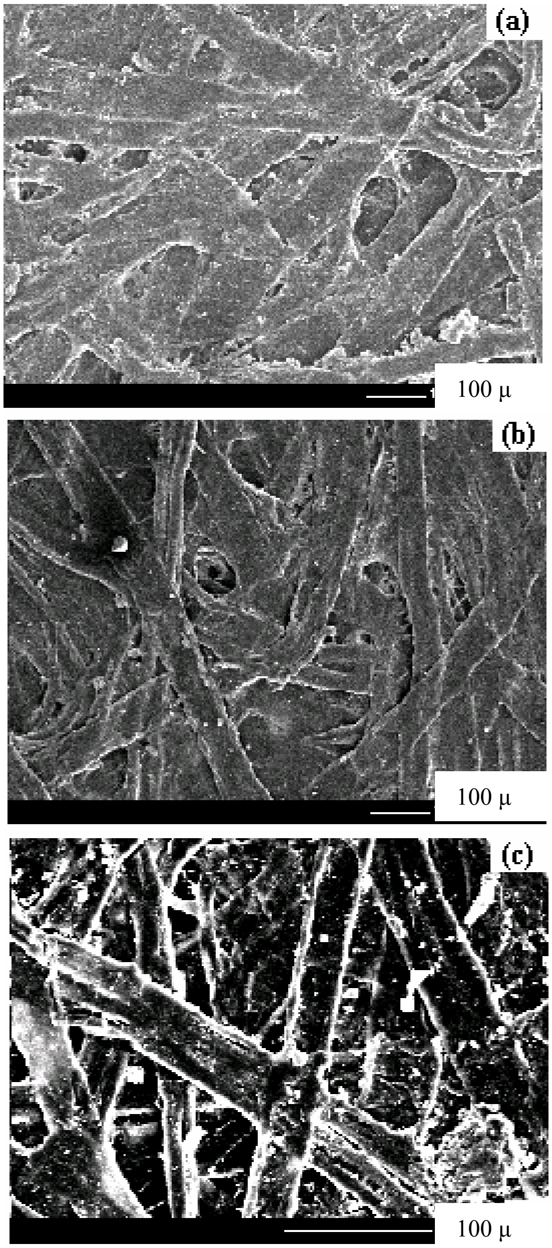

Fig. 5.2 SEM micrograph of paper aged at 120^{o}C for 1440 hrs with electric stress (a) 1.0 kV (b) 1.5 kV (c) 2.5 kV

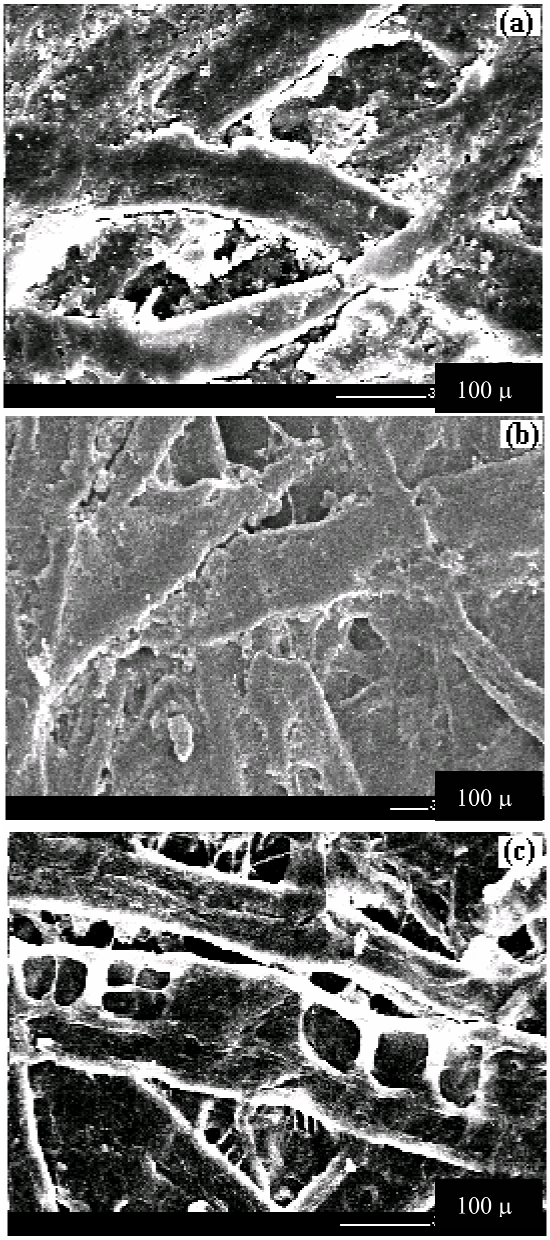

Fig. 5.3 SEM micrograph of paper aged at 140°C for 1440 hrs with electric stress (a) 1.0 kV (b) 1.5 kV (c) 2.5 kV

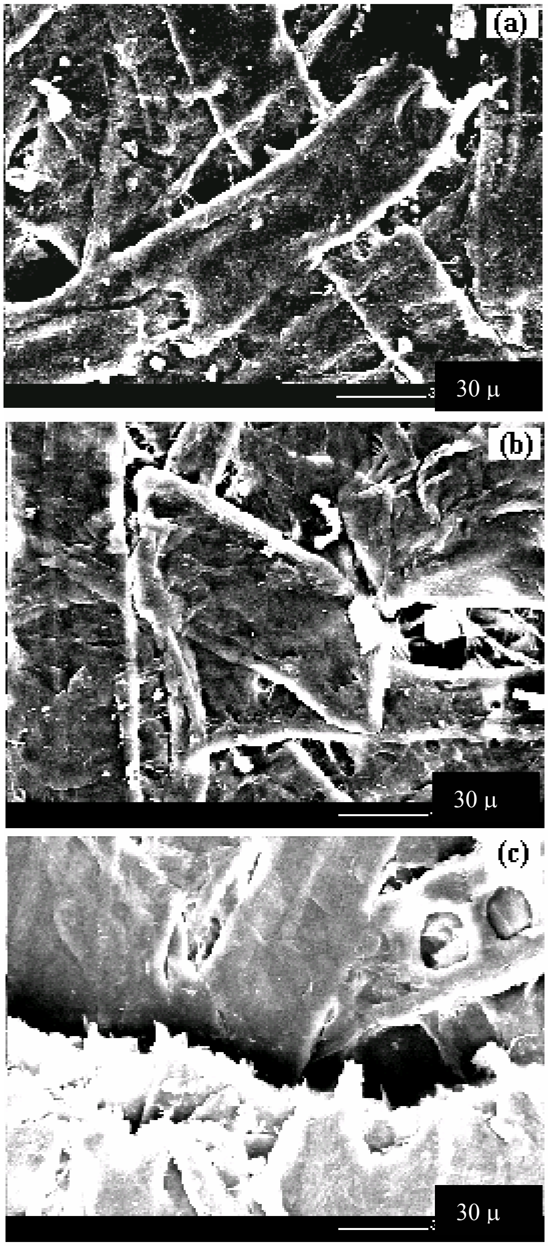

Fig. 5.4 SEM micrograph of paper aged at 160°C for 1440 hrs with electric stress (a) 1.0 kV (b) 1.5 kV (c) 2.5 kV

In the paper making process, fibers form flocs of some characteristic size. The flocculation tendency of fibers gives rise to random distribution of fiber. The structure of paper appears to be non-uniform, disordered and irregular in nature. The strength of fiber depends on the connectivity of fiber network. While processing paper, fiber connectivity is an essential parameter. This connectivity or bonding of the fiber network controls the strength of paper. The network would have no cohesion if there were too few bonds between the fibers. At very low coverage, a connected fiber network forms only if a sufficient number of bonds per fiber exist. The limit is at the percolation point [3]. Below this, the network consists of several disjointed paths. Mechanical pulp fibers reduce bonding between reinforcement fibers through the screening effect, though its concentration is less [4]. These points where the bonding is not achievable, provides nucleation centre for development of polarity under electrical field. As the electrical stress is increased, the polarity also increases and ultimately the pores are developed at these points due to partial discharge currents. A typical characteristic observed in the paper is micro tearing phenomenon of paper under the influence of flow of discharge current. The fibers themselves start tearing due to polarity and leakage of current as shown in figure 5.4(c)

5.2 X-Ray Diffraction Analysis

The crystal structure analysis of low molecular weight compounds that form large crystals is usually possible by determining both the crystallographic unit cell and the atomic positions within the unit cell by X-ray diffraction methods. However, in the case of complex macromolecules such as cellulose that do not form a single crystal, it is difficult to determine definite atomic positions from X-ray data only and therefore, approximations have to be made for the spatial model of the cellulose molecules. In the past two decades, many model-building methods have been developed not only for the conformational analysis of an isolated chain, but also for the subsequent packing of the chains in the crystallographic lattice. The other research groups have analyzed cellulose structure by using the linked atom least square approach and various packing methods [5,6,7]. In order to find the change in crystallinity, different methods have been suggested [8,9]. However, in the present investigation the method suggested by Segal etal. [10] was followed. They selected the intensity of the 002 maximum at $2\theta=22^0(I_{002})$ and that of the minimum at $2\theta=18^0(I_{am})$ in plane cellulose as the two points and defined the crystallinity index as

$Cr\ l = [(I_{002} - I_{am})/ I_{002}]x100$

In our case, shift in peak position was observed at $[2\theta=25.6^0(I_{002})]$ and that of the minimum at $[2\theta=23.8^0(I_{am})]$ because Cellulose is bonded to hemicellulose and lignin in paper.

The X-ray diffraction study of virgin paper has been done and is shown in figure 5.5 (a). It is evident from this figure that there are two types of phases present in the system. One corresponding to hollow and broad peak with very less intensity corresponding to amorphous structure and another corresponding to sharp with higher intensity corresponds to crystalline/microcrystalline character. Since paper consists of higher amount of cellulose (90%) that exhibits crystalline character and other constituents lignin and hemicellulose present are around 10%, which are amorphous in nature. The diffractogram corresponds to these phases.

The X-ray diffraction of the aged samples at 120^0C for 1440 hours under electric stress of 1.0 kV, 1.5 kV and 2.5 kV is shown in figure 5.5. The figures indicate no change of 2θ value but the intensity of peak increases at 120^0C at three different electric stress level. The crystallinity of virgin paper is calculated 79.5%. The increase in crystallinity for the electric stress 1.0 kV, 1.5 kV and 2.5 kV is from 79.5% to 83.2%, 85.6% and 86.5% respectively.

The similar trend is visible for 140^0C and 160^0C under electric stress of 1.0 kV, 1.5 kV and 2.5 kV and is shown in figures 5.6 (a) (b) & (c) and figures 5.7 (a), (b) & (c) respectively. The change in crysatallinity is from 79.5 % to 89% for the sample aged at 160^0C and 2.5 kV electric stress. It is likely that extensive degradation of amorphous compounds, i.e. lignin and hemicellulose has occurred in paper as compared to crystalline cellulose structure.

From the above variation in intensity, degree of crystallinity was calculated from the diffraction data recorded for the paper samples aged under different electrical and thermal conditions from the above equation and is given in table-5.1. It is obvious from the diffraction patterns and the data presented in table 5.1 that there is significant change in the degree of crystallization of the cellulose due to degradation under accelerated thermal and electrical ageing. The change in crystallinity is shown graphically in figure 5.8. The results suggest little changes in crystallite size of cellulose fibers. Thus it is likely that most of the chain scission occurred in the amorphous region of the paper as compared to crystalline region [11]. Amorphous structure has higher free energy as compared to crystalline structure. Therefore under the influence of temperature the deterioration of amorphous area is more as compared to crystalline area. It has been reported that even within the amorphous regions, some areas are more reactive than others [12,13]. However, on comparing these data with our results and comparing the ratio of intensity, it can be concluded that there is change in the crystallnity of Kraft paper under accelerated thermal and electric stress. M.Ali et.al have also mentioned in their work that the crystallinity of the aged paper is higher than that of as received material [14].

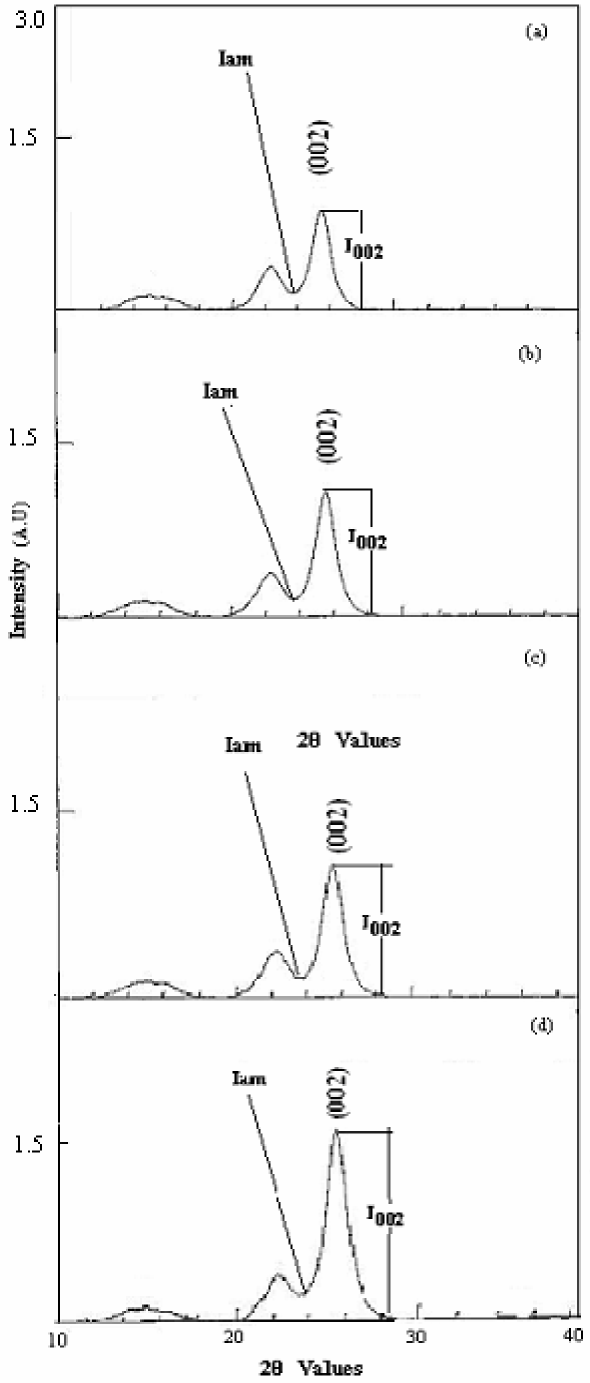

Fig. 5.5 X-Ray of paper aged at temperature 120°C for 1440 hrs with electric stress (a) Virgin paper (b) 1.0 kV (c) 1.5 kV (d) 2.5 kV

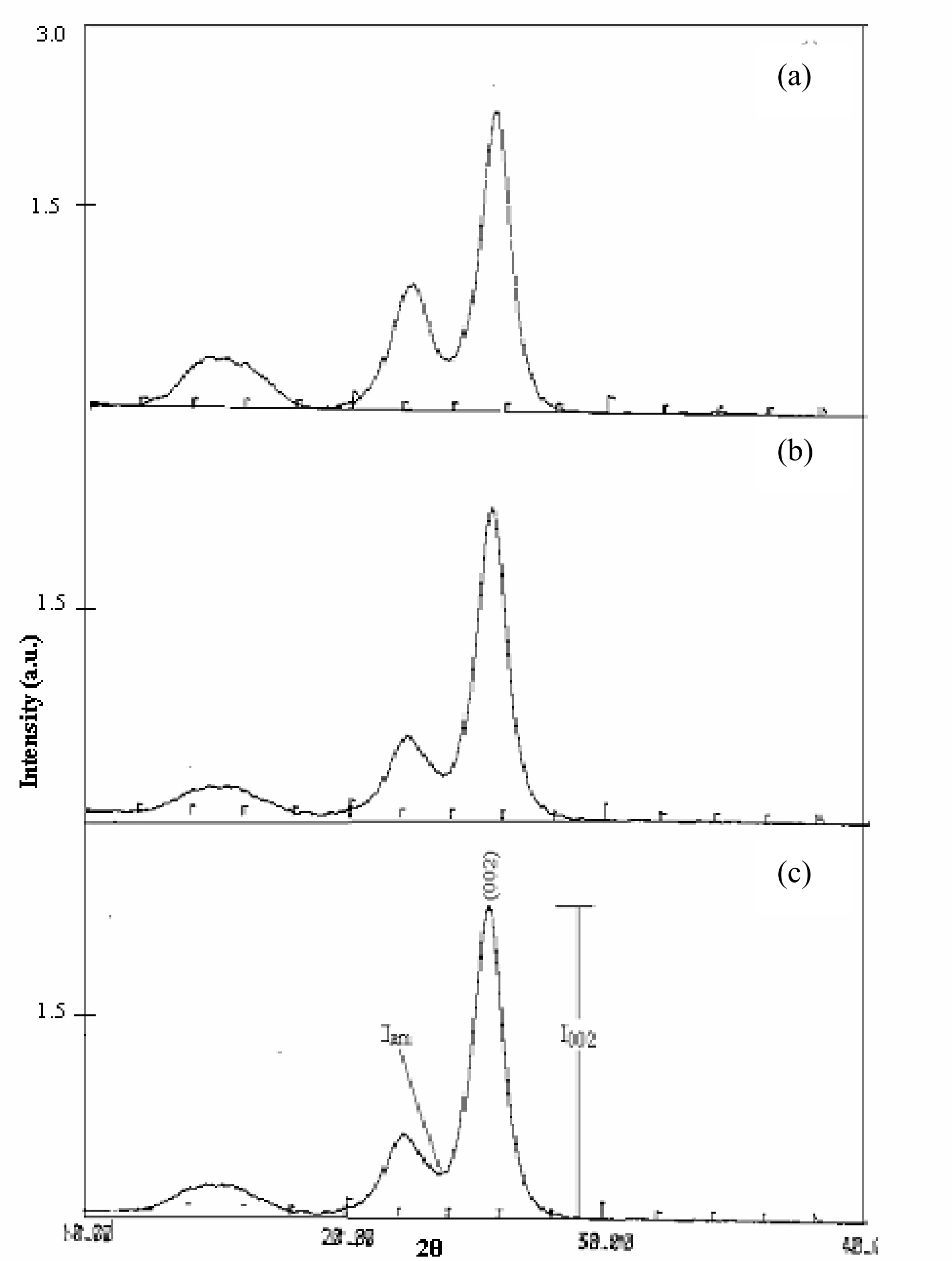

Fig. 5.6 X-Ray of paper aged at temperature 140°C for 1440 hrs with electric stress (a) Virgin paper (b) 1.0 kV (c) 1.5 kV (d) 2.5 kV

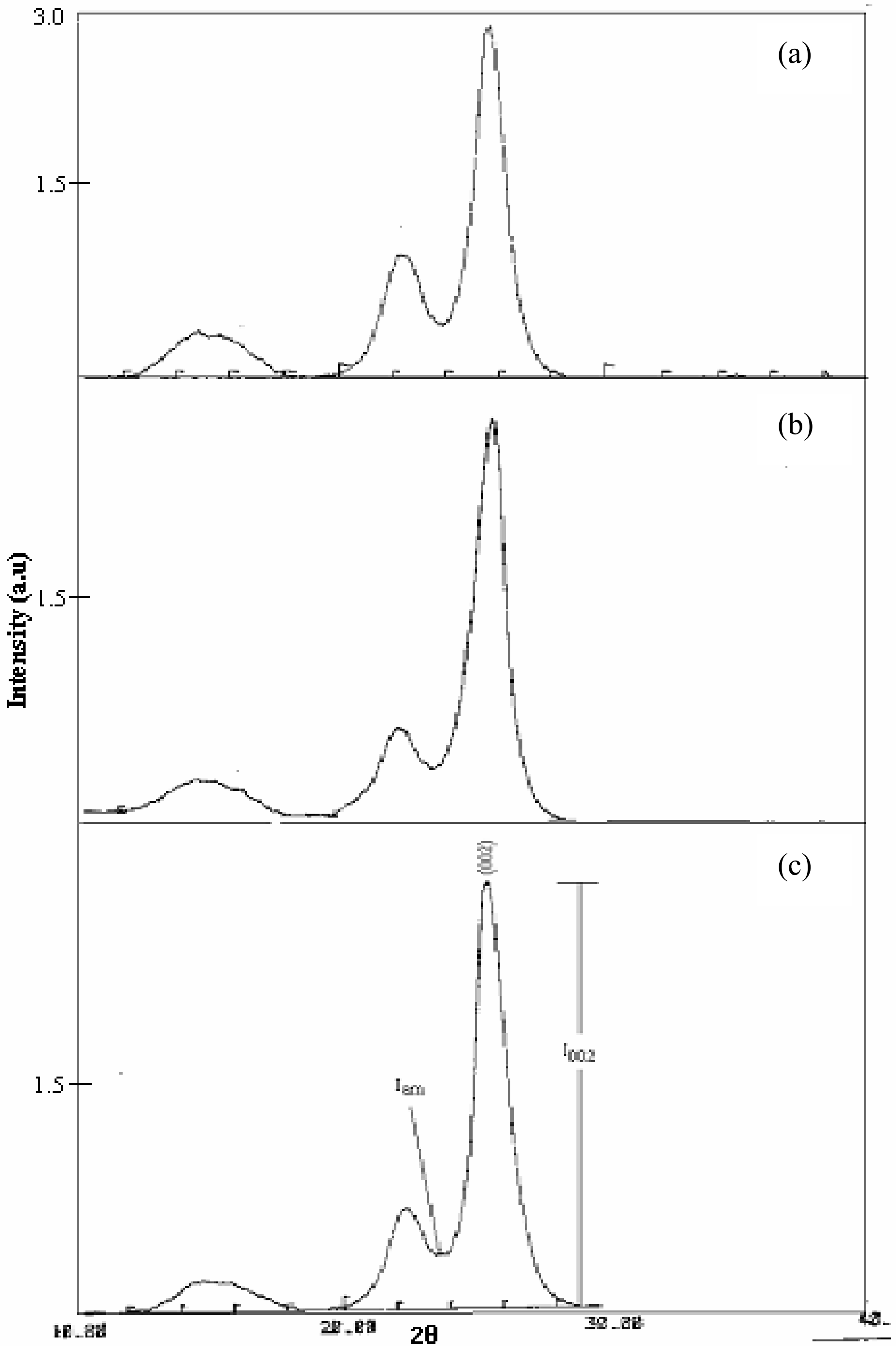

Fig. 5.7 X-Ray of paper aged at temperature 160^{o}C for 1440 hrs with electric stress (a) 1.0 kV (b) 1.5 kV (c) 2.5 kV

Table: 5.1 X-ray diffraction

Temperature ^{0}C	Electric Stress (kV)	2θ Value	Max. Increase in Intensity at 2θ (I_{002})	Minimum at 2θ (I_{am})	Crystallinity (Crl) (%)
Virgin Sample	0	25.6	881	180	79.5
120	1.0	25.6	1077	180	83.2
	1.5	25.5	1251	180	85.6
	2.5	25.6	1337	180	86.5
140	1.0	25.5	1590	210	86.7
	1.5	25.5	1615	210	86.9
	2.5	25.5	1661	210	87.3
160	1.0	25.7	2316	300	87.9
	1.5	25.6	2633	300	88.6
	2.5	25.7	2809	310	89

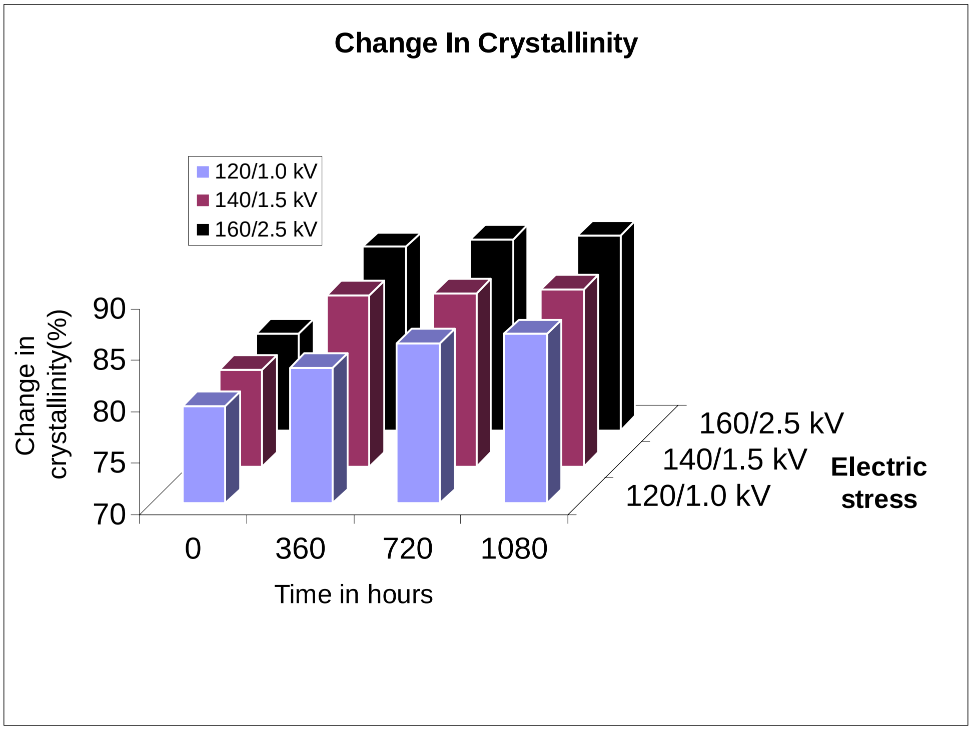

Fig. 5.8 Crystallinity vs. Thermal and Electrical Stress

5.3 FT-IR Study

5.3.1 Aged paper

As described earlier paper consists of cellulose, hemicellulose and lignin. In order to understand the change in structure, Fourier Transform Infrared Spectroscopy (FT-IR) has been done for virgin and accelerated aged papers as is shown figure 5.9 (a) & (b) respectively. This study is important to analyse the structure as many of the absorption peaks are assigned to specific bond vibration.

Kolboe and Ellefsen [15] used IR spectroscopy as an independent method for estimating lignin content and coumaran groups. In their study they mentioned that the absorption at 1515 cm^{-1} was chosen for the determination of lignin, because this region is assigned to aromatic skeletal vibrations. The absorption band at 1495 cm^{-1} was assigned to coumaran ring, and it was estimated to contribute about 5% of the total phenyl propane units.

Sarkanen et.al [16] in their study mentioned that bands at 1420 to 1450 cm^{-1} were considered to be associated with the ring stretching modes strongly coupled with the C-H in plane deformation similar to the 1500 cm^{-1} band. The 1340 to 1380 and 1100 to 1250 cm^{-1} bands were usually assigned to phenolic hydroxyl groups. The latter 1150 to 1250 cm^{-1} band may be described as an “O-H in plane deformation with ring stretching character” and 1340 to 1380 cm^{-1} band as having a ring- stretching with O-H bonding character. The 1240 cm^{-1} band seemed to have the most pronounced methoxyl character, because on methylation, the intensity of the 1240 cm^{-1} band increases at the expense of the 1275 cm^{-1} band. Peak at 1715 cm^{-1} amounts to ester groups related to various lignins. Peak at 1670 cm^{-1} corresponds to conjugated carbonyl group.

In cellulose the region 980 to 1500 cm^{-1} spectra is generally very complicated and the assignment of the bands is difficult. Tsuboi [17] investigated the polarised infrared spectrum and found that stretching bands near 2900 cm^{-1} can not be interpreted on the basis of the orientation of CH_2 group. He proposed that the rotation of CH_2- OH group of each glucose unit around the C-5-C-6 bond by 45 degree was a better explanation. It has been reported that bands at 1430 (due to CH_2 bending) and at 900 cm^{-1} (due to C-O stretching) are sensitive to crystallinity [18]. Fengel [19] has shown that peaks at 895, 985 and 1165 cm^{-1} increase with decreasing crystallinity while 1280 and 1430 cm^{-1} bands decrease. Yousef .et al. [20] use the ratio of line intensity at 1400 and 900 cm^{-1} to measure crystallinity changes during air ageing of paper. They reported the decrease in crystallinity with increasing temperature up to 160^{0}C. However, on comparing these data with our results of the ratios of intensities, there was sign of change in the crystallinity in the Kraft paper.

Liang and Marchessautt [21] investigated the hydrogen bonds in cellulose lattice. They concluded that there is intramolecular hydrogen bonding between the C-3 hydroxyl group of one glucose unit and the ring oxygen of the next unit. There are also two sets of intermolecular hydrogen bonds, that is the C-6 hydroxyl of the antiparallel chains are joined to the bridge oxygens of the adjacent parallel chains in the (101) plane and the C-6 hydroxyls of the parallel chains are joined to the bridge oxygen of the adjacent antiparallel chains.

Our study indicates that there are distinct peaks at 1600-1700 cm^{-1} and a broad peak at 3400-3500 cm^{-1} due to increase of carbonyl group and hydroxyl group of cellulose. It is observed that the virgin paper and the paper under combined thermal and electrical stress level of 160^{0}C/2.5 kV show no sign of change in group though intensity of peak variation exists. The broader peak around 3400-3500 cm^{-1} becomes narrow on ageing. This corresponds to O-H stretching. Its narrow character after the ageing treatment indicates that the associated intermolecular bonding decreases and intra association of O-H group takes place by condensation mechanism. Thus providing very less free O-H group in the system.

5.3.2 Aged oil

Figure 5.10 (a) & (b) shows the FT-IR studies of virgin and aged oil. It indicates that there are peaks in the region of 2850-2950 cm^{-1}. These peaks correspond to the C-H stretching of hydrocarbon. Aged samples do not show any difference in position and intensity of the those peaks compared to the virgin sample

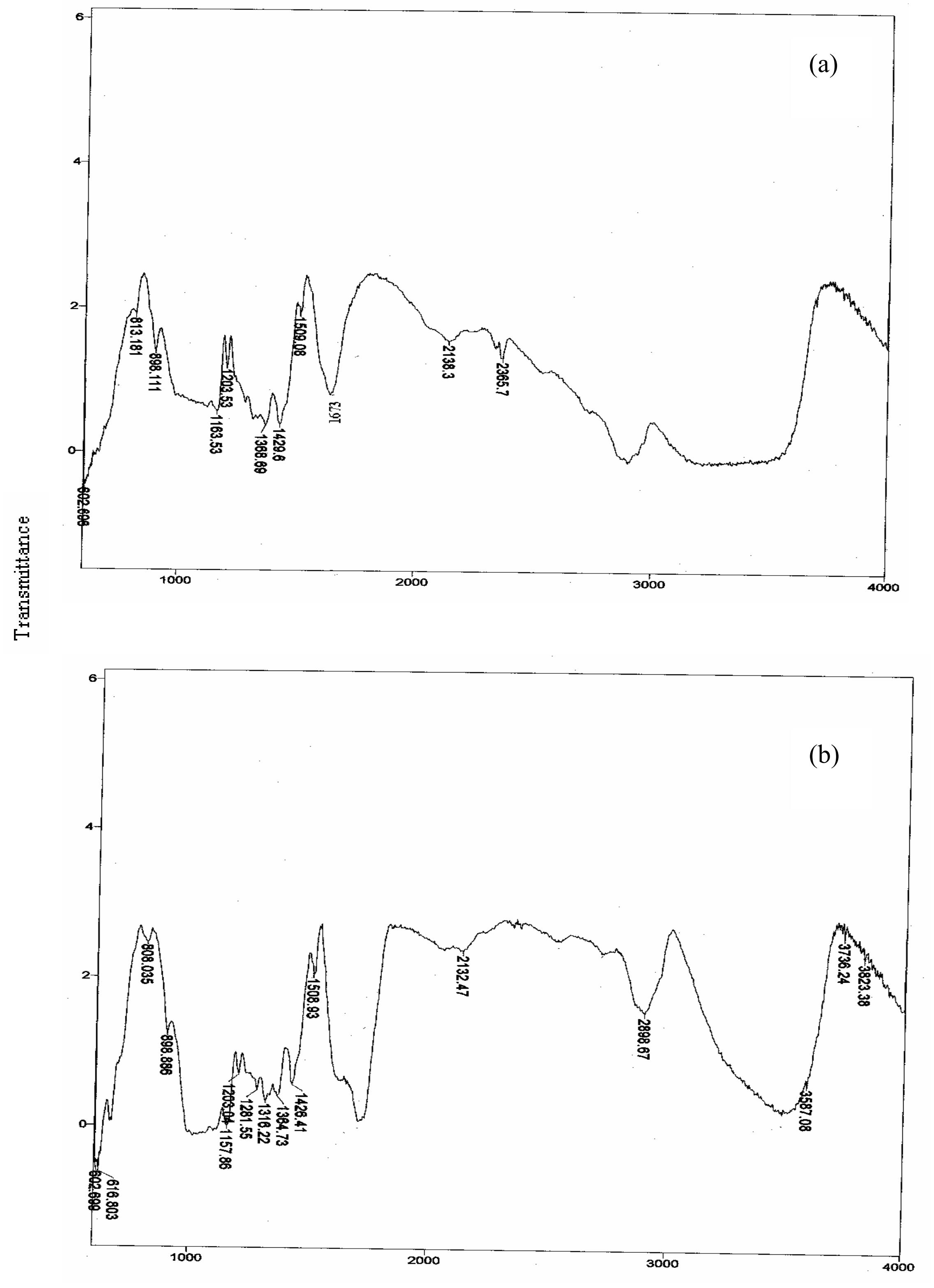

Fig. 5.9 FT-IR Analysis of (a) Virgin paper (b) Aged paper sample at 160^{0}C/2.5 kV for 1440 hrs.

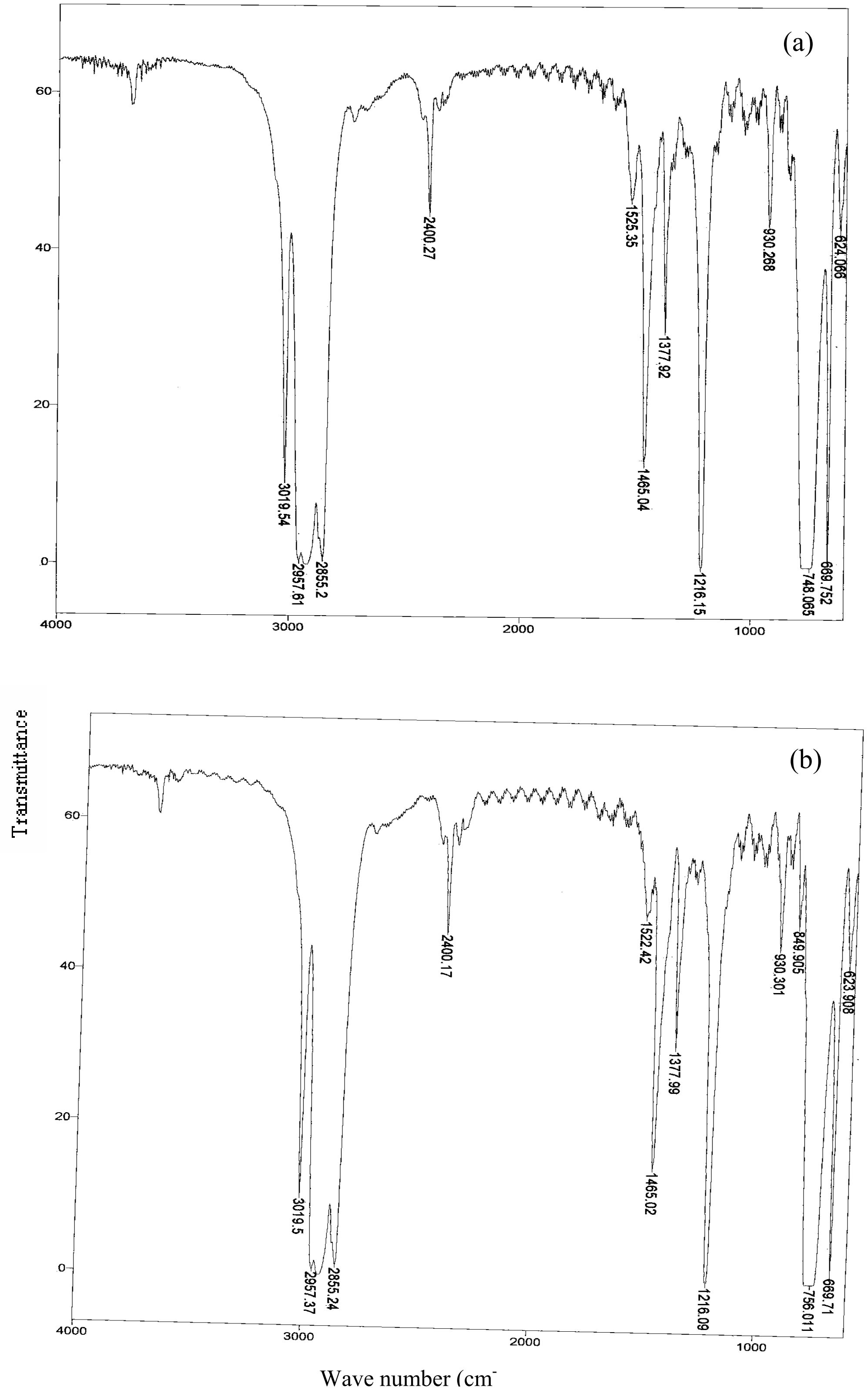

Fig. 5.10 FT-IR Analysis of (a) Virgin oil sample (b) Aged oil sample at 160^{0}C/2.5 kV for 1440 hrs.

5.4 Nuclear Magnetic Resonance Study on Oil

^{1}HNMR spectra have also been recorded for the virgin and highly aged oil sample (160^0C, 2.5 kV) for 1440 hrs as shown in figure 5.11 (a) & (b). No change in the spectra have been observed. The peak at 1.3 ppm corresponds to the methyl group of hydrocarbon and appearance of a weak peak in the region of 7.3 ppm corresponds to the slight aromatic character of the oil.

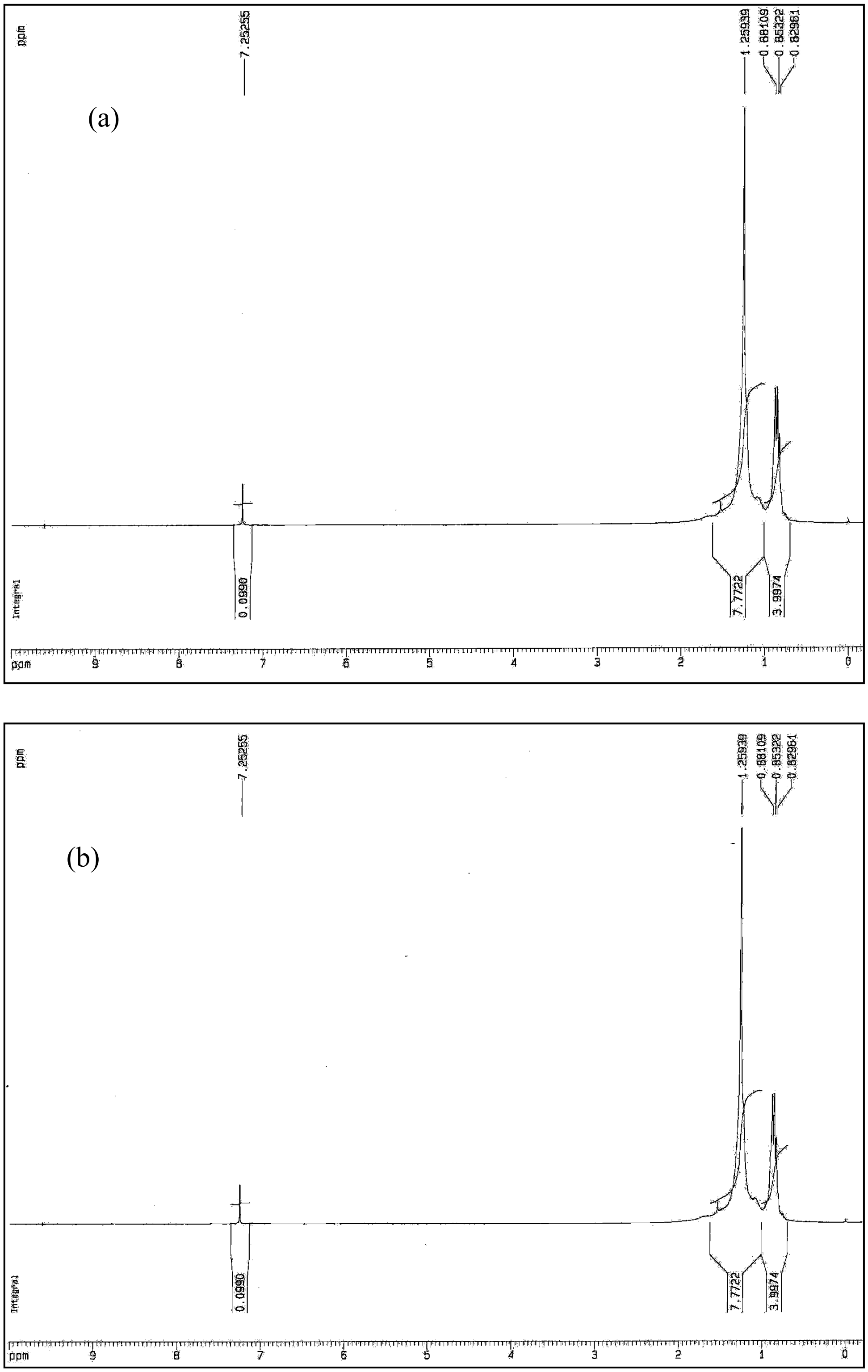

Fig. 5.11 NMR study of (a) Virgin oil sample (b) 160^0C/2.5 kV oil sample aged for 1440 hrs

5.5 DSC Study on Paper

The virgin and highly aged samples at 160^0C/2.5 kV for 1440 hrs were tested for Differential Scanning Calorimetric analysis as shown in figures 5.12 (a) & (b). In case of virgin paper, it indicates that minor endothermic reaction takes place just at 80^0C, corresponding to loss of absorbed water, and reaction becomes exothermic in the vicinity of 350^0C. As shown in figure 5.12 (b) of highly aged paper sample for a maximum period of 1440 hrs there is minor change in DSC pattern: the paper undergoes minor endothermic reaction at 67^0C corresponding to the loss of absorbed water, followed by a major exotherm near 350^0C. The data is interpreted as being indicative of a two-step reaction, with the change in the mechanism occurring at about 350^0C.

According to Shafizadeh and Bradbury [22], the reduction in molecular weight is due to random breakage of bonds within the cellulose occurring at the junction between the crystalline and amorphous regions. This proposed influence of the fine structure of cellulose in the course of pyrolysis also has been examined by Weinstein and Broido [23], who found that the degree of crystallinity remained fairly constant even at weight reductions of more than 50%, after which the crystallinity decreased rapidly. Cabradilla and Zeronian [24], who showed that major differences occur in the results of DSC and TGA with alteration in the degree of crystallinity.

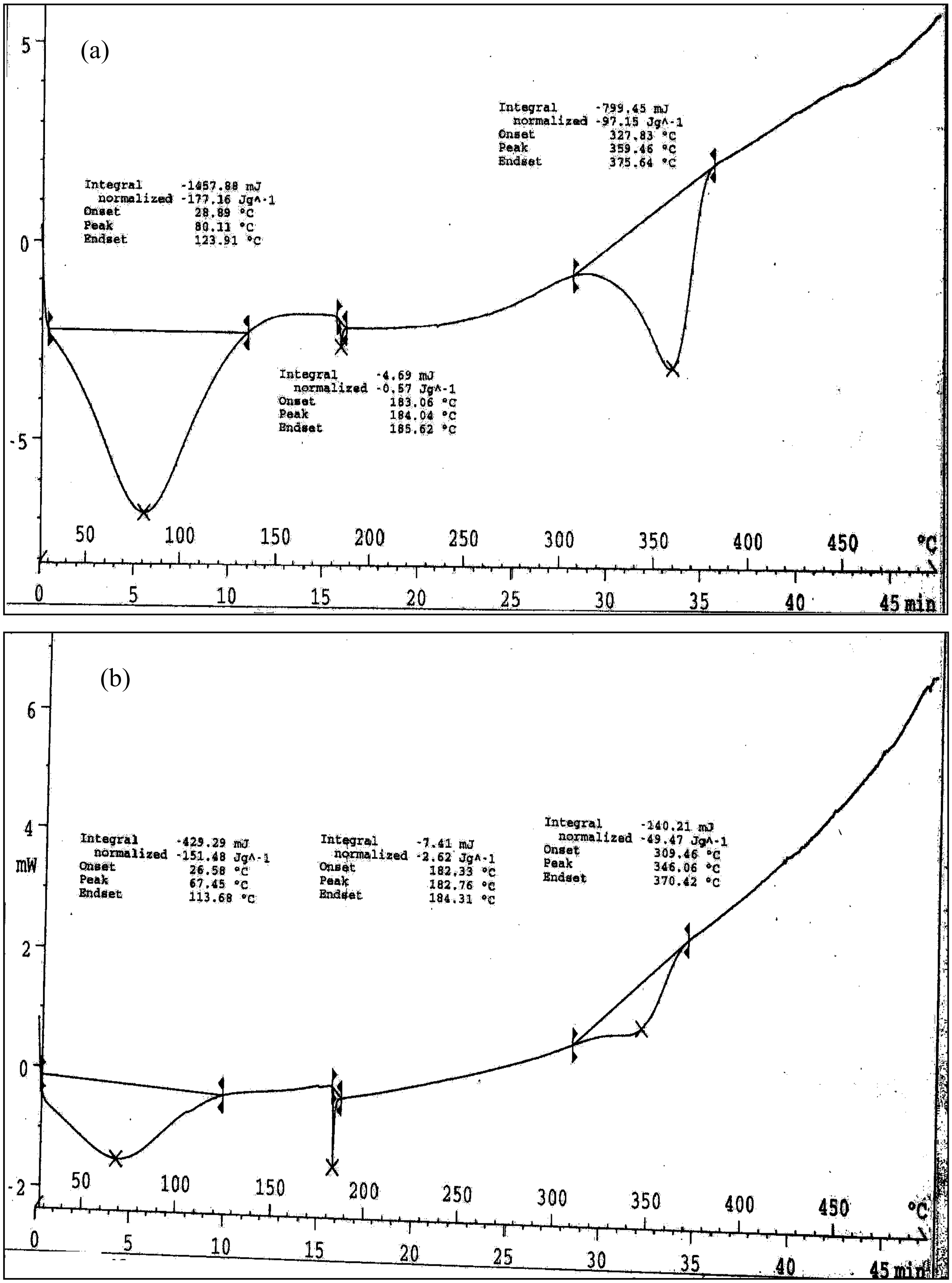

Fig. 5.12 Differential scanning calorimetry of (a) Virgin paper sample (b) Aged paper sample at 160^0C/2.5kV for 1440 hrs.

5.6 TGA Study on Paper

The results of the application of thermal analysis on virgin and aged samples are shown in figures 5.13 (a) & (b). The sample was heated from room temperature of 23^0C to maximum temperature of 500^0C. The heating rate was 10^0C/min. It is reported that the isothermal pyrolysis of cellulose at temperature of 275^0C to 325^0C indicates that after an initial period, the decrease in weight follows first order kinetics. As the temperature is increased, the initiation period is shortened [25,26,27]. In our study, the TGA pattern, figures 5.13 (a-b) seem to be identical as in both the cases the temperature at which the weight loss starts is same. An extensive study on the thermal degradation of cellulose has also been reported by Shafizadeh and numerous co-workers [28].

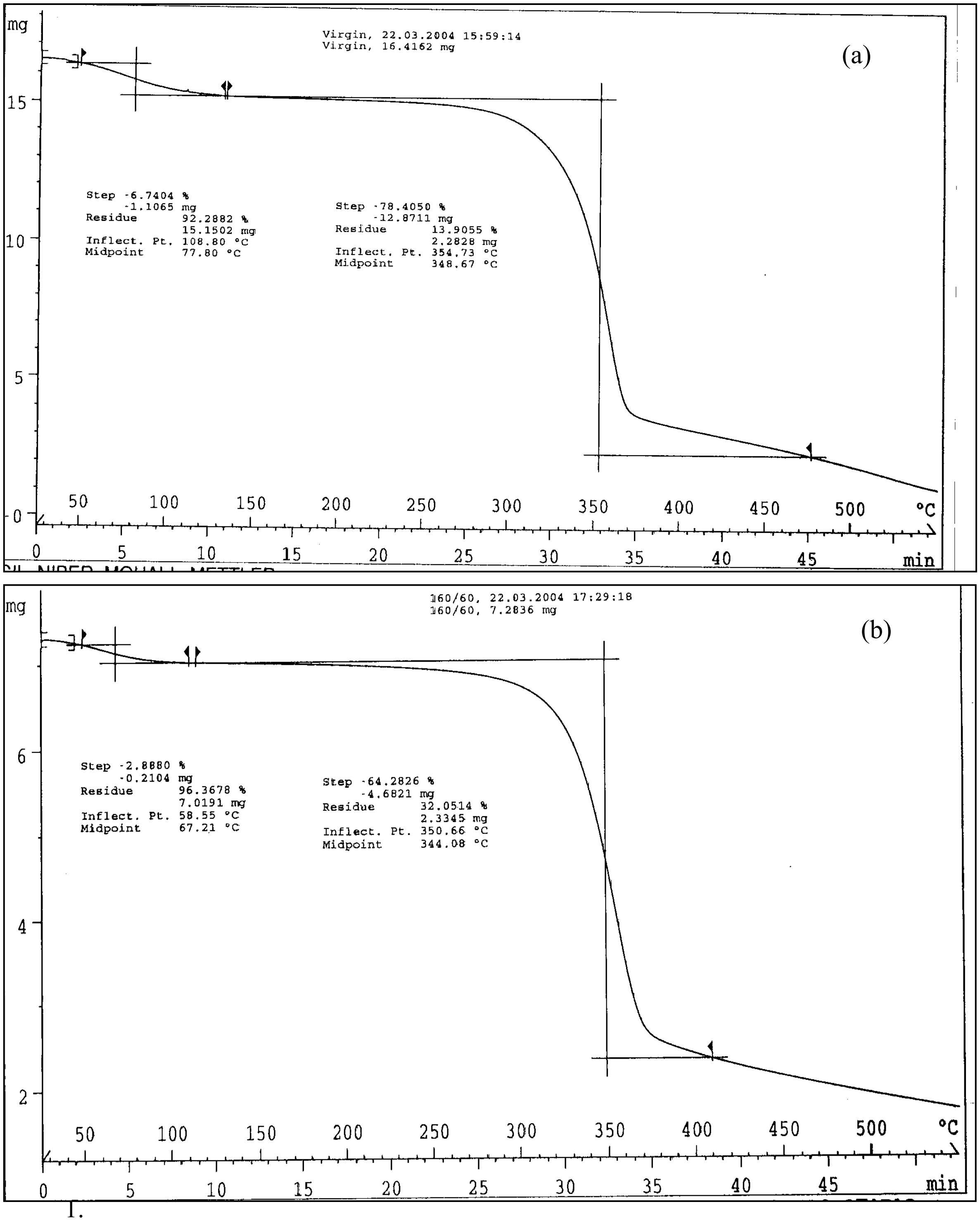

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Fig. 5.13 Thermal gravimetric analysis of (a) Virgin paper (b) Aged paper at 160^{0}C/2.5 kV for 1440 hrs.

Conclusions:

1. Scanning Electron Microscopy appears to be a promising tool for assessing the extent of degradation of paper under combined thermal and electrical stress. For paper aged at 120^0C for 1440 hrs, at an electric stress of 2.5 kV, the sign of degradation of paper is just beginning to show up, but as the paper undergoes higher thermal and electric stress, SEM micrograph shows the fiber breakage and punchring of paper at 160^0C, 2.5 kV electric stress.

2. X-ray diffraction analysis shows that though there is no change in 2θ value under accelerated thermal and electrical stress, there is a distinct increase in crystallinity with respect to ageing.

3. FT-IR of virgin paper and the paper under combined thermal and electrical stress level of 160^0C/2.5 kV show no sign of change in-group though intensity of peak variation exists. The broader peak around 3400-3500 cm^{-1} becomes narrow on ageing. This corresponds to O-H stretching. Its narrow character after the ageing treatment indicates that the associated intermolecular bonding decreases and intra association of O-H group takes place by condensation mechanism. Thus providing very less free O-H group in the system.

4. The FT-IR of virgin and aged oil samples indicates that there are peaks in the region of 2850-2950 cm^{-1}. These peaks correspond to the C-H stretching of hydrocarbon. Aged samples do not show any difference in position and intensity of those peaks compared to the virgin sample.

5. ^{1}HNMR spectra have also been recorded for the virgin and highly aged oil sample (160^0C/2.5 kV). No change in the spectra was observed.

6. The Differential Scanning Calorimeter (DSC) and Thermo Gravimetric Analysis (TGA) were carried out on virgin and most aged paper sample. There is no distinct change in their pattern.

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Chapter 6

CORRELATIONS AND CONCLUSIONS

Overview

In this chapter, an attempt has been made to correlate the different properties of insulating oil and paper under thermal and electrical stress. The role of thermal and electric stress has been discussed. The variation of different Electrical, Chemical and Mechanical properties, under combined thermal and electrical stress, have been investigated. An effort has been made to establish possible correlations between Viscosity and Acidic value, Interfacial Tension (IFT) and Acidic value, Resistivity and Tan-delta, Degree of Polymerization (DP) and Furan content, Tensile strength and Degree of Polymerization. A correlation between Dissolved Gas Analysis (DGA) and Partial Discharge (PD) was found. The Scanning Electron Microscopy (SEM), and X-ray Diffraction (X-RD) were found to be useful tools for studying the degradation of paper. The Fourier Transform Infrared Spectroscopy (FT-IR), Nuclear Magnetic Resonance (NMR), Differential Scanning Calorimeter (DSC) and Thermal Gravimetric Analysis (TGA) did not yield much information on the understanding of degradation mechanisms.

6.1 Effect of Accelerated Thermal Stress

Temperature has an accelerating effect on oxidation. From our results, it is observed that for every 20^0C rise in temperature, most of the properties are affected significantly. The changes are physico-chemical in nature involving a time dependent decomposition of both solid and liquid phase. At higher temperature, oxidation products such as acids and alcohols are formed along with water, carbon monoxide and carbon dioxide. At higher temperatures the moisture in solid insulation migrates and gets into oil and the reverse happens as the temperatures go down. Considering the fact that most of the transformers operate at temperatures ranging from 40^0C to 90^0C, the presence of moisture plays an important role in the failure of the transformer. There is no doubt that moisture is recognized to be the major cause of insulation failure

6.2 Effect of Accelerated Electric stress

The accelerated electric stress is an important factor considered in the oxidation of the oil. The weight and dimension restrictions of the transformer lead to a decrease in insulation clearances. Consequently, the oil ducts also become narrower and hence the strength of the electrical field increases which exerts a great effect on the oxidation process. From our study it is clear that there is a significant change in properties going from normal electric stress, i.e. 1.0 kV to highest applied electric stress, i.e. 2.5 kV. Essentially, the electric stress supplies the energy (approximately 4 eV) required for the cleavage of a covalent bond.

6.3 Correlation between Viscosity of Oil and Acidic value

The relationship between viscosity and acidic value of oil has been drawn from the results obtained for 160^0C at 2.5 kV electric stress. The result is shown in figure 6.1 (a). The figure shows that the increase in acidic value has direct impact on the viscosity i.e. viscosity of the oil increases with increase in acidic value. From the regression analysis, the maximum R^2 (coefficient of determination) value is found 90.95% as shown in figure 6.1(b)

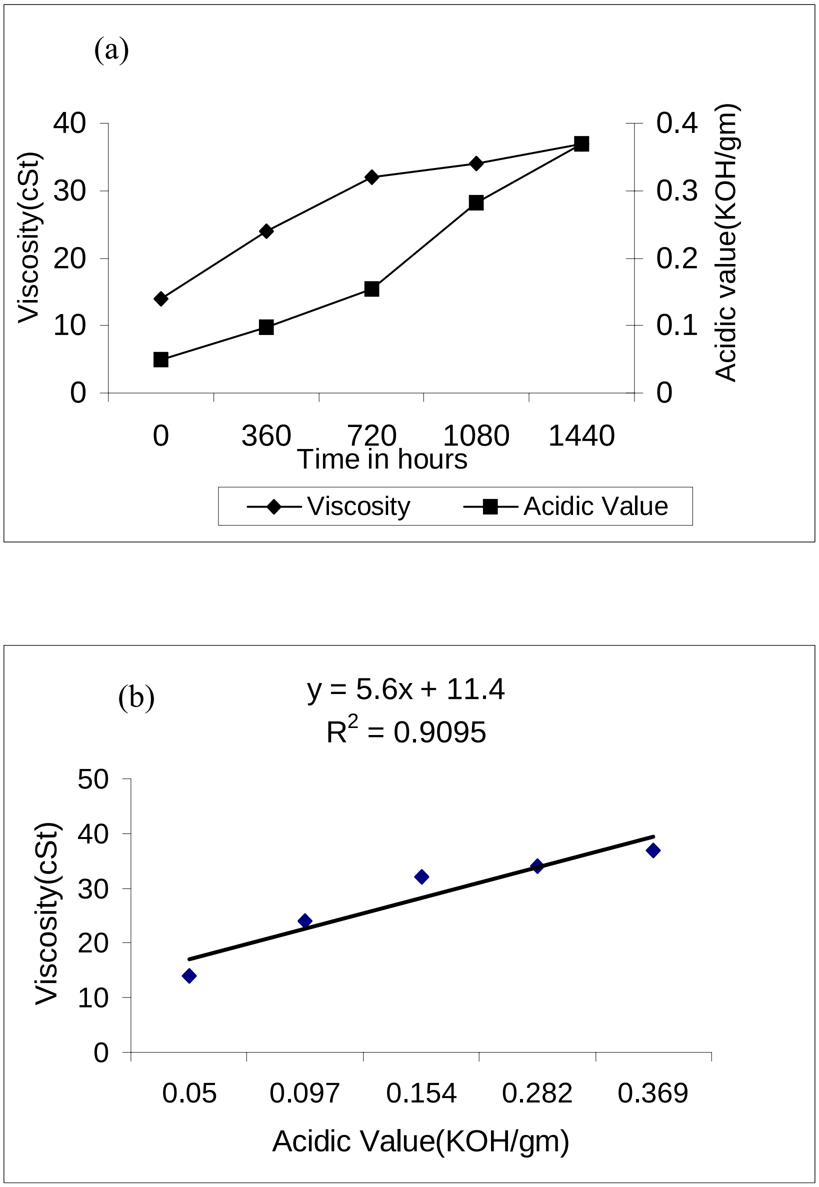


Fig. 6.1 (a) Viscosity and acidic value with aging (b) Correlation between viscosity and acidic value

6.4 Correlation between Interfacial Tension (IFT) and Acidic Value

The figure 6.2 (a) shows the relationship between Interfacial tension and acidic value. It is evident that the increase in acidic value reduces the interfacial tension of oil. The decrease in interfacial is quite uniform with respect to acidic value. The relationship is drawn for 160^0C at 2.5 kV electric stress. The maximum R^2 value is found 96.69% as shown in figure 6.2 (b).

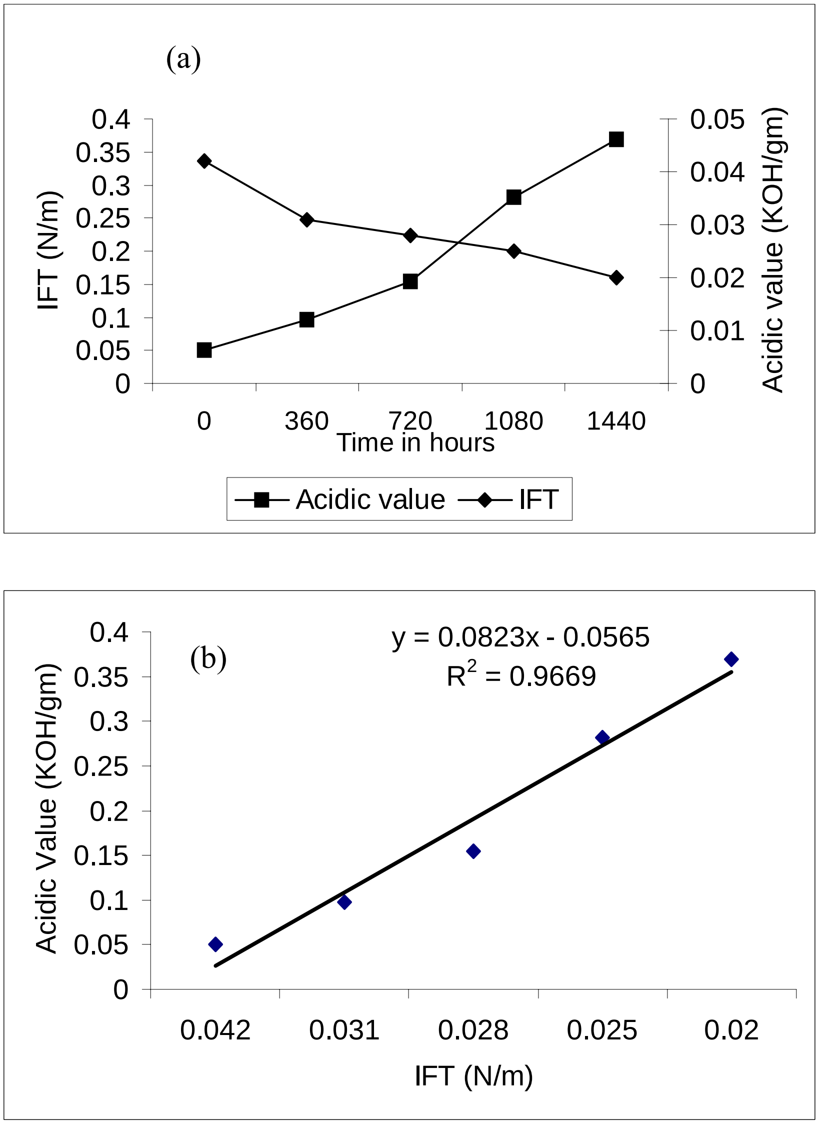
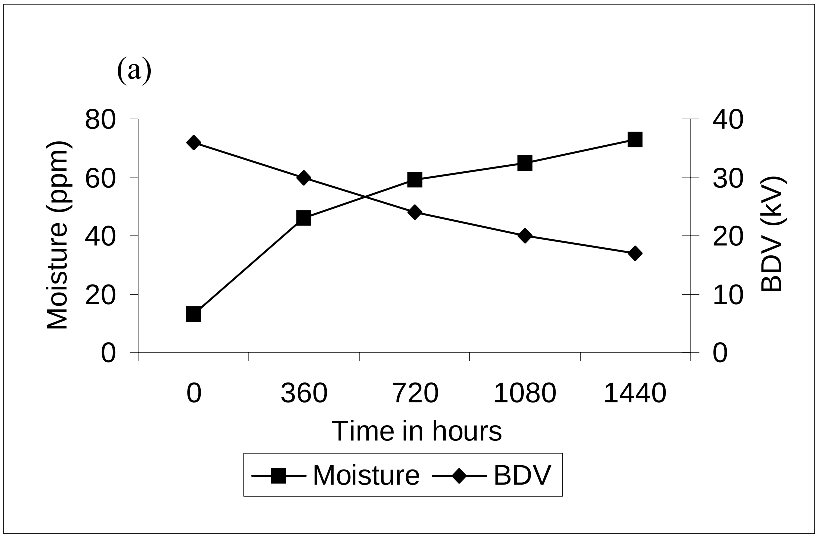


Fig. 6.2 (a) IFT and acidic value with aging (b) Correlation between IFT and acidic Value

6.5 Correlation between BDV of Oil and Moisture

The figure 6.3 (a) shows the relationship between break down voltage of oil (BDV) and moisture content for 160^0C at 2.5 kV electric stress. Based on the results it is evident that presence of moisture is an important initiation factor leading to failure. The type of degradation is well understood and has been reported by other researchers as well. While monitoring the moisture level it is very important to correlate this with the temperature, as the moisture content in oil has a strong dependence on the temperature. At higher temperatures the moisture in solid insulation migrates and gets into oil and the reverse happens as the temperatures go down. Considering the fact that most of the transformers operate at temperatures ranging from 40^0C to 90^0C, the presence of moisture would play an important role in the failure of the transformer. The maximum permissible level of oil should not be more than 10 ppm for a reliable operation. It is clear that moisture content has the direct impact on the BDV of oil. The maximum R^2 value is found 97.96% as shown in figure 6.3 (b).



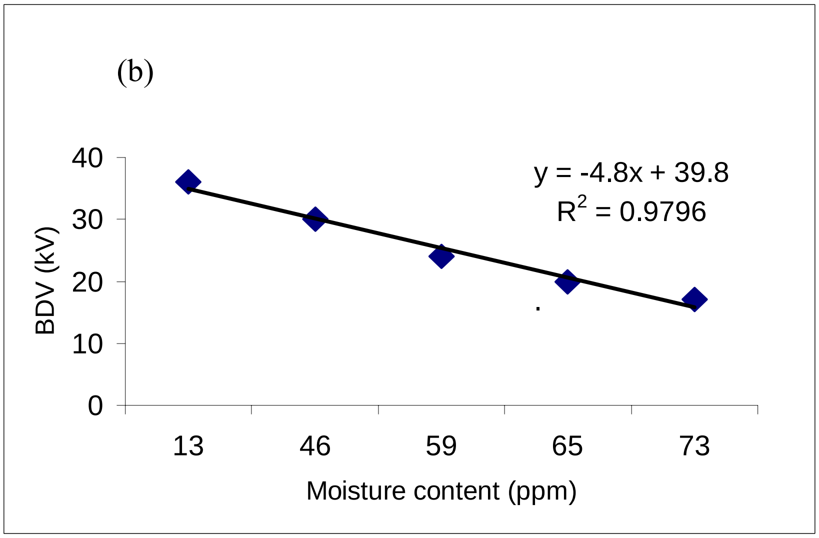


Fig. 6.3 (a) Moisture and BDV with aging (b) Correlation between moisture and BDV

6.6 Correlation between Resistivity of Oil and Tan-delta.

The figure 6.4 (a) shows that the resistivity of oil decreases at a faster rate in comparison of tan-delta. But after 360 hours of ageing the resistivity decrease is more uniform. There is generally a relation between tan-delta and resistivity, both being affected by the same contaminants. A decrease in resistivity is coupled with increase in tan-delta as shown in figure. The maximum R^2 value is found 97.76% as shown in figure 6.4 (b).

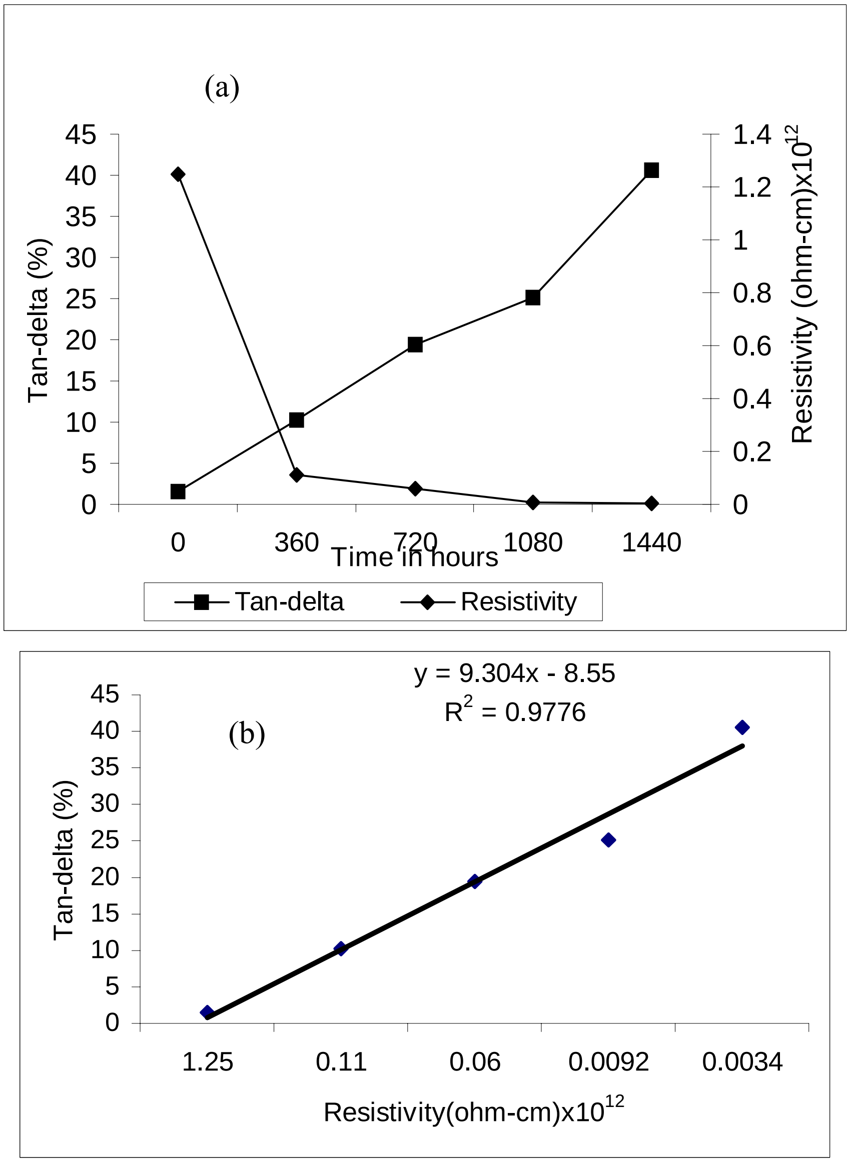
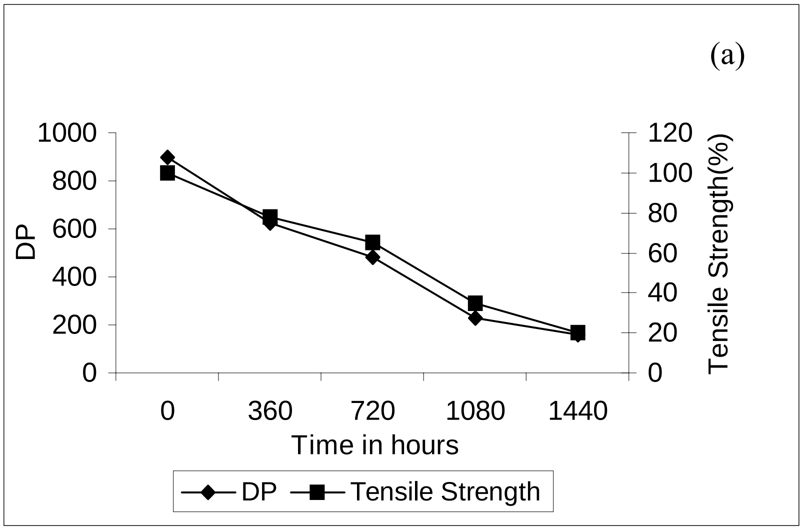


Fig. 6.4 (a) Resistivity and tan-delta with aging (b) Correlation between resistivity and tan-delta

6.7 Correlation between DP and Tensile Strength of Paper

The figure 6.5 (a) shows the good correlation between Degree of Polymerization (DP) and Tensile strength of paper. A.M. Emsely et.al have mentioned in their work that the strength of paper is critically dependent on the DP of cellulose. It decreases in direct proportion to DP. The rate of loss of strength is temperature dependent with energy of activation very similar to that for degree of polymerization of cellulose. Tensile Strength and DP are intrusive tests that destroys the sample being tested and decreases the amount of the material left in the unit, which might be deleterious to the unit. Therefore, these tests are not suitable for on-line monitoring. The maximum R^2 value is found 97.03% as shown in figure 6.5 (b).



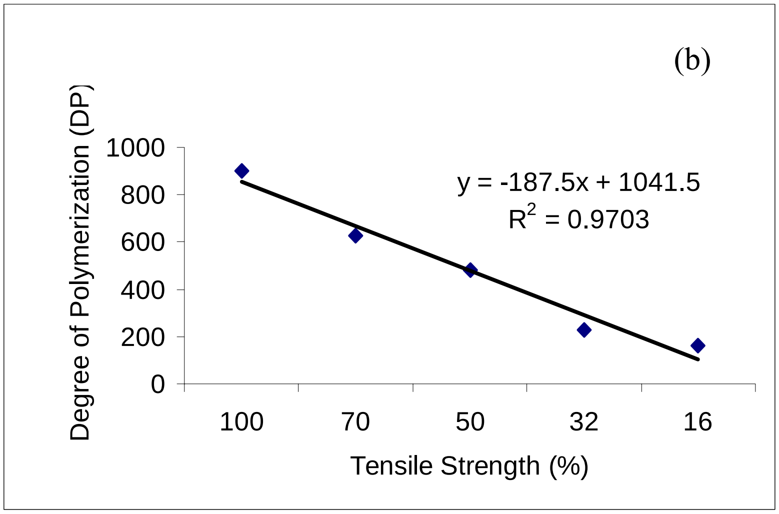


Fig. 6.5 (a) DP and tensile strength with ageing (b) Correlation between DP and tensile strength.

6.8 Correlation between Furan Content and DP of Paper

The figure 6.6 (a) shows the correlation between degree of polymerization and furan content of paper. As the paper undergoes ageing, the polymer chains degrade into smaller units or if the paper is subjected to a severe fault such as overheating or arcing the polymers will also be degraded. As shorter length chains are formed the average degree of polymerization is decreased. Thus this method allows one to assess the condition of cellulose insulation within the unit. Since these values do represent averages, when evaluating a sample of cellulose, it is compared to a fresh sample of the virgin paper. It should be pointed out that this test requires a sample of paper, which means that the unit must be taken out of service to be sampled. Further it is intrusive test that destroys the sample being tested and decreases the amount of the material left in the unit, which might be deleterious to the unit. Therefore, Furan testing technique seems to be the best one to analyse the degradation of paper. The six compounds that arise from the degradation of paper are 2-furfuraldehyde, 5-hydroxy-methylfurfuraldehyde, 2-acetylfuran, 5-methylfurfuraldehyde, furfurylalcohol and furoic acids, but major formation of 2-furfuraldehyde is evident from our results under thermal stress. Schroff and Stannett (1985) also have reported the degradation of insulating oil in detail. They have shown that furfural formation depends upon the temperature and ageing time, which is true in our case also. At 160^0C for 1440 hours, the 2- furfuraldehyde content was 5600 ppb. Therefore, Furfural analysis may prove to be the most useful as a troubleshooting tool, i.e. as indicative of rapid rates of ageing, rather than a monitor of ‘normal’ ageing.

The DP and furan content exhibit good correlation as the concentration of furans gives an indication of the condition of the paper in terms of the degree of polymerization, while the rate of change of furan concentration can indicate the rate of ageing of paper. The main advantage of using this technique of furan analysis as a diagnostic tool is that these compounds are degradation products specific to paper, and cannot be produced by oil. The maximum R^2 value is found 97.03% as shown in figure 6.6 (b).

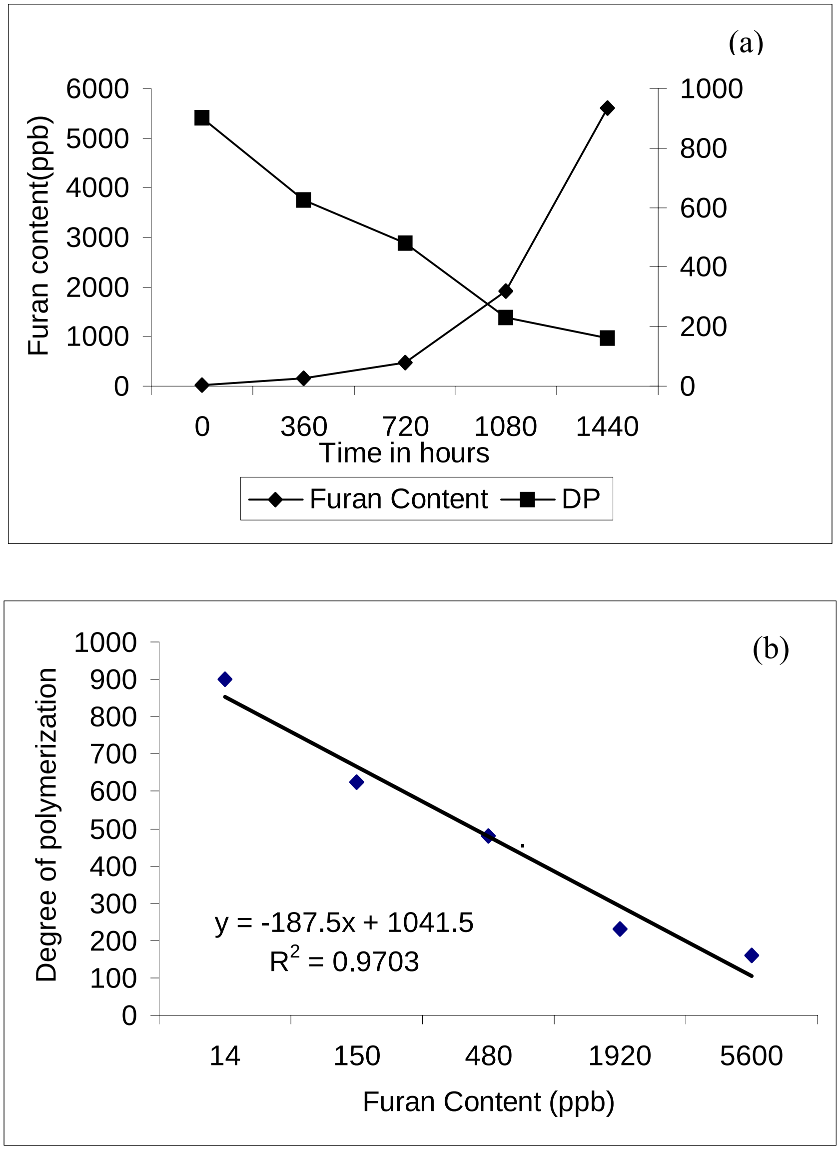


Fig. 6.6 (a) DP and furan content with ageing (b) Correlation between DP and furan content

6.9 Dissolved Gas Analysis (DGA)

The incipient faults, especially in the form of overheating, arcing or partial discharge, develop certain gaseous hydrocarbons, that are retained by the insulating oil as dissolved gases. Thus the evaluation of the gas compositions and their interpretation, known as Dissolved Gas Analysis (DGA), seems to be the only and life saving diagnostic test on bulk oil equipment as there is no direct method to detect these faults.

Dissolved Gas Analysis is a very powerful technique to find out incipient faults within the transformer. Certain gases are produced by decomposition of oil or paper insulation when transformer undergoes abnormal thermal or electrical stresses. These gases come out and get collected in buchholtz relay when their quantity is more. But when the fault is in very small area or if the severity of fault is less, these gases get dissolved in oil. As the composition and quantity of the gases generated is dependent on type and severity of the fault, regular monitoring of these dissolved gases reveal useful information about health of a transformer and prior information of fault can be had observing the trend of various gas contents.

Analyses of DGA results indicate that there has been a significant increase in gas content under thermal and electrical stress. The results indicate that CO_2 content remains low at lower thermal stress. As the temperature increases its concentration increases and at very high thermal stress i.e. at 160^0C, the concentration of gases is maximum. Variation of electric stress does not cause any significant increase of CO_2 and at 160^0C the concentration of CO_2 remains almost same irrespective of electric stress.

The presence of higher CO_2 is mainly due to decomposition of cellulose in paper. The sample taken out at 120^0C at 1.0 kV for 1440 hours shows that the H_2 gas content is 200 ppm, which indicates the low energy electrical discharges. Further the H_2 also increases uniformly at 140^0C at 1.5 kV and 160^0C at 2.5 kV, however the maximum increase is at higher thermal and electric stress i.e. 160^0C for 1440 hours at 2.5 kV. The variation of C_2H_2 is within permissible range at 120^0C, 1.0 kV and at 140^0C, 1.5 kV but at 160^0C, 2.5 kV for 1440 hours it suddenly jumps to the level of 500 (ppm), which indicates the arcing occurs through high current and high temperature conditions. CH_4, C_2H_6 and C_2H_4 content also increases uniformly under the various thermal and electric stress level. The results also indicate that C_2H_4 (C=C formation) content is much higher compared to CH_4 and C_2H_6 (C-C formation) at higher temperature. These gases are generated mainly due to overheating.

Though there is a correlation between the dissolved gases and ageing/faults inside the transformer, owing to the complexity and cost of the equipment this would not qualify for on-line monitoring. DGA can be used as a deterministic tool to find the type of ageing/nature of faults in a transformer after the transformer has been detected to change its properties based on monitoring of certain parameters, such as BDV, Moisture, Viscosity, Resistivity and Tan-delta etc.

6.10 Partial Discharge Measurement (PD)

The partial discharge test was conducted on all the samples at 150% of rated voltage i.e. 15 kV and the magnitude of partial discharge was measured. The partial discharge magnitude of virgin sample at 120^0C and at 2.5 kV for 1440 hours was in the range of 7 pC to 20 pC. The partial discharge magnitude was found to have increased and was in the range of 70-450 pC under thermal and electric stress. The maximum increase in partial discharge at 160^0C at electric stress 2.5 kV is found 450 pC, which strengthen our dissolved gas analysis results i.e. at the same stress level the acetylene (C_2H_2) gas content is found 500 ppm which is only due to partial discharge. The Scanning Electron Microscopy study also shows that the cellulose fiber bonding is totally broken due to arcing. The PD pattern also exhibits a marked change with ageing. Considering these and fact that partial discharge measurement can be applied on–line, partial discharge monitoring can be an ideal on-line condition monitoring and diagnostic tool.

6.11 Scanning Electron Microscopy (SEM)

Microstructural studies were conducted on the fresh and also on aged cellulose paper to compare the extent of degradation of paper. SEM photographs of fresh paper indicate closely packed cellulose fibers with dense interwoven network having no deformation. The micrographs of the paper corresponding to ageing temperature of 120^0C, 140^0C and 160^0C for 1440 hrs with electric stress of 1.0 kV, 1.5 kV and 2.5 kV show the start of deformation of fibers at 120^0C but there is no evidence of breakage of paper. The micrographs for the paper aged at 140^0C for 1440 hrs show the fiber degradation and is clearly visible in all the three conditions. The micrographs of paper aged at 160^0C for 1440 shows the pinhole type morphology on all around the fiber, the paper breakage in different places of the paper, the complete rupturing of paper, the discharge current flow through it under the influence of higher voltage and finally burn the paper. SEM can at best be used as confirmatory diagnostic test and can be used as effective tool to identify the failure mode or initiating cause.

6.12 X-RD Analysis

The X-ray diffraction study of virgin and aged paper indicates that there are two different peaks, one corresponding to hollow and broad peak with very less intensity and another corresponding to sharp with higher intensity. Since paper consists of higher amount of cellulose (90%) that exhibits crystalline character and other constituents lignin and hemi cellulose present are around 10%, which are amorphous in nature, the broad and sharp peaks may correspond to amorphous structure and crystalline/microcrystalline character of cellulose respectively.

The diffraction pattern shows that there is significant change in the degree of crystallinity of the cellulose due to degradation under accelerated thermal and electrical ageing but there is no change in 2θ value. The crystallinity of virgin paper is calculated 79.5%. The crystallinity at 160^0C for 1440 and 2.5 kV electric stress is 89%. Thus it is likely that most of the chain scission occurred in the amorphous region of the paper as compared to crystalline region. Amorphous structure has higher free energy as compared to crystalline structure. It is evident that under the influence of temperature the deterioration of amorphous area is more as compared to crystalline area. It has been reported that even within the amorphous regions, some areas are more reactive than others. Therefore, X-RD may be a promising technique to assess the degradation of paper.

6.13 FT-IR Study on Paper and Oil

As described earlier, paper consists of cellulose, hemicellulose and lignin. In order to understand the change in structure, Fourier Transform Infrared Spectroscopy (FT-IR) has been done for virgin and accelerated aged papers. This study is important to analyse the structure as many of the absorption peaks are assigned to specific bond vibration. Our study indicates that there are distinct peaks at 1600-1700 cm^{-1} and a broad peak at 3400-3500 cm^{-1} due to carbonyl group and hydroxyl group of cellulose respectively. It is observed that the virgin paper and the paper under combined thermal and electrical stress level of 160^0C/2.5 kV show no sign of change in group though intensity of peak variation exists. The broader peak around 3400-3500 cm^{-1} becomes narrow on ageing. This corresponds to O-H stretching. Its narrow character after the ageing treatment may be due to decrease in associated intermolecular Hydrogen bonding and intra association of O-H group by condensation mechanism. Thus providing very less free O-H group in the system.

On the other hand, the FT-IR of virgin and aged oil shows that there are peaks in the region of 2850-2950 cm^{-1}. These peaks correspond to the C-H stretching of hydrocarbon. Aged samples do not show any difference in position and intensity of those peaks compared to the virgin sample.

6.14 Nuclear Magnetic Resonance Study on Oil

^{1}HNMR spectra have also been recorded for the virgin and highly aged oil sample (160^0C/ 2.5 kV). No change in the spectra have been observed. The peak at 1.3 ppm corresponds to the methyl group of hydrocarbon and appearance of a weak peak in the region of 7.3 ppm corresponds to the slight aromatic character of the oil. Hence NMR study on oil does not give much information about the degradation of oil.

6.15 DSC Study on Paper

The Differential Scanning Calorimetric pattern of virgin and highly aged samples at 160^0C/2.5 kV is taken. It is observed that there is no change in pattern of virgin and aged paper samples.

6.16 TGA study on Paper

The results of the application of thermal analysis on virgin and aged samples indicate that after an initial period with only slight reductions in weight, a major weight loss occurs as the temperature approaches about 350^0C which is the transition point of order of the reactions as reported by Tang during a study of wood with TGA. The identical observation has been obtained i.e. both the cases the temperature at which the weight loss starts is same.

6.17 Scope of Future Work

In the present study the various electrical, chemical and mechanical properties of oil and paper have been studied under accelerated thermal and electrical stress for different ageing time. A study of this kind will be helpful in identifying the most sensitive properties with respect to ageing. Eventually, this knowledge data base will also be helpful in evolving a condition monitoring strategy and instrumentation for actual transformers.

The present and the current research have thrown up a few interesting problems in which further research could be undertaken, these problem are outlined below:

1. Partial Discharge characterization: Using pattern recognition techniques to build a library and use it for more accurate diagnostics when applied to on-line monitoring.
2. Diagnostic software, which gives more definite indications of transformer problems than conventional analysis, is under investigation by many researchers and utilities but still this area needs to be tapped fully. The use of software can improve the reliability and repeatability of the analysis of test data. It can also be used to extract information that is not available from the data directly.
3. The present advancement in Artificial Intelligence (AI) modeling techniques has enabled power engineers and researchers to develop powerful and versatile AI software to diagnose transformer faults. The use of expert systems offers the potential of reducing the manpower and financial overhead required by utilities to assess transformer condition.
4. Expert systems have to be developed that give an alarm signal to system operators. Frequency Response Analysis along with specialized software may be developed to asses the displacement inside the transformer.