Combined effect of temperature and electrical discharges on the properties of transformer mineral oils

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ABSTRACT. *The service life of power transformers is expected to be between 35 and 40 years. As a consequence of ageing, the transformer oil deteriorates gradually and becomes increasingly contaminated. Life of a power transformer depends primarily on life of its insulation system. Then, it is important to keep the oil's properties near to those of new oil. One way to resolve the problem is to reclaim the insulating oil before the degradation goes too far. The reclaimed oil should have many similar characteristics of those of new oils. For instance, this work is devoted to study the physicochemical properties of reclaimed oil simultaneously submitted to thermal stresses and electric discharges. It will be compared with three transformer mineral oils of different levels of degradation. The first oil is new and untreated whereas the second is taken from a transformer still operational after thirty years of service, and the third oil is extracted from a transformer just having incurred a Buckholtz after eight years of service. The considered parameters are water content, breakdown voltage, dielectric constant, dissipation factor and resistivity. Dissolved gas analysis (DGA) has also been performed on the oil which is extracted from a transformer just having incurred a Buckholtz, and the reasons of such failure have been discussed.*

RÉSUMÉ. *La durée de vie des transformateurs de puissance est estimée entre 35 et 40 ans. En raison du vieillissement, l'huile du transformateur se détériore progressivement et devient de plus en plus contaminée. La vie d'un transformateur de puissance dépend principalement de la durée de vie de son système d'isolation. Il est alors important de garder les propriétés de l'huile proches de celles de l'huile neuve. Une des façons de résoudre le problème consiste à régénérer l'huile isolante avant que la dégradation ne s'aggrave. L'huile régénérée doit avoir plusieurs caractéristiques similaires à celles des huiles neuves. Le présent travail est dédié à l'étude des variations des propriétés physico-chimiques de l'huile régénérée simultanément soumise à des séries de décharges électriques et à l'application d'un champ de température croissant. Elle sera comparée avec trois huiles minérales de différents niveaux* *de dégradation. La première huile est neuve et non traitée tandis que la seconde est extraite d'un transformateur toujours opérationnel après trente ans de service, et la troisième huile est extraite d'un transformateur juste après avoir subi un déclenchement Buckholtz après huit ans de service. Les paramètres analysés sont la teneur en eau, la tension de claquage, la permittivité relative, le facteur de dissipation et la résistivité. L'analyse des gaz dissous (DGA) a également été réalisée sur l'huile qui est extraite du transformateur ayant subi un déclenchement Buckholtz, et les raisons de cette défaillance ont été discutées.*

KEYWORDS: *transformer oil, reclaimed oil, temperature, electrical discharges, dissolved gas analysis.*

MOTS-CLÉS : *huile de transformateur, huile régénérée, température, décharges électriques, analyse des gaz dissous.*

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1. Introduction

The power transformer is one of the most important and expensive components in electrical grids. In this critical component, large quantities of fluids are used, with a dual role: to provide insulation protection by preventing direct contact of atmospheric oxygen with the cellulosic insulation, which is susceptible to oxidation, and to dissipate the heat of the transformer generated by the windings, due to their thermo-conduction properties (Fofana, 2013). Mineral oil is the most widely used as electrical insulating liquids in a large variety of transformers, because of its availability, relatively low cost, good dielectric and thermal characteristics and compatibility with cellulose paper (Oommen, 2002).

During transformer operation, the oil is exposed to electrical, thermal, and chemical stresses, causing its gradual degradation (Augusta *et al*., 2012), which process consists of an irreversible chain of reactions leading to changes in oil properties, and therefore to ageing. As transformer oil ages, it becomes increasingly contaminated. Aged oils mainly contain by-products from degradation process including acids, aldehydes, peroxides, sludge, fibers, gases, moisture, etc (Liao *et al*., 2011). Eventually, the ageing by-products may largely affect the performance of the insulation, which cause damage to the power transformer and can lead to its failure (Pradhan et Yew, 2012). Therefore, it is important to monitoring the transformer oil condition and evaluate its status, and thus to reach a proper maintenance plan for reconditioning or replacing the oil (Martin *et al*., 2011).

Changing the aged oil with a new one does not seem to be a good idea, because 10% of the volume of oil in the transformer stays in the cellulose insulation after the change; this oil can ruin large quantities of new oil, because it contains impurities (Raymon and Karthik, 2015). Also, the changing does not eliminate all the residual sludge. The remained oil with the residual sludge will dissolve in the new oil and initiate the oxidation process directly (Wada *et al*., 2013). This procedure is also not economically attractive, due to the increasing prices of the mineral transformer oils.

Regenerating the oil is a beneficial alternative for both technical and financial considerations and the regenerated oil might be even better than new oil. Regeneration rejuvenates the transformer oil by eliminating contaminants and products of degradation such as sludge, acidic, or colloidal materials, to obtain an oil with characteristics similar to those of new oil (Raymon and Karthik, 2015; Cho *et al*., 2012).

The present paper is focused on an experimental comparative study regarding the combined influence of temperature and electrical discharges on the variations of the properties of reclaimed oil and three oils of different levels of deterioration. The investigated parameters are water content, dielectric strength, dissipation factor, resistivity and permittivity. The discussions will be reinforced by the dissolved gases analysis as a technique for ageing diagnosis of the oil.

2. Experimental technique

The investigations were performed on samples of naphtenic transformer oil (Borak 22) used by the Algerian Electricity and Gas Company, Sonelgaz. The principal oil (oil B) is a reclaimed oil, it was obtained by chemical treatment using Fuller’s Earth based reclamation techniques. This oil will be compared to three oils of different levels of deterioration: the first oil (oil A) is a new untreated oil, the second oil (oil C) is taken from a transformer still operational after thirty years of service, the third oil (oil D) is extracted from a transformer just having incurred a Buckholtz after eight years of service.

Since receipt, a sample zero is taken from each type of oil to be characterized through measurements of the color (Col), flash point (FP), acidity number (AN), viscosity (µ) and water content (WC), respectively in accordance with ISO 2049, NFT 60-103, ISO 6618, ISO 2909 and IEC 814 standards. The characteristics results are presented in Table 1.

For each type of oil, five samples have been constituted; each one is heated at a given temperature, between 20 and 100 °C during a period of 1h30mn. All the samples are agitated during the heating operation at atmospheric pressure. For each level of temperature, the following parameters have been measured: water content, breakdown voltage, resistivity, relative permittivity and dissipation factor. After that, we submit the samples to a series of discharges (60 discharges), and we measure the same parameters. The discharges are applied by using a programmable oil tester of type BAUR DTA 100 E which is equipped by an automatic counter of discharges. The protection device is dimensioned to break the circuit when the discharge energy reaches 5mJ, corresponding to electrical charges ranged between 50 and 200 nC. The ac voltage is automatically increased with a linear rise of 2 kV/s until the discharge occurs, with a time delay of two minutes between two tests. The time delay is required in order to exclude the by-products influence on the following measurement.

The breakdown voltage was measured in accordance with IEC 156 standard. In this case, hemispherical electrodes with the separation of 2.5 mm were used. One must ensure that there is no air bubbles before testing. The average of six values is taken as the breakdown voltage of the oil sample. The electrodes are carefully rinsed and dried at each renewal of oil.

The water content is measured just after the opening of the cell, after having mixed the oil with the help of a magnetic agitator. It is however important to consider an average of 3 to 4 values corresponding to removals from different locations in the cell. The resistivity, relative permittivity and dissipation factor measurements were performed with a standard test system (Dieltest DTL).

The dissolved gas analysis is executed thanks to a gaseous phase chromatograph of type TFGA P200, consistently to IEC 60 567. The oil sample of about 100 ml is put in a glass test bottle. The gas chromatograph is run for about 45 minutes for each sample. A chromatogram which shows the types and the concentration of gas can be attained. The gases are extracted by the "Shake Test" technique.

Table 1. Physicochemical properties of the tested naphthenic oils

Type of oil	WC (ppm)	μ (mm^2/s)	Col	AN (mg KOH/g)	FP (°C)
A (new)	36	11.4	< 0.5	0.0168	149
B (reclaimed)	37.1	9.66	< 0.5	0.024	144.5
C (30 years old)	44.6	13.93	4	0.075	142.5
D (8 years old)	21.5	8.855	1	0.0224	147

3. Experimental results

3.1. Water content

The water content or moisture is a key parameter in insulating oils. The moisture is considered as 'the main enemy' for transformer insulation as it accelerates the deterioration of the oil/paper insulation which can lead to the transformer failure. It can vary quickly within an operational transformer (Fofana *et al*., 2001).

Water content values for all samples decreases with the increase of the temperature as clearly depicted in Figure 1 for all considered oils. This effect can be explained by the oils drying due to water evaporation. Indeed, the temperature evaporates the suspended water and even the amounts dissolved in the oils. However, this decrease is less important for oil C, which had originally much higher water content. Nevertheless the new and reclaimed oils (oil A and oil B) have almost the same behavior with the temperature variation, where they have the same value at

100°C. The obtained results in the three oils (A, B and D) at higher temperature are less than the maximum of 30 ppm that is tolerated by standards. Contrary for oil C, where the water content is higher than the acceptable value, more drying is required for its utilization.

Under the combined stress (thermal + electrical) as can be seen in Figure 1, the variation seems to be more stable after its submission to the series of discharges for oil A. The water content of oil B shows an increase tendency after undergoing the series of discharges and tends to stabilize around 25 ppm for temperatures above 40°C. For oil C, the water content decreases with the series of discharges until 60°C, then starts to increase. Water content is reduced by the application of discharges in oil D. The reduction in the water content with the application of discharges is due to the evaporation of water traces that are present in the zone of discharge occurrence. An unexpected behavior of the water content for temperatures above 60°C is observed in the three oils (A, B and C), where the water content has a tendency to increase with the application of temperature. A high increase in water content is especially measured in oil A for temperatures close to water boiling point. This can have two reasons: the first is bound to the measurement technique (Karl Fischer titration method in agreement with IEC 814 standard that consists in making three removals from different places of the sample and considering their average).The second is linked to the variable humidity inside the experiment room (it varies between 35 and 66% during a series of tests for breakdown voltage in oil A). This humidity can interact with the oil at high temperature and thus increase the humidity of the sample.

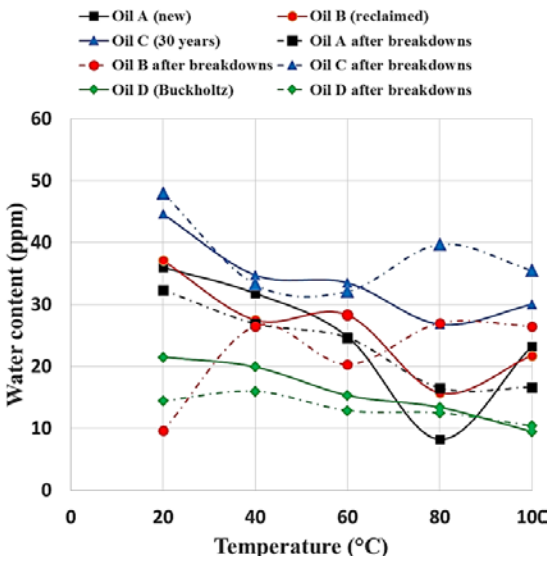

Figure 1. Water content as a function of temperature (before and after breakdowns)

3.2. Breakdown Voltage

The Breakdown Voltage (BDV) test is one of the most common and important tests done on all insulating liquids, it is very sensitive to the oil quality. Figure 2 represents the variations of breakdown voltage as a function of temperature. This figure reveals, for the three oils (A, B and D), that an increase of temperature from 20 to 100°C is combined with a significant rise of the breakdown voltage values. This effect can be explained by the evaporation of dissolved water with the increase of temperature, which correlates well with the decrease of the water content as seen in Figure 1. The existence of moisture in insulating oils is the most important reason of electrical breakdown since it increases the ionic conductivity of the oil, and hence dropping the breakdown voltage (Suleiman *et al*., 2014).

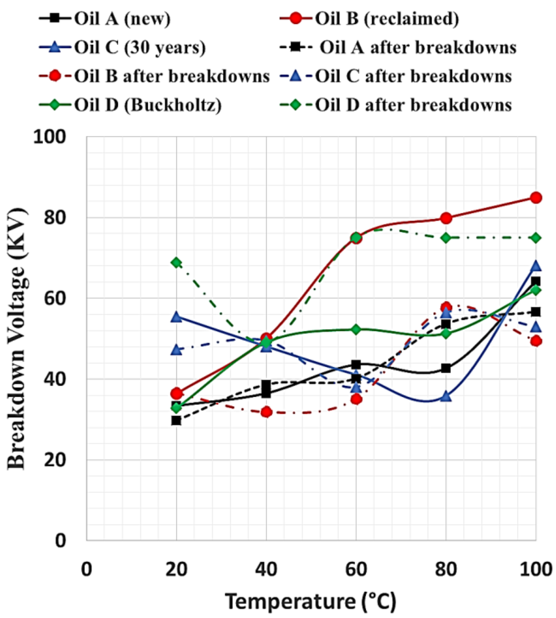

Figure 2. Breakdown voltage as a function of temperature (before and after breakdowns)

The second aspect is the dependence of the breakdown voltage with the relative humidity (the relative humidity is calculated by the following ratio: absolute concentration of water in oil, at a certain temperature/concentration of water in oil, at saturation, at the same temperature). The effects of water on the dielectric breakdown voltage of insulating oils are inversely proportional to the relative water content or humidity rather than to the absolute concentration of water in oil (Augusta *et al*., 2012). The relative humidity reflects more than just the moisture content. The saturation limit of the oil depends on its type, its chemical composition and mean molar weight. It is highly temperature dependent; the maximum moisture solubility of oils increases in an exponential function with temperature. The increase in temperature reduces considerably the relative humidity in the oil. The relative humidity reduction results in a higher ac breakdown strength, justifying the obtained results (Liao *et al*., 2011) (Figure 2).

The acceptable minimum breakdown voltage for high voltage transformer oils at which this oil can safely be used in transformer is 30 kV. Indeed, the obtained results for the three oils were in accordance with the standards, especially in oils B and D, which show high values in high temperatures. The breakdown voltages are between 50 kV and 85 kV for oil B and between 50 kV and 62 kV for oil D, for temperatures above 40°C.

One notes that the breakdown voltage values of the reclaimed oil (oil B) are greater than the ones of the other oils. As a comparison, the BDV in oil B is twice greater than in oil A at 80°C, the variation of the absolute water content with temperature is nearly the same for oil A and oil B, which confirms that the BDV depends on the percentage of saturation (relative humidity) and not on the absolute water content. In fact, the reclaimed oil does not have the same stability as new oil even though it conforms to the same industry standards. The Fuller’s earth process is not effective at removing some of the polar compounds like acids (Cho *et al*., 2011), these acids increase the H+ ions concentration, which increase the water absorption capacity of the oil (Badicu *et al*., 2012), and then the saturation level increases significantly which causes the rise of the BDV. Oil C with higher water content compared to oil A, shows almost the same BDV behavior with the last oil. This is because aged or contaminated oils have higher water solubility due to polar compounds presence in the oils (Fofana *et al*., 2001; Badicu *et al*., 2012), since water molecules can be captured by hydrogen bonds with carboxyl groupings.

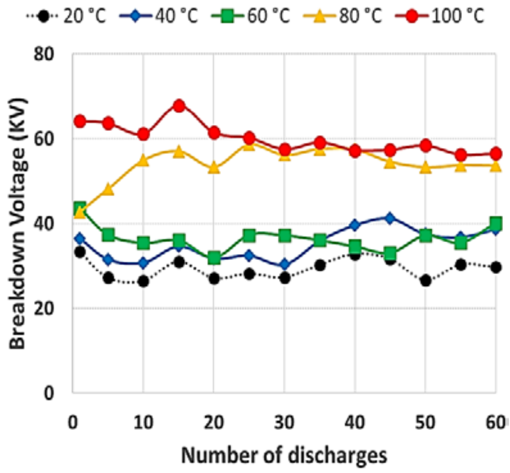

Figure 3. Breakdown voltage as a function of electrical discharges for oil A (new), electrode gap 2.5mm

For all oils, the BDV tends to increase with the number of discharges at weak temperature (Figures 3 to 6); it presents a tendency to improvement and to stabilization as the oil is progressively submitted to discharges (Figure 4). In this case, the oil undergoes the dominant effect of water traces vaporization at this level of temperature. However, the discharges have a strong influence on the BDV of the reclaimed oil (oil B) and oil D compared to the others oils (oil A and oil C).

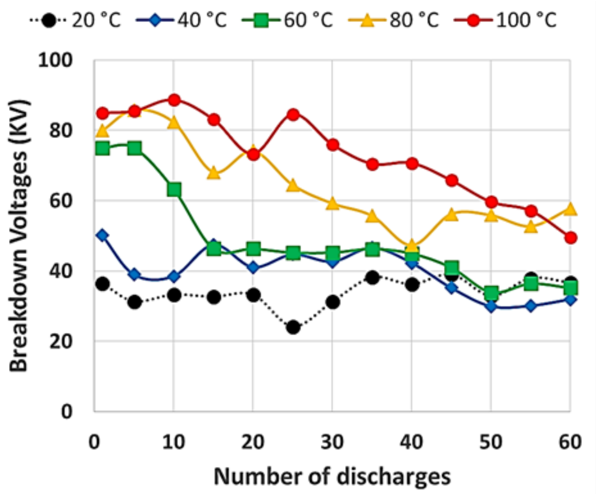

Figure 4. Breakdown voltage as a function of electrical discharges for oil B (reclaimed) with an electrode gap of 2.5 mm

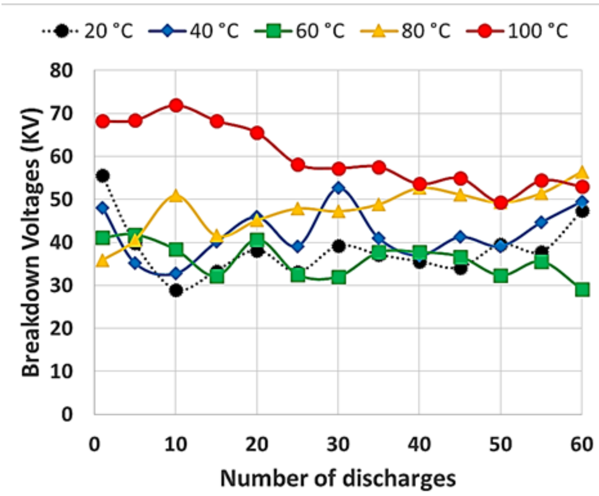

Figure 5. Breakdown voltage as a function of electrical discharges for oil C (30 years old), electrode gap 2.5mm

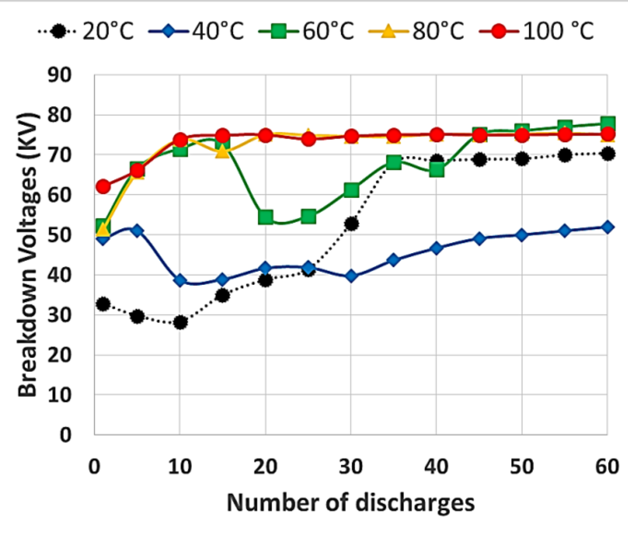

Figure 6. Breakdown voltage as a function of electrical discharges for oil D (Buckholtz) with a gap of 2.5 mm

3.3. The relative permittivity

The relative permittivity is sensitive to temperature changing. As can be seen in Figure 7, the relative permittivity slightly increases with temperature for all the oils, and in the two cases (before and after breakdowns). However, the variation in the two cases is modest (between 2.18 and 2.25 for oil A, between 2.17 and 2.22 for oil B, between 2.2 and 2.28 for oil C and between 2.16 and 2.17 for oil D). Relative permittivity expresses the ability of the oil to polarize. The polarization is a complex phenomenon which depends on the molecular structure of the oil (composition of the oil, size and polarity (polar and non-polar) of molecules, etc.) and contaminations (Paraskevas *et al*., 2006). It is difficult to know the real reasons for this increase of the relative permittivity, but it can possibly be attributed to the increase of the density of charge carriers and the decrease of the viscosity in the oils with temperature (Zhou *et al*., 2012).

In all the oils, the measured values after breakdown are higher than those measured before. Generally, high permittivity values characterize the state of aging (degradation) of the oil which suggests that the oils have undergone a significant molecular degradation as a result of the applied discharges. In fact, when the breakdown occurs, it will degrade the oil locally, causing the disruption of the molecular structure of oil by the dissipated energy.

It should be also noted that the reclaimed oil (oil B) shows low values compared to the other oils (oil A and oil C), which demonstrates the capacity of the regeneration process to eliminate the polar contaminants. The high values of the relative permittivity in the oil C were expected. As the transformer ages in service, then aged oil becomes increasingly contaminated. Ageing byproducts are mostly polar in nature and will affect the relative permittivity; the variation with aging is not wanted for transformer applications because it will perturb the electric field distribution (Singha *et al*., 2014). Nevertheless, an interpretation of the condition of oils only based on this parameter is difficult. It can be in combination with the dissipation factor.

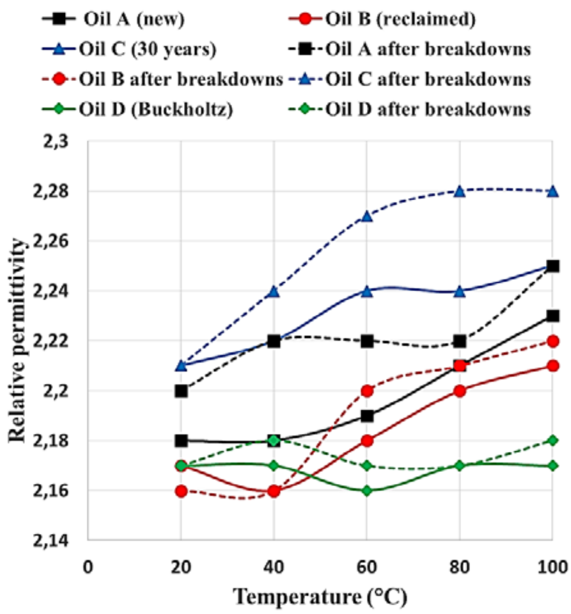

Figure 7. Relative permittivity as a function of temperature (before and after breakdowns)

3.4. Resistivity

The resistivity of an insulating liquid is affected by many factors including temperature, ionic additives, water, acid, free radical, peroxide …etc. Figure 8 shows the change curves of resistivity as a function of temperature and electrical discharges. From this figure, when temperature is lower than 60°C, the resistivity increases with the increase of temperature, and when it reaches 60°C, it decreases significantly with the increase of temperature, especially at 80°C. The increase of the resistivity for temperatures below 60 °C can be due to the reduction of the water content with temperature. The resistivity of insulating liquids is well known to depend on water content (Toudja *et al*., 2014). However, the reduction for temperatures above 60°C was also recorded with low water content, suggesting that the water content loses its dominance on resistivity in this range of temperature. Concerning the decrease in the resistivity, it may be due to the change in oil-conductivity. As the temperature increases, the conductivity will increase due to the increase of the number of charge carriers and also their mobility (Badicu *et al*., 2012). Therefore, the resistivity will decrease.

The resistivity is an important property of transformer oil and must be high at ambient temperature, and similarly it must have good values at high temperature.

The resistivity values of the reclaimed oil are close to those of the new oil and very superior to those of the aged oil, which shows the usefulness of the regeneration process to remove contaminants and products of degradations. The values of the aged oil are lower than the admissible limits imposed by standards. Compared with new oil, there are more impurity ions in aged oil; the impurity ions play an important role in the conductive process (Abedian and Baker, 2008), causing thus low values of the resistivity in the oil C. It is obvious that the resistivity in the last oil is more impaired by particles than by the moisture that it contains.

The application of discharges seems to have limited influence on the resistivity of oils A, C and D. The behavior of these oils with temperature variation before and after breakdowns is almost the same. For oil B, the discharges have influenced the resistivity, mainly between 20°C and 75°C.

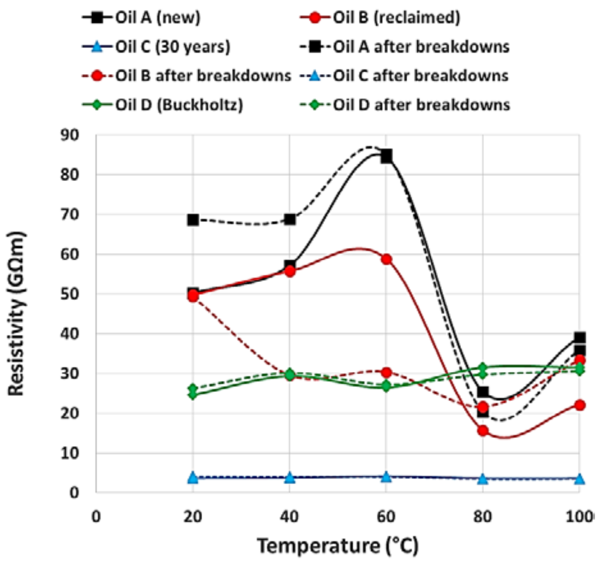

Figure 8. Resistivity as a function of temperature (before and after breakdowns)

3.5. Dissipation factor

The dielectric dissipation factor or tan delta (tan δ) of transformer oils is directly related to the resistivity. After the comparison between the two figures (Figures 8 and 9), it is clear that there is a relationship between tan δ and resistivity of insulating oils. When the resistivity values increase, the ones of tan-delta decrease, and vice versa.

The tan δ values of the reclaimed and new oils were almost identical, and showed the same behavior with temperature variation. The application of discharges seems to have no influence on oils A and D, contrary to the other two oils (oil B and oil C). However, the values of tan δ of the regenerated and new oils in the two cases (before and after breakdowns) are above the limit authorized by standards. Moreover, the aged oil shows high values because of the high number of suspended charged particles or contaminants.

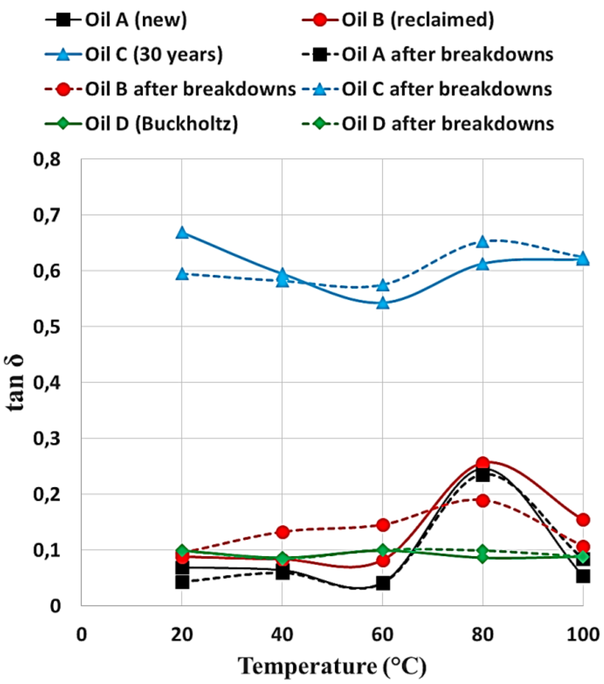

Figure 9. Dissipation factor as a function of temperature (before and after breakdowns)

3.6. Dissolved gases analysis in oil D

The oil D is extracted from a transformer just having incurred a Buckholtz release. The transformer was disconnected from the supply which means that severe internal faults were occurred. The reasons of this failure are not clearly expressed by the quantitative aspect of the measurements of the different properties of this oil; the origin of the transformer failure is not necessarily linked to the quality of the oil. A resort to the historic of dissolved gases in this oil was necessary. It extends between the first year of service, and the instant where it underwent damage (after 8 years).

Dissolved gas analysis (DGA) is one of the most important techniques for diagnosing incipient faults in the transformer (Moulai *et al*., 2012). The technique involves detecting and measuring the concentrations of certain gases dissolved in the oil such as hydrogen (H_2), methane (CH_4), ethylene (C_2H_4), acetylene (C_2H_2), ethane (C_2H_6), carbon monoxide (CO), and carbon dioxide (CO_2), which are generated by thermal and/or electrical faults in transformers (Khan *et al*., 2007).

With the high precision and sensitivity of the gaseous phase chromatograph, we can have a low detection limits for each gas (at parts per million level of accuracy). Table 2 represents the evolution of the amount of each dissolved gas in oil D extracted from the same transformer.

Table 2. Dissolved gases concentrations in oil D

Years of service	Gas concentration (ppm)						
	H_2	CO	CH_4	C_2H_4	C_2H_6	C_2H_2	CO_2
1 year	5	233	18	48	46	11	4176
4 years	0,5	89	0,5	33	17	14	1975
7 years	17	84	6	61	23	17	1724
8 years	493	341	121	204	29	326	1767

There are many methods for the interpretation of the dissolved gas results, the most commonly used is Duval triangle method (Duval, 1989; 2002). This method is a graphical approach utilizing only three hydrocarbon gases (CH_4, C_2H_4 and C_2H_2) and providing diagnosis for all cases. The relative proportions of these gases represent the coordinates (x, y, z) in a triangular coordinate system, so the fault region in which the data point is placed corresponds to a fault type. The representation of Duval's triangle for fault diagnosis is shown in Figure 10. The triangle coordinates are (Duval, 1989):

$$\%\ C_2H_2 = \frac{100x}{x+y+z}\ ;\ \%\ C_2H_4 = \frac{100y}{x+y+z}\ ;\ \%\ CH_4 = \frac{100z}{x+y+z}$$

With x = [C_2H_2]; y = [C_2H_4]; z = [CH_4] in ppm

The Duval's triangle (Figure 11) diagnoses the occurrence of electrical arcing discharges of high energy level for the last measurement performed 8 years after operation. This is in agreement with the observation of the operators. On the other hand, one can note that CO_2 gas overtakes the tolerated limits, this gas is known to not being an oil default gas (IEEE Std C 57.104, 2008) (it expresses the deterioration of the paper cellulose).

It is well known that the thermal decomposition of paper cellulose produces carbon monoxide (CO), carbon dioxide (CO2), and water vapor at temperatures much lower than that for decomposition of oil and at rates exponentially proportional to the temperature. Because the paper begins to degrade at lower temperatures than the oil, its gaseous byproducts are found at normal operating temperatures in the transformer. The paper degradation produces furan compounds that are mixed in the oil. It consists of b-hydroxymetyl-2, furaldehyde, 2-furaldehyde and four other furans. Three main reactions are known to produce furan compounds: Thermal degradation, oxidative degradation and hydrolytic degradation, but only the first one produces carbon mono and di-oxide byproducts. The C2H2 and CO2 amounts recorded on the first measurement overtake the limits set by IEEE Std C57.104-2008. They are in the condition 3 of the classification made by this standard, suggesting then hot spots occurrence inside the paper followed by high energy discharges.

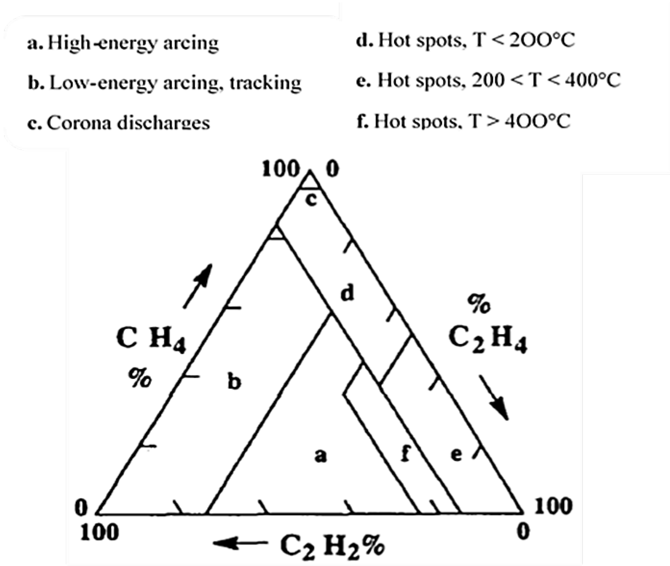

Figure 10. The Duval's triangle (Duval, 1989)

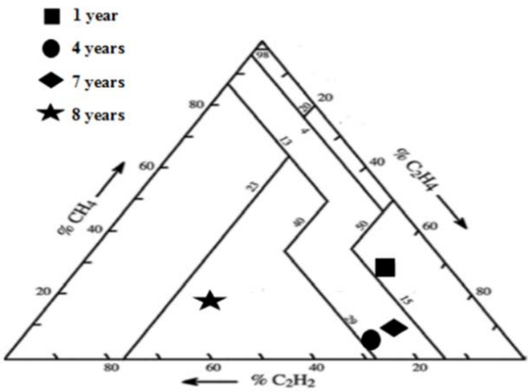

Figure 11. The Duval's triangle results

4. Conclusion

The experimental study has allowed us to follow the behavior of the reclaimed oil under the combined effect of temperature and electrical discharges, and characterization of the main properties required for normal operation. We found in this work that the properties of the reclaimed oil were very close to those of new oil, and show similar behavior with the temperature variation. However, compared to the other oils, the electrical discharges have greatly influenced the properties of the reclaimed oil, especially the breakdown voltage.

Measurements of the physicochemical parameters helped us to evaluate the condition of the oils, but they can't indicate the faults types. Only the gaseous phase chromatography is able to give additional information for a formal diagnosis. The bad values of dielectric strength and water content of the oil D are not sufficient to explain the raisons of the transformer failure from which this oil is extracted.

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