SAKARYA UNIVERSITY
INSTITUTE OF SCIENCE AND TECHNOLOGY

CONCEPTION OF AN ONLINE CONDITION MONITORING AND ASSESSMENT FOR TRANSFORMER OIL AND DESIGN OF A HUMAN-MACHINE INTERFACE FOR REAL TIME ANALYSIS

M.Sc. THESIS

Lamine Cherif NDOUOP MOUCHILI

Department	**:**	**COMPUTER ENGINEERING**
Supervisor	**:**	**Asst. Prof. Dr. Metin Varan**

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This thesis has been accepted unanimously / with majority of votes by the examination committee on 31.07.2015

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DECLERATION

I declare that all the data in this thesis was obtained by myself in academic rules, all visual and written information and results were presented in accordance with academic and ethical rules, there is no distortion in the presented data, in case of utilizing other people's works they were refereed properly to scientific norms, the data presented in this thesis has not been used in any other thesis in this university or in any other university.

Lamine Cherif Ndouop Mouchili

31.07.2015

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In the name of ALLAH, the Most Gracious, The Most Merciful, To Him belongs all praise.

Every work is a great effort, mine no less than anyone else's. I would therefore like to use this space thank those whose assistance has been invaluable to me. First and foremost, I would extend my gratitude to my advisor Asst. Prof. Dr. Metin Varan for his endless and ongoing efforts and supports he has providing me with throughout this work. I am grateful to Sakarya University and his Scientific Research Projects Unit who supported this work. I am especially grateful to TEAIŞ operator and his oil analysis laboratory staffs for the field data they provided to strengthen this work.

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And all praise belongs to ALLAH, The Most Gracious, The Most Merciful.

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LIST OF SYMBOLS AND ABBREVIATIONS

AC	: Alternative Current
ASTM	:American Society for Testing And Materials
C_2H_2	:Acetylene
C_2H_4	:Ethylene
C_2H_6	: Ethane
CBM	: Condition Based Maintenance
CH4	: Methane
CIGRE	:International Council on Large Electric Systems
CO	: Carbon Monoxide
CO_2	: Carbon Dioxide
DC	: Direct Current
DGA	: Dissolved Gas-in-oil Analysis
H_2	: Hydrogen
HSB	:Hartford Steam Boiler
LTC	: Load Tap Changers
O_2	: Oxygen
PD	: Partial Discharge
TBM	: Time Based Maintenance

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SUMMARY

Keywords: Power transformers, Transformer maintenance, dissolve gas-in-oil analysis, measurement and analysis systems, real-time systems

Power transformers are the most critical component of an electrical power generation and distribution system as far as the system stability, the quality of the energy produced and the availability of its delivery to end users are concerned. Periodical maintenance activities of transformers are paramount for the proper operation of the system. Mineral oil used in transformers as insulating medium and coolant plays a central role in their operation. By monitoring gases dissolved in transformers oil, it is possible to device methods to assess the health of transformers as well as schedule maintenance activities.

In this work, using dissolved gas-in-oil analysis procedures we propose a model for a real-time measurement and analysis system to determine fault conditions oil-immersed transformers.

ELEKTRİK GÜÇ TRAFOLARINDAKİ KULLANILAN YAĞLARIN GERÇEK ZAMANLI ANALİZİ İÇİN BİR ÖLÇÜM SİTEMİNİN GELİŞTİRİLMESİ VE İNSAN-MAKİNE ARAYÜZÜ TASARIMI

ÖZET

Anahtar kelimeler: Güç trafoları, yağda çözünmüş gaz analizi, trafo bakımı, ölçüm ve analiz sistemi, gerçek zamanlı sistem.

Güç trafoları elektrik güç sistemlerinin en önemli bileşenlerindendir. Güç trafolarının sağlığı şebeke güvenilirliği ve verimliliği için oldukça hayati bir durumdur. Program dışı meydana gelen elektrik kesintilerinin veya aniden gelişen bir arızanın yol açacağı maddi zararlar genellikle büyük olur. Arıza sadece trafoya hasar vermekle kalmaz, aynı zamanda sanayi ve hizmet kuruluşları, konutlar, hastane ve okul gibi binlerce kurumu etkiler. Enerji sisteminin ve elektrikle çalışan cihazların zarar görme olasılığı artar. İş ve zaman kaybı ile birlikte maddi zararlar çok büyük rakamlara ulaşabilir. Örneğin 3 fazlı 500MVA'lık yükseltici bir trafonun servis harici kalma durumu günlük sadece güç kayıpları açısından 12 milyon liralık bir bedel oluşturur. Bu nedenle, trafo hakkında erken uyarı bilgisi alındıktan sonra yeni programlar hazırlanıp gerekli önlemlerin acilen alınması çok sağlıklı ve ekonomik olacaktır.

Trafoların sağlıklı çalışma göstergelerinden en önemli birisi de hiç şüphesiz yağ ve gaz analizleridir. Yağlar elektrik mühendisliğinde başta izolasyon ve soğutma temel özelliklerini sağlamak için güç trafolarında yaygın olarak kullanılır. Yağlı trafolar güç sistemlerinde güç iletimi ve dağıtımının oransal olarak en fazla yapıldığı trafolardır. Trafolarda temel olarak izolasyon ve soğutma iki ana fonksiyonunu yerine getiren yağlar trafoların güvenilir ve uzun ömürlü olmasını sağlar. The Council on Large Electric System (CIGRE) tarafından güç trafo arızları hakkında yapılan bir araştırmada trafo arızalarının oransal olarak oluşum sebepleri Figure 3.1 de gösterilmiştir.

Arızların büyük oranda kademe değiştirme, sargılar ve sızıntı üzerinde yoğunlaşması yağ ve gaz analizlerinin önemini daha anlamlı hale getirmektedir. Zira yağ ve gaz analizleri ile trafonun yüklenme sınırları, kademe değiştirmelerinde meydana gelen ark oluşumu, sargıların sıcaklıkları ve elektriksel sızıntı oluşumları trafo kalıcı bir hasara uğrayıp servis harici olmadan tespit edilebilir. Trafo yağının elektriksel izolasyon özelliği sayesinde yüksek enerjilere sahip iletkenlerin birbirinden ayrılması sağlanır. Yağ bozulmadığı sürece izolasyonu sağlarken aynı zamanda metallerin oksitlenmesinin önüne de geçer. Servis altında çalışan bir trafoda meydana gelen ısının dışarıya atılması oldukça önemlidir. Trafo yağı soğutma vazifesini büyük hacme sahip trafo yağı ve yağ tankı üzerinden sargılar ve nüve arasında ısıyı dışarı taşımaya yardım etmesiyle gösterir. Trafo yağının bir başka özelliği teşhis amaçlı kullanılabilmesidir. Özellikle servis harici yapmadan trafonun deşarj durumları ve aşırı ısınma durumu ile ilgili kılavuz bilgiler verebilir.

Trafonun Yağını Etkileyen Faktörler

Trafonun yağ kalitesini etkileyen faktörler şunlardır:

- **Aşırı Isınma**: Yağın kimyasal yapısını bozacağından kalitesi de bozulur.
- **Oksitlenme**: Yağın kalitesini azaltan en temel bir özellik oksitlenmedir. Oksitlenme ile trafo içerisinde karbondioksit, su, alkol, aldehit, keton ve asit oluşumları görülür.
- **Nem**: Yağın dielektriksel dayanımını azaltır.
- **Asitler**: Yağın içinde 0,6 mg KOH/g ve daha üzeri bir asit oluşumunda trafo yağı ve elektriksel donanımları için korozyon etkisi oluşturur.
- **Korona Deşarjları**: Yüksek enerjili bu deşarjlar oluştuğunda su ve bazı gaz oluşumları görülür.

Trafolarda Yağ Testleri

Trafo yağların yukarıda bahsi geçen bozucu etkiler dolayısıyla sürekli gözlem altında tutulması elzemdir. Yağ kalitesinin sadece dielektrik kabiliyetini değil trafonun genel anlamda servis kalitesi düşük bir çalışmaya gitmesi anlamına gelir. Trafo yağ izlemesi için genel anlamda iki grup test yapılır; İlk grup testlerde elektriksel, kimyasal ve fiziksel testler yapılırken, ikinci grup testlerde yağ içindeki çözünmüş gazın niteliksel ve niceliksel analizi yapılır.

A) Kimyasal Yağ Testleri

1) **Su miktarı:** Yağın içindeki su miktarı yağın dielektriksel dayanımını azaltır ve kâğıt izolasyonun bozulmasını hızlandırır
2) **Nötralizasyon sayısı(NS):** Trafo yağının asitlik durumunu tayin eder. 1 gram yağ içindeki mg olarak KOH miktarını temsil eder. Asitlik arttıkça tank içindeki metal, selüloz ve sargı kâğıt izolasyonları bozulur.
3) **Aşındırıcı Sülfür:** Yağ içindeki aşındırıcı sülfür miktarını tespit eder. Elektriksel deşarj ve kıvılcımlara neden olur. Özellikle sargılarda ve katı izolasyon malzemelerinin üzerinde sülfür birikir.
4) **Tortu oluşumu:** Sargılar ve kâğıt izolasyonlarda yağların bozulması ile meydana gelen tortulardır. İzolasyonu ciddi anlamda tehdit ederler. Soğutmaya da engel olurlar. Tortu oluşumunun derecesi azalan izolasyon derecesini belirler.

B) Fiziksel Yağ Testleri

1) **Viskozite:** Viskozite sıvının akışkanlığı önündeki dirençtir. Isı yayılımını etkiler. Yağın viskozitesi sıcaklığı ile ters orantılı olarak değişir. IEC-60286,

standartlarına göre izolasyon yağı üç sınıfta olmalıdır;40°C de 16cSt I. Sınıf yağ için, 11cSt II. sınıf yağ için ve 3,5cSt III. sınıf yağ için.

2) **Yüzeysel gerilme:** Su ve yağ yüzeyinde iki sıvının bozularak karıştığı metre başına milinewton gerilme kuvveti değeridir. Yüzeysel gerilme değeri yağın saflık derecesinin göstergesidir. Yağın boya, vernik ve sabun içeriğinin artmasıyla yüzeysel gerilme azalır. ASTM D 3487 standardına göre, 40mN/m yüzeysel gerilme değeridir.

3) **Akma Noktası:** Yağ akışının olabileceği en düşük sıcaklık değeridir. ASTM D 3487 standardına göre , -40°C **"pour"** noktası değeridir.

4) **Parlama Noktası:** Sıcak yağın havada kıvılcım oluşturabileceği minimum sıcaklık noktasıdır. Parlama noktası trafoda yangın oluşma riskinin endeksidir. ASTM D 3487 standardına göre bu değerin 145 C olması gerekiyor.

5) **Göreceli Yoğunluk:** Yağın içinde barındırdığı su ile birlikte yoğunluğu yağ kalitesini izah eder.

6) **Renk ve Görsel Tespit**: Açık renkli trafo yağı kalite oranını gösterir. Koyu renk trafo yağ kalitesini azaldığının göstergesidir.

C) Elektriksel Yağ Testleri

1) **Kırılma Gerilimi: Dielektrik** dayanım olarak da bilinir. Yağın yüksek gerilime dayanımının endeksidir. Örneğin 288 kV altında çalışan bir trafonun minimum kırılma gerilimi 20 kV iken bu değerin üzerindeki trafo için yağın kırılma gerilimi 25 kV üstünde olmalıdır.

2) **Dielektrik Yayılma Faktörü:** güç katsayısı olarak da bilinir. Trafo yağının saflığını gösteren önemli bir endekstir. Yüksek gerilimin oluşturduğu enerji ısıya dönüşerek trafo yağı üzerinden yayılım yapar. Sağlıklı yağlarda bu değer 0.005 in altında olmalıdır. 0.005-0.001 arasındaki yağların filtre edilmesi gerekir. 25 EC standardına göre güç faktörü 0.01 üzerinde olan bir trafo yağının değişmesi gerekir.

3) **Özel Direnç:** Yağın elektriksel geçirgenliğinin göstergesidir. 1 santimetreküp yağın Ohm cinsinden direnci ölçülür. Doğru akım Meger cihazı ile bu değer tespit edilebilir. Yağ içerisinde iletken partiküller direnç değerini düşürür.

Elektrik güç trafolarının rutin kontrolleri yapılarak ileride oluşabilecek arıza ve hasarların erken teşhisi için ve oluşmuş arızaların sebebini belirlemede gaz analizleri de çok önemli bulgular verir. Çözünmüş gaz analizi (DGA olarak anılır), azot, oksijen, karbon monoksit, karbon dioksit, hidrojen, metan, etan, etilen ve asetilen gibi yağ içinde belli gazların konsantrasyonlarını belirlemek için kullanılır. Bu gazların konsantrasyonu ve nispi oranları, yağın bir fiziksel ya da kimyasal özelliğindeki değişikliği ile ilişkili olabilir ve transformatör ile belirli işletme sorunlarını teşhis etmek için kullanılabilir. Trafoyu servis dışına çıkarmadan yağ örneğinin alınabilmesi, DGA yöntemini üstün kılar. DGA yöntemi sayesinde arıza ve olayların gelişim süreci kontrollü şekilde izlenebilir.

Yağda Çözünmüş Gaz Analizleri (DGA)

DGA, 1970'li yıllarda, Westinghouse Electric Corporation, Analitik Associates gibi kuruluşlar tarafından yapılan kapsamlı araştırmalar sonucunda bir kestirimci bakım aracı olarak kabul edilmiştir. DGA 'nın genel prensibi şöyledir: yağ izoleli trafolar çalışma sırasında ısı, elektrik ve mekanik gerilimlerine maruz kalır. Bu gerilmeler sonucunda izolasyon yağının molekülleri aromatik, naftenik ve parafinik hidrokarbon karışımı parçacıklara bozunacak ve bu parçacıklar bir dizi kimyasal reaksiyondan geçerek yeni bileşenler ortaya çıkaracaktır. Gerilmelerin tipine, bulunduğu yere ve şiddetine bağlı olarak oluşan gazların miktar ve yapısı değişir. Yağ içinde gazlar – hidrojen (H_2), metan (CH_4), etan (C_2H_6), etilen (C_2H_4), asetilen (C_2H_2), propan (C_3H_8), propilen (C_3H_6), bütan (C_4H_{10}) ve butil (C_4H_9) - farklı konsantrasyonlarda yağ içerisinde çözünecektir. Kraft kâğıtları selülozdan üretilir ve trafo sargılarının yalıtımında kullanılırlar. Yüksek sıcaklıkta yanarlar. Bu reaksiyon sonucunda CO, CO_2 ve su ortaya çıkar. Bu gazların analizi ile trafolarda tedbirler, bakım, yenileme ve değiştirme yapılıp yapılmamasını belirlemek mümkündür.

DGA hassas ölçümler ve teşhis için genellikle laboratuvarda yapılır. Bir DGA analiz sürecinin aşamalarını aşağıdaki gibi özetlemek mümkündür:

- Transformatörden yağ numunesi alınması
- Yağdan gazları çekme
- Çekilen gazlarda nicel ve nitel analizler yapılması
- Analiz sonuçlarının yorumlanması

A) Yağ Numunesi Alınması

Doğru bir teşhis yapabilmek için yağ numunesini doğru bir şekilde almak gerekir. Bazı hususlar şöyledir:

- Numune alma cihazının temiz, kuru ve kapalı olması
- Numune kabından tüm havanın çekilmesi
- Sıcaklık, konum, seri numara gibi tüm bilgilerin tutanakları yazılması

B) Yağdan Gazları Çekme

Yağ numunesi, yanıcı gazları çekmek için bir vakuma tabi tutulur.

C) Çekilen Gazlarda Nicel ve Nitel analizler

Her bir gaz miktarı toplam mevcut gaz milyon (ppm) başına parça ya da yüzde olarak ölçülür. Gaz mevcut bu kalitatif ve kantitatif analiz trafosunun durumunun değerlendirilmesinde yararlı bir araçtır.

D) Analiz Sonuçlarının Yorumlanması

Bir DGA analiz sürecinin son aşaması ayıklanan gazların kalitatif ve kantitatif analiz sonucu yorumudur. Bu yöntemler ile saptanabilen arızalar termal ve elektrik arızaları halinde gruplandırılmıştır. Sıcaklık arızaları olduğunda, sıcaklık artışlarına göre hidrojen konsantrasyonlu bazı gazlar tespit edilir. Örneğin C2H2 gazı üst sıcaklıklarda tespit edilir. Elektriksel arızalar ise, örneğin elektrik deşarj ve yüksek yoğunluklu ark önemli miktarda asetilen üretebilir.

DGA Veri Yorumlama Yöntemleri

DGA yöntemler, genel olarak iki kategoriye ayrılır; orana dayalı olmayan yöntemler ve oran-dayalı yöntemler. Orana Dayalı Olmayan Yöntemler, Kılavuz Gaz ve Toplam Çözünmüş Yanıcı Gaz metotlarından oluşur. Orana Dayalı Yöntemler ise, hata tipini belirlemek için Table 4.4'de 1'de yer alan oranların uyumuna göre alt yöntemler içerir. Doernenburg Oranı, Rogers Oranları, Duval Üçgen yöntemleri bu sınıftadır.

Bu proje çalışmasında elektrik şalt sahalarında servis ekiplerinin elektrik güç trafolarından vakumlu şırıngalarla alacağı yağın çözünmüş ve serbest gaz analizlerinin sağlıklı yapılması önündeki en büyük engel olan laboratuvar ortamına gelinceye kadar meydana gelen bozulmaları tamamen ortadan kaldırabilecek ve doğrudan sahada analizlerini yapabilme yeteneğine sahip "Trafo Yağlarının Gerçek Zamanlı Analizi İçin Bir Ölçüm Sisteminin Geliştirilmesi ve İnsan Makine Arayüzü Tasarımı" geliştirilecektir. Böylelikle trafolarda arıza ve olayların gelişim süreci sahada kontrollü şekilde izlenebilecek ve erken uyarı mekanizmaları hazır hale getirilecektir.

Proje bünyesinde sensörlerle ölçüm değerleri alınan yağda çözünmüş ve serbest halde bulunan gazların oranları literatürde bilinen Duval üçgen, Rogers, Key Gas ve Doernenburg analiz yöntemleri ile önce yağ numunesinin sahada analiz edilmesiyle ve analiz sonuçlarının merkezi veri tabanına kaydedilerek uzaktan izleme ve değerlendirme arayüzü üzerinden paylaşılarak trafonun sürekli olarak izlenebilmesi ve meydana gelen arıza oluşumlarının daha erken safhalarda tespit edilebilmesi mümkün hale getirilecektir.

Geliştirilecek sistemin hâlihazırda olarak uygulanan trafo ve yağ bakım prosedürleri ve veri havuzu ile entegrasyonu açık hale getirilecek olup, sistemin master düzeyde bir trafo izleme sisteminin önemli bir parçası olma amacı kuvvetlendirilecektir. Projenin bu kapsamda başka ARGE projeleri oluşturabilme potansiyeli mevcuttur.

CHAPTER 1. INTRODUCTION

1.1. Background

The power transformers, due to their role in power generation and distribution system, are seen as the most critical and capital intensive asset whose failures may induce undesirable economic consequences due to the cost of property damage, repairs and the costs due to transmission service interruption. In order to minimize failures risks of these important assets, power utilities have long been applying maintenance activities which are carried out periodically. However this time-based maintenance (TBM) scheme is not optimal as it shows many drawbacks. This maintenance scheme does not eliminate the probability of catastrophic failures, some maintenance activities due the scheduling are performed when they are not required, which lead to extra expenses and risk of damaging material when performing this unnecessary maintenance activities. Therefore, there is a need to move from this model to a more efficient maintenance model. In these days of reduced operating budgets, power utilities have been applying condition based maintenance (CBM) models to maintain their transformers fleet. Condition based maintenance is a maintenance strategy that uses the actual condition of the asset to decide what maintenance needs to be done. CBM dictates that maintenance should only be performed when certain indicators show signs of decreasing performance or upcoming failure. One of the most important tools used in CBM models has been the dissolved gas in oil analysis. By analysing types of gas present in the insulating oil, their concentrations, and the rates of generation can be used to determine the condition of the transformer and requirements for maintenance.

1.2. Objective

The main objective of this work it to propose an online condition monitoring and diagnostic system for transformers insulating oil based on DGA techniques, which can enable real time analysis and help maintenance teams in taking critical decisions. The system to be proposed will try as much as possible to conform to the principles of condition based maintenance models.

1.3. Structure of the Work

This work is topically structured in the following parts:

- CHAPTER 2 reviews the theory of electrical transformers and the maintenance models of transformers

- CHAPTER 3 expands on transformers oil condition monitoring techniques

- CHAPTER 3 is a review of the principles of dissolved gas in analysis (DGA) and a survey of the different DGA methods.

- CHAPTER 5 gives the details for graphical implementations of some of the DGA methods

- CHAPTER 6 proposes a model of online condition monitoring and diagnostic of transformers insulating oil based on DGA

CHAPTER 2. TRANSFORMERS AND MAINTENANCE PROCEDURES

2.1. Introduction

Electrical Transformers have been around for more than on hundred years. For power utilities, Electrical transformers are considered critical assets due to their role in a power generation and distribution network, importance to everyday business as well as cost and lengthy lead time to replace. To have an insight of what these devices really are and how they function, this chapter will review the following elements:

- The principle of electromagnetic induction (Section 2.2.)
- The structure of transformers (Section 2.3.)
- The failure modes of transformers and maintenance models (Section 2.4.)

2.2. Electromagnetic Induction

In 1831, a series of experiments on the relation between electricity and magnetism conducted by Michael Faraday put in evidence the principle of electromagnetic induction. The test apparatus he set up for the experimentations [1] consisted of a continuous ring made of solid iron on the two opposite sides of which are wrapped two sets of copper wires - that we will call primary coil and secondary not connected to each other, and inter-wound with cotton wadding for insulation . He created a first circuit by connecting each end of the primary coil to a battery which supplied a DC current, and set up a second circuit separated from the first one by linking each end of the secondary coil to a galvanometer for current flowing detection. The complete equipment is illustrated in Figure 2.1.

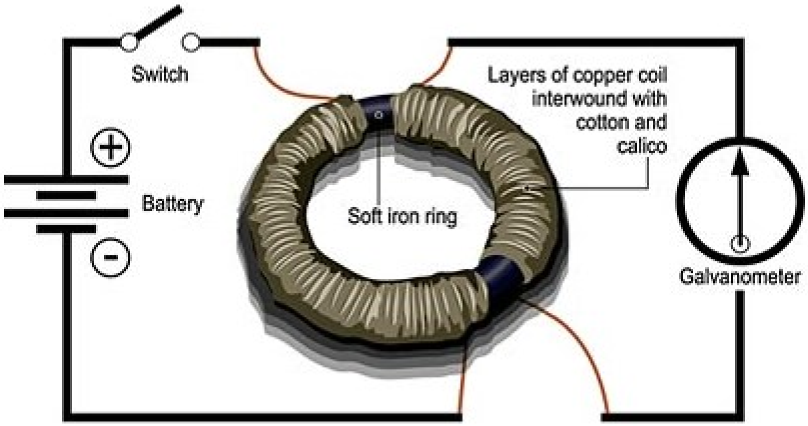

Figure 2.1. Faraday's equipment for the experimentations on the electromagnetism phenomenon.[1]

During the experimentations, Faraday alternatively opened and closed the first circuit formed by the battery and the primary coil. He noticed that when this circuit is opened, the needle of the galvanometer will oscillate for a short period of time which is an indication of an electrical current flowing through the second circuit. After this transient oscillation, the needle of the galvanometer would go back to its initial position. He further noticed a transient deviation of the needle, but in the opposite direction this time, whenever he opened the first circuit [2]. This is illustrated in Figure 2.2. The problem to solve was to determine how the current passed from the first circuit's coil to the second circuit's coil since both circuits were unconnected. What is happening that is taken place is that when the battery is turned on, the flow of electron through the first circuit will induce a magnetic field in the ring. The second circuit - which is closed and inside the induced magnetic field- consisting of the secondary coil and the galvanometer will have an induced current flowing through it whenever the first circuit is opened. This phenomenon just described is what is referred to as the electromagnetic induction. Even though the current flowing through the second circuit due to the electromagnetic induction during his experimentations was lasting a short period of time, and thus having no real practical application at that period, Faraday proved that electricity could be transmitted through space by electromagnetic induction. Electromagnetic induction is the founding principle on top of which transformer theory and application is built. Faraday's apparatus comprised all the necessary components for the construction of an electrical transformer namely a closed iron core and two unconnected coils, and is considered as the predecessor of current electrical transformers.

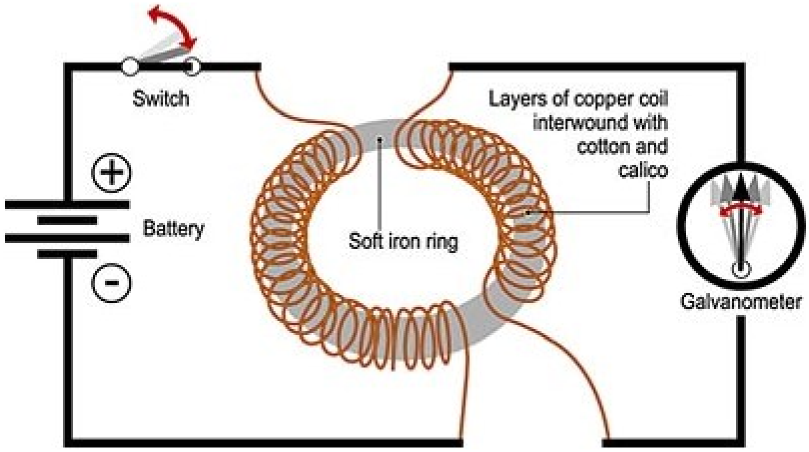

Figure 2.2. Deviation of the galvanometer's needle when the circuit is alternatively closed and opened. [1]

2.3. Transformers

2.3.1. Definition

A transformer, as defined by the ANSI/IEEE, is "a static electrical device, with no continuously moving part, used in electric power systems to transfer power between circuits through the use of electromagnetic induction"[3]. The power transfer between circuits via electromagnetic induction by transformers is done at the same frequency, but generally with change of voltage and current values[4].

2.3.2. Transformer components

A transformers is generally an assemblage of different components which serve different purposes. These components comprise a core, windings, an insulating system and set of auxiliary equipment.

2.3.2.1. Windings

Windings also referred to as coils are copper or aluminum conductors wound around a metallic core, and used as input and output of the transformer. Transformers have two windings. The first coil that produces magnetic flux when connected to an AC voltage source, is called primary winding. As for the second coil that the magnetic flux produced by the primary coil have linked, and supplies the energy at the transformed voltage to loads, it is known as the secondary coil. Adequate insulation and cooling mechanisms of the two windings is necessary for the windings to withstand the operational and testing conditions of transformers [3].

2.3.2.2. Core

It a closed magnetic circuit whose function is to provide a low reluctance path to the flux that links the primary coil to the secondary coil of the transformer. In order to maximize the transmitted flux, transformers cores are generally metallic structures made up of thin laminated steel sheets electrically separated by a thin coating of insulation material. This type of structures is also helpful for heat reduction and elimination [5]. Transformers cores are of two types:

- Core type: in this type, the windings are wound around the laminated core
- Shell type: here, the laminated core surround the windings.

The group formed by the core and the windings is called the active part, i.e. the part where the transformation of the energy effectively takes place.

2.3.2.3. Insulating system

The insulating system in transformers is of two kinds, the solid insulation system and the liquid insulation system. The solid insulation is made of cellulose-based material such as press board and paper, and its primary function is the insulation of the windings [3, 6]. For liquid insulation of transformers, mineral oils are the main type fluids used for the purpose. These insulating oils have two functions. First and foremost, they provide an insulating medium that surrounds different energized conductors; and a coating that protects the metal areas within the transformer against chemical reactions such as oxidation that can affect the transformer’s integrity [3] . Last but not the least, the insulating oils have the function of heat dissipater. Heat dissipation is crucial for transformers where heating of windings and core can be very serious. Insulating oils transfer heat from these components to the surrounding environment using conduction, convection and radiation.

2.3.2.4. Ancillary equipment

The auxiliary equipment [4] refer to equipment whose role is to guarantee the survival and the proper operational process of transformers in the field. Depending on their types and their applications, transformers are equipped with various types of auxiliary equipment. We describe below some of the most common of ancillary devices found on transformers.

a. Tank

The tank serves as a container for the active part and the insulating system. It protects them from dirt, mechanical damages and environmental stresses such corrosive atmosphere and sun radiation [6].

b. Bushings

The purpose of transformers bushings is connecting the leads of the active part of transformers, enclosed in the tank and producing the electrical power, to the rest of the electrical system. Bushings are structures generally consisting of a direct conductor or a passage for such a conductor, and provision where the tank can be mounted [3]. They are equipped with an insulating system, most often consisting of oil-impregnated kraft paper, to insulate and isolate the leads from each other and from the tank since the leads are energized at line voltage [3].

c. Oil preservation system

The oil preservation system has as goal the protection of the insulating oil from contaminants that affect the dielectric properties of the oil, and thus making it useless as insulating medium. The most common preservation system types include sealed-tank, conservator, gas-oil-seal and inertaire types [4].

d. Cooling system

The transformer cooling system -- generally consisting of equipment such as cooling fans, oil pumps or water-cooled heat exchangers – is a critical component as far as the transformer life expectancy and its performance are concerned [3, 4, 6]. Indeed, the cooling system prevent transformers overheating by dispatching the heat due to copper and iron losses to the surrounding environment.

e. Temperature, Oil level, and Pressure Gauges

Temperature controls are important in the activation or deactivation of the cooling system and in practice, they consist of gauges for windings temperature and top oil temperature measurement [4]. The difference between these two temperatures provides an information on how heavily the transformer is loaded.

Oil level controllers are also important equipment in transformers. Transformers in which the insulating oil is not at the proper level are exposed to overheating risks if the oil level is too low, or they can experience over pressurization if the oil is too high. The oil level controlling system consists of a gauge with a mark that shows the proper level of oil at 25°C.

Pressure controls are of the utmost importance in transformers with as gas blanket over the oil. In these transformers, the pressure in the sealed tank should be slightly positive or negative. A zero pressure indicated by the pressure measurement system is an indication of the “breathing” of the transformers, breathing that might have led to its contamination.

f. Tap changing equipment

This is one of the most complex and most important component of electrical networks and industry. It enables the regulation of the voltage level of transformers, while on-load or deenergized, by adding turns to or subtracting turns from either the primary or the secondary winding [3].

2.3.3. Working principle of transformers

First of all, it is worth mentioning that transformers do not produce electrical power, they transfer electrical power through electromagnetic induction from one AC circuit to another one. The alternating current that flows in the primary winding when an input AC voltage is applied to it creates a varying magnetic field that flows in the transformer's core. This time varying magnetic field, which through the coil will link the secondary winding, according to Faraday's law of electromagnetic induction will induce in the secondary winding an alternating output electromagnetic force. The value of the output voltage is a function of the ratio between the actual number of wire turns in the primary winding and in the secondary winding. The ratio of the input voltage to the output voltage is equal to the ratio of the number of winding turns in the primary coil to number of winding turns in the secondary coil. Equation
(5.12) summarizes the previous statement.

$$\frac{N_1}{N_2} = \frac{V_1}{V_2} \tag{2.1}$$

Where,
N_1 = number of turns in the primary coil of the transformer,
N_2 = number of turns in the secondary coil of the transformer,
V_1 = input voltage at the primary coil of the transformer,
V_2 = output voltage at the secondary coil of the transformer.

2.3.4. Classification of transformers

The classification of transformers can be done in various ways when considering certain parameters of transformers. The following sections will review some of the features of transformers taken into account for their classification.

2.3.4.1. Design of transformers

According to this criterion [7 – 9], transformers are classified into two main categories, namely core type transformers and shell type transformers. In shell type transformers, there is a double magnetic circuit. The core, which encircles the primary and the secondary coils, has three legs with the two coils wound around the central leg. In contrast to shell type transformers, core type ones have a single magnetic circuit. The core has two legs around each of which the primary and the secondary coils are wound in helical layers insulated from each other by insulating material as mica [7]. Core type and shell type transformers are illustrated in Figure 2.3 .

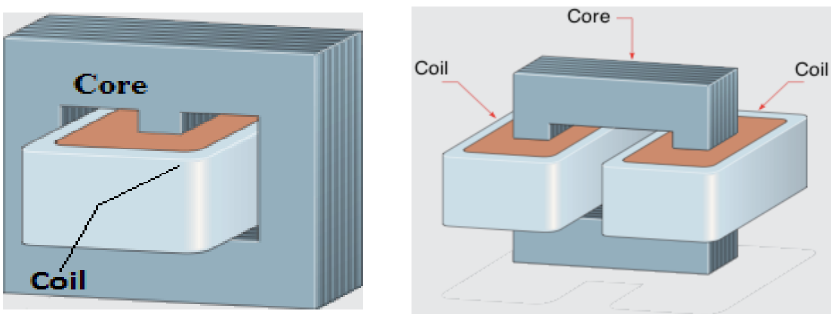

Figure 2.3. Structures of Shell type transformers (left) and core type transformers (right) [7].

2.3.4.2. Number of phases

When the number of phases in transformers comes into play, transformers are grouped into single-phase transformers and three-phase transformers. devices such as residential lightning, receptacle, air-condition and heating needs are main loads supplied by single-phase transformers [5]. The active part of a single-phase transformer consist of just the two isolated windings wound around the same magnetic core. As for three-phase transformers, they are mainly used for electrical power generation, transmission, and distribution. They can be constructed by connecting three single-phase transformers, or can come as a single three-phase transformer. Both designs have their advantages and limitations. A single three-phase transformer is approximatively 15% cheaper and occupies less space than a unit consisting of a bank of three single-phase transformers. However, due to the limitations in manufacturing and transporting a single three-phase transformer, the other design must be sometimes adopted [8].

2.3.4.3. Insulation system

With regards to the insulation system, transformers are grouped into two main categories, dry-type transformers and liquid-filled transformers. Transformers qualified as dry-type are those whose the insulating medium surrounding the coils is a gas or a dry compound [3]. As for the liquid-filled transformers, the insulation function is accomplished by a liquid which for most transformers of this category is mineral oil. Other types of liquids used in these transformers include silicone-based or fluorinated hydrocarbons and natural esters [3].

2.3.4.4. Purpose

Transformers are used to increase or decrease the voltage level (with a subsequent decrease or increase of the current) at the secondary winding. Transformers that decrease the voltage level are termed as step down transformers, and those that increase the voltage level are called step up transformers.

2.3.4.5. Application

This is one of the most practical parameters considered by practitioners for transformers classification. As far as transformers applications are concerned, transformers can be of power transformers, distribution transformers, and instrument transformers [8].

Power transformers [10] are found distribution networks, substations, industries etc., and they are also used as interconnection between two power systems. Because they can step up and step down the voltage level depending on the requirements, power transformers are utilized in transmission systems for the reduction of copper losses in transmission line by increasing the voltage level and reducing the current flow. In industries, the reason of their use is to supply loads at their voltage rates.

Distribution transformers are those that take voltage from a primary distribution circuit and reduce that voltage's level to a secondary distribution circuit or a consumer's service circuit [3]. They are used by power utilities at the end of the electrical energy delivery system to supply relatively small amount of power to residences [5].

Instrument transformers provide an isolation medium between the main primary circuit and the secondary control and measuring devices [3]. There are two groups of instrument transformers, namely current transformers and potential transformers. Current transformers are used with an ammeter to measure current in AC voltages, and potential transformers are used with a voltmeter to measure voltages in AC.

2.4. Failure Modes and Maintenance of Transformers

Transformers are amongst the most important components in an electrical power distribution system, and their share in the investment of power utilities is significant. Thus, assuring that these major components of their power systems will operate without experiencing failures is paramount to power utilities for failures of these devices can result in critical economic consequences in terms of unit repair and replacement and operational constraints [11]. Transformers in service experience electrical, mechanical and thermal stress that affect their life expectancy. In the same way, environmental and climatic conditions are factors that can precipitate the failures of transformers. In order to prevent transformers failures [4], power utilities have developed maintenance methods that over time have proven very effective in prolonging equipment life. In the following sections, we will review the failure mechanisms of transformers and the corresponding maintenance activities associated with them.

2.4.1. Transformers failure modes

The manner a component, process, or system fails, usually in terms of how the failure is perceived as opposed to how the failure is caused, is called a failure mode [11]. Transformers have different failure modes, and the common result of these failure modes is an outage of the power system. The following subsections will be presenting power transformers failure modes and their mechanisms.

2.4.1.1. Insulation degradation

Insulation degradation [11] of transformers in service are usually the result of high thermal and electrical stresses undergone by transformers. Insulation media, mostly mineral oil and paper in oil-immersed transformers deteriorate under thermal or electrical stresses of operating transformers. The consequences from this insulation degradation are problems such as short circuit within the transformers, extra heating, or partial discharge or arcing between different surfaces, problems which can necessitate the removal of the transformer from service, and in the worst case, they can result in damage to the transformer.

2.4.1.2. Winding failure

Lightning, overload and shot-circuits [11] are some of the main causes of winding failures. Overload and short-circuit can cause windings overheating that can damage the windings. Lightning combined to short-circuit may engender winding displacement, distortion and vibrations.

2.4.1.3. LTC failure

Load tap changers [11] (LTC) have a high failure rate, even though the consequences associated with their failure for transformers are often not dramatic. The main causes of LTC failure are for the most part wrong position of tap which can generate excessive core loss resulting in excessive overheating, and also contact coking which increases contact resistance which will finally lead to heat increase and carbon buildup of carbon.

2.4.1.4. Partial discharge

A partial discharge (PD) [11] is an electrical discharge that appears across a specific area of the insulation between two conductors, but does not completely bridge the gap between the conductors. The causes of a partial discharge might be a transient over-voltage, a weakness in the insulation system introduced during manufacturing, or the degradation of the transformer over its service life. The consequences of a partial discharge, particularly in oil-immersed transformers, include the following: bad contacts, floating components, suspended particles, protrusions, rolling particles, and surface discharges, deterioration of the insulation.

2.4.1.5. Bushing failure

Bushings [11] face high electrical and mechanical stresses the might cause a combination of bushings cracking, corrosion, wear and contamination. Failure modes of bushings are serious issues for transformers health since they can be at the origin of flashovers, short-circuits that will lead to transformers outages, or even they may lead to even more serious damages such as tank rupture, explosion and fire.

2.4.1.6. Other failure modes

Even though the failure modes of this category do not often occur, they may as well be damageable to transformers. A failure mode of this category is loss of sealing [11] that may cause insulation problem as well as pollution of the environment. In the same order, the blocking of pressure relief equipment might cause the accumulation of combustible gases in the transformer tank, which will lead to an explosion [11].

2.4.2. Maintenance activities of transformers

Transformers maintenance has as objective the control of factors which speed up the aging of transformers as well as the detection and the correction any electrical, thermal and mechanical failure mode that might affect the operation of transformers [3]. Maintenance activities are grouped under two categories, namely preventive maintenance activities and predictive maintenance activities.

Preventive maintenance activities are those whose purpose is to protect transformers components from aging and wearing out, or to restore or replace worn component before their failure. These activities are performed periodically, or on a specific timetable depending on the component failure modes history [4].

Predictive maintenance activities, commonly referred to as testing, are carried out with the purpose of detecting aging or aging in transformers components so that preventive maintenance activities can be applied on the components before the occurrence of a failure [4].

2.4.2.1. Preventive maintenance activities

When referring to preventive maintenance activities, two important sets of activities are involved. The first set of activities is concerned with those related to the insulation improvement [6]. The activities carried out here are oil filtering and degasification whose purposes are:

- The removal Oxygen and other gases from transformer or LTC oil.
- The reduction of acid and moisture contents in the transformer or LTC oil
- The Metal or other particles in the oil.

The other set of activities are concerned with the overhaul, repair, or replacement of any worn component of a transformer. This activities are collectively termed as mechanical maintenance [11]. Mechanical maintenance include the following activities:

- Bushing repair and cleaning
- Transformer rewinding
- Repair or replacement of the heat exchanging devices such as fans, radiators and pumps
- Inspect and repair the pressure relief blocking.

2.4.2.2. Predictive maintenance activities

Predictive maintenance or testing of transformers equipment includes activities satisfying some specific requirements. These requirements are [4]:

- Sensitivity: early warning of future trouble should be given
- Selectivity: real troubles and false positive should be clearly identified
- Practicality: performing the test and interpreting the results should neither require an uncommon skill level nor an unusual set of test apparatus.
- Non-destructiveness: the test should not the transformers equipment.

Failure prevention, maintenance support, life assessment, optimized operation, commission verification tests, failure analysis, operational status of transformers monitoring, personnel safety and environment safety [6] in general are the benefits from the application of preventive maintenance activities. Predictive maintenance often include the following activities [3, 6, 11]:

- Operating condition monitoring Transformer
- Temperature monitoring
- Dissolved gas-in-oil analysis
- Moisture-in-oil monitoring
- Insulating oil Power Factor Testing

- Measurement of Degree of Polymerization the solid insulation
- Partial discharge monitoring.

In general, the application of preventive or predictive maintenance activities is in accordance with the different failure modes of transformers. Table 2.1 summarizes maintenance activities (predictive and preventive) associated with each failure mode.

Table 2.1. Failure modes of transformers and associated maintenance activities

Failure mode	Predictive maintenance	Preventive maintenance
Cellulose insulation degradation	Degree of polymerisation, fluid analysis	N/A
Oil decomposition	DGA, fluid analysis	Oil refinement (filtering, degasification)
LTC failure	DGA, internal inspection	Oil refinement, replacement of damage part
Partial discharge	Partial discharge monitoring, DGA	Overhaul after the partial discharge has been located
Bushing failure	Power factor test, visual inspection	Replacement, cleaning and greasing
Loss of sealing	Visual inspection	Repair, replacement
Pressure relief blocking	Visual inspection	Repair the blocked relief device

2.5. Summary

In this chapter we saw what transformers are, their structure and the fundamental principle of their operating process. We reviewed the classification of transformers. The importance of these devices in a power system has been spoken of, and the criticality of the types of maintenance activities were analyzed.

CHAPTER 3. TRANSFORMERS OILS CONDITION MONITORING

3.1. Introduction

The vast majority of load-bearing transformers in electric power delivery systems are liquid-immersed. The liquid used in these transformers, which is mostly mineral oil, has two functions, namely the insulation of the active part of the transformer and the heat dissipation [12]. The capability of these transformers to operate reliably and efficiently over many years can be economically advantageous for power utilities. The Council on Large Electric System (CIGRE) conducted a research to determine the main causes of power transformers failures, results of which are shown in Figure 3.1. Another survey with the similar objective has been directed from 1975 to 1998 by Hartford Steam Boiler (HSB). The results of the survey are summarized in Table 3.1. Even though the parameters considered by these two studies were not all the same, both agreed on the fact that deterioration of the insulating oil is one of the main causes of transformers breakdown. Thus quality of this oil is primordial not only to the reliable and efficient operation of transformers, but also to their life expectancy. Therefore regular transformers oil condition monitoring and assessment is of the utmost importance in the management of these critical assets that transformers represent in electrical power distribution and transmission systems. This chapter will be reviewing the following elements:

- The types of transformer oils (Section 3.2.)
- The functions of transformers oils (Section 3.3.)
- Factors of Transformer oils degradation (Section 3.3.)
- Different tests of transformers oil (Section 3.4.)

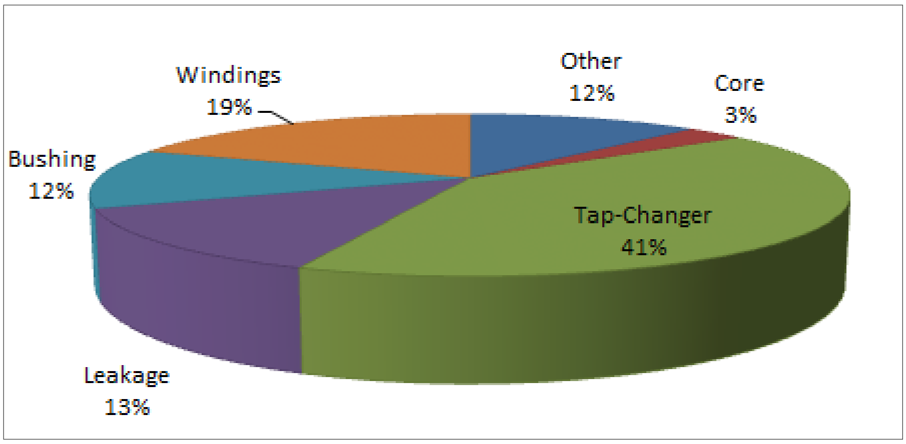

Figure 3.1. Causes of power transformers failure [13]

Table 3.1. Root causes of power transformers failure as reported by HSB [14].

Failure causes	1975	1983	1998
Lightning surges	32.3%	30.2%	12.4%
Line surges /External short circuit	13.6%	18.6%	21.5%
Poor Workmanship/Manufacturer	10.3%	7.2%	2.9%
Deterioration of Insulation	10.4%	8.7%	13%
Overloading	7.7%	3.2%	2.4%
Moisture	7.2%	6.9%	6.3%
Inadequate Maintenance	6.6%	13.1%	11.3%
Sabotage and Malicious Mischief	2.6%	1.7%	0%
Loose Connections	2.1%	2.0%	6%
All others	6.9%	8.4%	24.2%

3.2. Types of Transformer Oils

Transformer oils are obtained from the refinement of a fraction of the hydrocarbons collected during the distillation process of a petroleum crude stock [12]. As the crude oils from which they are produced, transformer oils are complex mixtures of many hydrocarbon molecules whose types, structures and relative amounts can vary with respect to the origins of crude oils [12], [15]. In general, three classes of hydrocarbon molecules are found in transformers oils, namely paraffinic, naphthenic and aromatic hydrocarbons.

3.2.1.Paraffinic oils

The term paraffinic refers to carbon atoms bonded to one another in straight chains and thus called alkanes, wax or n-paraffin; auto or arranged in branched chains and thus referred to as isoparaffin [3, 12, 15]. Paraffinic based oils have low oxidation rate, but are poor solvent and thus cannot quickly dissolve oxidation byproducts such water and acid [15]. This inability to dissolve quickly oxidation byproducts leads to a high rate of sludge formation, sludge which will be precipitated to the bottom of the oil thus impeding circulation of the oil and therefore disrupting the transformer cooling mechanism[16]. The circulation of paraffinic based oils is also obstructed by low temperatures due to the richness of these type of oils in wax. Despite all these drawbacks, paraffinic based oils are still in use in many countries, especially in countries with warm climate conditions, due to their easy availability.

3.2.2.Naphthenic oils

In naphthenic structures, also known as cyclo alkanes, carbon atoms are joined to one another to form cyclic structures of generally 5, 6, or 7 carbons [3, 15]. Naphthenic based oils, unlike paraffinic oils, have high oxidation rate, but oxidation byproducts of naphthenic oils are more soluble than the ones of paraffinic oils. The sludge from the oxidation is not precipitated to the end of the oil, which means that it does not obstruct the circulation of the oil and consequently the cooling mechanism is not affected [16]. It's preferable to use naphthenic based oils in cold regions for naphthenic oils have lower pour point than paraffinic oils, and there is almost no wax formation in low temperature conditions.

3.2.3.Aromatic oils

Aromatic hydrocarbons are present in every insulating oil. Aromatic compound – which physical and chemical properties are very different from those of paraffinic and naphthenic hydrocarbons - have carbon atoms bonded as ring of benzene [3,15]. Aromatic hydrocarbons with only one ring called mono-aromatic hydrocarbons contain only discrete benzene ring structures (e.g., methyl benzene-"toluene," biphenyl); those with two or more rings called poly-aromatic hydrocarbons contain two or more benzene rings fused together (e.g. naphthalene, anthracene) [12]. Aromatic based oils are good solvent, however their utilization is noxious [15].

Paraffinic, naphthenic and aromatic hydrocarbons configurations alongside a typical oil molecule configuration are illustrated in Figure 3.2. and Figure 3.3.

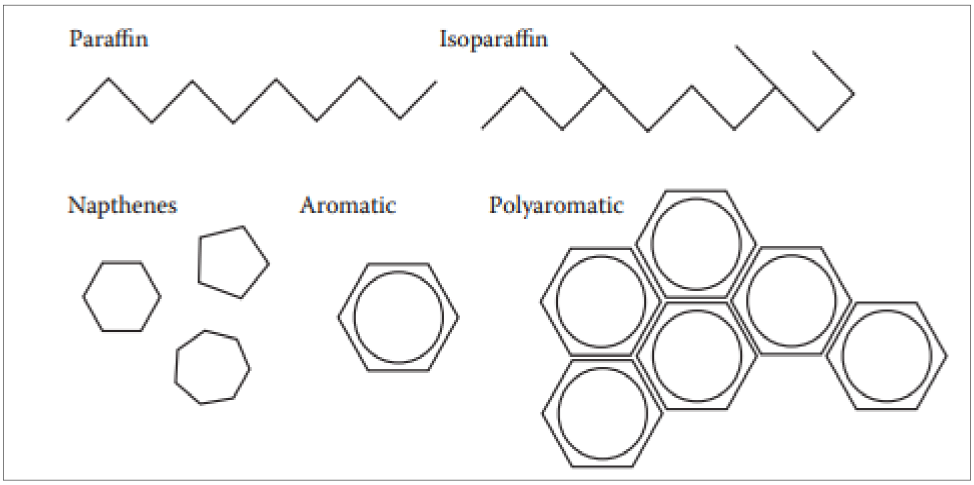

Figure 3.2. Carbon configuration in oil molecules [3].

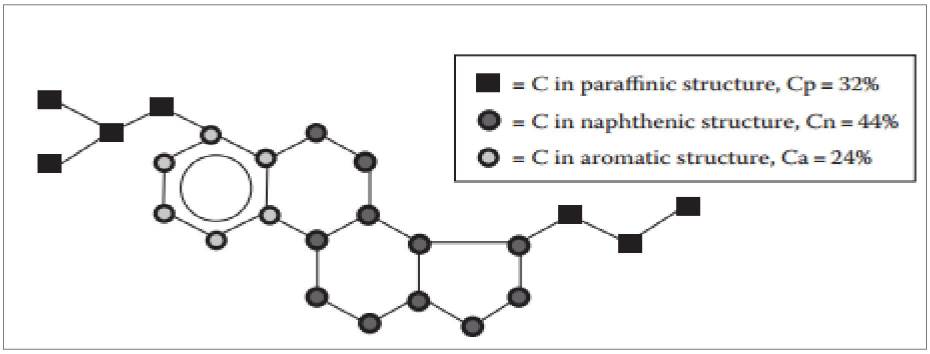

Figure 3.3. Typical oil molecule [3]

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3.3. Functions of Transformer Oils

3.3.1.Electrical insulation

Transformer oils first and foremost function is the provision of a liquid insulating medium surrounding various energized conductors. Alongside [3] providing insulation to energized parts of transformers, they also offer to metal surfaces within transformers a protective layer against chemical reactions such as oxidation which affects the integrity of connections as well as the formation of rust whose contribution is significant in the system contamination.

3.3.2.Heat dissipation

Heat removal is an important concern in operating transformers. Transformer oils acts as a heat dissipater from areas such as windings and core, where localized heating can be very serious, by distributing the heat over a large mass of oil and the transformer's tank [3]. The heat from the oil can be dispatched to the surrounding environment by means of convection, conduction, or radiation.

3.3.3.Diagnostic purposes

In-service transformers experience electrical and thermal stresses such as discharges and overheating. During these events, there is formation of certain gases that will dissolve readily in the oil. The qualitative and quantitative analysis of the dissolved gas in oil can give important information about the nature and the severity of the fault that happened. In that sense, transformer oils serve as an indicator of the health of the operating transformer.

3.4. Factors Affecting Transformer Oil Degradation

3.4.1. Excessive heat

Heat plays an important role in the degradation of the solid insulation as well as in that of the insulating oil. Excessive heat can be at the origin of the decomposition of the oil and/or can increase its oxidation rate of the oil [17]. In fact, oil degradation reactions rates double for every temperature rise of 10°C [3].

3.4.2. Oxidation

Also known as aging, oxidation is the most common cause of the degradation of the insulating oil [3, 17]. It is due to the abundance in the atmosphere of oxygen which the main reactant of the oxidation reaction, reaction that will generate in the oil products such as carbon dioxide, water, alcohols, aldehydes, ketones, acids [3].

3.4.3. Moisture

Moisture is the main contaminant of the insulating oil, it contains products that can react with the oil when there is sufficient heat[17]. One of the major consequences of moisture in oil it weakens the dielectric strength of the oil[17].

3.4.4. Acids

Sludge is a solid product of complex chemical composition whose formation can be due high levels of acid in oil (greater than 0.6 mg KOH/g of oil) in the oil. Sludge deposition throughout the transformer is harmful for the transformer for this greatly and adversely affect heat dissipation and ultimately result in equipment failure [3].

3.4.5. Corona discharges

Insulating oil molecules can break down due to corona discharges. As result of these reactions, products such as water and gases will be produced which ultimately can engender the formation of acids and sludge in the oil [17].

3.5. Transformer Oil Tests

Transformer oils deteriorate, as seen in section 3.4. because of factors such as excessive heat, moisture, etc.…, or while aging they lose their properties, and consequently will not be able to fulfill efficiently their functions [15]. These transformer oils will not only have their dielectric strength weakened which will affect their electrical insulation capability, but also their can damage the metal surfaces with which they are in contact. For these reasons, it is important to periodically monitor and assess the condition of the insulating oils in order to have transformers that can regularly operate in a secured and productive way but also can operate over many years.

Generally, two groups of tests are apply to transformer oils to monitor and assess their conditions. The first group of tests which includes series of electrical, chemical and physical tests, is concerned with the determination of the levels of contamination, deterioration and aging of the insulating oil. As for the second group of tests will try to discover incipient faults by performing quantitative and qualitative analyses of dissolved gases in the oil. The following subsections will review routine tests, and the dissolved gas-in-oil analysis methods will be the subject of the next chapter.

3.5.1. Oil chemical tests

3.5.1.1. Water content

This is performed in laboratory on a sample of the insulating oil from the transformer to measure the moisture level of the sample with the sample temperature and the winding temperature of the transformer [3]. High level of water content in oil is undesirable as it not only dielectric breakdown strength of the oil [18], but also accelerates the degradation process of the paper insulation [4].

3.5.1.2. Neutralization number (NN)

Neutralization number (also known as acid number) is the amount of potassium hydroxide (KOH) in milligrams (mg) that is required for the neutralization of the acid in 1 gram (gm) of transformer oil [19]. The more the oil contain, acid the higher the acid number. The presence of acids in oil is not good for transformers as acid attack metals inside the tank, cellulose, accelerate winding paper insulation degradation and the formation of sludge [16, 19]. The recommendation for the maximum acid number is 0.20 mg KOH/gm before the reclamation of the oil.

3.5.1.3. Corrosive sulphur

This test is carried out to detect the presence of undesirable quantities of elemental sulfur and thermally unstable sulfur-beating particles in an oil [18]. Black sulfide coating on copper and silver areas can sometimes be considered as signs of corrosive sulfur in transformers, and when detected, corrosive sulfur can cause corrodes certain transformer metals like copper, iron, aluminum. Electrical discharges appearance probabilities are increased, thereby the accumulation of metallic sulfurs from these corrosions on solid insulation components and conductors.

3.5.1.4. Sludge content

The oxidation process of the insulating oil, which is facilitated by factors as contact of the oil with the oxygen or temperature increase, is a process that can last many years. During this process, there is degradation of the insulating oil itself as well as that of the paper insulation of the windings [15], degradation at the end of which sludge among other products will be formed. Sludge is harmful for the transformer for it will accumulate at the windings other electrical part of the transformer thus causing electrical breakdown of the insulation system. By measuring the sludge amount, it is possible to determine the level of degradation of the insulation system.

3.5.2.Oil physical tests

3.5.2.1. Viscosity

The viscosity of a fluid is the internal resistance to its flow. The viscosity of the insulating oil is an important parameter in its function of heat dissipation. This property of the insulating oil is inversely proportional to the oil's temperature; it increases when the temperature decreases [20]. However is important for the viscosity not to increase at low temperature. As recommended by IEC-60286 [18], which has categorized insulating oils in three classes, the maximum value for the viscosity at 40°C is 16cSt for oils of class I, 11cSt for oils of class II, and 3,5 for those of class III.

3.5.2.2. Interfacial tension (IFT)

The interfacial tension (IFT) of an oil is the force in millinewtons per meter needed for the rupture of the oil surface existing at an oil-water interface [12]. The IFT gives an indication about the degree of refining and contamination of new oils, and also help in the evaluation of the quality of the oil on in-service transformers [18, 21]. A high value for new mineral insulating oil is an indication of the absence of objectionable contaminant. The IFT will decrease as the oil gets contaminated by substances such as metal soaps, paints, varnishes, or oxidation byproducts. ASTM 3487 standard [21] recommends a minimum value of 40 Millinewtons/m as acceptable IFT.

3.5.2.3. Pour point

The pour point is the lowest temperature at which oil flow is possible. The pour point test is carried out by determining the temperature below which the oil flow is no more possible when the container in which the oil has been cooled is tilted [18]. A low pour point is desirable especially in cold regions as it ensures the flowing of oil which can then accomplish its roles of insulator and heat dissipater [18]. As specified by ASTM D 3487 standard [21], -40°C is recommended as pour point value.

3.5.2.4. Flash point

The flash point is the minimum temperature at which heated oil generates vapor that can form a ignitable mixture with air [18]. A high flashpoint is desirable as it prevents the risk of fire in the transformer. The flashpoint test is usually performed to service-aged oils to determine their level of deterioration. The recommended value for flashpoint are 145°C according to ASTM D 3487 standard [18].

3.5.2.5. Relative Density (Specific Gravity)

The relative density of an oil is the ratio of the weights of equal volumes of oil and water determined under specific condition [18]. The heat transfer rates of the insulating oil are affected by its relative density [21], and this parameter may be of pertinence in determining the suitability of the use of the oil for particular applications [18]. ASTM D 3487 recommends 0.5 as the maximum color number for oils suitable to use.

3.5.2.6. Colour and visual inspection

The color of a new oil is an evaluation method of the degree of refinement. Deteriorating oil in-service will usually have an increasing or high color number [18], [21]. A low color number is an essential requirement for visual inspection of transformer components in the tanks as this is well performed if the oil has a clear color [18].

3.5.3. Oil electrical tests

3.5.3.1. Breakdown voltage

Transformer oil breakdown voltage (also known as dielectric strength) test determines the oil's capability to withstand electric stress without failing [22], to be more precise the maximum voltage the oil can withstand before losing its insulating capability. As specified in [22], oils used in transformers rated less than 288 KV should have a minimum breakdown voltage of 20KV and 25KV for transformers rated 287.5KV and above. If a dielectric test is not satisfactory, it is a sign of moisture and may be other conducting particles in the oil, and therefore the oil should be reclaimed [23].

3.5.3.2. Dielectric dissipation factor

The dielectric dissipation factor (also known as power factor) measures the dielectric losses in the insulating oil when used in an alternating electric field and the energy dissipated as heat ; it is useful in oil quality control, can be a good indicator of changes in quality coming from contamination and deterioration in service [24].Generally, deterioration and/or contamination from byproducts such as water, carbon, or other conducting particles will cause high dielectric losses and this will be translated by a high dielectric dissipation factor [19]. The recommendation [19] for power factor values is as follows:

- Oils with power factor below 0.005 are considered in good condition;
- Oils with power factor between 0.005 and 0.01 need more investigation. Oil replacement or filtering might be required;
- When power factor is greater than 0.01 at 25 EC, failure of the transformer due to oil might happen; immediate replacement or reclaiming of the oil is necessary.
- Above 2%, oil should be removed from service and replaced because equipment failure is imminent. The oil cannot be reclaimed.

3.5.3.3. Specific resistance

Specific resistance also called resistivity is, as defined in [25], the ratio of the 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. It is numerically equal [25] to the resistance between opposite faces of a centimeter cube of the liquid and it is measure in ohm-centimeters. When applied to the insulating oil, the resistivity designates a measure of its electrical insulating properties under conditions similar to those of the test; high resistivity is desirable since it indicates low content of free ions and ion-forming particles which means a low concentration of conductive contaminants [25].

CHAPTER 4. DISSOLVED GAS-IN-OIL ANALYSIS

4.1. Introduction

Mineral oil, in addition to cellulose, has been used as insulating in power transformers for their insulating and cooling functionality. However, this oil, while generating amounts of gases which dissolve in it, steadily deteriorates due abnormal electrical and mechanical stresses to which power transformers are subject. The natures and quantities of generated gases are indicative of fault types in the transformers. The health of the oil is reflective of the health of the transformer itself. Dissolved Gas in oil analysis (DGA) has proven to be a valuable tool to power utilities in assessing the condition of the insulating oil and thus for detecting incipient faults in power transformers. It is of primary importance in indicating an existing problem in the transformer and can identify deteriorating insulation and oil, overheating, hot spots, partial discharge, and arcing [19]. Standards-compliant DGA methods have been developed for the interpretation of DGA data. In this chapter, the following element will be reviewed:

- The general principle of DGA (4.2.)
- The DGA process (4.3.)
- DGA data interpretation methods (4.4.)

4.2. General Principle of DGA

In the 1970s, DGA was adopted as a predictive maintenance tool in result of extensive researches done by organizations such as Westinghouse Electric Corporation, Analytical Associates, Inc. [4]. The general principle that lays the foundations for DGA is described in [3, 4, 15] as follows: oil-insulated transformers during their operations are exposed to thermal, electrical, and mechanical stresses. Molecules of the insulating oil which is a complex mixture of aromatic, naphthenic and paraffinic hydrocarbon, will break down into particles at the end of these stresses. These particles undergo a series of chemical reactions to bring out new components among which are different type of gases. This whole process is referred to as the cracking process. Depending on where the stresses took place, their severity and their type, the natures and quantities of formed gases will vary. When transformers insulating oil molecules experience cracking, gases formed –which are for the most part hydrogen (H_2), methane (CH_4), ethane (C_2H_6), ethylene (C_2H_4), acetylene (C_2H_2), propane (C_3H_8), propylene (C_3H_6), butane (C_4H_{10}) and butyl ($-C_4H_9$) – will quickly dissolve in the insulating oil in different concentrations. The kraft paper materials made up of cellulose and used as insulation for transformer windings, will deteriorate at high temperatures because oxidation of the cellulose. The gaseous byproducts of this reaction will comprise carbon dioxide (CO_2), carbon monoxide (CO) and water By sampling the transformer oil and performing a qualitative and a quantitative analysis of dissolved gas in oil using gas chromatography, it is possible to determine the kind of fault transformers might have undergone, thus allowing appropriate measures to be taken for transformers maintenance, reconditioning or replacement.

4.3. DGA Process

DGA is usually performed in laboratory for accurate measurements and diagnostics. The steps of a DGA analysis process can be summarize as follows [6]:

- Oil Sampling from the transformer
- Gases extraction from the oil
- Quantitative and qualitative analysis of the extracted gases
- Interpretation of the results of the analysis

4.3.1.Oil sampling

The sampling process must collect valid samples of the oil in order to get an accurate diagnostic. The recommended steps for samples collection include the following elements [3]:

- Eliminate any risk of entrance of external atmosphere by verifying positive oil head pressure at sample location

- Flush sample location, sampling lines, and collection syringe to get representative sample
- New sampling must be used lines for each compartment or piece of equipment
- Sampling devices must be clean, dry and sealed
- All air from sample vessel should be removed
- Typically 30 mL samples are required for analysis
- Plated or galvanized fittings likely to produce gases as the result of chemical reaction should be used
- Record all the information related to the sampling task such as serial number, sample location, sample temperature, and equipment identification.

4.3.2. Gases extraction

The oil sample is subjected to a vacuum to remove the combustible gases [26]. A gas chromatograph is used for the determination of the types and quantities of gases present.

4.3.3. Qualitative and quantitative analysis of extracted gases

At this step, the focus is given to the analysis of the quantities of different fault gases. A partial list of fault gases that can be found within a sample of oil is shown in the following three groups [27]:

- Hydrocarbons and hydrogen : H_2, CH_4, C_2H_6, C_2H_4, C_2H_2
- Carbon oxides: CO, CO_2
- Non-fault gases: N_2, O_2

The quantity of each gas is measured in part per million (ppm) or percent of the total gas present. This qualitative and quantitative analysis of gas present is a useful tool in the assessment of the condition of the transformer.

4.3.4. Interpretation of the analysis

The final step of a DGA analysis process is the interpretation of the result of the qualitative and quantitative analysis of the extracted gases. If the quantities of fault gases are suspicious, various types of interpretation methods will be applied to the DGA data to try to figure out the kind of fault experienced by the transformer. Faults detectable by these methods are grouped into thermal faults and electrical faults [28].

4.3.4.1. Thermal faults

Relatively large quantities of the low molecular weight gases, such as H_2 and CH_4 are generated due to decomposition of mineral oil under the effect of temperatures ranging from 150 °C to 500 °C and higher molecular weight gases C_2H_4 and C_2H_6 can be found in small amounts [28]. With the fault temperature increasing, the hydrogen concentration exceeds that of methane, and significant quantities of higher molecular weight gases will be generated. Trace of C_2H_2 can be detected at upper temperatures. As for the thermal decomposition of cellulose and other solid insulation carbon oxides (CO, CO2), and water vapor at temperatures are produced at much lower than that for decomposition of oil and the rates of the production of these product are exponentially proportional to the temperature [28].

4.3.4.2. Electrical faults

Partial discharges and very low level transient arcing produce mainly hydrogen, with decreasing quantities of methane and trace quantities of acetylene. With the increase of the intensity of the discharge increases [28], the C_2H_2 and C_2H_4 quantities increase significantly . Important quantities of acetylene are produced as the level the electrical discharge reaches high intensity arcing that can generate temperatures from 700 °C to 1800 °C.

4.4. DGA Interpretation Methods

This section will review DGA data interpretation techniques used in laboratories to detect fault conditions in oil-immersed transformers. DGA methods are generally classified into two categories [29], namely non-ratio based methods and ratio-based methods

4.4.1. Non-ratio based Methods

These methods do not use ratios to determine the type fault from the DGA data. This class of methods comprises the Key Gas and the Total Dissolved Combustible Gas (TDCG).

4.4.1.1. Key gas method

The key gas method [28] determines the fault type depending on certain types of gases referred to as key gases , that are in significant amounts at various temperatures. The method uses the relative proportions of key gases, listed in Table 4.1 to determine one of the four following fault conditions:

- Thermal fault due to overheated oil
- Thermal fault due overheated cellulose materials
- Electrical fault due to corona
- Electrical fault due to arcing

The different fault conditions the key gases considered in each case are illustrated in Figure 4.1, Figure 4.2, Figure 4.3, and Figure 4.4.

Table 4.1. Key Gases ordered in ascending order by the energy required to produce it. *Combustible gas.

Key gas	Symbol	
Hydrogen	H_2	*
Methane	CH_4	*
Ethane	C_2H_6	*
Ethylene	C_2H_4	*
Acetylene	C_2H_2	*

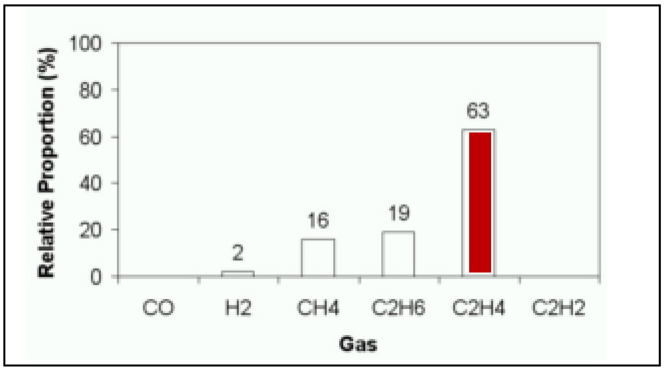

Figure 4.1. Overheated oil with ethylene as predominant gas and smaller proportions of hydrogen, methane and ethane. Key gas: ethylene.

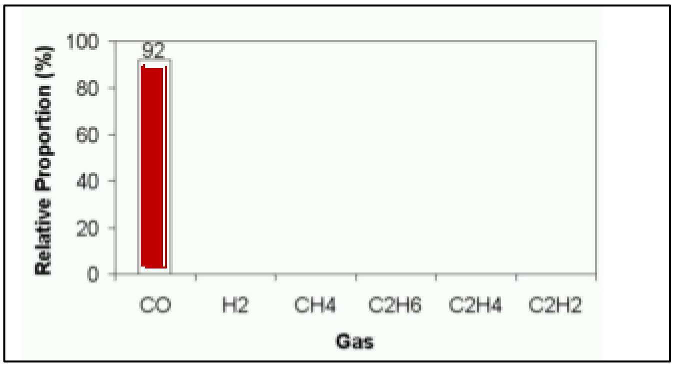

Figure 4.2. Overheated cellulose with carbon monoxide as predominant gas. Key gas: carbon monoxide.

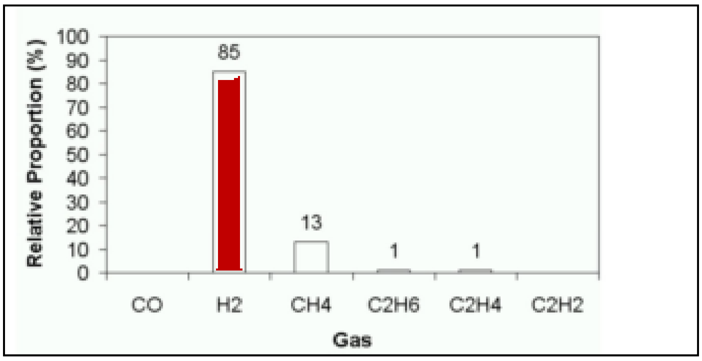

Figure 4.3. Partial discharge fault condition with hydrogen as predominant gas and smaller quantity of methane. Traces of ethane and ethylene. Key gas: Hydrogen.

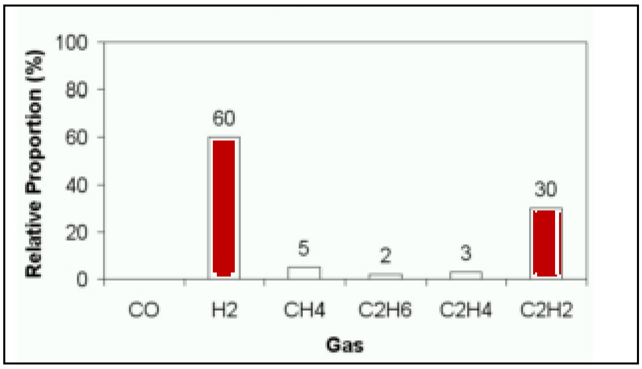

Figure 4.4. Arcing fault condition with hydrogen as predominant gas but a significant amount of acetylene and traces of methane, ethane and ethylene. Key gas: acetylene.

4.4.1.2. Total dissolved combustible gas

Total dissolved combustible gas (TDCG) is a four-condition DGA guide devised by the IEEE to classify risks to transformers that have yet to experience a problem [28]. TDCG utilizes combinations of individual gases and total combustible gas concentration. This guide is not unanimously agreed upon and is only one of the tools used to evaluate transformers. The four conditions are specified as follows [28] :

- **Condition 1:** TDCG below this level (refer to Table 4.2) indicates the transformer is operating satisfactorily. Any individual combustible gas exceeding specified levels should prompt additional investigation.

- **Condition 2**: TDCG within this range indicates greater than normal combustible gas level. Any individual combustible gas exceeding specified levels in Table 4.2 should have additional investigation. A fault may be present. Take DGA samples at least often enough to calculate the amount of gas generation per day for each gas. Refer to Table 4.3 for recommended sampling frequency and actions.

- **Condition 3**: TDCG within this range indicates a high level of decomposition of cellulose insulation and/or oil. Any individual combustible gas exceeding specified levels in Table 4.2 should have additional investigation. A fault or faults are probably present. Take DGA samples at least often enough to calculate the amount of gas generation per day for each gas. Refer to Table 4.3 for recommended sampling frequency and actions.

- **Condition 4:** TDCG within this range indicates excessive decomposition of cellulose insulation and/or oil. Continued operation could result in failure of the transformer.

Table 4.2. Dissolved Key Gas Concentration Limits in Parts Per Million (ppm) [28]

Status	H_2	CH_4	C_2H_2	C_2H_4	C_2H_2	CO	CO_2[1]	TDCG
Condition 1	100	120	35	50	65	350	2500	720
Condition 2	100-700	121-400	36-50	51-100	66-100	351-570	2500-4000	721-1920
Condition 3	701-1800	401-1000	51-80	101-200	101-150	571-1400	4001-10000	1921-4630
Condition 4	>1800	>100	>80	>200	>150	>1400	>10000	>4630

[1] CO_2 is not included in adding the numbers for TDCG because it is not a combustible gas.

Table 4.3. Actions Based on Total Dissolved Combustible Gas [28]

Condition	TDCG levels (in ppm)	TDCG rate (in ppm/day)	Sampling intervals and operating procedures for gas generation rates	
			Sampling interval	Operating procedures
Condition 1	≤ 720	> 30	Monthly	Exercise caution Analyse for individual gases Determine load dependence
		10 to 30	Quarterly	Continue normal operation
		< 10	Annual	
Condition 2	721 to 1920	> 30	Monthly	Exercise caution
		10 to 30	Monthly	Analyse for individual gases
		< 10	Quarterly	Determine load dependence
Condition 3	1921 to 4630	> 30	Weekly	Exercise caution
		10 to 30	Weekly	Analyse for individual gases
			Monthly	Plan outage Advise manufacturer
Condition 4	> 4630	> 30	Daily	Consider removal from service.
		10 to 30	Daily	Advise manufacturer.
		< 10	Weekly	Exercise extreme caution Analyse for individual gases Plan outage Advise manufacturer

Table 4.2 is to be consulted in the case that no previous DGA tests have been made on the transformer or that no recent history exists. If a previous DGA exists, it should be reviewed to determine whether gases generation rates are within the recommended limits or not as specified in Table 4.3. Indeed, a significant gas generation rate is more important in assessing transformers condition than the accumulated amount of gas [19]. However acetylene (C_2H_2) should be given special attention. Small amount of this gas (above a few ppm) can be generate by a high-energy arcing, a very hot thermal fault (500°C or higher), a onetime arc due to a nearby lightning strike or a high voltage surge. Oil samples should be taken on a weekly or daily basis If C_2H_2 is found in the DGA, to determine if generation is an ongoing process. If no additional C_2H_2 is found and the level is below the Condition 4, the transformer may continue their operation. However, if acetylene continues to increase, the transformer has an active high-energy internal arc and an immediate outage of the transformer should be planed. Further

operation is extremely hazardous and may result in explosive catastrophic failure of the tank, spreading flaming oil over a large area.

4.4.2. Ratio-based methods

This class of diagnostic tools includes methods that make use of a subset of ratios specified in Table 4.4 to determine the fault type based on the fit of each ratio result to defined range of values [29]. Though the methods in this category involve more computation, they tend to have a more effective diagnostic accuracy rate. It is important to mention that when applying any ratio based method to DGA data, important levels of the gases must be present for the result of the method to be considered relevant [28,29].

Table 4.4. Gases ratios used by DGA methods

Code	Ratio
R1	$\frac{CH_4}{H_2}$
R2	$\frac{C_2H_2}{C_2H_4}$
R3	$\frac{C_2H_2}{CH_4}$
R4	$\frac{C_2H_6}{C_2H_2}$
R5	$\frac{C_2H_4}{C_2H_6}$

4.4.2.1. Doernenburg ratio method

The Doernenburg ratio method is one of the earliest technique for analysing DGA data. It analyses the ratios R1, R2 and R3 to determine one of the following fault type: thermal faults, corona discharge and arcing. The operational mode of the Doernenburg illustrated in can be described as follows [28]:

- **Step 1:** Determining gas concentrations (in ppm) by extracting and separating the gases by gas chromatography.
- **Step 2:** Verifying if at least one of the gas concentrations for H_2, CH_4, C_2H_2, and C_2H_4 exceeds twice the values for limit L1 (given in Table 4.5) and one of the other two gases (C_2H_6 and CO) exceeds the values for limit L1. If this test is positive, there is a high probability of the occurrence of a fault in the unit faulty; proceed to Step 3 to determine validity of the ratio procedure.
- **Step 3:** Determining validity of ratio procedure: The ratios are not valid if none of the gases used in each ratio R1, R2, R3, or R4 exceeds limit L1 and the unit should be resampled and investigated by alternate procedures.
- **Step 4:** When the validity of the ratios is confirmed, the ratios R1, R2, R3, and R4 in this order are compared to the values obtained from Table 4.6.
- **Step 5:** If all succeeding ratios for a specific fault type fall within the values given in Table 4.6, the suggested diagnosis is valid.

Table 4.5. Limit concentrations of dissolved gas [28]

Key gas	Limit concentration L1 (in ppm)
Hydrogen (H_2)	100
Methane (CH_4)	120
Carbon monoxide (CO)	350
Acetylene (C_2H_2)	1
Ethylene(C_2H_4)	50
Ethane (C_2H_6)	65

Table 4.6. Ratios for key gases—Doernenburg [28]

Ratios				Fault diagnosis
R1	**R2**	**R3**	**R4**	
> 1	< 0.75	< 0.3	> 0.4	Thermal decomposition
> 0.1	not significant	< 0.3	> 0.4	Partial discharge (low intensity PD)
$[0.1 - 1.0]$	< 0.75	< 0.3	< 0.4	Arcing (High intensity PD)

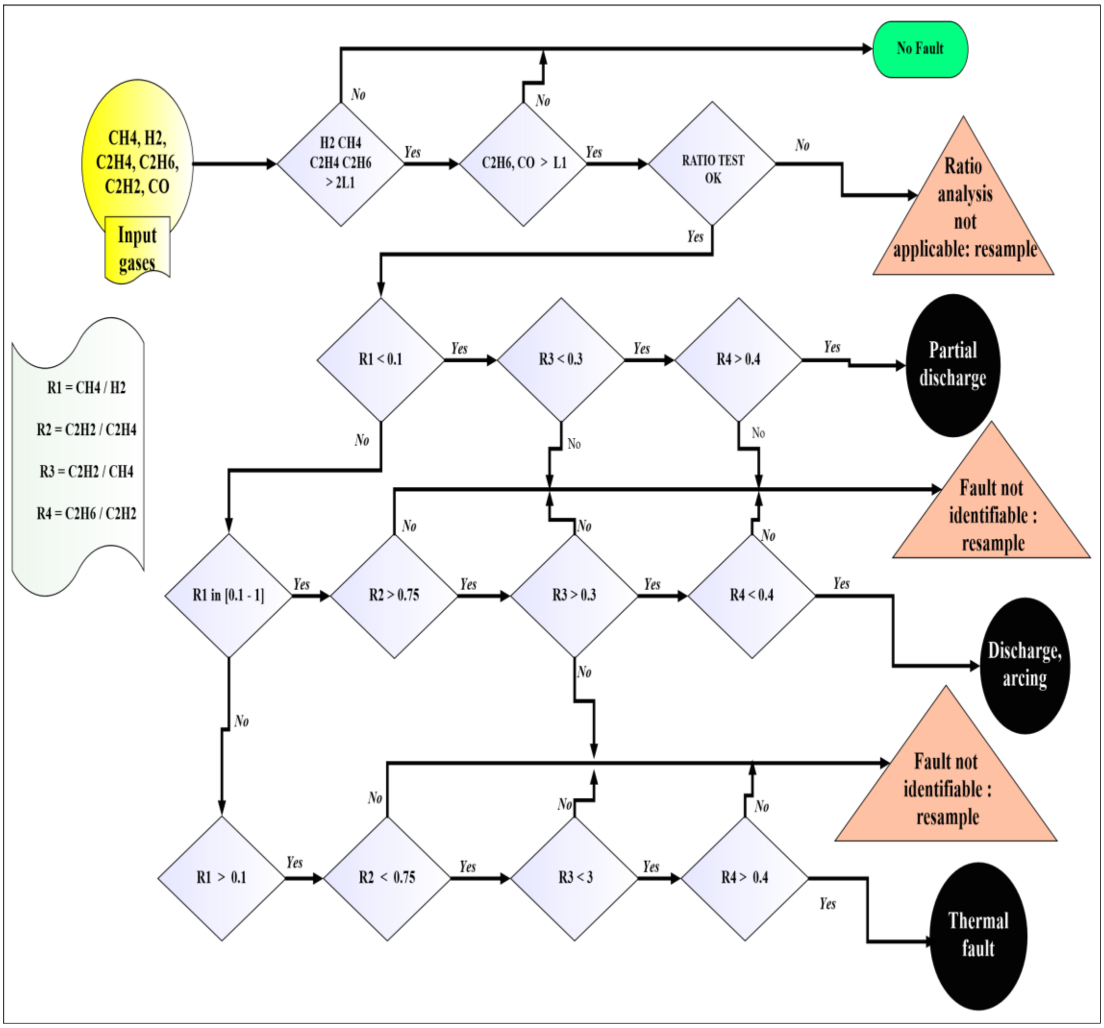

Figure 4.5. Doernenburg ratio method flowchart [28].

4.4.2.2. Rogers ratio method

The Rogers ratio method utilizes R1, R2 and R5 ratios to analyse DGA data. For each of these ratios, it generates codes whose combinations help in diagnosing the types of faults at the origin of the gases formation [4]. The diagnoses of these faults are results of years of empirical observations. The codes generated by the Rogers ratio method and the interpretations given by the combinations of the generated codes are given below in Table 4.7 and

Table 4.8 respectively.

Table 4.7. Rogers ratios codes [30].

Ratio range	Ratios and generated codes		
	$\boldsymbol{R1}$	$\boldsymbol{R2}$	$\boldsymbol{R5}$
$\leq \mathbf{0.1}$	1	0	0
0.1 – 1	0	1	0
1.0 – 3.0	2	1	1
$\geq \mathbf{3}$	2	2	2

Table 4.8. Faults types detectable by the Rogers ratio method [30].

$\boldsymbol{R2}$	$\boldsymbol{R1}$	$\boldsymbol{R5}$	**Diagnosis**	**Case**
0	0	0	No fault	**-**
0	1	0	Partial discharge of low energy	**PD**
1	1	0	Partial discharge of high energy	
1/2	0	1/2	Discharge of low energy, arcing	**D1**
1	0	2	Discharge of high energy, arcing	**D2**
0	0	1	Thermal fault 150°C, conductor overheating	**T1**
0	2	0	Thermal fault 150°C–300°C, mild oil overheating	
0	2	1	Thermal fault 300°C–700°C, moderate oil overheating	**T2**
0	2	2	Thermal fault 700°C, severe oil overheating	**T3**

4.4.2.3. Duval triangle method

The Duval Triangle method was devised by Michel Duval of Hydro Quebec in the 1970s, by using thousands of DGA results and transformer problem diagnosis [19]. It is a modern method for graphically detecting incipient fault conditions in operating transformers [31]. Three gases, CH_4, C_2H_2 and C_2H_4 are used by the Duval Triangle method. The relative percentages of the three gases are plotted as a point in a triangular coordinate system on an equilateral triangle subdivided into seven disjoint areas corresponding to the types of abnormal conditions experienced by a transformer that the method can figure out [6]. Table 4.10 describes the fault conditions detectable by the Duval Triangle method. However, this method should not be used to verify whether a fault condition exists or not. It must be used in conjunction with the TDCG method (described in section 4.4.1.2.) or with Table 4.11, which will be used to detect fault conditions, and the Duval Triangle used to diagnose what the problem is [19]. If used alone, the Duval Triangle will lead to false positive detection even though no fault exist.

To use determine the type of fault with the Duval triangle method, we proceed as follows:

1- Use the TDCG method, and/or Table 4.11. At least one of the hydrocarbon gases or hydrogen must be Condition 3, and increasing at a generation rate (G2) from Table 4.11, for a problem to exist. For Table 4.11 to be used alone, at least one of the individual gases must be at L1 level or above and the gas generation rate at least at G2. However, one should use both methods to confirm that a problem exists.

2- In the case of the existence of a problem, use either the total accumulated amount of CH_4, C_2H_2 and C_2H_4; or the amounts of CH_4, C_2H_2 and C_2H_4 generated between since the sudden increase in gas began, and plot the percentages of the total on the triangle to arrive at a diagnosis. Detailed instructions for the generated amounts of gases method are given below (the total accumulated gases can also be used):

a. Calculate the amount of (in ppm) CH_4 produced since the beginning of the problem by subtracting the amount of CH_4 from an earlier DGA, before the sudden increase in gas.

b. Repeat this process for the remaining two gases C_2H_4 and C_2H_2.

3- Add the three numbers (differences) obtained by the process of step 2 above. This gives 100 percent (%) of the three key gases generated since the fault, used in the Duval Triangle.

4- Divide each individual gas difference by the total difference of gas obtained in step 3 above. This gives the percentage increase of each gas of the total increase.

5- Plot the percentage of each gas on the Duval Triangle, beginning on the side indicated for that particular gas. Draw lines across the triangle for each gas parallel to the hash marks shown on each side of the triangle.

An example of DGA with the Duval triangle method is given below.

Table 4.9. Gases amounts in oil samples and their relative percentages obtained with the Duval triangle methods computations.

	DGA No.1	DGA No.2	Increase	Percentage Increase	Percentage accumulated gases
CH_4	142	192	50	36%	52%
C_2H_4	84	170	86	62%	46%
C_2H_2	4	7	3	2%	2%
Total	230	369	139	100%	100%

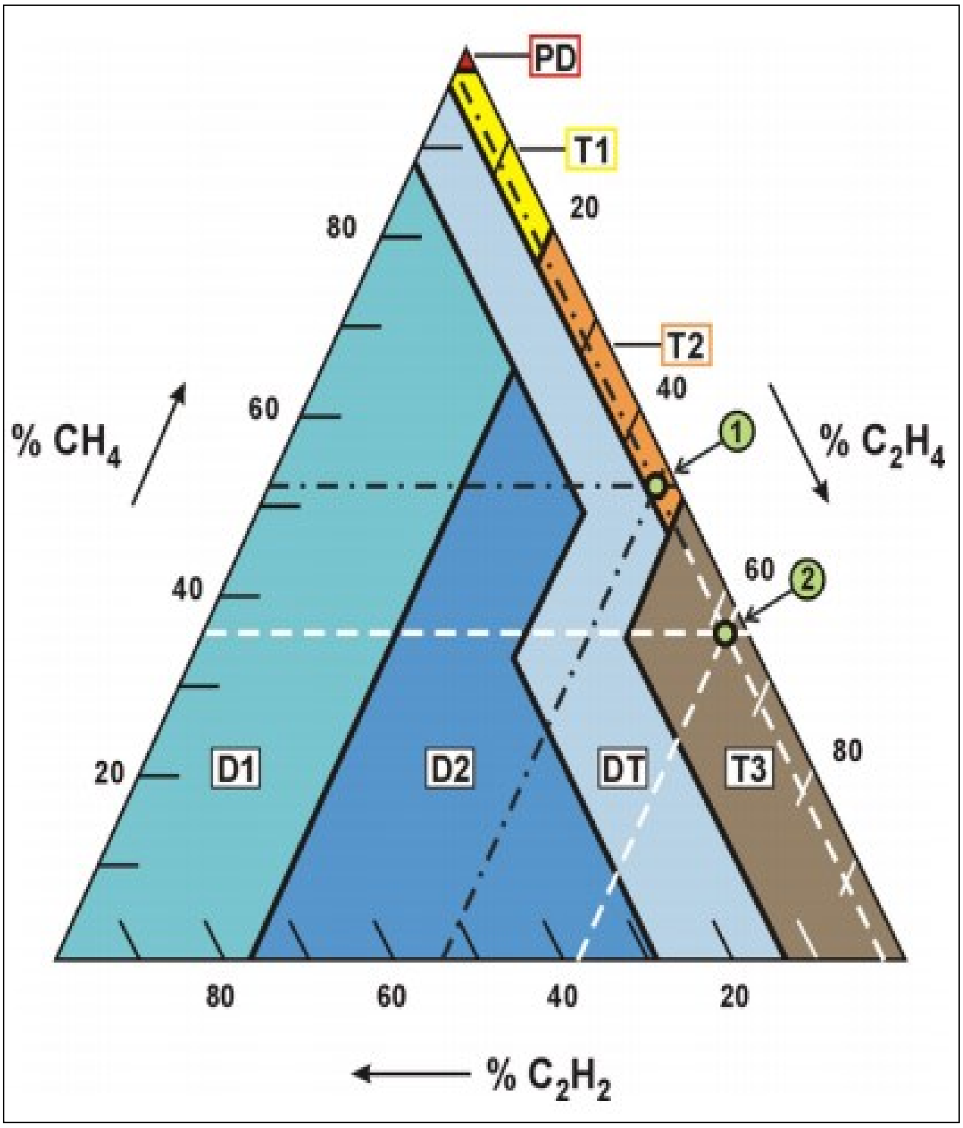

Figure 4.6. Duval triangle diagnosis for the DGA data provided in Table 4.9. Point 1 represents the diagnosis obtained by using the generated amounts of gases between the two samples and Point 2 the diagnosis obtained by using the total accumulated gases [19].

Table 4.10. Faults detectable by the Duval Triangle Method [30, 32].

Code	Fault	Diagnosis
PD	Partial discharge	Discharges of the cold plasma (corona) type in gas bubbles or voids, with the possible formation of X-wax in paper.
D1	Discharge of low energy	Partial discharges of the sparking type, inducing pinholes, carbonized punctures in paper. Low energy arcing inducing carbonized perforation or surface tracking of paper, or the formation of carbon particles in oil.
D2	Discharge of high energy	Discharges in paper or oil, with power follow-through, resulting in extensive damage to paper or large formation of carbon particles in oil, metal fusion, tripping of the equipment and gas alarms.
T1	Thermal fault<300°C	Evidenced by paper turning brownish (>200 °C) or carbonized (> 300 °C).
T2	Thermal fault<700°C	Carbonization of paper, formation of carbon particles in oil
T3	Thermal fault>700°C	Extensive formation of carbon particles in oil, metal coloration (800 °C) or metal fusion (> 1000 °C).
DT	Thermal and electrical faults	Mix of thermal and electrical faults

Table 4.11. Gas amounts limits and Generation Rate Per Month Limits [19].

Gas	L1 Limits	G1 Limits (ppm per month)	G2 Limits (ppm per month)
H_2	100	10	50
CH_4	75	8	38
C_2H_2	3	3	3
C_2H_4	75	8	38
C_2H_6	75	8	38
CO	700	70	350
CO_2	7000	700	3500

4.4.2.4. Duval Pentagon method

The Duval pentagon method [33] is a graphical tool for interpreting DGA results. It makes uses of five gases, to wit H_2, CH_4, C_2H_6, C_2H_4, and C_2H_2 to locate on a pentagon whose vertices are the five gases, the types of faults undergone by a transformer. The pentagon is subdivided into zones corresponding to the different faults the method can diagnose. This method can operate in two modes, and the types of faults it can detect depend on the mode in which it is used as presented in Table 4.12. When used in the first mode, the method can diagnose the six "basic" electrical and thermal faults used by IEC, IEEE, and Duval Triangle; as well as a type of fault (S in Table 4.12) for stray gassing of mineral oil at 120 and 200°C in the laboratory [33]. As for its used in the second mode, the basic electrical faults PD, D1 and D2 can be diagnosed in addition to faults of type S and three more well defined fault types. These are:

- O: Thermal fault Overheating <250°C
- C: Thermal fault with carbonization of paper
- T3-H: Thermal fault in oil only.

To determine the type of fault, the relative percentage of each of the five gases is calculated. The relative percentage of hydrogen is computed using the following equation:

$$\%H_2 = (\text{ppm } H_2)/(\text{ppm } H_2 + CH_4 + C_2H_6 + C_2H_4 + C_2H_2) \qquad (4.1)$$

The relative percentages of the remaining four gases are computed the same way. A relative percentage of a gas is then plotted as a point on the axis between the pentagon centre and the pentagon summit for that gas. The centre of the pentagon corresponds to a gas concentration of 0%. A pentagon summit represents 100% of the corresponding gas. The five points from the representation of the relative percentage of each gas on the corresponding axes of the pentagon, as illustrated in Figure 4.7, form an irregular polygon whose centroid indicates the localization of the fault on the pentagon.

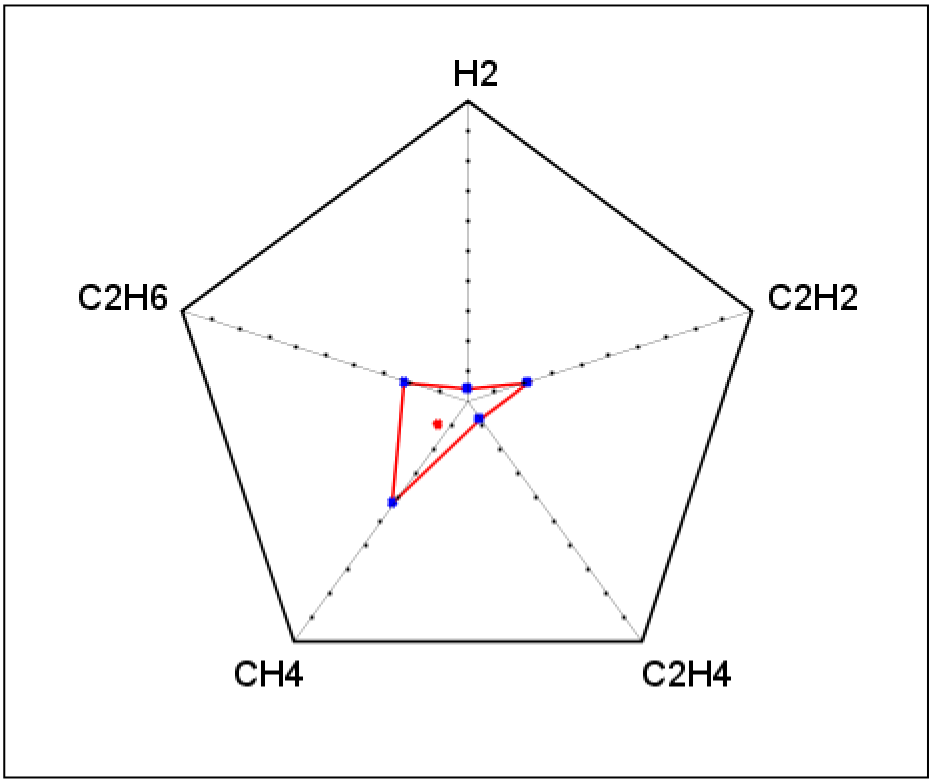

Figure 4.7 Example of Duval Pentagon representation

The Duval pentagon is represented in Cartesian coordinates system. This will help in the determination of the centroid of the irregular polygon formed by the five points corresponding to the relative percentages of the analysed gases. The coordinates (C_x, C_y) of the centroid of the irregular polygon formed by these five points can be computed using the following equations [33]:

$$C_x = \frac{1}{6A}\sum_{i=0}^{4}(x_i + x_{i+1})(x_i * y_{i+1} - x_{i+1} * y_i) \tag{4.2}$$

$$C_y = \frac{1}{6A}\sum_{i=0}^{4}(y_i + y_{i+1})(x_i * y_{i+1} - x_{i+1} * y_i) \tag{4.3}$$

Where x_i and y_i are the coordinates of the five points, C_x and C_y the (x, y) coordinates of the centroid, and A the surface of the irregular polygon calculated with the following equation [33]:

$$A = \frac{1}{2}\sum_{i=0}^{4}(x_i * y_{+1} - x_{i+1} * y_i) \tag{4.4}$$

The definition of the zones of the pentagon that correspond to the various identifiable faults this method can identify has been done by the analysis of about 180 DGA data [33]. The various areas of faults of Duval Pentagon 1 and Duval Pentagon 2 are shown in Figure 4.8 and Figure 4.9 respectively.

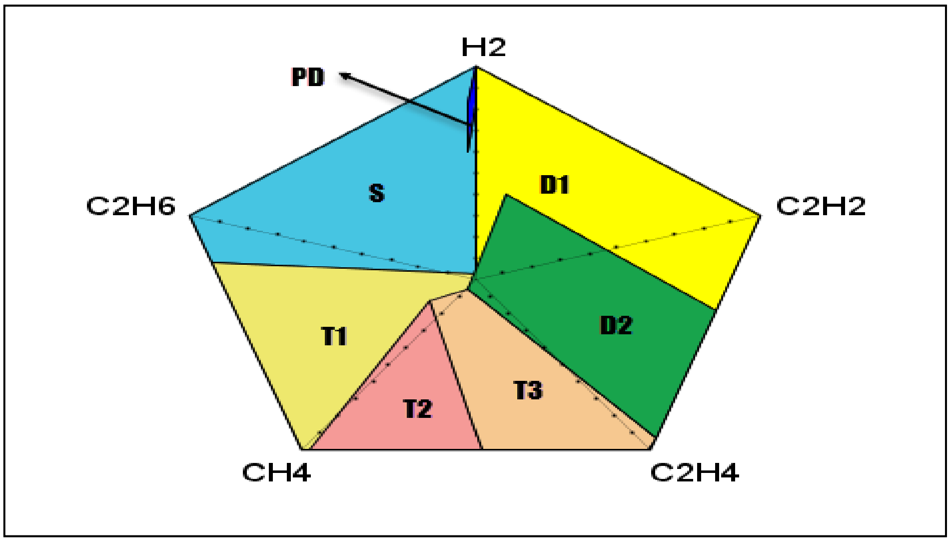

Figure 4.8. Fault zones in Duval Pentagon 1

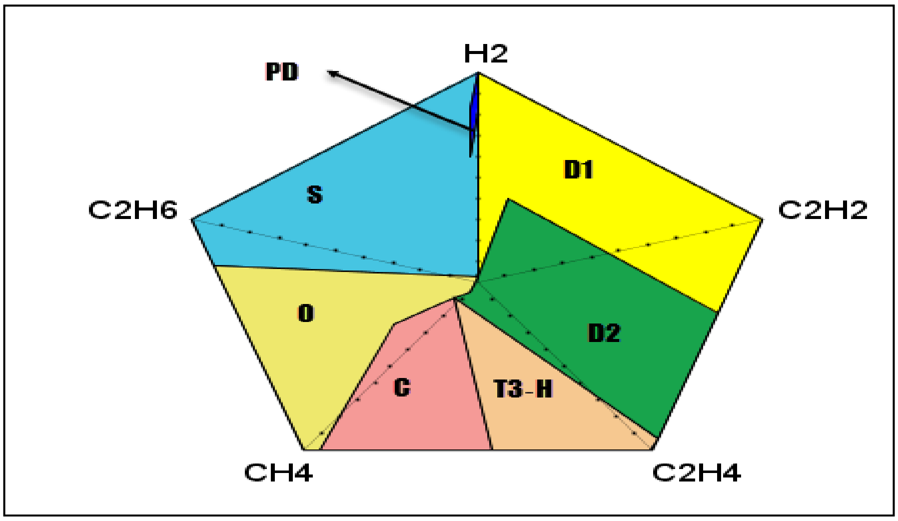

Figure 4.9. Fault zones in Duval Pentagon 2

Table 4.12. Type fault detected by the Duval Pentagon method and the associated modes.

Code	Descriptions	Mode
PD	Partial discharge	1 and 2
D1	Discharge of low energy	1 and 2
D2	Discharge of high energy	1 and 2
T1	Thermal fault<300°C	1
T2	Thermal fault<700°C	1
T3	Thermal fault>700°C	1
S	Stray gassing of mineral oil at 120 and 200°C in the laboratory.	1 and 2
O	Overheating T1-O <250°C	2
C	thermal faults T3-C, T2-C, and T1-C with carbonization of paper	2
T3-H	Thermal faults T3-H in oil only	2

4.4.2.5. Other useful ratios

Three other ratios that are analyzed individually can be also used as complementary tools to the main diagnosis methods presented previously.

The first ratio $\frac{CO_2}{CO}$ is used to detect paper contribution to the fault. Under normal loading and temperatures conditions, the production rate of CO_2 is 7 to 20 times higher than that of CO. There is little concern when this ratio is above 7, and even though care should be taken for ratios below 7, values down to 5 are seen as normal for some transformers [19]. Values of this ratio under 5 are sign of abnormally high temperatures and rapidly deteriorating cellulose insulation which occurs for values equal to 3 or less[19].

The next ratio is $\frac{O_2}{N_2}$. O_2 and N_2 are not considered as key gases when investigating the fault type, however they provide important information about leakages, excessive pressure, and temperature changes that may exist within the transformer [15]. This ratio is approximatively equal to 0.5 in normal conditions, and may decrease during the oil oxidation and overheating processes [15,29].

The final ratio is $\frac{C_2H_2}{H_2}$. values of this ratio ranging from 2 to 3 indicate contamination of the main tank by the LTC compartment [15, 29]. In these situations, due to the high level of acetylene in the main tank, it is essential to monitor incremental changes of acetylene level in order to figure out the very problems of the main tank.

CHAPTER 5. GRAPHICAL IMPLEMENTATION OF DGA METHODS: CASE OF DUVAL TRIANGLE, DUVAL PENTAGON AND ROGERS RATIO METHODS

5.1. Introduction

The previous chapter reviewed the DGA concept and different DGA data interpretation methods. In this chapter, we are going to give the details of the implementation of the graphical representation of some of the methods described previously, viz. the Duval Triangle method, the Duval Pentagon method, and the Rogers ratio method. For implementation purposes, the Java programming language is used.

5.2. Duval Triangle Method

The Duval Triangle method makes use of an equilateral triangle to represent the relative concentrations of CH_4, C_2H_2 and C_2H_4 gases as triangular coordinates that correspond to a unique point within the triangle's limits. Cartesian coordinates are handy for plotting point described by their triangular coordinates in a plane. Given the Cartesian coordinates of the equilateral triangle's vertices, we will derive formulas to compute the Cartesian coordinates of the point described by the current triangular coordinates.

5.2.1. Triangular coordinates to Cartesian coordinates transformation

Let's consider the equilateral triangle *ABC* and a point *T* within the triangle's boundaries defined by its triangular coordinates (P_1, P_2, P_3) as shown in Figure 5.1.

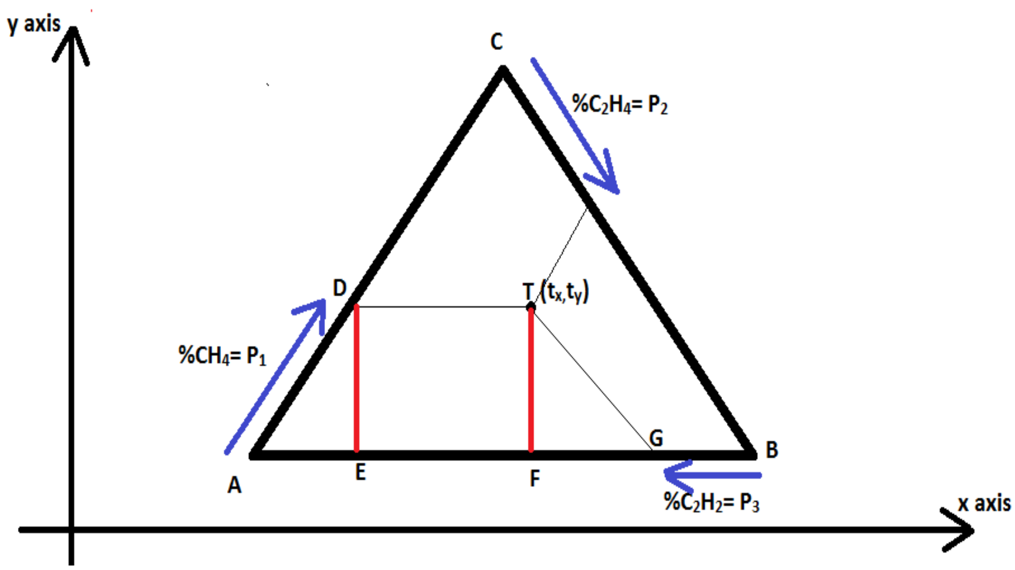

Figure 5.1. Cartesian coordinates of a point within the triangle's boundaries.

With ABC being equilateral, let AB=BC=BC=L be the length of the triangle side. If (Ax, Ay) the Cartesian coordinates of *A*. therefore we can compute the coordinates of *B* and *C* as follows:

$$B_x = A_x + L \tag{5.1}$$

$$B_y = A_y \tag{5.2}$$

$$C_x = A_x + 0.5 \times L \tag{5.3}$$

$$C_y = A_y + \frac{\sqrt{3}}{2} \times L \tag{5-4}$$

The Cartesian coordinates (T_x, T_y) of T are computed as follows. In triangle *ADE*:

$$DE = AD \times \sin 60° = \sqrt{3} \times P_1 \times \frac{L}{2} = TF \tag{5.5}$$

Then,

$$T_y = A_y + TF = A_y + \sqrt{3} \times P_1 \times \frac{L}{2} \tag{5.6}$$

In triangle *TFG*:

$$GF = \frac{TF}{\tan 60°} = P_1 \times \frac{L}{2} \tag{5.7}$$

We also have the following relations:

$$AF = AB - BF \tag{5.8}$$

$$BF = BG + GF \tag{5.9}$$

$$BG = P_3 \times AB = P_3 \times L \tag{5.10}$$

From equations (5.7), (5.8), (5.9) and (5.10) we have:

$$AF = L(1 - (\frac{P_1}{2} + P_3)) \tag{5.11}$$

From the relation $P_1 + P_2 + P_3 = 1$ and
(5.11) we deduce:

$$T_x = A_x + AF = A_x + L(\frac{P_1}{2} + P_2) \tag{5.12}$$

5.2.2. Representation in the plane of regions corresponding to fault types detectable by the Duval Triangle method

The Duval triangle is subdivided into seven disjoint areas, each region mapping to a specific type of fault detectable by the Duval Triangle method. In the Duval Triangle, each region is represented by a polygon whose each of the vertices is determined by well-defined triangular coordinates. The equations (5.13) and (5.12) can be used to compute de Cartesian coordinates each vertex of a polygon representing fault area in the Duval triangle by using the triangular coordinates provided in Table 5.1

Table 5.1. triangular coordinates for Duval Triangle fault zones [32].

Area	Points	P1	P2	P3
D1	D11	0	0	1
	D12	0	0,23	0,77
	D13	0,64	0,23	0,13
	D14	0,87	0	0,13
D2	D21	0	0,23	0,77
	D22	0	0,71	0,29
	D23	0,31	0,40	0,29
	D24	0,47	0,40	0,13
	D25	0,64	0,23	0,13
DT	DT1	0	0,71	0,29
	DT2	0	0,85	0,15
	DT3	0,35	0,50	0,15
	DT4	0,46	0,50	0,04
	DT5	0,96	0	0,04
	DT6	0,87	0	0,13
	DT7	0,47	0,40	0,13
	DT8	0,31	0,40	0,29
T1	T11	0,76	0,20	0,04
	T12	0,80	0,20	0
	T13	0,98	0,02	0
	T14	0,98	0	0,02
	T15	0,96	0	0,04
T2	T21	0,46	0,50	0,04
	T22	0,50	0,50	0
	T23	0,80	0,20	0
	T24	0,76	0,20	0,04
T3	T31	0	0,85	0,15
	T32	0	1	0
	T33	0,50	0,50	0
	T34	0,35	0,50	0
PD	PD1	0,98	0,02	0
	PD2	1	0	0
	PD3	0,98	0	0,02

5.3. Duval Pentagon Method

In this section, the details for a graphical representation of the Duval Pentagon will be given.

5.3.1. Specification of the pentagon

In order to facilitate the calculations, the pentagon is represented in a Cartesian coordinates system, with the centre of the pentagon positioned at the origin of the coordinates system.

5.3.1.1. Vertices of the pentagon

The five gases used by the method correspond to the five summits of the pentagon. The order of gases at the five summits of the pentagon corresponds to the increasing energy required to produce these gases in transformers, from H_2 to C_2H_2, counter clockwise [33] as illustrated in Figure 5.2.. Since the pentagon is regular, is it straightforward to derive the coordinates of four of the five vertices from the coordinates of one vertex that can be arbitrary set to some predefined values. Let V_i (x_i, y_i) be an arbitrary chosen vertex whose coordinates have been set to some values. Then, the other vertices can be determined using the following formula:

$$V_{i+1} = R_\theta(V_i) \tag{5.13}$$

Where R_θ is the rotation centred at the origin and of angle $\Theta = \frac{2\pi}{5}$, and V_{i+1} being the next vertex following V_i counter clockwise.

For implementation purpose, we fixed the coordinates of the summit corresponding to H_2 to (0, 100) and we derived the coordinates of the remaining summits to obtain (-95.1, 30.9), (-58.8, -80.9), (58.8, -80.9), and (95.1, 30.9) for C_2H_6, CH_4, C_2H_4, and C_2H_2 respectively.

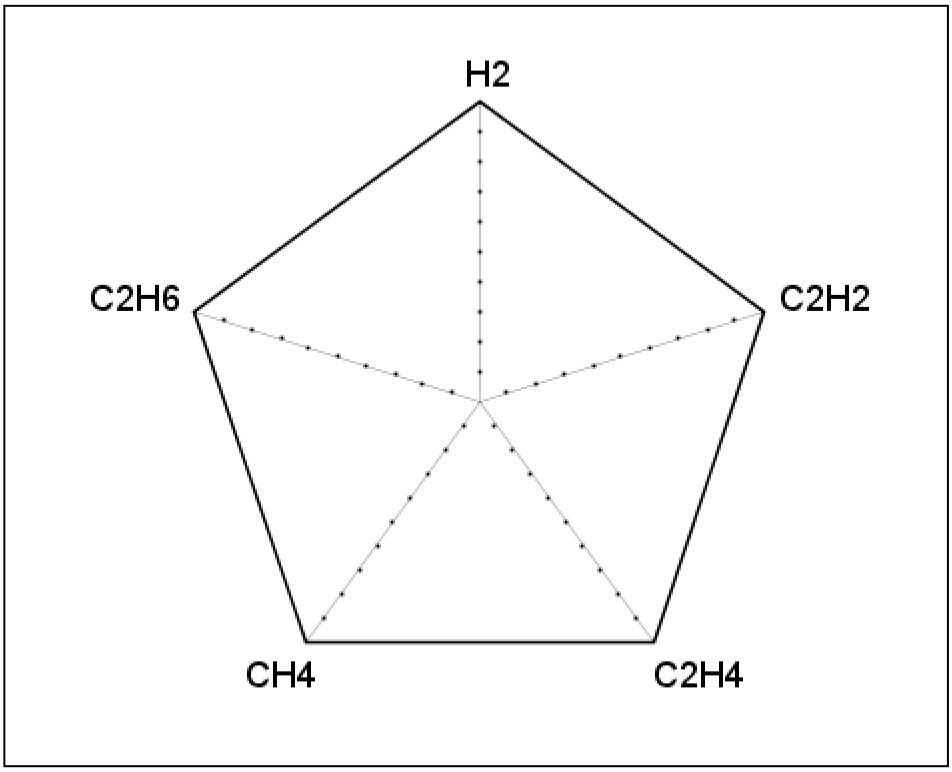

Figure 5.2. Representation of the vertices of the Duval pentagon

5.3.1.2. Fault zones in the Duval pentagon

As stated in [33] , about 180 DGA results due to faults have been applied to the method to define fault zones in the Duval Pentagon representation. The different locations of the centroid for each result were used to define the areas corresponding to each fault type. The (x, y) coordinates of the summits of zone boundaries in Pentagons 1 and 2are given in Table 5.2. The values of the (x, y) coordinates of the summits of the different fault areas are used to represent the boundaries of fault type areas in both Duval Pentagon 1 and Duval Pentagon 2 as shown in Figure 5.3 and Figure 5.4.

5.3.1.3. Determination of the fault's location

As explained in section 4.4.2.4. , the relative percentage of each of the five gases is calculated. The five points from the representation of the relative percentage of each gas on the corresponding axes of the pentagon, as illustrated in Figure 4.7 , form an irregular polygon whose centroid indicates the localization of the fault on the pentagon. The coordinates of the centroid are computed using Equation (4.2) and Equation (4.3).

Table 5.2. Fault area boundaries coordinates

Zones	Boundaries coordinates
PD	(0, 24.5), (0, 33), (-1, 24.5), (-1, 33)
D1	(0, 40), (38, 12), (32, -6), (4, 16), (0, 1.5)
D2	(4, 16), (32, -6), (24, -30), (-1, -2)
T3	(24, -30), (-1,-2), (-6,-4), (1, -32)
T2	(1, -32), (-6, -4), (-22.5, -32)
T1	(-22.5, -32), (-6, -4), (-1, -2), (0, 1.5), (-35, 3)
S	(-35, 3), (0, 1.5), (0, 24.5), (0, 33), (-1, 24.5), (-1,33), (0, 40)
T3-H	(24, -30), (-3.5, -3), (2.5, -32)
C	(2.5, -32), (-3.5, -3), (-11, -8), (-21.5, -32)
O	(-21.5, -32), (-11,-8), (-3.5, -3), (-1, -2), (0, 1.5),(-35, 3)

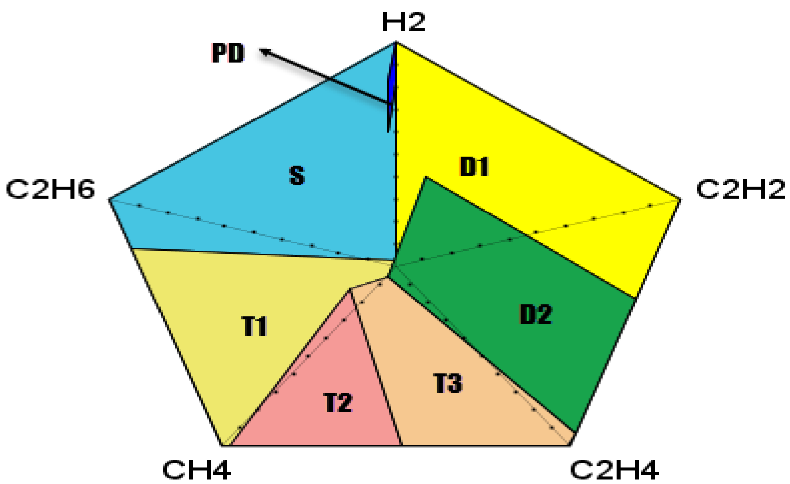

Figure 5.3. Duval Pentagon 1faults areas boundaries

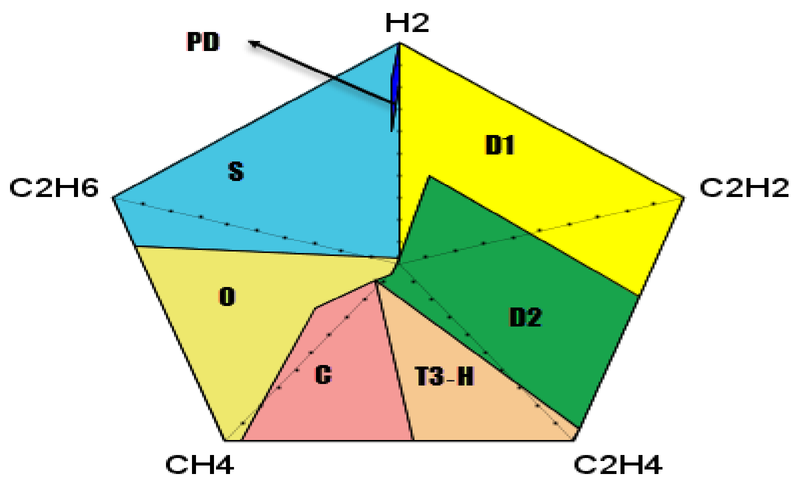

Figure 5.4. Duval Pentagon 2 faults areas boundaries

5.4. Rogers Ratio Method

In this section, the specification for a 3D graphical representation of the Rogers ratio method will be presented .The system to be developed will use CH_4/H_2, C_2H_2/C_2H_4 and C_2H_4/C_2H_6 ratios to locate in a 3 dimensional space the type of electrical, thermal stresses experienced by a transformer at a given period. Three steps are required to achieve this:

- Defining the axes and the scales of each the axes of the 3 dimensional space,
- Representing regions of the 3D space that correspond to each type of faults,
- Locating faults experienced by the transformer according to the ratios' current values

5.4.1. Definition of the axes and axes' scales

The x, y and z axes of the system are represented by CH_4/H_2, C_2H_2/C_2H_4 and C_2H_4/C_2H_6 ratios respectively. Values ranges of ratios make the use of a linear scale on axes these ratios represent inadequate. Thus a log scale with base 10 is used on each axe. For implementation purposes, the point $\boldsymbol{O}$ $(0.001, 0.001, 0.001)$ has been defined as the origin of the system. All the preceding points are illustrated in Figure 5.5.

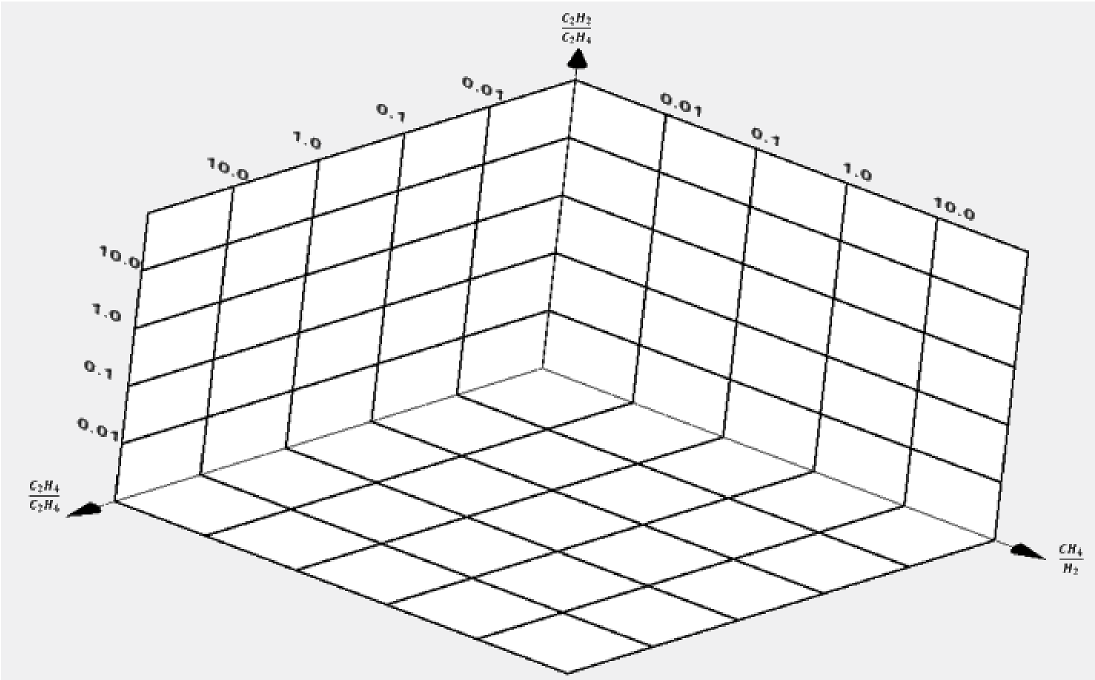

Figure 5.5. 3D space for three-ratio method graphical representation

5.4.2. Representation of regions corresponding to fault types identified by the three-ratio method in the 3D space

As shown in

Table 4.8, the Rogers ratio method identifies 6 fault types (PD, D1, D2, T1, T2, and T3). Regions to which the fault types will be mapped correspond to parallelepipeds in the 3 dimensional space, parallelepiped whose boundaries will be computed according to ratios limit values on each on each axe as specified in Table 5.3. The construction of a regions is described by the following algorithm:

- **Step 1** : construct a cube of side length 1

- **Step 2** : along each axe of the space, scale the cube by a factor **Sfactor** computed as follows:

$$Sfactor = \begin{cases} \log_{10} \dfrac{max}{min} & If\ min > 0 \\ \log_{10} max & If\ min = 0 \end{cases} \tag{5.14}$$

Where *min* and *max* represent the lower bound and upper bound of gases ratio respectively along each axe.

- **Step 3:** Position the obtained parallelepiped in the 3D system by applying a translation to it of vector ***V***. The components of this translation vector are given by the following formula:

$$V_i = \begin{cases} \log_{10} \frac{min_i}{10*O_i} + 1 & If\ min > 0 \\ 0 & If\ min = 0 \end{cases} \tag{5.15}$$

Where min_i is the lower bound of gases ratio respectively along the ith axe, and V_i the ith component of the translation vector.

Table 5.3. Rogers ratios limit values for fault zones determination

Fault case	**Fault description**	**R2**	**R1**	**R5**
PD	Partial discharge	≤ 0.01	≤ 0.1	≤ 0.2
D1	Discharge of low energy, arcing	> 1	$[0.1 - 0.5]$	> 1
D2	Discharge of high energy, arcing	$[0.6 - 2.5]$	$[0.1 - 1]$	> 2
T1	Thermal fault 150°C, conductor overheating	< 0.01	> 1	< 1
T2	Thermal fault 300°C–700°C, moderate oil overheating	< 0.1	> 1	$[1 - 4]$
T3	Thermal fault 700°C, severe oil overheating	< 0.2	> 1	> 4

5.4.3. Location of faults experienced by the transformer according to gases ratios' values

Locating a potential issue undergone by the transformer in accordance to gases ratios values is done by using Equation (5.15) to compute the components of the translation vector showing a point, in the 3D system, pertaining or not to regions corresponding to the different fault types.

5.5. Summary

In this chapter we gave the details of the graphical implementations of three DGA methods, namely the Duval Triangle, the Duval Pentagon and the Rogers Ratio methods. These methods are intensively used for detecting incipient faults in transformers by DGA laboratories, and we provide here their graphical counterparts to help DGA practitioner to visually confirm their results.

CHAPTER 6. SPECIFICATIONS OF AN ONLINE CONDITON MONITORING AND DIAGNOSTIC SYSTEM FOR POWER TRANSFORMERS INSULATING OIL

6.1. Introduction

Transformers maintenance is of the utmost importance for the business of power utilities. This process has long been carried out periodically or performed on some other timetable based on past experience of the component failure modes [4]. This time based model of transformers maintenance has revealed flaws such as cost-ineffectiveness, inability to detect problems developing between planned inspections. Power utilities are now going towards online monitoring and diagnostic of transformers and ancillary equipment which is performed by measuring certain parameters or conditions while transformers are in service as maintenance model for their transformers fleet. The adoption of this model is justified by the need to increase the availability of transformers, to facilitate the transition from time-based and/or operational-based maintenance to condition-based maintenance, to improve asset management, and to enhance failure-cause analysis [3]. Transformer insulating fluid and oil preservation system, the coil and core assembly, bushings, and the load tap changing equipment are the main transformer components for which online monitoring solutions are available. The following sections will cover the following elements:

- Benefits of transformer online monitoring systems (Section 6.2.)

- Components of an online monitoring system (Section 6.3.)

- Proposal of an online monitoring and diagnostic system for transformers insulating oil (Section 6.4.)

6.2. Benefits of Transformer Online Monitoring and Diagnostic Systems

Various benefits can result from the application of the online monitoring and diagnostic model as maintenance scheme of transformers. This benefits are classified into two main categories, to wit: direct benefits and strategic benefits.

6.2.1. Direct benefits

Cost-saving benefits resulting strictly from shifting maintenance activities from a time-based to a condition-based assessment model are termed as direct benefits [3]. Reduction of expenses are the main consequence of condition-based maintenance models for these models reduce the frequency at which equipment are inspected thereby reducing or delaying manual interventions (repair, replacement, etc.) on the equipment [3].

6.2.2. Strategic benefits

Benefits coming from the ability to prevent, mitigate, or avoid catastrophic failures are referred to as strategic benefits. Because failures can be damaging and costly, strategic benefits are potentially substantial and generally comprise better safety (preventing injuries to workers or the public in the event of catastrophic failure), protection of the equipment, and avoiding the potentially large impact caused by system instability, loss of load, environmental clean-up, etc. [3].

6.3. Components of Transformer Online Condition Monitoring and Diagnostic Systems

The implementation of an online condition monitoring and diagnostic system for transformer requires a set of equipment that are meant to operate different levels of the system. An online condition monitoring and diagnostic system consists of three main layers namely data acquisition layer, data communication layer and data analysis layer.

6.3.1. Data acquisition layer

Collecting data from in service transformers provides a clear understanding of the condition of transformers that offline testing simply cannot offer. Monitors and sensors are the main devices that constitute this layer. Various thermal, chemical, electrical and physical parameters can be measured by means of these devices. These monitors and sensors are the bases for a condition based maintenance schemes, however they have to be supported and complemented by both communication and analysis infrastructures to provide a truly useable solution [34].

6.3.2. Data communication layer

The capacity to reliably and securely transfer data collected at the data acquisition layer for processing and analysis is necessary for a successful an online condition monitoring strategy. Data are usually transferred by means of digital communications based on proprietary or industry standard protocols such as MODBUS, DNP3, or IEC61850 [3,34]. These protocols can be communicated via serial interfaces, or transmit information via TCP/IP.

6.3.3. Data analysis layer

Data analysis and interpretation is at the heart of a successful online condition monitoring and maintenance scheme. The size of data to analyse in order to get insight as to the condition of transformers combined to the shortage of experts in the interpretation of these data within reasonable time have led to the need for intelligent and efficient algorithms whose role is to automatically evaluate the measured data in order to determine the risk of failure of transformers, and highlight assets requiring specific attention [34]. At this layer, there will be computer hosting a database of transformer data and software to process these data. The software can range from a data historian to analysis software capable of alerting the user to conditions which may require immediate attention [3].

6.4. Online Condition Monitoring and Diagnostic System for Transformers Insulating Oil

We are proposing here a model of online monitoring and diagnostic system for transformers insulating oil based on dissolved gas analysis. We will propose for each of the three layers of an online condition monitoring and diagnostic system the required devices and software to achieve online condition monitoring and diagnostic of transformers insulating oil using dissolved gas in oil methods.

6.4.1. Data acquisition layer

Many solutions are offered to us here in order to collect key gases generated by transformers during their operation. We can make use of sensors based on fuel cell/catalytic, solid state and thermal conductivity detection (TCD) technologies [35]. Sensors based on fuel-cell/catalytic technology produce a composite signal of hydrogen and carbon monoxide, together with small amounts of other hydrocarbon gases, whereas TCD and solid state technologies based sensors are meant to measure hydrogen [35].

Another possibility to gather gases data is by means of multi-gas online DGA monitors [3], [35]. These devices are based on gas chromatography, and are to detect and quantify all the key gases (refer to Section 4.3.3).

6.4.2. Data communication layer

The ability to transfer the collected gas data from the data communication to the online analysis centre is critical for the application. Therefore, the communication method to be used should ensure certain desirable properties, namely [35]: data integrity, efficient data transfer, flexible data transmission, standards compliancy, OSI-model compliancy, flexibility in data transmission, addressability of devices. Many protocols that can be used in data transfer from the data acquisition layer to analysis centres have been developed, the most notable ones being the distributed network protocol (DNP), the IEC 60870-5 protocol, and the substation LAN protocol.

6.4.3. Data analysis layer

Gas data analysis is paramount to successful online condition monitoring and diagnostic of transformer insulating oil. This layer comprises two main components, a database of transformer oil data (generated gases and other parameter if available) and programs for the analysis of these data.

6.4.3.1. Dissolved gases database

It is important to maintain a database of different gas in oil samples collected overtime by online sensing devices as well as samples collected during offline inspection activities. This will be useful in establishing trends, generation rates of gases and correlations between data and transformers failure risks. The proposed data model for our online transformer oil condition monitoring and diagnostic system is illustrated in Figure 6.1 with the relevant entities.

We defined four entities, namely **Transformer**, **Location**, **Sample** and **DiagnosticMethod** whose meanings and associations that exist between some of them can be described as follows:

- The **Transformer** entity represents a physical transformer. It holds the properties related to a particular transformer such as its type, rating etc.

- The **Location** entity defines a geographical area where transformers can be situated.

- The **Sample** entity holds the gas data necessary for DGA, collected during a transformer oil gas sampling operation (both online and offline sampling are considered).

- The **DiagnosticMethod** entity represent a particular diagnostic DGA method that can be applied to collected samples.

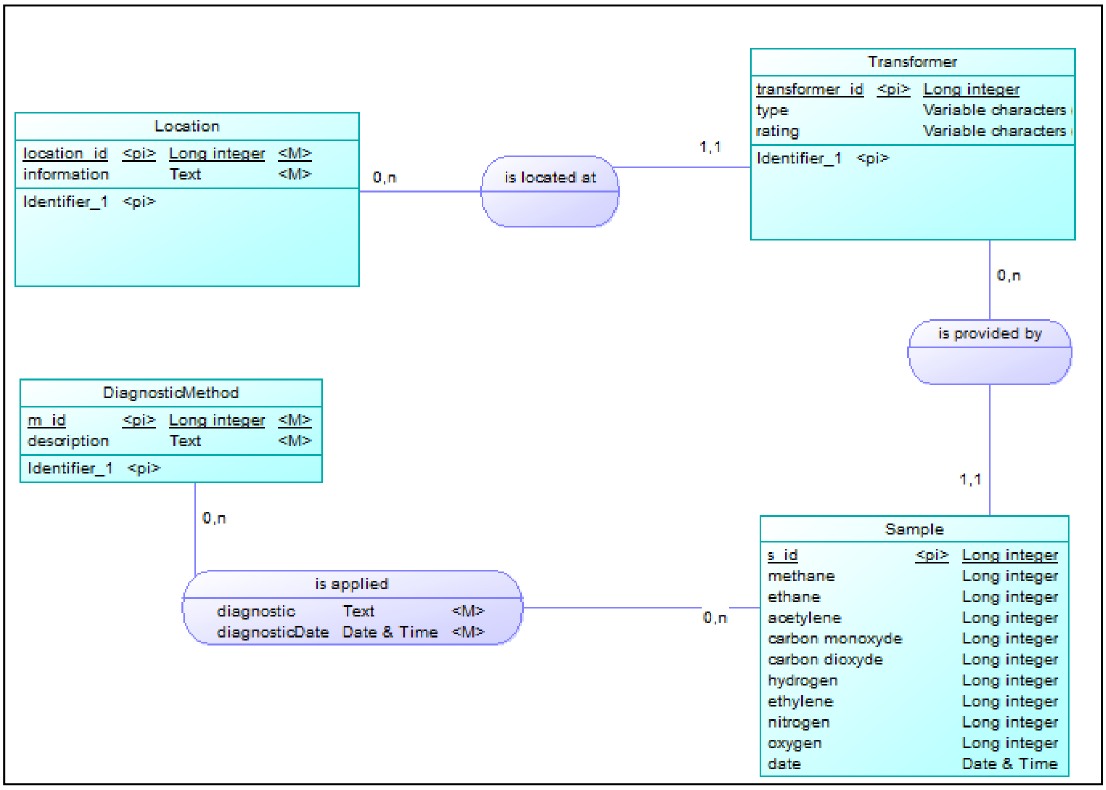

Figure 6.1. Data model for online DGA

6.4.3.2. Software tools for DGA data analysis

The software package for online DGA is provided to allow the traceability of fault severity on real time through graphical DGA tools that include the Duval Triangle, the Duval Pentagon and the Rogers ratio methods. It also provides a tool for displaying the continuous evolution of the key gases used in DGA so as to derive trends and allow the application of corrective measures on critical monitored nodes.

6.5. Summary

In this chapter, we proposed a model of online monitoring and diagnostic system for transformer insulating oil based on DGA. The tools to be integrated at the different layers of an online monitoring and diagnostic system, for insulating oil in this case, were reviewed. Although DGA is the primary tool for transformer condition assessment, it is possible to further extend this system by the incorporation of other transformer insulating oil parameters such viscosity, temperature (top, bottom, ambient), moisture content to have a more comprehensive and accurate diagnostic tool.

CONCLUSION

Transformers are the most critical node in a power generation and distribution system, and therefore having transformers in good condition is paramount for power utilities. Besides fulfilling its primary functions as insulator and heat dissipater, transformer insulating oil can serve as a diagnostic indicator of the condition of the transformer much like blood can provide diagnostic information about the human body. Dissolved gas-in-oil analysis has been widely used by power utilities as the primary tool for transformer condition assessment due to its ability to give early warning on developing thermal and electrical faults within the transformer. However, applying dissolved gas analysis in the context of the traditional time based maintenance scheme will not provide the full benefits of this technique. It is important, and even necessary to apply dissolved gas analysis in the context of a real time monitoring scheme so that corrective measures can be taken when needed.

In this work, we try to propose a model of an online condition monitoring and diagnostic system for transformer insulating oil based on dissolved gas in oil analysis. This model includes a data acquisition layer that comprises devices to collect the concentrations of gases uses DGA methods, a data communication layer in order to transfer reliably the collected data to analysis centre, an a data analysis layer constituted of programmes for data analysis. The expected result from this system is the ability to provide real time information about the condition of the insulating oil and by extension on the operational condition of the transformer.

The system only focuses on dissolved gases in oil analysis and could be extended to other oil parameters such as oil temperature, moisture content, and viscosity in other to provide a more comprehensive view of the condition of the oil so that more precise measures can be applied.

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RESUME

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