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Winding Temperature Measurement in a 154 kV Transformer Filled with Natural Ester Fluid

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Abstract – This paper measures the hot spot temperatures in a single-phase, 154 kV, 15/20 MVA power transformer filled with natural ester fluid using optical fiber sensors and compares them with those calculated by conventional heat run tests. A total of 14 optical fiber sensors were installed on the high-voltage and low-voltage windings to measure the hot spot temperatures. In addition, three thermocouples were installed in the transformer to measure the temperature distribution during the heat run tests. In the low-voltage winding, the hot spot temperature was 108.4 °C, calculated by the conventional heat run test. However, the hot spot temperature measured using the optical fiber sensor was 129.4 °C between turns 2 and 3 on the upper side of the low-voltage winding. Therefore, the hot spot temperature of the low-voltage winding measured using the optical fiber sensor was 21.0 °C higher than that calculated by the conventional heat run test.

Keywords: Power transformer, Hot spot temperature, Temperature measurement, Optical fiber, Heat run test

1. Introduction

When a city grows and population density increases, indoor and underground substations are built in the downtown area instead of outdoor substations in the outskirts of the city. Generally, mineral oil has been used to oil immersed transformers because of its outstanding dielectric strength and cooling performance. However, mineral oil has a flash point of 147 °C. Furthermore, it is a fire hazard due to its tendency to short-circuit. Therefore, transformers installed in indoor and underground substations require less flammable fluid to prevent fires. Silicone oil (300 °C) and high molecular weight hydrocarbon (HMWH, 276 °C) fluid are less flammable fluids because of their higher flash points. Applications of natural ester fluid as a less-flammable fluid have increased. The flash point of the natural ester fluid in this paper is 324 °C, which is twice as high as that of mineral oil [1].

The life of the power transformer depends on the life of cellulose paper, which influences the hot spot temperature. Thus, the hot spot temperature should be known to estimate the life of the power transformer. The aging rate of thermally upgraded Kraft paper in natural ester fluid was significantly slower compared with that in mineral oil [2]. This lifespan increase of insulating paper in natural ester fluid occurs because the water absorption capability of natural ester fluid (1,050 mg/kg at 25 °C) is higher than that of mineral oil (60 mg/kg at 25 °C). The high water absorption capability of natural ester fluid extracts moisture from paper, thereby decreasing hydrolytic deterioration. Thus, when enhancing the thermal insulation life of insulation paper, the life of paper in natural ester fluid is five to eight times longer than that of paper in mineral oil at 50% retained tensile strength [3]. However, the kinematic viscosity (33 cSt at 40 °C) of natural ester fluid of this paper is more than three times higher than that of mineral oil (9.2 cSt at 40 °C) [4]. The high kinematic viscosity of insulation oil decreases its flow rate, lowering its performance in cooling the heat generated from the core and from winding. Thus, the transformer filled with natural ester fluid increases the hot spot temperature. In addition, the increase of winding temperature accelerates the aging of the insulation paper surrounding the winding and shortens the life of the transformer.

According to the results from Kweon et al. [5], the hot spot temperature shown in the heat run test was 92.6 °C in the low-voltage winding filled with mineral oil. However, the hot spot temperature measured by the optical fiber sensor between turns 2 and 3 on the upper side of the low-voltage winding was recorded at 105.9 °C. The hot spot temperature of the low-voltage winding filled with mineral oil measured by the optical fiber sensor was 13.3 °C higher than the hot spot temperature calculated by the heat run test.

The winding temperature of the transformer filled with natural ester fluid was studied by Smith, Ahuja, Bachinger, and Martin. In particular, Smith and Ahuja et al. [6, 7] reported that the average winding temperature rise of the transformer filled with natural ester fluid was 5 °C to 8 °C higher than that when the transformer was filled with mineral oil, based on the heat run test. According to Bachinger et al. [8], the hot spot temperature of the

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transformer filled with natural ester fluid increased by approximately 8 °C compared with that of the transformer filled with mineral oil in the ONAN cooling mode of a 60 MVA transformer, using the thermohydraulic network model.

Martin et al. [9] installed a 132 kV, 50 MVA transformer filled with natural ester fluid in the power system. They measured the hot spot temperature under operating conditions using optical fiber sensors, and reported that the hot spot temperature was approximately 40 °C, which was 5 °C higher than the top liquid temperature. However, this transformer was not fully loaded. Previous studies have measured the average winding temperature rise based on the heat run test, or have measured the hot spot temperature of the transformer under operating conditions, rather than measuring the rated power.

Nonetheless, McShane et al. [2] used the hot spot temperature for the life curve of the insulation paper in natural ester fluid and compared it with that in mineral oil as suggested by the IEEE guide for loading mineral-oil-immersed transformers (IEEE standard C57.91-1995). This paper measured the hot spot temperature in a 154 kV power transformer filled with natural ester fluid using optical fiber sensors, and compared it with that calculated by conventional heat run tests.

2. Manufacture of a 154 kV transformer to measure the hot spot temperature

2.1 Manufacture of a 154 kV transformer

A single-phase, 154/22.9 kV, 15/20 MVA, 60 Hz transformer filled with natural ester fluid was manufactured to measure the temperature distribution and the hot spot temperature of the transformer. The transformer used in this paper had the same structure as that used in the power system. The transformer's core was a shell-type with an ONAN/ONAF cooling method. The total loss of the transformer was 89.188 W based on 15 MVA. The no-load loss was 11,160 W and load loss was 78,028 W. The temperature rise limit of the top oil was 60 °C and that of the average winding was 65 °C, as in the transformer specification.

2.2 Optical fiber sensor

A total of 14 optical fiber sensors were installed on the high-voltage and low-voltage windings to measure the temperature distribution and the hot spot temperature. The temperature measurement range of the optical fiber sensor was 20 °C to 275 °C. The maximum temperature sensitivity of the optical fiber sensor was 10 pm/°C (±1.7 pm/°C), and its response time was 0.2 s. The probe diameter of the fiber was 1.07 mm. In addition, fiber bend radius was at least 17 mm. The major specifications are shown in Table 1.

Table 1. Specifications of the optical fiber sensor.

Classification	Specification
Operating temperature range	20 °C to 275 °C
Temperature sensitivity (picometer per °C°C)	10
Response time	0.2 s
Fiber type (Single Mode Fiber)	28-compatible
Probe (Diameter × Length)	1.07 mm × 27.1 mm
Fiber bend radius	Over 17 mm

In general, the upper side of the winding shows the hot spot temperature. However, measuring the location of hot spot temperature with one optical fiber sensor is difficult. Thus, several optical fiber sensors should be installed on the upper side of the winding where the hot spot temperature is expected to occur.

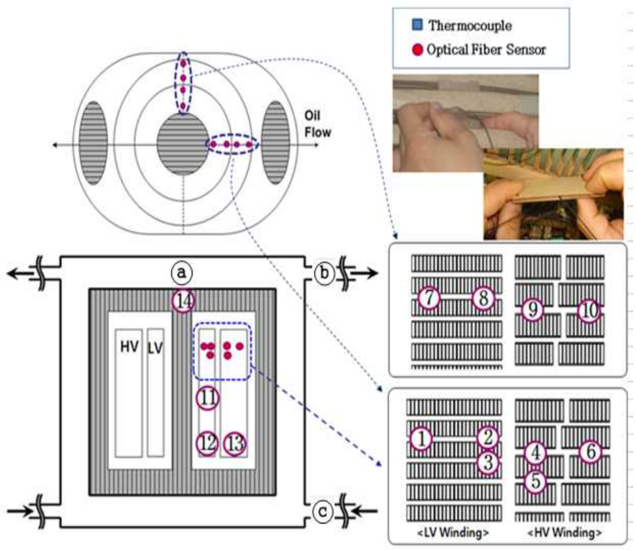

Fig. 1. Locations of the optical fiber sensor.

Fig. 1 shows the installed locations of the optical fiber sensors in the 154 kV transformer. Three optical fiber sensors were installed on each of the upper sides of the high-voltage winding and low-voltage winding to measure the hot spot temperature (①–⑥). The temperature of the highest winding was lower than the hot spot temperature because of the liquid flow. The optical fiber sensors were installed between turns 2 and 3, and between turns 3 and 4 of the winding (②–⑤). In addition, the optical fiber sensors were installed inside the low-voltage winding (①) and outside the high-voltage winding (⑥) to measure the temperature distribution of the windings.

Two optical fiber sensors each were installed on the high-voltage winding and on the low-voltage winding to compare the temperature in the flow direction of oil and in the direction perpendicular to the flow of oil (⑦–⑩).

Moreover, one optical fiber sensor each was installed at the center (⑪) and at the bottom (⑫) of the low-voltage winding and at the bottom (⑬) of the high-voltage winding to measure the temperature distribution of the windings. Another optical fiber sensor was installed on top of the core (⑭) to measure its temperature. In addition, thermocouples were installed on top of the tank (ⓐ), the outlet pipe (ⓑ) through which oil flows to the radiator, and the inlet pipe (ⓒ) through which oil flows from the radiator.

Fig. 2. Installation of the optical fiber sensor.

Fig. 2 shows the methods for installation of the optical fiber sensor used in this paper. The optical fiber sensor must be inserted between the windings to mount in the spacer; only the insulation paper of the winding should be between the optical fiber sensor and the winding conductor.

3. Measurement of the hot spot temperature

3.1 Hot spot temperature calculated by the heat run test

Generally, the heat run test is conducted to determine whether or not the temperature rise limit of the top liquid and the average winding in the specification are satisfactory. The heat run test methods include the actual loading method, the loading back method and the short circuit method. In this paper, the short circuit method was used for the heat run test. The heat run test by the short circuit method makes the secondary winding short and applies a voltage to the primary winding corresponding to the loss.

The top liquid temperature rise test was conducted when the transformer was subjected to a test current corresponding to the total losses (the sum of the no-load loss and the load loss) of the transformer. After the top liquid temperature rise test was established, the average winding temperature rise test was continued without a break. The test current was reduced to the rated current equivalent to the load loss (the sum of copper loss and stray loss).

The primary rated voltage is the voltage that generates the maximum loss. A total of 77,798 V was measured on the lowest tap (21 tap), which was equivalent to the lowest voltage under the rated phase voltage ($154\text{ kV}/\sqrt{3} \pm 12.5\%$). A no-load loss is indicated as a loss when the rated voltage is applied to the primary winding and the secondary winding is open; this was measured as 11,160 W. Load loss was measured as 78,028 W, which was the sum of copper loss (63,459 W) and stray loss (14,569 W). Therefore, the total loss was 89,188 W, obtained by adding the no-load loss and the load loss.

The rated current (I_r) equivalent to load loss is;

$$\frac{\text{Rated capacity}}{\text{Primary rated voltage}} = \frac{15\text{MVA}}{77{,}798\text{V}} = 192.8\text{ A} \tag{1}$$

The ratio of the current transformation is 400/5 A;
Thus,

$$I_r = \frac{192.8}{400/5} = 2.410\text{ A} \tag{2}$$

The total loss current ($I_t \frac{1}{2}$) is;

$$\begin{aligned}&\text{Rated current} \times \sqrt{\frac{\text{Total loss}}{\text{Load loss}}}\\ &= 192.8 \times \sqrt{\frac{90{,}236}{78{,}953}} = 206.1\text{ A}\end{aligned} \tag{3}$$

$$I_t = \frac{206.1}{400/5} = 2.576A \tag{4}$$

In this paper, the injection current (I_t) of 2.577 A was supplied in the heat run test.

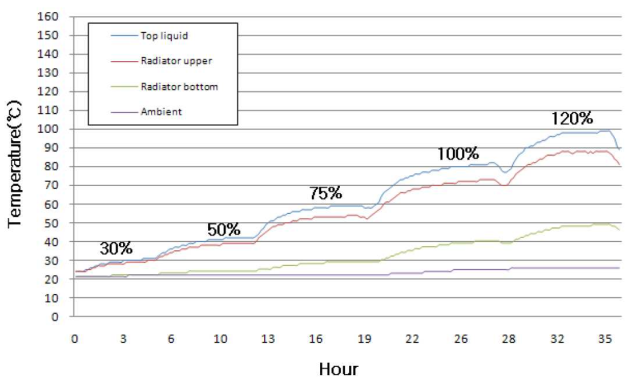

Fig. 3. Top liquid, radiator upper and bottom temperatures.

Fig. 3 shows the top liquid temperature, radiator upper temperature, radiator bottom temperature, and ambient temperature with 30%, 50%, 75%, 100%, and 120% of the rated power during the heat run test.

3.1.1 Top liquid temperature rise test

(1) Ambient temperature (θ_a)

The temperature of the cooling liquid in the heat run test is based on the ambient temperature in the ONAN transformer. The ambient temperature was 25.6 °C, which was the average of the measurements from three thermocouples. The thermocouples were distributed around the transformer, approximately 2 m away from the tank, and placed at a level halfway up the radiator.

(2) Top liquid temperature (θ_o)

The top liquid temperature is the temperature of the insulating liquid at the top of the tank, representative of the top liquid in the cooling flow stream. The top liquid temperature is conventionally determined by a thermocouple immersed in the insulating liquid at the top of the tank. The top liquid temperature was measured while the injection current (I_l) was applied at 2.577 A. The test was terminated when the rate of change in the top liquid temperature rise had fallen below 1 K/h and had remained there for 3 h. In this paper, continuous automatic recording was applied, with the average value taken during the last hour. The top liquid temperature is conventionally determined by a thermocouple immersed in insulating liquid at the top of the tank. The top liquid temperature was 80.7 °C on the rated power. The top liquid temperature rise ($\Delta\theta_o$) was 55.1 °C, which is the temperature difference between the top liquid temperature and the ambient temperature.

(3) Radiator upper temperature (θ_u) and radiator bottom temperature (θ_b)

The radiator upper temperature measured on the outlet pipe where liquid flowed to the radiator was 71.3 °C. The radiator bottom temperature measured on the inlet pipe was 38.4 °C when it flowed in through the bottom pipe after it was cooled down in the radiator. Bottom liquid temperature refers to the temperature of the liquid entering the windings at the bottom. For practical reasons, it is identified with the temperature of the liquid returning from the radiator to the tank.

(4) Average liquid temperature (θ_{om})

The average liquid temperature is, in principle, intended to be the average temperature of the cooling liquid in the windings. The average liquid temperature is the average temperature of the top and bottom liquid temperatures.

The average liquid temperature was

$$\theta_o - \frac{\theta_u - \theta_b}{2} = 80.7 - \frac{71.3 - 38.4}{2} = 64.3 \quad (5)$$

Therefore, the average liquid temperature rise ($\Delta\theta_{om}$) was 38.7 °C, which is the temperature difference between the average liquid temperature and the ambient temperature.

3.1.2 Average winding temperature rise test

The winding temperature at the end of the temperature rise test is normally determined by the measurement of the winding resistance. Based on the winding resistance detection method [10], the measurement of winding resistance is started after the test power is shut down and a connection to the windings of DC measuring current source is established.

(1) Winding resistance after shutdown of the power supply (R_2)

The measured winding resistance after shutdown of the power supply was 0.94396 Ω in the high-voltage winding and was 0.020503 Ω in the low-voltage winding.

(2) Decrease in the resistance (ΔR)

The average winding temperature was determined using the value of resistance at the instant of shutdown. In this case, the winding temperature decreased when the power supply in the winding was shut down, the DC power supply was connected, and the winding resistance was measured,. This resulted in a lower measurement of the winding resistance compared to the instant of power shutdown. Therefore, the decrease of the resistance was calculated by the extrapolation method until the period in which the power was shut down, the DC power supply was connected, and the winding resistance was measured. The extrapolation method is used to shut down the power, measure the winding resistance at a certain interval, and calculate the decrease of the winding resistance as it decreases exponentially.

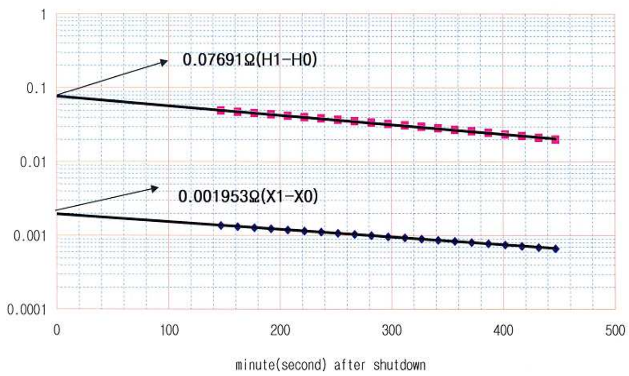

Fig. 4. Decrease of resistance by the extrapolation method.

As shown in Fig. 4, the change of resistance as measured by the extrapolation method was 0.07691 Ω in the high-voltage winding and 0.001953 Ω in the low-voltage winding. Thus, the winding resistance at the instant of shutdown (R_W) was 1.02087 Ω in the high-voltage winding and 0.022456 Ω in the low-voltage winding.

(3) Average winding temperature (θ_W)

The average winding temperature is the winding temperature determined at the end of the temperature rise test from the measurement of winding resistance.

$$\theta_W = \frac{R_W}{R_1}(235+\theta_1)-235 \tag{6}$$

Reference measurements R_1 and θ_1 are the winding resistance and the liquid temperature, respectively, before the heat run test.

The cold temperature (θ_1) was;

$$\theta_{o_1} - \frac{\theta_{u_1}-\theta_{b_1}}{2} = 20 - \frac{20-19}{2} = 19.5 \tag{7}$$

The cold resistance (R_1) was 0.80280 Ω in the high-voltage winding and 0.017437 Ω in the low-voltage winding. Accordingly, the average winding temperature was 88.6 °C in the high-voltage winding and 92.8 °C in the low-voltage winding. The average winding temperature rise ($\Delta\theta_W$) was 63.0 °C in the high-voltage winding and 67.2 °C in the low-voltage winding.

(4) Average winding to liquid temperature gradient (g)

The average winding to liquid temperature gradient is the difference between the average winding temperature and the average liquid temperature. This gradient was 24.3 °C in the high-voltage winding and 28.5 °C in the low-voltage winding.

(5) Corrected average winding to liquid temperature gradient (g_c)

The top liquid temperature rise should be tested by flowing 2.576 A, which is equivalent to the total loss (I_t). The average winding temperature rise should be tested by flowing 2.410 A, which is equivalent to the rated current (I_r) by load loss. In this paper, however, the above two steps of the test were combined in one single application of power under the injection current (I_l) at 2.577 A. Thus, the temperature rise values for the top liquid and the average winding should be corrected following rule [10].

$$g_c = g\left(\frac{I_r}{I_l}\right)^{1.6} \tag{8}$$

The corrected average winding to liquid temperature gradient was 21.8 °C in the high-voltage winding and 25.6 °C in the low-voltage winding.

(6) Hot spot factor (H)

Hot spot factor is a dimensionless factor that estimates the local increase of the winding gradient due to the increase of additional losses and variations in the liquid flow stream. Based on IEC 60076-2, the winding temperature of the liquid-immersed transformer is assumed to increase in parallel on a linear basis with a certain gap (g) remaining against the liquid temperature rise. The hot spot temperature in the winding is higher by the hot spot factor (H) than the temperature difference (g) between the winding and insulating liquid. The IEC suggests that a hot spot factor in the power transformer of 1.3 should be used. Therefore, this paper applied 1.3 as the hot spot factor (H). The difference between the hot spot temperature and the top liquid temperature ($H \times g_c$) was 28.3 °C in the high-voltage winding and 33.3 °C in the low-voltage winding.

(7) Hot spot temperature (θ_h)

The hot spot temperature is the hottest temperature of winding conductors in contact with solid insulation or insulating liquid.

$$\theta_h = \theta_o + (H \times g_c) \tag{9}$$

The hot spot temperature was 109.0 °C in the high-voltage winding and 114.0 °C in the low-voltage winding.

(8) Hot spot temperature rise ($\Delta\theta_h$)

The hot spot temperature rise is the difference between the hot spot temperature and the ambient temperature. The hot spot temperature rise was 83.4 °C in the high-voltage winding and 88.4 °C in the low-voltage winding.

(9) Hot spot temperature at 20 °C ($\Delta\theta_{h(20)}$)

At an ambient temperature of 20 °C, the hot spot temperature was 103.4 °C in the high-voltage winding and 108.4 °C in the low-voltage winding.

3.2 Hot spot temperature measured by optical fiber sensor

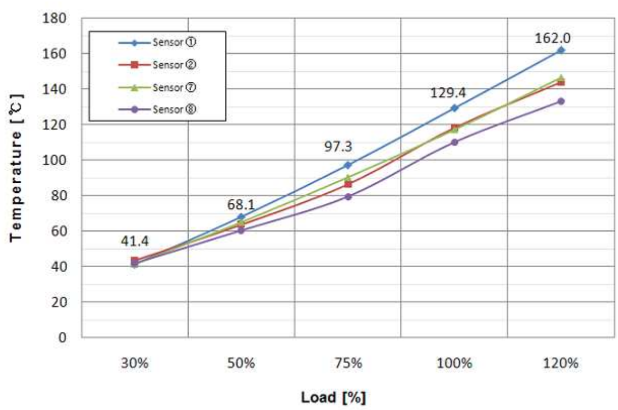

Fig. 5. Hot spot temperature in the low-voltage winding.

Fig. 5 shows the temperature on the upper side of the low-voltage winding measured using the optical fiber sensors with 30%, 50%, 75%, 100%, and 120% of the rated power. During the test, the ambient temperature ranged from 20 °C to 26 °C. In this paper, the data below were set to 20 °C. As load increased, the winding temperature also rose on a linear basis. The hot spot temperature on rated power was 129.4 °C at sensor ① in the direction of liquid flow and 117.2 °C at sensor ⑦ in the direction perpendicular to liquid flow. Therefore, hot spot temperature in the direction of liquid flow was 12.2 °C higher than that in the direction perpendicular to liquid flow. The temperature measured at sensor ② installed outside of the winding in the direction of liquid flow was 118.2 °C or 11.2 °C lower than that measured at the sensor inside the winding. However, in the direction perpendicular to liquid flow, sensor ⑧ installed outside of the winding was 110.0 °C, which was 7.0 °C lower than that measured inside the sensor.

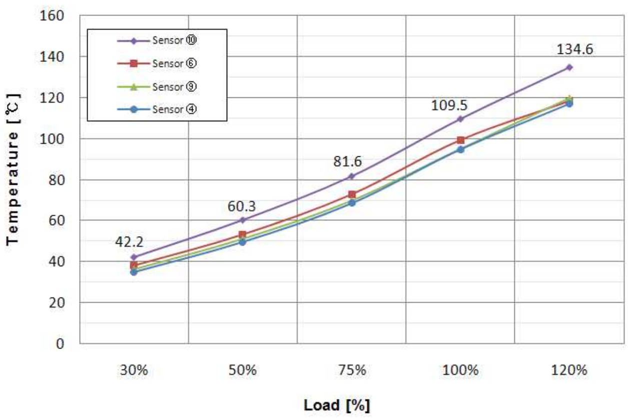

Fig. 6. Hot spot temperature in the high-voltage winding.

Fig. 6 shows the temperature on the upper side of the high-voltage winding measured using the optical fiber sensors with 30%, 50%, 75%, 100%, and 120% of the rated power. The hot spot temperature on the rated power was 99.2 °C at sensor ⑥ in the direction of liquid flow. In the direction perpendicular to liquid flow, sensor ⑩ measured 109.5 °C. Thus, the latter was 10.3 °C higher in the high-voltage winding.

The temperature measured at sensor ④ installed inside of the winding in the direction of liquid flow was 94.8 °C, which was 4.4 °C lower than that measured on the outside sensor. The temperature measured at sensor ⑨ installed inside of the winding in the perpendicular direction of liquid flow was 95.2 °C, which was 14.3 °C lower than that measured on the outside sensor. The hot spot temperature in the low-voltage winding was 19.9 °C higher than that in the high-voltage winding.

Fig. 7 shows the temperature distribution in the low-

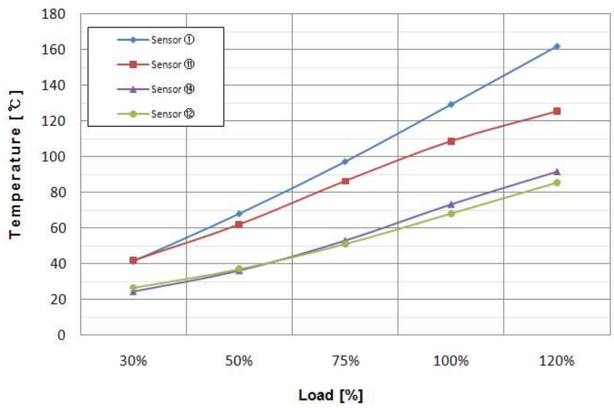

Fig. 7. Temperature distribution in the low-voltage winding.

voltage winding and the core temperature measured by using the optical fiber sensors. The temperature on top of the core was 73.4 °C on the rated power. The temperature at the bottom of the low-voltage winding was 68.1 °C; that in the middle of the low-voltage winding was 108.6 °C. Thus, the temperature difference between the top and bottom of the low-voltage winding was 61.3 °C. The temperature at the bottom of the high-voltage winding was 63.7 °C, which was 4.4 °C lower than that at the bottom of the low-voltage winding.

Fig. 8 shows the temperature measured using the optical fiber sensor on the transformer with the rated power. As seen in Fig. 8, the top liquid temperature was 76 °C. The temperature between turns 2 and 3 of the low-voltage winding was 129.4 °C; that between turns 3 and 4 was 116.8 °C. Therefore, the hot spot temperature between turns 2 and 3 of the low-voltage winding was 12.2 °C higher than that between turns 3 and 4 of the low-voltage winding. The hot spot temperature of the low-voltage winding measured using the optical fiber sensor was 21.0 °C higher than the hot spot temperature calculated by using the heat run test, which was 108.4 °C.

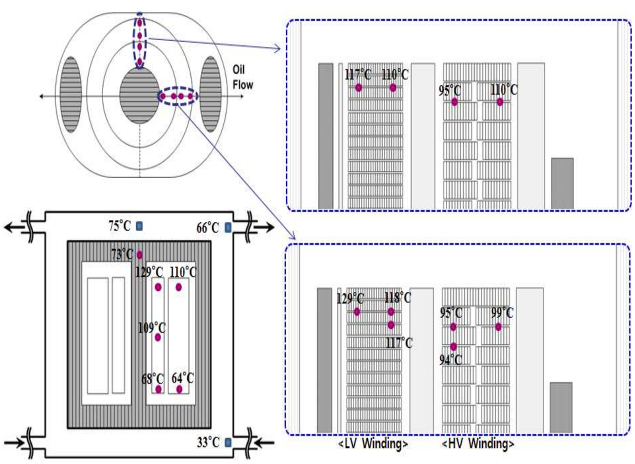

Fig. 8. Temperature at each position of the transformer.

4. Conclusion

This paper measured the hot spot temperatures in a single-phase, 154 kV, 15/20 MVA power transformer filled with natural ester fluid using the optical fiber sensors and compared them with calculations from conventional heat run tests. The hot spot temperature was 103.4 °C in the high-voltage winding and 108.4 °C in the low-voltage winding, both calculated via the conventional heat run test. The ambient temperature was 20 °C. However, the hot spot temperature measured using the optical fiber sensor was 129.4 °C between turns 2 and 3 on the upper side of the low-voltage winding. Therefore, the hot spot temperature of the low-voltage winding measured using the optical fiber sensor was 21.0 °C higher than that calculated by the conventional heat run test. The temperature between turns 2 and 3 in the low-voltage winding was 12.6 °C higher compared to that between turns 3 and 4. Moreover, the temperature difference between the top and the bottom of the low-voltage winding was 61.3 °C. The temperature on the outlet pipe through which oil flows to the radiator was 66 °C, whereas that on the inlet pipe was 33 °C when it flowed in through the bottom pipe after it was cooled down in the radiator. Thus, the cooling temperature was 33ºC in the radiator.

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