Improved transformer temperature monitoring

Increasing the availability, reliability, and reducing maintenance costs

ABSTRACT

This article discusses transformer temperature monitoring where a strategy of reduction in maintenance costs and outages, by replacing older ancillary technology with modern IEDs, can offer a reduction in maintenance costs, while providing an increase in availability and reliability.

Winding temperature indicators are critical devices on a transformer as they not only control the cooling system, but also provide the transformer with thermal protection. Utility experience indicates that a significant part of transformer maintenance is devoted to winding temperature indicators.

With the advent of on-line monitoring, the preferred transformer temperature monitoring solution is to use fully electronic devices, which continuously calculate the winding hottest temperature based on the measured values of top oil temperature and load current measurements.

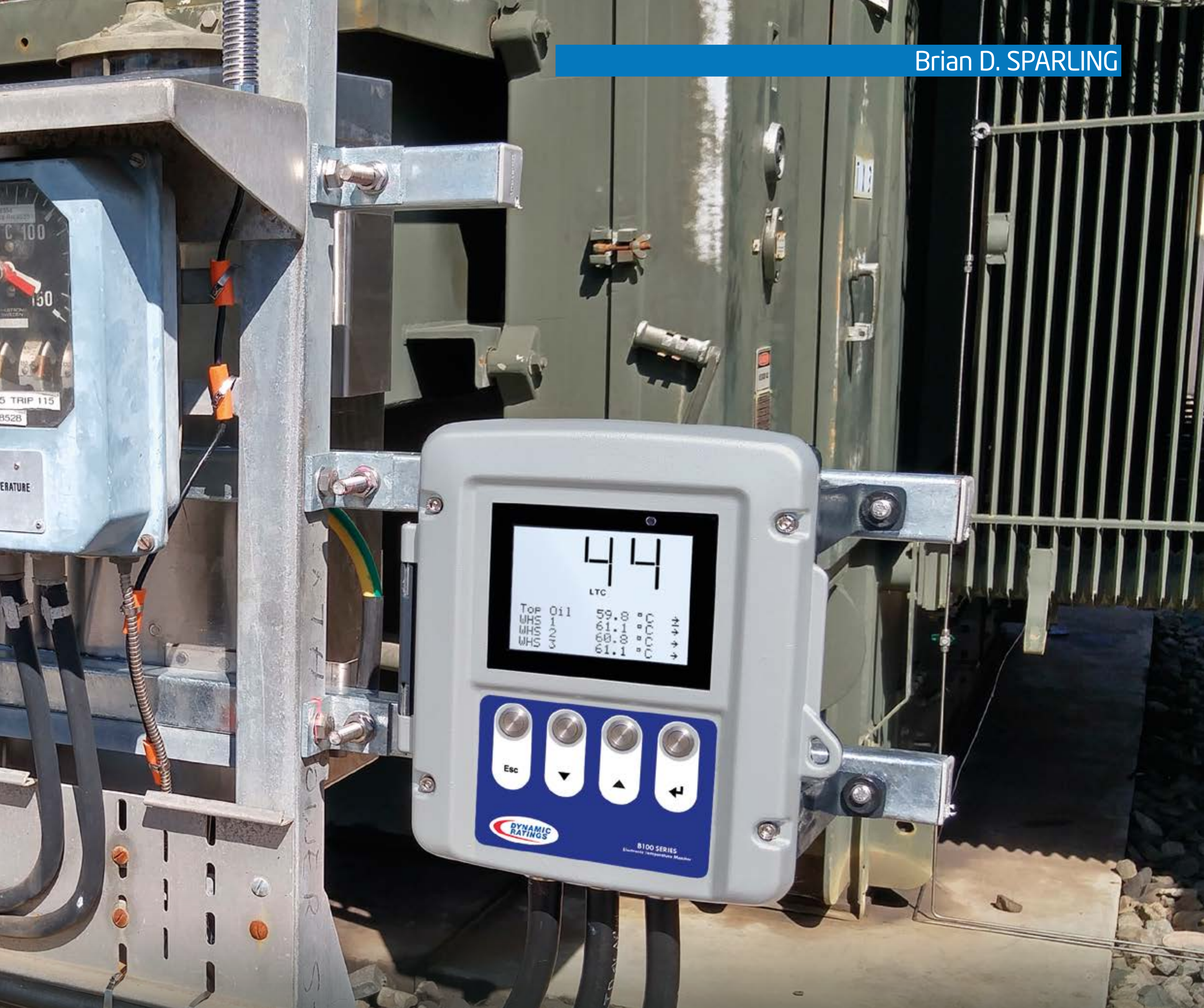
KEYWORDS

transformer, temperature monitoring, winding temperature indicator

1. Introduction

In my previous article [1], I focused in broad terms on the benefits of continuous on-line monitoring of HV substation assets. In this issue, I will cover some specific areas where a strategy of reduction in maintenance costs and outages, by replacing older ancillary technology with modern IEDs, can in fact offer more than a reduction in maintenance costs, while providing an increase in availability and reliability.

This article will discuss the opportunities to be discovered by upgrading the Oil Temperature Indicator (OTI) and Winding Temperature Indicator (WTI) technology developed in the 1940s, which at the same time reduces maintenance costs associated with those devices. The now commonly called Electric Temperature



Indicators (ETM) combine real-time operating information of the transformer and modern communications to enable decision making as part of any smart grid application.

The prospect of using on-line monitoring IEDs to make intelligent decisions to optimize the load on such important substation assets as transformers follows the adoption of load management technology for power generation systems and equipment. In addition, real-time monitoring of equipment and its operating environment will enable system planners and operations personnel to dynamically load transformers to optimum limits without compromising reliability, a*nd do it safely.*

2. Background

Power transformers are monitored and dynamically loaded in order to:

- utilize transformer assets closer to their real operating limits without compromising their life expectancy or reliability;
- fully optimize real-time substation loading based on changes in ambient condition or operating modes;
- assist in making intelligent decisions about shifting load from the unit, based on the time to reach peak load capability (as an early warning);
- forecast operating conditions with given load shifted to the unit at a specific time, or to determine how much load could be shifted to a unit; and to
- collect accumulated loss of insulation life data to enable forecasting of residual life of transformers in the fleet.

Current loading practices and the limitations they impose in setting dynamic loading criteria must be updated in today's ever-congesting networks.

Many countries around the world are operating in a deregulated environment, which is driving transmission & distribution (T&D) companies to find ways to improve their competitive position and increase their return on investment (ROI).

Replacing older ancillary technology with modern IEDs can offer a reduction in maintenance costs, while providing increased availability and reliability

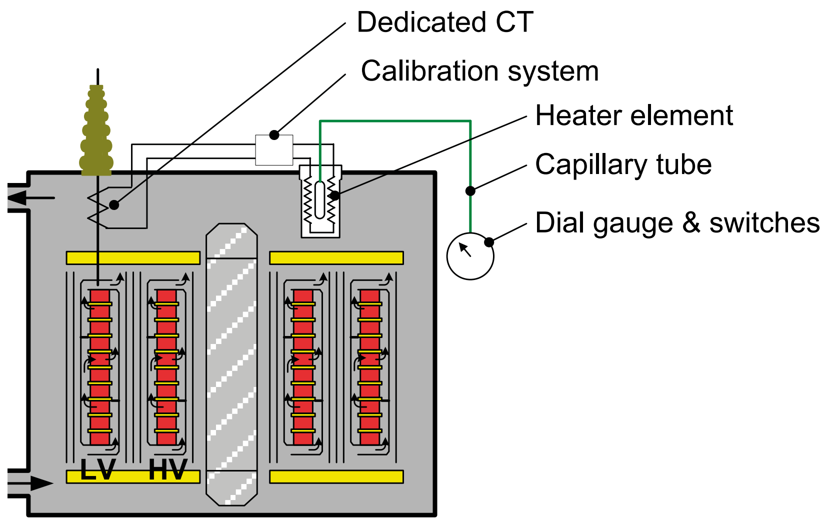


Figure 1. Principal scheme of the winding temperature indicator

Utility experience indicates that a significant part of transformer maintenance is devoted to WTIs

3. Maintenance

3.1 Limitations of traditional OTI and WTI

For many decades, it has been a standard practice to install OTIs and WTIs on new transformers. These devices are typically comprised of a temperature sensing bulb inserted into a dry well in the top layer of the insulating fluid, as shown in Figure 1. In addition to this, the WTI incorporates a heater element to which a sample of the load current carried by the transformer is applied. This current causes the temperature bulb to read the oil temperature plus a temperature increment that is intended to be the same as the winding hottest-spot temperature rise above top oil temperature. The fluid in the bulb expands through a capillary tube connected to a dial gauge equipped with switches that can be adjusted to any temperature within the operating range. These mechanical devices provide an accuracy of 3 °C to 5 °C if the transformer designer has properly evaluated the winding hottest-spot temperature. These devices are typically used for cooling control and temperature alarms. They are sufficiently rugged to be used for protection purposes *if* the recommended maintenance and/or calibration verification is carried out every four to five years.

The WTI is a critical device on a transformer because it not only controls the cooling system, but also provides the transformer with thermal protection.

Therefore, a failure of this device, or even an incorrect indication, may have an important impact on transformer aging, and may affect transformer reliability, especially if a transformer must be operated under overloading conditions. Utility experience indicates that a significant part of transformer maintenance is devoted to WTIs.

There are occasions when this regular maintenance is not carried out for extended periods of time, or is never carried out, either through oversight or ignorance of the issue.

WTIs are prone to mechanical damage of the small-bore tubing or spiral wound Bourdon tube in the measuring device. Moreover, internal component oxidation may lead to increased mechanical friction or seizing up entirely, further reducing the accuracy without signalling this malfunction to the operator. It may result in an inaccurate simulation of the winding hotspot temperature, which can lead to inefficient cooling and tripping control.

The devices in Figure 2 reveal this very issue on a transformer that was only three years old. The WTI is indicating 5 °C *less* than the top oil measured. This is a physical impossibility.

4. Utilization

Maintenance associated with the OTI and WTI is only one part of the equation in managing the assets of the system. The other equally important item is the utilization (loading) of the equipment.

With the advent of on-line, real-time monitoring of transformers, the necessary real-time data and information can be made available via remote access (communication); therefore, driving decisions regarding loading can be made rapidly.

In the past, the requirement to overload transformers was rare, plus most units on the T&D system were rarely loaded to 50 % of their nameplate rating. Now, as load growth has increased and new additions to substations (in terms of increased capacity) are not always the priority, the existing transformers are experiencing increased load, and more frequent demands to be overloaded.

For many years, the limit for normal transformer loading was based on the maximum nameplate rating. However, T&D substation transformers have historically been loaded beyond nameplate rating to accommodate emergency or contingency conditions.

Until recently, the operation of transformers would fit into one of the following loading categories, as defined in the IEEE Loading Guide C57.91 [2]

A. Normal life expectancy loading – Continuous load

As the term implies, this is the constant loading at rated nameplate output (MVA) when the transformer is operated under a constant 30 °C ambient condition. This condition implies a continuous hotspot conductor temperature of 110 °C, which is the sum of the following temperatures:

65 °C (average winding rise) + 30 °C (ambient) + 15 °C (hotspot rise) = 110 °C.

Of course, this loading condition rarely happens over the life of a transformer,

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where both load and ambient temperature vary over time.

B. Normal life expectancy loading – Cyclical load

This loading implies a cyclical load at a normal constant ambient (30 °C) where the hottest-spot conductor temperature varies above and below the normal 110 °C, as the load cycles above and below the nameplate MVA of the transformer. From the thermal aging standpoint, this cycle is equivalent to the case of rated constant load at the normal ambient temperature (30 °C). This is the case because thermal aging is a cumulative effect over time and temperatures above 110 °C are permitted provided the transformer is operated for much longer periods below 110 °C. Of course, maximum allowable hotspot and top oil temperatures cannot be exceeded.

C. Long-time emergency loading

This operation results from the prolonged outage of a system component which causes transformer loading that results in hottest-spot conductor temperatures in the range of 120 – 140 °C. This type of occurrence would be rare and would be expected to happen two to three times over the transformer life, and each event may last weeks to months.

This type of operation causes accelerated aging of the transformer insulation system, and may have other associated risks. Loss of insulation life calculations should be made to assure it is acceptable for such an event, and top oil temperatures should not exceed 110 °C.

D. Short-time emergency loading

This loading condition is unusually quite high, and is caused by one or more events, which seriously disturb normal system loading and are expected to occur rarely, two to three times over the transformer life. This loading condition can cause hottest-spot conductor temperatures as high as 180 °C for a short period. Significant acceleration in insulation loss of life can occur during this event, and calculations should be made to determine if the loss is acceptable. Because of the rapid aging, load must be reduced quickly, typically within two to four hours. This type of loading has several risks associated with it, such as reduced dielectric strength, stray flux heating and exceeding ancillary equipment ratings.

The move toward dynamic loading will include all the above operating modes, in addition to a relatively new loading condition that came into existence in 1995. This new mode of operation is driven by the need to utilize assets more effectively, without compromising the overall life expectancy of the transformer. This new loading condition is discussed in the following section.

E. Planned loading beyond nameplate – Normal operation

This loading results in the conductor hottest-spot or top oil temperature exceeding the limits suggested for normal life expectancy loading. The user accepts this loading as a normal, planned-for operating condition. There is no associated equipment outage or emergencies with this type of loading. Cyclic loads resulting in hottest-spot conductor temperatures in the range of 120 – 130 °C would be associated with this loading requirement. This type of loading would occur frequently, and in some cases daily, during a short part of the transformer's load cycle. Loss of insulation life calculations must be done to make sure it is acceptable for this loading condition.

Table 1 shows the suggested maximum temperatures given in IEEE C57.91-1995 [2] and IEC Standard 60076-7 [3] for the four types of transformer loading. In addition to these criteria, it is always advisable to calculate the loss of insulation life and make sure it is acceptable for the loads beyond nameplate. Acceptable limits of loss of insulation life for various loadings are very important in developing a loading policy and thermal model limits to facilitate real-time dynamic loading.

NOTE: *These loading conditions make one very important assumption: that the solid insulation is DRY. The definition of DRY is a solid insulation system (most importantly, the winding conductor insulation) with moisture content of less than 0.5 % (weight of water/weight of solid insulation).*

Figure 2. WTI on a three-year-old transformer indicating 5 °C *less* than the top oil measured with the OTI, which is a physical impossibility

Acceptable limits of loss of insulation life for various loadings are very important in developing a loading policy and thermal model limits to facilitate real-time dynamic loading

Table 1. Suggested maximum temperatures

		Normal life expectancy	Planned loading beyond nameplate	Long-time emergency 1-3 months	Short-time emergency 0.5-2 hours
Insulated conductor hottest-spot temperature	IEEE	120 °C	130 °C	140 °C	180 °C
	IEC	120 °C	(N/A)	140 °C	160 °C
Other metallic (supports, core, etc.)	IEEE	140 °C	150 °C	160 °C	200 °C
	IEC	140 °C	(N/A)	160 °C	180 °C
Top oil temperature	IEEE	105 °C	110 °C	110 °C	110 °C
	IEC	105 °C	(N/A)	115 °C	115 °C
Load factor per unit (p.u.) current	IEEE	(N/A)	(N/A)	(N/A)	1.5 p.u.
	IEC	1.3 p.u.	(N/A)	1.3 p.u.	1.5 p.u.

5. Risks and consequences of overloading transformers

The consequences of loading a transformer beyond its nameplate rating are as follows:

- The temperature of the windings, cleats, leads, insulation and oil will increase and can reach unacceptable levels.
- The leakage flux density outside the core increases, causing additional eddy-current heating in metallic parts linked by the leakage flux.
- As the temperature changes, the moisture and gas content in the insulation and in the oil will change.
- Bushings, on-load tap changers (OLTCs), cable-end connections and current transformers will also be exposed to higher stresses, which encroach upon their design and application margins.

6. Electronic temperature monitors

The preferred solution is to use fully electronic devices such as Electronic Temperature Monitor (ETM), which continuously calculates the winding hottest temperature (WHS) on up to three windings based on the measured values of top oil temperature (via existing PT100 RTD sensors) and load current measurements from the bushing CTs.

The computations follow the well-known and established equations found in the loading guides of IEEE and IEC, where the WHS is taken as the sum of the top oil temperature, plus an increment proportional to the load level elevated to a power (typically 1.8). With that information, cooling control of up to (typically) two stages of cooling can be programmed and the thermal aging rate of the transformer calculated. All measured and computed data is recorded and stored every minute.

Using the ETM will significantly reduce installation and maintenance requirements. Manufacturers of traditional WTIs recommend calibration verification at regular intervals. With the ETM, the sensors are continuously checked, and the system has a fail-safe watch-dog function to ensure proper operation of all components.

The further benefit of the ETM, is its capability to be connected to SCADA and communicate its data and alarms to the operating and maintenance staff – even over the existing substation cabling (no need to lay fibre optic cables). That possibility is non-extant with traditional OTI and WTI devices.

The use of ETM-type devices within the electricity network is becoming commonplace, and many utilities are already starting to realize the benefits of the newer technologies over the historic equivalents.

References

[1] B. Sparling, *On-line monitoring of HV substation equipment: Myths and truths,* Transformers Magazine, Vol 4, Issue 2, April 2017

[2] IEEE Std. C57.91™, *IEEE Guide for Loading Mineral-Oil-Immersed Transformers*

[3] IEC 60076-7, *Power transformers – Part 7: Loading guide for oil-immersed power transformers*

The preferred transformer temperature monitoring solution is to use fully electronic devices, which continuously calculate the winding hottest temperature

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