Assessing Insulating Oil Degradation by Means of Turbidity and UV/Vis Spectrophotometry Measurements

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ABSTRACT

Oil is a vital part of the transformer body and (similarly to blood in a human being body) keeps responsibility for the condition of the entire organism. Oil is particularly responsible for functional serviceability of the entire insulation system. The insulating oil must be kept in pristine condition, since its condition can be a decisive factor, which determines the life span of the transformer. Fields and laboratory experiences have shown that transformer oil contains a vast amount of information. Oil analyses can be extremely useful in monitoring the condition of power transformers. To meet pressing needs of power industries, fast, inexpensive and reliable laboratory testing procedures are necessary. To ensure long-term reliability of oil filled power transformers, it is important to identify early sign of degradation of the insulating oil. In this paper, oil degradation was monitored with various ASTM test methods. Investigations were performed on service-aged oil samples as well as on oil samples aged in laboratory conditions. Many key parameters actually used to monitor the condition of transformer oil relative to oxidation/degradation were investigated. From the obtained results, correlations were found between some of them. The results indicate that Dissolved Decay Products (DDP) and turbidity, which change with a higher rate than interfacial tension (IFT) and Acid Number (AN) values, can be possibly used as an effective index for insulating oil degradation assessment. Limits are suggested which provide a "picture" of the fluid condition.

Index Terms - **Power transformer, insulation condition assessment, aging, oil, UV-spectrophotometry, turbidity, acidity, interfacial tension, dielectric dissipation factor, color.**

1 INTRODUCTION

POWER transformers are considered critical equipment in any power generation and transmission systems and large industrial plants. In these expensive machines, the main insulation system consists of oil, paper and other cellulose based solids. This insulation system is designed to withstand these stresses for extended periods of time, but there is a gradual loss in mechanical and dielectric properties that eventually compromises the unit's reliability. While in service, both the liquid and solid insulation are subjected to various stresses including high temperatures, vibration, electric fields, exposure to moisture, oxygen, acids and other chemical contaminants [1, 2]. Utilities frequently require transformers operation at maximum capacity for extended periods of time, it is therefore vital that dielectric and coolant properties of the oil be in optimum condition. Mineral oil in transformer is the inseparable component of the dielectric insulation system. The oil gets contaminated mainly due to aging. Moisture, sludge, acids, metal particles and other compounds produced by aging insulation (mainly cellulose) changes the oil chemical and physical properties.

Manuscript received on 30 November 2014, in final form 28 May 2015, accepted 24 June 2015.

DOI 10.1109/TDEI.2015.005111

Electric utilities worldwide are now focusing on reliability-centered maintenance of their assets for extended life and hence maximum return on investment. Recent utility survey shows that a large proportion of transformers has attained their designed life and are operating close to their nameplate rating or beyond [3]. The load growth is compounding this problem on the existing transformers due to fewer extension projects, market deregulation and economic conjuncture.

Diagnostics and proper monitoring plays key role in the life expectancy of a power transformer. By accurately monitoring the condition of oil, many types of faults can be detected before they become serious failures and outages. Early detection of insulation oil deterioration, allows performing the appropriate maintenance actions. Consequently, the unplanned outages associated with catastrophic failures can be avoided.

In this contribution, many key properties, providing a "picture/health", relative to the oxidation stability of the fluid, are being investigated. In addition to traditional testing methods such Acid Number (AN) interfacial Tension (IFT) used to detect the formation of decay products, two alternative methods developed by ASTM in the last two decades, namely the ASTM D 6802 [4], and the ASTM D 6181 [5], are considered.

2 BACKGROUND ON INSULATION OIL DEGRADATION/AGEING

Although the transformer oils are carefully refined, they undergo degradation processes even under normal operating regime, resulting in the generation of decay products. These impurities diminish the service reliability and shorten the life expectancy of power transformers.

Oil quality deteriorates mainly due to electric field, oxygen and water with the assistance of heat [6, 7]. The chemical reactions lead to the decomposition of oil and result in the formation of fault gases, liquid by-products, sludge and acids [8, 9].

The mechanism of transformer oils oxidation involves the homolythic breakdown of the hydrocarbon bonds and is greatly accelerated by the presence of catalysts such as copper/copper alloys in aluminum windings and iron which are primary transformer components and the action of heat and moisture.

Moisture is particularly detrimental to paper, as it will initiate hydrolysis and scission of the cellulose chain. Oxygen attacks both the paper and the oil producing a range of acids and other polar materials. Soluble oxidation by-products includes initially peroxide gas, water soluble acids, low molecular weight acids, fatty acids, water, alcohols, and ketones [10]. Further reaction of these decay products then change to insoluble compounds or sludge and varnish deposits, the final step of oil deterioration. Sludge once precipitated onto the hot parts of the transformer will continue to oxidize. Over longer periods of time, the degradation products accumulate in the insulation and become increasingly active in promoting further degradation. Aggressive decay products being adsorbed by the solid insulation attack the cellulose fibres. In the worst case, the oil canals may be restricted and the transformer is not cooled adequately. The results are higher temperatures, which then cause additional oil decomposition. The cycle can then continue which further exacerbates the oil or cellulose insulation. A generalized degradation mechanism is shown in Figure 1.

3 OIL DEGRADATION ASSESSMENT AND CLASSIFICATION

To avoid catastrophic failures, adequate monitoring of the quality of the insulating oil is required. The early detection of oil's deterioration can reduce maintenance cost only if the formation of oil-born decay products is determined as trace impurities and removed before being adsorbed by the cellulose fibers of solid insulation. In spite of all the differences in their standpoints, the refiners, manufacturers and users have worked together. The development of several new laboratory testing procedures for mineral insulating oils over the past years has been the rewarding result of a cooperative work involving refiners, manufacturers and users, to produce mutually acceptable standard specifications for oil characteristics and test requirements.

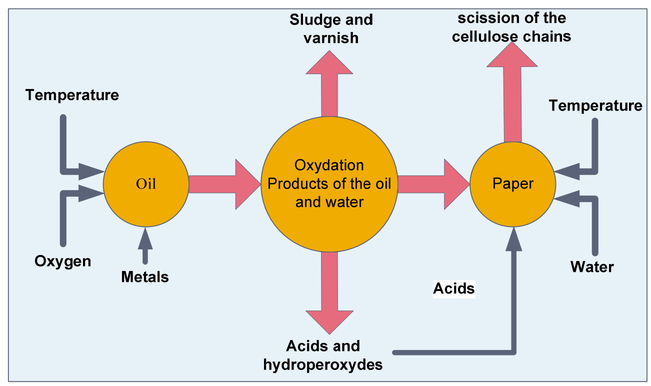

Figure 1. Simplified decomposition mechanism of transformer insulation [6].

Over the past years a ASTM standard set of tests methods have been developed to assess the oil transformer quality. For the monitoring oil condition some of the key characteristics are: water content (ASTM D1533), AC dielectric strength (ASTM D877 and D1816), the Dielectric Dissipation Factor or DDF (ASTM D 924), the Acid Number or AN (ASTM D 974), the Interfacial Tension or IFT (ASTM D 971) [11].

All these tests provide information whether the insulation is normally or extremely aging. With regard to oil oxidation, the ASTM D974 (Acidity) and ASTM D971 (IFT) tests have been found sensitive to oxidation because they address themselves directly to acid content and presence of sludge [10].

3.1 ACID NUMBER (AN)

The AN or acidity is the measure of acid concentration in a non-aqueous solution. It is determined by the amount of potassium hydroxide (KOH) base required to neutralize the acid in one gram of an oil sample. The standard unit of measure is mg KOH/g. As the oxidation level of in service oil increases, polar compounds, particularly organic acids form in the oil. These react with the other materials in the transformer and ultimately form sludge, which deposit on the surface of paper insulation affecting the proper cooling of the windings and accelerating the degradation of the paper insulation. The acids promote corrosion within the transformer.

Utility professionals recommend reclaiming the oil when the acidity reaches 0.20 mg KOH/g [12].

3.2 INTERFACIAL TENSION (IFT)

The IFT is a measure of the molecular attraction force between a layer of oil and layer of water. It is expressed in dynes/cm. The IFT is decreased by the presence of trace amounts of polar groups. These polar compounds are the precursors to sludge. It is recommended to reclaim oil when the IFT decreases to 25 dynes per centimeter. At this level, the oil is contaminated and must be reclaimed to prevent sludging, which begins around 22 dynes/cm [12].

There is a definite relationship between the acid number and the IFT. An increase in AN should normally be followed by a drop in IFT. Although a low IFT with a low AN is an unusual situation, it does occur because of contamination such as solid insulation materials, compounds from leaky pot heads or bushings, or from a source outside the transformer [13].

Dividing the Interfacial Tension (IFT) by the Acid number (AN) provides a numerical value (Myers Index Number: MIN or oil quality index number: OQIN) [13]. The OQIN provides a sensitive and reliable guide in determining the remaining useful life of transformer oil. New oil, for example has an OQIN of 1500. An OQIN below 100 indicates that the oil is significantly oxidized and that the oil needs to be replaced in the near future.

Some guidelines for IFT, AN or OQIN/MIN values have been suggested by some commercial laboratory [13] and given in Table 1.

3.3 COLOR (ASTM D 1500)

An oil's color comes from the light transmitting through it. Different colors are formed depending on the concentration and type of light-absorbing groups suspended in the oil. Color of new oil is generally accepted as an index of the degree of refinement. For oils in service, an increasing or high color number is an indication of contamination, deterioration, or both. Oxidation is a common cause of an over-all darkening to occur. Increase in acidity and reduction of IFT are followed by darker oil colour that indicates polar contaminant (Figure 2).

This Figure is only useful as a guideline; the decision as to the eventual action to be taken on the oil must be based on the values of other properties provided in the IEEE Guide Std 637-1985 [14].

In the last decades, two methods have been developed by ASTM, namely the ASTM D 6802 [4], and the ASTM D 6181 [4, 5] for oil diagnosis.

3.4 DISSOLVED DECAY PRODUCTS (ASTM D 6802)

UV/VIS spectrophotometer is used to describe the relative level of dissolved decay products in transformer insulating oils. New oils are almost transparent and therefore no absorbance in the visible can [15] be detected. The increasing concentration of dissolved decay products shift the absorbance curve to longer wavelengths. As described in the standard ASTM D6802, there is a relationship between the area under the absorbance curve and the total amount of dissolved decay products in mineral insulating oils, such as: peroxides, aldehydes, ketones and organic acids in the fluid samples.

Table 1. Transformer oil classification [13]. IFT always represents the Interfacial Tension, AN for the Acid Number while OQIN stands for the oil quality index number.

1.	**Good Oils**	
	AN	0.00 -0.10
	IFT	30.0 -45.0
	Color	**Pale Yellow**
	OQIN	300-1500
2.	**Proposition A Oils**	
	AN	0.05 -0.10
	IFT	27.1 -29.9
	Color	**Yellow**
	OQIN	271 -600
3.	**Marginal Oils**	
	AN	0.11 -0.15
	IFT	24.0 -27.0
	Color	**Bright Yellow**
	OQIN	160 -318
4.	**Bad Oils**	
	AN	0.16 -0.40
	IFT	18.0 -23.9
	Color	**Amber**
	OQIN	45 -159
5.	**Very Bad Oils**	
	AN	0.41 -0.65
	IFT	14.0 -17.9
	Color	**Brown**
	OQIN	22 -44
6.	**Extremely Bad Oils**	
	AN	0.66 -1.50
	IFT	9.0 -13.9
	Color	**Dark Brown**
	OQIN	6 -21
7.	**Oils in Disastrous Condition**	
	AN	1.51 or more
	Color	**Black**

Good	Prop A	Marginal	Bad	Very Bad	Extremely Bad	Disastrous
Effect on transformer						
Proving these functions 1. Efficient cooling 2. Preserving insulation	Polar compounds (sludges) in solution (products of oil oxidation) causes the drop in IFT	Fatty acids coat the windings. Sludges in solution ready for initial fall out. Sludges in insulation voids highly probable.	In almost 100% of the transformers in this range sludges are deposited on core and coils. **Sludges are fisrt deposited in fin areas.**	Deposited sludges continue to oxidize and harden. **Insulation shrinkage is taking place.** Premature failure a good possibility.	Sludges insulate cooling fans, block vents causing higher operating temperatures.	Vast quantities of sludges may require other means than desludging procedures.

Figure 2. Effect of oil quality on transformer's condition.

3.5 TURBIDITY (ASTM D 6181)

This method utilizes a ratio turbidimeter to evaluate the degree of contamination by solid particles in suspension produced either from external sources such as varnish and metallic particles from the materials used in transformers or internal chemical reactions such as oxidation.

These two methods are not listed in the oil properties mentioned in the ASTM D 3487 [16]. This is mainly related to the fact that field experiences and accurate interpretation of these tests with suggested limits to indicate oil condition are still missing. Actually, comparison with the past test signatures, provides however sufficient assessment of power transformer insulation condition and predicts its aging rate.

4 INVESTIGATIONS ON OIL SAMPLES AGED IN LABORATORY CONDITIONS

4.1 AGEING PROCEDURE

The preparation procedure for accelerated aging was carried out in condition similar to that used for power transformer. The insulating oil and paper were dried beforehand. To increase the rate of oxidation, a metal catalyst (cupper) was used according to the ASTM D 1934 [15]. The aging procedure was done by placing the oil impregnated paper samples in closed stainless steel containers, and aging them in a convection oven at 120ºC. An oil-paper volume weight ratio of about 20:1 was used (ratio for typical transformer [17]). The sampling was carried out every three days (72 hours). After sampling, the oil and paper samples were stored separately in sealed vessels. A total number of 12 samples were used for the correlation study between the traditional test methods (IFT, AN) and the alternative ones (DDP, Turbidity).

4.2 RESULTS AND DISCUSSIONS

Insulating oil is essentially a non-polar saturated hydrocarbon; when the sample undergoes oxidative degradation, oxygenated species such as carboxylic acids, which are hydrophilic in nature, are formed. The presence of these hydrophilic materials in the insulating fluid can affect the chemical properties (acidity, dissolved decay products and turbidity), the electrical properties (dielectric dissipation factor), along with the physical properties (interfacial tension, dissolved decay products and turbidity) of the fluid.

The properties of the aged oil samples were assessed: interfacial tension (IFT), acidity (AN), color, DDP and Turbidity (TUR).

In this work, the interfacial tension (IFT), the turbidity (TUR) and DDP of each sample were measured 3 times, while the acidity was measured once. The table 2 shows the average measurements as well as the confidence interval (CI) for each sample.

It can be noticed that the confidence interval varies depending on the oil quality. From this table, it was found that the average of the confidence interval for the IFT reached ± 0.71 dynes/ cm. However, for turbidity and DDP, the confidence interval is ± 0.31 NTU and ± 1, respectively.

Table 2. Average values and interval of confidence for each sample. DDP always represents the Dissolved Decay Products, IFT stands for the Interfacial Tension while TUR stands for the Turbidity.

Time (hours)	IFT (dynes/ cm)	TUR	DDP
0	35.30 (--)	0.81 (± 0.01)	7.9 (± 0)
72	32.5 (± 1.97)	1.41 (± 0.03)	15.1 (± 0.21)
144	30.16 (± 1.55)	1.36 (± 0.05)	59.81 (± 0.33)
216	27.8 (± 0.39)	1.42 (± 0.02)	210.00 (± 1.31)
288	26.2 (± 0.45)	1.59 (± 0.08)	270.53 (± 0.44)
360	24.00 (--)	1.68 (± 0.01)	306.16 (± 0.49)
432	21.96 (± 0.09)	2.02 (± 0.03)	326.85 (± 0.17)
504	20.33 (± 0.86)	2.83 (± 0.02)	314.98 (± 0.52)
576	18.8 (± 0.26)	3.80 (± 0.01)	313.58 (± 0.54)
648	16.93 (± 0.17)	4.84 (± 0.29)	326.61 (± 1.05)
710	15.33 (± 0.86)	18.3 (± 0.21)	353.29 (± 1.31)
782	15.13 (± 0.52)	73.4 (± 2.9)	413.29 (± 3.39)

The results of IFT and AN as function of aging time are shown in Figure 3. As expected, Oil oxidation contaminants, lower the IFT while the acidity (AN) and the color increases.

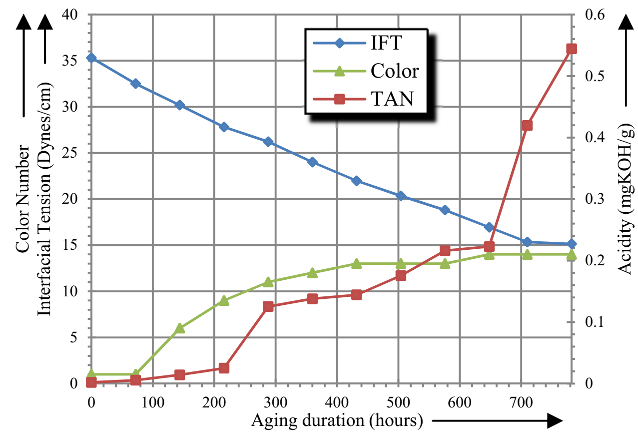

Figure 3. Oil samples condition assessment after different aging durations. IFT always represents the Interfacial Tension, AN stands for the Acid Number while TUR stands for the Turbidity.

Figure 4 shows the absorbance spectra of some oil samples using UV/VIS spectrophotometer.

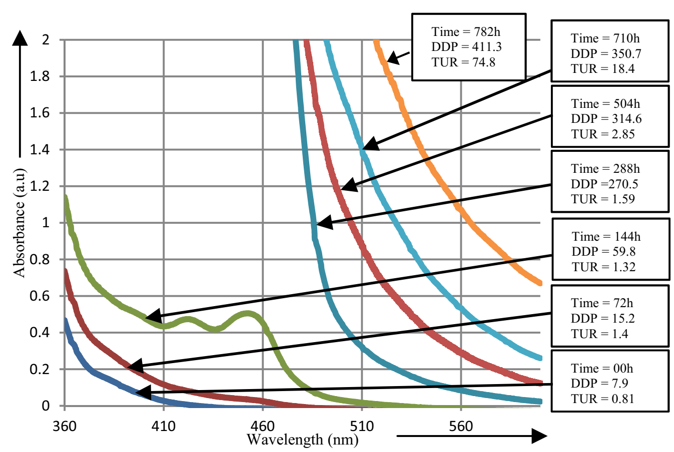

Figure 4. Effect of aging on oil Turbidity and absorbance in the UV/Visible spectrum range. DDP always represents the Dissolved Decay Products while TUR stands for the Turbidity.

The corresponding values of DDP, turbidity and the aging are also shown on the same Figure. It can be noticed that an increase in the dissolved decay products (DDP) in the oil is accompanied with an increase in turbidity (TUR), which exacerbates with oil degradation.

The impact of increasing age of oil on the turbidity and dissolved decay products (DDP) together with the relationships with the AN and the IFT need to be evaluated.

The correlations between oil properties (DDP, Turbidity) and interfacial tension are summarized in Figures 5. A mathematical approach to process the data reveals a relationship between the turbidity and the DDP. Out of this Figure, the DDP bear a linear relationship with IFT, while the relationship between turbidity and the IFT is exponential. At the early stages of aging, a rapid increase of DDP can be noticed.

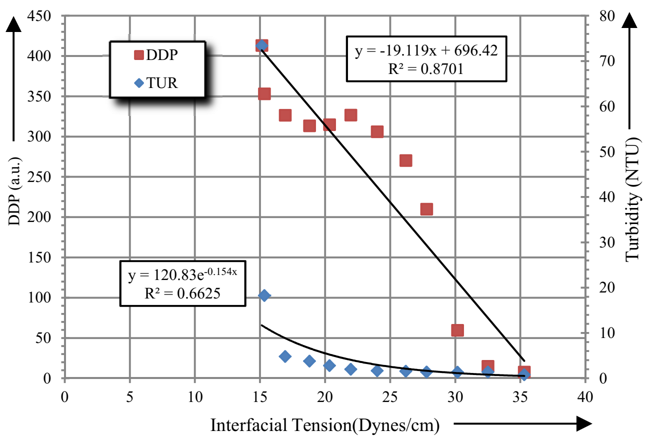

Figure 5. Correlation between dissolved products and turbidity versus IFT test results. DDP always represents the Dissolved Decay Products while TUR stands for the Turbidity.

The correlations between the DDP and turbidity with acidity (AN) are reported in Figures 6 to 7 respectively. It may be observed that, the acidity provides a better correlation with DDP and turbidity with a correlation coefficient of about 0.95.

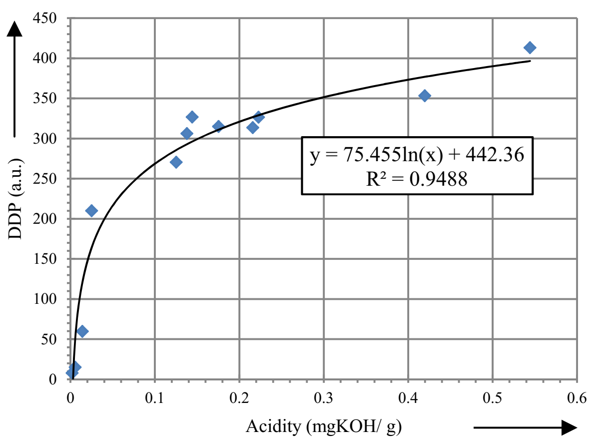

Figure 6. Correlation between the Dissolved Decay Products (DDP) and Acidity test results.

While a logarithmic relationship was found between acidity (AN) and dissolved products (DDP), the turbidity depicts an exponential relationship with the acidity (AN).

The rapid increase in the DDP (Figure 6), can be explained by oxidation processes at the initial stage. The oxidation rate is accelerated by temperature and oxygen content. Since the peroxide bond is weak and can easily be broken even by absorbing thermal energy, the two new free radicals that arise promote the auto-oxidation chain reaction [18]. This is the initiation of the well-known auto-oxidation reaction, which can generate not only soluble decay products that darken the colour of in-service-aged oil, but also produce large insoluble molecules. Indeed, large free radicals may combine, leading to the formation of insoluble colloidal suspensions. The collision of two large free radicals leads to the formation of large colloidal compounds known as sludge (solid phase) that are no longer soluble in the oil [10]. This phenomenon is clearly visible in Figure 7. As the acidity of oil increase due to the oil oxidation, the turbidity increases too.

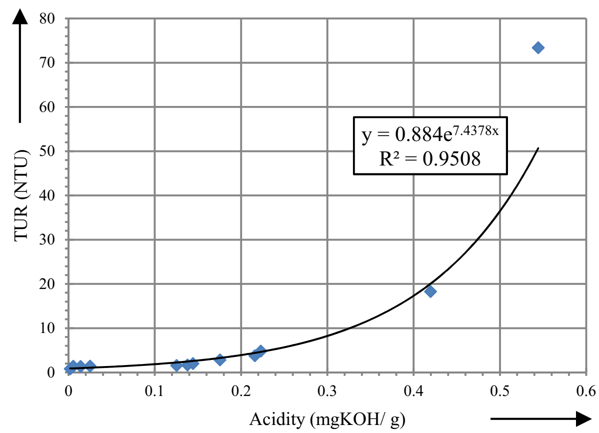

Figure 7. Correlation between Turbidity (TUR) and Acidity test results.

From the values given in Table 1 and the results reported in Figures 6 and 7, guidelines may be proposed for DDP and Turbidity as well (Table 3).

Table 3. Transformer oil classification based on the Dissolved Decay Products (DDP) and Turbidity values deduced from Figure 6, 7 and Table 1.

Oil classification	DDP (a.u.)	Turbidity (NTU)
1. Good Oils	4.03 - 216	0.9 - 1.28
2. Prop A Oils	217 - 268	1.29 - 1.85
3. Marginal Oils	267 - 299	1.86 - 2.69
4. Bad Oils	300 - 373	2.7 - 17
5. Very Bad Oils	374 - 409	18 - 111
6. Extremely Bad Oils	410 - 473	> 112
7. Oils in Disastrous Condition	> 473	--

To verify the feasibility of using Table 3 to classify oil quality through DDP and Turbidity measurements, additional experiments were performed. Oil samples have been submitted to thermal oxidative aging during 2500 hours in presence of paper. The acidity (AN), IFT, Turbidity and DDP values were measured every 500 hours during this investigation, so to speak, a total of 6 samples have been evaluated. The obtained results are summarized in Figure 8.

The characteristics and classifications results for the previous samples based on the classification criteria (Table 3) and Table 1 are presented in Table 4. From this table, it can be noticed that a good agreement is found between the traditional methods (AN, IFT), and the classification criteria based on the DDP and Turbidity. A very low standard deviation has been observed (S.D < 1).

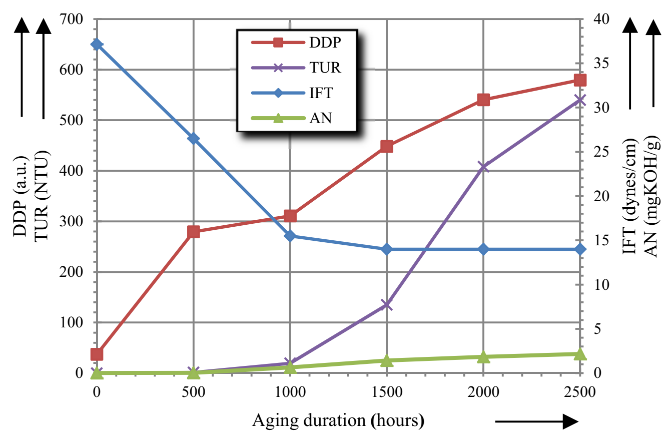

Figure 8. Oil samples condition assessment after different aging durations. DDP always represents the Dissolved Decay Products, IFT stands for the Interfacial Tension, AN for the Acid Number while TUR stands for the Turbidity.

The color is often used as a qualitative method. The technique is based on the comparison of oil color to a standard coloured and numbered disc. Since the absorbance of light in the UV/Visible range can be related to the oil color changes, a correlation between the oil color and DDP can be used to validate the DDP classification criteria, reported in the Table 3.

Table 4. Aged oil assessment based on DDP and Turbidity classification according to Table 3. DDP always represents the Dissolved Decay Products, IFT stands for the Interfacial Tension while TUR stands for the Turbidity.

	Aging time (hours)	Acidity (mgKOH/g)	IFT (dynes/cm)	DDP (a.u)	TUR (NTU)	
Measure-ments	00	0.003	37.15	1.66	< 1	
	500	0.03	26.5	279.37	1.4	
	1000	0.639	15.5	310.82	19.5	
	1500	1.415	14	448.47	135	
	2000	1.84	14	540.44	408	
	2500	2.16	14	579.52	540	S.D
Classific-ations	00	1	1	1	1	0
	500	1	2	3	2	0.8
	1000	5	5	4	5	0.5
	1500	6	6	6	7	0.5
	2000	7	6	7	7	0.5
	2500	7	6	7	7	0.5

The ASTM D1544 color disc comparators were used to make direct relationship to Table 1 and the results are reported in Table 5.

Table 5. Oil condition based on color comparisons.

Color comparator number	Color	Oil condition
< 7	Pale yellow	Good oil
7 - 10	Yellow	Proposition A oil
10 - 11	Bright Yellow	Service-aged oil
11 - 14	Amber	Marginal condition
14 - 15	Brown	Bad condition
16 - 18	Dark brown	Severe condition (reclaimed oil)
> 18	Black	Extreme condition (scrap oil)

Figure 9 shows the correlation between the color and the DDP results (Figure 8). A very good linear relationship was found with a correlation coefficient of $R^2 = 0.95$.

Using this relationship, a comparison of the DDP classification criteria obtained from the correlation between DDP and acidity, along with the criteria obtained from correlation between DDP and color, is shown in Figure 10. A small difference is found between the both classifications, with an average standard deviation at about 14.6.

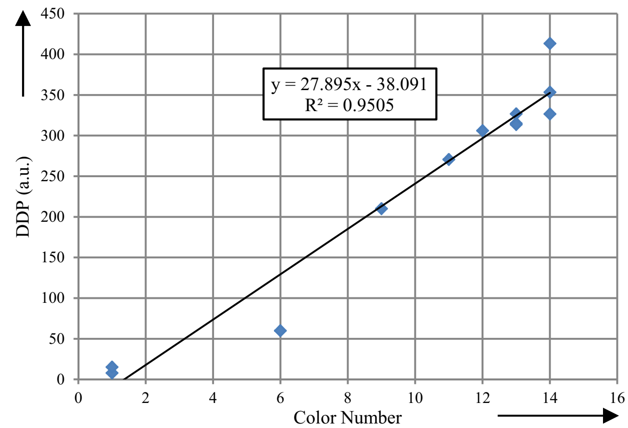

Figure 9. Correlation between the Dissolved Decay Products (DDP) test results and color.

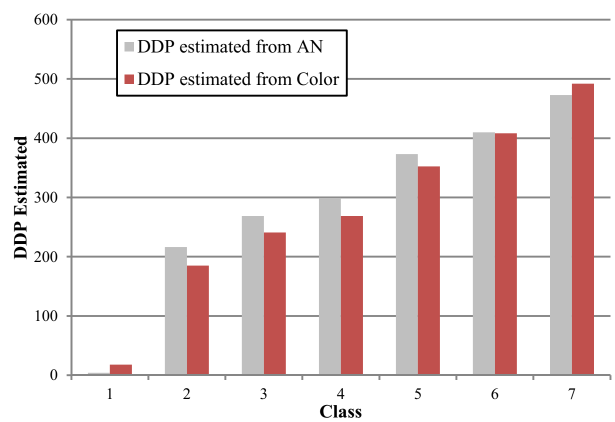

Figure 10. Comparison between DDP classification criteria obtained from AN and Color. DDP always represents the Dissolved Decay Products while AN stands for the Acid Number.

5 APPLICATION OF THE CLASSIFICATION TO SERVICE-AGED TRANSFORMER OIL SAMPLES

The validation of the DDP and Turbidity based classifications using oil samples collected from in service power transformers are discussed in this section. Table 6 lists the specifications of the units sampled in this study. Insulating oil samples were collected from a total of 17 power transformers, commissioned between 1976 and 2012.

Table 7 summarizes the characteristics and the classifications of insulating oil sampled from the units described in Table 6. The classifications results show a good agreement between the proposed classifications and the traditional ones. From this Table, it can be noticed that the TS5 sample can be classified in the group 1 according to the criteria of DDP and acidity (AN).

Table 6. specifications in field transformer oil survey and outline of data on insulating oil samples collected.

Item	Commissioning date	Power/ Voltage class (kVA)	Insulating oil brand
TS1	1998	250 kVA	Borak22
TS2	1991	250 kVA	Borak22
TS3	1999	250 kVA	Borak22
TS4	1987	250 kVA	Borak22
TS5	1997	100 kVA	Borak22
TS6	2012	3360 kVA 13.2/4.16 kV	Nynas
TS7	1979	100 MVA 13.8/287 kV	YPF 65
TS8	1979	100 MVA 13.8/287 kV	YPF 65
TS9	2011	1000 kVA	Mineral oil
TS10	1976	153 kVA	Mineral oil
TS11 (GSU unit)	2002	100 MVA	Nynas 10 GB
RS12 (Reactor)	1979	500 kV 16.7 MVAr	YPF 65 oil
TS13	Spare	100 MVA	Nynas GX 11
TS14	1999	100 MVA	Nynas GX 11
TS15	2000	100 MVA	Nynas 10 GB
RS16	Spare	500 kV 16.7 MVAr	YPF 65
RS17	1980	500 kV 16.7 MVA	YPF 65

However, according to the classification by interfacial tension (IFT) and turbidity (TUR), it is classified in the group 5. It can also be noted that the color of this sample is comparable to the color of the sample TS4. Therefore, the TS5 can be classified in Group 1. Recall that there is a definite relationship between acidity and interfacial tension. However, IFT not accompanied by a corresponding increase in AN indicates polar contamination which have not come from normal oxidation [13]. Therefore, in the case of the sample TS5, other substances of an internal or external source, had influenced the interfacial tension and turbidity of the oil. The same observations applied for sample TS7.

6 CONCLUSIONS

Insulation system condition is a decisive factor for the condition of the entire power transformer. UV/Visible Spectrophotometer (DDP) and turbidity, two alternative diagnostic methods developed by ASTM have been used to assess decay products as trace impurities in insulating oil. Until now, the use of these reliable, quick and accurate methods is limited in qualitative evaluation, where no preliminary decision can be taken based on these methods. This contribution reports a correlation/regression study between the proposed alternative diagnostic methods and traditional ones. The obtained results show how these two methods can be used to monitor step-by-step the decay products formation and how promising they are. A low correlation coefficient was obtained from the correlations

Table 7. Insulating oil characteristics and test methods. DDP always represents the Dissolved Decay Products, IFT for the Interfacial Tension while TUR stands for the Turbidity.

	Sample	Acidity (mgKOH/g)	IFT (dynes/cm)	DDP (a.u)	Turbidity (NTU)	Color
Measurements	TS1	0.205	15.5	369.95	5.36	15
	TS2	0.219	15	311.64	3.9	13
	TS3	0.149	16	308.8	3.55	12
	TS4	0.022	26	162.75	0.863	8
	TS5	0.034	16	153.96	7.6	7
	TS6	0.008	33	174.81	0.95	7
	TS7	0.0308	27	96.52	1.92	5
	TS8	0.0058	32	26.67	0.97	2
	TS9	0.003	35.2	3.32	1.8	-
	TS10	0.024	28.4	189.2	2	-
	TS11	0.02	34.8	15.33	0.52	-
	RS12	0.04	41.5	169.16	1.37	-
	TS13	0.02	36.5	27.43	1.2	2
	TS14	0.025	33	204.22	0.32	7
	TS15	0.025	32.5	106.78	0.368	7
	RS16	0.0084	28	34.7	1.09	1
	RS17	0.003	30	69.96	2.02	4
Classifications	TS1	4	5	4	4	5
	TS2	4	5	4	4	4
	TS3	3	5	4	4	4
	TS4	1	3	1	1	2
	TS5	1	5	1	5	2
	TS6	1	1	1	1	2
	TS7	1	3	1	3	1
	TS8	1	1	1	1	1
	TS9	1	1	1	2	-
	TS10	1	2	1	3	-
	TS11	1	1	1	1	-
	RS12	1	1	1	2	-
	TS13	1	1	1	1	1
	TS14	1	1	1	1	2
	TS15	1	1	1	1	2
	RS16	1	2	1	1	1
	RS17	1	1	1	3	1

between the alternative methods and the interfacial tension. This might be due to the absorption of part of the dissolved decay products by the paper, and to the decrease limit of the interfacial tension with aging. However, the correlation between acidity and these methods (DDP, Turbidity) gives a better correlation coefficient. The obtained mathematical relationships can be applied to any maintenance standard to establish classification criteria of the oil quality according to DDP and turbidity. The applicability of the proposed classification to in service transformers oils, has confirmed the feasibility of using UV/ Visible spectrophotometer (DDP) and turbidity as a diagnostic tool and oil quality assessment. As part of an overall maintenance strategy, Turbidity and DDP tests can help taking restorative measures before deterioration reaches a point where failure of the transformer is inevitable. However, oil in service will vary widely in the extent of degradation and the degree of contamination. In general, a single type of test is not enough to evaluate the condition of the oil sample. Evaluation of condition should preferably be based upon the composite evaluation of significant characteristics before taking accurate decisions.

ACKNOWLEDGMENT

This work was carried out within the framework of the Canada Research Chair, ISOLIME at the Université du Québec à Chicoutimi (UQAC). The authors express thanks to NSERC (Canada) for funding this project along with all the sponsors/collaborators.

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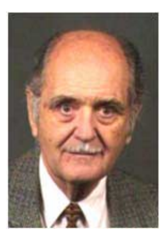

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