Getting the Most out of Key Gas Monitoring

by **Chris Rutledge**

As maintenance practices for utilities are quickly shifting from cyclic to a more condition-based approach, it has become a customary practice to install online monitoring for most high-value assets. Much of this monitoring has focused on dissolved gas analysis for power transformers. The formation of hydrogen and hot metal gases is typically the leading indicator of excessive thermal conditions developing within the transformer. This can result in solid insulation degradation, causing the unit's premature failure. While there are several approaches to applying this type of monitoring, ranging from complex multi-gas systems to key gas monitoring, there must be a good understanding of the data being collected and how that data can be used to best determine the overall health of a particular transformer. When key gas monitoring is considered, it requires a good understanding of several factors to establish a successful monitoring program. This would include the types of conditions associated with various levels of hydrogen generation, where alarm points need to be set to best detect these conditions, and how to utilize offline tests in conjunction with key gas monitoring to provide the best assessment of transformer health.

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Introduction

While some form of dissolved gas monitoring has become a standard practice for most utilities, there is still a strong reliance on the data collected from manual samples. This continuance of manual testing procedures, even in cases where there are multi-gas monitors in place, should raise the question of what purpose in the overall maintenance plan these monitors serve. To best answer this question, there are several factors to be considered, such as the type of monitoring being installed, as there is a much higher level of analytics that can be performed using the data collected from a multi-gas monitor compared to that of key gas monitoring. How is the transformer being operated? This question is critical when determining the type of monitoring being installed as transformers, which are heavily loaded, tend to operate at thermal conditions which can cause a considerable amount of hydrogen generation and make it difficult to assess the health of the transformer on hydrogen values alone. Finally, how frequently is the offline DGA testing being performed? Typically, if samples are being collected on an annual basis, this can provide enough data to detect many of the common root cause failures, as transformers tend to show deterioration over a period of several years before failure occurs. Monitoring is then responsible for detecting conditions that can occur suddenly between sample periods. These would include things such as partial discharge, in-tank arcing or exposure to high through-fault values. Since hydrogen is typically the leading indicator of these conditions having occurred, key gas monitoring should provide a reasonably high level of confidence that there has not been a sudden change in transformer condition since the last oil sample was collected. Therefore, this article will examine the use of key gas monitoring in conjunction with trending data from manual samples as a means of maintaining optimal transformer reliability.

Hydrogen Generation

Hydrogen monitoring represents one of the earliest and most frequently used types of online transformer monitoring. This is due to its relatively low cost, ease of installation and the association of hydrogen as being an indicator of many of the common faults which occur in transformers. To better understand this association, an examination of the conditions under which hydrogen is produced and empirical data from case studies will be displayed.

Hydrogen in transformers is produced due to a breakdown of the hydrocarbon chains which form mineral oil. This process starts when the thermal, condition within the transformer exceeds 150°C. At this point, we would begin to see hydrogen and methane molecules as a byproduct of the degradation of the temperatures increase, these methane molecules will be replaced by ethane at around 250°C, ethylene at around 350°C and finally acetylene at 1000°C. However, despite these changes in the production of other hydrocarbon gasses, hydrogen production remains constant through all these thermal ranges. It is this consistent formation despite the thermal condition that makes hydrogen an ideal key marker for single gas monitoring. Taking that into consideration, there are several adverse conditions that can occur within a transformer of which hydrogen is a leading indicator.

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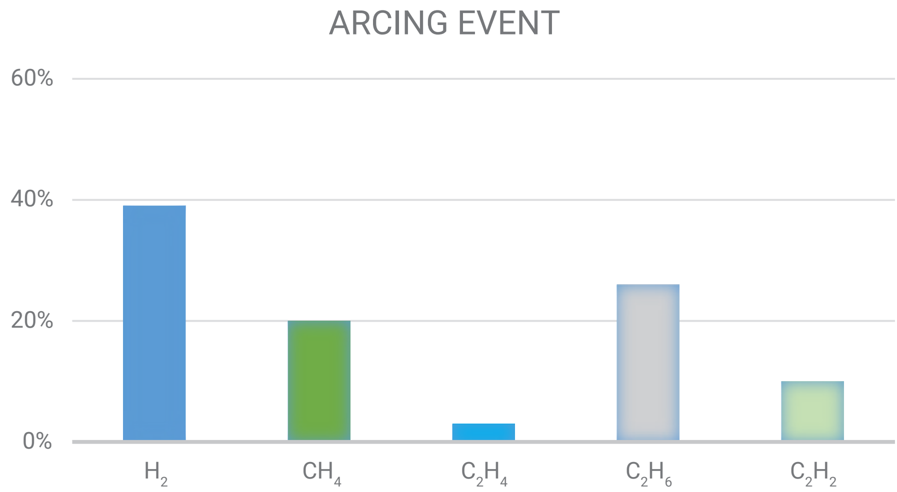

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Event 1

is from a transformer that experienced an internal arc while in service.

The DGA results from this event exhibit a signature example of arcing occurring within the transformer. The key indicator of this arc being the levels of hydrogen present are roughly two times greater than that of acetylene. While the key gas monitor alone would not allow this analysis to be performed, the levels of hydrogen produced would be sufficient to raise an alarm that the event had occurred. Typically, these types of events tend to occur suddenly and result in relaying tripping the unit out of service at which time a DGA sample could be collected, and a full analysis performed. Another factor that needs to be considered is that saturation of the gasses into the oil does not occur instantaneously, and in some cases may take as much as 24 hours before an accurate assessment of the event can be made. So, when these types of events occur, there would be little advantage in having a multi-gas monitor in place, other than the ability to perform an analysis of the event remotely once equilibrium of the gasses had occurred.

In instances of partial discharge occurring within the transformer, hydrogen is the key indicator. Because partial discharge typically starts as a low-energy event, thermal conditions are lower than those associated with other types of incipient faults.

Event 2

DGA Test Results

In Event 2, hydrogen is the key indicator of PD occurrence followed by the production of methane and low levels of ethane. However, it should be noted that as this condition evolves in severity, we start to see increased production of ethane and ethylene, which is indicative of higher thermal conditions developing at the site of the defect. Again, this level of analytics is not possible with key gas monitoring alone, however key gas monitoring would have raised an alarm to provide notification that the PD event is present and allow for preventative action to be taken.

Setting Alarm Points

Many of the conditions associated with sudden failure, which may develop rapidly between manual sampling intervals, can successfully be detected in their initial stages using key gas monitoring. However, another critical point to consider is at what level alarm points should be set at for the earliest notification of these critical conditions. While setting alarm points based on a total ppm value can prove to be useful in detecting abnormal conditions, there are several factors to be considered when establishing these limits. The first thing to be established when setting alarm points is the historical data for the transformer on which the monitor is installed. While IEEE guidelines provide a useful starting point, the user must review historical data for the transformer to determine what is considered normal operational levels. For many transformers, this will be well within the guidelines recommended tables, but in other cases normal operation may range in the 100 or 200 ppm range. By examining the transformer's historical DGA data, alarm points can be established in a manner that provides notification when gas levels have deviated outside of that transformer's normal operating levels. This approach will help eliminate instances of false alarms occurring. Another approach to consider is alarming based on a rate of change. This can be done in unison with the total ppm values but provides much earlier notification that something has changed in the way the transformer is performing. These rate of change alarms can be based on daily, weekly, or monthly rates of change. The reason these alarms are preferred is that the sudden generation of hydrogen can always be associated with an active event occurring within the transformer and will provide an alarm even if the levels of hydrogen generated do not exceed a total ppm value. This is important because of the volatile nature of hydrogen when in a dissolved state. Hydrogen is the least soluble of all the hot metal gasses and tends to diffuse quickly across the oil gas partition. This in conjunction with hydrogen's nonhomogeneous distribution in the oil can lead to a cumulative ppm value representative of actual hydrogen generation difficult to achieve at the monitor's static measuring point. These physical attributes of hydrogen, combined with any possible leaks which may be present in the transformer's tank, can greatly affect the levels of hydrogen saturated in oil, causing total ppm values to appear much lower due to the loss of hydrogen to the atmosphere. In these instances, the rate of change alarm may be triggered based on a 25-ppm daily rate of change, whereas the total ppm value may never be exceeded due to conditions not allowing for complete saturation of hydrogen in oil.

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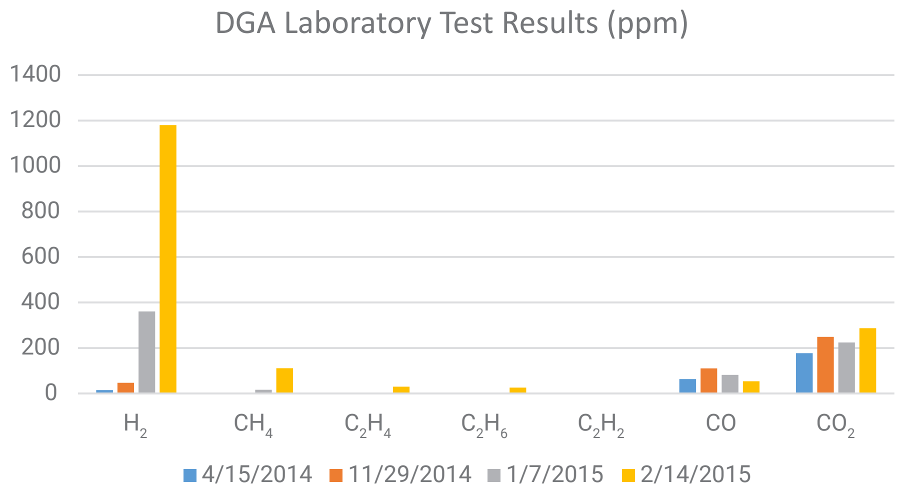

Developing a maintenance plan

While key gas monitoring can prove effective in detecting changes in transformer condition in the incipient stages it is not comprehensive enough to forego the manual DGA testing required to optimally maintain a transformer fleet. This requires a combination of routine sampling and electrical testing or monitoring in conjunction with key gas monitoring to provide the most reliable level of service. With manual sampling, many conditions which could lead to transformer failure can be detected, many of which would not be associated with rapid hydrogen generation. A good example of this would be moisture ingress into the transformer's tank. While this could easily be detected through manual sampling of the transformer oil, it would likely not lead to significant hydrogen production until a great deal of damage to the transformer's solid insulation system had already occurred. Also, slow-developing hot spots within the transformer may progress over time due to poor insulation or electrical connections. While this would result in some low-level hydrogen production, values may not rise quickly enough to trigger any of the alarms associated with the monitor. However, when trending values over time from manual samples, the condition is likely to become apparent through increases in ethane or ethylene values. The total ppm values of these gasses would likely be a better indicator of the condition than that of hydrogen values due to their higher solubility in oil. The maintenance plan would also need to take into consideration some of the other components which are primary causes of transformer failure. This would require online monitoring of bushings as well as OLTC compartments.

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Conclusion

Key gas monitoring can be highly effective at increasing the overall reliability of the electrical grid. This is due to its ability to rapidly provide an early warning when a transformer deviates from its normal operating conditions. Also, because of the relatively low cost of implementing key gas monitoring, it can be more widely dispersed across the entire grid than more complex monitoring systems, increasing the chances of detecting problems before they result in failure. Key gas monitoring also requires less maintenance than many multi-gas systems, allowing operating costs to be better directed. While these devices alone cannot provide the level of data needed for a comprehensive analysis of equipment condition, when used as part of an overall maintenance plan, they can be a welcome addition in the effort to improve transformer reliability.