Hydrogen – the most measured and monitored transformer parameter

Relevance of a 100-year maintenance paradigm in the 21st century

ABSTRACT

Hydrogen gas has been the most measured transformer parameter in the last 30 years. At least 95% of all online monitors used for continuous monitoring of transformers measure hydrogen. The majority of online monitoring performed on transformers measure only hydrogen, or the composition of gases as one figure relative to hydrogen. Subsequently, the data obtained for these single dissolved gasses is huge compared to any other measurement for transformer maintenance. The hydrogen concentration value seems to be the greatest contributor to making what is the most important decision for transformers worldwide – determining the transformer condition. While my previous columns looked at a big picture of transformer maintenance through oil analysis, this article will scrutinize a very small element; in fact, the smallest molecule measured inside the transformer. The article will review historical facts related to hydrogen-based maintenance as well as modern approaches to hydrogen detection, measurement and especially diagnosis. Based on all these evidence, it is probably the right time to consider monitoring other dissolved gases in order to obtain an improved diagnosis. Future gas monitors will need to have less false alarms and greater rate of success in predicting fault condition and prolonging the transformer life.

KEYWORDS
dissolved gas analysis, hydrogen, maintenance
Hydrogen, as the smallest molecule inside the transformer, has been the most measured parameter in the last 30 years

1. Introduction
Transformers have been used for more than 130 years. For most of that time, over 120 years or so, transformer cooling oil has been the most popular choice for insulating and cooling the transformer, and since those early days of their operation, the engineers, mostly electrical engineers, have been trying to measure as many available parameters as possible based on the knowledge and possibilities available in each time period. The first such measurements were performed at the beginning of the 20th century. Probably the first measurements were the breakdown voltage or the capabilities of the insulating oil to support an increasing DV voltage applied between various tips. As soon as the knowledge and the technology became available, engineers started to perform most of the tests we perform today, such as oxidation stability, moisture and acidity, and they even started estimating the gasses produced in the insulating oil at different stresses.

This is probably the first paper where hydrogen (H₂) was mentioned as the most distinctive indicator of electrical discharge in the oil – the famous D2 fault type, as we call it today.

The next major development in transformer monitoring was the genius invention of the Buchholz relay in 1921. This protecting device is still mounted in probably all oil-filled transformers with the conservator in the world, based on the same principles laid by Max Buchholz almost 100 years ago. The great qualities of the Buchholz relay, its reliability and contribution to transformer performance make it the most important protective transformer device. The malfunctions and limitations of the Buchholz relay were extensively described by P. Ramachandran [2].

Although this was probably not considered by its inventor, one of the most important aspects of the Buchholz relay is the possibility to analyse the gas that accumulates in the relay. The gases that develop following a fault in a transformer accumulate in the relay and cause the transformer to trip. In most cases, the cause of the sudden failure was arcing, which, as we know today, contains mainly acetylene and hydrogen. From the beginning engineers correlated the nature of gases to the type of failure.

The first detection method for measuring and diagnosing the gas composition was of course by lighting the flame with a match. Most engineers remember the old days when the Buchholz alarm was checked in a very simple way by letting the gases exhaust the pipe and then lighting the flame. The diagnostic was rather rough and simple, but very quick; and not safe of course. Considering that not all combustion gases are fault-related gases, even when present in unusual amounts, it was possible to miss a real failure. Excessive overloading mainly produces methane and ethane at relatively low temperatures. If the oil is not degassed, saturation is easily achieved, and the reality is that due to combustion gases the Buchholz will switch off the transformer. In cases when it is not possible to identify gases, the only choice is to remove the transformer from service. The field experience has shown that overloading a healthy transformer does not affect its routine operation. So, if the combustion gases do not contain acetylene, the transformer can be safely energized, needing frequent DGA testing afterwards.

In the 1940s identification of gases in gas cushion started [3]. Since significant amounts of gases are mainly caused by arcing, the identified gases were rarely due to faults or overload.

2. History of gas in oil measurements
The first observation in transformer history that correlates faulty condition to evolved gasses from the mineral oil is documented in a paper from 1919 [1].

The first paper that mentions hydrogen as the most distinctive indicator of electrical discharge in the oil – the famous D2 fault type – dates back to 1919

Figure 1. Ampules for sampling gas and oil, the U.S. and European versions
Even non-leaking syringes of gas-in-oil standards have a 2 % loss rate of hydrogen per day

Between the 1950s and 1970s, the mainly used detecting methods of gases were IR and Mass Spectra, Sloat 1967 [4] and Vora & Aicher 1965 [5]. In the late 1960s and from the 1970s onwards, the most used procedures to perform DGA included sampling by syringes, extracting by vacuum extraction [6] and detecting by Gas Chromatography (GC). Until the 1980s, Mass Spectra was a real competition to GC [7]. Due to the skills required to use syringes, many transformers were traditionally sampled by using ampules. Other inexperienced sampling teams adopted oil sampling procedures using metal or bottle cans. All these sampling vessels were approved by ASTM and IEC standards. But without doubt, the most accurate sampling method, especially for low concentrations of the lightest gas of all – hydrogen, is to carefully sample the insulating oil using syringes.

Even non-leaking syringes of gas-in-oil standards have a 2 % loss of hydrogen per day. If the syringe is leaking due to impurities or air transport stresses, then the uncertainty of hydrogen can be higher than 30 % for the normal interval between sampling and testing. It can be noted that for Morgan Schaffer’s gas-in-oil standards, the concentration is guaranteed for one month only, even though they are specially sealed between the piston and glass body, Fig. 3.

The bubble in a syringe, or in any other type of bottle, attracts and extract mainly the hydrogen gas due to its lower solubility compared to other gases. Tenbohlen et al. [8] showed that the concentration of hydrogen decreases up to 30 % in two weeks if the bubble is
Users have to be very careful when considering any diagnosis based on hydrogen values that have been obtained by PAS devices.
The industry needs diagnostic algorithms which are based only on reliable measurements obtained from a device with a proved medium and long-term stability.

For the record, it has to be mentioned that all Furan measurements are lower than 0.1 ppm, without any other evidence for cellulose destruction. In this situation, the error for the fuel type device in comparison to the real hydrogen value is found to be higher than 100 %.

Some of the new online devices for selective hydrogen lead to improper sampling because the oil flows from the main tank to the sensor. Without a forced or directed flow, the value measured is not representative. The main advantages of fuel cell-type monitors over new hydrogen-type online gas monitors are the long-term stability, reliability and experience of the industry. As was a case in the past, some of the new online devices will disappear in the future. This is possible considering that approximately a third of the brand names mentioned in Table 1 of the CIGRE brochure 409 [11], which is dated 2010, are already unavailable in 2018.

The transformer users and especially the algorithm and health index developers have to be aware of all those possibilities and build algorithms based only on reliable measurements obtained from a device with proved medium and long-term stability.

### Table 2. Transformer fault type probability classified by [16]

<table>
<thead>
<tr>
<th>Type of fault</th>
<th>No. of faults</th>
<th>Ratio %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overheating</td>
<td>226</td>
<td>53.0</td>
</tr>
<tr>
<td>High energy discharging</td>
<td>65</td>
<td>18.1</td>
</tr>
<tr>
<td>Overheating and high energy discharging</td>
<td>36</td>
<td>10.0</td>
</tr>
<tr>
<td>Spark discharging</td>
<td>25</td>
<td>7.0</td>
</tr>
<tr>
<td>Dumping or partial discharging</td>
<td>7</td>
<td>1.9</td>
</tr>
</tbody>
</table>

### Table 3. Fault type classification by key gas method [17]

<table>
<thead>
<tr>
<th>Fault type</th>
<th>Relative proportion of gases %</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>H₂</td>
</tr>
<tr>
<td>Overheating in the oil</td>
<td>2 %</td>
</tr>
<tr>
<td>Overheating cellulose</td>
<td>/</td>
</tr>
<tr>
<td>Partial discharge</td>
<td>85 %</td>
</tr>
<tr>
<td>Arcing</td>
<td>60 %</td>
</tr>
</tbody>
</table>

Figure 7. Thermodynamics of gases vs. temperature (IEEEC57.104-2008), based on previous research by Halstead in 1973
A recent study observes that in a big majority of failures, hydrogen is not a significant gas.

In a fleet of more than 200 monitored transformers, in 70% of the cases where faulty condition was discovered by DGA, there was not a significant concentration of hydrogen. In the rest of the cases where there was a significant hydrogen concentration, other hydrocarbons or carbon oxides were also present in such concentrations that they allowed predicting the failure. However, in at least five cases, the hydrogen development was confirmed as stray gas, and the hydrogen alarm and trigger was indeed a false alarm. Stray gassing produces high concentration of gases, which leads to a false alarm. So, stray gassing is a very tricky issue in diagnostics. Not all transformers filled with potentially stray gassing oil actually develop stray gassing.

Figures 9, 10 and 11 illustrate some of the issues related to diagnosing a failure based on hydrogen.

Figure 11 depicts a real PD fault – an internal failure that occurred after eight years of continuous monitoring by offline and online devices, with a high but fluctuated concentration of hydrogen, between 500 and 1200 ppm. The failure occurred at 800 ppm hydrogen and 55 ppm methane, but the recorded fluctuation of the concentration made it difficult to decide if the fault was active or not. Finally, the fault was detected on the basis of ethylene, and not on the basis of abnormal hydrogen value.

According to different studies, the most popular and successful diagnostic method, the classic Duval Triangle [18], is able to reveal the fault in more than 90% of cases if applied correctly, and it achieves these performances without using hydrogen. It seems that the undisputable success of this method lies in the fact that it is not affected by the uncertainty of hydrogen evaluation. The used hydrocarbons are much less sensitive to usual stray gassing.

F. Jacob and J. Dukarm [19] recommend not to take into consideration hydrogen and carbon monoxide concentration values for fault evaluation. More and more experts warn about problematic interpretation of those gases. In a recent study [20] it was established that most of the available diagnosing methods suffer from inaccuracy due to stray gassing, which is at

<table>
<thead>
<tr>
<th>Main gases</th>
<th>Abnormal conditions</th>
<th>Abnormal conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>H₂</td>
<td>Partial discharge, arc discharge</td>
<td>Short circuit between winding layers, winding breakdown; partial discharge between the tap-changer contacts, arc discharge, short circuit</td>
</tr>
<tr>
<td>CH₄, C₂H₂</td>
<td>Overheating, loose contact</td>
<td>Loose contact of tap-changer, joint becoming loose, insulation is poor</td>
</tr>
<tr>
<td>C₂H₂</td>
<td>Arc discharge</td>
<td>Winding short circuit, flashover between the tap-changer contacts</td>
</tr>
</tbody>
</table>
It seems that the success of Duval Triangle lies also in the fact that it is not affected by the uncertainty of hydrogen evaluation. Among other chemical parameters which are worth monitoring are:

- Ethylene – present in all faulty thermal conditions and less susceptible to stray gassing
- Oxygen – probably the most important gas dissolved in oil for all non-breathing transformers, especially those filled with natural ester. Oxygen is the best indicator of oil ageing, and of course, the integrity of the sealing system. Its importance was observed a long time ago [21], and the technology to monitor the dissolved oxygen concentration correctly is now available. Also, in case of transformer fire due to external reasons such as the bushing ignition, degassed oil with low oxygen is less susceptible for fire.

Conclusion

In the early days of DGA, the most measured gases were hydrogen, carbon monoxide and acetylene. These gases were present in a gas cushion above the oil or the protective relays, in connection to electrical discharge that mostly involved cellulose. The early measurements were performed with low sensitive devices, as early IR and Mass Spectra. It is time for a rethink about the necessity and advantages of monitoring hydrogen alone or with carbon monoxide and their relevance to obtaining a reliable health index. In the 21st century, the technology allows developing new detectors, even based on old MS principles or on new inventions. The elevated inaccuracies of low concentration measurements of dissolved hydrogen, together with still unexplainable phenomenon of stray gassing, impose an additional concern about using hydrogen and, to a lesser degree, carbon dioxide parameters for transformer diagnosis.

It is reasonable to gradually diminish the hydrogen role in transformer maintenance.

DISCLAIMER: Marius Grisaru contributed to this article in his personal capacity. The views and opinions expressed in this article are those of the author only and do not reflect the policy or position of Israel Electric.
It is time for a rethink about monitoring hydrogen and carbon monoxide, and their relevance to obtaining a reliable diagnosis.

Table 5. Inaccuracies in transformer diagnosis by hydrogen solely

<table>
<thead>
<tr>
<th>Offline DGA</th>
<th>Sampling</th>
<th>Extraction</th>
<th>Measurement</th>
<th>Diagnosis</th>
<th>Overall inaccuracy</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum inaccuracy</td>
<td>10 %</td>
<td>15 %</td>
<td>10 %</td>
<td>30 %</td>
<td>Greater than 500 %</td>
</tr>
<tr>
<td>Maximum inaccuracy</td>
<td>50 %</td>
<td>40 %</td>
<td>60 %</td>
<td>70 %</td>
<td>Greater than 5000 %</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Online DGA</th>
<th>Measurement</th>
<th>Diagnosis</th>
<th>Overall inaccuracy</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum inaccuracy</td>
<td>20 %</td>
<td>30 %</td>
<td>Greater than 500 %</td>
</tr>
<tr>
<td>Maximum inaccuracy</td>
<td>70 %</td>
<td>70 %</td>
<td>Greater than 5000 %</td>
</tr>
</tbody>
</table>

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