Transformer Design and Sulphur Corrosion: The Missing Link?

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INTRODUCTION

In recent years sulphur corrosion has been a cause of major concern to the power industry. According to some experts more than one hundred transformers have failed worldwide owing to sulphur corrosion. Most of these failures occurred suddenly and with little or no warning. Transformers built between the early 1990s and the mid 2000s have been worst affected, although, as will be seen later in this paper, certain older transformers have also failed. Large, heavily loaded transformers seem to have been worst affected. Transformers with sealed oil preservation systems of different types also seem to have been worst affected.

Laboratory-based research, much of it conducted by Doble Engineering, has shown that some oils contain excessive amounts of potentially corrosive sulphur compounds. These can react with copper conductors in transformers to form copper (I) sulphide deposits. Formation of these deposits is promoted by higher temperatures and low levels of dissolved oxygen.

Oils containing potentially corrosive sulphur passed the original international standard tests and were in widespread use in many countries. Recent improvements in the tests, culminating in the Doble CCD test and IEC standard 62535, are better able to find potentially corrosive sulphur. One therefore hopes that oils supplied today are free from potentially corrosive sulphur. Nevertheless large amounts of oil containing potentially corrosive sulphur remain in use in transformers supplied between the early 1990s and the mid 2000s, and in older transformers which were refilled or topped-up with new oil during the same period.

Problems with the oil now seem to be well understood, even if they have not yet been overcome. However sulphur corrosion is not merely an oil problem, it is a problem for complete transformers. It appears that certain conditions which favor sulphur corrosion can be created by errors in construction or design. The purpose of this paper is to present three case studies where this has occurred and to draw conclusions of general interest from them.

Case Study 1 – 1000MVA Autotransformer

This case study concerns a 1000MVA 400/275/13kV autotransformer, built by GEC Alsthom at Stafford in 1992. In common with most other large transformers in Great Britain, it had a free-breathing oil expansion and preservation system. It was installed at a sub-station in North-East England in 1994 and commissioned in 1996. In normal service it was operated in parallel with two other autotransformers of the same ratio and rating. The three transformers were used to export the output of a large gas-fired power station, which has a declared capacity of approximately 1800MW. It therefore follows that each transformer was loaded to approximately 600MVA.

This autotransformer was ODAF cooled, with an ONAN rating of 500MVA. The fans and pumps were controlled by the winding temperature indicator. The winding temperature indicator should have been set to turn the fans and pumps on at 75°C and off again at 55°C. Instead it was set to turn the fans and pumps on at 90°C and off again at 65°C. It is still not clear why these settings were used. They had the effect of raising the load at which the fans and pumps were switched on to slightly more than 600MVA, the exact load depending on the ambient temperature. As the normal load on the autotransformer was approximately 600MVA, it can be seen that for most of the time the autotransformer was operating with ONAN cooling.

The autotransformer failed suddenly in May 2007. The dissolved gas signature of the transformer before failure gave no indication of developing problems. The oil contained a small amount of furans (0.30ppm), which was most unusual for a member of this family, and in retrospect may have been an indication of a developing problem.

Electrical testing at site after failure was rather limited in scope by practical constraints, not least the loss of oil. Magnetizing (excitation) currents and other tests indicated short-circuited turns in the C phase winding assembly. It was not completely clear which winding was affected.

The top eighteen discs of the C phase series winding were found to be extensively damaged. The damage was so extensive that it was difficult to tell where the original point of failure was. On examining the A and B phase series windings, the area close to the radial centre of the top discs was found to be suffering from both severe solid insulation aging and severe sulphur corrosion. No other part of the winding was similarly aged. Some sulphur corrosion was found elsewhere in the series windings, although this was rather less severe.

The series winding was a centre-entry interleaved disc design, wound from double flat conductors. As is standard practice with most manufacturers, the separators between double-discs were substantially thicker than the separators within double discs. The radial width of the winding was such that little if any oil could reasonably be expected to circulate through the ducts within the double discs under ON conditions, therefore each disc was cooled on one side only. The discs at the end of the windings were therefore cooled by oil flow in the duct between the shield ring and the disc. Unfortunately at the top of the winding, the oil guide had been placed next to the top disc rather than next to the shield ring. This effectively blocked the oil flow in this duct, meaning that the top disc received little if any oil circulation under ON conditions. As can be imagined this created precisely the conditions which favor sulphur corrosion – high temperatures and low levels of dissolved oxygen. The high temperatures also resulted in severe solid insulation aging.

Damage to the C phase series winding is shown in FIGURE 1 and FIGURE 2. Sulphur corrosion on a conductor from the top disc of the C phase series winding is shown in FIGURE 3. A general view of the B phase series winding is shown in FIGURE 4. Note the discoloration close to the radial centre of the top disc. Sulphur corrosion on a conductor from the top disc of the B phase series winding is shown in FIGURE 5.

Scanning electron microscopy (SEM) along with energy dispersive X-ray analysis (EDX) was used to magnify the samples and identify their elemental composition. Selected results on conductor and conductor insulation samples taken from the top discs of the B and C phase series windings are listed in TABLE 1

Degree of polymerization results on conductor insulation samples taken from the top disc of the B phase series winding are listed in TABLE 2. Note the conductor insulation taken from the top disc of the C phase series winding was too extensively scorched to obtain reliable degree of polymerization results.

Case Study 2 – 600MVA Generator Transformer

This case study concerns a 600MVA 300/22kV generator transformer, built by English Electric at Stafford in 1966. In common with most other large transformers in Great Britain, it had a free-breathing oil expansion and preservation system. It was installed at a power station in South Wales and commissioned in 1971. In normal service it was used to export approximately 500MW. It was not normal for this particular power station to supply reactive power. Owing mainly to poor availability during the 1970s, the generator had completed only approximately 160 000 running hours by January 2006, when the generator transformer failed suddenly.

The generator transformer was tripped by differential and negative sequence protection. The Buchholz relay also operated. Both bursting-diaphragm pressure relief devices opened and expelled a small quantity of oil.

Electrical tests after failure indicated short-circuited turns and significant loss of conductors somewhere in the B phase HV winding.

Prior to failure, indications concerning the condition of the generator transformer were not particularly good. The dissolved gas signature had for many years been characterized by a moderate level of methane, typically around 100ppm. Throughout most of the period for which results are available the ethane and ethylene levels had been rather lower; typically, around 25ppm. However levels of both ethylene and ethane rose from 2004 onwards, reaching parity with the methane level. Levels of carbon oxides were rather erratic; however the level of carbon monoxide relative to the level of carbon dioxide showed a rising trend throughout the period for which results are available.

The dissolved gas signature is typical of a thermal fault with moderate temperatures only (less than 300°C). It also suggests progressively more advanced solid insulation aging. No oil quality results and no reliable furan results were available.

On examination it was found that the main-tank lid flange of the transformer was very leaky on the LV side of the transformer. The gasket was found to be badly deteriorated. It was found that the LV busbars ran close to the tank flange, resulting in image current heating and the gasket deterioration and leaks observed. It has been necessary to top the transformer up with new oil at regular intervals. The main tank-lid flange may have been the origin of the thermal fault indicated by the dissolved gas signature.

Large quantities of debris from the B phase HV winding, including copper globules, were found spread throughout the transformer. When the scrapping contractor attempted to remove the B phase winding assembly for further examination, it collapsed onto the core. This limited the scope of the inspection somewhat. Damage to the B phase HV winding was very severe. A large proportion of the conductors in discs close to the axial centre of the winding had melted. The melting was worst close to the radial inside of the winding. Consequential damage, including melting of conductors, had affected much of the rest of the winding.

The HV winding was a centre-entry interleaved disc design, wound from flat conductors. It had been assembled from individual double-discs. The double-discs closest to the line end, which was at the centre of the winding, had been over-wrapped with crepe paper. Much of the crepe paper had then been cut away from the radial outside of the winding, although not the radial inside. This crepe paper restricted the oil flow and acted as thermal, as well as dielectric, insulation. Furthermore there were no axial laths at the radial inside of the HV winding to make a cooling duct. Axial oil flow was via two axial ducts in the discs themselves and an oil duct formed by axial laths at the radial outside of the winding. The inner third of the winding thus received little oil flow, especially close to the line end. This created precisely the conditions which favor sulphur corrosion – high temperatures and low levels of dissolved oxygen. The high temperatures also resulted in severe solid insulation aging.

Examination of the other two HV windings revealed both severe solid insulation aging and severe sulphur corrosion close to the radial inside of the winding in the over-wrapped area.

The LV busbar arrangement and the damage to the flange gasket are shown in FIGURE 6. The scrapping contractor removing the badly damaged B phase winding assembly is shown in FIGURE 7. The damage to the B phase HV winding is shown in FIGURE 8 (close to origin) and FIGURE 9 (consequential damage further up). The over-wrapping on the A-phase HV winding is shown in FIGURE 10.

Selected SEM-EDX results on conductor samples taken from the B phase HV winding are listed in TABLE 3.

Selected DP results on conductor insulation samples taken from the A phase HV winding are listed in TABLE 4. Although some samples were taken from the B phase HV winding, it was not possible to identify their exact provenance. Furthermore some were too extensively scorched to obtain reliable degree of polymerization results.

The root cause of this failure was a combination of poor design of the HV winding and topping-up using oil containing potentially corrosive sulphur. The need to top-up the oil level can be traced from poor design of the LV busbars and tank-lid flange, through localized overheating and deterioration of the gasket. On reflection, the operator might have paid more attention to the oil leaks from the tank-lid flange and the indications of overheating from the dissolved gas signature. On reflection the operator might also have made regular checks on oil quality and dissolved furans. These might have given an indication of developing problems.

Case Study 3 – 192MVA Generator Transformer

This case study concerns a 192MVA 400/15kV generator transformer, built by ABB Pomezia in 1998. It was installed at a gas-fired power station in South Italy. It is believed to have been heavily utilized during its life. Note that the annual average temperature at the power station is approximately 18°C. The operating temperatures of the generator transformer must have been correspondingly high.

The generator transformer used ONAF cooling. “ON” cooling modes have the advantage of eliminating oil pumps and the associated problems, including poor pump reliability and static electrification. However, it should be noted that the oil flows are much less than for OF or OD cooling modes. Furthermore oil flows within certain types of winding, especially disc windings without vertical ducts, can be very non-uniform. Large number of discs between oil guides in such windings has the beneficial effect of reducing the top oil temperature rise; however they can lead to certain discs, typically those immediately below the oil guides, receiving little oil flow. As can be imagined this creates precisely the conditions which favor sulphur corrosion – high temperatures and low levels of dissolved oxygen.

The generator transformer failed suddenly in April 2006. It was tripped by differential protection. Analysis of fault recorder traces strongly suggested an internal fault in the transformer, affecting V phase. Electrical tests after failure indicated short-circuited turns and significant loss of conductors somewhere in the V phase HV winding. The core and windings were removed from the tank for further examination, which did not reveal any problem. They were the stored until late September, when the transformer was rewound to the original design.

Before failure the dissolved gas signature for the generator transformer was not particularly healthy – with more than 20ppm of ethylene and rather higher levels of methane and ethane. The dissolved gas signature is typical of a thermal fault with moderate temperatures only (less than 300°C). The carbon monoxide level was also rather high – more than 500ppm. Levels of dissolved furans were also unexpectedly high for a transformer with less than ten years’ service – 1.32ppm. The high levels of carbon monoxide and furans suggest more advanced solid insulation aging than might have been expected.

A more detailed examination of the windings was possible during the rewind. This revealed that the cause of the failure was an inter-turn fault in the V phase HV winding, in the disc immediately below the first oil guide from the top of the winding. This disc was found to be suffering from severe solid insulation aging and severe sulphur corrosion.

The V phase HV winding is shown in FIGURE 11. Note that there are sixteen discs between oil guides. A limit of ten is widely used within the industry, although not by this manufacturer. The point of failure is shown in FIGURE 12. Sulphur corrosion on conductors from the same disc is shown in FIGURE 13.

Selected SEM-EDX results on conductor samples taken from the V phase HV winding are listed in TABLE 5.

Selected DP results on conductor insulation samples taken from the V phase HV winding are listed in TABLE 6.

The operator provided Doble PowerTest with a copy of the temperature rise type test certificate for review. According to the test certificate the transformer passed the test by a wide margin. However, in the opinion of Doble PowerTest there are a number of irregularities in how the raw results were interpreted. The most important of these is derogation from the method given in IEC standard 60076-2 for calculating mean oil temperature rise. This seems to have been based on the cooler inlet temperature, rather than the average of the top and bottom oil temperatures. Using the IEC standard 60076-2 method gives a mean oil rise around 5K lower. This in turn gives winding temperature gradients 5K higher and a winding hot spot temperature more than 6K higher. According to IEC standard 60076-7, the rate of solid insulation aging doubles for a 6K rise in temperature. The generator transformer failed a little under half-way through its expected useful life.

Some of the temperature rise test results are shown in graphical form in FIGURE 14. Selected results are also listed in TABLE 7.

This case study highlights a number of problems during the specification, design and testing of the generator transformer. Firstly, customers and manufacturers should have a realistic approach to the selection of cooling modes. Although there are problems associated with oil pumps, ON cooling is not always the best option. Secondly, there is a need for realistic approach to the detailed design of ON cooled winding, especially disc windings without vertical ducts. Designers should consider the need to control the hot spot temperature. This area should be examined during the design review. Thirdly, a rigorous approach to testing is required. The problem with localized overheating could have been found using fiber optic temperature probes, had such a probe been positioned in the correct place. The effects of derogation from IEC standard 60076-2 are also particular striking.

Finally, as with case study 1, although dissolved gas analysis did not give any clear indication of developing problems, dissolved furan analysis may have done.

GENERAL CONCLUSIONS

The author was motivated to write this paper after seeing clear links between transformer design and sulphur corrosion in these three case studies. In every case the designer has inadvertently created conditions which favor sulphur corrosion – high temperatures and low levels of dissolved oxygen. The high temperatures also promote solid insulation aging, even in the absence of potentially corrosive sulphur in the oil.

Manufacturers and operators are therefore advised carefully to review designs to ensure that all parts of windings receive sufficient oil flow. The correct positioning of oil guides is of particular importance. It is worth some discussion during design review meetings.

Manufacturers and operators are reminded that checking the local temperature in windings is now straightforward thanks to the great improvements in fiber optic sensors. Operators are also reminded of the importance of witnessing the temperature rise test and of thoroughly checking the results for any irregularities. Apparently minor irregularities can have significant consequences later.

Operators are also advised that sulphur corrosion can and does affect transformers built before oil containing excessive amounts of potentially corrosive sulphur came into widespread use. Refilling or topping-up with such oil can have significant consequences later. Doble PowerTest also respectfully suggest that some operators might be advised to pay more attention to preventing and correcting oil leaks from their transformers, rather than continuously topping-up with new oil.

The conditions which promote sulphur corrosion also promote solid insulation aging. In two of the case studies in this paper furan analysis gave an indication of developing problems. Unfortunately this indication will not always be present, and will not always be clear when it is present.

Finally, good transformer design should be combined with careful selection of oil using the improved tests now available for potentially corrosive sulphur.

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TABLE 1
Case Study 1 – SEM-EDX Results

Sample Location			SEM Result (% wt – S/Cu/others)
Phase	Winding	Location	
B	Series	Top disc, conductor	8.8/89.7/1.5
		Top disc, Nomex insert	11.4/60.6/28.0
		Top disc, conductor insulation	15.1/51.8/33.1
C	Series	Top disc, conductor	15.1/82.7/2.2
		Top disc, Nomex insert	7.0/47.1/45.9
		Top disc, conductor insulation	13.0/76.9/10.1
Pure copper (I) sulphide			22.2/77.8/-

TABLE 2
Case Study 1 – DP Results

Sample Location			DP Result
Phase	Winding	Location	
B	Series	Top disc, inside	778/798
		Top disc, radial centre	282/314
		Top disc, outside	533/557

TABLE 3
Case Study 2 – SEM-EDX Results

Sample Location			SEM Result (% wt – S/Cu/others)
Phase	Winding	Location	
B	HV	Disc above centre, conductor	11.7/56.5/31.8
		Disc 8 above centre, conductor	-/25.2/74.8
		Disc 14 above centre, conductor	-/33.2/66.8
Pure copper (I) sulphide			22.2/77.8/-

TABLE 4
Case Study 2 – DP Results

Sample Location			DP Result
Phase	Winding	Location	
A	HV	Disc above centre, outer 1/3	553/595
			571/607
		Disc above centre, middle 1/3	529/559
			504/538
		Disc above centre, inside 1/3	301/347
			269/297
			271/323

TABLE 5
Case Study 3 – SEM-EDX Results

Sample Location			SEM Result (% wt – S/Cu/others)
Phase	Winding	Location	
V	HV	Adj. point-of-failure, conductor	22.2/77.8/-
Pure copper (I) sulphide			22.2/77.8/-

TABLE 6
Case Study 3 – DP Results

Sample Location			DP Result
Phase	Winding	Location	
V	HV	Top disc, outside	392/404
		Top disc, inside	427/451
		Adj. point-of-failure	359/391

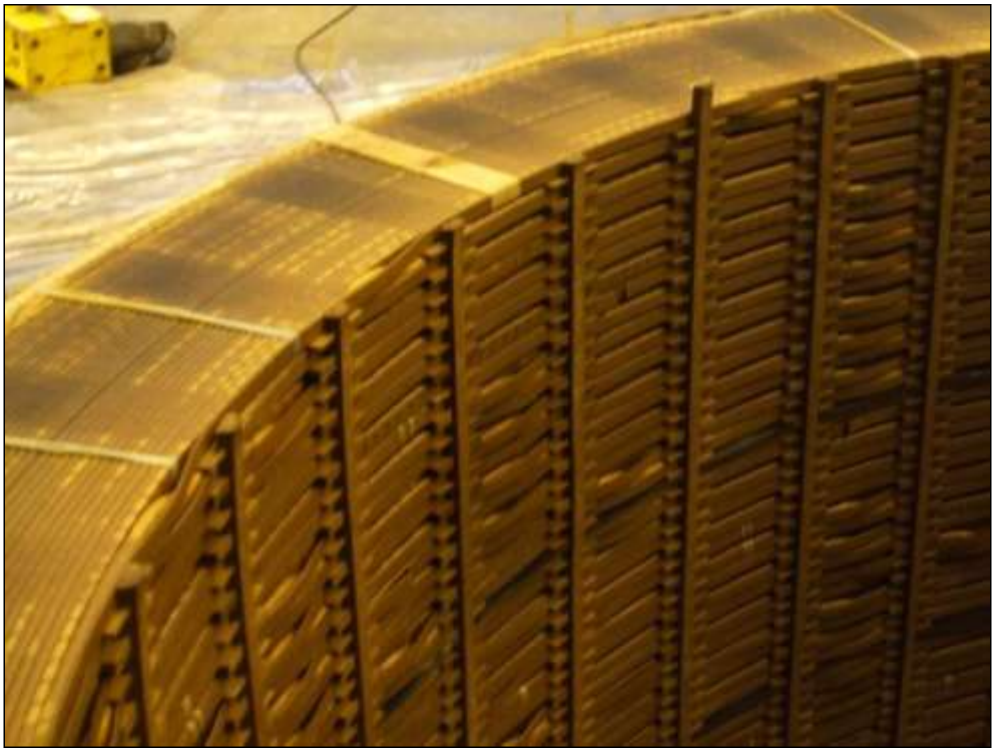
TABLE 7
Case Study 3 – Temperature Rise Test Results

Parameter	Test Certificate	DPT Estimate	Field Experience	IEC 60076-2/7
Top oil rise	51.6K	52.8K		60K max
Mean oil rise	39.2K	34.5K		
Ave. winding rise (HV)	59.8K	60.1K		65K max
Winding HS rise (HV)	78.4K	85.9K		78K
Ageing rate (18.5°C ambient)	0.88pu	2.11pu		
Max useful life	205 000 hrs 23 yrs	85 000 hrs 10 yrs	8 yrs	180 000 hrs 21 yrs

Case Study 1 – Damage to C Phase Series Winding, General View from Inside
FIGURE 1

Case Study 1 – Damage to C Phase Series Winding, General View from Outside
FIGURE 2

Case Study 1 – Sulphur Corrosion on Conductor from Top Disc of C Phase Series Winding
FIGURE 3



Case Study 1 – B Phase Series Winding, General View
FIGURE 4

Case Study 1 – Sulphur Corrosion on Conductor from Top Disc of B Phase Series Winding
FIGURE 5

Case Study 2 – LV Busbar Arrangement
FIGURE 6

Case Study 2 – Scrapping Contractor Removing Damaged B phase Windings
FIGURE 7

Case Study 2 – Damage to B Phase HV Winding, Close-up
FIGURE 8

Case Study 2 – Consequential Damage to B Phase HV Winding, Close-up
FIGURE 9

Case Study 2 – Over-wrapping from A Phase HV Winding
FIGURE 10

Case Study 3 – V Phase HV Winding
FIGURE 11

Case Study 3 – Point-of-failure
FIGURE 12

Case Study 3 – Sulphur Corrosion on Conductor Adjacent to Point-of-failure
FIGURE 13

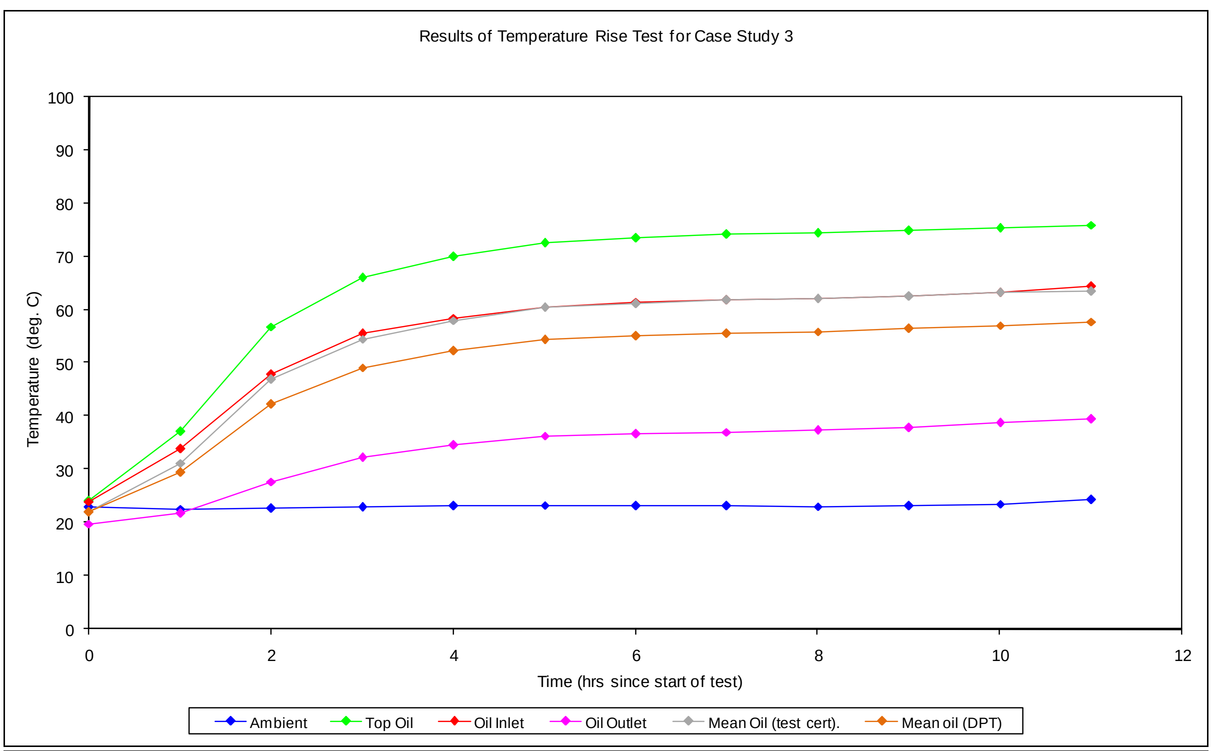


FIGURE 14

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BIOGRAPHY

Simon Ryder studied Engineering Science at St John’s College, Oxford, graduating in 1996. He was a student apprentice with Hawker Siddeley Power Transformers, before joining GEC Alsthom where he worked for seven years in design, development and eventually research. He was known for his work on frequency response analysis (FRA), thermal characteristics of transformers and winding technology. He joined Doble PowerTest in 2003, working mainly on transformer asset health review and condition assessment. More recently he has become involved with transformer procurement.

He is a member of IET and IEEE-PES and a chartered engineer