# Best Practices for using Infrared Thermography for Condition Monitoring of Utility Substation Assets

We have all grown dependent on power being delivered reliably and continuously whenever we need or want it. Many utility system assets are both aging and being loaded past anything previously imagined. Replacement equipment, especially transformers, may be months or years in construction and delivery. The cost of a failure in the grid can, as a result, have costly, even devastating, consequences.

Utilities have long practiced preventive maintenance (PM), but economic pressure on all line items in a budget has not spared maintenance where cost reductions have been common and considerable. The use of condition monitoring technologies, such as dissolved gas-oil analysis (DGA), airborne ultrasound, and infrared thermography, have not only helped reduce unnecessary PMs, but have also offered greater assurance that assets are performing as they should.

## What is Infrared Thermography?

This remarkable technology utilizes electronic imaging cameras that detect emitted heat, or infrared radiation, in much the same way that conventional, video "camcorders" see visible light. Infrared is radiated by all objects above absolute zero and is also reflected by many types of surfaces and transmitted by a few. For the most part, we see *surface thermal patterns only* and must interpret their relationship with internal and surrounding thermodynamics. It is vital to understand that thermal imaging cameras do not "see" inside components as an X-ray might. Surfaces emit with different efficiencies, termed their emissivity; unpainted metals are inefficient and have low emissivity values. In addition, low emissivity surfaces are typically highly reflective of the radiant energy of their surroundings.

Today's cameras can see temperature difference as small as 0.1C on a high-emissivity surface at 30C. Some infrared cameras are specially designed and calibrated so that detected radiation can be converted into a radiometric temperature measurement. When properly used, these systems can consistently yield non-contact measurements accurate to ± 2 °C or ± 2% of the measurement range. Unfortunately, despite this precision available under the right conditions, *it is extremely difficult to make accurate, repeatable measurements of unpainted metal surfaces under field conditions*.

## Condition Monitoring of Utility Assets:

In order for thermal images of utility assets to have diagnostic value, it is necessary to (1) know how the asset is constructed and function, (2) to understand how it fails and what the thermal signature of that failure is, and (3) to understand how system and ambient conditions will affect the thermal signature.

The vast majority of failures in utility assets result from either (1) abnormal, high-resistance heating at a point of electrical contact, (2) overheating caused by an overload,

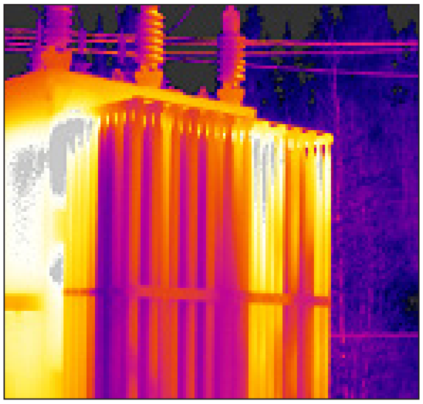

Figure 1. The cooler (dark) fins suggest either low oil or flow blockage.

Figure 2. Heating on this oil-filled circuit breaker bushing is caused by high-resistance in the connection between the cap and the bushing rod.

imbalance or undersized equipment, or (3) overheating of the asset as a whole due to a failure of the cooling system. When conditions are right, a detectable thermal signature precedes these failures. The value of thermography, then, is being able to locate these problems in advance of failure. We see surface temperatures only, and, while this is important, many system and environmental influences affect surface temperature other than the severity of the problem. Once a suspect component or problem area is located, additional tests may prove more valuable to identify the exact nature or the condition or to determine how advanced it is.

We will look at what assets can be monitored with thermography and the conditions required to do so successfully. We will also discuss the mistakes that are most commonly made in the process.

## What to Inspect:

Utility assets are a diverse group of complex devices. For the purposes of discussion we can look at these more generically and divide them into several groups that include oil-filled transformers, oil-filled devices, surge protection, disconnects, lines and connectors. More and more assets are also gas-insulated; this creates unique difficulties for thermographers, related to the large thermal gradient they exhibit, that are beyond the discussion of this paper.

• **Oil-filled Transformers:** Baseline thermal signatures of all sides of the tank may have some limited value for trending changes over time. Two problems exist: first, changes to the thermal signature that are indicative will often be extremely subtle because of the massive nature of the tank. Second, it is difficult to see all surfaces on most transformers and those that can be seen are subject to considerable influences in heat transfer that are difficult to characterize.

• **Cooling Systems:** Inspection of cooling systems can have immense returns, even if the simple technique is often unappreciated and undervalued. A normal pattern for a convective system is to find warmer fluid at the top and cooler at the bottom with an even thermal gradient between the two.

The most common anomalies show cool tubes related to reduced oil circulation (Fig. 1 caused by a low oil condition, either normal or abnormal or out-of-level pads, inverted riser tubes, closed valves, and blockage in the tubes or headers. Reduced oil circulation during summer peak conditions can often result in a transformer that overheats, dramatically reducing its life cycle. Cooling fans and oil circulation pumps, if present, can also be inspected.

Cooling system inspections should be scheduled *prior* to the warm-weather peak season to insure all is operating as designed. Inspections after any repairs or maintenance work can verify work, document running conditions and minimize problems such as inadvertently leaving a valve closed or a fan running backwards.

• **Bushings:** Both high- and low-side bushings can be profitably inspected with thermography. When under load, anomalous conditions can often be found easily on the line-side connections. Internal connections, both in the bushing head (Fig. 2) and in

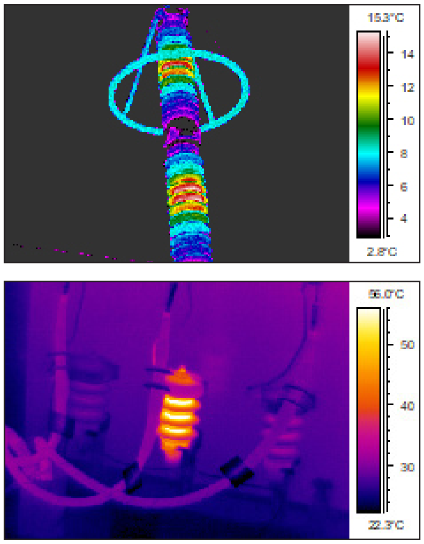

Figure 3. Two different classes of surge arrestors are both showing abnormal heating.

the connections to the coils, may be more challenging due to the large thermal gradient between the source of heating and the exterior surface being viewed. A normal signature shows the busing at or close to ambient air temperature. Any unexplained, anomalous thermal signature or rise over ambient/another phase is considered indicative and warrants further investigation. Internal faults will be indicated by much more subtle signatures at the base of the bushing as heat is conducted up the bushing stud itself from the coil connection.

• **Tap Changers:** Most, but not all, tap changer compartments run at the same temperature or slightly cooler than the transformer tank. Abnormally overheating tap connections under oil will often generate enough heat to cause the entire changer compartment to overheat. A tap changer that appears warmer than the tank, unless normal by design, is cause for further investigation. Unfortunately, the faulty tap may *not* be energized at the time of the inspection so that finding a (latent) problem is not assured. Regular DGA is still recommended and of immense diagnostic value.

• **Line Connectors:** A normally operating line connector will typically operate at the same temperature as the line or slightly cooler and, in either case, are typically not much above ambient air temperature. Connectors with abnormal resistance will heat up compared to those that are normal. Ground connectors will behave similarly.

• **Surge Protection:** Surge protection in and around a substation vary widely by design and type [1]. Most commonly it is some sort of a high-resistance path connected to ground. Normally surge protection will operate at ambient air temperatures because there is no current flow.

A breakdown of a surge device, commonly due to intrusion of moisture [2, 3], will result in a small leakage of current to ground at all times, even when a surge is not present; this, in turn, will cause the arrestor to heat continuously, typically in small sections (Fig. 3) defined by its structure and at only a few degrees (Fahrenheit) above ambient. Despite this seemingly insignificant signature, arrestor failure may be imminent. Because failure, at least of ceramic devices, is often catastrophic and dangerous to any nearby personnel, these early warnings should not be ignored.

A few metal-oxide varisters (MOVs) may operate *normally* at a few degrees (Fahrenheit) above ambient because the constantly leak small quantities of energy to ground. Numerous reports from the field suggest that a 5F or greater rise over ambient on these MOVs indicates further monitoring or testing by other means is warranted; temperatures of 10-50F rise over ambient have been reported.

• **Insulators:** Normally, insulators operate at or near ambient air temperatures. The only other "normal" thermal signature shown by an insulator is one caused by solar absorption; here darker insulators will often be warmer than lighter colored ones. Cracked or dirty insulators may indicate a subtle thermal signature due to the slight current leakage that occurs, called "tracking," over the resulting high-resistance pathway to ground. These signatures can change or disappear with changes in ambient conditions or as the insulator is washed by rain, so the lack of a signature is not positive proof that a problem might not exist at another time.

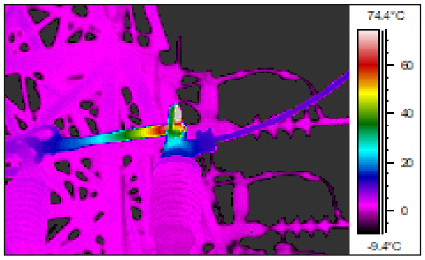


Figure 4. A typical “hot spot” at the latch end of a disconnect switch.

• **Associated Switches and Disconnects:** Problems with high-resistance heating are common in all types of switching and disconnect mechanisms (Fig. 4). A normally operating device will should be at or near ambient air temperatures. Optimally, all switch/disconnect devices should be inspected after they are put back into operation. Even slight heating (approximately 200F) over time can result in annealing damage that will be exacerbated quickly into a device that has significant damage to contact surfaces or, in the worst case, has welded itself together.

## Conditions for Inspection:

For the most part thermography cameras see surfaces; the radiant energy seen is a combination of both energy emitted by the surface—this tells us something about its temperature—and energy that is *reflected* by the surface, which tells us nothing about its temperature. Unpainted metals have a low efficiency of emission while at the same time having a high reflectivity. This means they don’t reveal much about their true thermal nature and mask over the little information that is there with other, misleading information. Ideally we can correct the readings in radiometric infrared cameras for both emissivity and background reflected temperature; unfortunately, and this despite what the literature and the suppliers would have us believe, for all but *highly* oxidized metals, measurement error is unacceptably large.

We must therefore recognize that even small temperature increases may be the only indication of severe heating. When conditions change, the thermal signature may fall below the threshold of detection. We must ask ourselves “What changes are significant?” and “Can these be detected?”

**System Load:** As load increases, heat output also increases, but at the square of the load; a tripling load, not uncommon in a distribution substation, will result in a nine-fold increase of heat being produced by an already abnormally hot connection. If the system is inspected when loads are light, some anomalies will have thermal signatures below the threshold of detection and others, though detectable, will be cooler than they will be when might loads later increase at, for example, daily or summer peak periods.

While some standards suggest that 40% of design load is an acceptable condition for inspection, inspections are best done under “worst case” conditions if possible.

**Convection/Wind:** The most significant of the limitations to using infrared thermography out-of-doors is typically convective cooling by the wind. Convective cooling results in two issues; first, connections that are early in the failure cycle, i.e. only slightly warmer than normal, will often be cooled below the threshold of detection. Second, anomalies that are detected are being cooled, often significantly, and will increase in temperature, to varying degrees, when the wind’s cooling effect lessens.

**Ambient Conditions:** The exact impact of changing air temperatures is difficult to predict. Clearly, an increase in air temperature will result in an increase in the measured temperature of a component. Thus, because warmer summer air has less cooling capacity, a high resistance connection will increase in temperature during warmer months.

**Most practitioners fail to pay attention to the influences of changes in ambient conditions and system conditions.**

Solar heating of component, especially those with a high absorptivity of the sun's energy (such as aged conductors, dark insulators/bushings), will mask over small thermal differences. Mid- to late-afternoon inspections during the summer months are particularly problematic and should be avoided if possible.

Precipitation in any form, whether snow, rain or fog, will often result in evaporative cooling – especially of the abnormally warm component where there is enough heat energy to power evaporation. Evaporative cooling can result in temperatures falling below ambient air temperature.

## Other Oil-filled Assets:

Many of the same techniques and problems apply to other oil-filled utility assets, such as oil-filled circuit breakers, voltage regulators, and re-closers. In these cases, however, heat is not normally generated in the same degree as is in transformers. The tanks, thus, will run *much* closer to ambient air temperature. When *any* unexplained deviation in tank temperatures among the three phases occurs, it is cause for concern and, often, immediate action to determine the root cause. The reason for this is that the abnormal heating, even if slight, is caused by a small high-resistance heat source, typically an internal connection, that must be very hot in order to change the temperature of an entire tank of oil.

As with transformers, bushing connections can also exhibit heating either internally and externally, the former being much more difficult to detect and, typically, more serious to rectify. DGA testing can be very useful to better understand many internal faults that are located with thermography.

## Common Problems with Many Inspection Methodologies:

Far too many of the inspections being conducted today fail to adhere to best practices or, in many cases, even to common sense. The most common issues are as follows:

• **A Focus on Radiometric Temperature Measurements:** As has been shown, the surface temperature represented in a thermal signature can vary widely with a number of variables, most of which are difficult to characterize and quantify. Most practitioners fail to pay attention to the influences of changes in ambient conditions and system conditions. As a result, many problems are not detected while others, even after they are detected, are all too often misdiagnosed.

• **Basic Thermodynamics:** Even without an advanced degree in heat transfer, a simple understanding of the relationship between the source of heating (almost always internally generated) and the surface we see in the thermal image (always external) is essential. Many factors affect exactly what the surface temperature will be at any given moment. The precise relationship between that "moving target" and the internal heating source is often just as complex, especially when the thermal gradient is very large.

All this points to two things often ignored by thermographers. First, we must work with conditions such that, if there is an anomaly, we will be able to see it. Less than optimum conditions will often result in many important anomalies being at or just above the threshold of detection, i.e. with a very low rise over ambient or similar assets. Second,

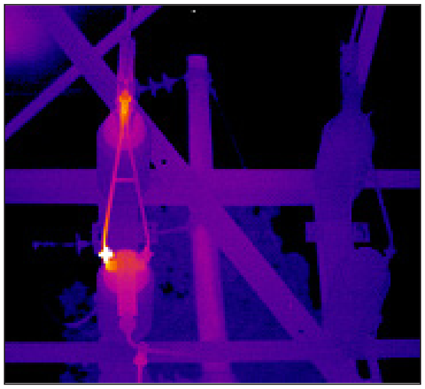

Figure 5. The “hot spot” on this disconnect may not be the point of high resistance. Current can “shunt” away leaving the problem cooler.

the radiometric temperature of an anomaly, especially a single “snapshot in time,” is not a reliable indicator of its progress toward failure.

• **The Relationship between Temperature and Electrical Resistance:** As an abnormally high-resistance component begins to heat up, resistance increases; this, in turn, results in additional heating and, as a consequence, in a further increase in temperature. In other words, a bad situation gets worse, often quickly! An increase in component temperature of 10°C results in a 4% increase in resistance. This is one of the reasons why some components may not fail for long periods of time, but then reach a “runaway” stage and degrade rapidly and, often, catastrophically.

• **Current Shunting:** Also commonly overlooked are situations where a warm component or asset may be the normal one, while the cooler one may be have a higher resistance. The most basic example is the “barber pole effect” often seen on multi-strand conductors. This occurs when several strands are broken or isolated electrically by corrosion, the remainder of the strands must care the entire load and, thus, appear warmer. Current is shunted away from cool strands that, because of their higher resistance, do not function properly. A similar situation can often be seen to exist on many yoke-type disconnects (Fig. 5).

A ring-bus is an example of a larger, and much more significant, double-fed circuits, where inspections must be done only with great care and understanding of the whole circuit.

• **Emissivity and Reflected Background:** A best practice for radiometric temperature measurement suggests that none be made until an anomaly is located. Even then, attention must be given to low emissivity surfaces as they will fail to emit strongly and may also offer confusing reflections. When a suspect asset is located, a careful evaluation should be made of the emissivity of the surface(s) in question. Emissivity correction value look-up tables can be helpful, but, in the end, the qualified thermographer will need to interpret many of these values to fit reality. As an example, any oxidized copper surface that still appears “coppery” in color, will have an emissivity too low to reliably measure.

• **Two Additional Important but Impossible Questions** are “How hot is too hot?” and “How long will it last?” Unfortunately, little is known about the temperature/time relationship for failures caused by high-resistance heating at a small contact surface. What we do know it that the process often proceeds slowly; even if early heating does not appear severe, pitting and melting occurs at a micro-site inside the point of contact. This, in turn, results in increased heating, increased resistance and increased oxidation. Annealing begins to occur at fairly low temperatures (200F) over a fairly short period of time (30 days). Once the metals have lost their temper, a “run away” condition—at which point more melting occurs—can result quickly.

It must be noted that the heating is concentrated on an area that is most often extremely small; this has little to do with a temperature-based specification that typically accompanies all assets. The asset itself will probably not be heated greatly, but temperatures at the localized, high-resistance hotspot will, given time and the right conditions, certainly reach the melting point of the metal. Resistance changes are in micro-Ohms but with high currents and heating on a small area, damage is typically significant.

**Spatial resolution is a function of the detector size and the optical path of the system, including the lens, as well as target shape and thermal contrast.**

• **Limitations of the Infrared System:** While the utility asset and the surrounding environment present a number of difficulties for thermographers, all infrared systems themselves have inherent limitations, many of which are poorly understood by thermographers and are often ignored in the literature. All optical systems, including infrared, have limits to their abilities to resolve data. Thermographers must deal with both spatial and measurement resolution.

Spatial resolution is a function of the detector size and the optical path of the system, including the lens, as well as target shape and thermal contrast. Longer lenses can improve resolution, but result in a narrower field of view. Moving closer, if an option, achieves the same results. Distance and object size are the two variables.

The measurement resolution of an infrared system is less than its spatial resolution, typically by a factor of between two and four. It is, therefore, common to be able to see hot spots while still being outside of the measurement resolution for the system. Measurements taken beyond the limits of resolution typically appear less than they actually are because the hot spot is averaged together with the cooler sky temperature that often makes up the rest of the field of view. Unfortunately most infrared system suppliers do not provide the specification for measurement resolutions so it must be derived from best practice.

• **Qualifying Thermographers:** Too many thermographers are not adequately qualified, and this results in, on the one hand, less than optimum returns on the investment or, on the other, dangerous errors and omissions in their work.

Qualification of thermographers is best defined by the personnel qualification guidelines of the American Society for Nondestructive Testing (ASNT) *SNT-TC-1A*. Qualification is based on training, experience and testing. Clearly the skills required to perform high quality utility asset inspections are considerable; some are general to the field of thermography while others require specialized knowledge of the assets themselves.

Level I thermographers are qualified to gather data; certification entails a week of training and three months experience, at a minimum. At Level II thermographers may also interpret the recorded data. To be certified at Level II requires an additional week of training and up to nine months additional experience. Training at both levels should follow the training outlines prescribed in *SNT-TC-1A*. Performance-based testing, including a practical examination, should be done for general knowledge as well as knowledge specific to utility applications.

Unfortunately the market has not widely adhered to ASNT standards, opting instead for more simplistic and fairly confusing definitions put forth by camera manufacturers, training companies and consultants. This poor practice results in a significant risk of error and a reduction in overall effectiveness of the use of the technology.

• **Educate Users of Thermography Services:** Too often the expectations of users of thermography inspection services are not based on the reality of heat transfer and radiation physics. Disappointment is the only thing that can be assured! The popular press has done little to dispel the many industry myths that contribute to this unfortunate situation. Inspections are routinely conducted in high wind or with light loads, for example, ignoring best practice and common sense.

**A pre-inspection meeting can establish the requirements necessary for condition monitoring as well as define the limits of the technology.**

A pre-inspection meeting can establish the requirements necessary for condition monitoring as well as define the limits of the technology. If work must be done with less than ideal conditions, as is often the case, expectations can be adjusted appropriately, and provisions made for completing the inspection at a later date.

Unfortunately, very few industry standards exist. ASTM E1934, Standard guide for examining electrical and mechanical equipment with infrared thermography can provide some minimal guidance even if it is not specific to utility assets; it is in the process of a major revision at this time. Some thermographers use "rules of thumb" that masquerade as standards; some are even now incorporated into formal standards despite the fact that they are not based in science. This situation is problematic and costly for all. Until this changes, we can expect continued problems with achieving anticipated results.

Thermography is a powerful tool for monitoring the condition of many utility assets. When properly used it can validate operating condition and help to locate and, in some cases, diagnose, anomalous conditions. Thermography is often poorly used with the result being that detectable failures continue to occur unnecessarily. Qualifying thermographers and educating customers will go a long way to achieving success.

## References:

[1] Hill, Keith: "Surge arresters and testing," *Proceedings of Doble Conference 2004*
[2] Srmiska, Richard: "Lightning arresters' effect on power line reliability," *Proceedings of Inframation 2003*
[3] Sullivan, Jeff: "Infrared diagnostics of substation feeder problems," *Proceedings of Thermal Solutions 2002*