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# High Voltage Power Transformer Dissolved Gas Analysis, Measurement and Interpretation Techniques

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## Abstract

Dissolved Gas Analysis (DGA) is widely accepted powerful tool in diagnosing power transformer health condition. Several DGA measurement techniques have been developed since 1950's, from limited laboratory testing up to site online monitoring. Gas Chromatography (GC), Hydrogen On-line Monitor and Photo-Acoustic Spectroscopy (PAS) are most popular among existing DGA techniques. Basic operating principle, advantages and disadvantages of GC, Hydrogen On-line Monitor and PAS are reviewed and discussed in this paper. Several DGA interpretation techniques such as Key Gas Method, Doernenburg, Rogers, IEC ratio methods and Duval Triangle method are also reviewed in this paper.

## Introduction

Dissolved Gas Analysis (DGA) is used to assess the health condition of a power transformer based on the type and amount of dissolved gases in transformer oil due to the decomposition of paper and oil insulation. DGA has gained worldwide recognition as a diagnostic method for the detection of transformer incipient faults.

Due to the thermal and electrical stresses that dielectric insulations of operating transformers experience, paper and oil decomposition occurs evolving gases that dissolve in insulation oil and reduces its dielectric strength [1-6]. Gases produced due to oil decomposition are hydrogen ($H_2$), methane ($CH_4$), acetylene ($C_2H_2$), ethylene ($C_2H_4$) and ethane ($C_2H_6$). On the other hand, carbon monoxide (CO) and carbon dioxide ($CO_2$) are generated as a result of paper decomposition [7,8]. Faults such as overheating, partial discharge and sustained arcing produce different types and concentration of the aforementioned gases that can be used for fault quantification and identification.

In 1978, IEEE published a guideline for the detection of generated gases in oil-immersed transformers known as ANSI/IEEEC57.104-1978 Standard [9]. This standard covers the use of instrumentations, sampling procedures, methods for analyzing and extracting gases and data interpretation. In 1992, IEEE published another guideline (IEEE Std C57.104-1991) [8] that mainly focused on interpretation of DGA results. This standard has been revised in 2008 (IEEE Std C57.104-2008) [10]. On the other hand, IEC published a guide for the sampling of gases and of oil from oil-filled electrical equipment and for the Analysis of Free and Dissolved Gases in 1977, while in 2002, ASTM issued ASTM Standard (D3612-02) for analysis of gases dissolved in electrical insulating oil by using Gas Chromatography method [2].

Conventionally, DGA measurement is done in a laboratory environment due to the complexity of the equipment required where oil samples are to be collected from operating transformers, and transported to the laboratory for gas extraction and measurement processes. There are three common techniques currently used in laboratory to extract gases; vacuum extraction, stripper extraction and headspace sampling as stated in ASTM D3612 [2]. Another technique known as shake test can also be used [11]. After extraction process done, all the gases are analyzed using gas chromatography (GC). Due to the time and costs involved with GC analysis, DGA analysis using this technique is only performed once a year for operating transformers. Frequent DGA testing only take place when significant fault gases are detected during routine analysis[12].

By considering the limitation of using GC method, several new techniques are developed to analyze dissolved gases in transformer oil such as Hydrogen On-line Monitor [13, 14] and Photo-Acoustic Spectroscopy (PAS) [12,15], also known as DGA On-Line monitoring. Both techniques can minimize the testing time that GC analysis takes.

Various DGA interpretation techniques are developed to evaluate power transformer condition such as Key Gas Method, Doernenburg Ratio Method, Rogers Ratio Method, IEC Ratio Method and Duval Triangle Method. All of these techniques are based on practical knowledge and experience assumption by experts rather than mathematical formulation [1,7]. Therefore, it may lead to the different conclusion even though for the same oil sample.

In this paper, common DGA methods such as GC, Hydrogen On-line Monitor and PAS along with the most popular interpretation techniques such as Key Gas Method, Doernenburg Ratio Method, Rogers Ratio Method, IEC Ratio Method and Duval Triangle Method are briefly elaborated and discussed.

## DGA Quantification Methods

## A. Gas Chromatography (GC)

Gas chromatography has been used to analyze gases dissolved in insulating oil during the last 60 years [16]. This technique is introduced by James and Martin in 1952 [17]. Rogers reported in [18] that the first GC diagnose is attempted in 1956 by Howe et al, and later on, regularly used by C.E.G.B for monitoring and routine assessment since 1968. However, this technique's became more popular after IEEE, IEC and ASTM published guidelines on how to measure and analyze gases dissolved in transformer insulating oil. Currently, GC analysis is well accepted as the best among DGA techniques to quantify all gases dissolved in transformer oil including total dissolved gases (TDG), individual dissolved gases (IDG) and individual gases present (IGP) in the gas blanket. However, due to the complexity of the equipment required, GC analysis can only be conducted in laboratory environment, hence several standards should be followed to handle the gas sample since extracting the oil sample from an operating transformer and transporting it to the laboratory site till extracting dissolved gases using GC [2, 9, 19-21].

According to ANSI/IEEEC57.104-1978 Standard [9], oil sample can be stored and transported to the laboratory by using either calibrated stainless steel cylinders, flexible metal cans, syringes or glass bottles. However, all the

containers must meet the leak criterion stated in this standard. ASTM D923[21] stated that amber or clear glass bottles may use glass-stopper or can be fitted with crew caps having a pulp-board liner faced with tin or aluminum foil, or at least with a suitable oil-resistant plastic such as polyethylene, polytetraflouroethylene (PTFE) or fluoro-elastomers. ASTM D3612[2] quotes that gases in the oil can be separated by using vacuum extraction, stripper column extraction or headspace sampling methods. Vacuum extraction (shown in Fig. 1) is suitable method to extract a portion of gases, while stripper column extraction method can extract all gases in oil sample. On the other hand, headspace sampling which (shown in Fig. 2) is used to get a portion of the headspace gases. Another method to extract dissolved gas in oil sample is developed by Morgan–Shaffer in 1993 known as Shake Test [11]. Through shake test, dissolved gases in the oil can be extracted quickly, even at the site.

After the extraction of dissolved gas from the oil sample, it is analyzed by using GC. A basic GC as shown in Fig. 3 consists of a carrier gas source, a pressure regulator, a sample injection port and chromatography columns, flow meter, detector, and recorder or recording integrator [2]. Basic operating principle of GC involves volatilization of the sample in injection port of a gas chromatograph, followed by separation of the components of the mixture in chromatography columns [17]. Argon, helium, nitrogen and hydrogen are normally used as carrier gases to transfer the sample from the injector, via the column, and into a detector or mass spectrometer [2, 17, 22]. However, the nature of the carrier gases used may affect the separation characteristics of the GC system and can vary the sensitivity of the detection.

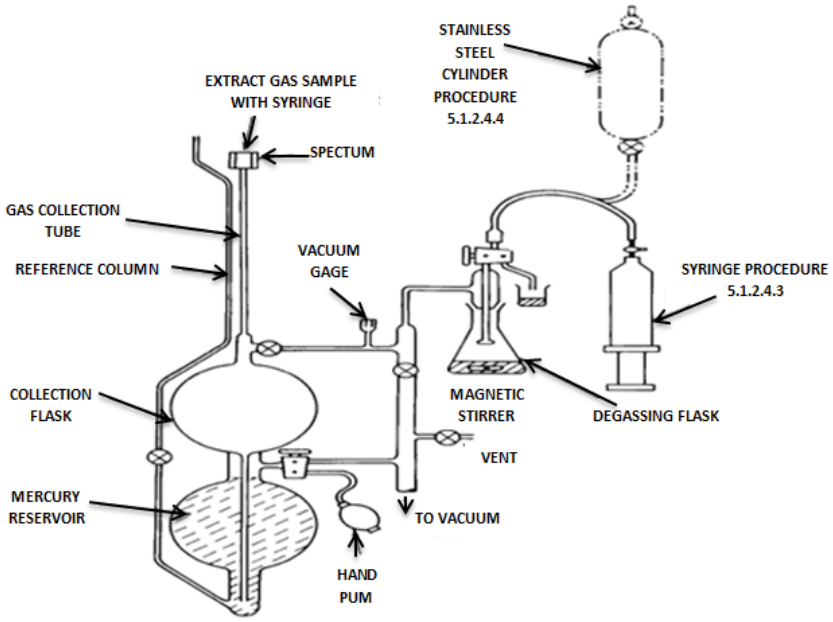



**Figure 1.** Extraction of gas from insulating oil using vacuum extraction method[2]

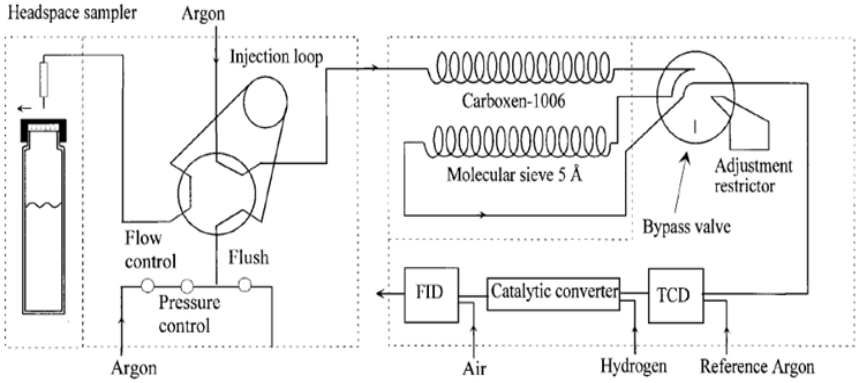



**Figure 2.** Extraction of gas from insulating oil by using headspace method[2]

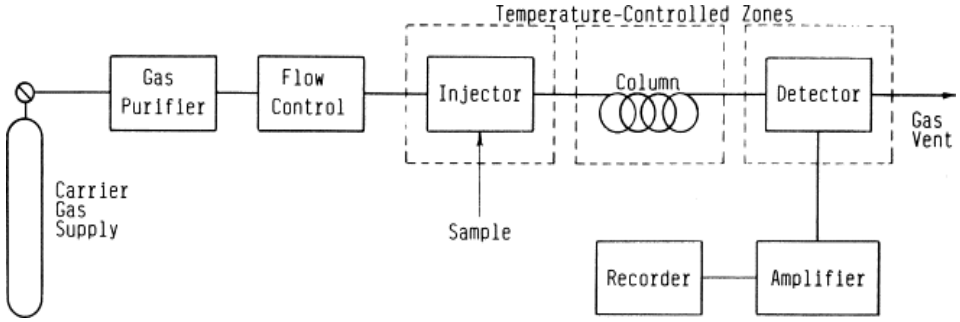



**Figure 3.** An example of basic Gas Chromatography[23]

As reported in [22], GC columns can be divided into two categories; packed and capillary columns. However, majority of GC users use capillary columns/tubes with a stationary phase coated on the inner wall [17] which has the advantage of substantially higher separation capacity when compared with the packed columns [22]. Separation capacity is determined by the portioning of each component between carrier gas and the stationary phase[17]. Component with delay in the stationary phase is eluted, while remaining components in the carrier gas flow into a detector or a mass spectrometer. It is necessary to retain a constant temperature of gas chromatographic column in order to achieve effective and reliable separation. The solute molecules existed in the column interact with the detectors, and is converted into an electrical signal [22]. This signal is sent to the recording or data-storage device. The detectors used are specifically designed for gas chromatograph such as thermal conductivity detector (TCD), flame ionization detector (FID), nitrogen–phosphorus detector (NPD), flame photometric detector (FPD), electron capture detector (ECD), atomic emission detector (AED) and electrolytic conductivity detector (ELCD) [17, 22].

As reported in [2], FID is normally used to detect hydrocarbons and carbon oxides gases due to its greater sensitivity, while TCD is used to detect permanent gases such as $H_2$, $O_2$ and $N_2$. Alternatively, using mass spectrometer (MS), prior separation of mixture component is an optional process.

By using GC, some individual gases can be identified included hydrogen, oxygen, nitrogen, carbon monoxide, carbon dioxide, methane, ethane, ethylene, acetylene, propane and propylene[2]. Other studies also show that GC/MS also capable to detect and analyze methyl acetate, 2-methylfuran,

phenol, methyl formate, furan, methanol, ethanol, acetone, isopropyl alcohol and methyl ethyl ketone [24-27].

## B. Hydrogen On-Line Monitor

Due to the time-consuming and expensive laboratory equipment required for GC technique, a rugged low-cost with continuously monitoring device known as Hydrogen On-line Monitor has been developed [16]. Hydrogen On-line Monitor system has been invented by Syprotec [16, 28], and followed by extensively research by the Institut de Recherche d'Hydro Quebec (IREQ) since 1974 in order to produce a rugged low-cost device for site implementation. As it is widely accepted that majority of faults in oil-filled electrical equipment generate hydrogen gas [8], Hydrogen On-line Monitor systems is developed to mainly focus on monitoring key gases such as hydrogen along with carbon monoxide instead of considering all dissolved gases [14]. By monitoring $H_2$ gas dissolved in transformer oil, an early detection of faults growth especially for hot spots, partial discharges and arcing is warned. Another gases that can be detected by Hydrogen On-line Monitor are ethylene and acetylene, but in smaller amounts.

Basic principle of Hydrogen On-line Monitor operation which is shown in the schematic diagram of Fig. 4 is based on the reaction of the hydrogen from the oil permeates through a membrane with the atmospheric oxygen[16], which generates a small current proportional. This current is amplified by electronic circuits, and translated into gas level in parts per million (ppm). Alarm is actuated when the gas value reached certain level. Recent improvement in membrane technology allowed Hydrogen On-line Monitor systems to detect the combination of hydrogen, carbon monoxide, ethylene and acetylene. With 100% efficiency of hydrogen, the sensitivity of other gases is yet low; approximately 15% for carbon monoxide, 8% for acetylene and 1% for ethylene [16, 29].

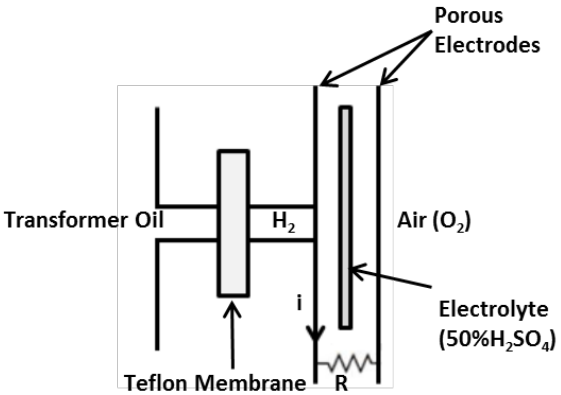



**Figure 4.** Hydrogen On-line Monitor principle schematic diagram[16]

Basic Hydrogen On-line Monitor consists of a sensor, contacted with the oil and an electronics unit. The sensor is placed in a rugged brass housing containing the fuel cell, temperature sensing and the membrane. This sensor can be installed either into a flange or valve on the transformer pipe work [16], between the cooling bank and the main tank, or on the upper part of the transformer [29].

Although Hydrogen On-line Monitor is incapable to provide the concentrations of all fault gases like GC, but its reliability to detect incipient faults of power transformer is proven. Due to the benefit offered by this system costing, it is reported that approximately 18,000 Hydrogen On-line Monitor systems have been globally installed in 2003[11]. Additionally, Hydrogen On-line Monitor is not only performed when the membrane is in contact with moving oil, but also with static oil [16]. However, there are few complications of using Hydrogen On-line Monitor since it is sensitive to temperature and the reading of the unit may vary with the variation of oil temperature [28]. Hydrogen On-line Monitor accuracy is proven to be ±10% at temperature range between 20°C to 40°C and cannot provide precise concentrations for fault gases[29].

## C. Photo-Acoustic Spectroscopy (PAS)

Photo-Acoustic Spectroscopy (PAS) is another DGA on-line monitoring technique that utilizes spectral analysis to detect the volume of absorbed gases based on photo-acoustic effect [30]. Instead of using composite gas detectors likes Hydrogen On-line Monitor, PAS employed the common headspace gas extraction technique along with infrared/acoustic based detector for gas measurement [12]. According to [31], the first photo-acoustic application was used by Alexander Graham Bell in 1880, when he found that a sound is emitted when a thin disk is exposed to mechanically chopped sunlight. Similar effects are observed by using infrared or ultraviolet light. Since that, PAS has been used in various applications such as ambient air monitoring, air polluting emission from car exhausts, biological and medical experiments. However the use of PAS technology to monitor power transformer health condition is still new and is not fully matured yet.

The basic principle of PAS is that fault gases absorb the infrared light energy and convert it into kinetic energy[12] that lead to sequences of pressure waves (sound) which can be detected by a microphone. This microphone converts the amount of pressure in the measurement chamber (where the gas sample is exposed to the light) into electrical signal [32]. The photo-acoustic spectrum of a fault gases is recorded by measuring the sound at different wavelengths, which is used to identify the concentration of the faults gases involved. By using PAS, several fault gases can be detected such as $H_2$, CO, $CO_2$, $CH_4$, $C2H_4$, $C_2H_2$ and $C_2H_6$[12, 32]. Figs. 5 and 6 show the basic operation of PAS-based DGA system while Fig. 7 shows the absorption characteristic of fault gases [32].

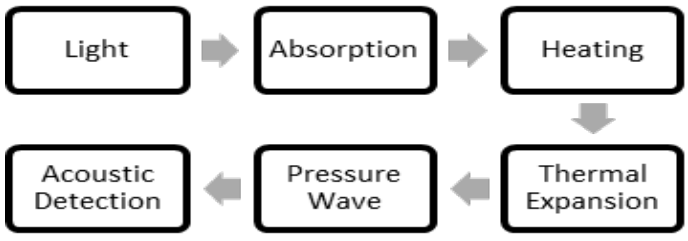



**Figure 5** Basic principle of PAS process[33]

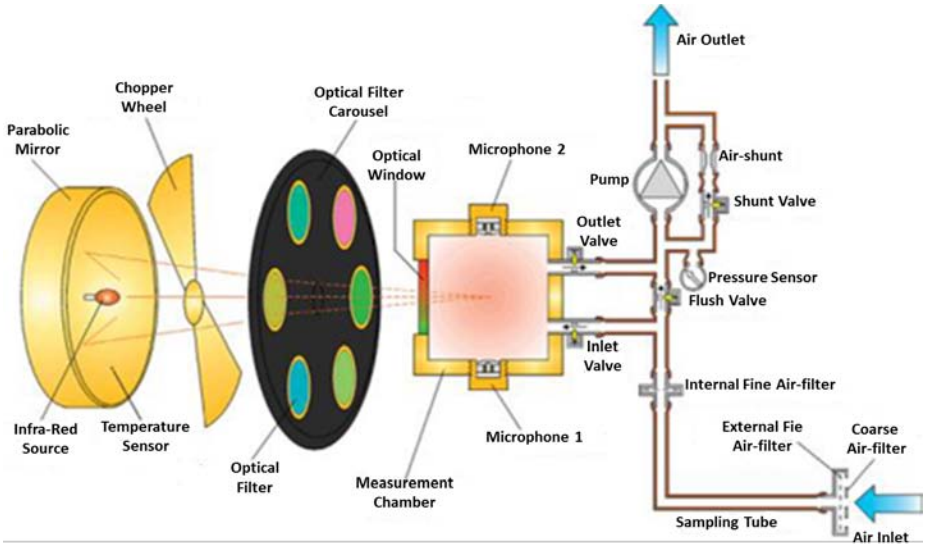



**Figure 6.** An example of PAS-based DGA system[32]

A historical analysis reported in [12] found that PAS is very stable diagnostic tools and suitable for monitoring critical transformers. However, although each fault gas absorbs the infrared light at specific wavelength, selecting the center wavelength is a critical process. Incorrect center wavelength will cause mutual interference between gases involved [32]. In fact, there is cross-interference between various gases including water vapor as shown in Fig. 7. Meanwhile the sensitivity of each gas is influences by the wave number of the optical filter and its characteristics absorption spectrum. Investigation done by Fu et al [30] found that the detection accuracy of PAS is also influenced by the external gas pressure, vibration, light temperature and environmental factors.

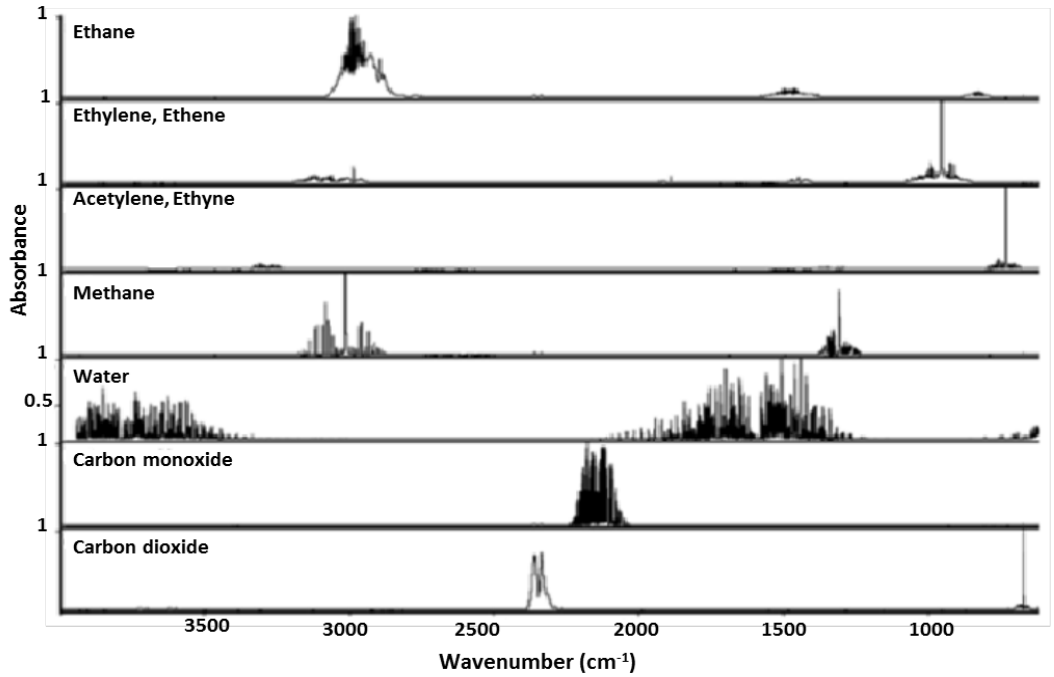



**Figure 7.** Characteristic absorption of diagnostic fault gases[32]

A comprehensive comparison between the above three DGA measurement techniques is given in Table 1.

**Table 1.** Comparison between GC, Hydrogen On-line Monitor and PAS

| Method | Advantage | Disadvantage |
|---|---|---|
| **GC** | • Able to detect and analyze every individual gas dissolved in transformer oil.<br>• Provides highest accuracy and repeatability results.<br>• Results can be used to interpret the faults roots. | • Only can be done in laboratory due to complex equipment required.<br>• Long time required to complete each test.<br>• Possibility missed diagnostic opportunity due to limited sample collected per annum.<br>• Need an expert to conduct the test. |
| **HYDROGEN ON-LINE MONITOR** | • Rugged low-cost with continuous online monitoring.<br>• Able to detect incipient faults. | • Only capable to detect $H_2$, CO, $C_2H_2$ and $C_2H_4$.<br>• Low accuracy at temperature range 20°C to 40°C.<br>• Sensitive to oil temperature variation.<br>• Unable to interpret faults roots. |
| **PAS** | • Able to provide continuous online monitoring.<br>• Capable to detect more dissolve fault gases than Hydrogen On-line Monitor<br>• Results may be used to interpret the fault roots. | • Results influenced by the wave number of the optical filter and its absorption characteristics.<br>• Detection accuracy influenced by external gas pressure, vibration and light temperature.<br>• Still not fully matured. |

## DGA Interpretation Techniques

## A. Key Gas Method (KGM)

The presence of fault gases within transformer oil depends on the temperature or energy that will break the chemical bonding of the insulation oil and hence reducing its dielectric insulation strength [34]. KGM considers the individual concentration of gases produced during faults. KGM interprets DGA results by referring to the four sets of charts shown in Fig. 8 that have been developed based on empirical experience and knowledge of experts. These charts represent the combination of significant gases involved in four common transformer faults, which are partial discharge (PD), arcing, overheated of oil and overheated of cellulose. The significant gases involved with each fault are shown in Fig. 8. As per the IEEE Standard C57.104-2008, $H_2$ is the key gas for

PD while $C_2H_2$ is the key gas for arcing. DGA results in high concentration of CO in case of overheating fault involving cellulose. On the other hand $C_2H_4$ is a sign for overheating in oil and a traceable amount of $C_2H_2$ is a sign for a sustained arcing [35]. Even though the KGM charts look simple, it is not widely accepted as a diagnostic tool for power transformers as it is considered very conservative. Studies based on the IEC data bank of inspected transformers shows that only 42% of diagnosis using KGM is correct, while the rest is under misinterpretation [36].

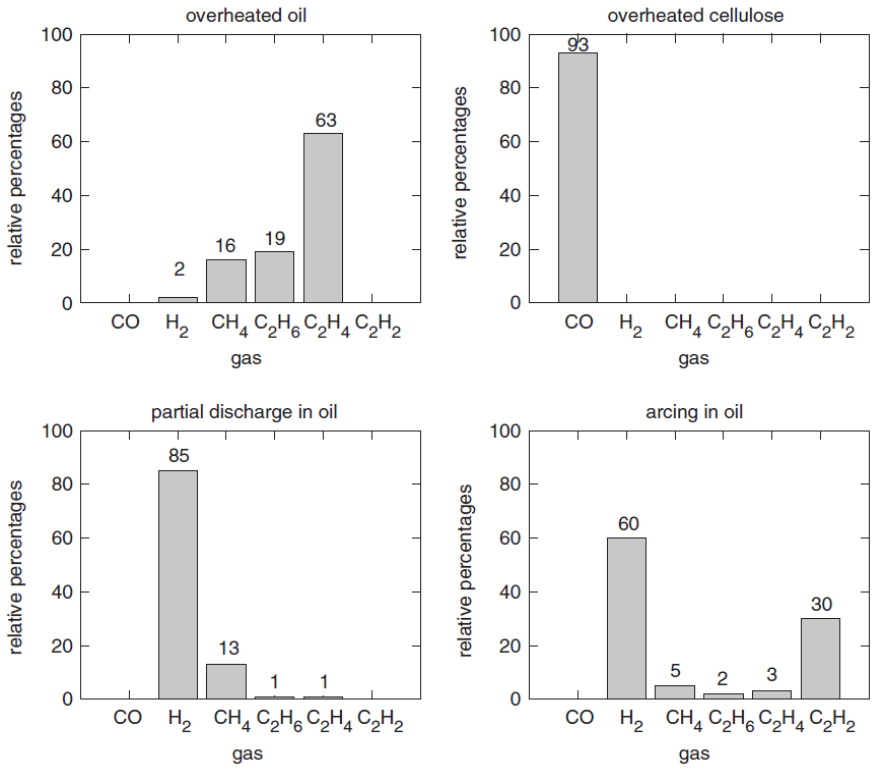



**Figure 8.** Key Gases Method Chart [5]

## B. Doernenburg Ratio Method (DRM)

Doernenburg Ratio method is developed based on thermal degradation principles in 1970 [18, 35]. The method utilizes the ratio of gas concentration to indicate fault types. Predefined set limit for $CH_4/H_2$, $C_2H_2/CH_4$, $C_2H_2/CH_4$ and $C_2H_6/C_2H_2$ ratios is used to interpret the DGA results [35]. Table 2 shows the ratio interpretation table of DRM.

To get valid results using DRM, at least the concentration of one of the key gases used in the 4 ratios must exceed twice the value of predefined limit L1 given in Table 3 and another one of gas concentration exceeds the limit L1 [8]. The main drawback of DRM is that the rate of unresolved diagnoses is still high due to the incomplete ratio ranges [1].

**Table 2.** Ratio interpretation table of DRM [35]

| Suggested fault diagnosis | Ratio 1 (R1) $CH_4/H_2$ | | Ratio 2 (R2) $C_2H_2/C_2H_4$ | | Ratio 3 (R3) $C_2H_2/CH_4$ | | Ratio 4 (R4) $C_2H_6/C_2H_2$ | |
|---|---|---|---|---|---|---|---|---|
| | Oil | Gas Space | Oil | Gas Space | Oil | Gas Space | Oil | Gas Space |
| 1. Thermal decomposition | >1 | >0.1 | <0.75 | <1 | <0.3 | <0.1 | >0.4 | >0.2 |
| 2. Partial discharge (low-intensity PD) | <0.1 | <0.01 | Not significant | | <0.3 | <0.1 | >0.4 | >0.2 |
| 3. Arcing (high-intensity PD) | >0.1 to <1 | >0.01 to <01 | >0.75 | >1 | >0.3 | >0.1 | <0.4 | <0.2 |

**Table 3.** Concentration limits of dissolved gas [8]

| Key Gas | Concentrations L1 (ppm) |
|---|---|
| Hydrogen ($H_2$) | 100 |
| Methane ($CH_4$) | 120 |
| Carbon Monoxide (CO) | 350 |
| Acetylene ($C_2H_2$) | 35 |
| Ethylene ($C_2H_4$) | 50 |
| Ethane ($C_2H_6$) | 65 |

## C. Rogers Ratio Method(RRM)

RRM follow the similar procedure initiated by DRM, but with some modification and improvement in order to fill in the gap of DRM [18]. While DRM requires significant levels of the gases to be present in order for diagnostic to be valid, RRM can be used when any of individual gases exceeds its normal limit and it does not depend on specific gas concentrations [8].An original RRM utilizes four ratios; $C_2H_6/CH_4$, $C_2H_2/C_2H_4$, $CH_4/H_2$, and $C_2H_4/C_2H_6$ that leads to twelve proposed diagnosis as shown in Table 4 [9].

RRM diagnosis provides more interpretation details in terms of temperature range of decomposition. However, the ratio $C_2H_6/CH_4$ can only indicate a limited temperature range of decomposition and do not assist in further fault interpretation [18, 37]. Therefore in the IEEE Standard C57.104-1991, RRM diagnosis is revised and the ratio of $C_2H_6/CH_4$ is excluded from the RRM code was revised to include only six diagnosis interpretations; normal, low-energy density arcing- PD, arcing- high-energy discharge, low temperature thermal, thermal<700°C, and thermal>700°C (Table 5) [35]. This method does not consider dissolved gases below normal concentration limits, also certain ratio values are inconsistent with the diagnostic assigned and lead to invalid codes [1, 7].

**Table 4.** Original diagnosis proposed by RRM [9]

| $CH_4$/ $H_2$ | $C_2H_6$/ $CH_4$ | $C_2H_4$/ $C_2H_6$ | $C_2H_2$/ $C_2H_4$ | Suggested Diagnosis |
|---|---|---|---|---|
| >0.1 to <1 | <1 | <1 | <0.5 | Normal |
| ≤0.1 | <1 | <1 | <0.5 | Partial discharge -Corona |
| ≤0.1 | <1 | <1 | ≥0.5 to <3 or ≥3 | Partial discharge – Corona with tracking |
| >0.1 to <1 | <1 | ≥3 | ≥3 | Continuous discharge |
| >0.1 to <1 | <1 | ≥1 to <3 or ≥3 | ≥0.5 to <3 or ≥3 | Arc – With power follow through |
| >0.1 to <1 | <1 | <1 | ≥0.5 to <3 | Arc – No power follow through |
| ≥1 to <3 or ≥3 | <1 | <1 | <0.5 | Slight overheating – to 150°C |
| ≥1 to <3 or ≥3 | ≥1 | <1 | <0.5 | Overheating 150-200°C |
| >0.1 to <1 | ≥1 | <1 | <0.5 | Overheating 200-300°C |
| >0.1 to <1 | <1 | ≥1 to <3 | <0.5 | General conductor overheating |
| ≥1 to <3 | <1 | ≥1 to <3 | <0.5 | Circulating currents in windings |
| ≥1 to <3 | <1 | ≥3 | <0.5 | Circulating currents core and tank; overloaded joints |

**Table 5.** Latest version of RRM diagnosis table

| Case | R2 $C_2H_2$/ $C_2H_4$ | R1 $CH_4$/ $H_2$ | R5 $C_2H_4$/ $C_2H_6$ | Suggested Fault Diagnosis |
|---|---|---|---|---|
| 0 | <0.1 | >0.1 to <1 | <1 | Unit normal |
| 1 | <0.1 | <0.1 | <1 | Low-energy density arcing- PD |
| 2 | 0.1 to 3 | 0.1 to 1 | >3 | Arcing – High-energy discharge |
| 3 | <0.1 | >0.1 to <1 | 1 to 3 | Low temperature thermal |
| 4 | <0.1 | >1 | 1 to 3 | Thermal less than 700°C |
| 5 | <0.1 | >1 | >3 | Thermal exceeding 700°C |

## D. IEC Ratio Method (IRM)

The IEC Ratio method was developed in 1978 as an evolution of RRM [18]. Even though the three IRM ratios are similar to those used in the revised RRM (IEEE Standard C57.104-1991), it developed different code ranges as given in Table 6 [7]. An original IRM proposed nine classifications of faults with various temperatures ranges from partial discharge of low energy density up to thermal fault more than 700°C [18].

**Table 6.** An original diagnosis interpretation proposed by IRM [7]

| $C_2H_2/C_2H_4$ | $CH_4/H_2$ | $C_2H_4/C_2H_6$ | Range of gas ratio |
|---|---|---|---|
| 0 | 1 | 0 | <0.1 |
| 1 | 0 | 0 | 0.1 to 1 |
| 1 | 2 | 1 | 1 to 3 |
| 2 | 2 | 2 | >3 |
| **Characteristic Fault** | | | |
| 0 | 0 | 0 | Normal ageing |
| 2 | 1 | 0 | Partial discharge of low energy density |
| 1 | 1 | 0 | Partial discharge of high energy density |
| 1-2 | 0 | 1-2 | Continuous sparking |
| 1 | 0 | 2 | Discharge of high energy |
| 0 | 0 | 1 | Thermal fault of low temperature less than 150°C |
| 0 | 2 | 0 | Thermal fault of low temperature between150-300°C |
| 0 | 2 | 1 | Thermal faults of medium temperature between 300- 700°C |
| 0 | 2 | 2 | Thermal faults of high temperature exceeding 700°C |

IEC Ratio method has been revised in IEC Publication 60599 in 1999 from previous publication, IEC 599 [38]. The revised version contains interpretation of the six general faults usually found in electrical equipment in service. The six general faults are referred to partial discharge, discharges of low or high energy, thermal faults of temperature less than 300°C, temperature between 300°C to 700°C, or temperature more than 700°C [39]. Two new gas ratios; $C_2H_2/H_2$ to detect possible contamination from OLTC compartment, and $O_2/N_2$ to detect abnormal oil heating/oxidation were introduced [38]. Table 7 shows the diagnosis proposed in the revised version of IRM [40]. Another improvement was introduced to the new IRM version by using the 3D graphical representation of ratio ranges that can give more precise results [38], and to estimate or observe the faults that out of diagnostic codes [1].

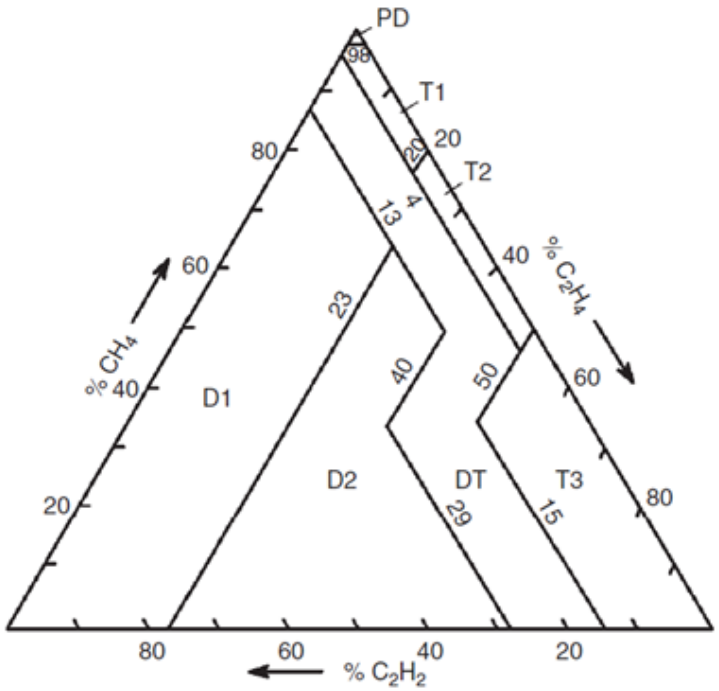
**Table 7.** IRM diagnosis interpretation based on IEC60599 [40]

| Case | Characteristic Fault | $C_2H_2/C_2H_4$ | $CH_4/H_2$ | $C_2H_4/C_2H_6$ |
|---|---|---|---|---|
| **PD** | Partial Discharges | NS | <0.1 | <0.2 |
| **D1** | Discharges of low energy | >1 | 0.1-0.5 | >1 |
| **D2** | Discharges of high energy | 0.6-2.5 | 0.1-1 | >2 |
| **T1** | Thermal faults not exceeding 300°C | NS | >1 but NS | <1 |
| **T2** | Thermal faults exceeding 300°C but not exceeding 700°C | <0.1 | >1 | 1-4 |
| **T3** | Thermal faults exceeding 700°C | <0.2 | >1 | >4 |
| NS = Non-significant whatever the value | | | | |

## E. Duval Triangle Method (DTM)

Duval Triangle method is an innovation developed from an existing IEC 60599 Ratio Method and IEC TC10 databases which represent the DGA results in more user-friendly graphical form [39, 41]. DTM faults interpretation is based on the values of three gases, $CH_4$, $C_2H_2$ and $C_2H_4$, and their location on triangle developed by Duval [39] as shown in Fig. 9. Duval Triangle is characterized by six faults zones, which covered partial discharge, thermal fault at various temperatures, and electrical arcing [39].

According to [7],[34] and [36], DTM provides the most accurate and consistent interpretations compared with the other methods. However inconsiderate implementation leads to wrong diagnoses [41]. Moreover, as Duval triangle does not encompass normal zone, it cannot be used to detect incipient faults.




| | |
|---|---|
| **PD** | Partial Discharges |
| **D1** | Discharges of low energy |
| **D2** | Discharges of high energy |
| **DT** | Combination of thermal faults and discharges |
| **T1** | Thermal faults not exceeding 300°C |
| **T2** | Thermal faults exceeding 300°C but not exceeding 700°C |
| **T3** | Thermal faults exceeding 700°C |

**Figure 9**. Coordinates and fault zones of the DTM[39]

Table 8 below summaries the various DGA interpretation techniques discussed above.

**Table 8**.[39] Comparison between KGM, DDM, RRM, IRM and DTM

| Types | Method | Fault Types | Gas Involved |
|---|---|---|---|
| **KGM** | Uses the individual gases concentration.<br>Correlates DGA results with 4 sets of charts. | PD, Arcing,<br>Overheated oil,<br>Overheated cellulose. | CO,$H_2$, $CH_4$, $C_2H_2$, $C_2H_4$ and $C_2H_6$ |
| **DRM** | Uses four ratio of gas concentration to indicate 3 faults. Uses limit spec. to differentiate faults. | Thermal decomposition, PD, Arcing | $H_2$, $CH_4$, $C_2H_2$, $C_2H_4$ and $C_2H_6$ |
| **RRM** | Uses ratios of gas concentration to indicate faults.<br>Uses limit spec. to differentiate fault. | PD, Arcing, Low temperature, Thermal<700°C, and >700°C | $H_2$, $CH_4$, $C_2H_2$, $C_2H_4$ and $C_2H_6$ |
| **IRM** | Evolution from Rogers method but excludes the $C_2H_6/CH_4$ ratio. Indicates 6 faults. Uses limit spec. to differentiate faults. | PD, Low energy discharge, High energy discharge, Thermal(T) fault T<300°C , 300<T<700°C, and T>700°C | $H_2$, $CH_4$, $C_2H_2$, $C_2H_4$ and $C_2H_6$ |
| **DTM** | Uses triangle map to indicate six faults. | P PD, Low energy discharge, High energy discharge, Thermal fault <300°C , 300<T<700°C, and T>700°C | $CH_4$, $C_2H_2$, and $C_2H_4$ |

## Conclusion

Three different DGA methods are discussed and compared in this paper. There is no doubt about GC performance and high accuracy in analyzing dissolved gases in transformer oil. Due to the time-consuming and cost involved, industries are looking towards online DGA monitoring such as Hydrogen On-line Monitor and PAS technologies. Hydrogen On-line Monitor is more suitable in detecting early faults of power transformer but unable to provide enough information for fault diagnosis interpretation. Meanwhile PAS can provide better gas detection compared to Hydrogen On-line Monitor, however its accuracy may be affected by external gas pressure and vibration waves. There are several techniques used for DGA results interpretation. Among them, Doernenburg, Rogers, IEC ratio methods, Duval triangle and key gas method are the most popular techniques widely used by utilities. These techniques are not consistent and may lead to different results for the same oil sample.

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