REDUCE RISK EXPOSURE FOR SUBSTATION TRANSFORMERS

By Patrick McShane, Product Manager, Fluids and Transformer Components

Liquid	Approved Transformer or Equivalent	Liquid Volume, gal (m^3)	Horizontal Distance: Two Hour Fire Resistant Construction, ft (m)	Horizontal Distance: Non-combustible Construction, ft (m)	Horizontal Distance: Combustible Construction, ft (m)	Vertical Distance ft (m)
Less Flammable (Approved Fluid)	Yes	N/A	3 (0.9)			5 (1.5)
	No	≤10,000 (38)	5 (1.5)		25 (7.6)	25 (7.6)
		>10,000 (38)	15 (4.6)		50 (15.2)	50 (15.2)
Mineral Oil or (Unapproved Fluid)	N/A	<500 (1.9)	5 (1.5)	15 (4.6)	25 (7.6)	25 (7.6)
		500-5,000 (1.9-19)	15 (4.6)	25 (7.6)	50 (15.2)	50 (15.2)
		>5,000 (19)	25 (7.6)	50 (15.2)	100 (30.5)	100 (30.5)

Table 2a Separation Distance Between Outdoor Liquid Insulated Transformers and Buildings

Liquid	Approved Transformer or Equivalent	Fluid Volume, gal (m^3)	Distance ft (m)
Less Flammable (Approved Fluid)	Yes	N/A	3 (0.9)
	No	≤10,000 (38)	5 (1.5)
		>10,000 (38)	25 (7.6)
Mineral Oil or (Unapproved Fluid)	N/A	<500 (1.9)	5 (1.5)
		500-5,000 (1.9-19)	25 (7.6)
		>5,000 (19)	50 (15.2)

Table 2b Outdoor Fluid Insulated Transformers Equipment Separation Distance

The aging of the substation infrastructure in the United States is causing increasing concerns for risk management. The rate of installation of new units is currently very low. Compounding the problem, the load demand on existing units continues to grow, however slowly.

One report by a major insurance group predicts substation transformer failures to rise by 500% within ten years as many units installed in the heyday of the '50s and '60s are exceeding their expected operational life cycle. Another insurance group reported that in a recent study period, the operational life cycle appears to be decreasing. The failures, due to insulation deterioration, occurred in transformers with an average age of just 17.8 years vs. the average expected life of around 40 years.

Unfortunately, a small but significant percentage of substation transformer failures occur in an "eventful mode," resulting in ruptures and/or fires. In spite of established safeguards, such as deluge systems, separation distance requirements, and firewall barriers, significant fires have been reported. One insurance company reported 25 substation transformer failures costing over $100,000 each in just one year. But often the real cost is not the damaged transformer, but rather consequential damages. For example, just this past January, two transformer substation fires were reported nationally, one at a nuclear power plant and one at a petrochemical plant. Production downtime, lasting weeks, was estimated to cost approximately one million dollars per day for each incident. Other potential eventful failure costs include the potential for damage to adjacent equipment and property, casualties and resulting liabilities, potential environmental risk exposures, and unfavorable publicity that often accompany such eventful failures.

Fortunately, there is a practical and proven means to significantly reduce, if not eliminate the risk of substation fires: The replacement of mineral oil with fire-resistant, ester-based dielectric coolants for new and aged power transformers.

Factory Mutual Global has increased the amount of fluid volume by a factor of ten eligible for significant reduction in fire protection safeguarding for transformers containing the fire-resistant fluids.

The recent revision of the Factory Mutual Global Property Loss Prevention Data Sheets 5-4 for transformers, has two major changes:

Reduction in minimum separation distances for medium power transformers and increase in fluid volume threshold before containment is required for highly biodegradable fire-resistant fluids.

The reduction in minimum separation distance appears in both Tables 2a, Separation Distance Between Outdoor Liquid Insulated Transformers and Buildings and Table 2b, Outdoor Fluid Insulated Transformers and Equipment Separation Distance. In the previous version of the LPDS (Revision Jan. 2001), the minimal horizontal distance for FM Approved, fire-resistant, dielectric fluid-filled equipment was 5 feet to non-combustible construction, and was limited to transformers containing 1,000 gallons. The volume has been increased to allow transformers containing up to 10,000 gallons with this clearance. This compares to the limit of less than 500 gallons for conventional mineral oil transformers with a minimum of 15 feet to noncombustible construction. In addition, the distance is measured from the transformer for the FM Approved fluids, but for mineral oil units it typically must be measured from the outside edge of the required containment means.

For example, consider a 100 MVA unit with a total of 10,000 gallons in the main tank and LTC compartment. The minimum required horizontal distance between its tank and the next closest equipment or non-combustible construction wall is 5 feet if the dielectric coolant is FM Approved. For mineral oil filled transformers, the minimum separation is the distance from the tank to the edge of the containment area, plus 50 feet.

The bases of the above changes are primarily due to both the fire safety record of less-flammable fluid and recent "worst case" fire testing performed at the Thomas A. Edison Technical Center in Franksville, Wisconsin. Previous high fault primary and secondary testing has shown that it is essentially not possible to ignite liquid-less-flammable fluids by arcing as the ignition source. The more recent testing has shown that another ignition means, glowing hot metal, easily and quickly ignites conventional transformer mineral oil, but does not ignite fluids with fire points greater than 300°C under the same operational conditions.

There have been no reported fires involving any of Cooper Power Systems' fire-resistant fluids since the introduction of the first such dielectric coolant, R-Temp Fluid, in 1975.

The other major revision in the new FM LPDS for transformers involves changes in the threshold volumes requiring fluid containment for environmentally preferred dielectric fluids such as Envirotemp FR3, the natural vegetable oil based fluid. Transformers filled with fluids certified as biodegradable by the EPA, containing less than 2640 gallons where the release of such a fluid does not expose navigable waterways, may be exempt from the FM Global containment requirement. The threshold for mineral oil is 500 gallons or less, depending on exposure to buildings.

Significant transformer fires have been reported despite established safeguards

The U.S. EPA has certified the biodegradability of Envirotemp FR3. When tested per the EPA Method OPPTS 835.3100, its biodegradation rate and completeness slightly exceeds that of a material the EPA classifies as "Ultimate Biodegradability." Because the U.S. EPA has published its verification of our published environmental claims of Envirotemp FR3 fluid, transformers with the fluid can bear the U.S. EPA ETV logo. ETV is the acronym for Environmental Technologies Verification. Envirotemp FR3 is the first transformer material to receive the U.S. EPA ETV status.

Both initial and maintenance cost sfor containment and fire protection at a substation can be very high. The new FM Global requirements offer high potential savings by substituting alternative fluids for mineral oil.

VOLTAGE SAGS: AN EXPLANATION - CAUSES, EFFECTS AND CORRECTION - PART II

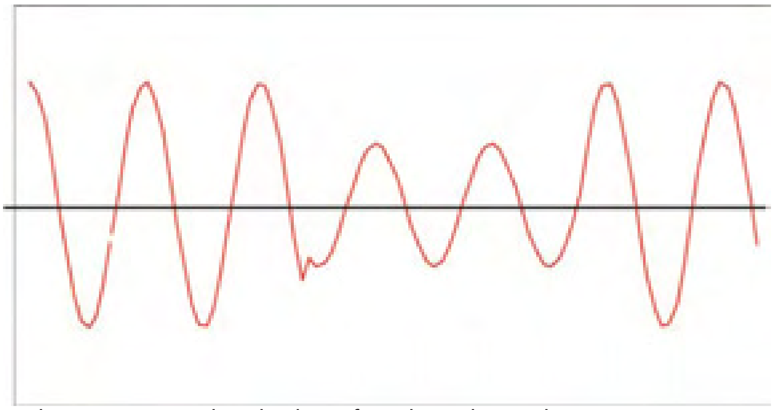
By Ian K.P. Ross, MIEE, Omniverter Inc.

8.0 THE SOLUTION

8.1 First Identify the Problem

8.1.1 Equipment Identification

In order to provide an optimal and cost effective solution to voltage sag problems, it is necessary to determine which equipment is susceptible to unplanned stoppages. In most industries, there is still a significant amount of electrical equipment which is not sensitive to voltage variation or which can be restarted at little or no cost. Usually it is not necessary to protect an entire industrial facility, it is sufficient to protect the key sensitive equipment.



Voltage Sag - A reduced voltage for a limited period
Figure 1

8.1.2 Identify the Voltage Sags

The next stage is to determine the frequency, depth and duration of the voltage sags.

These can vary widely even in apparently similar industrial facilities. Collection of this data is essential if the optimal solution is to be identified.

In North America, only a small proportion of manufacturing businesses have installed electrical metering which is capable of measuring and recording the voltage variations which are responsible for the majority of their very costly Unplanned Production Stoppages.

8.2 Measure the Problem

8.2.1 Install Metering

To identify the depth of the voltage sags and their duration, the sag events need to be measured and recorded for subsequent analysis. As typical voltage sag events last only a few cycles, the most cost effective way to measure these is by installation of an electronic meter with wave form capture capability.

As and when a voltage sag occurs, these devices capture the 3-phase voltage values throughout the sag event, the duration of the event in cycles, and can time stamp the start and or finish of the event. The data is captured automatically and is downloaded to a computer for later analysis.

8.2.2 Record Unplanned Production Stoppages

It is extremely helpful to record precisely the time and date of unplanned production stoppages and then to compare these against voltage variations recorded by the meter, as not all voltage sags lead to stoppages. This analysis will show the value of the sag voltage which typically causes production problems and equally those events which have not caused problems.

Surprisingly, in many industries, people are so busy trying to restart the process, they fail to record the time of the stoppage with any formal system. Even in large companies, precise data on the number and duration of unplanned stoppages is often difficult to find.

8.2.3 Meter Cost vs. Cost of Unplanned Production Stoppage

The cost of an installation with a meter capable of wave form capture and its software is typically a few thousand dollars.

This is often only a small fraction of the cost of even one unplanned production stoppage. Unfortunately installation of such meters has not become commonplace in many industries as "there is no money in the budget for this".

8.3 Choose a Solution

Once the characteristics of a typical voltage sag have been determined by examining recorded data from the waveform capture meter over a period of time, it is possible to calculate the type of voltage sag correction required to cover the depth and duration of expected future voltage sag events.

If it is possible to correct the problem by changing some sensitive components, this may well be the least expensive solution. This approach has been widely adopted in the semi-conductor industry and it is notable that this industry has invested heavily in high quality meters to identify the problems. This is an industry where an unplanned stoppage may cost $1 million per event or more.

If component substitution is not practical, it is necessary to identify the size of the load to be protected in kVA and its supply voltage. This may be an entire plant at medium voltage or a critical machine at low voltage or anything in between.

9.0 THERE ARE VOLTAGE SAG CORRECTION DEVICES AVAILABLE

9.1 Traditional Solutions

Traditional methods of Voltage Control included Transformer Tap Changers both mechanical and SCR switched units, Servo-Variac technology