THERMAL PROTECTION

FOR

POWER TRANSFORMERS

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General Overview

Protection engineers traditionally are concerned with the differential, overcurrent, fault pressure, harmonic, and other regularly used protective relaying devices for transformers. These protective devices serve as the front line of protection in the system to prevent damage to the station equipment.

In this paper we are going to concern ourselves only with the thermal protection of the transformer. While you can set relaying to protect for overcurrent, overvoltage, and even protect from damage due to single phasing and harmonics, there are basic problems that can be overlooked such as problems with the transformer cooling systems and tap changers.

There are commonly used devices that can monitor the status of the cooling systems, transformer temperature, tap changer temperature, and other items.

Traditional Protection

In the traditional area, the relay engineer has many tools available for use. While we were limited to single function differential and overcurrent in the past, this is not the case in today's relaying world. Many suppliers of protective equipment have multi-function relays that can monitor virtually anything you want that has to do with the current in and out of the transformer no matter how many windings and what configuration they may be. Yes, you can use the standard mechanical top oil thermometers to send alarms or even trip, but calibration is a problem as is possible contact corrosion that can prevent such actions from actually taking place. Also, these devices are also prone to false trips requiring additional time delay and interposing relays to improve security.

So, the devices we commonly use are looking at the current and voltage quantities at the terminals of the transformer. True, most problems are going to be detected this way and quickly dealt with. However, there are other things that can go wrong…and if you are familiar with Murphy's Law, you are absolutely sure they will happen no matter how absurd the probability of such a thing happening.

As usual, we will protect the transformer with backup and front line protection, being careful to use different manufacturer's relays and even mix differential and overcurrent so that one mode of failure won't cause both sets of relays to malfunction. All the quantities in and out of the unit are measured, monitored, and processed to make sure we can catch the fault or problem before serious damage can occur….or have we?

Traditional protective relaying can not detect such things as problems with the cooling equipment in the transformer and problems with tap changer contacts. Also, control of the cooling for conserving the life of the transformer unit is not within the scope of these devices. These could be called low-grade problems that creep up and nail us because we were so sure everything was covered.

The fan sets that do not come on, the tap changer contacts that are coking up, and even individual cooling fans that do not come on can cause overheating to shorten the life of the transformer just as surely as a through fault or overcurrent.

Thermal Protection

Modern digital methods can give an exact measure of the top oil temperature and make it available to a SCADA system through standard protocols or, if necessary, a current loop. From this information, a system operator can monitor actual temperatures or the gauge can alarm and/or trip the unit at pre-determined points.

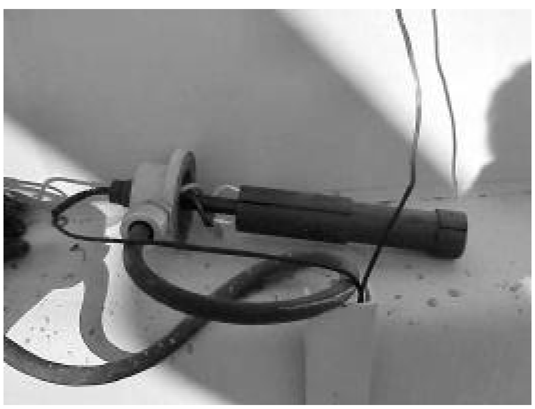
Mechanical temperature devices are much like the device pictured below. A robust weatherproof case with glass cover and mechanical setpoints to be used for fans and/or relaying functions.

To make adjustments, a technician opens the glass and moves the pointer to where they want the action to occur. The contacts are generally configured as in the picture below

This system has functioned well for many years, but does have drawbacks in that setting the temperature correctly depends on the accuracy of the thermometer as well as the skill of the technician. Water and contaminants can enter the case over time and may corrode the parts and contacts causing failures. Newer replacement mechanical gauges may have plastic windows that cloud and become unreadable over time. Also, these instruments have no ability to provide an alarm if they become defective.

The hottest-spot temperature on a transformer is a "manufactured" measurement arrived at by the influence of a heating element around a thermometer well submersed in the transformer top oil. Such a well can be welded into the side of the tank or bolted in with appropriate gaskets as in the picture below.

Into this well is inserted an inner well surrounded by a heating element powered by a bushing current transformer so that the heating corresponds to the KVA loading of the transformer.



This assembly is then inserted into the well in the transformer top oil. In some designs, the heating element is actually part of the well and cannot be removed separately.

In the above picture, the top oil measurement probe can be seen to the left of the hottest spot probe inserted into the heated well.

A mechanical thermometer measures the elevated temperature and it (hopefully if the system is properly designed) is close to the hottest spot temperature deep in the transformer winding. The user must remember that the thermal lag in the top oil is rather large and can take many minutes to react to load changes. These systems tend to be extremely slow and to drift over time.

Surely, fiber optic measuring probes can be included in the transformer during manufacture. While these probes will accurately measure the temperature of the winding where they are placed, they are not guaranteed to measure the hottest spot temperature as a location believed to be the hottest spot may not be the hottest spot temperature. Many of these fiber optic devices have multiple fiber inputs and it is conceivable that enough fiber optic probes can be installed at the time of manufacture to have a higher probability of measuring the true hottest spot temperature. However these fiber optic measuring systems are difficult to justify because they are very expensive and fragility of the glass fiber needed.

Modern digital methods can take the CT current, top oil temperature and then calculate the estimated hottest spot temperature using IEEE standard methods. When set up with measurement s made during the testing done at the factory before the transformer was shipped, these measurements can be a reasonably accurate measure, but only if the load/temperature change is slow.

With the “brainpower” of the microprocessor, the user can accurately set the temperature at which each stage of cooling is to activate as well as the temperature at which it is to deactivate. Now, the interesting part is that, if the controller has access to the CT, it knows the status of the loading of the transformer. Now, we know the temperature rise in the top oil is slow to respond to a loading change, so, if the user elects, the device can sense a step or fast increase in loading that will eventually cause the fans to come on, but do it immediately to help reduce the amount of time the transformer is subject to elevated winding temperatures…and thus extend the life of the unit.

While tripping on high temperature may not be recommended in all applications, the additional programmable timers reduce the probability of hair trigger trips thus improving security. In addition, some electronic gauges have digital inputs which can be mapped in to the device’s programmable scheme logic to permit the creation of permissive tripping schemes.

Fan Control

Mechanical temperature gauges control fans through linkage from the gauge pointer to actuate switches internal to the instrument. With the advent of modern microprocessors, control systems now can have built in logic. As mentioned above, the temperature of the transformer can activate banks of fans through the controller. The controller can be set to alternate banks of fans to prevent one set from having more running time than another.

Depending on the location of the station and the way the fan guards are constructed, the fans can be an attractive location for birds to build nests or grass and vines can grow into the area around the blade. Obviously, with the power available in a microprocessor based controller, you can set the fans to activate for a few minutes each day to clear out any such accumulation of debris that could well stop the fan from turning, burning out the fan motor, and thus reduce the available cooling when needed. Also, exercising fans is important to ensure that the fan motor bearings stay lubricated especially during times of the year that are colder and wetter.

Some companies will actually turn on the fans at the start of the summer season and let them remain on until fall due to the experience of systems where the fans have not come on as needed. If you are monitoring the temperature remotely, there is little need for this and you can save on power not used to power fans not needed for cooling.

Tap Changer Protection

Most problems (other than damage due to through faults) in tap changers have to do with the moving contacts in the changer. This is commonly referred to a “coking” and occurs as a contact becomes dirty, heats up and the heating process causes the oil to carbonize and further contaminate the contact. This is a vicious circle that results in damage to the contact structure and possibly more as the carbon contamination can migrate to the insulation within the compartment. This layer of carbon reduces the insulation level and can cause flashovers to occur within the tank.

Protection of a tap changer can be problematic as by the time a relay activates, damage has been done that most likely will cause the unit to be shut down for repairs. This period could be rather long depending on the extent of damage and the availability of replacement parts.

Since the LTC tank is mechanically coupled to the Main tank, normally the LTC tank is either at the same temperature or lower than the Main tank temperature because there is nothing in the LTC tank that should generate any significant heat. Monitoring the difference in temperature between the tap changer oil and the main tank oil can be used to alarm when the differences exceed preset levels. Of course such alarms can be sent back via SCADA so that corrective measures can be taken immediately. From a practical perspective, in using differential temperature, care should be taken so that sunlight heating does not cause false alarms. Reliability of the alarm can be improved through the use of a programmable time delay that allows for the Main tank to catch up with the LTC tank.

Replacement of Old Style Equipment

An example of what can be done is the replacement of older gauges that read out in percentage of transformer thermal rating such as the Westinghouse TRO with the modern winding temperature indicator systems. Alabama power has replaced several of these, encountering various problems in going from one analog device to another.

Replacing the TRO device with a regular winding temperature indicator requires the replacement of the heater (see illustrations above) and installation of a current balancing autotransformer (CBA). To achieve the desired rise for a given current input the CBA ratio must be adjusted. A chart is provided by the gauge manufacturer that estimates what the rise will be for a given current input to the heater, so it should be fairly straightforward to get the proper response from the heater. In practice the chart is not accurate and it is a trial and error method that can turn into a long and tedious task.

Maintenance of older devices

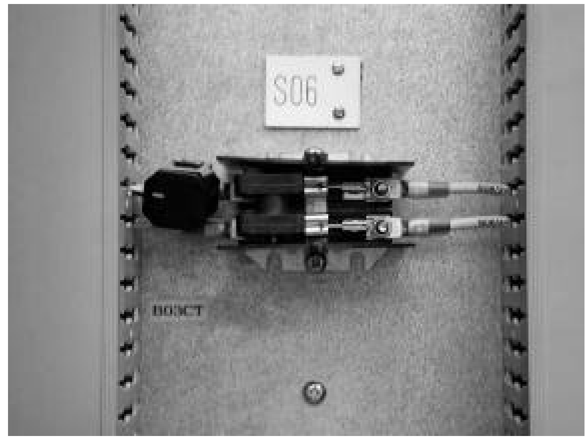
From a maintenance point of view there are a couple of issues with the heaters/calibration circuits. The pictures of the heater device are of a heater that is accessible without removing any oil from the transformer. The great majority of heaters at Alabama Power are internal and inaccessible without requiring outage and some of the oil to be removed. Some internal heaters rarely have problems that require access, but others have heaters that are integral to the well and can be the cause of many problems. They are hard to diagnose and difficult to repair due to their inaccessibility.

The calibration circuit consists of a CBA to adjust the amount of current available to the heater or a resistor in parallel with the heater that shunts current from the heater. These resistors are either fixed or variable. In practice, these resistors can fail and cause the temperature rise for a given load to change. It can be hard to detect that a failure has occurred because during a station inspection the load on the transformer is seldom known by the journeyman performing the inspection. Therefore, almost any reading on the hotspot gauge might look normal. The only way to definitively detect a problem is to inject a known current into the circuit until the gauge temperature stabilizes and verifies a reasonable rise is achieved. If a variable resistor has to be replaced the trial and error method is employed to get the right resistance for the circuit. Again this can turn into a long and tedious task.

Retrofit

When the decision is made to replace the older equipment, the procedure is relatively simple. The heated well in not needed and a new electronic temperature probe is inserted in the place of the old top-oil temperature indicator. This is all that is needed to have both the top-oil temperature and hottest-spot temperature. The new probe will be of a universal nature with fittings and sleeves to fit several standard wells.

If the leads to the CT that had powered the thermal well are not accessible, any CT (other than the neutral CT) can be used instead. A simple clip on split core auxiliary CT can be put around the lead from an existing CT. The picture below shows the split core around an existing lead next to a CT shorting switch.



Since the new device will actually compute the hottest-spot temperature, the CT ratio is entered in during the setup process.

As the dial unit is replaced in the process with a simple probe where the dial indicator used to be,

it is necessary to have a display on the digital unit down at eye level.

From here, programming can be done and readings made as needed. Also, connections to the station SCADA or other instrumentation via common protocols or current loop will be made in this location.

Should there be a suitable cabinet on the transformer, another option is to panel mount the device.

Practical Considerations

While you can use the oil temperature to detect problems with a transformer or to trip on overload, there are problems associated with such options. While we have been talking about the accuracy of these devices and the use in the power system, there are some practical observations that need to be noted.

The traditional mechanical temperature gauges applied in the past were and are not very accurate. Even when the device measures accurately, the reading can be affected by the location of the person trying to read the gauge. Also, the calibration of these devices tends to change over time. Furthermore thermal problems associated with internal problems are not easy to detect. They do not appear suddenly so that a relay can trip the transformer.

The only practical direct thermal measurement available is the top bulk oil temperature. When a load is applied or a thermal malfunction occurs there is a very long time period before the top bulk oil temperature responds. And the top bulk oil temperature difference between a normal condition and a malfunction condition is usually quite small.

Adding more to the confusion is the winding temperature indication. This indication, even in its best form, is confusing and misleading at best and flat wrong at worst. The traditional winding temperature gauge is an assembly that simulates the hottest spot winding temperature. The probe for this gauge is inserted in a resistive well. This resistive well is in direct contact with the top bulk oil. It receives a CT current input which is directly proportional to the line current. The resistive well produces heat proportional to the load. The thermal characteristic of the resistive well is calibrated to produce the hottest spot temperature gradient over the top oil temperature. The resultant gauge temperature reading is the top oil temperature plus the temperature rise produced by the resistive well.

Electronic devices are also widely used. These monitors are microprocessor based and some are capable of performing very sophisticated functions. Electronic monitors are more accurate than mechanical gauges, easier to read, and stay in much better calibration. However this method is still a calculation with all of the limitations of the simulation described above.

The winding temperature simulation or calculation reading is only valid for a constant load several hours after the load is first applied and when the transformer is in its maximum rated cooling mode. Constant loads almost never occur except for some high load factor industrial customers and base load generating units. For the typical cyclical load, a simulated winding temperature reading is never correct. On rising load, the winding temperature gauge reading is always lower than the actual winding temperature. On falling load, the opposite is true. The inaccuracy occurs because the top bulk oil temperature responds very slowly to an incremental change in load while the simulated or calculated winding temperature gradient responds very quickly. Within minutes, the winding temperature will approach its ultimate level for a given load.

Thermal protection of transformers is a multi-stage process. First the user must plan, manage, and monitor the load prudently. Then the user must be able to diagnose when problems or malfunctions occur. It is easy to set a load limit and alarm for overloads. It is also relatively easy to monitor and alarm for loss of cooling. However there are two (2) other general thermal events to consider that are not so easily diagnosed.

An oil flow problem in the cooling equipment or winding ducts is a potential problem. These are extremely difficult to diagnose with the available equipment. In fact, they are virtually impossible to detect. The good news is that they seldom occur. Given that the cooling equipment operated properly I recall only one oil flow problem on the Alabama Power Company system. That was a radiator valve that was inadvertently left closed when the transformer was initially installed. And it took 20 years to discover it.

The other thermal event to consider is hot spot problems. The difficulty here is that hot spot problems do not occur at “the hot spot”. The hot spot problems that do occur are inadvertent. These usually occur when a transformer is heavily loaded. They occur because of poor shielding, excessively taped leads, poor designs that do not control stray and eddy losses sufficiently, etc. These inadvertent hot spots can be fatal to a transformer if they are extreme or remain too long.

One of the difficulties in diagnosing inadvertent hot spots is the they take a long time to manifest themselves as problems; sometimes years. The other difficulty is that they are very localized and there is very little energy associated with these inadvertent hot spots. Consequently they do not produce detectable changes in the top bulk oil temperature. These hotspots are so unpredictable that even fiber optic direct winding temperature measurement will not detect them.

If a hot spot problem occurs, the user must have the tools to diagnose these conditions. The winding temperature gauge reading is only what the hottest spot winding temperature is supposed to be. A microprocessor based monitor can have algorithms that eliminate the thermal lag described above in order to calculate a real time value. Even if this microprocessor calculates the exact winding temperature value, the reading is still only what the hottest spot winding temperature is supposed to be. And finally fiber optics does make direct measurements. However they only measure discreet locations where designers place them. The probability of having an inadvertent hot spot problem at the location of a fiber optic sensor is approximately zero.

Consequently the indication that we traditionally think of as the winding temperature has no direct monitoring value without significant user interpretation. The intended purpose of the winding temperature gauge is to provide an alternate method of controlling the cooling equipment. The winding temperature gauge will pick up the cooling equipment for sudden and large increases in load long before the bulk top oil temperature gauge.

Thermal protection of transformers is very difficult. The user must manage the load, monitor the cooling equipment, monitor the temperatures, understand how a transformer should respond to a given condition, interpret the available data which can be confusing and adequately maintain the transformer. And finally the user should obtain regular oil samples to perform dissolved gas analysis (DGA). DGA is the only diagnostic tool that will reveal the presence of inadvertent hot spots.

One of the keys to this entire process is applying a temperature monitor/controller that provides an extremely accurate and reliable temperature measurement of the top bulk oil. It should also control the cooling accurately and reliably. Reliable and accurate communication is also critical. And finally a monitor with winding temperature calculation also measures the current. An accurate and reliable current measurement allows control of the cooling equipment under sudden increases in load. The current measurement will respond almost instantly while the oil temperature responds in hours. And in an LTC transformer, a multi-probe monitor can provide information that aids in maintaining the LTC. These are the monitor's contribution to thermal protection of power transformers.

Conclusion

For years, we have done protection of transformers for the most part by monitoring the current and voltages associated with them. Now, with the advent of new measuring devices, we can integrate the actual temperature of the transformer and tap changer into the protection scheme if the user is aware of problems involved.

Such devices as described here are not really useful for internal faulting or local heating problems in a transformer, but are useful in a “last ditch” protection of the unit from extreme oil temperatures if you are concerned only with the main tank of an LTC transformer or a transformer without LTC.

For an LTC transformer, the differential between the two tanks, main and tap changer, can be a useful measurement for alarm or even tripping if you are so inclined.

In contrast to the older mechanical devices, microprocessor based ones will send an alarm if problems occur so that operational problems do not go undetected offering a higher level of security and dependability.

Finally, microprocessor based electronic temperature monitors include a whole host of features never possible with mechanical temperature monitors. These include:

- Built-in data logging.
- Programmable scheme logic for greater flexibility.
- Fan exercising for reducing maintenance costs and improved reliability.
- A variety of SCADA options for communicating temperatures and status.
- Ability to remotely control cooling.
- Ability to command cooling on a sudden increase in transformer loading.
- Universal power supply operation.
- Tap position monitoring.
- Programming through a laptop.

Biographies

Gary Hoffman

Gary Hoffman is Founder and President of Advanced Power Technologies. Prior to founding Advanced Power Technologies Mr. Hoffman was General Manager of the USA Protection and Control operation of ALSTOM T&D. Prior to that he was VP of Engineering and Operations of RFL Electronics. He is the holder of five patents in the areas of protective relaying and monitoring of substation apparatus. Mr. Hoffman has a BSE and MSEE from the State University of Stony Brook and is a Senior Member of the IEEE

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Mike Springrose is a Principal Engineer at Alabama Power Company. He has worked in Generating Plant Technical Services and in Substation Support with responsibility for plant relaying, switchgear, and transformers. He is currently working at Alabama Power General Shops where substation equipment is repaired and reconditioned. Mr. Springrose earned a BSEE from the University of Alabama in Birmingham.

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Tom Tennille is Vice President, Application Engineering of Advanced Power Technologies. Prior to joining APT, he was General Manager, Engineering until 2000 and Manager, Rate Analysis until retirement in 2003 at Savannah Electric and Power Company. Mr. Tennille has a BEE degree from Georgia Institute of Technology, is a Senior Member of IEEE, and is a Registered Professional Engineer in the State of Georgia.

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Bob Tillman obtained a BS degree in Electrical Engineering from Auburn University in 1969. He is a registered professional engineer in the state of Alabama. Bob joined Alabama Power Company, a Southern Company, in 1970. He worked through several engineering classifications in District Operations and Power Delivery-Substations. He is currently Principal Engineer, Power Delivery-Substations. Present responsibilities are engineering applications, specification, and procurement for substation major equipment.