Spatially continuous transformer online temperature monitoring based on distributed optical fibre sensing technology

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Abstract
Transformer internal thermal monitoring exists huge blind areas, and it is difficult for traditional methods to get fully distributed temperature in real time. In this contribution, the distributed optical fibre sensor was creatively applied inside an operating 35 kV oil-immersed transformer which is also qualified for actual power grid operation through the ex-factory tests. Furthermore, the full-region temperature along the windings and iron limbs were firstly monitored in a spatiotemporally continuous manner and the hotspots were also closely traced, fluctuating at 90% of the high-voltage winding height (80% for low-voltage winding) during the whole process of the heat-run test. Corresponding Finite Element Method (FEM) for thermo-fluid field calculation was then utilized for deeper analysis. On the former basis, the actual detected temperature distributions (both spatial and temporal) were compared with the International Electrotechnical Commission traditional model and some modifications were suggested based on the real time measured data. This novel online monitoring application and the detailed internal thermal information may provide a solid reference for the delicate management of power transformers, which also offers a new horizon for the online monitoring in electrical apparatus industry.

1 | INTRODUCTION

Power transformer, as the core equipment of energy system, has a direct influence on the load stability of an entire area. Transformer overheating, gradually becoming a common problem due to the rapid growth of power consumption, directly threatens its life expectancy and the safety of entire grid. Thus, the internal thermal monitoring has attracted widespread attention [1–4].

Currently, the transformer internal temperature detecting technology can be roughly divided into four types: model-based calculation, thermal circuit simulation, numerical simulation, and direct measurement. For the first type, the widely used method was proposed in International Electrotechnical Commission (IEC) 60076-2 and IEC 60076-7 which offered a simplified oil-winding temperature model to estimate the hotspot based on the thermocouples and measured warm winding resistance [5–7]. This method stands out for its concise calculation, but it also ignores many actual interference factors. In practical application, modifications are necessary for various situations. The thermal circuit method, evolved from electric circuit, establishes the winding hotspot model based on the thermal field inside transformers. It is very intuitive and avoids the voltage isolation [8]. In 2002, Tang et al. used a heat capacity integration method to obtain a simplified transformer thermal circuit diagram [9]. Subsequently, in 2005, Susa et al. from Finland optimized the heat circuit parameters based on heat transfer theory, which is closer to the actual test [10–12]. However, this method mainly considers some key areas inside transformer, leaving large monitoring blind spots. The numerical simulation method establishes the differential equations for internal convective heat exchange based on thermodynamics and solves them through relevant algorithms [13–15]. In 2003, Pradhan et al. first established a winding temperature estimation model, but the electrical parameters and the actual design parameters, and so on must be obtained in advance [16]. Therewith, El Wakil conducted a two-dimensional modelling of a transformer and used Computational Fluid Dynamics software to acquire the temperature distribution at different inlet flow rates [17]. The numerical simulation method can theoretically obtain the temperature...
distribution of entire area, but it is limited by the slow response to the load change and is also lack of real-time monitoring. Restricted by the convergence of the solving algorithm and the simplification of the actual conditions, its accuracy also needs a further improvement [18].

In recent years, with the rapid development of optical fibre sensing technology, some scholars have begun to utilize the good insulation and stability of optical fibres to directly detect the internal temperature of transformer [19–25]. The remarkable achievement was a measurement performed by Ribeiro in 2008 on a 66 kV transformer in Portugal (optical fibre probes were located at the transformer winding, iron core and the entrance and exit of oil tank) [26]. Followed by Arabul, arranging large quantity of fluorescent fibre sensors in the oil passages between each adjacent winding wire for the detection of overheated regions in a 1.5 MVA transformer [27]. However, this method belongs to a point-type measurement that is difficult to achieve spatially continuous distributed monitoring. Affected by the complicated circumstances inside transformer, the different positions chosen for sensors may lead to different conclusions. Meanwhile, the point-type technology also leaves numerous sensor probes together with complex internal leads inside transformer and once fell into a bottleneck.

The distributed fibre optic sensing technology (DFOS) was first proposed by Hartog in 1983, utilizing the characteristics of optical fibre as both a sensing medium and a transmission medium. It has been applied in many fields [28–30] after decades of development, such as dynamic monitoring of deformations in buildings or highways, temperature and strain monitoring of oil pipelines, metro operation monitoring, power transmission lines, and so on due to its spatiotemporally continuous monitoring and excellent real-time performance [31].

Therefore, it exhibits great potential for DFOS applying in the electrical apparatus field. In this contribution, an oil-immersed 35 kV power transformer prototype with built-in distributed optical fibre sensors was successfully fabricated and qualified for power grid operation through the corresponding type tests. Through the heat-run test, the online internal temperature was firstly obtained in a spatiotemporally continuous manner, and the hotspots were also closely located and traced in real time. The actual detected data were furtherly compared with the IEC traditional calculating model and some modifications were thus suggested for a more precise prediction of hotspot temperature and location. This new application of DFOS in transformer online monitoring may provide a solid reference for the delicate management of power transformers.

2 | EXPERIMENTAL PLATFORM SET-UP

The high-voltage (HV) and low-voltage (LV) windings of the studied transformer both adopt a layered structure, that is, leaving no oil passages between each adjacent wire, and the temperature sensing can be achieved by attaching optical fibre to the surface of the entire winding. The fibre will be spirally and densely winded along the surface of all the windings, during which process the friction and stress generated will cause the fibre highly integrated with the winding. Meanwhile, a layer of insulating paper will be wrapped around the fibre composite winding to reduce the effect of external oil flow, possible vibrations and knocks during the manufacturing process and daily operation of transformers. The designed optical fibre integrated winding maintains its original structure and the sensing fibre would be synchronously heated with the adjacent wire. Thus, the real-time thermal data along the whole winding can be easily obtained by just detecting the Raman scattering changes. The core limbs were also winded by the sensing fibres, which is similar to the aforesaid process (the exact fibre length of each monitored area is exhibited in Figure 7).

To ensure that the distributed optical fibre sensor works stably under the high temperature environment of transformer and has good compatibility with the insulating oil, ethyl enetetrafluoroethylene was finally selected as the sheath material based on our previous researches [32]. The whole detecting system is based on Raman optical time domain reflection technology (Weihai Beiyang Optoelectronic Info-Tech Co. Ltd), enjoying a temperature accuracy of ±0.5°C and a positional accuracy of 0.8 m (The densely winded procedure of optical fibres has been applied along the windings to obtain the massive data).

The distributed optical fibre sensor integrated power transformer prototype was fabricated in strict accordance with the normal manufacturing process and it was up to standard for power grid operation through the corresponding type tests required by the relevant standards of IEC (such as induced over voltage withstand test, power-frequency voltage withstand test, tightness test, dielectric routine tests, and so on). Thus, from the application’s perspective, this transformer prototype has no difference with the traditional one and it could be applied in any working condition (including various loading conditions or other situations) within the design requirements.

The temperature-rise test was strictly performed according to IEC 60076-2 [33], during which, the spatiotemporal temperature changes inside the transformer were monitored in a distributed manner. The field application is displayed in Figure 1. And the sensing schematic diagram of the online monitoring is exhibited in Figure 2.

The optical fibre was connected to the temperature measuring system through a fibre flange sealed on the tank, and the processed information would be delivered to a local database, uploaded to the cloud storage or transferred to the remote terminal unit for a timely monitoring.

3 | DETECTING AND SIMULATION RESULTS

3.1 | Real time temperature distribution by DFOS

The whole temperature-rise test was performed with short-circuit method, lasting for nearly 9 h composed of two steps,
namely, applying total losses (first 8 h) and applying rated current (the last hour). During the test, the as designed optical fibre sensor displays an effective sensing performance under the complex thermal conditions inside power transformers and works stably all the time.

Since the optical fibre was spirally and uniformly wound along the winding surface, the helix equation (whose parameters are related to the fibre length and the winding size) could be used to describe the spatial position of sensing fibre. Thus, the detected data can correspond to its spatial position.

Meanwhile, as the transformer studied in this study adopts a layered winding structure, the temperature along the whole winding will be uniform and continuous. In the case of densely wound optical fibres, interpolation methods can be used to estimate the temperature which located below the spatial resolution to achieve a completely distributed temperature sensing. The real time temperature visualization of transformer windings is displayed in Figures 3 and 4.

From the detected data, it can be noticed that the temperature distribution for each phase of winding exhibits a consistent trend but with a little difference, which may be caused by manufacturing deviations or internal irregular oil flow and different, time-varying thermal conditions. Thus, the actual temperature distribution inside an operating power transformer is highly relevant to the position and thereby, whether the model-based calculation or the point-type measurements will inevitably deviate from the real situation and exist huge blind zones, leaving hidden dangers for the safe operating of transformers. The observed temperature fluctuations along the winding may be caused by the internal circulating oil flows.

As shown in Figures 3a and 4a, the HV winding temperature presents an increasing trend with the height for each phase excluding some reduction at the top of the whole winding, which may be possibly caused by the relatively good heat dissipation conditions in the top area. The hotspot at 8 h appears at 89%, 90%, and 88% of the winding height for phase A, B, and C, exhibiting 60.8°C, 61.9°C and 61.6°C, respectively. And at the end of test, the hotspot drops down to 54.2°C, 55.1°C, and 55.0°C located at 91%, 90%, and 91% of the height for phase A, B, and C, respectively. The I.V winding displays a higher temperature compared to the HV winding due to its higher current, as shown in Figures 3b and 4b. The temperature increases first and then decreases with the height, quite similar to the former. And the hottest region arises lower than the HV winding, at around 80% of the height for three phases, about 80°C (76°C) at 8 h (9 h). For the iron core limbs in Figures 3c and 4c, the temperature decline at the top area is not as obvious as the windings, which may be probably due to the different structures (the core is composed of many laminate layers and its construction in the vertical direction is also quite different with the windings) and the little magnetic flux in the core during the whole test. Phase C of the core limb displays a relatively lower temperature, possibly caused by the structure deviations during the manufacturing process.

3.2 Thermo-fluid transient simulation result

The actual-detected temperature distribution was different from the IEC common model which believes the hotspot would appear at the top of the winding where the generated heat easily tends to accumulate. It is true that massive oil continuously brings heat to the top area, which can be attributed to the density changes. However, the aforesaid recognition obviously ignores the heat dissipation conditions existing in this area, which may have a huge impact on the real location of hotspot. For further analysing the deeper reason for this reduction phenomenon, Finite Element Method (FEM) has been utilized to help simulate the real process happening inside an operating power transformer.

The thermo-fluid model was established according to the studied transformer design paper based on laminar flow module of COMSOL Multiphysics (5.4, COMSOL AB) software. To betterly approach the real situations and for the convenience of calculation, the model considered as much components as possible and inevitably ignored some detailed structures. But the simulation result can still serve as an important reference to help understanding.

Considering the different structural characteristics of the transformer, different FEM mesh types were chosen for the sake of computation. For the windings, cooling fins and the insulating cylinders, which are all quite symmetrical, structured grid (composed of quadrilateral and hexahedral mesh) was applied. It has advantages of good mesh quality, simple data structure, and thus helps improving the calculation accuracy. And for irregular areas like the oil domain, unstructured grid (composed of triangular and tetrahedral mesh) was utilized due to its good adaptability. The whole model enjoys a high unit quality with about 1.44 million mesh vertices, 80 thousand edge units, and so on, totalling around eight million units. Such design of mesh distribution was the balance of calculation accuracy and the computing time, which was observed no more than 2% changes in results with higher mesh density. The heat transfer transient state was mainly focused during the simulation.

The transformer exhibits a gradient temperature trend as shown in Figure 5a. And in Figure 6a, the detailed simulated
data are compared with the optical fibre measured values. The simulation results exhibit a similar trend to the actual measured values but have a lower temperature difference. This may be caused by some inevitable simplifications of a real transformer such as tiny structural support parts, winding structures (lack of the wire details), slices of papers tightly wrapped around each wire, and so on. Thus, the windings would have a more sufficient and direct contact with the cooling oil in the calculating model, which may lead to a relatively flat temperature distribution.

The flow field and oil streams inside the transformer are displayed in Figure 5a and d. The maximum oil velocity is 2.5 cm/s, arising in the top area which is quite similar to the actual state. An obvious trend can be observed that the
heated oil gradually floats up and gathers at the top of winding where lots of vortexes begin to build up and continuously lose heat to the external. Then part of the cooled oil starts sinking along the fins and becomes colder until they reinject into the bottom of the winding while the other cooled top oil would sink directly and meet with the upward oil streams to continuously maintain the vortexes in the top area. Thereby, the heat dissipation mainly occurs at the cooling fins and the top of the windings. Verified by the heat flux distribution in Figure 5c, the main heat flux is along the fins while the top of the transformer also exhibits a very strong heat exchange, the ignition of which may result in a deviation of the hotspot.

The distributed optical fibre sensor was extracted from the transformer through a fibre flange sealed with the oil tank (as shown in Figure 2) and a section of optical fibre was directly exposed in the external environment for detecting the ambient temperature changes. The fibre measured value was compared with the thermocouples as shown in Figure 6b and it exhibited a stable performance within an error of 1°C.

At the beginning of the heat-run test, all the hotspots of the detected areas displayed a rather random state while as time passed by, the hotspots gradually transferred to a relatively fixed position, that is, around 90% height for HV windings and 80% height for LV windings.

It shows a common trend for both the windings and iron core limbs that the hotspots all reached a certain fixed position at around 1 h, which might suggest that at this moment, the transformer windings have gradually warmed up and the surrounding oil has begun to flow (It is also proved by Figures 9b and 10b, in which the hotspot temperature has a transitory drop at around 1 h). While before this moment, the relatively static oil almost had no contribution to the heat transfer process as described in Figure 5c and d, leading to the huge fluctuations in hotspot locations.

3.3 | Hotspots real time tracing based on DFOS

The hotspots of all the windings and the iron core limbs were closely traced and continuously located during the whole temperature rise test, as shown in Figure 7. And the exact total length of fibre sensor in each monitoring area is also exhibited.

4 | MODIFICATION HOTSPOT CALCULATION MODEL BASED ON THE DETECTED DISTRIBUTED TEMPERATURE

The last moment (end of the entire heat-run test) winding temperature distribution was selected to compare with the traditional hotspot prediction model proposed in IEC 60076-2. The measured temperature curve was smoothed from the raw data for the convenience of comparison (the temperature fluctuation caused by the external oil flows has been denoised within an error of 1°C), as shown in Figure 8.
Thermocouples are utilized for the temperature detection of bottom and top oil while the winding average temperature is obtained through the instantaneous warm resistance measurement at the last moment (the exact moment when the power was cut down), as recommended by IEC 60076-2. The standard believes that the hotspot is always located at the top of winding and the temperature distribution of windings is the same with oil (which can be obtained by directly connecting the top and bottom oil temperature, as exhibited in Figure 8). Also, the hotspot temperature can be equal to the winding top temperature times the factor $H$ (which is usually very hard to accurately obtain and varies greatly with the load rate and the transformer types). This method stands out for its relatively fast prediction and is welcomed by most occasions. However, an operating power transformer often has a time-varying load and the method is thereby difficult to follow the load changes.

**FIGURE 6** Temperature comparison between distributed fibre optic sensing, thermocouples and simulation results. (a) Temperature distribution along the high voltage winding (phase A) and (b) detected ambient temperature

**FIGURE 7** Hotspots spatial trace during the whole test process. (a) High-voltage (HV) windings, (b) low-voltage windings, (c) iron-core limbs, and (d) HV winding (phase C)
Meanwhile, the contradiction between the rapidity requirements of the warm resistance measurement and the current stabilization process (determined by the inductor voltage) often leads to deviations in the measurement results. In this study, the warm resistance measuring errors were ignored and the hotspot factor $H$ is set to one according to the actual transformer type based on the IEC model (i.e., the hotspot temperature is assumed equal to the winding top temperature). The IEC model calculated results compared with the optical fibre detected results are shown in Figure 8.

It is obvious that the IEC model owns a relatively higher hotspot temperature for both the HV windings (65°C) and LV windings (79°C), which may be attributed to the ignorance of the top area heat dissipation conditions (possible reasons were explained in Section 3.2). While the fibre detected hotspot temperature is 55°C and 76°C for the HV and LV windings, respectively. Also, the actual temperature distribution along the windings exhibits a piecewise linearity rather than a monotone increasing trend. For the HV winding, the temperature rises rapidly during 0%-10% of winding height and then slowly increases till the 90% of winding height followed by a decline tendency. The LV winding shows a similar distribution but with different inflection points (20% and 80% of the winding height).

This phenomenon corresponds well with the simulation results (Figure 5b–d) that the oil flow and heat dissipation in the top area of windings is more sufficient than that in the middle area, leading to a reduction in temperature. At the same time, the bottom area of the winding is significantly affected by injection of cooled oil sinking along the fins, also resulting in an abrupt temperature drop.

The detected temperature curves are further fitted through the least square method based on the aforesaid process and the correlation coefficient is higher than 0.94. Hereby, a modified three-segment linear model has been proposed, as shown in Figure 8.

The modified HV winding temperature distribution is between the oil temperature and the HV winding average temperature from IEC. For LV winding, the new model is between the original HV and LV average winding temperatures. This does not mean any inaccuracy of the traditional model, just the reverse, we still believe that the warm resistance method can effectively reflect the overall winding thermal situation through the rapid measurement. The critical point lies in the fact that these two models focus on totally different detected objects, more precisely, the average winding temperature calculated from the warm resistance is essentially the copper inner temperature while the distributed optical fibre sensor monitors the temperature of insulation materials close to the copper. Affected by the continuous flow of cooling medium, the insulating materials between the copper and the oil actually exhibit an average temperature of both. However, the transformer life expectancy is mainly determined by the thermal status of insulating materials, and thus, the direct measurement of the materials close to the copper is of great significance and the real material temperature is actually the result of both the copper and oil. For the LV winding located at the inner side of HV winding, its material temperature is indeed the average of HV and LV winding average temperature.

It can be seen that the modified HV winding temperature in the middle area enjoys a similar slope to the oil temperature, which could be attributed to its relatively closer location with the external oil flows. While the HV winding, much closer to the core, has worse thermal conditions and the generated heat is harder to lose, resulting in a much steeper slope (the largest temperature difference in the HV and LV winding interzone region is the difference between the HV winding bottom temperature and the LV winding top temperature, based on which, the LV winding temperature slope can be calculated).

The modified hotspot calculation formula can be thereby obtained on the former basis:

\[
\begin{align*}
T_{\text{hotspot HV}} &= \left( T_{\text{top oil}} + T_{\text{bottom oil}} + \Delta T_1 \right) / 2 \\
&+ (90 - 50)\% \times \Delta T_1 / 100\% \\
T_{\text{hotspot LV}} &= \left( T_{\text{HV avg}} + T_{\text{LV avg}} \right) / 2 \\
&+ (80 - 50)\% \times (\Delta T_2 + \Delta T_3) / 100\% \\
\end{align*}
\] (1)

Where $T_{\text{hotspot HV}}$ and $T_{\text{hotspot LV}}$ are the hotspot temperature of HV winding and LV winding respectively; $T_{\text{HV avg}}$ and $T_{\text{LV avg}}$ are the average temperature from the warm resistance measurement for HV winding and LV winding respectively; $T_{\text{top oil}}$ and $T_{\text{bottom oil}}$ are the top oil and bottom oil temperature detected from the thermocouples; $\Delta T_1$, $\Delta T_2$ are the temperature difference between the average temperature of oil, HV winding and LV winding respectively; $\Delta T_3$ is the temperature difference between the top oil and bottom oil. All the above parameters can be directly obtained through the traditional IEC calculation model.
Furtherly, the hotspot temperature temporally transient distribution is also studied and compared with the IEC traditional calculating model (IEC 60076-7: top oil and hotspot temperatures at varying ambient temperature and load conditions) [34], as shown in Figures 9 and 10. The load factor $K$ during the entire heat-run test is 1.052 for the first 8 h (applying the total losses) and drops to one during the last 1 h (applying rated current). The hotspot transient temperature formula was the same as the IEC formula while the original $\Delta \theta_{ht}$ (the temperature gradient of hotspot to top oil) has been modified according to the Equation (1). Phase A HV winding and LV winding are selected as the contrast objects (the three phases share a similar temperature distribution and take phase A for example).

It is observed from Figures 9b and 10b that the transient hotspot temperature formula fits better with the actual measured data when applying the modified parameter calculated from the three-segment linear model (or from the Equation [1]).

However, the formula does not fit well before 1 h, during which time, an apparent temperature drop can be discovered at both HV and LV windings for all the hotspot regions. This can be attributed to the viscosity changes of transformer oil. The heat-run test was performed from no load to final rated current, which means the transformer was at a rather low temperature (the ambient temperature) at the very beginning. During this period, the cold oil viscosity was relatively high and little circulating flow happened, leading to a rapid temperature rise of
the winding. And as the generated heat continued to accumulate, the oil would be heated up and had a lower viscosity. Thus, more and more developing oil flows took away the excess heat, resulting in a temperature drop of winding at 1 h.

But this transitory phenomenon cannot be effectively calculated or predicted based on the current theories (the above IEC formula indeed calculates from an operating steady state and lacks of the heat-run temporal information) and thereby, the distributed optical fibre sensor is of great significance in the full-region, spatiotemporally continuous temperature monitoring.

5 | CONCLUSION

The DFOS technology was creatively applied inside an operating 35 kV oil-immersed transformer, based on which, the first distributed optical fibre sensor integrated power transformer prototype with fully internal temperature sensing capability has been successfully fabricated and is qualified for power grid operation through the corresponding ex-factory tests. The sensing fibre also worked stably during the whole experiment process.

At the same time, the spatiotemporally continuous temperature information along all the windings and the iron core limbs was firstly obtained during a temperature-rise test and the hotspots were also continuously located and closely traced. Actual distributed temperature exhibited that the hotspots of HV winding (LV winding) would fluctuate at 90% (80%) of the winding height. Verified by the thermo-fluid transient simulation, the detected temperature distribution was furtherly explained from the perspective of fluid thermodynamics. Also, the possible oil circulating process inside an operating power transformer was simulated.

Based on the real time online measured data, the actual temperature distribution was compared with the IEC traditional hotspot calculation model and a more detailed three-segment linear modified model was proposed (temperature turning point was located at 10% and 90% height of HV winding while 20% and 80% height of LV winding). A common hotspot calculating formula was thereby obtained. Meanwhile, the modified model was also proved by the following IEC hotspot temperature temporal formula and the corrected temperature fits well with the actual measured data.

The DFOS successful application inside the power transformers can be furtherly popularized and would greatly improve the thermal sensing capability. And the actual distributed temperature data and hotspot model can serve as a solid reference for the delicate operation of transformers, providing a new horizon in high voltage electrical apparatus online monitoring field.

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