The University of Manchester

Title: **WP3, Final Report**

Synopsis: This final report represents the outputs of WP3 which focuses on the possible impacts of CLASS techniques on the health conditions of transformer main tanks and tap changers by the University of Manchester (UoM) and University of Liverpool (UoL) respectively. The preliminary work by UoM gives some suggestions about data monitoring and device installation. Based on these, the UoL has installed the transformer monitoring systems on the selected transformers. Those systems installed gave valuable information on the behaviour of the tap changers and main tanks during CLASS type of operations. The acoustic signatures from the tap changers and the main tanks were similar to non CLASS (i.e. normal) operations. Although there are detailed differences, there were no incidences that gave concern. The analyses are also performed on the oil sampled during the trial period. The oil samples from main tank show no correlation with the CLASS techniques, while oil samples from the tap changer indicate the association with heating. Moreover, there is an issue around contact wear in the tap changer which could be of concern if there were significant increases in load current. A doubling of current will increase the erosion of the contact by a factor of 4 and would therefore impact on maintenance schedules. The long-term impacts of CLASS techniques on transformer main tank health have been assessed by UoM through thermal modelling and health index calculation. Simulation results show that the transformer tripping at high peak loads will cause the large reduction of paper life expectancies. In contrast, the health impacts of tap staggering on main tanks are negligible. Furthermore, the violation of temperature cannot be neglected from the system safety point of view and a loading guide is finally established to avoid the high hot-spot temperatures within the transformer main tanks.

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Executive Summary

This final report represents the results of the Low Carbon Networks Fund Tier 2 project "Customer Load Active System Services (CLASS)" run by Electricity North West Limited (ENWL).

The aim of CLASS project is to provide Electricity North West Limited with greater understanding of the possible techniques to maximise the usefulness of their assets and potential provision of services to National Grid by actions undertaken exclusively at primary substation level. It addresses three main solutions:

1. Peak reduction at primary substation: resulting from voltage changes obtained through on load tap changer (OLTC) actions.
2. Reactive power absorption: resulting from tap staggering actions.
3. Provision of fast reserves and frequency response: provided by the fast tripping of one parallel transformer and OLTC actions.

The aim of WP3 is to analyse the impact of CLASS techniques on the health of 33/11(or 6.6) kV primary substation transformer assets in two aspects—main tank and tap changer. The work has been conducted by two universities.

Executive Summary of University of Manchester

The University of Manchester (UoM) aims to identify the possible impacts of CLASS techniques on the health of transformer main tank and to recommend remedy measures accordingly. This part of work consists of the preliminary work of CLASS trial tests, the analysis of load and oil data, the thermal assessment of CLASS techniques, the modification of health indices and the establishment of loading guide.

In the preliminary work of CLASS trial tests, the analysis on the CLASS techniques found that the main tank health is only concerned with Trial 3a (transformer tripping) and Trial 4 (tap staggering) which would increase the current passing through a transformer and thermally impact its health and lifetime. Suggestions on data monitoring and device installation were therefore made to Electricity North West Limited for implementation during the trials.

The analysis was then performed on the load data. In Trial 3a tests, the current of an operating transformer will double following the trip of the other parallel transformer. In Trial 4 tests, the maximum current difference due to tap stagger is 150A if the power factor of the load is above 0.9. In addition, the load data analysis has identified control problems within some substations which always have circulating current flowing through two parallel transformers.

The oil data were also analysed by focusing on the oil sampled before and after trial tests, and it is concluded that it is unlikely that the change of oil test results is correlated with the CLASS techniques. Consequently, the CLASS techniques are unlikely to bring any detrimental impacts on transformer operational health. Furthermore, the condition of transformers was assessed and the accelerated acidity growth has been found in a number of transformers with their acidity values over 0.15 mgKOH/g before the commissioned age of 30 years. This phenomenon indicates the early onset of ageing of some transformers which could lead to unexpected maintenance challenges for Electricity North West Limited.

In order to assess the long-term thermal impacts on of transformers and their vulnerability to tripping and tap staggering scenarios, over a hundred transformers were thermally modelled through simulation based on the assumed worst-case operational scenarios. Simulation results show that only a handful of transformers with high peak loads will have paper insulation life expectancies reduced below the expected asset life (70 years) due to the implementation of tripping. In contrast to transformer tripping, the impacts of tap staggering are negligible with all the paper life expectancies in excess of 90 years.

The calculated paper insulation life expectancies were subsequently incorporated into the calculation of health indices of transformer main tanks, and it was found that transformer tripping at the time of peak load is detrimental only to the health of these small numbers of transformers. Therefore, in the case, that the CLASS transformer tripping techniques are implemented on them, the detailed monitoring, assessment and reinforcement of transformer's main tank may only need to focus on these small numbers of transformers.

In spite of this, when implementing CLASS techniques, the safe operation of the network cannot be neglected due to potential transformer alarms and trips which occur because of possible hot-spot temperature violations during the time of transformer tripping. Therefore, a loading guide has been established by setting a load limit, within which a certain type of transformer can be safely tripped under different ambient temperature conditions without causing any temperature violations in the substation.

In the future, the primary substation with circulating current may need to be identified to solve the potential control problem. Moreover, the transformers with accelerated or abnormal acidity growth may need to be identified in order to prepare for the oil maintenance in advance. One of the recommendations is to record and alternate the new CLASS operational mode i.e. tripping, between two parallel transformers. This means the operator needs to make two parallel transformers suffer the higher current caused by tripping in turn, so to age the two transformer equally and reduce the risk of failure at the supply point.

Executive Summary of University of Liverpool

The University of Liverpool is responsible for studying the impact of CLASS techniques on tap changer health condition.

Three primary transformers were monitored during the trial period one at each at Irlam, Longsight and Romiley. Each transformer was fitted with an external optical fibre based acoustic sensor attached to the tap changer enclosure and three external temperature sensors were attached respectively to the top, middle and bottom of one of the circulation pipes servicing the main tank of the transformer. The acoustic sensors were not only able to detect the operation of the tap process but they were also able to provide signatures of the transformer pre and post the operation of the tap mechanism. The acoustic signatures were processed via chromatic processing[1] to extract information from the complex signal. The signals from the temperature sensors were processed in a conventional manner. Current, Voltage, and reactive and real power were also recorded. The data was uploaded to iHost and then downloaded for analysis off line.

In addition to monitoring the behaviour of the tap changer and transformer experiment work was undertaken in the laboratory to assess potential additional electrode wear due to CLASS operations and the likely impact of this on the maintenance intervals currently in force. An empirical equation is developed that relates the additional electrode wear due to CLASS operations and which can be used to modify current maintenance regimes.

Oil samples from the tap changer compartments of each of pair primary transformers at Longsight and Romiley were taken and analysed in the laboratory during a sequence of CLASS tests. Single oil samples were obtained from the each of the pair of primary transformers at Irlam. The analysis was based on examining the oil for any permanent molecular degradation due to heating, arcing operations etc. These oil samples were analysed using a tuneable broad band optical source and optical images capture and processed chromatically[2]. The approach has been previously used to determine permanent degradation of oil taken from the main tank where it had been subjected to continuous normal transform operations. The chromatic values in those tests were correlated with residual dissolved gas data obtained from the same oil sample tested in an analytic laboratory. The purpose of this approach is to reduce the complexity of the information being presented so that a clear indication of the extent of any degradation is immediate apparent. This will also aid the development of an empirical method for assessing any additional deterioration due to CLASS type of operations.

The monitoring system recorded the temperature on a circulation pipe at three locations and the acoustic signatures of the transformer. Regarding the temperature changes recorded these were relatively small with the maximum being recorded of 5 degrees above the temperature trend profile for the transformer. These rises took place after the tests had been initiated due to thermal lag as any additional heating involve would have to be conducted from within the transformer core to the surrounding oil. Temperature sensors at the top of the cooling pipe recorded a higher temperature than those at the bottom of the pipe, as expected.

Acoustic signals were recorded and processed for CLASS and non CLASS type of operations. The processed acoustic signatures are split into three parts to cover pre, actual and post tap changing operation. The pre and post analysis can be used to compare the transformer response to the tap change event. The non CLASS signals can be used to provide a typical pattern for the behaviour for the transformers. This so called base line is how the transformer and tap changer behaves under normal conditions. Under normal conditions the acoustic signatures produced by the transformers pre and post are variable even for the same transformer, the main difference being in the amplitude of the signature whilst the frequency content is similar. The same behaviour occurs for the signatures collected from CLASS tests. The acoustic signatures for the actual tap change process for non CLASS operations are similar in amplitude to the pre and post tap signatures of the transformer but have a wider spread in frequency content. Those for the Class operations exhibited the same variability as for the non CLASS tests with no discernible differences or additional patterns to these signatures between the two sets of conditions.

Electrode wear is governed by a number of interacting factors (electrode material, rated current of the contacts, switching current levels, arcing duration, arcing environment, etc). Analysis undertaken has produced an empirical formula to provide a relative value of additional wear that arises under the CLASS test conditions. For the test conditions undertaken in the project all but one can be defined as “normal” tap operations with “normal” being defined as the level of switching current is within the range of currents that would take place under non CLASS operations. The most onerous CLASS condition was when one of the parallel transformers took the full load effectively doubling the load current. Experimental data indicates that the erosion is approximately four times that of a “normal” switching current (i.e. the square of the ratio of the actual switching current to the normal switching current). Analysis of the tap changer operations during the tests compared with non test operations did not show any significant increase in the time for the tap change operation. The extra erosion is therefore attributed to the additional switching current. If maintenance of the tap changer is based on a total number of operations irrespective of which tap position is involved in the switching, then maintenance may have to be scheduled more frequently if the type of CLASS operation requires the disconnection of one of the parallel transformers and the increase of current in the remaining transformer.

Single oil samples taken from the tap changer compartments of the transformer pair (T11 and T12) at Irlam were processing using the chromatic method. The results from the analysis indicated that the oil T12 had been subject to more use than in T11.Since T11 had recently been installed and T12 had been in operation for approximately two years. This confirms that the approach can detect changes in the oil related to operation usage. Oil samples taken from the transformer pairs at Longsight and Romiley (T11 and T12) from CLASS operations indicate that there is a change in the oil in all four transformers. Smaller changes in the oil were noted for the transformers at Longsight than at Romiley with T11 at Romiley showing the largest change. The optical signatures of all the oil samples indicated that the oil had been subject to “over” heating. Although the instantaneous change in the optical signature of the oil was greater than the steady state conditions for Irlam T11 and T12 the overall extra “ageing” of the whole oil volume after diffusion is probably small but it was not quantifiable from the test data obtained to date.

External temperature changes were insensitive to CLASS operations. Those temperature rises were small. This implies that no significant heating of the bulk oil is happening within the time scale of the tests although there might well be localised hot spots.

The acoustic signature for the transformers for pre, during and post tap changer operation did not show any significant changes for non CLASS and CLASS operations. This implies that mechanically there were no adverse affects on the mechanism.

For higher current switching operations above what is deemed normal for the tap changer, there is a significant increase in the erosion of contacts. For a doubling of the switching current above the normal, the erosion rate increases by approximately a factor of four. This higher erosion rate could affect the time interval between routine maintenance for tap changers and will need to be factored into a simple numerical approached based on maintenance of counting the number of tap changers.

Oil samples taken from the tap changer chamber after the CLASS tests show a residual change in the oil. These changes are indicative of oil heating. However, the effect of the local degradation in the oil is diminished as it mixes with bulk of the oil. Higher switching currents will increase oil degradation.

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1 Introduction

1.1 Background

In 2008, the UK parliament passed the Climate Change Act, which sets binding targets to reduce carbon emissions to at least 26% (of 1990 levels) by 2020 and 80% by 2050 [1]. This target requires a reduced dependence on traditional fossil fuels and prompts the transition to renewable energy resources. This transition will cause an increase in the number of distributed renewable-energy generation plants to be introduced, which might cause voltage violations when high distribution generation coincides with low local demand. Moreover, UK government estimates suggest that electricity demand could double by 2050 [2]. The increase in power will result in higher current which impacts network transformer assets from a thermal aspect, by raising the temperature.

Network reinforcement is a solution to these future challenges, however, this solution requires more investment through higher bills for customers, and also has negative social and environmental impacts on citizens residing near to assets. Hence, the low-carbon network, funded by the Office of Gas and Electricity Markets (Ofgem), is expected to incorporate significant volumes of renewable energy resources while also coping with the load growth based on the existing assets.

Electricity North West Limited are pioneers in the low-carbon network and propose the CLASS (Customer Load Active System Services)) project which aims to meet the future challenges. This project aims to enhance the capability of Distribution Network Operator (DNO) by providing demand and frequency response services, while also maintaining the voltage statutory limits. For instance, the peak load demand could be lowered by voltage reduction. In this case, network reinforcement would be deferred or avoided.

1.2 Motivation

Non-conventional approaches are applied in the CLASS project. These approaches require more frequent tap changer operation and transformer tripping events to occur. Consequently, this may result in the existing transformer assets (including transformer main tank and tap changer) experiencing higher currents and temperatures that, in turn, may impact on the asset management strategy of the DNO in terms of loss of life or risk of failure in service.

1.3 Aims and Objectives

As a part of the CLASS project, this research aims to analyse the impact of CLASS techniques on the health of 33/11 (or 6.6) kV primary substation transformer assets in two aspects—main tank and tap changer. The work is conducted by two universities. The University of Manchester mainly focuses on the health condition of transformer main tanks under the newly proposed operational scenarios. The University of Liverpool is responsible for studying the possible impact of the proposed CLASS techniques on tap changer health condition. Brief objectives of the University of Manchester are summarised as follows,

- Analyse CLASS techniques and the transformers under the CLASS trial tests. Give some suggestions about data monitoring and device installation for trial tests.

- Analyse the load data and oil sample test data acquired during the period of trial tests.

- Assess thermal effects due to higher currents flowing through transformer under new operational modes, by using thermal modelling.

- Incorporate the results of thermal modelling into the health indices for transformer main tank so as to understand the impacts of CLASS techniques on main tank health.

- Establish a loading guide for DNO to implement the CLASS techniques in the future.

Another five aims for University of Liverpool are:

- To develop a monitoring systems for retrofitting to primary transformers to detect acoustic emissions, temperature, current, voltage and power.
- To develop a methodology to assess tap changer operations under normal network conditions and to compare these with those undertaken for CLASS conditions.
- To assess wear on contacts of the tap changer mechanism under CLASS network conditions and its impact on maintenance schedules compare this to normal network conditions.
- To assess the potential impact of CLASS network operations on the oil inside the tap changer.
- To determine the effects of CLASS operations on the transformer before and after tap changers to assess any impact on the transformer.

In this report, joint efforts are made by two universities in order to present the impacts of CLASS techniques, including the preliminary work before trial tests, the installation of transformer monitoring systems, the data analysis for CLASS trial tests, the thermal modelling of transformers and the assessment of long-term thermal impacts on the health conditions of both main tanks and tap changers.

2 Literature Review

2.1 Review of Primary Substation Transformers

Primary substation transformers, also known as system transformers [3], are applied in the distribution network to transform the voltage from 33 kV to 11 or 6.6 kV. These transformers are usually dual rated, with the lower rating corresponding to the ONAN cooling mode and the higher rating corresponding to the forced cooling mode (e.g. OFAF, ONAF or OD). Most primary transformers are classified as 'medium power transformers' in IEC 60076-7 as their three-phase ratings are in the range of 2.5-100MVA.

During the early 1960s regional electricity boards introduced the practice of operating more than one transformer in parallel at the primary substation level [3]. During that time, most primary transformers were designed according to the British Standard (BS), with typical ratings of 10/14MVA and 15/21MVA. However, in the mid-1960s a change of transformer design occurred [3]. It was after 1964 that the North West Electricity Board mainly adopted the Integrated System Transformers (IST) with typical ratings such as 11.5/23MVA and 16/32MVA [4], [5]. This type of transformer was specifically designed to meet the specific requirements of area electricity board instead of strictly following the British Standard (BS), with the intention of minimising the used materials and manufacturing costs [3], [5].

The different design philosophies of these two sets of transformers contribute to their different rating policies. As shown in Table 2-1, the large power rating of the Integrated System Transformer refers to the long-time emergency rating at the 0°C ambient temperature, while the large rating of the British Standard transformer refers to the continuous rating at 20°C. The rating is never a constant. The drop of ambient temperature and the working of cooler can somehow raise the ratings of primary transformers as shown in Table 2-1.

Table 2-1 Ratings for ONAN/OFAF primary transformers [6]

Transformer Design	Rating (MVA)		Loading Condition	Ratings (MVA)			
				20°C		0°C	
	ONAN	OFAF		ONAN	Forced	ONAN	Forced
BS	10	14	Continuous	10	14	11.25	16
			Long-Time Emergency	11	15.75	12.25	17.5
BS	15	21	Continuous	15	21	16.75	24
			Long-Time Emergency	16.75	23.75	18.50	26.5
IST	11.5	23	Continuous	11.5	18	12.75	21
			Long-Time Emergency	12.75	20.5	14	23
IST	16	32	Continuous	16	25.25	17.75	29
			Long-Time Emergency	17.75	28.5	19.5	32

(*Note: marked ratings are nameplate ratings*)

2.2 Review of Transformer's End-of-Life

The transformer end-of-life is defined by CIGRE working group A2.18 in [7] as follows:

"*The point at which a transformer should no longer remain in service because of an actual or potential failure of function which is uneconomic to repair or because it is no longer sufficiently reliable.*"

CIGRE working group A12.09 has interpreted this definition into the strategic, economic and technical end-of-lives which will be further discussed in this section.

The strategic end-of-life occurs when the transformer is unsuitable for the existing network due to its design limitation [8]. This would possibly means the transformer at a certain location is incapable of carrying the increasing power and voltage, or unable to withstand a level of short-circuit current which is expected to meet today [8]. Whatever reasons, all of these would cause potential failure of function and further reduce the system reliability.

Maintenance is a method to extend the lifetime of transformer. However, once the transformer asset manager realise it is not economic to continue the maintenance, or it is more economic to disassemble the transformer and use its component as spare part, the transformer reaches its economic end-of-life.

The actual failure undoubtedly means the technical end-of-life. However, before the failure happens, the preventive scrapping is often considered by the transformer asset manager based on the following aspects: 1) the oil test records which give the information about the thermal ageing of cellulose and oil; 2) the dissolved gases which are related to the fault history; 3) loading history based on which the temperature and the brittleness of cellulose paper can be estimated; 4) the ancillary equipment such as tap changer; 5) the records of repairs and internal inspections.

Since the aim of this project is to assess the impacts of CLASS techniques from only the technical aspect, the following sections review the literatures which are considered to be technically important by the asset manager.

2.3 Review of Transformer Thermal Ageing

Thermal ageing of insulation materials has long been an important issue in the asset management of power transformers. The insulation materials conventionally consist of oil and cellulose (mainly paper and pressboard) whose degradation with the passing of in-service time will be reviewed in the following two sections.

2.3.1 Thermal Ageing of Cellulose

Cellulose is a polymer of glucose units linked together as shown in Figure 2-1. It can be simply expressed as $[C_5H_{10}O_5]_n$, where n represents the degree of polymerisation (DP) which is the average number of glycoside rings in a cellulose macromolecule [9]. DP decreases with thermal ageing of cellulose, from around 1000 in a newly-commissioned transformer to 200, which is a widely accepted one of technical end-of-life criterions [9]–[12].

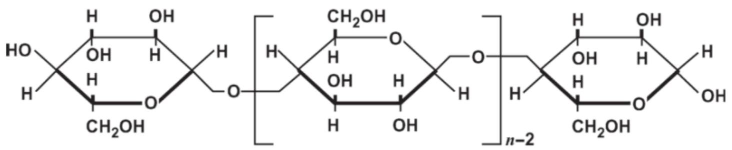

Figure 2-1 Structure of Cellulose [13]

Cellulose in the form of paper and pressboard mainly serves two purposes—electric insulation (like inter-winding and inter-turn insulation) and mechanical support (such as supporting turns and withstanding the mechanical force caused by short-circuits). The former functionality depends on the dielectric strength, and the latter depends on the mechanical strength. Since the dielectric strength does not degrade as fast as the mechanical strength, the study of cellulose ageing mainly focuses on the reduction of mechanical strength which is found to be correlated with DP reduction in paper [14].

It is commonly accepted that cellulose ageing can be described as three interwoven processes—oxidation (dominating below 60°C), hydrolysis (between 60°C and 150°C) and pyrolysis (usually dominant above 150°C) [9]. Many by-products (acids, moisture, furans, etc.) are generated and will accumulate due to those three ageing mechanisms.

Temperature is undoubtedly an influencing factor in cellulose ageing. Many researchers have made attempts to establish the relation between temperature and the ageing rate. In 1948, Thomas W. Dakin stated that the theory of chemical reaction rate can be applied to the ageing of organic material [15]. This means cellulose ageing can be modelled by the Arrhenius equation (Equation 1), where A (hour^{-1}), E_A (kJ•mol^{-1}) and T (°C) are the pre-exponential factor, activation energy and cellulose temperature respectively. R_{gas} is the gas constant which is equal to 8.3145 J•mol^{-1}•K^{-1}.

$$k = A \times e^{-\frac{E_A}{R_{gas} \times (T+273)}} \qquad \text{(Equation 1)}$$

Since then, lots of experiments under different ageing conditions have been conducted to determine the values of A and E_A. In 1994, A.M. Emsley identified that it is the pre-exponential factor A, instead of the activation energy, that is sensitive to the oxidizing nature of the environment and the susceptibility to degradation of the material [16]. This statement has been expressed as Equation 2 suggesting that the factor A of acid-catalysed hydrolysis should be a function of water (H_2O), acidity values, pKa (acid constant) and molecule weight of acids (Mr).

$$A = \text{function}(H_2O, \text{Acidity}, pKa, M_r) \qquad \text{(Equation 2)}$$

Moreover, [10] has correlated the pre-exponential factor A with moisture content by using curve fitting, which will be further introduced in section 6.1.4. In recent years, the values of E_A and A are determined based on different mechanisms of cellulose ageing. These values are summarised by CIGRE working group A2.24 in Table 2-2.

Table 2-2 Activation energy (E_A) and pre-exponential factor (A) for the hydrolysis and oxidation of cellulose paper [9]

	Reference	Oxidation	Hydrolysis	
Parameters	Dry, no oxygen	Dry, oxygen access	1.5% water in paper	3.5% water in paper
E_A (kJ/mol)	128	89	128	
A ($hour^{-1}$)	4.1×10^{10}	4.6×10^{5}	1.5×10^{11}	4.5×10^{11}

Based on the ageing rate calculated by the Arrhenius equation, the DP reduction model is finally applied to estimate the paper insulation life expectancy of transformers. The DP reduction model was developed by Ekamstam (1936) who mathematically expressed the previous results from Kuhn and co-workers in 1930 [16],

$$In\left(1-\frac{1}{DP_t}\right) - In\left(1-\frac{1}{DP_0}\right) = -kt \qquad \text{(Equation 3)}$$

Where DP_0 and DP_t are the cellulose paper's DP at the initial state and at the time t respectively. The parameter k is the ageing rate of cellulose. When DP is quite large, it is possible to simplify Equation 3 into Equation 4.

$$\frac{1}{DP_t} - \frac{1}{DP_0} = kt \qquad \text{(Equation 4)}$$

This simplified DP reduction model is used to calculate the paper insulation life expectancy based on the indirect measurement of hot-spot temperature which will be further reviewed in section 2.5.

2.3.2 Thermal Ageing of Oil

For mineral oil, oxidation is the only ageing process. It starts with the formation of peroxy radicals due to the reaction between hydrocarbon radicals and oxygen under the catalysis of the temperature and ionised metal (Fe^{2+}/ Fe^{3+}/ Cu^{2+} /Cu^{+}) [9]. The generated peroxy radical abstracts hydrogen and becomes hydroperoxide. The peroxide continues reacting with hydrocarbon radicals and produces some organic compounds (such as alcohols, aldehydes and ketones) [9]. These compounds undergo through a very complicated process and then form into carboxylic ester and acids as well as carbon dioxide (CO) [9]. Finally, a conductive material—oil sludge (not soluble in oil) can be formed through a series of processes such as the condensation reaction, polymerisation and salt formation [9].

Oil oxidation can be inhibited by adding antioxidants which stabilise radicals, reduce the production of peroxides and finally slow the accumulation of some by-products (carboxylic acids and sludge). In the UK, the uninhibited oil is widely applied to the transformer, unlike most other parts of the world where the inhibitor is added into transformer oil [3]. Therefore, the oil data analyses in section 5.1.2 do not consider oil inhibition.

The transformer oil can be replaced, purified or reclaimed during maintenance, while the cellulose insulation system cannot be treated. So the importance of oil ageing is not considered to be as important as paper ageing in [17]. This will be further explained in section 2.7.

2.3.3 Thermal Ageing Indicators

This section reviews four ageing indicators (acids, moisture, dielectric strength, and furans), all of which are the ageing by-products except the dielectric strength.

Acids are mainly produced by oxidation and hydrolysis [9]. The quantity of those acids, expressed in acidity of oil, can be measured based on milligrams of potassium hydroxide (KOH) per gram of oil sample used, by both colorimetric and automatic potentiometric titrations according to IEC 62021. Some maintenance actions are recommended for primary transformers in Table 2-3 if the measured total oil acidity values exceed certain thresholds. The intrinsic fluctuations have been identified as acidity drops (<0.05 mgKOH/g) in the growth trend of acidity versus age in [4]. These fluctuations could be attributed to either the inaccuracy of acidity measurement in IEC 62021, or the acidity partitioning between paper and oil in [18], [19].

The acid is also the catalyst of cellulose hydrolysis [9]. Its catalytic effects can be enhanced with the presence of moisture [19]. The moisture, as another ageing by-product, is produced by oxidation, hydrolysis and pyrolysis. The quantity of water dissolved in oil is measured as the milligrams of water per gram of oil according to IEC 60814. Table 2-3 classifies those measured moistures into three categories (“good”, “fair” and “poor”), based on which the asset manager could take maintenance actions. According to IEC 60422, the moisture content in cellulose is more stable than that in oil, as a small change of temperature can largely affect the moisture content of oil but slightly change that of cellulose [20]. In this case, the measured moisture contents would have some fluctuations as shown in [21]–[23]. For a newly-made transformer, the paper moisture content is less than 0.5-1% [20]. Every time moisture content in paper increases by 0.5%, the DP of cellulose paper will be halved [24], [25].

The dielectric strength, also named as breakdown voltage, is measured to show the capability of oil to withstand the voltage stress [26]. There are also three categories (>40kV, 30~40kV, <30kV) for dielectric strength, with the maintenance action recommended in each category in Table 2-3. The dielectric strength could be largely reduced in the presence of moisture according to IEC 60422. This means that the fluctuation of the water dissolved in oil could correspondingly cause the fluctuation of dielectric strength. Hence, the maintenance decision based on the measured moisture content would not always be the right choice.

Another ageing indicator is furan which refers to a group of compounds formed by cellulose ageing. One of furan compounds—furfural (2-FAL) can be used as an indication of paper ageing as it is much correlated with DP [27], [28]. The concentration of furans at the point of measurement depends on many factors such as the partitioning of furans between paper and oil, degradation of some furan compounds, etc. [29]. Those factors are likely to contribute to the variations of furan compounds.

Table 2-3 Categories of ageing indicators in oil for 33/11(or 6.6) kV transformers [20]

Categories	Good	Fair	Poor
Moisture content (ppm)	<30	30~40	>40
Dielectric strength (kV)	>40	30~40	<30
Acidity (mgKOH/g)	<0.15	0.15~0.30	>0.30

Good	Continue the oil sampling at normal frequency.
Fair	Require more frequent sampling.
Poor	Schedule effective maintenance actions.

2.4 Review of Dissolved Gas Analysis

Gases are formed by the decomposition of oil and cellulose as well as some other chemical reactions such as rusting [30]. The decomposition of oil starts with the scission of C-H and C-C bonds due to electrical and thermal faults [30]. This reaction generates small unstable fragments such as C^*, CH^*,

CH_2^* and CH_3^* [30]. These active chemicals, in either radical or ironic form, then undergo a series of complicated reactions and finally form into gas molecules such as hydrogen (H_2 / H-H), methane (CH_4 / CH_3-H), ethane (C_2H_6 / CH3-CH3), ethylene (C_2H_4 / CH_2=CH_2) or acetylene (C_2H_2 / CH≡CH) [30].
As shown in Table 2-4 the scission energy varies for different bonds, therefore, the formation of different fault gases requires different energies at different preferred temperatures. Based on these differences, a list of typical faults is related with their key gases in Table 2-5.

Table 2-4 Energies of different chemical bonds [30]

Bond Structure	C-H	C-C	C=C	C≡C
Bond Type	Single	Single	Double	Triple
Energy (kJ/mol)	338	607	720	960

Table 2-5 Key gases generated by typical faults [30], [31]

Key Gases	Characteristic Fault	Examples
H_2	Partial Discharge	Discharges in gas-filled cavities
C_2H_6	Thermal Fault <300°C	Overloading of transformer; broken item strict oil flow in winding; stray flux
C_2H_4	Thermal Fault 300°C~700°C	Defective contacts between bolted connections; circulating currents between yoke clamps and bolts, etc.
C_2H_2, C_2H_4	Thermal Fault >700°C	Large circulating current in tank and core; short links in laminations
C_2H_2, H_2	Discharge of Energy	Sparking or arcing, flashover, short-circuits, etc.

Besides these hydrocarbon gases in Table 2-5, both carbon monoxide and dioxide (CO and CO_2) are also important, as they are related to the decomposition of cellulose [30]. Since the C-O bond in cellulose is thermally less stable than the C-H bond in oil, the cellulose chains starts to be cut at a temperature above 105°C and will be completely decomposed at just above 300°C [30]. In this way, the majority of CO and CO_2 are formed during the process of cellulose decomposition.

Gases might be generated in some other ways other than faults, such as the reaction of steel with water, the exposure of oil to sunlight, and even equipment repair [30]. The formation of some of these gases from the mineral oil at relatively low temperature (90~200°C) is defined as 'thermal stray gassing of oil' in [32]. An experiment is done to prove the existence of stray gassing by heating three syringes of oil for over 164 hours at 120°C. The result shows that the main gas produced is hydrogen followed by methane [32]. For an in-service transformer, stray gassing in general will not affect the fault diagnosis of the dissolved gases unless the transformer is largely overloaded for a long time or the oil tends to gas under heat [32].

The range of 90% typical gas values is provided by IEC 60599 in Table 2-6. Once the gas is below the typical value in Table 2-6, the relevant faults related to this kind of gas need not to be considered.

Table 2-6 Range of 90% typical gas values (in ppm) observed in the main tanks of power transformers [30]

	C_2H_2	H_2	CH_4	C_2H_4	C_2H_6	CO	CO_2
Transformers with no OLTC	2-20	50-150	30-130	60-280	20-90	400-600	3800-14000
Transformers communicating OLTC	60-280	50-150	30-130	60-280	20-90	400-600	3800-14000

(*Note: OLTC refers to on-load tap changer*)

2.5 Review of Hot-spot Temperature Determination

This section reviews the determination of hot-spot temperature which can be measured by both direct and indirect means. The direct measurement can be achieved by using a fibre optic system. However, this system is quite expensive and is also vulnerable to physical damage [9]. Moreover, it is impractical to imbed the optical sensors between two conductors in an in-service transformer. Therefore, it is necessary to find a method to estimate the hot-spot temperature in the transformer winding. The following part of this section introduces a method based on the thermal diagram and thermal model.

- Thermal Diagram

The calculation of the hot-spot temperature, proposed by both IEC [33] and IEEE [34] standards, is mainly based on the temperature distribution in the transformer tank. This distribution is simplified in Figure 2-2 based on the following assumptions:

1. The oil temperature in the transformer tank linearly increases from the bottom to the top of the winding, regardless of the transformer cooling mode.

2. The winding temperature also linearly increases from the bottom to the top of the winding regardless of the cooling mode. In addition, it is assumed that winding temperature always exceeds the oil temperature at the same horizontal position by a certain constant named as the average-winding-to-average-oil temperature gradient at rated current (g_r).

3. Hot-spot temperature (θ_h) is higher than the top-winding temperature. At rated current, the hot-spot to top-oil gradient ($\Delta\theta_{hr}$) can be expressed as the hot-spot factor (HSF) multiplied by the average-winding-to-average-oil temperature gradient at rated current (g_r) in Equation 5.

$$\Delta\theta_{hr} = g_r \times HSF \qquad \text{(Equation 5)}$$

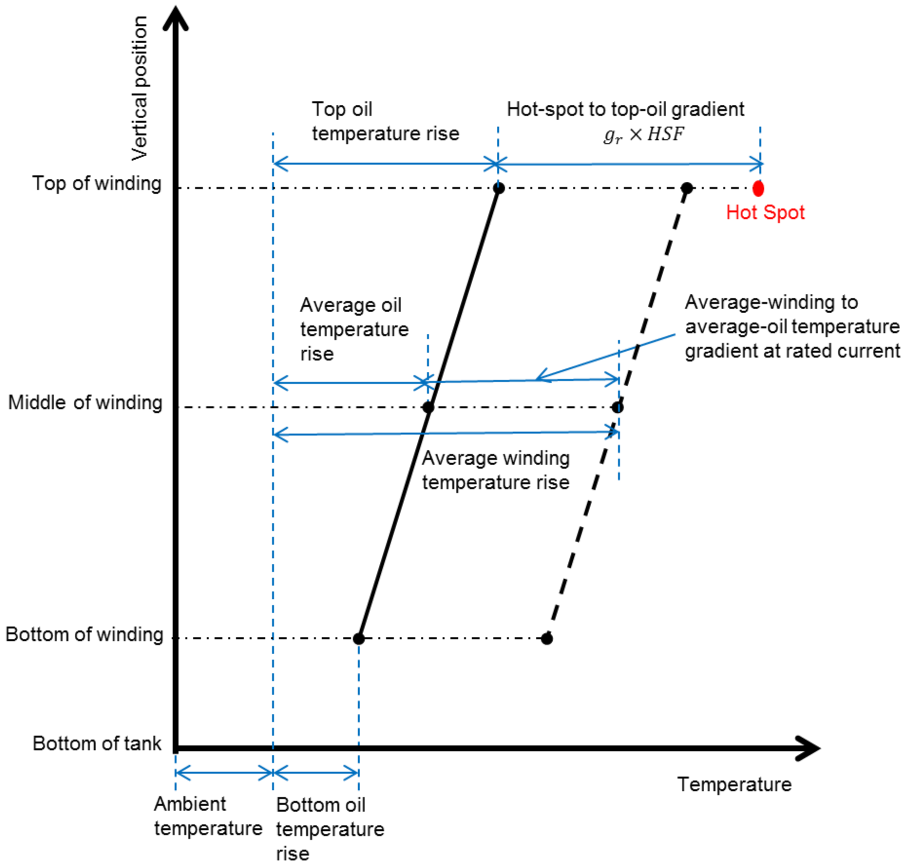

Figure 2-2 Transformer thermal diagram adapted from IEC 60076-7 [33]

- Thermal Model

Based on the thermal diagram, the hot-spot temperature is then modelled using the difference equations (Equation 6 to Equation 11). This calculation uses the results of routine and heat-run tests as follows,

R	Ratio of full load losses at rated current to no-load losses from routine test
$\Delta\theta_{or}$	Top-oil temperature rise at rated losses (no-load losses + load losses) from heat-run test
g_r	Average-winding-to-average-oil temperature gradient at rated current from heat-run test

The calculation of top-oil temperature (θ_o) is calculated by Equation 6 and Equation 7, with the inputs of per unit load (K) and ambient temperature (θ_a).

$$D\theta_o = \frac{Dt}{k_{11}\tau_o} \times \left\{ \left[\frac{1+K^2R}{1+R}\right]^x \times \Delta\theta_{or} - (\theta_o - \theta_a) \right\} \quad \text{(Equation 6)}$$

$$\theta_{O(n)} = \theta_{O(n-1)} + D\theta_{O(n)} \quad \text{(Equation 7)}$$

The hot-spot-to-top-oil gradient is separated into two components $\Delta\theta_{h1(n)}$ and $\Delta\theta_{h2(n)}$ in Equation 8, with their increase calculations expressed in Equation 9 and Equation 10.

$$\Delta\theta_{h(n)} = \Delta\theta_{h1(n)} - \Delta\theta_{h2(n)} \quad \text{(Equation 8)}$$

$$D\Delta\theta_{h1} = \frac{Dt}{k_{22}\tau_w} \times [k_{21} \times \Delta\theta_{hr}K^y - \Delta\theta_{h1}] \quad \text{(Equation 9)}$$

$$D\Delta\theta_{h2} = \frac{Dt}{(1/k_{22})\tau_o} \times [(k_{21} - 1) \times \Delta\theta_{hr}K^y - \Delta\theta_{h2}] \quad \text{(Equation 10)}$$

Finally, Equation 11 calculates the hot-spot temperature based on the results of previous calculations.

$$\theta_{h(n)} = \theta_{o(n)} + \Delta\theta_{h(n)} \quad \text{(Equation 11)}$$

The calculation of hot-spot temperature requires the measurement of thermal parameters which might not be suitable for some in-service transformers. In view of this, the IEC standard [33] has provided some empirical values in Table 2-7 for power transformers with a three-phase rating over 2.5 MVA. For dual-rated primary transformer, the state of cooler cannot be neglected in selecting thermal parameters in Table 2-7, since the shift of cooling mode can change the their values.

Table 2-7 Recommended values for parameters in the thermal model [33]

Thermal Parameters		Power transformers			
		ONAN	ONAF	OF	OD
Oil exponent	x	0.8	0.8	1.0	1.0
Winding exponent	y	1.3	1.3	1.3	2.0
Loss ratio	R	6	6	6	6
Hot-spot factor	HSF	1.3	1.3	1.3	1.3
Oil time constant	ζ_o	210	150	90	90
Winding time constant	ζ_w	10	7	7	7
Ambient temperature	θ_a	20	20	20	20
Hot-spot to top-oil temperature gradient at rated current	$\Delta\theta_{hr}$	26	26	22	29
Top-oil temperature rise	$\Delta\theta_{or}$	52	52	56	49
Average oil temperature rise	$\Delta\theta_{omr}$	43	43	46	46
Thermal coefficient	k_{11}	0.5	0.5	1.0	1.0
Thermal coefficient	k_{21}	2.0	2.0	1.3	1.0
Thermal coefficient	k_{22}	2.0	2.0	1.0	1.0

The thermal parameters in Table 2-7 satisfy the latest temperature rise limits in 2011, but may not meet the requirement of previous standards as shown in Table 2-8. As an example, the 52°C top-oil temperature rise for power transformer operating at ONAN mode is lower than the limit of the 60°C top-oil temperature in 2011 but higher than the 50°C limit set in 1959. In this case, the application of the latest thermal parameters in Table 2-7 to the transformer designed in the early times would cause the overestimation of hot-spot temperature as well as ageing rate. However, considering the lack of heat-run test results for the old transformer, such overestimation would not be a bad choice, i.e. at least it can give us some conservative results about transformer ageing.

Table 2-8 British standards for temperature rise limits for oil-immersed transformers [35]

British Standard in Year	Top-oil Temperature Rise (°C)		Average Winding Temperature Rise (°C)		
1959	50 (ALL)		60 (ON)	65(OF)	70(OFW)
1970	55*	60†	65 (ON)	65(OF)	----
1978	55*	60†	65 (ON)	65(OF)	70(OD)
1997	60		65 (ON)	65(OF)	70(OD)
2011	60		65 (ON)	65(OF)	70(OD)

(*Note: †transformer is equipped with conservator or sealed; *transformer is neither equipped with conservator nor sealed.)*

2.6 Review of Tap Changer

A tap changer is normally fitted to power transformers allowing the regulation of the output voltage to be controlled to the required specifications. The tap changer allows different windings in the transformer to be connected, allowing the output voltage to remain stable largely independent of the load. Tap changers come in two main categories being either off-load or on-load variants.

2.6.1 Off-Load Tap Changer

Off-load tap changers are mainly used in low voltage, low power applications where the connection between the taps can either be made manually or by the use of a suitable rotary switch. As each of the tapping points are at different potentials, there must always be a break in the circuit before the next connection is made, otherwise a short circuit would occur in the windings of the transformer producing massive circulating currents. As previously mentioned due to the design of the tap changer a break in the load current is experienced during the tap change making the design more suitable for use in the primary side of a high voltage transformer where the tap is only set once during commissioning.

2.6.2 On-Load Tap Changer

In many applications a break in the supply would be unacceptable each time a tap change occurs meaning that an on-load tap changer is fitted [36]. This type of tap changer can be classified as mechanical, electronically assisted (Thyristor-assisted tap changers) or fully electronic (Solid state (thyristor) tap changers). During the course of this report we only deal with the mechanical tap changer.

In the mechanical tap changer the new connection is made before the previous connection is released, but the problems with circulating currents described in the off-load tap changer are overcome by a diverter switch placing a large impedance in series with the short circuited windings. The process of the tap must be completed quickly to avoid problems with the diverter resistor overheating; this is achieved by using a low power motor to tension the springs of the diverter switch. During the switching process some arcing is unavoidable with both the tap changer oil and switch contacts slowly deteriorating with use. Both the tap selector switches and the diverter switches are located in a separate oil tank from the main transformer tank, which also allows easier maintenance of the tap changer.

Taking a specific case of tap changer as fitted in Longsight T11 a Ferranti DS2 tap changer which is a high speed resistor transition type, designed for continuous operation, a schematic of which is shown in Figure 2-3. The tap changers are designed to bolt directly onto the transformer tank, providing a maximum of 16 tapping steps 17 tap positions. These tap changers have combined diverters and selectors housed in a single compartment, with the motor drive and timing gear being provided in a separate compartment on the front. The two compartments being sealed from each other and independently oil filled having their own drain and filler points keeping the inspection and maintenance costs to a minimum. The front housing contains the single phase driving motor, the operation of which is initiated by means of push buttons or directly from contacts of the voltage control relay, the drive is taken by the chain through a reduction mechanism to charge the stored energy device, which ensures that the tap change switch cannot stop between taps should the supply to the motor drive fail. On release the device drives a Geneva mechanism, coupled through into the rear compartment to drive an insulated gear train and the selector switch assemblies. The front compartment also contains the timing, sequencing and motor control on printed control boards and is mechanically coupled to the drive system ensuring correct indexing and control over the complete tapping range. Both the tap position indicator and operations counter are visible through a sight glass in the front of the housing, with the timing equipment being a printed circuit board operating with plunger contact connection boards [37].

The failure modes for tap changers are a result of mainly mechanical defects which result in the worst case scenario of the mechanism failing to complete a tap changer resulting in excessive power dissipation into the diverter resistors and subsequent heating of the surrounding oil. This may be accompanied by internal arcing resulting in the dissociation of the oil. Both may lead to over pressurisation, rupture of the enclosure and an oil fire and loss of the tap changer and transformer. However, other failure modes are related to the contacts where a thin film coats the contacts which increases the resistance between the contacts. This coating develops more often when a tap changer is used infrequently used. This can lead to discharge activity which dissociates the oil and can cause greater heating at the surface of the contacts. As the formation of these thin films increases at higher temperatures such a situation could lead to thermal run away and greater wear of the contacts which may lead to the eventual premature failure of the tap changer. Frequent operation of the tap change does prevent the build up of these thin films by providing a disrupting wiping action. A larger load current also increase local heating of the contact and so too does low forces between the contacts which results in a higher resistance.

The main issues for the tap changers in this report is whether the operations they are required to perform add an extra burden outside of their normal envelope of operation. As such monitoring during the various tests has been performed to determine the response of the tap changers and the transformers compare to normal operations. From this main aspects of possible failure are identified and what is the likely impact on maintenance schedules.

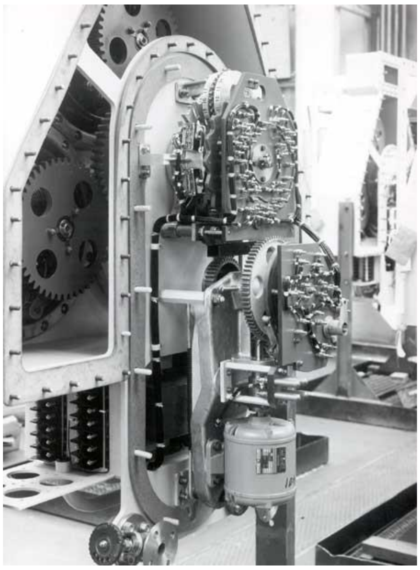

Figure 2-3 Ferranti DS2 tap changer internal view

2.7 Review of Health Index Calculation

The transformer health index (HI) adopted by Electricity North West Limited consists of an individual transformer main tank health index and tap a changer health index which will be reviewed separately in the following two sections. In general, the health index is a continuous value and ranges from HI=0 to HI=10. A value of HI=7 is considered as the end-of-life criteria.

2.7.1 Health Index Calculation for Main Tank

As shown in Figure 2-4, the calculation of the transformer main tank health index starts with the calculation of the transformer initial health index (HI(1)) and health indices for oil test results (including the dissolved gases (HI(2a)) and the oil and paper ageing indicators (HI(2b) & HI(2c)). These four health indices are subsequently combined to form a single 'main tank' health index which is then adjusted upon consideration of the transformers main tank external condition, fault history and general reliability. Some details of this process will be introduced in the following parts of this section.

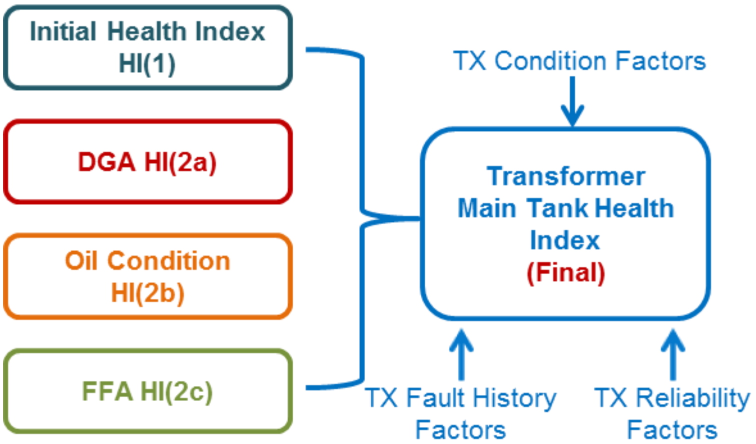

Figure 2-4 Health index calculation methodology for transformer main tank [17]

I. Initial Health Index

The initial health index is calculated based on Equation 12, where the initial health index (HI_{t0}) is constant. Therefore, the increasing rate of initial health index is determined by the age which is based on the transformers year of manufacture, and the ageing constant B which is a function of the modified expected life in Equation 13. The modified expected life only equals to the 70-year expected life when a transformer operates in an ideal environment and is lightly load. Therefore, for transformers operating in non-ideal environments and/or experience higher load levels the life can be modified based on the factors of environment and load duty as shown in Equation 14.

$$HI_{initial} = f(HI_{t0}, B, Age) \qquad \text{(Equation 12)}$$

$$B = f(modified\ expected\ life) \qquad \text{(Equation 13)}$$

$$modified\ expected\ life = f(load\ duty\ factor, environmental\ factor) \qquad \text{(Equation 14)}$$

The growth of health index reflects the ageing of a transformer. Usually, an index of seven (HI=7) means the transformer is so aged that the operator would risk in running this transformer. In this case, the replacement should be taken into consideration. The initial health index, however, can never spontaneously increase up to 7 as it is capped at a value HI_{cap} less than 7. This means that however poor the environment and the load are the transformer can also continue its service if the oil test results and external condition do not indicate any problems. However, once the initial health index reaches HI_{cap}, more frequent oil sampling and testing is needed. The following section will focus on the health indices for oil test results.

II. Health Indices for Oil Test Results

The health indices for oil data are also taken into consideration. As shown in Figure 2-5, the oil test results are classified into three groups: 1) dissolved gases 2) ageing indicators and 3) 2-FAL. Dissolved gasses such as hydrogen and hydrocarbons can indicate the type and severity of different electrical and thermal faults. The ageing indicators such as breakdown voltage (BD or dielectric strength), moisture and acidity indicate the oil condition. Finally, 2-FAL indicates the ageing status of the paper insulation.

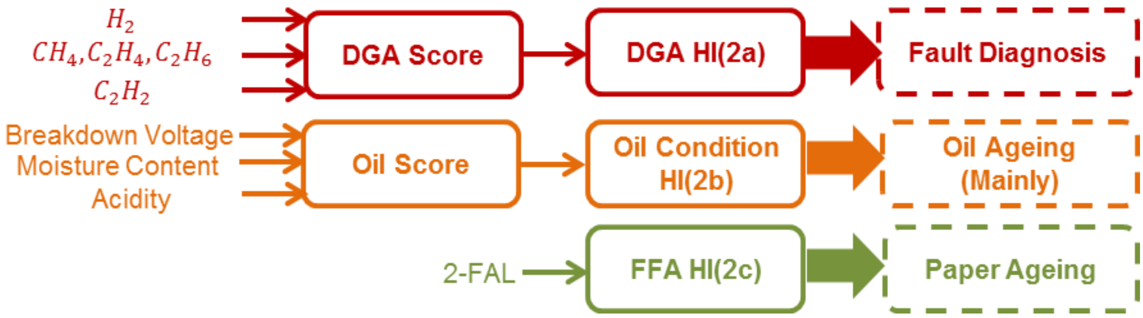

Figure 2-5 Health index calculation for oil test results [17]

The scoring procedure has set some baselines to dissolved gases as shown in Table 2-9. For each gas below the baseline, the score is set to zero, thus making no contribution to the final score and health index.

Table 2-9 Baselines for dissolved gases [17]

Dissolved Gases				
H_2 (ppm)	CH_4 (ppm)	C_2H_4 (ppm)	C_2H_6 (ppm)	C_2H_2 (ppm)
20	10	10	10	1

The scoring procedure for hydrocarbon gases based on values in Table 2-9 is more conservative than that based on IEC 60599 in Table 2-6, as the baseline for each gas in Table 2-9 is lower than the lower bound of the range for the corresponding gas in Table 2-6.

Different health indices have different importance. In [17], the indices for dissolved gases and 2-FAL range from 0 to10 while the oil condition health index is capped at a value less than 10. This implies that oil ageing is not as critical as the presence of a fault and/or paper ageing and reflects the fact that oil can be treated by conducting maintenance.

III. Combination and Modification of Health Indices

The process for combining the health firstly considers the initial health index. If this index HI(1) is the largest out of all the health indices, the combined health index is the initial health index modified by the factors based on the magnitude of the oil test health indices. If not, the initial health index is neglected and the combined value is based on the two largest oil health indices.

In the final stage, some external modifiers are applied to adjust the combined health indices based on the transformer fault history, reliability (with respect to the transformer design and manufacturer), and the main tank external condition (e.g. corrosion of main tank and radiators, oil leaks, etc.).

The interpretation of the final health index is necessary. If it is less than 7, the years taken to reach 7 is calculated based on the existing ageing constant B, as expressed in Equation 15.

$$Years\ to\ replacement = f(HI_{final}, B) \qquad \text{(Equation 15)}$$

2.7.2 Health Index Calculation for Tap Changer

Similar to the calculation methodology for the transformer main tank, the initial health index for the tap changer is also calculated based on the exponential model in Equations 12 and 13. The difference lies in the determination of the modified expected life in Equation 16 which considers the tap changer duty factor (average number of taps per day) instead of the load duty factor in Equation 14.

$$modified\ expected\ life = f(TC\ Duty\ factor, environmental\ factor) \quad \text{(Equation 16)}$$

The oil test results of the tap changer tank are not taken into consideration in the calculation of tap changer health index. So the initial tap changer only needs to be adjusted upon consideration of the tap changer external condition (such as oil leaks and corrosion of tap changer tank), operability related to tap changer types, the fault history and the reliability as shown in Figure 2-6.

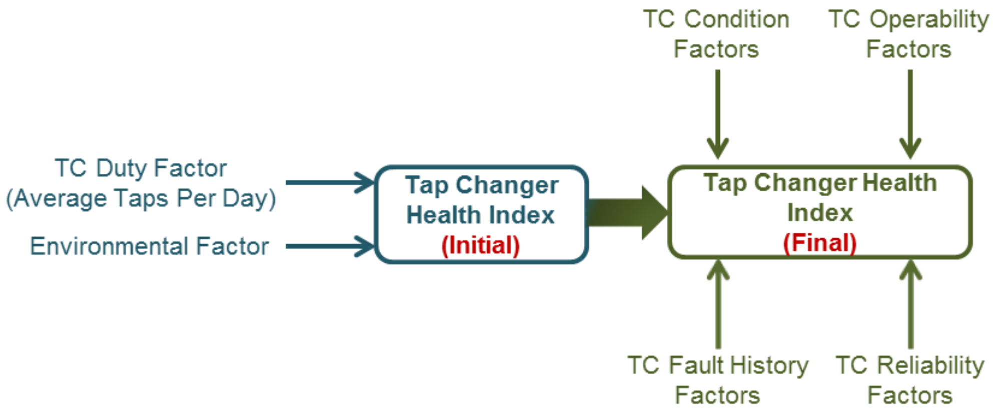

Figure 2-6 Health index calculation methodology for tap changer [17]

The initial health index for tap changer is also capped at HI_{cap}. Therefore, the decision of tap changer replacement when HI=7 is finally determined by the factors of external condition, operability, fault history and reliability. For HI<7, the time taken to reach the end-of-life is calculated in the same way as in Equation 15.

3 Preliminary Work of CLASS Trial Tests

3.1 Analysis of CLASS Techniques

The preliminary work initially focuses on the analysis of CLASS techniques. Table 3-1 summarises the analysis of four trials based on the assumption that the load demand is at unity or lagging power factor and the reduced demand is larger than the increased losses.

Table 3-1 Review of CLASS techniques

Reference	Description	Objective	Technique	Substation Number	Relevant to Asset Health Assessment
Trial 1	Load modelling	Establish voltage-demand relationship	Raise and lower tap positions	15	----
Trial 2	Peak demand reduction	Demand response for peak reduction	Lower tap position	14	Relevant to TC, not to TX
Trial 3a	Stage 1 frequency response	Response to reduce demand when system frequency falls	Switch out transformer	10	Relevant to TX and possibly TC
Trial 3b	Stage 2 frequency response		Lower tap position	All	Relevant to TC, not to TX
Trial 4	Reactive power absorption	Reduce high volts on transmission network	Stagger tap position	All	Relevant to both TX and TC

(*Note: TX means transformer and TC means tap changer in short*)

Trial 1 aims to establish the voltage-load relationship by raising and lowering tap positions on transformers at 15 substations, in order to develop accurate load models for different types of loads. Since the transformer operation in this trial is not applied to future operational modes, tests in Trial 1 will not be studied in this report.

Both Trial 2 and Trial 3b can reduce the demand by lowering the voltage; however, they serve different purposes. Trial 2 is only implemented on transformers at 14 substations in order to reduce the peak load demand, while Trial 3b aims to provide frequency response through demand reduction at any site which detects the low frequency of 49.8 Hz or the instruction from the TSO. Since the voltage reduction is only realised by lowering the tap, these two trials are only relevant to the tap changer.

Trial 3a also provides frequency response by reducing the voltage. However, differing from Trial 3b, it trips one transformer at the substation (which has two transformers operating in parallel) and shifts the load onto a parallel transformer. The load shift increases the current through the only transformer in operation, and raises the impedance of the supply point when the other parallel impedance is disconnected. The increase of both current and impedance across the primary supply point increases the voltage drop and further reduces the voltage on the secondary side of the transformer. In this way, the load demand can be reduced and the frequency can be raised.

The current of the transformer in operation might be doubled after the trip. This higher current can increase the winding temperature which can further accelerate the ageing of the transformer main tank insulation system. Moreover, if the tap position changes during the time of tripping, the on-load tap changer could have extra contact wear due to higher energy discharge caused by higher current above the nominal value. Therefore, the Trial 3a would have a thermal impact on the health condition of both main tank and tap changer which could be further reflected in the oil condition data.

In Trial 4 tests, one transformer is kept in a high tap position while the other parallel transformer stays in a low tap position. The circulating current will be generated in the offset tap positions which can absorb the excessive reactive power in the network. In this way, this operation can be applied to manage the unacceptable high voltages when high distribution generation coincides with the low local demand.

Trial 4 will undoubtedly affect the tap changer health. Besides, its possible impact on the transformer's health is also worth investigation, as the additional circulating current will increase the current in one of the parallel transformers and further increase temperature in the transformer, placing its insulation materials under much more thermal stress.

In conclusion, there are three trials (Trial 2, 3 and 4) relevant to future operational scenarios. Among those trials, only Trial 3a and Trial 4 are expected to have large thermal impacts on the health condition of transformers. In addition, Trials 2-4 are relevant to the health condition of tap changer.

3.2 Analysis of Trial Transformers

There are 120 trial transformers selected by Electricity North West Limited from over 700 primary transformers for trial tests. In this section, the representativeness of those trial transformers is checked by comparing them with all the transformers in the population.

The check starts with the comparison of transformer age. As shown in Figure 3-1, the similarity of age indicates the similar health conditions of the two transformer groups. In order to confirm this, the following comparison focuses on the combined health index which is based on age, load duty, tap changer operability, transformer, tap changer conditions, etc.

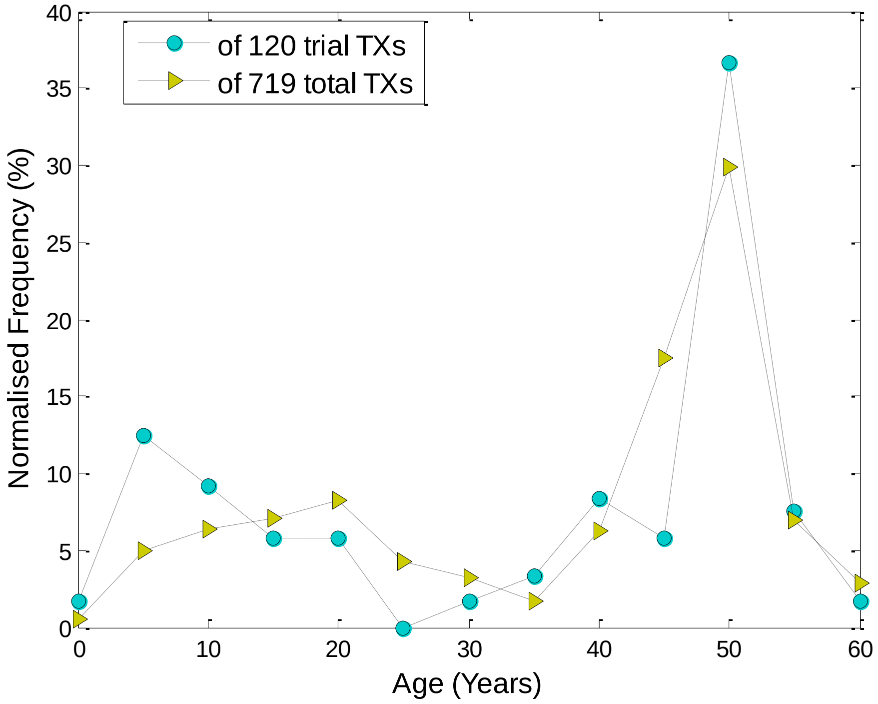

Figure 3-1 Comparison of age distributions of transformers in trial and database

Figure 3-2 makes this comparison and finds a similar distribution of combined health index in the two transformer groups. This similarity in Figure 3-2 double confirms the representativeness of the selected transformers and can further help to enhance the confidence in the results and conclusions in the following parts of this report.

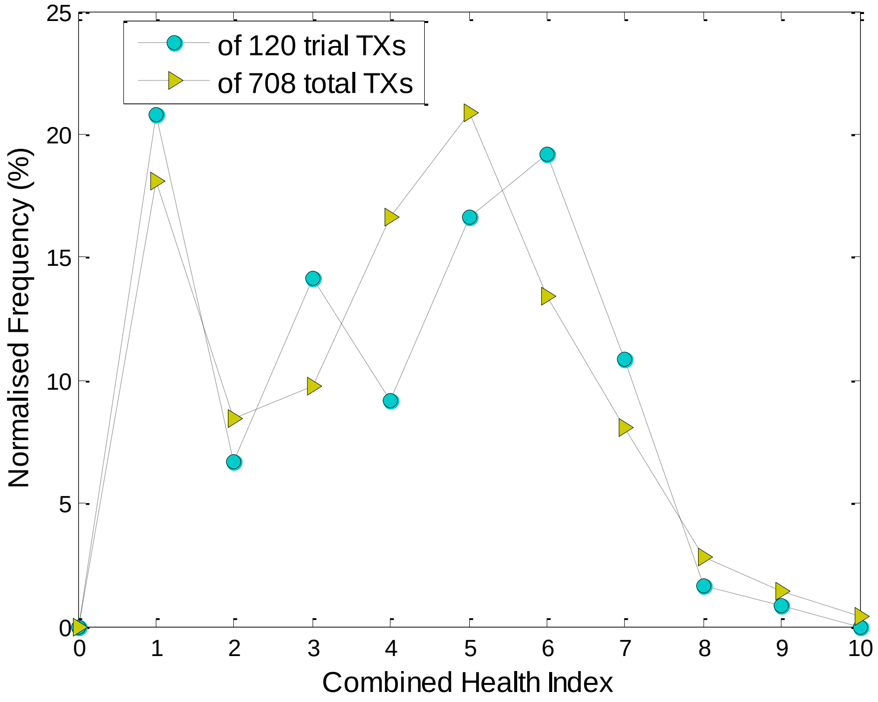

Figure 3-2 Comparison of the distributions of combined health indices of transformers in trial and database

3.3 Trial Suggestions

3.3.1 Data to Monitor

The trial analysis identifies the electrical, chemical, thermal effects of trial tests. Hence, the measurement should be taken in those three aspects.

- Electrical Measurement

Load information such as current, voltage, active and reactive power will be measured for every minute for every transformer under all the trial tests. The installation of load-monitoring devices was done by Nortech Company before the 1st of May, 2014.

- Chemical Measurement

Transformer oil should be sampled before and after Trial 3a and Trial 4 level 6 (with the largest tap position difference). Moreover, tap changer oil for three substations (Romiley, Longsight, Irlam) should be also sampled before and after Trial 4 level 6. It is also important to measure the transformer oil temperature at the time of taking oil sample, as suggested by [38].

- Thermal Measurement

The oil temperature should be indirectly measured by attaching the sensors to some transformer tanks. This work has already been completed by University of Liverpool in the following Chapter 4.

In addition, the acoustic data will be measured by the monitoring devices which are installed by University of Liverpool, in order to detect the mechanical behaviour of both the transformer main tank and tap changer.

3.3.2 Substation Selection

This section determines some substations whose transformer oil will be sampled according to the specification of chemical measurement above, and also selects three transformers where the monitoring systems will be installed.

According to the trial analysis, only Trial 3a and Trial 4 are expected to have large impacts on the transformer health condition. Hence, the substation selection for transformer oil sampling only considers the substations under those two trials. Ten substations under Trial 3a are firstly proposed for oil sampling. Then substations with top ten largest transformer health indices are selected from the remaining 50 substations. Those selected twenty substations are proposed in Appendix A for oil sampling before and after Trial 3a and Trial 4 level 6.

Three transformers need to be selected for the installation of transformer monitoring system by the University of Liverpool. The selection mainly depends on the trial participation. As shown in Table 3-1, all the trial substations participate in Trial 3b and Trial 4. Therefore, the selection for the three transformers only needs to focus on the other three trials in Table 3-1—Trial 1, Trial 2 and Trial 3a. The substations under at least two of these trials are shown in the participation Table 11-2 in Appendix B. Based on Table 11-2, five transformers are proposed in Table 3-2. These transformers can generally characterise all the old transformers in the database, since they are commissioned before 1980 and produced by three typical transformer manufacturers—FERRANTI, ENGLISH ELECTRIC and AEI.

Table 3-2 Proposed transformers for sensor installation

Substation	TX	Commission Date	TX Manufacturer	TC Type	Load Duty	Trial
LONGSIGHT	T11	01/10/1967	EE	DS2	120%	2,3a,3b,4
ROMILEY	T11	01/01/1964	FERRANTI	DC3	81%	1,2,3a,3b,4
IRLAM	T12	01/10/1963	AEI	M21AX4T	107%	2,3a,3b,4
BAGULEY	T11	01/09/1965	FERRANTI	DS2	87%	2,3a,3b,4
DICKINSON ST	T13	01/03/1970	AEI	3S21	77%	1,2,3b,4

(*Note: Commission date for IRLAM T12 is based on manufacture date*)

Romiley T11 is the preferred choice, since Romiley is the only substation participating in all the trials and T11 has larger TX health index than T12. Longsight T11 and Irlam T12 are also selected partly due to their large (over 100%) load duty (which is the demand as a percentage of firm capacity in a substation). The oil of these three transformers should also be sampled before and after Trial 3a and Trial 4 level 6.

4 Installation of Transformer Monitoring Systems

4.1 Introduction and Principle of Operation

A self-contained acoustic monitoring system with optical fibre acoustic sensors has been developed to be deployed at three distribution substations to enable the monitoring of tap changes; external temperature variations and power supply regulation and quality. The unit is designed to be self-contained stand alone, only requiring a 240V single phase supply, with a built in communication platform enabling remote configuration of operating parameters and remote collection of data for off line analysis. The unit is designed to operate intrinsically because the light never leaves the optical fibre sensor making it insensitive to dust and other environmental considerations. The sensing element is distributed because it can be operated anywhere along the length of the sensing element, which can range up to 10m. Finally, as it is optically based, the system is insensitive to ambient fields being both electrical and magnetic, the light being guided through the optical fibre and the light path being modulated by the micro bending of the fibre produced by acoustic vibrations.

4.2 System Development

Following some initial prototype principle trials, an industrialised system was developed which had the following functionality. The system required full remote access to minimise the amount of site access required and to allow software system upgrades to be performed remotely as they became available. Following a number of initial discussions it was decided to integrate a commercial communications system developed by Nortech into the package. A ‘system healthy’ pulse was to be reported back to the operator’s office in real time alerting operators when any problems occur. With the system being a research development prototype a large amount of onboard data storage was allocated to allow all the data to be archived on site for subsequent retrieval, removal and post processing analysis as required. A number of local indicators were included for Laser Active; System Healthy; Computer Power and Hard Disk activity, allowing easy on site diagnostics. The system also needed to be made weatherproof as the unit is mounted externally next to the transformer bund, yet still have a ventilation system allowing any internal heat build up to be dispersed. The unit was also designed to accept inputs from three external temperature sensors being based around the self-adhesive PT100 sensor. The system was split into three enclosures as shown in Figure 4-1, with the first enclosure containing the communications and data gathering function; the second containing the acoustic sensor electronics and processing; and the third smaller unit containing the PQube unit.

Figure 4-1 System Enclosures

4.3 System Installations

Three separate systems were built and commissioned, with the following showing a typical installation. Figure 4-2 shows the installation of the sensing fibre on a Ferranti DS2 tap-changer, the fibre is fixed to the outside of the transformer using self-adhesive flashing tape, meaning no service outages are required and all the work can be completed on a live transformer.

Once the sensing fibre is installed the feeder fibres are then routed back to the control enclosure, being encased in a black flexible conduit making them more robust, before being buried in the bund floor, as shown in Figure 4-3.

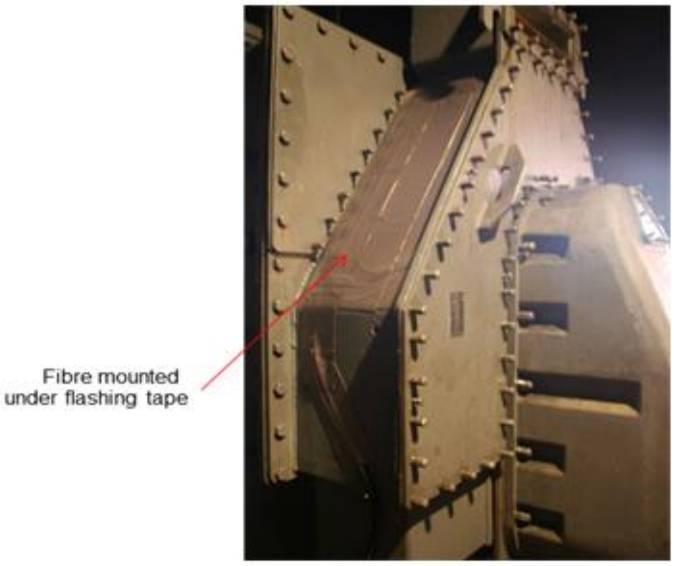

Figure 4-2 Sensing fibre installation

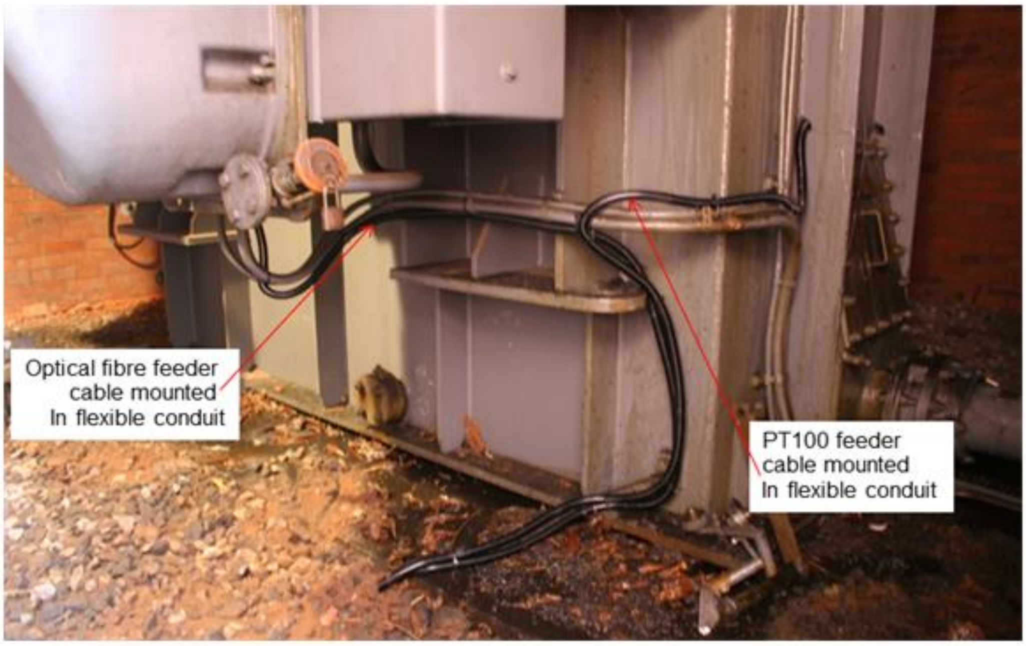

Figure 4-3 Routing of the optical fibre feeder and PT100 flexible trunking

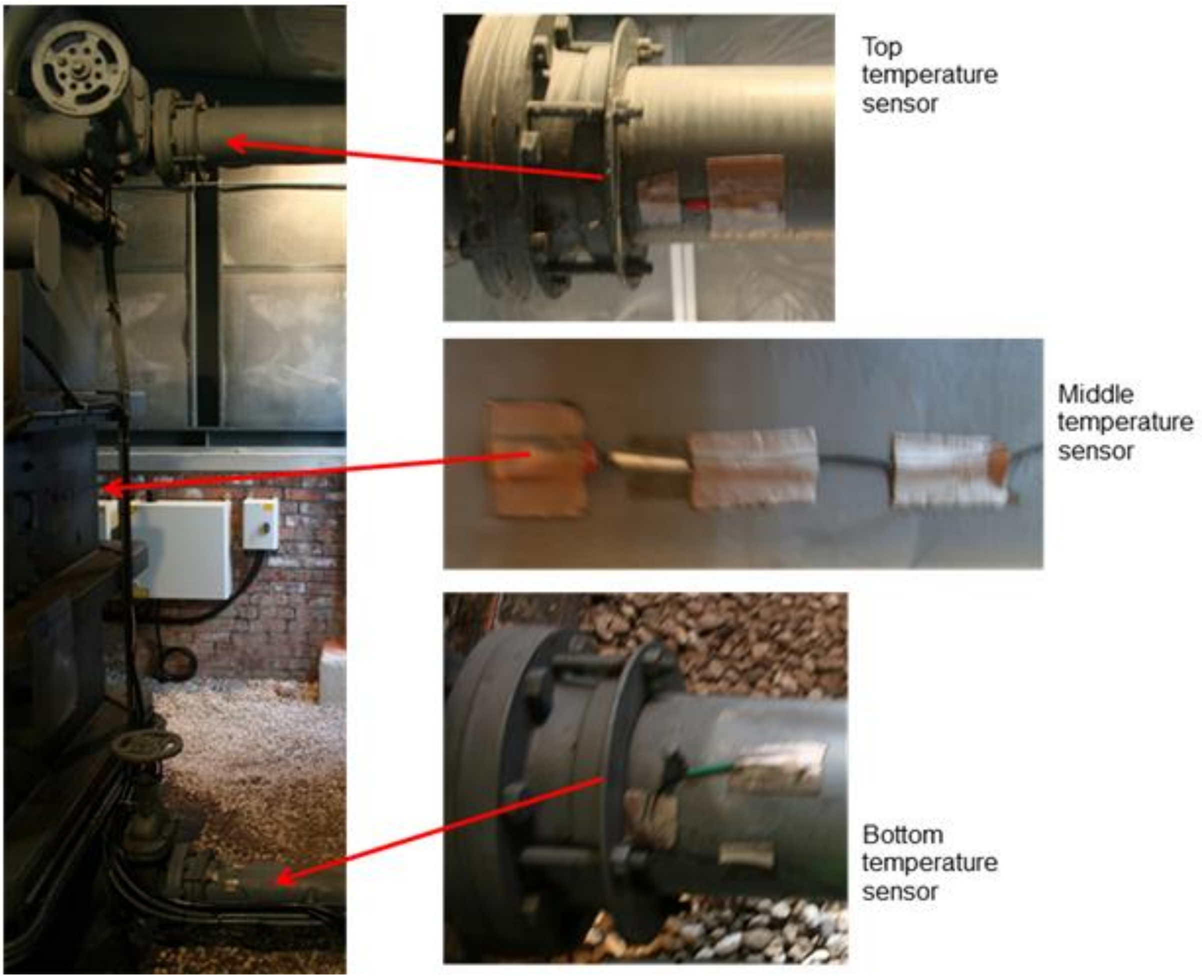

Figure 4-4 Routing of the optical fibre feeder and PT100 flexible trunking

The three external temperature sensors were mounted on the transformer, again enclosed in flashing tape to ensure they did not become loose over the monitoring period. The feeder cables for the external temperature sensors were also installed in a flexible PVC conduit being routed along the existing cable tray, before being buried in the bund floor as shown in Figures 4-3 and 4-4.

Each of the control cabinets were mounted on the bund wall, taking the case of the communications enclosure first with Figure 4-5 showing both internal and external views of the unit. Figure 4-6 shows the internal and external views of the acoustic enclosure and Figure 4-7 shows the internal and external views of the PQube enclosure.


Figure 4-5 Communications enclosure (external and internal views)


Figure 4-6 Acoustic enclosure (external and internal views)

Figure 4-7 PQube enclosure (external and internal views)

The three systems have now been installed; Figure 4-8 shows the spread of installations, with Table 4-1 showing the locations and unit numbers.

Figure 4-8 Map of system installations

Table 4-1 Key to system installations

Key	Location	Unit No	Transformer Bay
61	Romiley	Class Unit 1	T11
62	Irlam	Class Unit 2	T12
63	Longsight	Class Unit 3	T11

The three systems were installed and commissioned in March 2014. Since the commissioning phase has been completed a few communications issues have been experienced with a loss in communications being experience between the units and the host, whilst this issue was being worked on the units were upgraded with SD cards being installed. With the additional memory cards fitted, there should be no data loss when a break in communications is experienced, once the communication link is back up the missing data should be filled in using the data stored on the SD card.

5 Data Analysis for CLASS Trial Tests

In this chapter, data analysis is performed by two universities (the University of Manchester and the University of Liverpool) based on their research interests in the sections 5.1 and 5.2-5.4 respectively.

5.1 Data Analysis for Transformer Main Tank

The section 5.1 focuses on the data analysis for the transformer main tank, with two subsections 5.1.1 and 5.1.2 for the analyses of the load data and oil test results respectively.

5.1.1 Analysis of Load Data

The load data analysis focuses on how the current will increase under Trial 3a (transformer tripping) and Trial 4 (tap staggering) in the first two parts, with some important findings presented finally.

1. Load Data Analysis for Trial 3a Tests

For Trial 3a, the current response is quite straightforward. The current in a transformer will double when the parallel transformer is tripped in a substation. As shown in Figure 5-1, the detection of low frequency (49.7Hz) at 15:57 caused the tripping of Longsight T11, thus doubling the current of the only operating transformer—Longsight T12.

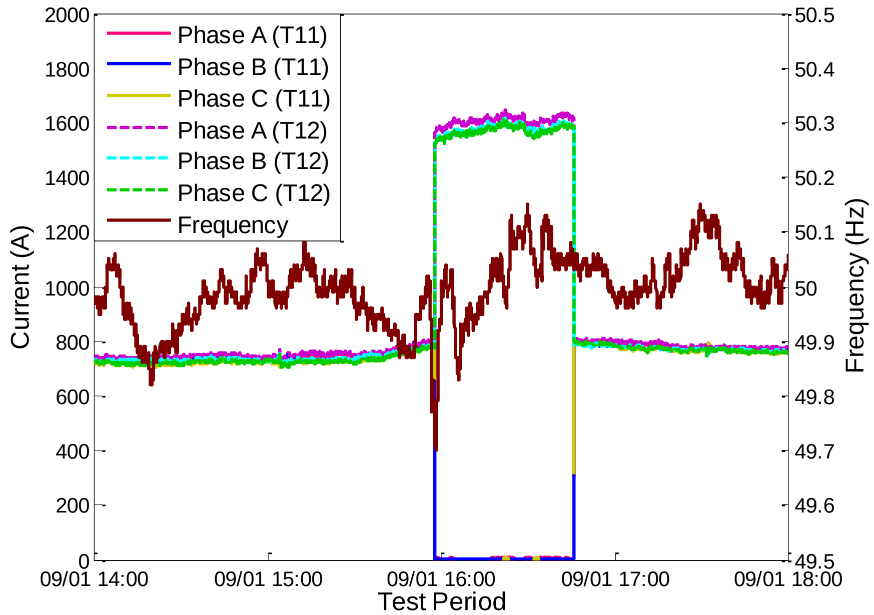

Figure 5-1 Currents and frequency of Longsight T11 and T12 in Trial 3a

This process lasts for about 50 minutes during which the high current flowing through T12 fluctuated around 1600A in Figure 5-1. This current is higher than the rated current (1006A) for ONAN cooling mode, but lower than the rated current (2012A) if the pump and fan are switched on.

Statistical analysis has been conducted on the increased currents due to transformer tripping for all the transformers participating in Trial 3a from August 2014 to May 2015. As shown in Figure 5-2, although the tripping could cause the current to exceed the rated current under the ONAN cooling mode, the equipped pump and fan can raise the transformer capacity and lower the per unit load, making the largest loading of forced cooling mode less than one. In other words, if the pump and fans of all the transformers in Trial 3a work well, no overload due to tripping will occur.

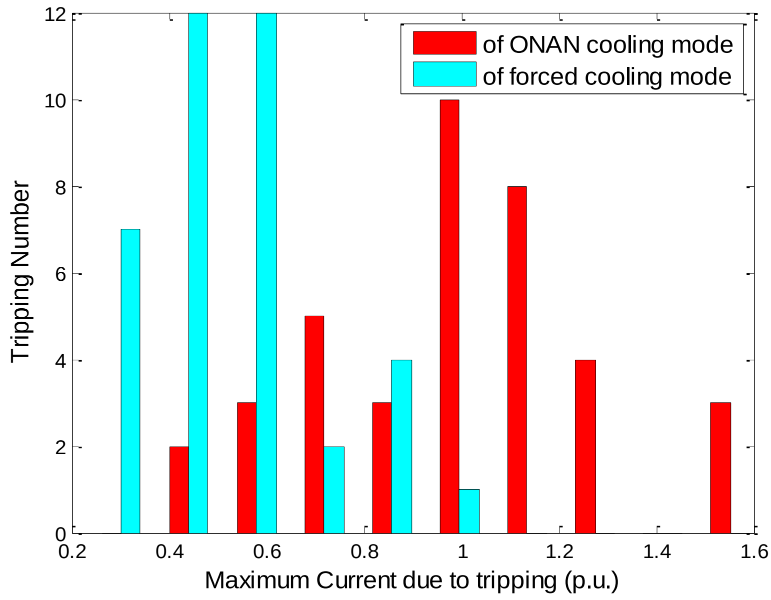

Figure 5-2 Statistics on the currents of Trial 3a transformers during the tripping period

2. Load Data Analysis for Trial 4 Tests

Tap staggering causes a current difference between two parallel transformers. Different numbers of staggered taps would cause different current gaps between two transformers. The following part of this section focuses on the current response under the largest number of staggered taps in CLASS project—six staggered taps with three taps up and down. As shown in Figure 5-3, the current in T11 increases, while that in T12 stays close to the equivalent current which is calculated based on two assumptions: 1) the voltage without test is the same as that during trial 4; 2) two transformers equally share the total active and reactive powers. The equivalent current is calculated to show the current level (load level) if there are no staggered taps as shown in Figure 5-3.

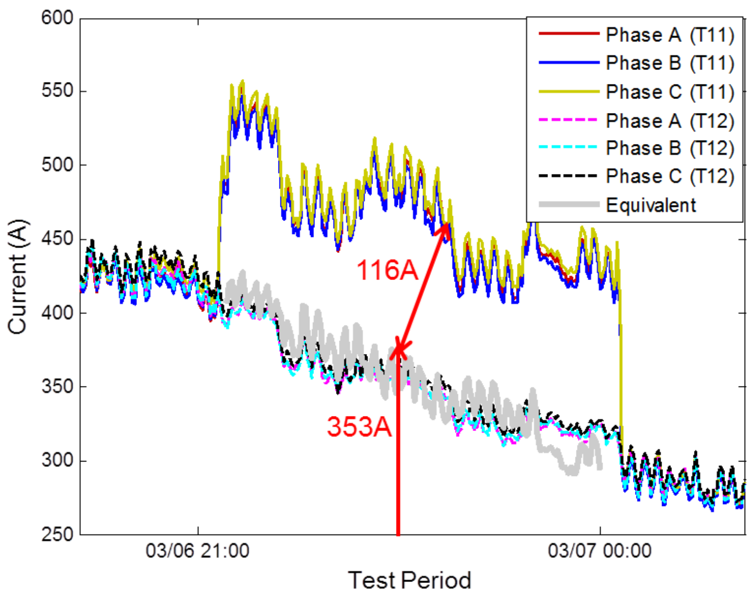

Figure 5-3 Currents of Stuart St T11 and T12 in Trial 4

The median value of such equivalent current is marked by an arrow in Figure 5-3, with a magnitude of 353A. This median value corresponds to the median value of current difference (116A). Such correspondence is utilised to investigate the relationship between the current difference due to tap staggering and the current level if no staggered taps. Figure 5-4 plots the median values of both the equivalent current and the current difference, only to find that the current difference seems to increase with the increase of load current. Moreover, all current differences seem to be lower than 150A except some unexpected high values which coincide with the unexpected low power factors in Figure 5-5.

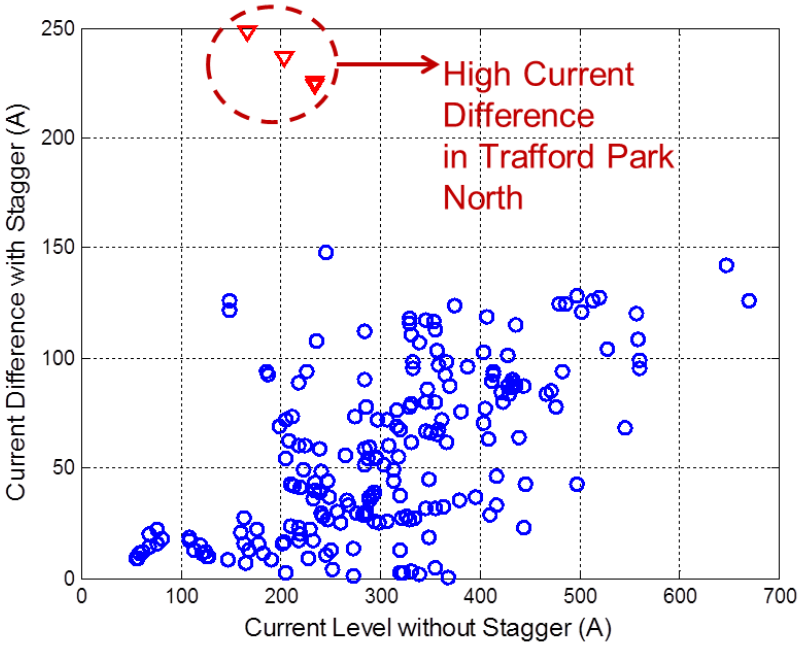

Figure 5-4 Relationship between the current difference due to tap staggering and the current level without staggered taps

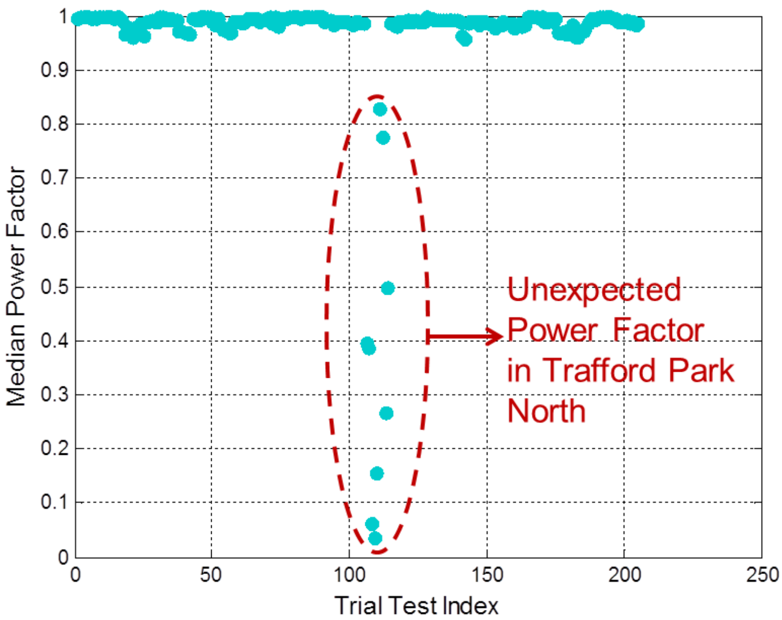

Figure 5-5 Statistics on the medians of power factors

In this case, a conclusion can be drawn according to the monitoring data that the maximum current difference due to tap stagger is 150A if the power factor of the load is above 0.9. The further study of the thermal impact of Trial 4 can conservatively choose the 150A as the current increase caused by the largest number of staggered taps.

3. Identification of Unexpected Circulating Current

The current difference between two transformers in a substation not only happens during the time with Trial 4 tests scheduled, but also occurs unexpectedly when there is no scheduled trial test. As shown in Figure 5-6, two transformers under the same substation have different currents. This current difference indicates the circulating current flowing through two parallel transformers. Since Trial 4 tests were not scheduled in those two days, the current difference in Figure 5-6 might be attributed to the control problem which makes the unexpected staggered taps. Whatever reasons, the phenomenon of current difference would have long-term accumulative thermal impacts on the transformer health and could also offset the effects of reactive absorption functionality when tap staggering is applied.

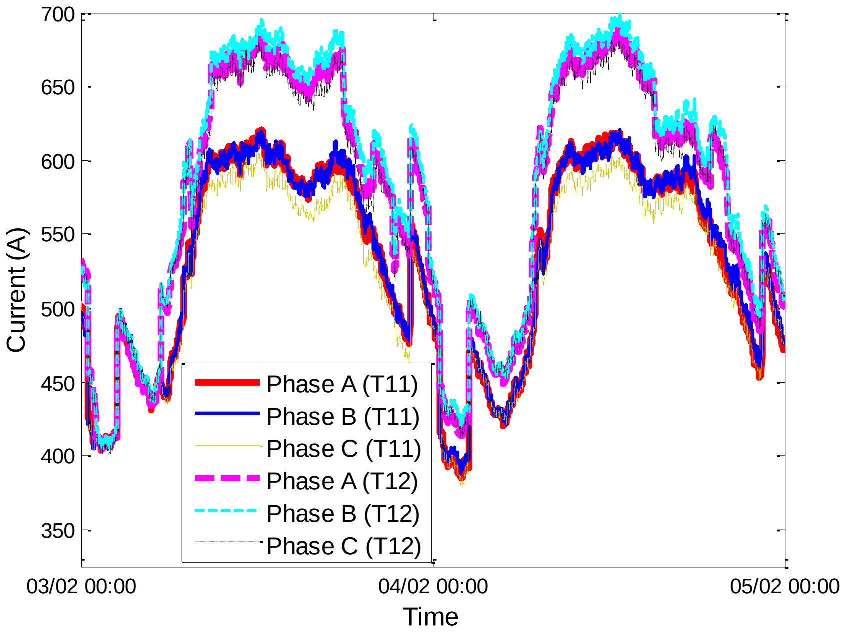

Figure 5-6 Current difference in Central Manchester Substation

5.1.2 Analysis of Oil Test Results

The first two parts of section 5.1.2 focuses on the short-term impact of the higher current caused by the transformer tripping and tap staggering on the oil test results such as four ageing indicators (acidity, moisture, breakdown voltage and 2-FAL) and dissolved gases (including hydrogen (H_2) and selected hydrocarbons (CH_4, C_2H_6, C_2H_4 and C_2H_2)). The final part will present some findings in the trend analysis of one of ageing indicators—acidity.

1. Oil Data Analysis for Trial 4 Tests

The analysis starts with the comparison of the oil sampled before and after Trial 4 tests. As shown in Figure 5-7, three Trial 4 tests took place between two oil samplings on the 20th and 23rd of April, 2015.

The gases dissolved in those two oil samples are compared in Figure 5-8. Since all the gases are below the baselines in Table 2-9, the importance of them can be neglected, thus making DGA health index zero before and after Trial 4 tests. This indicates those three Trial 4 tests in Figure 5-7 had no impact on the DGA score and thus it can be concluded that the implementation of the tests did not result in any faults.

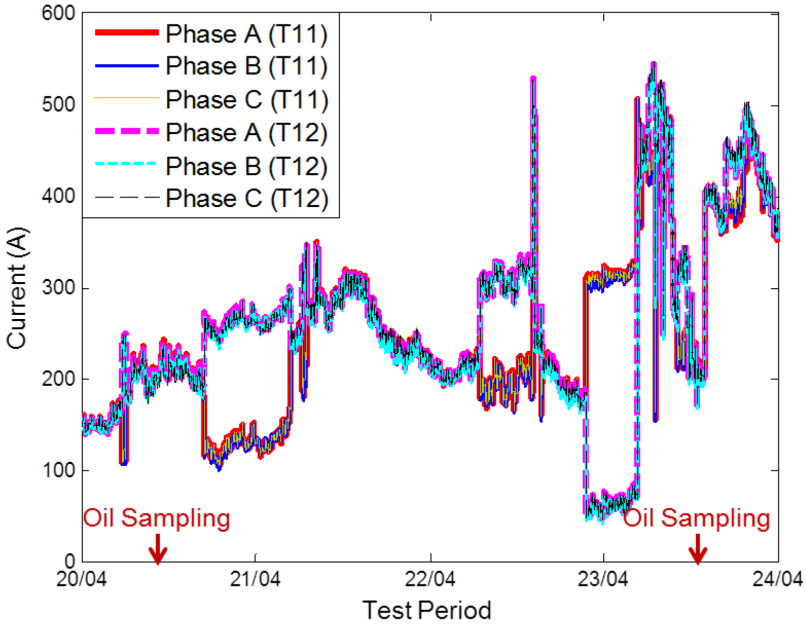

Figure 5-7 Currents of Trafford Park North T11 and T12 in Trial 4

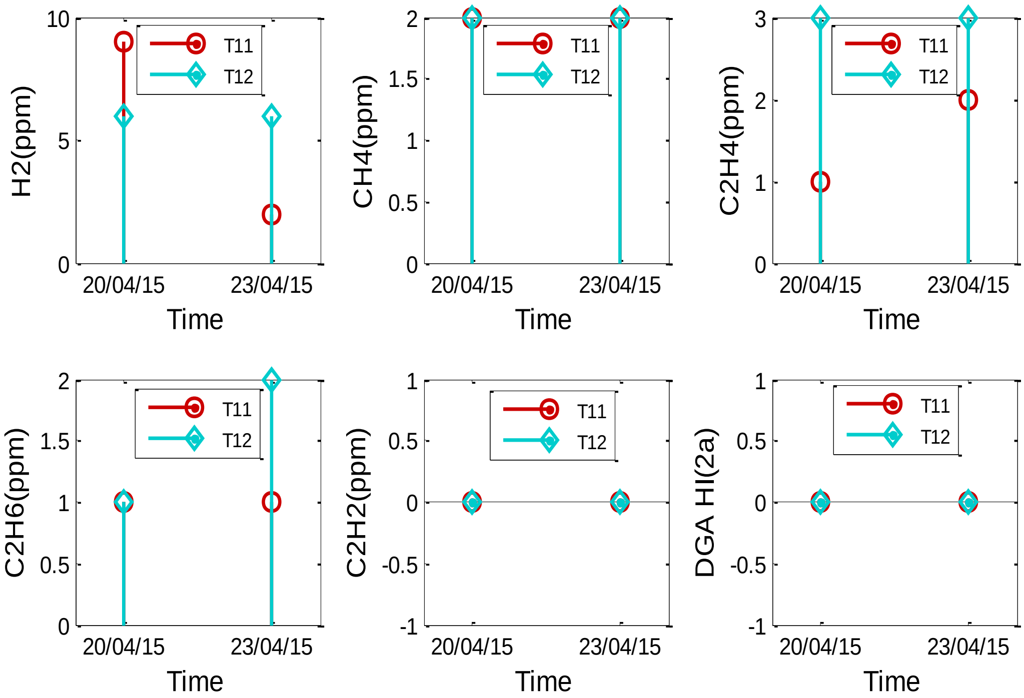

Figure 5-8 Comparison of dissolved gases sampled before and after tap staggering

The analysis is then performed on the relationship between the variations of ageing indicators and currents in Trial 4 tests. Although there are some fluctuations in moisture content, dielectric strength (breakdown voltage) and acidity, the final health indices for the oil condition are equal as shown in Figure 5-9.

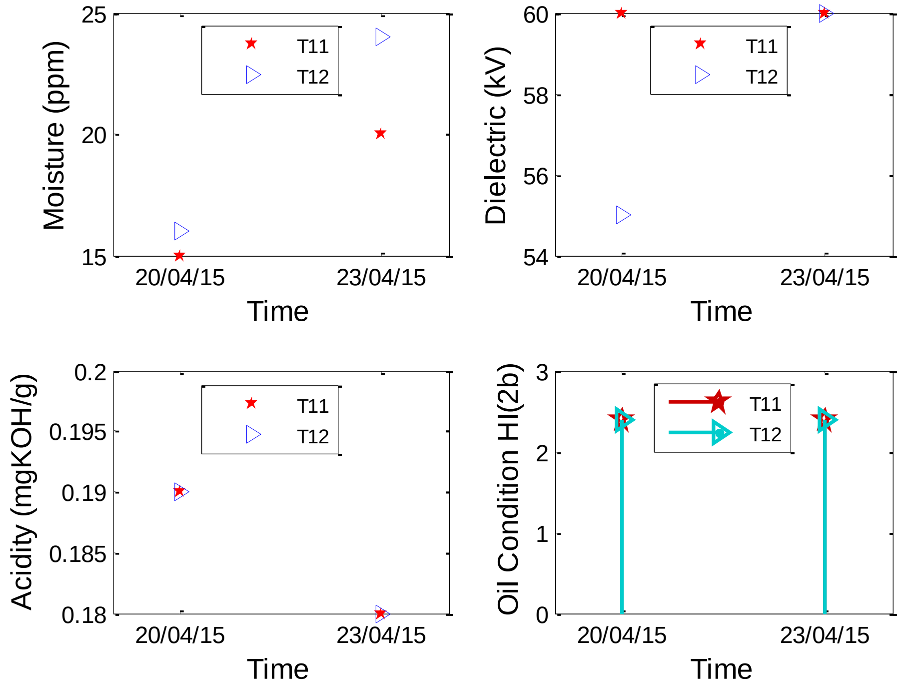

Figure 5-9 Comparison of moisture, acidity and dielectric strength sampled before and after tap staggering

Moreover, paper degradation is also investigated. As shown in Figure 5-10, the 2-FAL value and its health index after trial test is even smaller than those before. This means the current increase is not related to paper ageing during the period of Trial 4 tests in Figure 5-7.

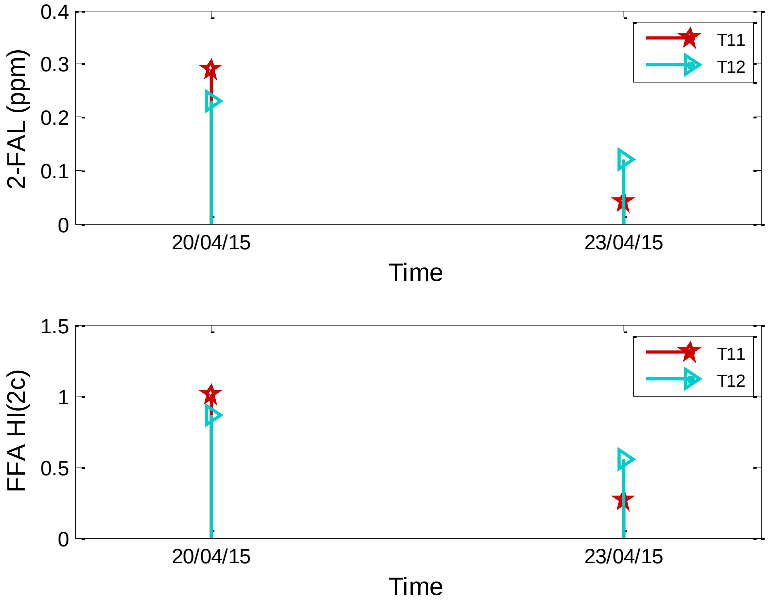

Figure 5-10 Comparison of 2-FAL sampled before and after tap staggering

In conclusion, there is no indication of the oil and paper degradation as well as the increase in the probability of fault for Trial 4 tests, with current differences even over 150A in Figure 5-7. This conclusion is also applicable to all the other Trial 4 tests in Figure 5-4 with the lower current increase and the higher power factor over 0.9.

2. Oil Data Analysis for Trial 3a Tests

Since the current increase in Trial 4 is not expected to cause the degradation of insulating materials and increase the probability of fault occurrence, the following analysis focuses on the Trial 3a (transformer tripping) test with higher current increase based on the health indices for oil test results.

The statistical analysis is initially done on the differences between health indices before and after transformer tripping. As shown in Figure 5-11 and Figure 5-12, those differences are classified as “stable” if the difference is less than 0.5 and “increase” or “decrease” if the difference is over 0.5. The “stable” dominates in each group accompanied by both the “increase” and “decrease”. Since both the increase and decrease of health index happen in two groups with and without Trial 3a tests, it is unlikely that the change in oil parameters is correlated with the current surges caused by transformer tripping.

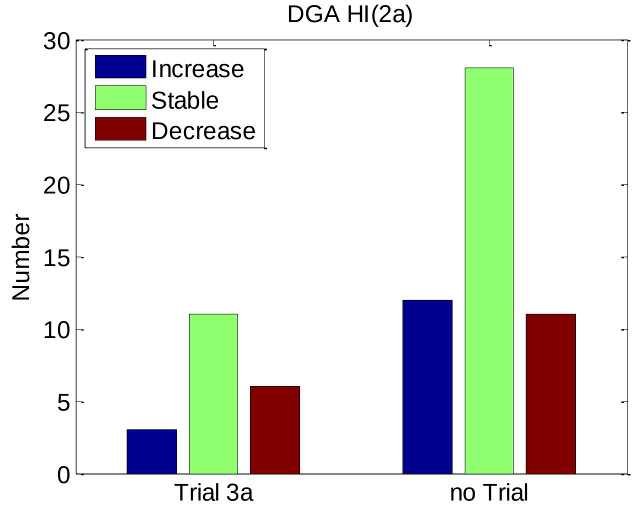

Figure 5-11 Statistics on the differences between DGA health indices before and after Trial 3a tests

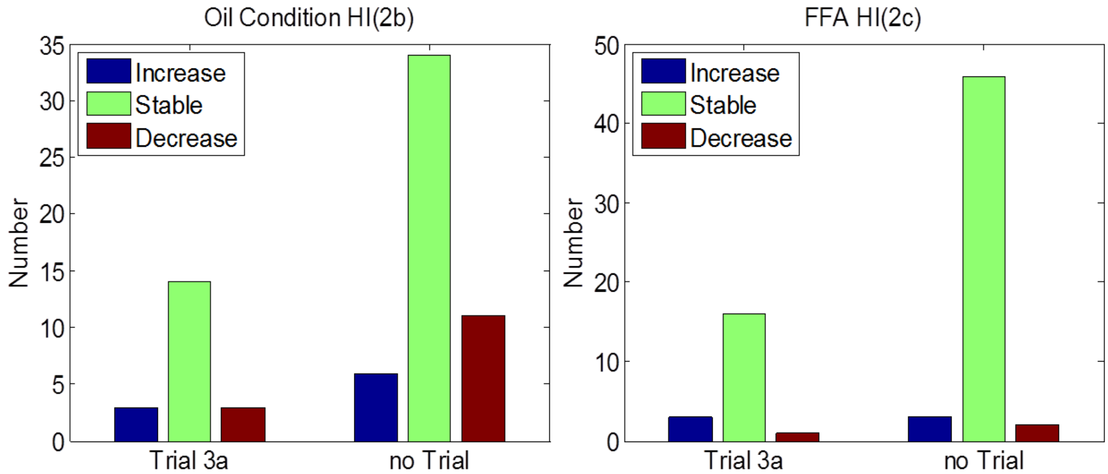

Figure 5-12 Statistics on the differences between health indices of oil and paper condition before and after Trial 3a tests

The analysis is then performed on the variations of health indices on specific Trial 3 tests in order to explain the conclusion in the statistical analysis. As shown in Figure 5-13, two transformers under the same substation alternate the heavy current due to tripping. In order to assess the short-term impact of the oil test results, the following part compares the oil data sampled before and after this Trial 3a test.

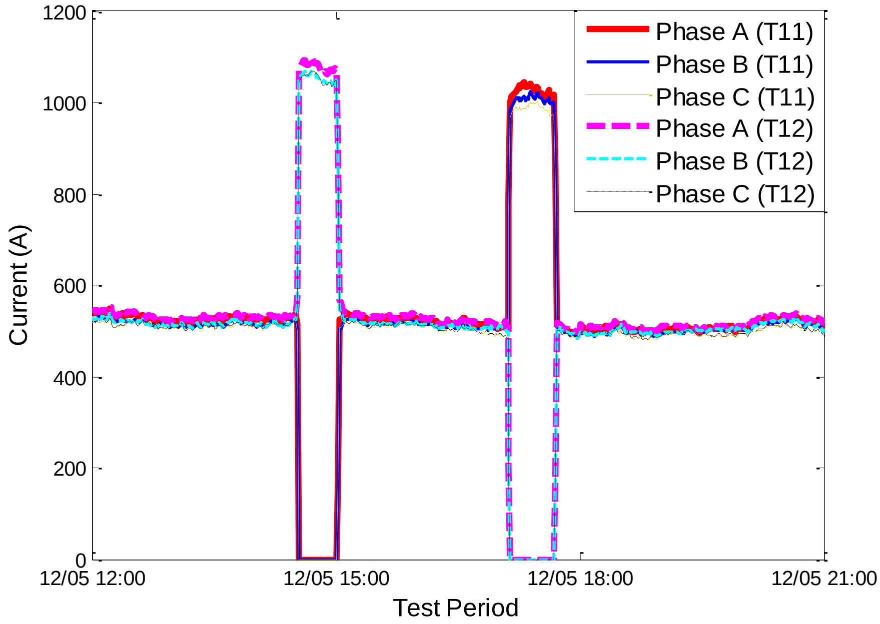

Figure 5-13 Currents of Longsight T11 and T12 in Trial 3a

This comparison is firstly made in the dissolved gases. As shown in Figure 5-14, all the values of each gas are within the set ranges in Table 2-9, except hydrogen (H_2) and acetylene (C_2H_2). Therefore, the analysis of gases mainly focuses on those two types of gases.

According to Table 2-5, the hydrogen indicates the partial discharge. Based on the sampled before and after the tripping, the hydrogen shows generally shows a decreasing trend with values in T11 dropping from 28ppm to 3ppm and in T12 from 10ppm to 9ppm. Since no accumulative effect is related to tripping, the transformer tripping might not cause the partial discharge.

The acetylene content (C_2H_2) is also worth consideration, as its surge usually indicates the occurrence of high energy discharges such as arcing in Table 2-5. Since both significant increase and decrease in acetylene are observed in transformers with heavy load, it is unlikely to relate the gas accumulation to the heavy load caused by transformer tripping. Therefore, it can be concluded that the transformer tripping might not cause the high energy discharges. The same conclusion can be drawn when comparing the DGA health indices which are mainly contributed by acetylene.

The oil condition before and after tripping is also taken into consideration. In Figure 5-15, the usual fluctuations occur in three ageing indicators. However, those fluctuations actually change neither the oil condition score nor the health index capped at 3. So the short-term current surge is unlikely to cause oil degradation.

The increase of 2-FAL is observed in two transformers in Figure 5-16. However, such increase should also be considered as normal fluctuations, as the 2-FAL values for two transformers in the following days in July 2015 dropped below 0.4ppm.

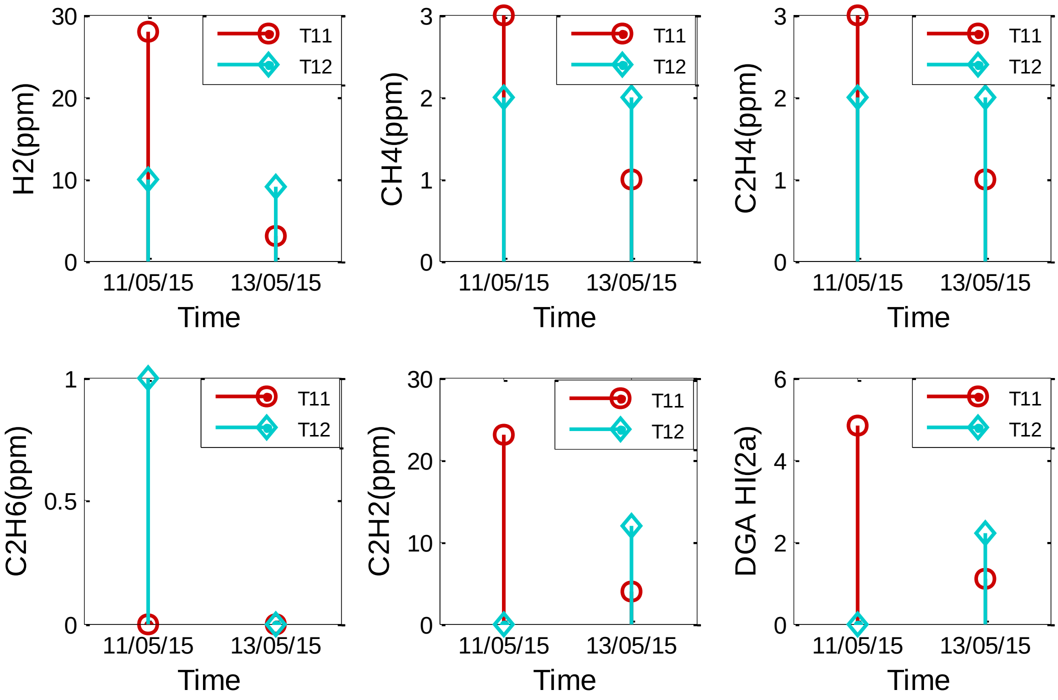

Figure 5-14 Comparison of dissolved gases sampled before and after transformer tripping

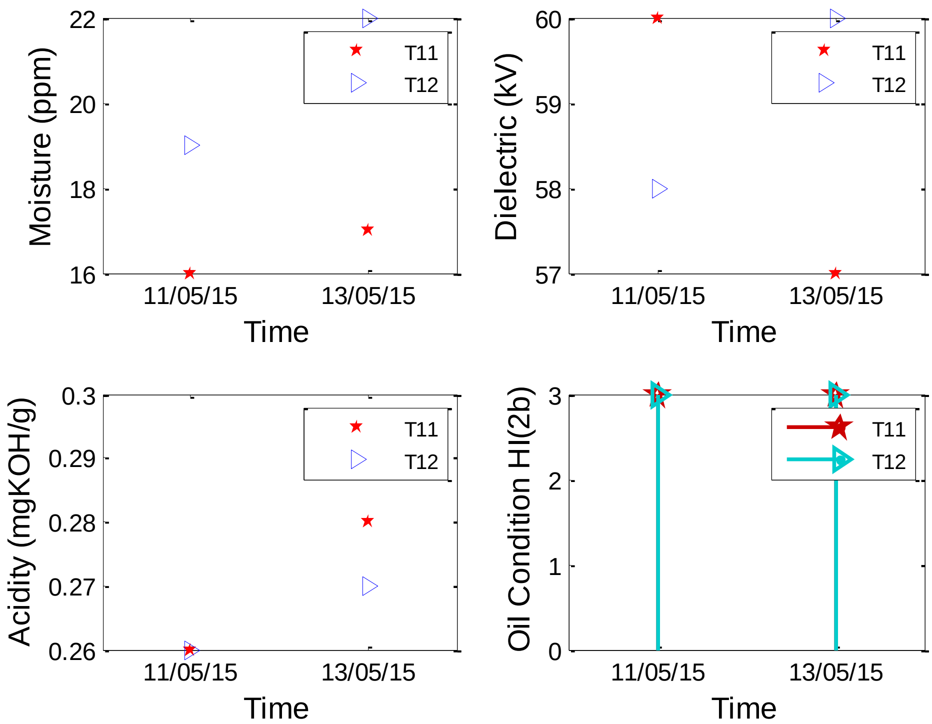

Figure 5-15 Comparison of moisture, dielectric strength and acidity sampled before and after transformer tripping

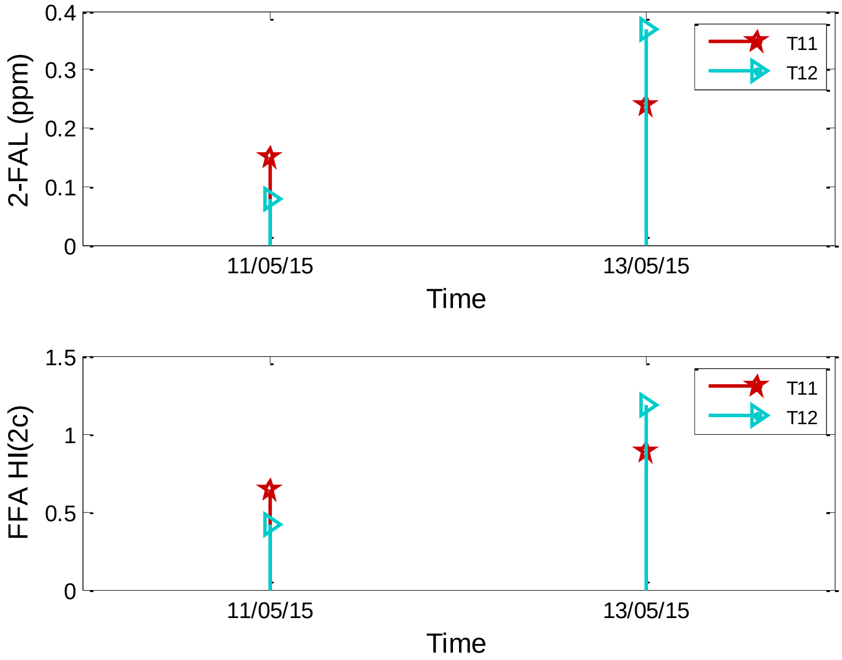

Figure 5-16 Comparison of 2-FAL sampled before and after transformer tripping

According to the oil data analysis, it is unlikely that the CLASS techniques are correlated with the oil and paper ageing. This is because the ageing of insulating materials is a long-term process and its indicators such acidity, 2-FAL and moisture take years to accumulate as mentioned in [4], [22]. In this case, the rises and drops over a short period can be generally attributed to either the measurement inaccuracy or the movement of by-products.

Consequently, there is no evidence to show that the high current caused by the CLASS techniques could increase the probability of fault occurrence. This can be attributed to the fact that no overload is observed during the trial period in Figure 5-2. Therefore, the occurrence of low-energy thermal faults at temperatures below 300°C (like 200°C) is not realistic. Moreover, stray gassing of oil is less likely to occur, as the maximum winding temperature read from the WTI is 62°C which is far from the minimum temperature (90°C) for the heated oil gassing. In this case, the apparent surge of some gasses during the trial period could be attributed to the following reasons: errors in the existing measurement of dissolved gases, the intrinsic fluctuations of dissolved gases in the oil and the existence of some other gas sources.

3. Identification of Early Ageing Phenomenon

The final part of section 5.1.2 focuses on the acidity trend of nearly 700 primary substation transformers. As shown in Figure 5-17, the acidity values of most transformers are generally fitted by an exponential curve, with the exception of some outliers over 0.15 mgKOH/g before 30 years. Those outliers indicate the accelerated acidity growth. About 17% of transformers experience such accelerated acidity growth. However, about 30% of these transformers appear to have been utilised as “spare” transformers for many years, since their manufacturer time is more than five years earlier than their commissioning time which age is based on. Therefore, the following statistics focus on the 70% transformers with acidity outliers. As shown in Table 5-1, the accelerated acidity growth is illustrated in fourteen manufacturers and mainly occurs in transformers manufactured after 1980. This phenomenon indicates the early onset of ageing of those transformers which could lead to unexpected maintenance challenges for Electricity North West Limited, since the increasing rate of the acids in oil is a good ageing indicator of the in-service transformer according to IEC 60422.

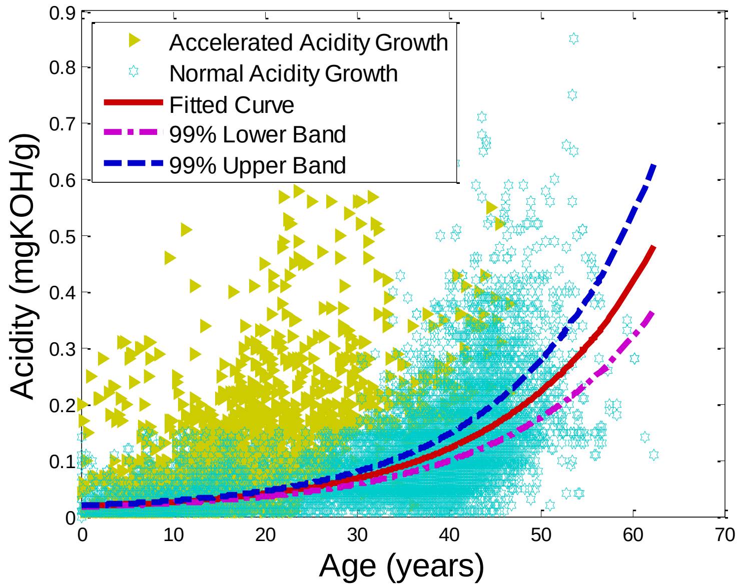

Figure 5-17 General acidity trend for 33/11(or 6.6) kV power transformers

Table 5-1 Survey on 33/11(or 6.6) kV transformers with accelerated acidity growth

	Manufacture Times				
Manufacturers	**1960s**	**1970s**	**1980s**	**1990s**	**2000s**
A	0	2	16	0	0
B	0	0	2	14	0
C	0	0	5	11	0
D, E, F…N	6	2	3	11	8
TX Number	6	4	26	36	8

5.2 Tap Changer Oil Analysis Using an Optical Method

Due to operational reasons, a limited number of oil samples were taken from the tap changer enclosures at Longsight and Romiley from both T11 and T12 during the test period 11th to 15th May. Single samples were taken from Irlam T11 and T12. Rather than analysing these oil samples using conventional DGA techniques an alternative method was used based on optically probing the oil and determining what has changed in the oil from the optical signatures. Such changes are related to the molecular structure, particulate contamination due carbonisation of the oil through heating and electrical discharges, metallic compounds formed from discharge activity during the tap changer operation etc. The technique does not give precise analytical data that the DGA method produces but provides a holistic view of the condition of the oil which can be easily assessment and compare to other transformer oil.

Correlating the DGA with the optical signature and the ultimate end of life condition of the transformer has been established using data collected by TNB Malaysia and processed at Liverpool (Cigre report to be published). Starting at the accepted point of DGA, Figure 5-18 shows how the DGA analysis can be processed to represent known conditions in a population of transformers. This figure shows a triangular envelope (not Duval's triangle) where conditions are indicated which give rise to the DGA components (e.g. Local Heating/PD etc). This figure also shows DGA results from oil samples with known end of life problems. New oil will lie around the 0.33, 0.33 point depending upon the type, source and where it was refined. As the oil degrades there is an associated change in coordinates depending on what is causing the degradation. Figure 5-19 is a view of the processed optical signatures for oils. Correlations between the data in these two figures link the optical oil condition and the DGA. In Figure 5-19 new oil lies between the boundary of the two coloured sections of the left hand diagram. Degradation in oil produces a similar trend on this diagram as in Figure 5-18. The right hand diagram indicates the level at which there is little oil degradation (below the yellow dotted line), moderate oil degradation occurs (above the yellow dotted line) and a level at which the oil degradation is considered to be of concern (above the red dotted line).

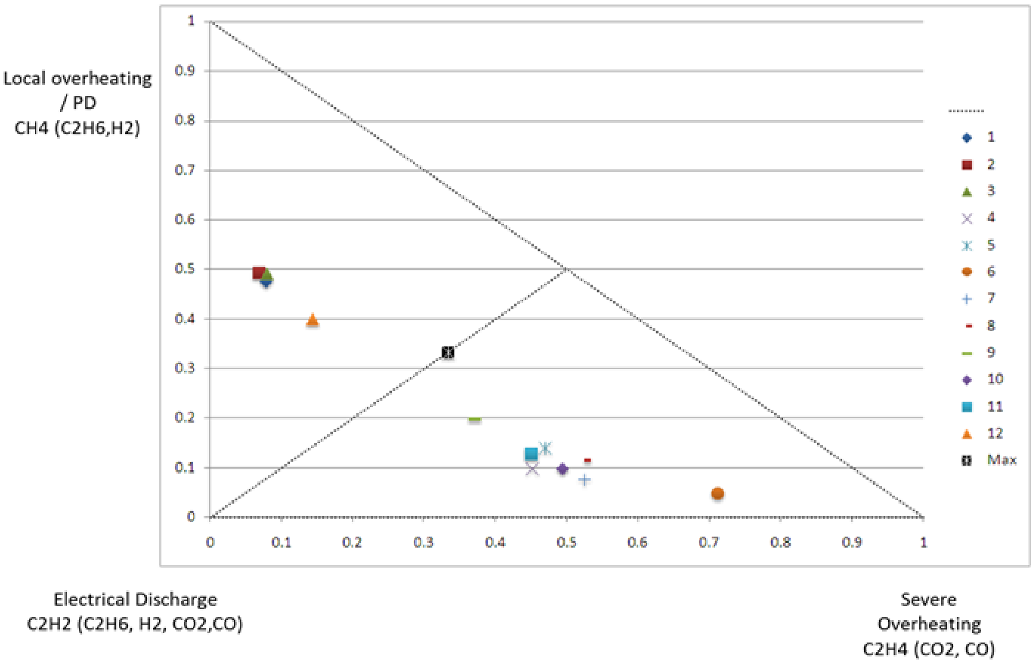

Figure 5-18 Processed DGA data correlated to the transformer condition

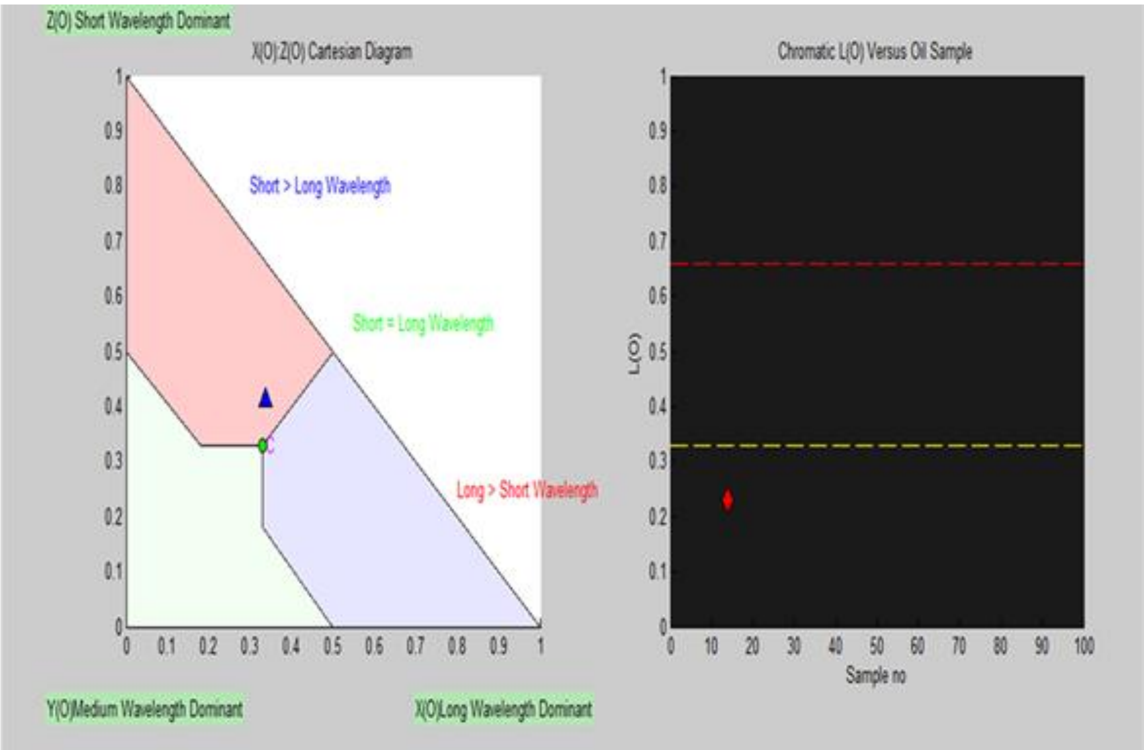

Figure 5-19 Processed optical signatures correlates to the condition of the transformer oil

Figure 5-20 shows optical signatures of the oil samples taken from tap changer tanks during the tests on 11th, 13th and 15th May. They are grouped in threes for each transformer. TC1-3 are for T11 at Romiley; TC4-6 are from T12 at Romiley; TC7-9 are for T12 at Longsight; TC10-12 are for T11 at Longsight and TC13 and 14 are for T11 and T12 respectively for Irlam.

This figure is a small section of a graph that goes from 0 to 1 on each axis and so the changes detected are relatively small. A straight line has been drawn through the data as a profile of how the oil deteriorates in these particular tap changer enclosures during normal operation based on the limited number of samples taken.

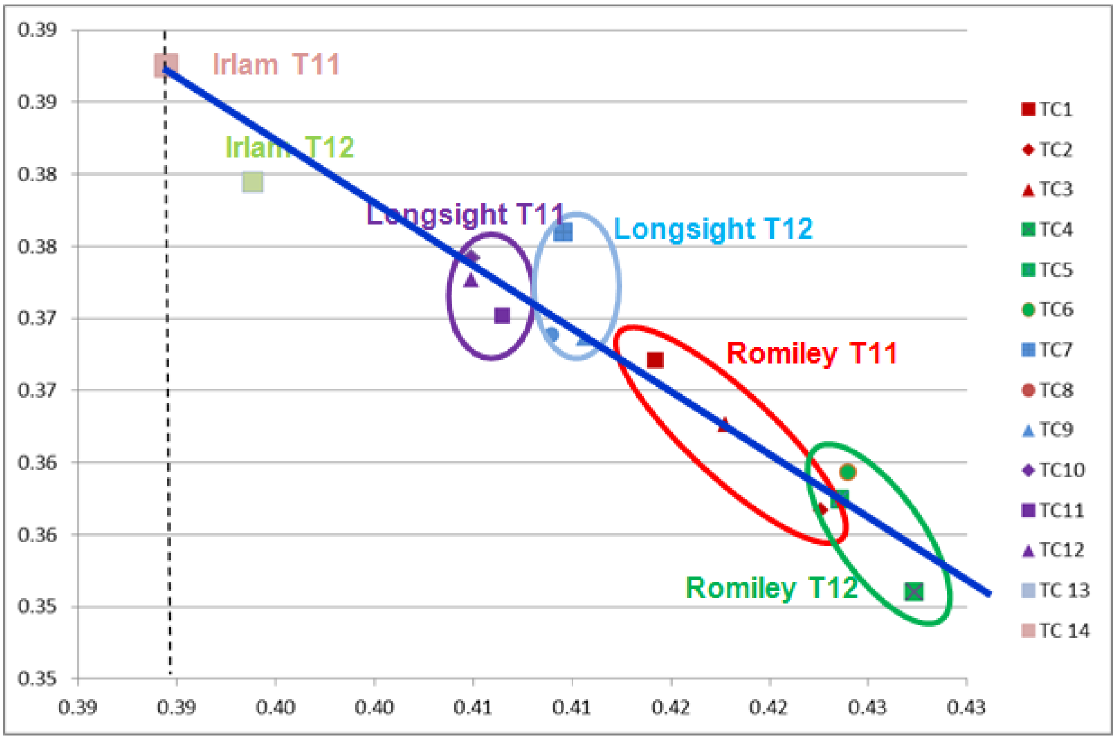

Figure 5-20 Processed optical signatures of oil samples from the tap changer

The difference in the data points between the transformers at Irlam represents T12 being approximately 18 months longer in service and doing approximately 3000 more taps than T11. This piece of information can be used to determine the quality of the oil based on degradation rather than physical age. The starting point shown by Irlam T11 can be taken as the new oil point and different zones highlighted for each transformer indicative of the level of degradation in the oil.

The variation within these marked zones for each sample of oil from the tap changer is due to the different conditions at the time of operation. This variation emphasises the local quality immediately after operation. Longsight T11 and T12 and Romiley T12 exhibit small changes compared to Romiley T11 were the change is greater. The general implication is that there is some heating of the oil taking place during the operation of the tap changers under these test conditions. The optical signatures reflect changes in the molecular composition in the oil locally. Over time these localised changes will diffuse into the rest of the oil and therefore making single tap operations difficult to detect. However, over many successive tap operations the oil will show some signs of degrading.

5.3 Contact Wear Assessment

Contact wear in any electrical device is a complex process and is affected by many different parameters including contact material, discharge environment, switching current level, rated switching current of the contacts switching duration etc. Assessment of contact wear mainly on the diverter switch will use a simple model and experimental data to estimate the extra contact erosion which takes place for the various switching operations used in CLASS.

Equation 17 is an empirically derived model derived from work undertaken on contact wear over a range of currents (REF).

$$W = \int_0^{tarc} K_w \left[\frac{i(t)}{I_{Rated}}\right]^b dt \qquad \text{(Equation 17)}$$

Where: W is wear
i(t) is the current through the contact.
I_{Rated} is the rated current for the switching contacts
K_w is a coefficient representing the complex arcing environment
b is an indices value related to the current being switched.

Both K_w and *b* change with the level of current through the contacts and models a number of material related factors such as the work function of the materal etc.

However, rather than calculate the individual unknowns, a ratiometric method can be used to eliminate so of these. A simple equation is formed that indicates the extra wear that might occur under the switching conditions used in the tests.

Equations 18 and 19 represent wear for two different currents through the contacts but for the same switch duration. Equation 20 is the ratio of wear for two different levels of current.

$$W_1 = \int_0^{tarc} K_w \left[\frac{i_1(t)}{I_{Rated}}\right]^b dt \qquad \text{(Equation 18)}$$

$$W_2 = \int_0^{tarc} K_w \left[\frac{i_2(t)}{I_{Rated}}\right]^b dt \qquad \text{(Equation 19)}$$

$$\frac{W_2}{W_1} = \left[\frac{i_{2pk}}{i_{1pk}}\right]^b \qquad \text{(Equation 20)}$$

Quoted values for *b* have been between 1.7 and 3 depending upon the value of the load current to rated. An estimate of the value of *b* can be obtained from experimental data for contacts in oil with load currents in a similar range as expected on site (Figure 5-21).

Assuming that the electrodes in the tap changer are CuW (60/40) and the current range is a few 100A to 2kA, an estimation of b can be made. From the data in Figure 5-21, b = 2.1. The implication from equation 20 is that doubling the switching current in the tap changer increases contact wear by a factor of 4 (i.e. under these conditions it matches the increase in power input - I^2R). A 10% increase in current increases wear by ~20%. The implication for the this project is that under all test conditions except when one transformer is switched out and the remaining transformer takes the extra load, there is no significant amount of additional wear compared to routine operations providing the load current is in the average range for the transformer. For the case when one transformer is switched out, the addition contact wear, if the load on the remaining transformer is doubled from its normal average value, is 4 times greater. If maintenance schedules are based on the number of taps irrespective of the tap position, then the maintenance schedule will need to factor in the additional wear for this particular type of operation. If the tap position is known then this information could also be used to assess wear on each particular tap points.

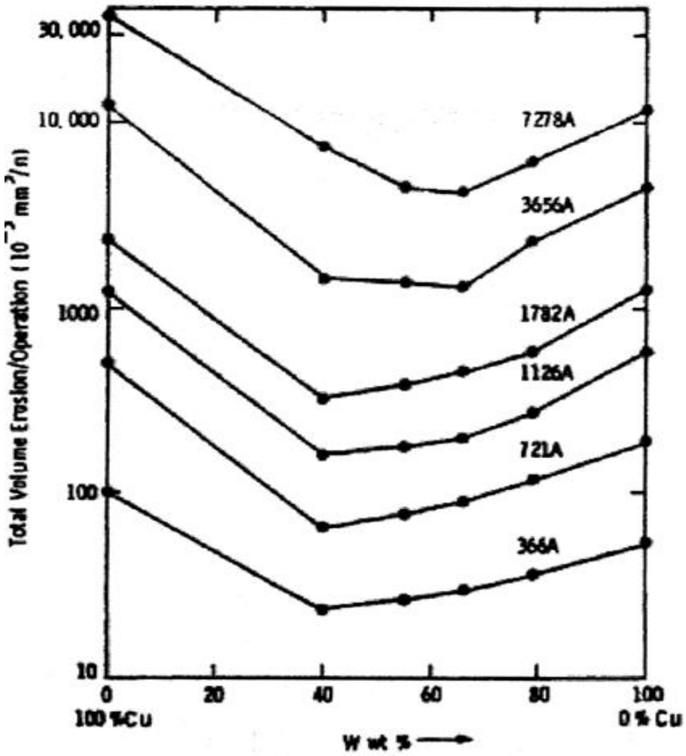

Figure 5-21 Experimental data on contact wear at different current levels

5.4 Data Analysis for Tap Changer

Acoustic vibration from the transformer tap changer is monitored continuously at three sites. The acoustic signal is generated by the transformer hum plus other acoustic events, which include operation of the tap changer mechanism (tap changes) and other noises from the transformer. Tap changes are usually performed automatically and at arbitrary times in accordance with demand. The continuous signal may be analysed using a chromatic approach [39] in order to identify candidate tap change events and also to monitor changes in the transformer's acoustic emissions before and after a tap change. Tap change events may be characterised using a chromatic approach and monitored over longer-term periods for tracking potential changes in the operation of the tap changer in terms of energy and similarity [40]. Changes in energy and similarity could indicate that the normal operation of the tap change mechanism is varying and intervention may be required. In particular, a significant increase in energy could be caused by mechanical wear in the mechanism, which could develop into a major fault. Tap changer faults represent a significant proportion of the overall faults that can affect transformers. Serious faults can have consequences ranging from outage to total loss of the transformer.

The tap change signature is distinct from the normal hum of the transformer. On the majority of the acoustic signals the tap event is evident. A representative set of acoustic signals from T11 at Longsight are shown in Figure 5-22 (a-c). These sample signals were taken from tap operations in response to normal network conditions, i.e. there were not part of the CLASS test sequence on three separate days in May, June and July. The tap change is clear on all three signals and looks similar but there are some discernible differences. These results also show that the transformer hum can change after a tap operation (July) and change prior to the actual tap (May). The acoustic signatures at Irlam and Romiley show similar behaviour.

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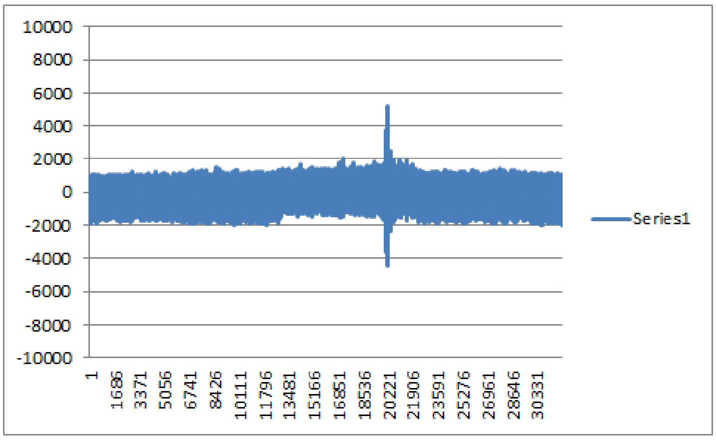
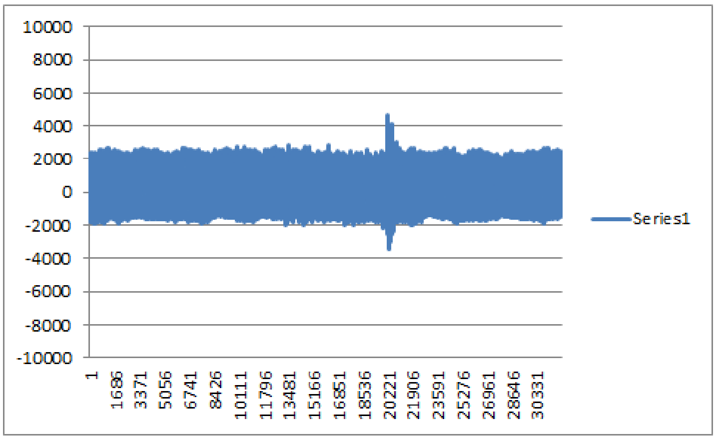
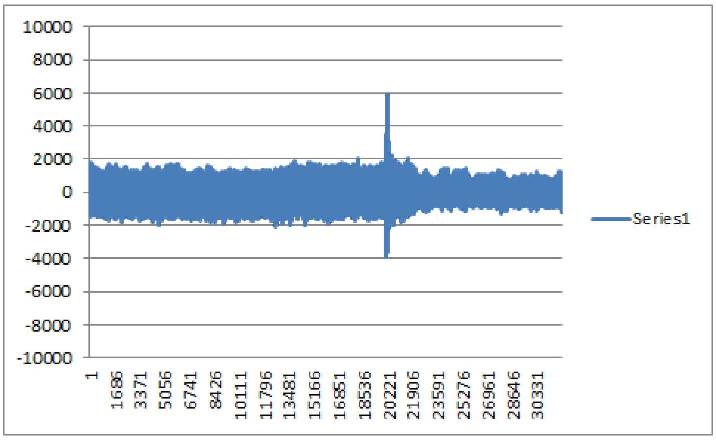


(a) May



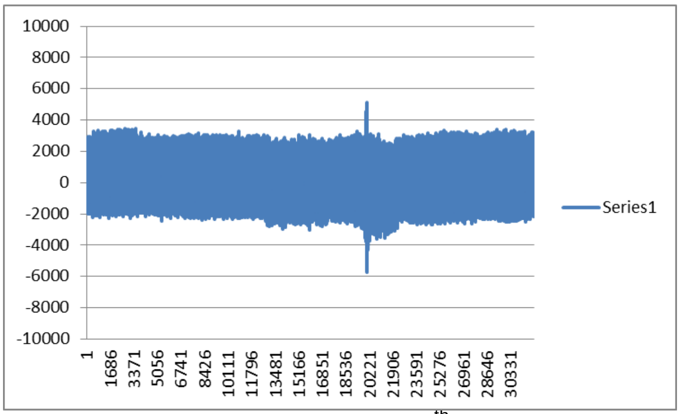
(b) June



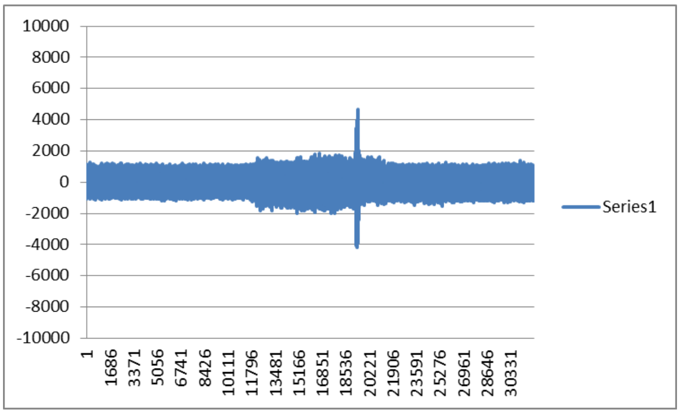
(c) July

Figure 5-22 Time varying acoustic signals recorded at Longsight (T11) under normal circuit operations on one day in May, June and July

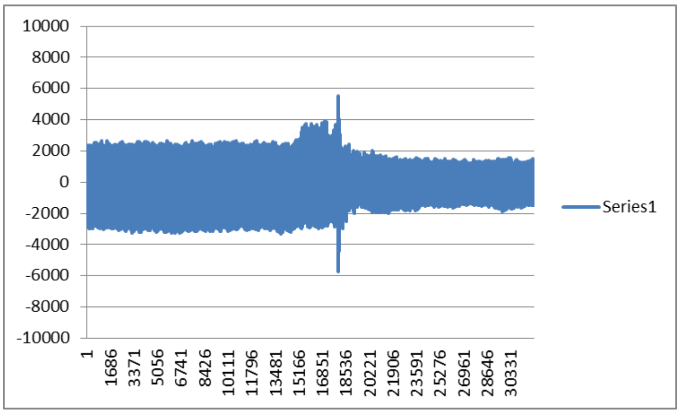
Figure 5-23 (a-e) show acoustic signals recorded on the same transformer at Longsight during CLASS operations. The (a, b) are for type 3 operations on the same day; (c-e) are type 4 operations on two separate days. The signals are complex but how do they compare with non CLASS tap operations?



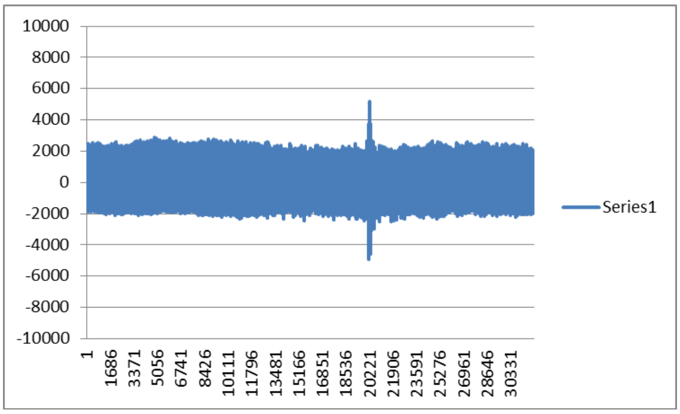
(a) Type 3 test 12th May



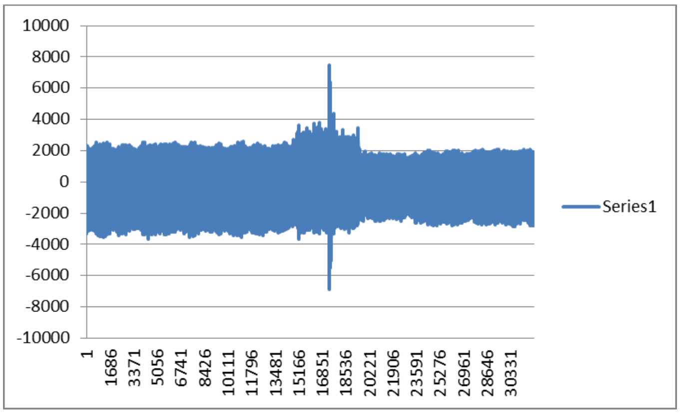
(b) Type 3 test 12th May



(c) Type 4 test 14th May



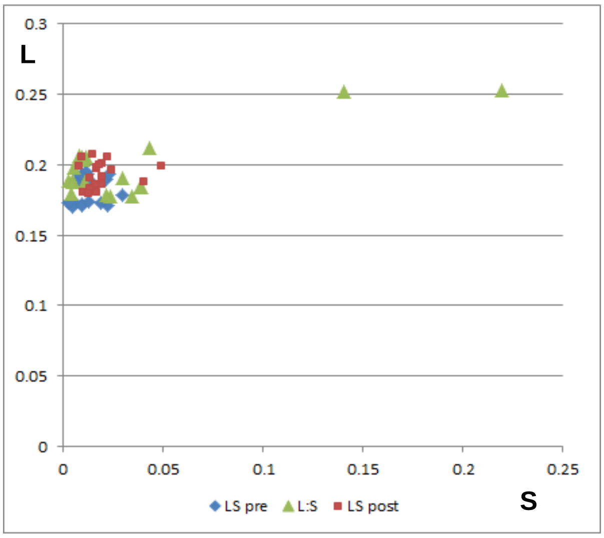
(d) Type 4 test 15th May



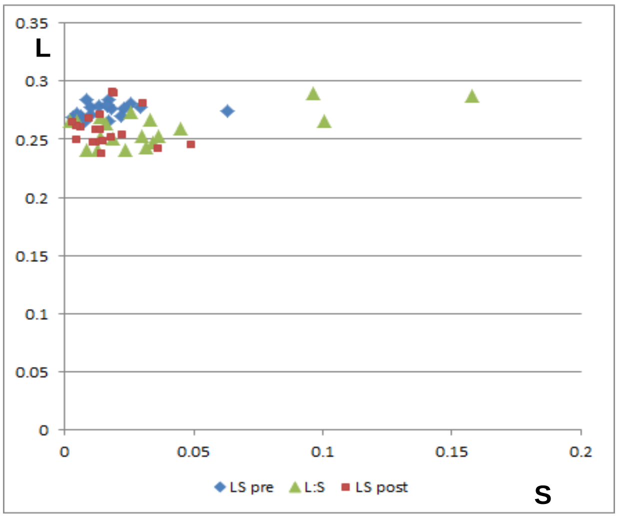
(e)Type 4 test 15th May

Figure 5-23 Time varying acoustic signals recorded at Longsight (T11) under CLASS circuit operations in May

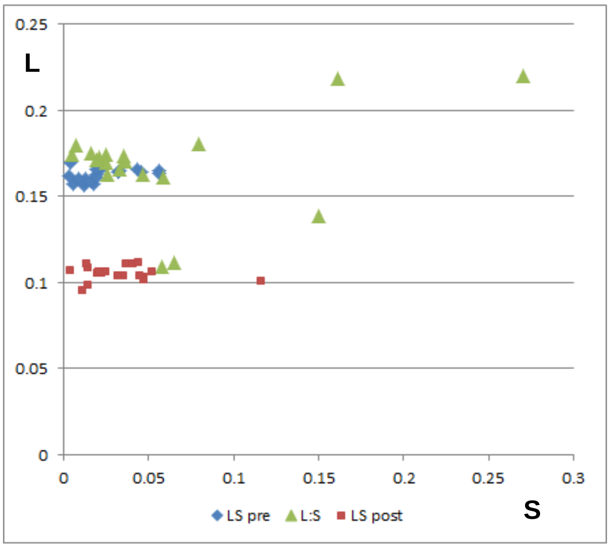
In order to compare these signals and to assess whether there is an effect on the tap operation of CLASS types of operation, these signals have been processed chromatically to determine the energy (L) and bandwidth (S) associated with them. The higher the L value the more acoustic energy is associated with the signal; a low value of S indicates a smaller bandwidth than a larger S value. The signals have been divided into three time periods corresponding pre-tap, tap and post-tap. Figure 5-24 (a-c) shows the processed output for the three normal tap change events as shown in Figure 5-22 (a-c).



(a) May



(b) June

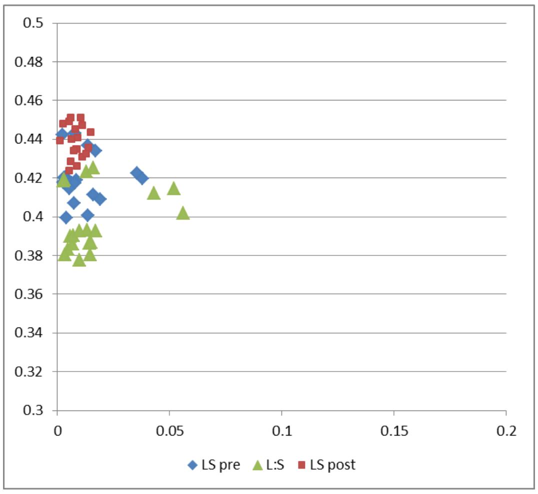


(c) July

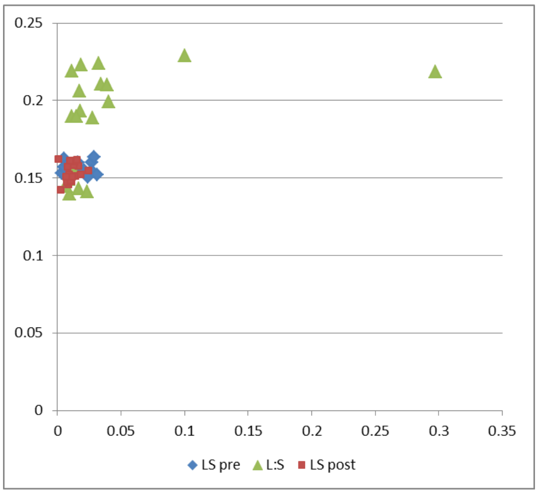
Figure 5-24 Processed acoustic signals from non CLASS tap changes for T11 at Longsight.

The blue points on the figures represents pre-tap, the green is the tap event and the red is post tap. The processed acoustic data for May and June looks very similar with a tightly group of points and a few outliers for the tap event. The July event indicates a difference in the post–tap behaviour compared to the pre-tap of the transformer but the pre and actual tap behaviour is similar to May and June, i.e. a clustering of points with some outliers.

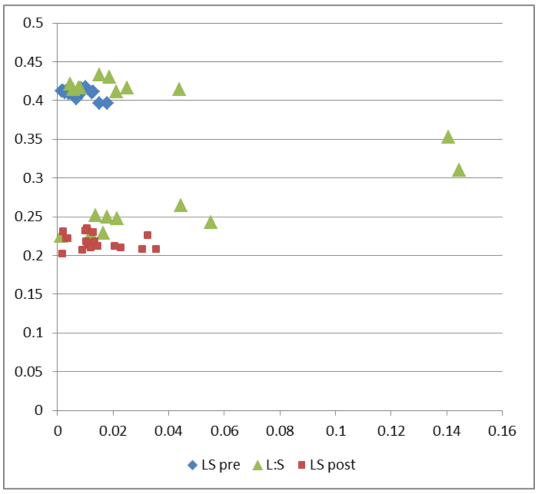
The processed acoustic signatures shown in Figure 5-23(a-e) from tap changers arsing during CLASS operations are shown in Figure 5-25(a-e).



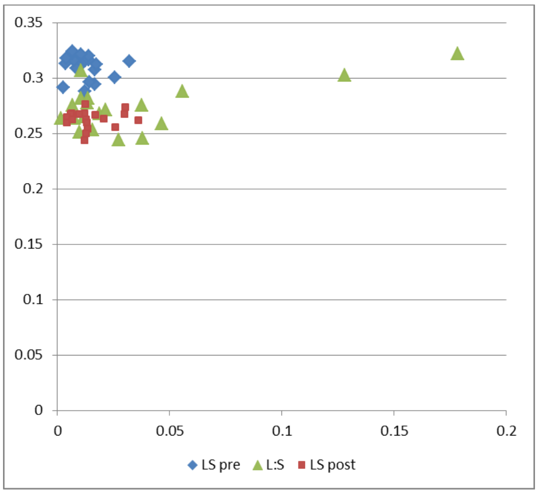
(a) T3a with no current in T11.



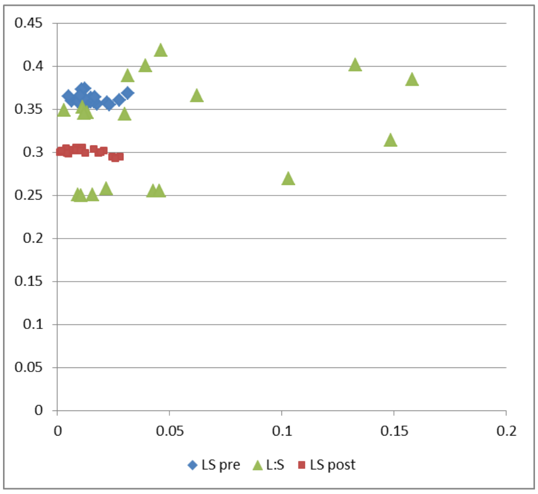
(b) T3b test on T11, a tap up in current 520A to 540A



(c) T4 test on T11, a tap up in current 500A to 535A



(d) T4 test on T11, a tap down in current 475A to 440A



(e) T4 test on T11, a tap down in current 380A to 355A

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Figure 5-25 Processed acoustic signals from T11 Longsight for CLASS network operations

Although there is more scatter of some of the points, they are still clustered together in the same area. Further analysis of the data of the whole tap process (not time sliced) provides a means of comparing the two sets of data. Figure 5-26 shows the three non CLASS (f, g, h) and 5 Class operations (a, b, c, d, and e). The pattern shows a broad grouping with one outlier (a). The conditions for this test show that at the time of the tap operation there was no load current on the transformer but there was an increase in voltage from 6475V to 6575V at that point the tap was operated (Figure 5-28 (a-b)).

Figure 5-27 shows a comparison of the base line tap changes with those for CLASS. This shows a grouping of points with a bias in the CLASS results towards the left hand side of the diagram. Points a & b and c & d are double tap events and this could account for their position. The results on this diagram do not raise any concerns.

The implications of these results are that there is a degree of variation in the signatures of the tap changers during normal operation and this is also seen in the CLASS operations but there no significant issues identified that cannot be explained.

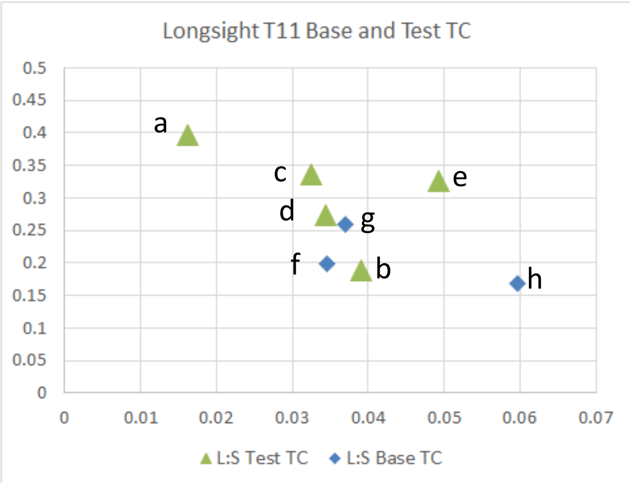


Figure 5-26 Comparison of the different tap behaviours for T11 at Longsight

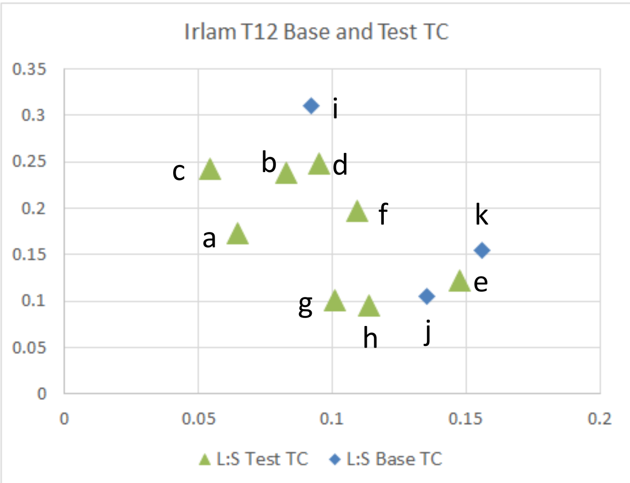
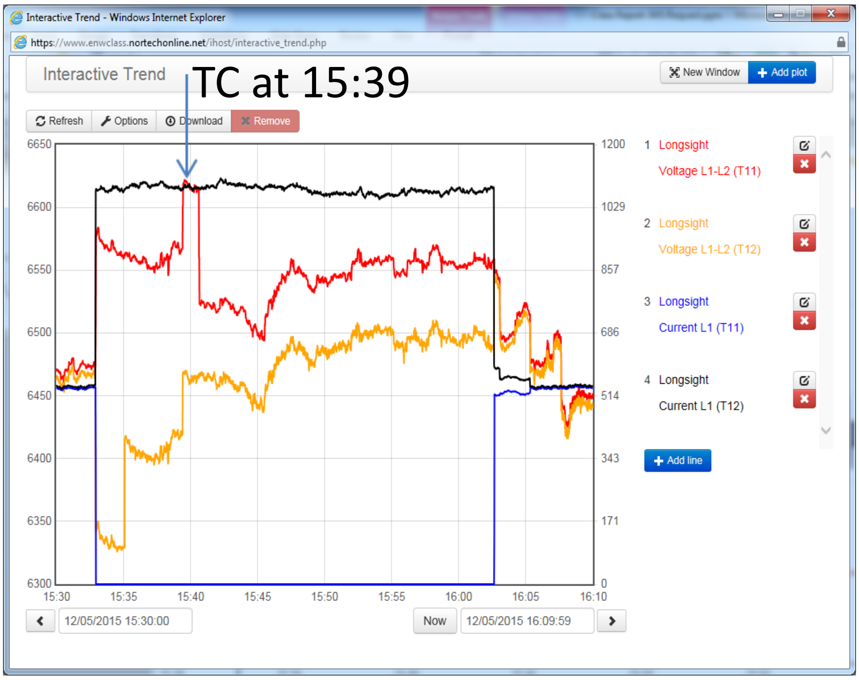


Figure 5-27 Comparison of the different tap behaviours for T12 at Irlam

(a) Reactive power in T11 and T12



(b) Current and Voltage in T11 and T12

Figure 5-28 Confirmation of T11 disconnected and tap change event at 15.39

Figure 5-28 clearly confirms a voltage increase on T11 at 15:39 due to a tap change but there is very little current flow through T11.

6 Thermal Modelling of Transformers

6.1 Introduction of Transformer Thermal Model

6.1.1 Procedure of Thermal Modelling

The procedure of thermal modelling consists of four steps: thermal model inputs, hot-spot temperature calculation, the ageing rate calculation, and the estimation of paper insulation life expectancy. Figure 6-1 illustrates a flow chart of those four steps with some details specified. The first step is just to prepare the inputs for the hot-spot temperature calculation. The method of this calculation mainly depends on the difference equations in the IEC standard 60076-7 [33]. Then the ageing rate is calculated based on the improved method in [10]. Finally, the paper insulation life expectancy is estimated with the assistance of the DP reduction model as mentioned in section 2.2.1. The following sections will discuss these four steps in detail.

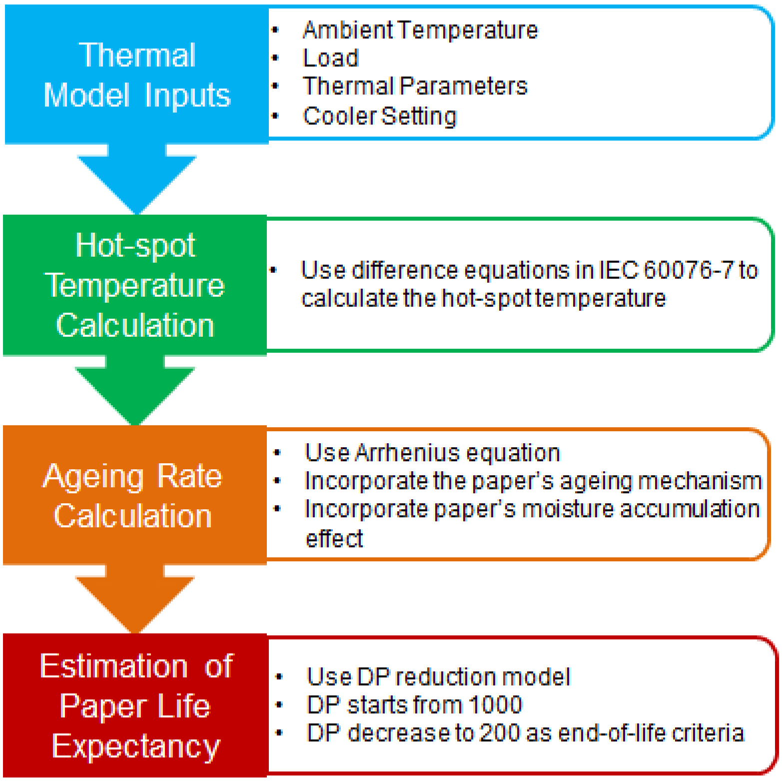


Figure 6-1 A flow chart of thermal modelling procedure

6.1.2 Thermal Model Inputs

Figure 6-1 illustrates four types of thermal model inputs: ambient temperature, load, thermal parameters and cooler setting. Each type of input will be introduced individually in this section.

I. Ambient temperature

The ambient temperature can be obtained in two ways. One is from the 'iHost' in which the ambient temperatures of three transformers (Romiley T11, Irlam T12 and Longsight T11) are measured and uploaded by Nortech Management Ltd. The other way is from the British Atmospheric Data Centre (BADC) which has a dataset titled as 'Met Office Integrated Data Archive System (MIDAS) Land and Marine Surface Stations Data (1853-current)'. This dataset contains the UK hourly weather observation data such as ambient temperature. The average ambient temperature profile for every minute is then made based on the data recorded by all the weather stations in North West England.

II. Load

One type of load data, provided by Electricity North West, is recorded every half an hour in the unit of mega volt-ampere (MVA). The first step of processing these data is to divide them by the transformer rated power, in order to get the per unit load. Then this per unit load is linearly interpolated into minute intervals, since the existing thermal model calculates the hot-spot temperature for every minute. Figure 6-2 illustrates the process of the linear interpolation, with the equally-spaced blue circles for the load in every minute interpolated between the red triangles representing the per unit load for every half an hour.

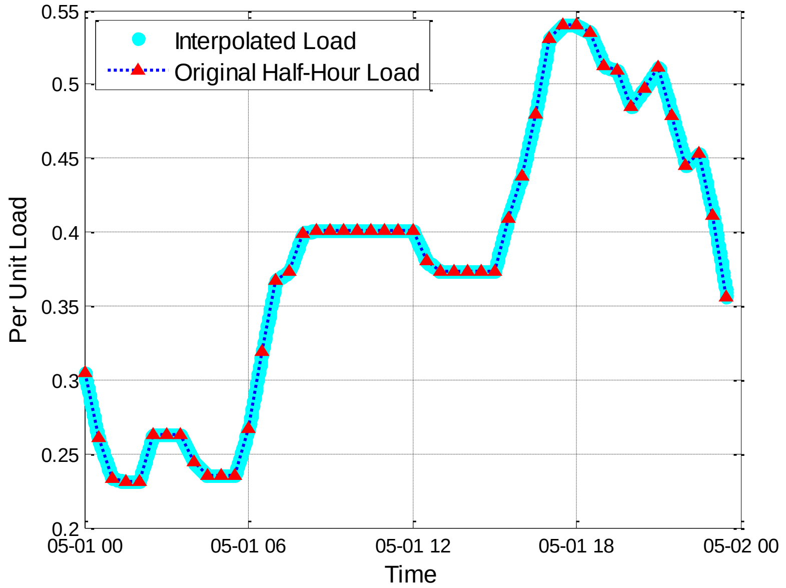


Figure 6-2 Daily loads before and after linear interpolation

Moreover, the raw load data could have some empty entries which need to be manually filled. As shown in Figure 6-3, it is quite common to have the empty entries for four days in the half-hour load database for the end of December. The data process in this report fills the empty entries by copying the load record from the previous four days.

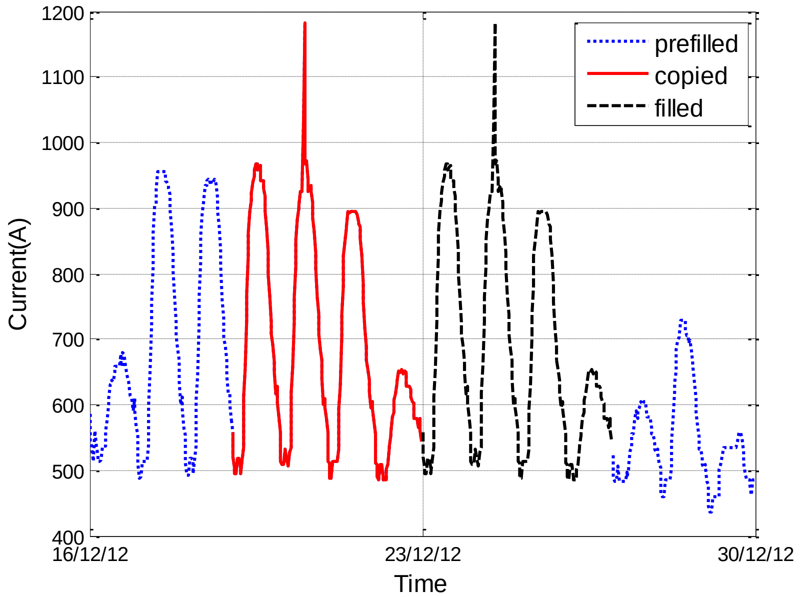


Figure 6-3 Completion of the empty entries by copying the previous records

III. Thermal parameters

In order to calculate hot-spot temperature in an accurate manner, three thermal parameters (R, $\Delta\theta_{or}$, g_r) are required from either the routine test or the heat-run test. However, in some cases, those parameters are neither recorded nor taken from the test. So the values of those parameters have to refer to the standard values in Table 2-7.

The hot-spot factor (HSF) is also required for hot-spot temperature calculation. The measurement of this factor requires the installation of optical sensors which is not feasible for the in-service transformers. In this way, the hot-spot factor has to refer to the recommended value in [33].

Other miscellaneous thermal parameters are oil exponent (x), winding exponent (y), oil time constant (ζ_o), winding time constant (ζ_w), and three thermal constants (k_{11},k_{21},k_{22}). In this thermal model, the values of these thermal parameters will be referred to the IEC standard values given in Table 2-7.

IV. Cooler setting

Table 6-1 illustrates the cooler setting for most primary transformers. The pump and fan would be switched on and off based on the reading of the winding temperature indicator (WTI). If below 55°C (above 70°C), the pump will be off (on) and the transformer will be kept in or switched to ONAN (OFAF) mode. For the detected temperature between 55°C and 70°C, the transformer will operate under its previous mode. The fan operates in the same way as pump, with the controlling temperature 5°C higher than that of pump. In this case, the pump is always switched on before the start of fan and also switched off after the stop of fan.

Table 6-1 Setting for winding temperature indicator contacts [6]

Function	Setting
Stop oil pump at falling temperature	55°C
Stop fans at falling temperature	60°C
Start oil pump at rising temperature	70°C
Start fans at rising temperature	75°C

The switching of pump and fan will cause the transition of the cooling mode as shown in Figure 6-4. Since the existing IEC standard classifies OFAN and OFAF into OF in Table 2-7, the cooler setting for transformers in Figure 6-4 only needs to consider two control temperatures of pump—55°C and 70°C.

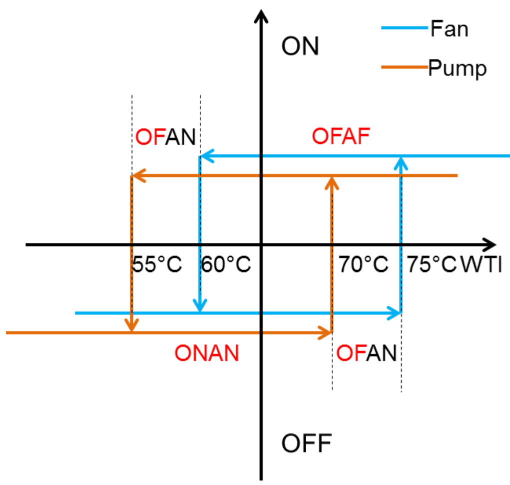


Figure 6-4 Diagram of cooler settings for typical ONAN/OFAF transformers

The cooler switching will cause the change of thermal parameters and power ratings. In the thermal modelling, the power ratings choose the continuous loading in The different design philosophies of these two sets of transformers contribute to their different rating policies. As shown in Table 2-1, the large power rating of the Integrated System Transformer refers to the long-time emergency rating at the 0°C ambient temperature, while the large rating of the British Standard transformer refers to the continuous rating at 20°C. The rating is never a constant. The drop of ambient temperature and the working of cooler can somehow raise the ratings of primary transformers as shown in Table 2-1. Table 2-1 at the ambient temperature of 20°C in consistence with the ambient temperature in Table 2-7 which the thermal parameters are based on.

6.1.3 Hot-spot Temperature Calculation

Difference Equations 6 to 11 are applied to calculate the hot-spot temperature. In order to ensure a reasonable accuracy, the time step (Dt) in difference equations is set to one minute which is much smaller than the half of both the oil and winding time constants. Moreover, both the ambient and load should be kept constant for 24 hours in order to stabilise the initial temperature. Therefore, it is necessary to initially do some additional temperature calculations for 24 hours based on the averages of the input ambient temperature and load in the first 24 hours.

The following part in this section calculates the temperature for only one single day, when the tripping of transformer T11 accidentally happened causing the doubled current in the other parallel transformer T12 in Figure 6-5. During that day, the input ambient temperature is quite stable, with fluctuations less than 5°C as shown in Figure 6-5. Moreover, the cooler sets the control temperature as 55/70°C for ONAN/OFAF cooling modes, and the thermal parameters of each mode are based on both the IEC 60076-7 and the heat-run test in Table 6-2.

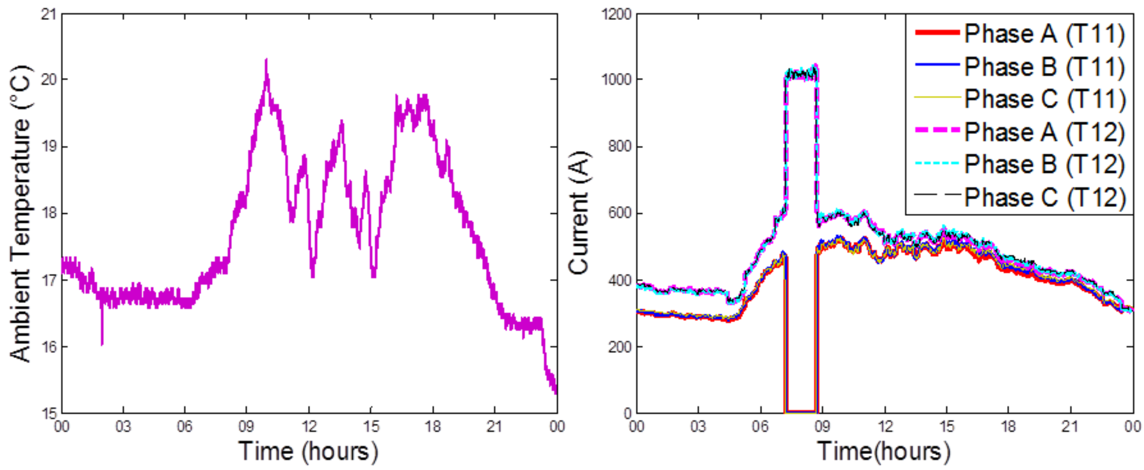


Figure 6-5 Ambient temperature and load profiles of Irlam transformers on the 3rd of June 2015

Table 6-2 Thermal parameters for different cooling modes

From	Mode	R	g_r	$\Delta\theta_{or}$	HSF	x	y	ζ_o	ζ_w	k_{11}	k_{21}	k_{22}
TEST	ONAN	10.2	6.9	46.7	1.3	0.8	1.3	210	10	0.5	2.0	2.0
IEC	ONAN	6	20	52	1.3	0.8	1.3	210	10	0.5	2.0	2.0
IEC	OFAF	43.8	16.9	56	1.3	1.0	1.3	90	7	1.0	1.3	1.0

(Note: unmarked parameters are based on IEC 60076-7)

The hot-spot and top-oil temperatures are then calculated in Figure 6-6, based on the inputs of the ambient temperature, the daily load profile, thermal parameters and cooler settings. The hot-spot temperature is always higher than the top-oil temperature under the same thermal parameters, due to the existence of the winding-to-oil temperature gradient. In Figure 6-6, the switching happens in the calculation based on IEC standard values, as the hot-spot temperature bounce between 55°C and 70°C.

The measured top-pipe temperature, which shows the temperature of the metallic surface of top pipe, could be considered as an indicator of top-oil temperature, as the top oil flows directly into the radiator via the top-pipe. In most of times, the calculated top-oil temperature based on the thermal parameters from the heat-run test is much closer to the measured top-pipe temperature than the top-oil temperature based on IEC standard parameters in Figure 6-6. In this case, a conclusion can be drawn that the hots-pot temperature calculation based on the results of heat-run test is more accurate than the IEC standard calculation which could only overestimate the temperature. However, in practice, the hot-spot temperature calculation based on the IEC standard values is usually made as a conservative method, considering the difficulty to obtain the heat-run test data for the old in-service transformer.

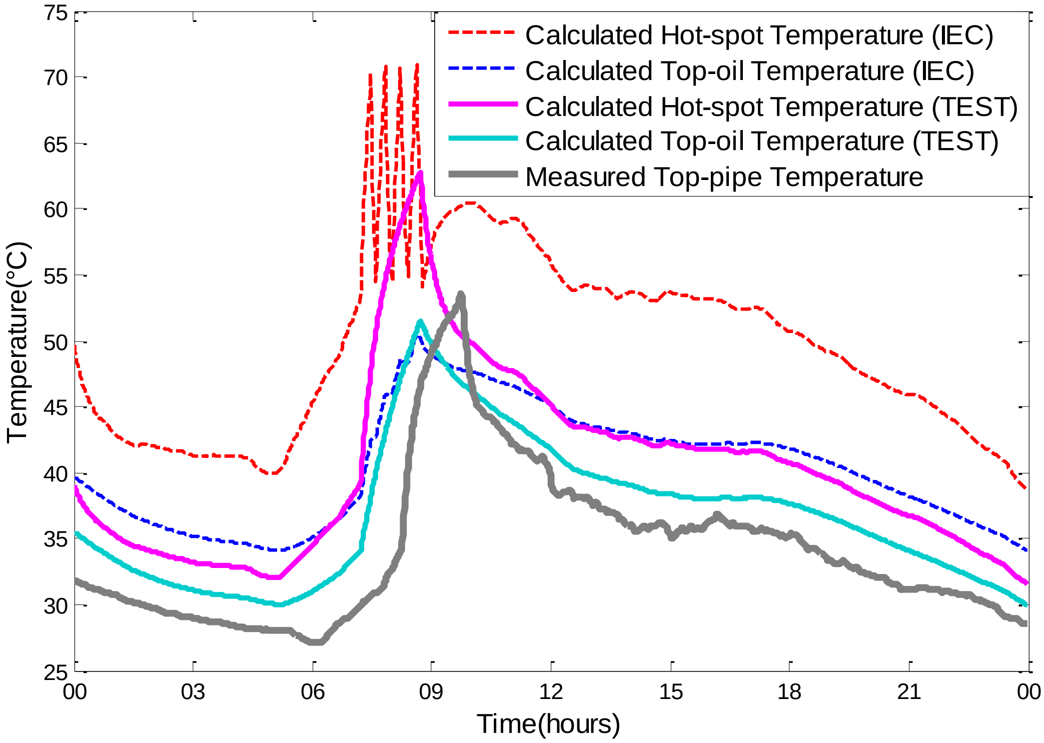


Figure 6-6 Profile of the hot-spot and top-oil temperatures

6.1.4 Ageing Rate Calculation

The ageing rate is calculated based on the hot-spot temperature by uses the ageing model developed by the University of Manchester in [10]. This model incorporates the different ageing mechanisms (such as oxidation and hydrolysis) into the Arrhenius equation by setting the temperature range for each ageing mechanism according to section 2.3.1.

The setting depends on a critical temperature—60°C. When the calculated hot-spot temperature is below (above) this critical temperature, the oxidation (hydrolysis) dominates and the ageing rate is then calculated based on two corresponding parameters for oxidation (hydrolysis). Those two parameters are the activation energy (E_A) and pre-exponential factor (A) as shown in Table 2-2. The activation energy (E_A) has two constant values—89kJ•mol^{-1} and 128kJ•mol^{-1} for oxidation and hydrolysis respectively. The pre-exponential factor (A), however, depends on not only the ageing mechanism but the paper moisture content in the process of hydrolysis. In this way, the accumulative effects of paper moisture could be also incorporated into the ageing model by obtaining different pre-exponential factors for different contents of moisture dissolved in cellulose paper.

However, there are only three pre-exponential factors available for three different paper moisture contents—0.5%, 1.5% and 3.5%. Two of those factors are provided in Table 2-2 for 1.5% and 3.5% paper moisture content. The other pre-exponential factor has been calculated as 2.81×10^{10} for 0.5% paper moisture content. This calculation is based on the assumption that it takes the well-dried and oxygen-free transformer 15000 hours to reach the paper's end-of-life at a constant temperature of 98°C, with its DP decreasing from 1000 to 200.

In order to obtain the pre-exponential factors for other paper moisture contents, the relationship between the pre-exponential factor and the paper moisture content is established through curve fitting based on those three available pre-exponential factors in Figure 6-7. Moreover, An equation is derived for the fitted curve as expressed in Equation 21, based on which the pre-exponential factors for the paper moisture content of 1% and 2% are calculated as shown in Figure 6-7.

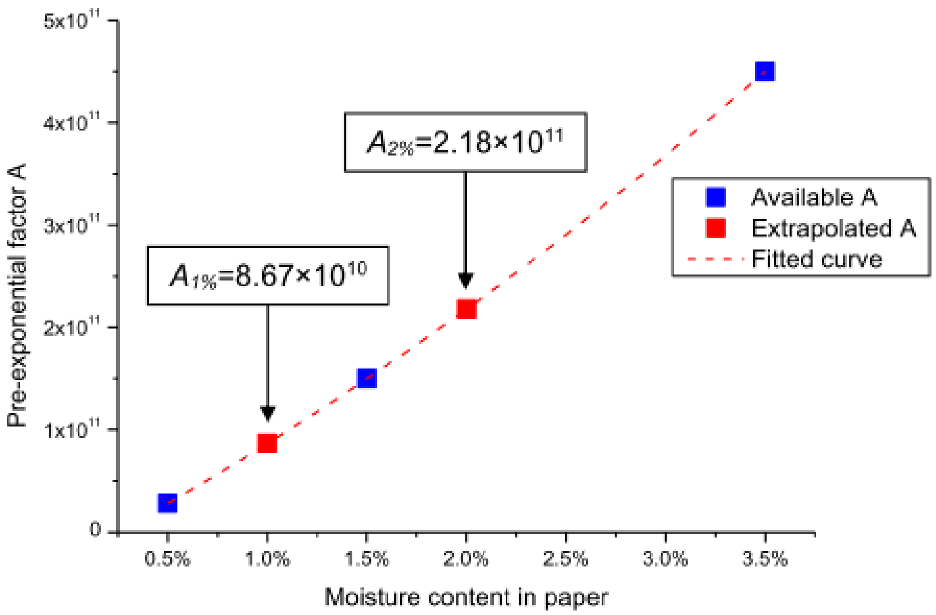


Figure 6-7 Extrapolation of pre-exponential factor A through curve fitting [10]

$$A = 9.37 \times 10^{13} \times moisture^2 + 1.03 \times 10^{13} \times moisture - 2.58 \times 10^{10} \qquad \text{(Equation 21)}$$

For an in-service transformer, it is impossible to directly measure the content of moisture dissolved in paper without physical damage of paper. Moreover, it would be difficult to calculate the moisture content of paper based on that of oil, partly due to dynamic partitioning of moisture between paper and oil. Therefore, the University of Manchester chooses to correlate the paper's moisture content with DP value, by making an assumption as follows,

> **'The moisture content of the modelled transformer's cellulose paper is 1%, 1.5% and 2% within the DP range of 1000-500, 500-250, and 250-200 respectively, and the pre-exponential factor A would be assigned with the value according to the moisture content to which paper is subjected'**

This assumption is based on the finding in [25] that paper's moisture content increases by 0.5% every time when DP is halved. Three typical moisture contents (1%, 1.5% and 2%) are chosen to reflect the average ageing rate at three stages (relatively new, moderate ageing and end-of-life) of paper's life. In summary, all the values of pre-exponential factors A and activation energies E_A which are used in the thermal model are presented in Table 6-3.

Table 6-3 Complete values of activation energies (E_A) and pre-exponential factors (A) used in the thermal model [10]

	Oxidation	Hydrolysis		
Parameters	Dry, oxygen access	1.0% water in paper	1.5% water in paper	2.0% water in paper
E_A (kJ/mol)	89	128	128	128
A (hour^{-1})	4.6×10^{5}	8.67×10^{10}	1.5×10^{11}	2.18×10^{11}

The comparison is then made between the ageing rates calculated by the UoM model and the IEC 6-Degree Rule. The ageing rate of the UoM model is an absolute value, while that based on IEC 6-Degree Rule is just an ageing ratio with respect to 98°C as shown in Equation 22.

$$k_{IEC} = 2^{(\theta_h - 98)/6} \qquad \text{(Equation 22)}$$

Hence, it is necessary to convert the absolute ageing rate into the relative value. The conversion is to divide the absolute ageing rate by the reference ageing rate based on the reference parameters in Table 2-2. Results of comparison are shown in Figure 6-8. The relative ageing rates of the UoM model are always above those of the IEC 6-Degree Rule, whatever the temperatures and ageing mechanisms. Therefore, it can be concluded that the UoM model is more conservative than the IEC model in aspect of ageing rate calculation.

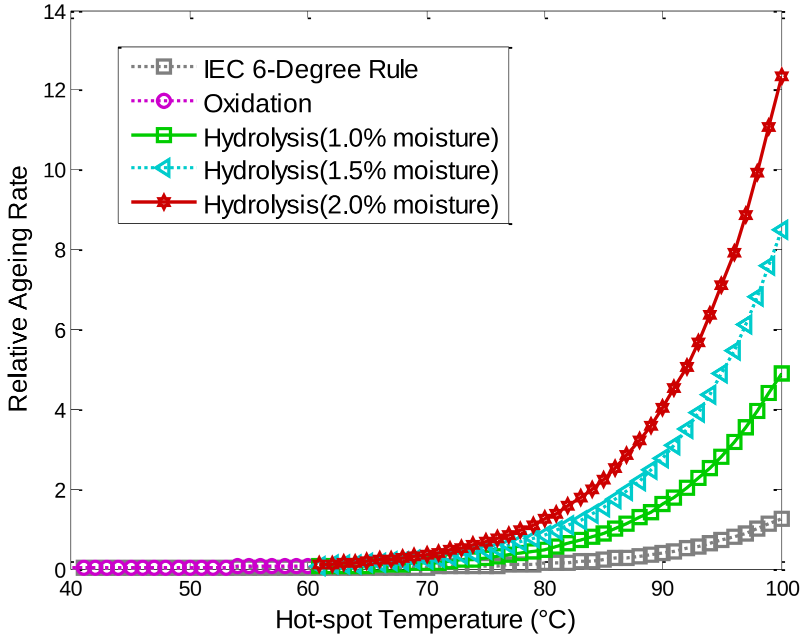


Figure 6-8 Ageing rates at different temperatures based on different ageing mechanisms

6.1.5 Estimation of Paper Life Expectancy

The estimation of thermal life expectancy requires the combination of the Arrhenius equation and DP reduction model as expressed in Equation 23.

$$A \times e^{-\frac{E_A}{R_{gas} \times (\theta_h + 273)}} = \frac{\frac{1}{DP_t} - \frac{1}{DP_0}}{t} \qquad \text{(Equation 23)}$$

The ageing rate (k) for every minute is calculated based on the Arrhenius equation (on the left-hand side) with the activation energy E_A controlled by the ageing mechanism and the pre-exponential factor A by the moisture content. The results of this calculation are then averaged in order to get the annual average ageing rate ($k_{average}$).

Based on that rate ($k_{average}$), the DP retention (DP_t) is calculated through the DP reduction model on the right-hand side of Equation 23. Every time the DP retention (DP_t) is halved, the moisture content will increase by 0.5%, causing the increase of the exponential factor A as well as the annual average ageing rate ($k_{average}$).

The paper's DP starts from 1000. Transformer's paper insulation life expectancy is the time that takes to make the DP decrease to 200 as the end-of-life criteria of cellulose paper as mentioned in section 2.3.1.

The comparison is made between the paper life expectancies of the UoM model and the IEC model. Table 6-4 illustrates the conservativeness of the UoM model as its paper insulation life expectancies are always smaller than the life expectancies based on IEC 6-Degree Rule. The following section will apply this conservative model to a single transformer.

Table 6-4 Comparison of paper life expectancies between the improved thermal model and IEC model

Constant Hot-spot Temperature (°C)	40	50	60	70	80	90	98	100
Paper life expectancies based on the improved thermal model (years)	1182	404	147	53	15	4.7	1.9	1.5
Paper life expectancies based on the IEC 6-Degree Rule (years)	13914	4383	1380	435	137	43	**17.12**	13.6

(Note: the reference paper life expectancy for IEC model is set to 17.12 years.)

6.2 Modelling Exercise on a Single Transformer

6.2.1 Assumptions of Thermal Modelling

In this section, the thermal model is applied to estimate the paper insulation life expectancy of a single transformer (Longsight T11), based on the following assumptions:

- Assume the given annual load data from the half-hour load database can represent the historical loading of the modelled transformer.

- Assume the annual ambient temperature in the BADC can represent the historical ambient temperature of the modelled transformer.

Moreover, by taking the thermal design into consideration,

- Every modelled transformer is assumed to be the IEC standard transformers with its thermal parameters corresponding to those ‘standard’ parameters in Table 2-7.

This assumption could overestimate the oil temperature of some old transformers as the top-oil temperature rise of 52°C in the existing loading guide in [33] is larger than the previous limit (50°C) of top-oil temperature rise in [41]. The accuracy of temperature detection is another concern. This report neglects the inaccuracy of winding temperature indicator (WTI), so an assumption is made as follows,

- The WTI can accurately detect the hot-spot temperature and immediately triggers the operation of pumps and fans.

As mentioned in section 6.1.2, the cooler setting for the primary transformer with pump and fan only needs to consider the start and stop temperatures of the pump. Those two temperatures are 55°C and 70°C for most pumps in the primary substation transformers. However, there are some pumps with the stop temperature at 50°C lower than 55°C according to the policy of transformer ratings [6]. Those pumps would keep their transformers at a lower operating temperature. The thermal modelling in this report, however, neglects the setting of the lower temperature and makes an assumption as follows.

- The modelled transformer with pump and fan will be switched to OF (ONAN) mode at the WTI temperature of above 70°C (below 55°C). For the WTI temperature between 55°C and 70°C, the modelled transformer will operate under its previous mode.

The switching of the cooling mode will cause the change of power ratings.

- It is assumed that the power ratings can be changed immediately after cooler switching, with a transitional stage neglected.

As mentioned in section 6.2.2, the continuous loading in Table 2-1 at the ambient temperature of 20°C are selected as the power ratings for thermal modelling. So for the Integrated System Transformers, power ratings at the forced cooling mode are smaller than the large nameplate ratings as shown in Table 6-5. This smaller rating will results in the slightly larger per unit load under the forced cooling mode. In this way, the hot-spot temperature will be conservatively overestimated in the thermal modelling.

Table 6-5 Ratings for ONAN/OFAF Integrated System Transformers [6]

Nameplate Rating (MVA)	4 / 8	7.5 / 15	11.5 / 23	16 / 32	19 / 38
Continuous Rating at 20°C (MVA)	4 / 6.25	7.5 / 12	11.5 / 18	16 / 25.25	19/30

6.2.2 Model Input Settings

This section focuses on the input settings for the thermal modelling of Longsight T11. Figure 6-9 illustrates the input of the ambient temperature which is the average ambient temperature of all the weather station in North West England in 2012. Figure 6-10 shows the load profile which corresponds to the time in Figure 6-9, per unit input given as what was initially calculated based on the power rating (11.5 MVA) under ONAN mode.

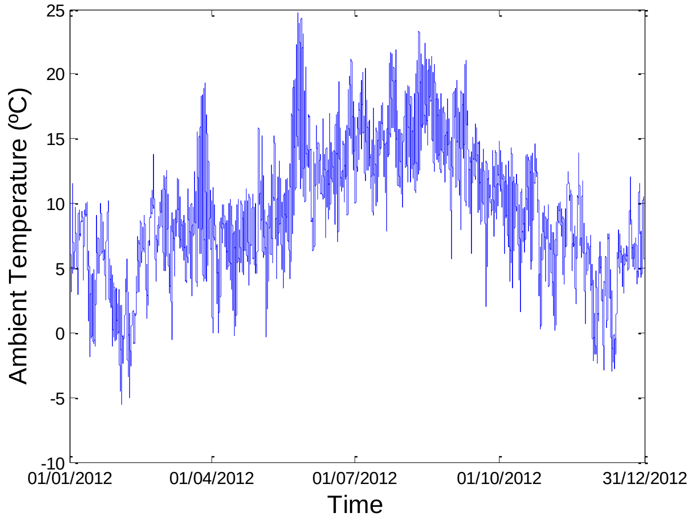


Figure 6-9 Annual profile of the ambient temperature

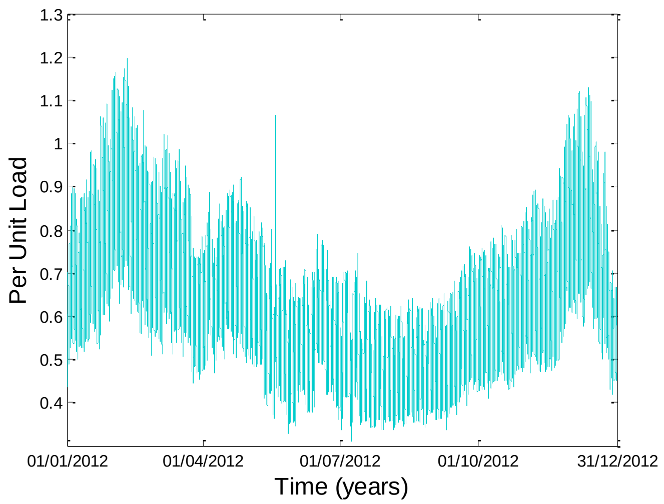


Figure 6-10 Annual profile of the per unit load based on ONAN power rating

Since Longsight T11 is equipped with both pump and fan, the thermal parameters refer to the values of parameters for the ONAN and OF cooling modes in Table 2-7. The switching between these two cooling modes depends on the control temperatures of pump (55/70°C) as explained in section 6.1.2. If that temperature is below 55°C (above 70°C), the pumps and fans will be off (on) and the transformer will be kept in or switched to ONAN (OF) mode in Table 2-7. For other measured temperatures, the transformer will operate under its previous mode. The change of cooling mode is usually accompanied with the transition of the power rating. The thermal modelling conservatively chooses the 11.5/18MVA continuous ratings at the ambient temperature of 20°C, for the Integrated System Transformer—Longsight T11 with the nameplate power ratings of 11.5/23MVA.

6.2.3 Calculation Results

In this section, the hot-spot temperatures are calculated based on those thermal inputs in section 6.2.2. Figure 6-11 illustrates the annual profile of hot-spot temperature, with most temperatures below 70°C. This is partly due to the effective cooling of pump and fan. Moreover, the high hot-spot temperatures fluctuating around 70°C mainly happen in the winter month—January, February and December. This can be attributed to the high load (with per unit value over one based on the ONAN rating) during the same time as shown in Figure 6-10.

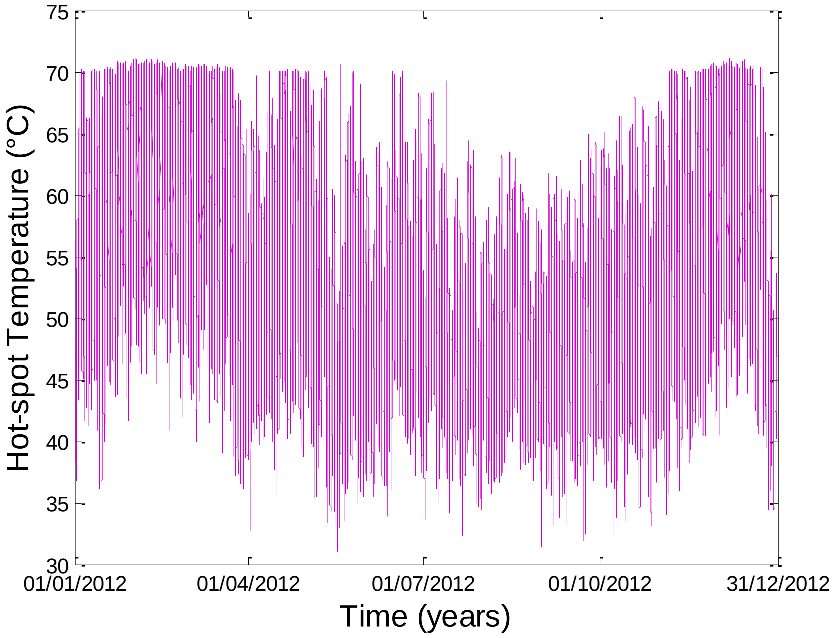


Figure 6-11 Annual profile of hot-spot temperature

Paper ageing rates are calculated by substituting each value of hot-spot temperature into the Arrhenius equation, with the consideration of paper's ageing mechanism and moisture accumulation effects. Figure 6-14 illustrates profiles of ageing rates in October 2012 with paper moisture contents of 1%, 1.5% and 2% which correspond to different DP retentions in the range of 1000-500, 500-250 and 250-200 respectively. The ageing acceleration effect of moisture accumulation in paper is also illustrated in Figure 6-14, with the large ageing rate corresponding to the high moisture content. Then the annual average ageing rates ($k_{average}$) for each type of ageing is calculated by averaging the ageing rates for every minute in a year.

The DP reduction model is finally applied to assess this transformer's life expectancy in Figure 6-13. The process of DP reduction is also controlled by annual average ageing rates ($k_{average}$). As shown in Figure 6-13, the reduction process is marked in different colours, with each colour indicating an ageing rate at a certain level of moisture content in paper. The DP retention finally drops down to 200 (end-of-life-criteria) after 190 years. Therefore, the paper insulation life expectancy is assessed as 190 years for this modelled transformer, based on the existing thermal model, inputs and assumptions. Such a large life expectancy of paper insulation can be attributed to the low hot-spot temperatures with median value of about 54°C which is just between the 147 and 404 years for 60 and 50°C respectively.

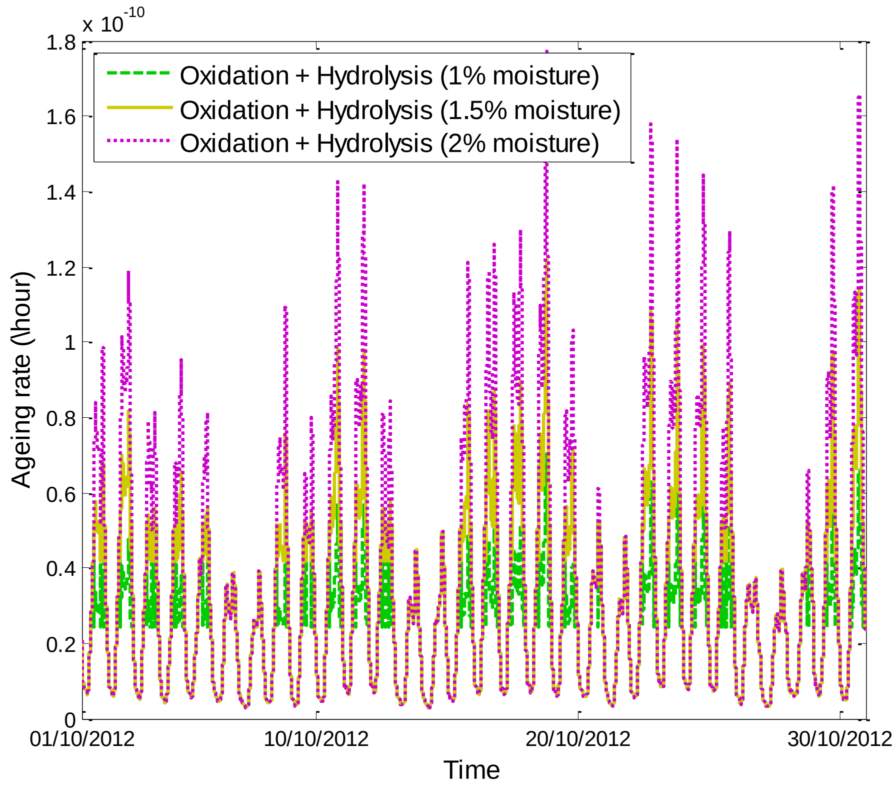


Figure 6-12 Instantaneous ageing rates with different moisture contents in paper

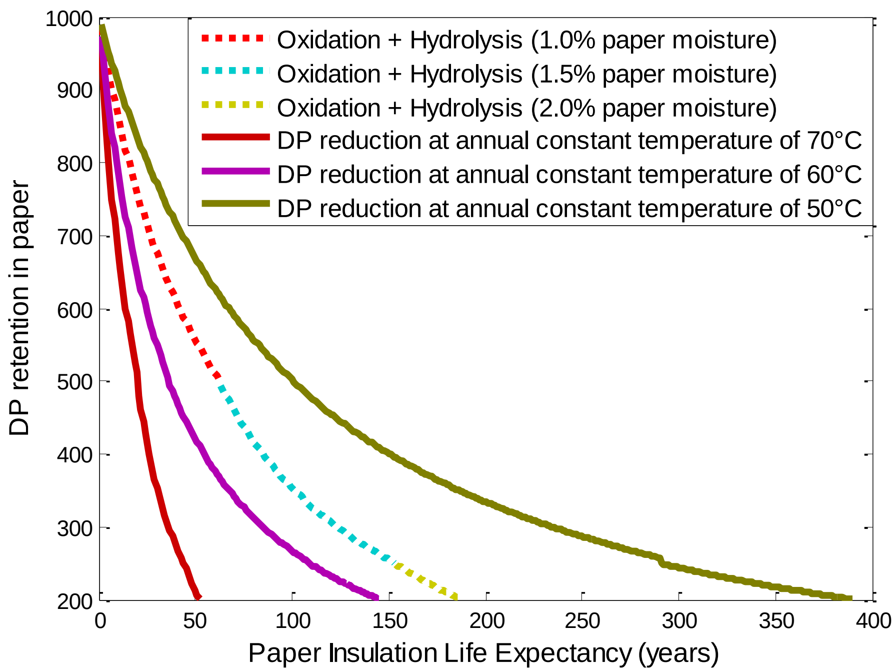


Figure 6-13 Reduction of DP throughout paper insulation life expectancy

6.3 Result Analysis for Transformer Population

Paper insulation life expectancies for over one hundred transformers are calculated based on the selected thermal model, the set inputs and the assumptions in section 6.2.1. As shown in Figure 6-14, most of life expectancies are quite large with the median value of 1213 years and the minimum value of 93.6 years.

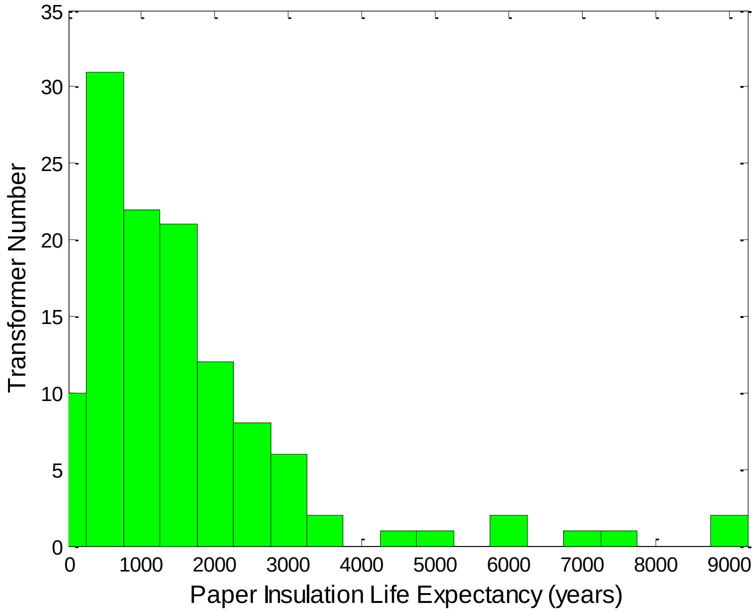


Figure 6-14 Distribution of paper insulation life expectancies

The large life expectancies can be attributed to the low hot-spot temperatures (in Figure 6-15) which can be attributed to two reasons: 1) the relatively low equivalent load (underutilisation) in Figure 6-16 for most of transformers: 2) the cooling effects of pump and fan. In spite of this, there are a few isolated cases which the temperature exceeds 70°C which are possible caused by unusual peak loads greater than 1 p.u. as shown in Figure 6-16. Those high peaks cannot be neglected in the followed thermal assessment of CLASS techniques, due to their potential to cause the accelerated ageing and unexpected high temperature.

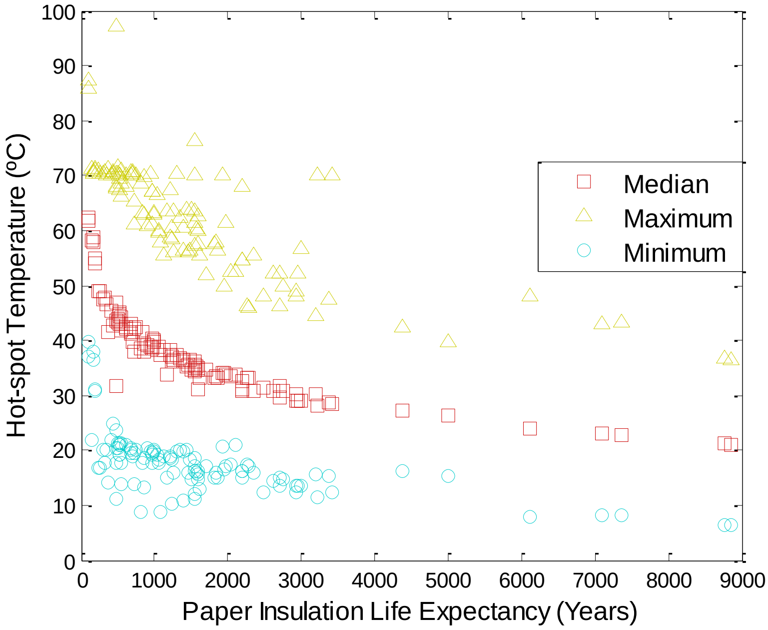


Figure 6-15 Statistics on hot-spot temperatures for different paper life expectancies

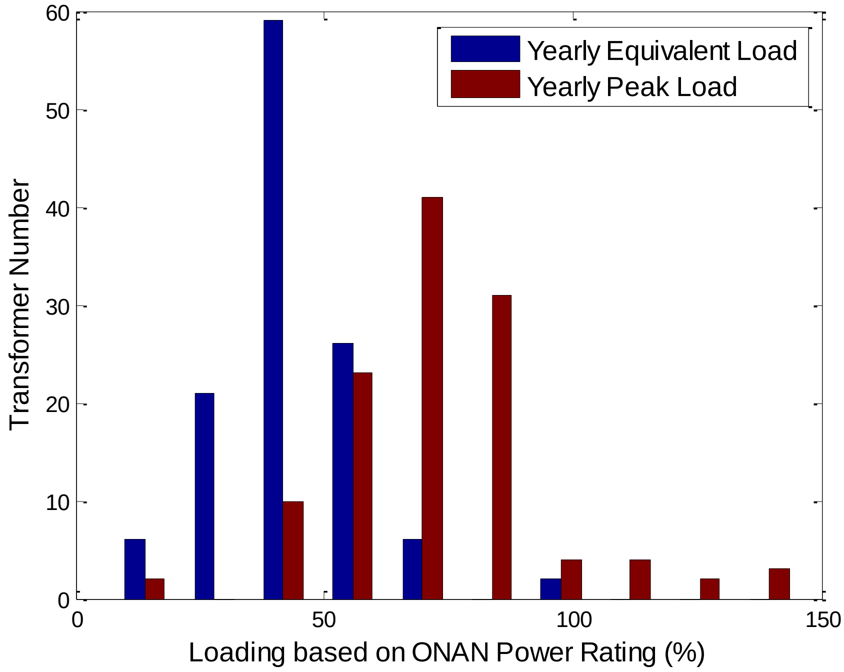


Figure 6-16 Distribution of transformer loads

7 Assessment of Impacts on Main Tank Health

In this chapter, the assessment of impacts on main tank health mainly focuses on the transformer tripping (tested in Trial 3a) and the tap staggering (tested in Trial 4), as those two operational modes could increase the current and further cause higher hot-spot temperature to shorten the paper insulation life expectancy. The assessment starts with the thermal modelling of over one hundred transformers based on the worst scenarios of those two operational modes, followed by the modification and comparison of health indices. Finally, a loading guide for new operational scenarios is built by considering the health of transformer main tank as well as the safe operation of the network.

7.1 Thermal Assessment of Transformer Tripping

In this section, the assessment of transformer tripping is based on the worst operational scenario: one of the transformers in a substation is always tripped for one hour at the peak load of each month every year.

The assumption arbitrarily sets the tripping at the time of monthly peak load, based on the statement in [42] that the frequency-managing service will be provided at any time of low frequency (49.7Hz) throughout the year. Since the low frequency (49.7Hz) typically occurs approximately once a month according to the historic National Grid Electricity Transmission (NGET) frequency excursion data in [42], the operational scenario assumes the transformer is going to be tripped once a month. Moreover, the duration of tripping time is set to a conservative value—one hour which is much larger than the 30-minute duration specified in [42].

At this stage, it is not decided which transformer in a substation is going to be tripped for the future frequency-managing service. So the future load profiles are made in a conservative manner, by just artificially doubling the peak current for an hour each month for every transformer in the population as an example in Figure 7-1.

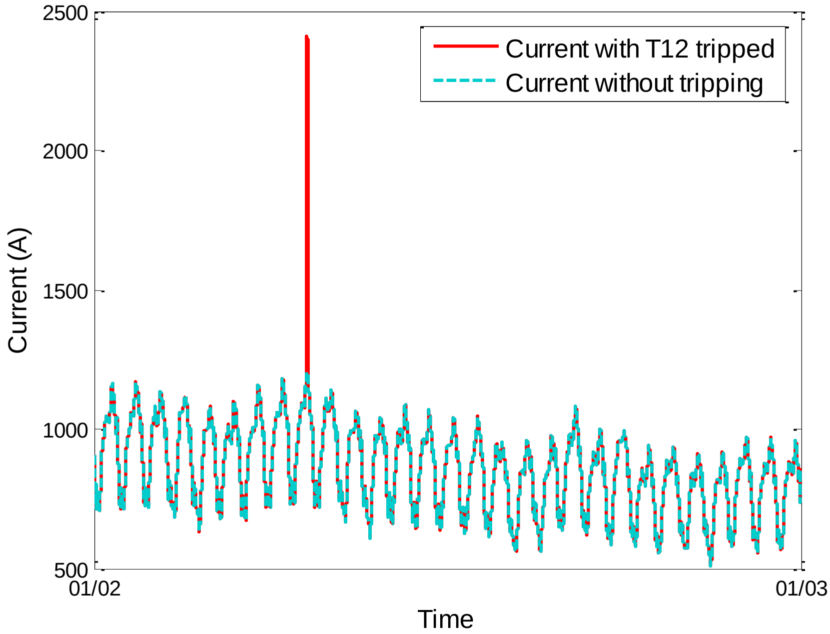


Figure 7-1 Different load profiles for Longsight T11 with and without tripping Longsight T12

The paper insulation life expectancies are then calculated based on those new load profiles. As shown in Figure 7-2, paper life expectancies with transformer tripping do not change much from those life expectancies without tripping in Figure 6-14. In spite of this, there are around 5% transformers cannot be neglected as their paper life expectancies are largely shortened to below 70 years as summarised in Table 7-1. The large reduction of paper life expectancies could be attributed to the increase in the number of the occurrences of high hot-spot temperatures caused by the transformer tripping at the time of high peak load as shown in Figure 7-3. There are over 14% transformers with the hot-spot temperature exceeding 90°C. These high hot-spot temperatures could further affect the safe operation of the network as the transformer could alarm and trip at over 90°C and 120°C respectively [6].

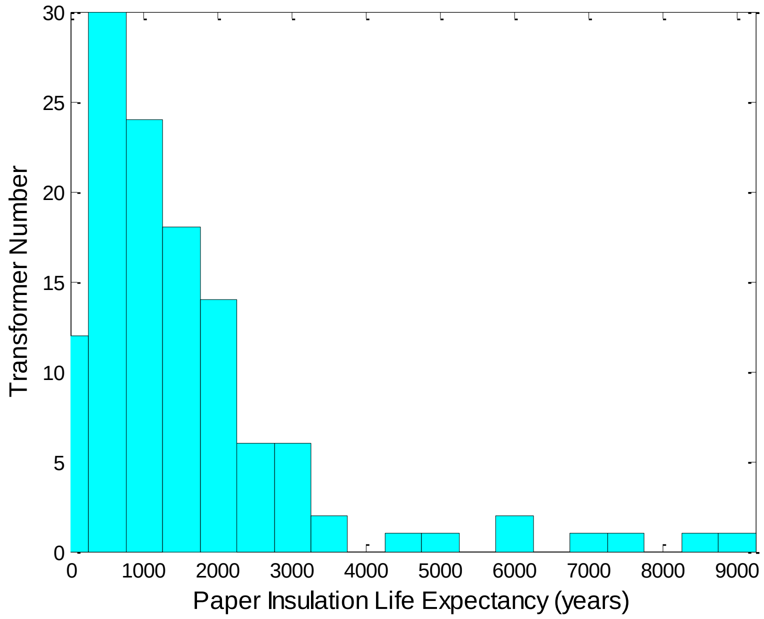


Figure 7-2 Distribution of paper insulation life expectancies for transformer tripping

Table 7-1 Five paper insulation life expectancies with and without transformer tripping

Life expectancies with tripping (years)	1.75	2.06	5.66	43.25	51.94
Life expectancies without tripping (years)	99.05	93.61	477.14	154.25	154.56

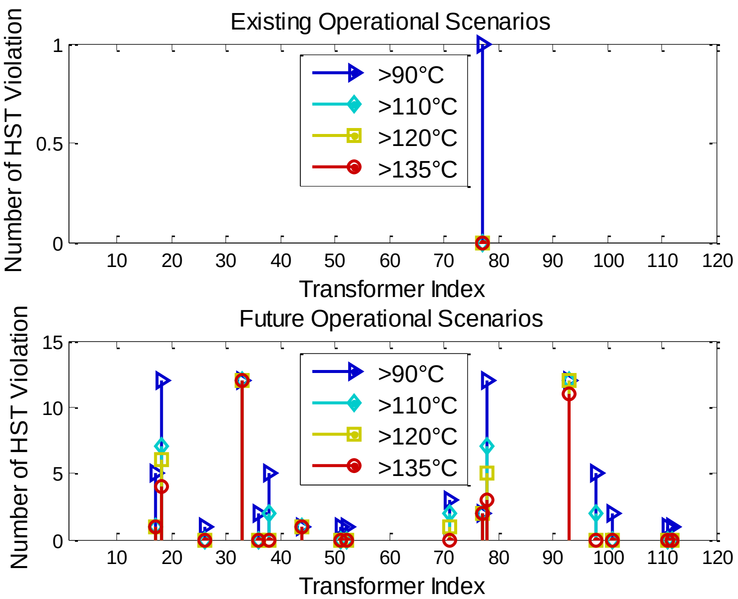


Figure 7-3 Statistics on high hot-spot temperatures caused by transformer tripping

In conclusion, the frequency-management service by transformer tripping is applicable to most of the substations without high peak load. For a small number of transformers with high peak load, the tripping could be only applied at some certain loading scenarios in order to avoid the accelerated ageing and the temperature violation. Those loading scenarios will be specifically discussed in section 7.4.

7.2 Thermal Assessment of Tap Staggering

The assessment of tap staggering is also based on the assumed worst operational scenario that the tap stagger always happens with a 150A current increase in a transformer, during 02:00–06:00 a.m. every day in the summer months (from June to August) every year.

The assumption of tap staggering in every summer day is based on the statement in [42] that the service of reactive power absorption by tap staggering would typically be required during the times of the lowest load—overnight, weekends and public holidays in the summer months. Moreover, the longest trial period (02:00–06:00 a.m.) in [42] combined with the maximum current increase (150A) is conservatively chosen in order to study the long-term accumulative thermal effects on paper life expectancies due to the possible highest current increase caused by tap staggering.

At this stage, it is not decided which transformer in a substation is going to be at the higher tap position than the other in the implementation of tap staggering in the future. So the future load profiles are made in a conservative manner by just increasing the current by 150A from 02:00 to 06:00 a.m. every summer day as shown in Figure 7-4.

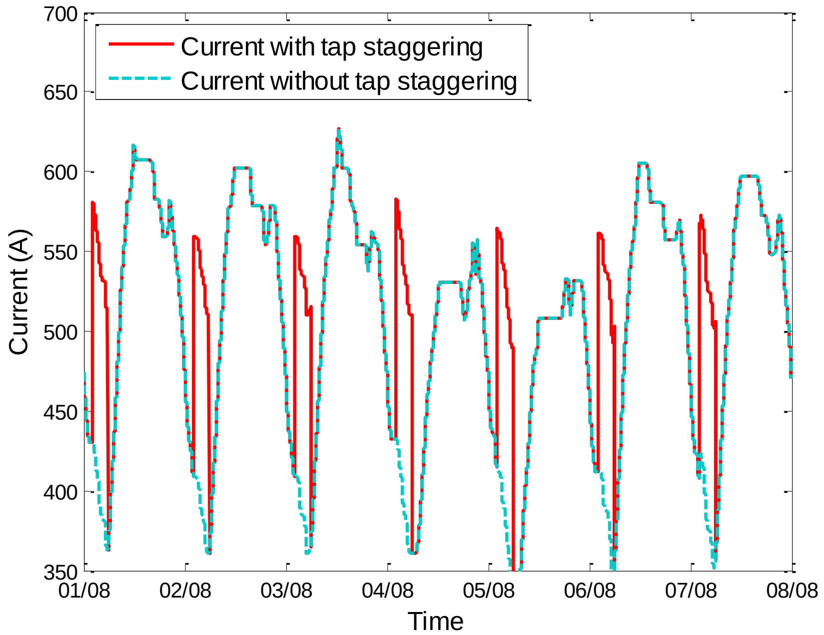


Figure 7-4 Load profiles with and without current increase due to tap staggering

The paper insulation life expectancies are then calculated based on the new load profiles. As shown in Figure 7-4, the distribution of paper insulation life expectancies with tap staggering is quite similar to that without tap staggering in Figure 6-14. This similarity can be attributed to the fact that the additional load caused by tap staggering is relatively small and can be considered as the normal variation of the load profile. The paper life expectancies with tap staggering are quite large, with the top five smallest values even exceeding the expected transformer lifetime—70 years in Table 7-2. Therefore, a conclusion can be drawn that the impact on the health of transformer main tank can be neglected when implementing the service of reactive power absorption by tap staggering in the future.

Moreover, tap staggering can be even neglected from the system safety point of view, as there is no evidence showing the assumed worst operational scenario of tap staggering is correlated with the increase in the number of high hot-spot temperatures as shown in Figure 7-6.

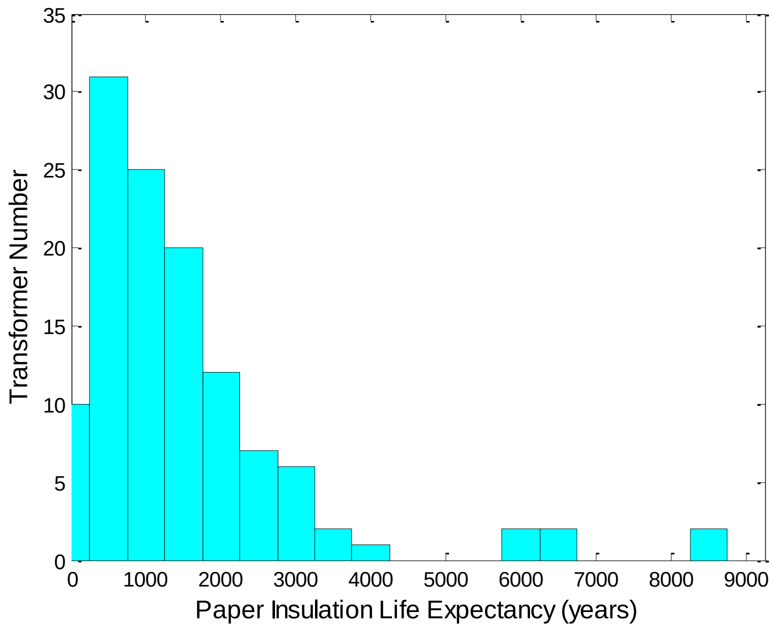


Figure 7-5 Distribution of paper insulation life expectancies for tap staggering

Table 7-2 Top five smallest paper insulation life expectancies with and without tap staggering

Life expectancies with tap stagger (years)	91.07	95.85	149.02	149.55	150.47
Life expectancies without tap stagger (years)	93.61	99.05	154.24	154.56	160.99

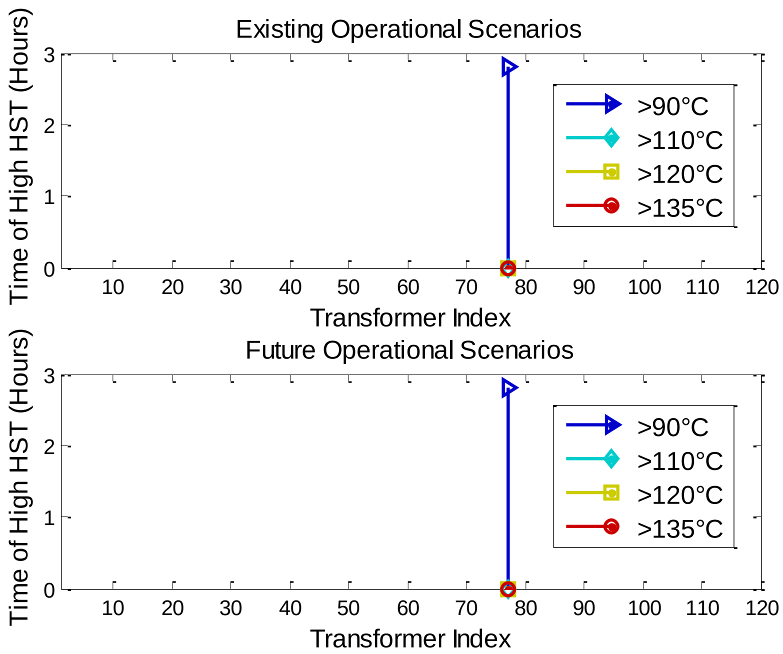


Figure 7-6 Statistics on high hot-spot temperatures caused by tap staggering

7.3 Modification of Transformer Health Index

According to the thermal modelling, only a handful of transformers with high peak loads will have paper life expectancies reduced below the expected in-service asset lifetime (70 years) due to the implementation of transformer tripping. In contrast, the impacts of tap staggering are negligible with all the paper insulation life expectancies in excess of 90 years. Therefore, in this section, the modification of transformer health index is only based on the simulation results of transformer tripping.

The health index modification is based on the philosophy that the in-service life of an asset must be no more than the life expectancy of one of its components. So the final modified expected life should be no more than the existing expected life modified by the environmental factor and load duty factor as well as the paper life expectancy as shown in Equation 24. In this way, the ageing constant of health index could be changed for some transformers as shown in Equation 25.

$$final\ modified\ expected\ life = \min(modified\ expected\ life,\ paper\ life\ expectancy) \quad \text{(Equation 24)}$$

$$B = f(final\ modified\ expected\ life) \quad \text{(Equation 25)}$$

The assumed worst operational scenario of transformer tripping only causes five transformers with life expectancies less than 70 years in Table 7-1. Therefore, the following modification mainly focuses on the health indices of those five transformers.

Table 7-3 initially compares the existing expected lives and paper life expectancies for transformer tripping, only to find that four of those five transformers with paper life expectancies smaller than the existing expected lives, could have the change of ageing constant as well as initial health index. In fact, only two of those four transformers have experienced the change in health indices, because the maximum setting (HI_{cap}) of initial health index has prevented the ageing constant from further raising the health index as exemplified in the 3rd and 4th transformers in Table 7-3.

Since there is no limit to ageing constant which the remaining life depends on, the change of the years taken to replace the main tank must happen in the transformers with their expected lives modified by paper life expectancies. As shown in Table 7-3, the main tanks of three transformers have the remaining years even less than one if the other parallel transformer is always tripped at the time of monthly high peak. This probably means one of CLASS techniques may not be suitable for these transformers.

Table 7-3 Modification of health indices for transformer tripping

TX No.	Existing Modified Expected Life (years)	Paper Insulation Life Expectancy (years)	Initial Health Index (Original)	Initial Health Index (Modified)	TX HI without TC HI (Original)	TX HI without TC HI (Modified)	Years to Replace Tank (Original)	Years to Replace Tank (Modified)
1	51.80	43.25	5.30	HI_{cap}	5.459	5.665	5.371	3.817
2	51.80	51.94	5.35	5.35	5.459	5.459	5.371	5.371
3	47.85	2.06	HI_{cap}	HI_{cap}	5.665	5.665	4.222	0.182
4	47.85	1.75	HI_{cap}	HI_{cap}	5.665	5.665	4.222	0.154
5	55.40	5.66	4.75	HI_{cap}	4.108	4.759	12.31	0.911

In conclusion, the impacts of CLASS techniques on the transformer main tank would be minimal and is only limited to a small number of transformers with high peak loads when implementing the frequency-management service by transformer tripping. This can be attributed to the following two reasons: 1) the design philosophy of most primary transformers allows short-term overloading, with both the cooler and protection system preventing the transformer from experiencing excessively high temperatures; 2) the existing low load levels allow the transformers rooms (in terms of thermal capability) for implementing CLASS techniques.

7.4 Loading Guide for New Operational Scenarios

In spite of this, when implementing CLASS techniques, the safe operation of the network cannot be neglected due to potential transformer alarms and trips which occur because of possible hot-spot temperature violations during the time of transformer tripping as shown in Figure 7-3. Therefore, it is necessary to establish a loading guide by setting a load limit, within which a certain type of transformer can be safely tripped under different ambient temperature conditions without causing any temperature violations in the substation.

Table 7-4 summarises all the possibilities of temperature violations for both the old and new winding temperature indicators, with the minimum alarming temperature set to 90°C. In this case, the load limit setting for a certain type of transformer only needs consider the violation of this relatively low temperature (90°C) under different ambient temperature conditions.

Table 7-4 Settings for Winding Temperature Indicator Contacts[6]

	Alarm	Trip
Old Winding Temperature Indicators	90°C	≤120°C
New Winding Temperature Indicators	110°C	135°C

The process of the setting of load limit is illustrated in Figure 7-7. It starts by setting a peak load at which the daily load is assumed to be constant. This assumption is to ensure that the hot-spot temperature stays at its daily peak before the tripping of the other parallel transformer.

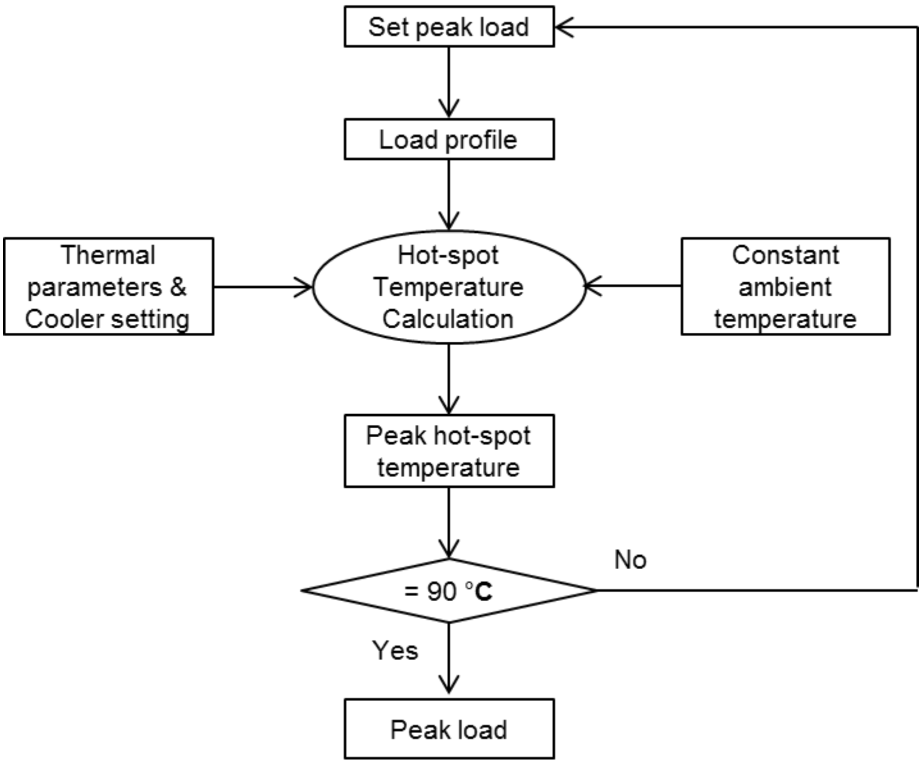


Figure 7-7 Flow chart for loading guide establishment

In order to make a load profile for transformer tripping, the daily load is kept constant for 11.5 hours (longer than three times of the oil time constant in Table 2-7) and then doubled for an hour in the middle of the day as shown in Figure 7-8. This load profile is then applied to calculate the hot-spot temperature based on the existing IEC standard thermal parameters, the cooler setting based on transformer type, and a constant daily ambient temperature profile.

The peak hot-spot temperature is then obtained and compared with the minimum alarming temperature. If the peak temperature is less (more) than 90°C, the daily peak load without tripping needs to be raised (lowered), and the calculation of hot-spot temperature should be repeated in order to find a peak load which corresponds to the 90°C peak temperature. Usually, the calculation process, shown in a loop in Figure 7-7, will continue many times until the peak hot-spot temperature equals to 90°C.

In Figure 7-8, the 0.85 per unit load of ONAN power rating corresponds to peak hot-spot temperature of 90°C at a constant ambient temperature of 20°C. This means that an 11.5/23MVA transformer should only provide the frequency-management service by tripping the other parallel transformer for no more than one hour if the usual peak load is below 0.85 of the ONAN rating at a daily ambient temperature no more than 20°C.

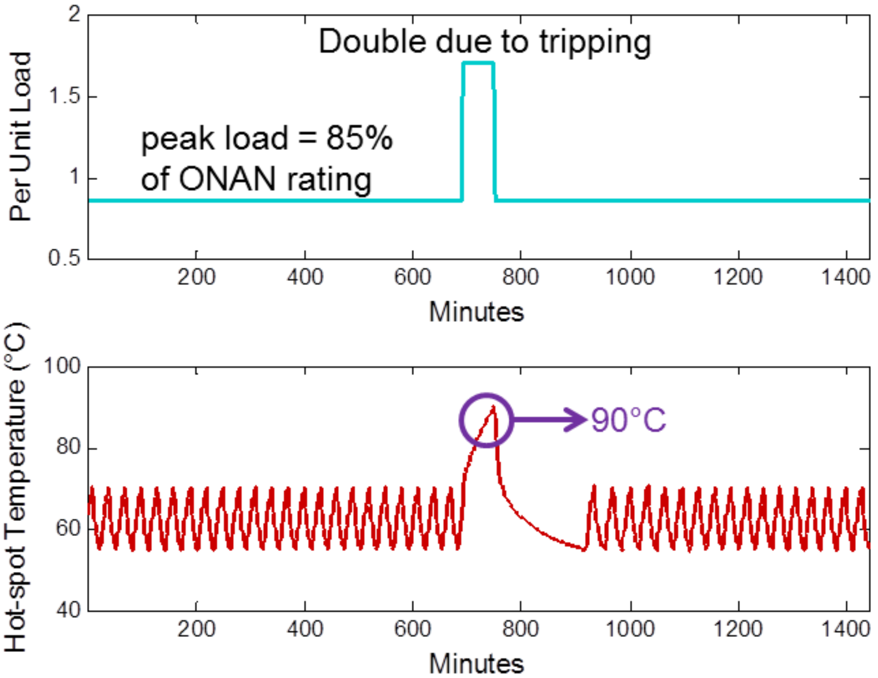


Figure 7-8 Load and hot-spot temperature profiles for Integrated System Transformer with the nameplate rating of 11.5/23MVA

The final output of peak load in Figure 7-7 depends on the transformer type which determines the cooler setting, thermal parameters as well as power ratings. Therefore, the maximum load can be derived for different transformer types at different ambient temperatures as shown in the loading guide in Table 7-5.

Table 7-5 Loading Guide for several typical transformer types

Rating: 7.5 MVA & 10MVA Cooling Mode: ONAN

Ambient Temperature (°C)	0	5	10	15	20	25	30
Maximum Load (%)	61.5	59	56	53.5	50.5	48	45

Rating: 10/12.5MVA Cooling Mode: ONAN/ONAF Fan Setting: 60/75°C

Ambient Temperature (°C)	0	5	10	15	20	25	30
Maximum Load (%)	73	70	67	64	60.5	57	53.5

Rating: 10/14MVA & 15/21MVA Cooling Mode: ONAN/OFAF Pump Setting: 55/70°C

Ambient Temperature (°C)	0	5	10	15	20	25	30
Maximum Load (%)	90.5	87	84	80.5	76.5	72.5	69

Rating: 11.5/23MVA   Cooling Mode: ONAN/OFAF   Pump Setting: 55/70°C

Ambient Temperature (°C)	0	5	10	15	20	25	30
Maximum Load (%)	100	96.5	92.5	89	85	81	77

Rating: 16/32MVA   Cooling Mode: ONAN/OFAF   Pump Setting: 55/70°C

Ambient Temperature (°C)	0	5	10	15	20	25	30
Maximum Load (%)	100.5	97	93.5	89.5	85.5	82	77.5

(Note: maximum load (%) refers to per unit load of the ONAN power rating)

8 Assessment of Impacts on Tap Changer Health

The weaknesses in a tap changer mechanism are around the mechanical integrity of the movement of various components, the wear tolerance of the contacts to both mechanical operation, electrical power dissipation and discharging and the resilience of the surrounding oil to degradation.

Within the scope of the trails and its relatively short duration compared to the design lifetime of transformers and tap changers there were no significant events observed. However, there are three issues that can impact on the health of the tap changer. The first is the increase in the number of tap operations that will occur; the second is the additional erosion of contacts in the tap changer due to larger currents than is normal for certain nodes of operation and the third is additional oil degradation due to the increase in tap changer operations especially at higher currents.

The first issue, around the increased number of additional taps, will impact maintenance schedules which are based on a risk assessment of the durability of tap changers, service experiences and mean time to failure. As maintenance is generally based on the total number of taps with no explicit reference to tap position, these additional operations will shorten the time interval between maintenances and will shorten the life time of the tap changer mechanism by a proportionate amount related to the addition operations. The trials showed that a larger range of tap positions will be used than for normal daily network service but the tap changer may be require to do multiple tap operations. This would spread out the contact wear to lesser used contacts at those tap locations but there will still be additional mechanical operations and additional wear on the diverter switch. Both these factors have a negative impact on the life time and maintenance schedule of tap changers

The second issue is around additional contact erosion which occurs when switching larger currents. For most of the tests conditions undertaken in Class, the change in the load current in the transformers has been within the “normal” daily variations in load current. However, there is one onerous condition whereby one transformer of a primary pair was switched out of circuit and the other took the additional load. This effectively doubles the current, increases the power dissipation in the diverter resistors by a factor of 4 and increases contact wear by the same factor. Both these factors may locally degrade the oil significantly through thermal decomposition due to heating, dissociation caused by any arcing and contamination from vaporised contact material. If maintenance is based on the number of operates then one switch operation at full load is equivalent to 4 switch operations at half load. So for the situation where one transformer is switch out and the full load current taken by the remaining transformer the number of switch operation should be counted as 4 and not one. However, at normal load currents then it would count as one.

The third issue is oil degradation. Tests on the oil highlighted the effect of operating the tap changer on the oil quality. Most of the degradation caused by the operation of the tap changer will diffuse into the surrounding oil and for a single tap this will be undetectable. However, the accumulation of degradation products over successful tap operations will become detectable and this could be monitored as seen in Figure 5-20.

9 Summary

In the past two years, the University of Manchester and the University of Liverpool have worked closely together on WP3 for the CLASS project, in order to study the impact of CLASS techniques on the transformer assets including transformer main tanks and tap changers. The following are summaries from the work conducted by the two Universities:

Summary of University of Manchester

The following are achievements from University of Manchester:

- The analysis on the CLASS techniques found that the main tank health is only concerned with Trial 3a (transformer tripping) and Trial 4 (tap staggering) which would increase the current passing through a transformer and thermally impact its health and lifetime. Suggestions on data monitoring and device installation were therefore made to Electricity North West Limited for implementation during the trials.

- The analysis was performed on the load data. In Trial 3a tests, the current of an operating transformer will double following the trip of the other parallel transformer. In Trial 4 tests, the maximum current difference due to tap stagger is 150A if the power factor of the load is above 0.9. In addition, the load data analysis has identified control problems within some substations which always have circulating current flowing through two parallel transformers.

- The oil data analysis initially focuses on the oil sampled before and after trial tests, and it is concluded that it is unlikely that the change of oil test results is correlated with the CLASS techniques. Consequently, the CLASS techniques are unlikely to bring any detrimental impacts on transformer operational health. Furthermore, the condition of transformers was assessed and the accelerated acidity growth has been found in a number of transformers with their acidity values over 0.15 mgKOH/g before the commissioned age of 30 years. This phenomenon indicates the early onset of ageing of some transformers which could lead to unexpected maintenance challenges for Electricity North West Limited.

- In order to assess the long-term thermal impacts on transformers and their vulnerability to tripping and tap staggering scenarios, over a hundred transformers were thermally modelled through simulation based on the assumed worst-case operational scenarios. Simulation results show that only a handful of transformers with high peak loads will have paper insulation life expectancies reduced below the expected asset life (70 years) due to the implementation of tripping. In contrast to transformer tripping, the impacts of tap staggering are negligible with all the paper life expectancies in excess of 90 years.

- The calculated paper insulation life expectancies were subsequently incorporated into the calculation of health indices of transformer main tanks, and it was found that transformer tripping at the time of peak load is detrimental only to the health of these small numbers of transformers. Therefore, in the case, that the CLASS transformer tripping techniques are implemented on them, the detailed monitoring, assessment and reinforcement of transformer's main tan may only need to focus on these small numbers of transformers.

- In spite of this, when implementing CLASS techniques, the safe operation of the network cannot be neglected due to potential transformer alarms and trips which occur because of possible hot-spot temperature violations during the time of transformer tripping. Therefore, a loading guide has been established by setting a load limit, within which a certain type of transformer can be safely tripped under different ambient temperature conditions without causing any temperature violations in the substation.

- In the future, the primary substation with circulating current may need to be identified to solve the potential control problem. Moreover, the transformers with accelerated or abnormal acidity growth may need to be identified in order to prepare for the oil maintenance in advance. One of the recommendations is to record and alternate the new CLASS operational mode i.e. tripping, between two parallel transformers. This means the operator needs to make two parallel transformers suffer the higher current caused by tripping in turn, so to age the two transformer equally and reduce the risk of failure at the supply point.

Summary of University of Liverpool

A monitoring system for these trials was designed built and installed on three primary transformers at Irlam, Longsight and Romiley. These monitoring systems recorded non CLASS and CLASS operations over 18 months and continue to do so. The data coming back from the monitoring systems indicates the complex pattern of behaviour of the three tap changers. Whilst the temperature and power data were of conventional in nature and easily understood, the acoustic and oil data were processed in a non conventional means in order to extract relevant and meaningful information. A method known as chromaticity was used to do this. The approach allowed comparison of signals taken over time and from different tap changers with different operational use profiles to be compared for CLASS and non CLASS operations. The comparison is important in order to assess the impact of CLASS operations on the tap changer and indeed the transformers.

External temperature changes were insensitive to CLASS operations. Those temperature rises were small. This implies that no significant heating of the bulk oil is happening within the time scale of the tests although there might well be localised hot spots.

The acoustic signature for the transformers for pre, during and post tap changer operation did not show any significant changes for non CLASS and CLASS operations. This implies that electrically and mechanically there were no adverse affects on the tap changer.

For higher current switching operations above what is deemed normal for the tap changer, there is a significant increase in the erosion of contacts. For a doubling of the switching current above the normal, the erosion rate increases by approximately a factor of four. This higher erosion rate could affect the time interval between routine maintenance for tap changers and will need to be factored into a simple numerical approached based on maintenance of counting the number of tap changers.

Oil samples taken from the tap changer chamber after the CLASS tests show a residual change in the oil. These changes are indicative of oil heating. However, the effect of the local degradation in the oil is diminished as it mixes with bulk of the oil. Higher switching currents will increase oil degradation.

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11 Appendices

11.1 Appendix A: Substations for Oil Sampling

Table 11-1 Selected transformers for oil sampling

Substations from Trial 3 Stage 1	Substations from Trial 4 Level 6
HYNDBURN RD	BOLLINGTON
BLACKFRIARS	LITTLEBOROUGH
GOLBORNE	DIDSBURY
FALLOWFIELD	WILLOWBANK
LONGSIGHT	BURROW BECK
ROMILEY	TRAFFORD PARK NORTH
IRLAM	DENTON EAST
BAGULEY	WITHINGTON
CENTRAL MANCHESTER	WINIFRED RD
MIDDLE JUNCTION	LEVENSHULME

11.2 Appendix B: Participation Frequency

Table 11-2 Frequency of trial participation

Substation	T1	T2	T3a
HYNDBURN RD	Yes	No	Yes
BLACKFRIARS	Yes	No	Yes
GOLBORNE	No	Yes	Yes
FALLOWFIELD	Yes	No	Yes
LONGSIGHT	No	Yes	Yes
ROMILEY	Yes	Yes	Yes
IRLAM	No	Yes	Yes
BAGULEY	No	Yes	Yes
CENTRAL MANCHESTER	Yes	No	Yes
EGREMONT	Yes	Yes	No
DICKINSON ST	Yes	Yes	No

(*Note: 'Red' marks most preferred substation; 'Blue' marks proposed substations*)