LIFE EXPECTANCY INVESTIGATION OF TRANSMISSION POWER TRANSFORMERS

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Abstract

The health of the transmission power transformers in the power system networks is critical to the reliability of electricity supply. Knowing the precise life expectancy of the transmission power transformer is of vital importance as it permits an optimised asset replacement. The traditionally regarded transmission power transformer’s life expectancy of 40 years is considered dated for the transformers in the UK according to the transformer life data in 2010. In this thesis, it is aimed to investigate the life expectancy of the transmission power transformer in the UK from three aspects: statistical analysis on historic transformer life data, thermal modelling of in-service transformers, and through the in-service transformers’ furan measurements.

A detailed statistical analysis shows that deriving the transformer’s reliability at a certain age by calculating the hazard rate is inadequate, as the hazard rate at each age has a statistical range in which the confidence band width is related to the amount of the reliability data. The transformer life data in all ages are grouped together to derive a general hazard rate of 0.27%. It is concluded that the transformer life expectancy could not be derived via statistical approaches due to the limited data available at the older transformer ages.

As an alternative approach, regarding the life of insulating paper as the ultimate life of a transformer, the thermal model published by the IEC transformer loading guide 60076-7 is reviewed and extended to estimate a transformer’s thermal lifetime. The model is improved in two aspects, such that Arrhenius equation is adopted to consider the paper’s practical ageing mechanism of oxidation and hydrolysis when calculating the paper’s ageing rate; and the model takes consideration of the paper’s moisture accumulation effect.

The developed thermal model is used to reversely derive the generally unknown model input – hot-spot factor, by the means of regarding the scrapped transformer’s degree of polymerisation (DP) predicted thermal lives as a benchmark. Assigning the derived hot-spot factor to the field units with regard to the design family, the thermal lives of 106 in-service transformers have been estimated. To enlarge the life sample, the modelling lives are combined with the 79 scrapped transformers’ DP predicted thermal lives. The thermal life expectancy, defined as the median life of the sample set, is derived as 88 years. A series of sensitivity studies are performed to examine the derived life expectancy’s responses on the variations of load, winding-to-oil gradient, top-oil temperature rise, and the setting of winding temperature indicator.

As a non-intrusive approach in transformer’s insulating paper assessment, the correlations between the 2-furaldehyde (2FAL) concentration dissolved in transformer oil and paper’s DP derived by different laboratories are reviewed which are found to differ significantly. As a first-time attempt to derive the 2FAL-DP correlation relationship for the field transformers, the paper’s DP is estimated at the age when oil was sampled using the thermal model, and is plotted with the 2FAL measurement. De Pablo’s equation is found to fit the plot of the DP estimates against the 2FAL measurements better than other function formats. The 2FAL concentrations corresponding to the paper’s critical DP levels are given using the developed 2FAL-DP correlation relationship.
Declaration

I declare that no portion of the work referred to in the thesis has been submitted in support of an application for another degree or qualification of this or any other university or other institute of learning.
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Acknowledgement

Writing this section has, in fact, been an enjoyable experience, when I recall all the persons who have helped and supported me during my researching and thesis writing.

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To my family and Miss Chenru Wang who have always been standing firmly by my side, I am indebted to their endless love and understanding.
Chapter 1 Introduction

1.1 Background

Electricity has been a vital resource in every aspect of human life. The phenomenon of electrification has been studied since the early 18th century, and its breakthrough should probably be attributed to Michael Faraday who made the discovery of the electromagnetic induction phenomenon in 1831 and revealed the production of voltage across a conductor moving through a magnetic field. Five years later, Nicholas Callan, the Irish scientist, invented the world’s first induction coil in 1836 based on the principle of electromagnetic induction, aiming to amplify the voltage from a battery source. Nicholas’s invention was seen as the world’s very first type of transformer that converted a low voltage DC supply into high voltage DC pulses. After decades of technological evolution in worldwide electrical engineering, in today’s three-phase AC transmission system networks, power transformers have been recognised as one of the most essential equipment.

The global economic growth and population expansion drive the growing power consumption and the developments of power system networks. Inevitably, utilities are forced to build more infrastructures with higher ratings. As the energy is transferred from remote power generation stations to urban and industrial districts, never has so much importance been placed on the reliability of power transmission equipment, as it guarantees a healthy power system network. Transformer failures in service should be minimised as it does not only mean the loss of capital asset, but might also lead to power supply interruption which could cost more than the loss of asset, or even worse, casualties [1].

The functional life expectancy of the transmission power transformers has been recognised as approximately 40 to 50 years [2-4]. However as the first vintage of the transmission power transformers worldwide are approaching this life expectancy, not many failures have been encountered by the utilities. Looking at the power system network in the UK, in 2010 over 50% of the transmission power transformers in operation have exceeded 40 years of age. The failure statistics, on the other hand, do
not suggest any sign of increase in age profile of failed transformers. This could be attributed to a variety of reasons including over-engineering of old transformers; low loading levels under the N-1 or N-2 operation criteria; and proactive retirement based on individual transformer’s condition.

In recent years, with the help of modern transformer monitoring and diagnosis techniques, utilities claim to be able to determine a transformer’s remaining life into a scale of approximately 3 to 5 years [5, 6]. Unfortunately the utilities have not been able to accurately predict the medium-term remaining life, say 5 to 10 years. It is foreseen that, by the swarming transformer installation prior to the 1960s as projected, a peak of transformer failure would eventually occur as the transformer population enters the ageing-related failure mode.

In the ageing-related failure mode, the ultimate life of a transformer is critically governed by its insulating paper, of which the condition is represented by the degree of polymerisation (DP) [7]. Paper undergoes thermal deterioration during transformer operation, and turn-to-turn faults in windings may occur in an increasing manner with aged paper insulation, which ultimately leads to a transformer failure. In this situation, the following question arises for the utilities: are today’s transformer asset management techniques advanced and effective enough to offer sufficient time response in order to plan for a massive volume of transformer purchase and replacement?

Recognising the situation, there have been attempts to quantify the ultimate life of the in-service transmission power transformers by assessing the condition of insulating paper. This includes the use of transformer thermal model which calculates winding’s hot-spot temperature and insulating paper’s loss-of-life; and the assessment of insulation ageing markers e.g. the concentration of 2-furaldehyde (2FAL) or methanol dissolved in oil. Theoretically speaking, both studies could lead to promising outcomes towards the transformer’s life assessment.
1.2 Statement of the Problem

Every utility should have a transformer database regarding the number of operating, replaced, and failed units. Ideally, one should be able to produce a failure function plot of the transformers based on the existing life data and use it to plan for the future replacement scheme. However since utilities do not have many failure data regarding the older transformers, the full life cycle of transformer has not yet been reflected by the existing database. Under this circumstance, it is desired to either predict the future transformer failure based on the existing life data; or if it is proved to be statistically impossible, to make full use of the existing data and extract as much information as possible from it.

As an alternative approach, recognising that the ultimate life of a transformer is critically governed by the life of its insulating paper, thermal models are developed to assess the paper’s ageing rate and loss-of-life by considering a transformer’s operating conditions and thermal parameters. Meanwhile, over the years, enormous work has been done in the laboratory to understand the mechanisms of paper ageing by the means of accelerated ageing experiments. Furthermore, forensic tear-down investigations on failed and retired transformers could help engineers learn the complete profile of a transformer’s paper deterioration. These studies seem to be running in parallel. There should be a potential opportunity to incorporate the latest knowledge gained in the laboratory and transformer scrapping into the existing thermal modelling approach for a more sophisticated transformer thermal life assessment.

Considerable work in the laboratory has been conducted to study the furan formation in transformer oil during paper ageing, and to correlate furan concentration dissolved in oil with paper’s DP retention. Although the methodology is without doubt correct, it is rather difficult to apply the laboratory derived results to the field transformers due to the complexity of furan formation and partitioning effect in field transformers. There remains a practical question of how one should correctly use the field transformer’s furan data to assess the condition of the insulating paper, and hence to predict the transformer’s thermal lifetime.
1.3 Objective of the Research

In this PhD research study, the work will be focusing on the life expectancy assessment of the transmission power transformer population owned by the National Grid Company in the United Kingdom. From this point forward, the transmission power transformer will automatically be referred to as the term transformer for simplification.

Based on the problems stated above, this research will aim to meet the following four objectives:

i). **Statistical analysis of the National Grid transformer life data**

This study acts as a conclusive piece of work for [8] which is a PhD thesis written by Dr Qi Zhong in the same topic. It concludes that the future failure rate of the National Grid transformers could not be predicted by the means of ordinary statistical approaches because the life data at the older transformer ages are limited. To complete the work of this topic, it is aimed to quantify the uncertainty of the National Grid transformer’s failure rate as the impact of the limited life data. Furthermore, the existing life data are mined in order to extract the useful information including the general hazard rate of the transformer population, and the critical sample size that guarantees a reliable statistical analysis.

ii). **Development of a systematic transformer thermal model based on the thermal model in the IEC transformer loading guide 60076-7**

A thermal model has been presented in the IEC transformer loading guide 60076-7 to estimate insulating paper’s hot-spot temperature and ageing rate. In this study, the original model is extended in order to estimate the thermal lifetime of a transformer by adopting the paper’s DP reduction model. Furthermore, in order to give a more practical estimation of the insulating paper’s ageing rate, the original model is modified in two aspects. Firstly, Arrhenius equation is adopted to calculate paper’s ageing rate in order to incorporate the latest knowledge of paper’s ageing mechanisms gained in the laboratory. Secondly, the paper’s moisture accumulation effect is accounted for in the model.
iii). **Examining the National Grid transformer’s hot-spot factor and thermal life expectancy using the thermal model**

With the help of the developed thermal model, the generally unknown hot-spot factor can be reversely derived by utilising the information from the scrapped transformers. The derived hot-spot factors can then be assigned to the in-service sister transformers to assess the transformer’s thermal lifetime. The thermal life expectancy, which is defined as median life of the transformer population, will be derived. A series of sensitivity studies are performed to examine how a transformer’s load, thermal parameters (i.e. winding-to-oil gradient and top-oil temperature rise), and winding temperature indicator setting would affect the derived thermal life expectancy.

iv). **Investigation of the field National Grid transformers’ 2FAL measurements and the derivation of 2FAL-DP correlation relationship**

Since the concentration of furan, or more specifically, 2FAL dissolved in oil can be correlated with paper’s DP retention, the 2FAL measurements of a large-scale of 342 National Grid field transformers will be investigated. With the help of the thermal model, the paper’s DP at the time when oil was sampled could be estimated. Plotting the DP estimates with the 2FAL measurements, a 2FAL-DP correlation relationship could be derived by fitting the data using various functions.

**1.4 Outline of the Thesis**

The remainder of this thesis is arranged as outlined in the following:

**Chapter 2: Literature Review**

In this chapter, the review of the relevant literature is presented on five topics: statistical analysis on product’s life data; transformer’s end-of-life and failure models; cellulose paper ageing; transformer’s hot-spot temperature determination; and furan formation during cellulose paper ageing.
Chapter 3: Life Data Analysis of National Grid Transformer by Statistical Approach

The chapter presents the statistical analysis of the life data of the National Grid transformers dated until 2010 is presented, including the hazard rate analysis and the determination of its 95% confidence band. The negative impact of the limited life data at older transformer ages and the data sufficiency will be discussed. Lastly, a general hazard rate of the National Grid transformer population is deduced.

Chapter 4: Development of Transformer Thermal Model

In this chapter, the procedure of the thermal model presented in the IEC transformer loading guide 60076-7 is presented. The model is extended to incorporate the paper’s DP reduction model to estimate a transformer’s thermal lifetime. To improve the quality of the model output, firstly, the latest knowledge in paper ageing mechanisms is introduced into the model through the use of Arrhenius equation; secondly, the paper’s moisture accumulation effect is considered. A modelling trial is presented at the end of this chapter.

Chapter 5: Identification of Transformer’s Hot-spot Factor and Thermal Life Expectancy Using Developed Thermal Model

In this chapter, the developed thermal model is firstly used to reversely derive the hot-spot factors of 35 National Grid scrapped transformers by regarding their DP predicted thermal lives as benchmarks. A series of sensitivity studies are performed to examine the response of the derived hot-spot factors towards possible errors during the derivation process. Assigning the derived hot-spot factors to the in-service transformer population according to the design family, the thermal lives of 106 National Grid field transformers are examined, followed by the sensitivity study on the modelled lives. The median life of the population is deduced as the thermal life expectancy. It is found that the transformer winding temperature indicator setting should be updated in order to make a full use of the cooling system. To increase the statistical significance, the 106 modelled lives are combined with the 79 scrapped transformers’ DP predicted thermal lives to form an enlarged life sample. Finally, the thermal lives are mapped into a 2-D thermal matrix which is presented as an initial
Chapter 1 Introduction

tool to assess a transformer’s thermal lifetime based on the essential information only.

Chapter 6: National Grid Transformers’ Paper Condition Assessment Using Furan Measurement

In this chapter, the furan data of 342 National Grid field transformers are presented and investigated. With the help of the developed thermal model, the paper’s DP at the age when oil was sampled is estimated using the furan measurement. The DP estimates are plotted with the 2FAL measurements, and several functions are used to fit the data in order to derive a 2FAL-DP correlation relationship.

Chapter 7 Conclusions and Future Work

In this chapter, the work carried out in this PhD research is summarised, and the conclusions are drawn. Some future work will be proposed which could hopefully enhance the life assessment of the National Grid transformers to a further extent.
Chapter 2  Literature Review

As a preface to this PhD research, a total of more than 170 articles have been reviewed and are presented in this chapter. The literature reviews are classified according to the content as:

- Literature review of statistical analysis on the product’s life data.
- Literature review of transformer’s end-of-life and failure models.
- Literature review of cellulose paper ageing.
- Literature review of transformer’s hot-spot temperature determination.
- Literature review of furan formation during cellulose paper ageing.

The remainder of this chapter will present the literature review of the above-mentioned topics.

2.1  Literature Review of Statistical Analysis on Product’s Life Data

2.1.1  Basic Concepts in Life Data Analysis

In the statistical analysis of the product’s life data, there are four basic terms which are transferrable between one another, namely failure probability distribution function, failure cumulative distribution function, reliability function, and hazard function.

In a complete life data sample where all the products have failed at the observation time, the failure probability distribution function at time $t$, $f(t)$, is effectively the failure rate at $t$ calculated by dividing the failure number by the population number. It is mathematically expressed as:
\[ f(t) = \frac{f_t}{N} \quad (2-1) \]

Where \( f_t \) is the failure number at time \( t \), and \( N \) is the population number. The failure cumulative distribution function at time \( t \), \( F(t) \), is the integral of the probability distribution function \( f(t) \) from 0 to \( t \). It has the mathematical expression of:

\[ F(t) = \int_0^t f(t) \, dt \quad (2-2) \]

The term \( F(t) \) has two useful interpretations. Firstly, within the product population, any product has the probability of \( F(t) \) to fail prior to time \( t \). Secondly, for a group of products that have all failed, \( F(t) \) is the portion of products that fails by the time \( t \).

In practice, as a complementary function of \( F(t) \), the reliability function \( R(t) \) is often calculated to describe the survived units. The term \( R(t) \) has the expression of:

\[ R(t) = 1 - F(t) = \int_t^\infty f(t) \, dt \quad (2-3) \]

Contrary to \( F(t) \), the two common interpretations of \( R(t) \) are: firstly, within the product population, \( R(t) \) is the probability of having a randomly drawn unit at time \( t \) that is alive (i.e. has not failed). Secondly, within a product population, \( R(t) \) is the portion of products that will survive for at least time \( t \).

Since the failure probability distribution function \( f(t) \) is the derivative of the failure cumulative distribution function \( F(t) \), which is the complementary of reliability function \( R(t) \), the linkage between them can be represented as:

\[ f(t) = \frac{dF(t)}{dt} = -\frac{dR(t)}{dt} \quad (2-4) \]

In life data analysis, the term hazard function is frequently used to calculate the product’s conditional probability of failure at specifically selected time interval \( \Delta t \), given that the product has survived up to time \( t \). Recalling the basic concept of conditional probability of event B’s occurrence given that the event A has occurred:
The mathematical expression of hazard function \( h(t) \) can then be written as:

\[
 h(\text{fail in next } \Delta t \mid \text{survive till } t) = \frac{F(t + \Delta t) - F(t)}{R(t) \times \Delta t} \quad (2-6)
\]

As \( \Delta t \) approaches zero, the hazard function is effectively the instantaneous failure rate at time \( t \) which is expressed as:

\[
 h(t) = \lim_{\Delta t \to 0} \frac{F(t + \Delta t) - F(t)}{R(t) \Delta t} = \frac{F'(t)}{R(t)} = \frac{f(t)}{R(t)} \quad (2-7)
\]

The above formula expresses the hazard function \( h(t) \) in reliability terms. A more practical formula used to calculate \( h(t) \) at each time interval \( t \) is shown as:

\[
 h(t) = \frac{\text{failure number at time } (t + \Delta t)}{\text{exposing number at time } t} \quad (2-8)
\]

where exposing number at time \( t \) stands for the total number of survived and failed units at the observation time \( t \). As an example, Table 2-1 lists the complete life data and analysis of 24 products that have failed within 10 hours. An interval of 1 hour has been defined as the observation time. Figure 2-1 depicts \( f(t), F(t), R(t), \) and \( h(t) \) of a data sample containing 24 products that have failed within 10 hours.

<table>
<thead>
<tr>
<th>Observation time ( t )</th>
<th>Failure between ( t ) and ( t+1 )</th>
<th>Exposing number before ( t )</th>
<th>( f(t) )</th>
<th>( F(t) )</th>
<th>( R(t) )</th>
<th>( h(t) )</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>24</td>
<td>4.17%</td>
<td>4.17%</td>
<td>95.83%</td>
<td>4.17%</td>
</tr>
<tr>
<td>2</td>
<td>1</td>
<td>23</td>
<td>4.17%</td>
<td>8.33%</td>
<td>91.67%</td>
<td>4.35%</td>
</tr>
<tr>
<td>3</td>
<td>2</td>
<td>22</td>
<td>8.33%</td>
<td>16.67%</td>
<td>83.33%</td>
<td>9.09%</td>
</tr>
<tr>
<td>4</td>
<td>3</td>
<td>20</td>
<td>12.50%</td>
<td>29.17%</td>
<td>70.83%</td>
<td>15.00%</td>
</tr>
<tr>
<td>5</td>
<td>5</td>
<td>17</td>
<td>20.83%</td>
<td>50.00%</td>
<td>50.00%</td>
<td>29.41%</td>
</tr>
<tr>
<td>6</td>
<td>5</td>
<td>12</td>
<td>20.83%</td>
<td>70.83%</td>
<td>29.17%</td>
<td>41.67%</td>
</tr>
<tr>
<td>7</td>
<td>3</td>
<td>7</td>
<td>12.50%</td>
<td>83.33%</td>
<td>16.67%</td>
<td>42.86%</td>
</tr>
<tr>
<td>8</td>
<td>2</td>
<td>4</td>
<td>8.33%</td>
<td>91.67%</td>
<td>8.33%</td>
<td>50.00%</td>
</tr>
</tbody>
</table>
In the practical analysis of a product life data, the product’s hazard rate $h(t)$ is the most important parameter to be determined. For products that are massively manufactured with homogeneous design and manufacture techniques such as light bulbs or mobile phones of the same model, the hazard rate is usually regarded as constant throughout the entire product life.

In many engineering applications, the product’s life data analysis can be complicated in two respects. Firstly, the hazard rate of the product is expected to increase with age due to the material ageing. This effectively forbids the use of a single value to characterise the product’s hazard rate over the entire life span. Secondly, some products could have a very long life expectancy and by the time observed, the full life cycle of which has not been completed and hence adds a significant degree of uncertainty to the product’s failure prediction in the future. This is referred to as the data censoring problem and has been greatly challenging engineers in many fields to develop a reliable failure prediction model.

![Figure 2-1 Plots of $f(t)$, $F(t)$, $R(t)$, and $h(t)$ in the example above.](image-url)
The following presents the two highlights of the life data analysis in engineering applications, namely the bathtub curve of hazard rate and the data censoring problem.

i). **Bathtub curve**

For many engineering products, the hazard rate is not constant with regard to the time [9], and this can be illustrated by the classic bathtub curve as depicted in Figure 2-2.

![Bathtub curve diagram](image)

**Figure 2-2** A typical bathtub curve of product’s hazard rate.

As illustrated by the bathtub curve, there are three stages in a product’s life in terms of the hazard rate. In the early stage, the product is subject to a high hazard rate, referred to as *infant mortality period*. This is mainly caused by the product’s congenital defects or weaknesses, either due to the material itself, or is concealed by product’s defective manufacture.

As time progresses, the hazard rate decreases as the weaker infants fail and are excluded from the population, or have been detected and repaired. As the product enters the mid stage, the hazard rate appears to be constant for a longer period and is independent of the product age. Strictly speaking, the flat behaviour of the hazard rate is caused by random events and the failure behaviour of the product at this stage is referred to as *random failure* [10]. This constant hazard rate will dominate most of the product’s life.

Eventually the product will enter the end stage of its life, often referred to as *wear out period*. During this period, the hazard rate increases rapidly as its age progresses.
due to the material’s deterioration. The product’s wear out period is particularly of interest to engineers, as one must quantify precisely the product’s hazard rate as the age progresses, in order to set up an effective replacement scheme.

Different types of products are likely to have different shapes of bathtub curve. Products with an easy and mature manufacturing process, such as printed circuit boards, tend to have an inconspicuous infant mortality period and a long period of constant hazard rate. On the other hand, products with complicated layouts, such as electric power equipment or aerospace engines, usually have high infant mortality and the hazard rate increases more rapidly with age due to the material ageing under heavy duty [10].

The shape of the bathtub curve can be affected by the action of product maintenance which has the incentive to control the product deterioration process by restoring the product condition [11]. In fact, as illustrated in Figure 2-3, maintenance works in both ways such that an effective maintenance will restore the product’s hazard rate; while some maintenance could work inefficiently. In the worst-case scenario, a bad maintenance, mostly attributed to human error, could damage the product’s condition and would push the product closer to the edge of failure.

![Figure 2-3](image.png)

**Figure 2-3** Impacts of effective (top figure), and ineffective or bad maintenance (bottom figure) on a product’s hazard rate.
ii). **Data censoring**

For an ideal life data analysis, all data are *complete*; that is to say, all units have failed at the observation time and their lives have been quantified. Figure 2-4 depicts such a complete sample that has 5 products.

![Figure 2-4](image)

Figure 2-4 A complete data set that all units have failed at the observation time.

For many field life data, however, the data are often *incomplete*, i.e. not all products have failed at the observation time [9]. The data could be *time censored* (also known as *Type I censored*) on both the left and right in the following manner: if there are units that are still alive at the observation time and the failures of which would take place in an unknown future, such data are termed as *time censored on the right*. If the failure time is only known to be before a certain time, the data is said to be *time censored on the left*. This is sometimes referred to as *truncation on the left* in some literatures [12].

In some cases such as an accelerated ageing test, the observation is terminated when a specified number of failures occur regardless of the observation time. Such data are termed as *failure censored* (also known as *Type II censored*). The two types of data censoring are depicted in Figure 2-5.

In a censored data sample, if all the units are from the same vintage, the data are termed as *singly censored*. In field data, many units are likely to enter the field at different times i.e. belonging to different vintages. Such data are referred to as *multiply censored* [9]. This is illustrated in Figure 2-6.
Chapter 2 Literature Review

2.1.2 Transformer Life Data Analysis

The use of statistical approaches in life data analysis was applied in fields such as medicine, military, economics, as well as to the power equipment. Throughout the years of development and with the aid of modern computing devices, the statistical approaches have become sophisticated and ready-to-use in many cases.
Due to the long life expectancy of the equipment itself, the application of statistical approaches to life data of power equipment, including transformers, only started a couple of decades ago.

In analysing the life data of transformers, many frequently used functions are used to fit the data including normal, lognormal, smallest extreme value, and Weibull distributions [9]. With the available fitting functions, the historic hazard rate per unit age is input into the model in order to predict the hazard rate in the future. Typical examples can be found in [12-16].

Some utilities tend to develop their own fitting functions based on their specific historic failure experiences. As an example, Perk’s formula has been adopted by many utilities in which the formula parameters can be artificially varied by the utility to better incorporate with their transformer life data [1]. The formula is expressed as follows:

\[
h(t) = \frac{A + \alpha \exp(\beta \times t)}{1 + \mu \exp(\beta \times t)}
\]

(2-9)

where \(A\) is a constant representing the risk of failure by random events such as lightning; \(\alpha\) and \(\beta\) are constants that control the shape of the hazard increase as time progresses; and \(\mu\) is a constant to slow down the rate of hazard increase at older ages.

As an example, Figure 2-7 below is a transformer hazard function plot in which \(A\) is defined as 0.005, and \(\alpha\), \(\beta\), and \(\mu\) are set to give a 50% hazard rate at the transformer age of 50.

Iowa Survivor Curve is another fitting technique in product’s life data analysis that has been adopted by utilities to analyse the transformer reliability [17]. The curve set contains 18 basic Iowa Curves and each has a unique two-character name. The first character of R, L or S indicates whether the curve has a right, left or symmetrical mode. The second character is a digit ranging from 0 to 6 which indicates the steepness of the modal peak. The failure data could simply be plotted on the provided graph paper to find the best fitted curve. The main drawback of the use of Iowa Survivor Curve is the subjective decision on the best fitted curve. As an example, Figure 2-8 illustrates the situation where the survivor life data of up to age
10 is fitted using the Iowa Curve type R1 to R5 but the drawback is that it is not easy to distinguish the best fitted curve.

Due to the censoring problems of the field transformers’ life data, or more specifically the right time censored data and the multiply censored data attributed to different transformer vintages, it is recognised that the transformer failure data are too few to yield reliable results using ordinary statistical approaches [18]. As a pioneering attempt to confront the problem, Li considered to use normal and Weibull distribution to not only fit the failed transformer data, but also the survivor data [19]. Li’s method has been further extended by the use of exponential distribution in [20].

Regarding Li’s method, although the derived mean lives appear to be reasonable, the fitted results are strongly dependent on the choice of the model (i.e. normal,
exponential, or Weibull distribution). This is illustrated in Figure 2-9 which depicts the life data analysis of 100 single-phase 500kV reactors with four failures in the past. As a result, different distributions of failure probability are predicted by using different models which causes ambiguity. In fact the selection of the pre-defined model is a common issue in every life data analysis. Furthermore, some of the model assumptions in Li’s method are argued in [8].

![Figure 2-9 Probability of failure using different distributions on 100 single-phase 500kV reactors with 4 failures [20].](image)

There have been incentives to classify the transformer that are believed to have different life expectancies and then to perform the statistical analysis accordingly. In [18], the transformers having ‘generic problems’, e.g. severely aged paper insulation, are isolated from the population and the hazard rates of the two sample groups are derived separately. This concept is illustrated in Figure 2-10.

The concept in Figure 2-10 is rather over-optimistic, as the determination of the transformer generic problem relies on sufficient operating experiences and post-mortem investigations on retired or failed units. As a more realistic approach, in [12] the transformers are classified according to the manufacturers and the analysis has shown obvious differences in the failure rate predictions from different manufacturers. This is illustrated in Figure 2-11. The notation of ‘MA’ to ‘ME’ are manufacturers A and E; ‘old’ and ‘new’ denote the transformers manufacture year prior to, and post 1987.
Figure 2-10 Concept of isolating transformers with generic problem from the population and derive the hazard rates separately [18].

Figure 2-11 Failure probability of transformers from 5 different manufacturers derived by fitting the life data by Weibull distribution [12].

Lastly, as an inspiration, a study of hazard prediction has been performed on other power equipment including overhead line, cable, interrupter switch, and line post insulator according to the location [21]. The results have shown that the equipment located in industrial and seaside areas have a higher hazard rate prediction than rural and remote areas due to the discrepancy in duty carried and the ambient condition.
This is illustrated in Figure 2-12 which is the failure rate prediction of the overhead transmission line located in different locations.

![Figure 2-12 Failure prediction of overhead line in different locations based on life data of 5418 failures in population of 366,654 [21].](image)

2.1.3 Life Data Analysis of National Grid Transformers

An intensive statistical analysis has been performed on National Grid transformer life data by Dr Qi Zhong in her PhD thesis [8]. The life data analysed is dated since 1952 to 2008, which is counted as 751 active transformers and 52 failures. The mean life of the failed units is 20 years.

The analysis utilises Least Square Estimator (LSE) to fit the hazard rate and failure cumulative distribution function (CDF) using four functions of normal, lognormal, smallest extreme value and Weibull distribution. The Li’s method proposed in [19] is also used to deal with the limited transformer failure data. Three methods are used in plotting the CDF of failure data, which are Kaplan-Meier (K-M) method, Herd-John (H-J) method and actuarial method. As a comparison to the result of LSE, the life data are also fitted by the four functions using the Maximum Likelihood Estimator (MLE) using the build-in Matlab function. To evaluate the goodness of fitting using LSE and MLE, the classical Kolmogorov-Smirnov test (K-S test) and the calculation of Coefficient of Determination (COD) are performed. The whole picture of the
The following will recap the results of the analysis using the different methods shown in the figure above.

i). **Life data analysis using LSE**

The hazard rate of transformer is fitted using normal, lognormal, smallest extreme value, and Weibull distributions. The fitted results are summarised in Table 2-2 and are plotted to compare with the observed historic hazard rates at various transformer ages as in Figure 2-14.

Table 2-2 Results of fitting National Grid transformer hazard rates using different functions by the means of LSE [16].
From the table it is seen that the derived mean lives differ significantly by different distributions. The mean lives estimated by normal and smallest extreme value distribution are relatively reasonable according to the engineering judgements. However the fitted functions are rejected by the K-S test, and neither do they have a very high value of COD, indicating that the fitting qualities are not satisfied.

By examining the hazard plot in Figure 2-14, it is discovered that the reason why the functions have been rejected is that the functions are strongly affected by the last hazard point of 0.0133 at transformer age 48. In fact, this outstanding hazard rate is caused by 1 failure out of a small transformer population size, and hence the limited sample size is a matter of fact that heavily biases the fitted result.

On the other hand, lognormal and Weibull distributions fit the overall data generally well and tend to ignore the last hazard point. Consequently they are accepted by the K-S test and have high values of COD. Unfortunately, the hazard rates of lognormal and Weibull distributions appear to be constant or decrease with age and lead to exceedingly large mean lives which disobey the rules of engineering with regard to transformer life expectancy.

An analysis has been performed on National Grid transformer life data by fitting the failure CDF data using K-M, H-J, actuarial methods, and by the means of Li’s method. The same conclusions have been drawn such that the fitted functions of
normal and smallest extreme value distributions yield a reasonable mean life but are statistically rejected, and the lognormal and Weibull distributions are accepted but the derived mean lives are unreasonably large. The fitted results are summarised in Table 2-3, Table 2-4, and Table 2-5. Note that the H-J method yields an identical result to K-M and is hence omitted in [16]. Furthermore, the hazard plots of the fitted functions are not included either.

Table 2-3 Results of fitting National Grid transformer failure CDF using K-M method by the means of LSE [16].

<table>
<thead>
<tr>
<th>parameters</th>
<th>Normal distribution</th>
<th>Lognormal distribution</th>
<th>Weibull distribution</th>
<th>Extreme value distribution</th>
<th>From failures only</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean $\bar{r}$ (year)</td>
<td>$73$</td>
<td>$12897$</td>
<td>$387$</td>
<td>$53$</td>
<td>$20$</td>
</tr>
<tr>
<td>Std $\sigma$ (year)</td>
<td>$27.8$</td>
<td>$156420$</td>
<td>$352.7$</td>
<td>$14.0$</td>
<td>$11.5$</td>
</tr>
<tr>
<td>K-S</td>
<td>R</td>
<td>A</td>
<td>A</td>
<td>R</td>
<td></td>
</tr>
<tr>
<td>COD</td>
<td>$0.903$</td>
<td>$0.973$</td>
<td>$0.987$</td>
<td>$0.854$</td>
<td></td>
</tr>
</tbody>
</table>

Table 2-4 Results of fitting National Grid transformer failure CDF using actuarial method by the means of LSE [16].

<table>
<thead>
<tr>
<th>parameters</th>
<th>Normal distribution</th>
<th>Lognormal distribution</th>
<th>Weibull distribution</th>
<th>Extreme value distribution</th>
<th>From failures only</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean $\bar{r}$ (year)</td>
<td>$75$</td>
<td>$16725$</td>
<td>$438$</td>
<td>$55$</td>
<td>$20$</td>
</tr>
<tr>
<td>Std $\sigma$ (year)</td>
<td>$29.1$</td>
<td>$236540$</td>
<td>$415.6$</td>
<td>$14.9$</td>
<td>$11.5$</td>
</tr>
<tr>
<td>K-S</td>
<td>R</td>
<td>A</td>
<td>A</td>
<td>R</td>
<td></td>
</tr>
<tr>
<td>COD</td>
<td>$0.914$</td>
<td>$0.970$</td>
<td>$0.987$</td>
<td>$0.873$</td>
<td></td>
</tr>
</tbody>
</table>

Table 2-5 Results of fitting National Grid transformer failure CDF using Li’s method by the means of LSE [16].

<table>
<thead>
<tr>
<th>parameters</th>
<th>Normal distribution</th>
<th>Lognormal distribution</th>
<th>Weibull distribution</th>
<th>Extreme value distribution</th>
<th>From failures only</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean $\bar{r}$ (year)</td>
<td>$79$</td>
<td>$13942$</td>
<td>$427$</td>
<td>$58$</td>
<td>$20$</td>
</tr>
<tr>
<td>Std $\sigma$ (year)</td>
<td>$30.9$</td>
<td>$179830$</td>
<td>$402.610$</td>
<td>$15.9$</td>
<td>$11.5$</td>
</tr>
<tr>
<td>K-S</td>
<td>R</td>
<td>A</td>
<td>A</td>
<td>R</td>
<td></td>
</tr>
<tr>
<td>COD</td>
<td>$0.870$</td>
<td>$0.969$</td>
<td>$0.986$</td>
<td>$0.825$</td>
<td></td>
</tr>
</tbody>
</table>
ii). **Life data analysis using MLE**

The National Grid transformer life data are also analysed by the four functions mentioned above by the means of MLE. As a result, the derived mean lives are at the same magnitude as what have been derived by LSE, but all four functions have been statistically accepted by the K-S test. The fitted results are summarised in Table 2-6 and are plotted to compare with the historic data as in Figure 2-15.

Table 2-6 Results of fitting National Grid transformer life data using different functions by the means of MLE [16].

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Normal distribution</th>
<th>Lognormal distribution</th>
<th>Weibull distribution</th>
<th>Extreme value distribution</th>
<th>From failures only</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean ( \bar{T} ) (year)</td>
<td>100</td>
<td>6152</td>
<td>368</td>
<td>81</td>
<td>20</td>
</tr>
<tr>
<td>Std ( \sigma ) (year)</td>
<td>41.2</td>
<td>49088</td>
<td>325.7</td>
<td>25.6</td>
<td>11.5</td>
</tr>
<tr>
<td>K-S</td>
<td>A</td>
<td>A</td>
<td>A</td>
<td>A</td>
<td></td>
</tr>
</tbody>
</table>

Figure 2-15 Fitted hazard plots using different functions by the means of MLE [16].

From the table above, it is seen that, although fitting the National Grid transformer life data with any of the four functions is statistically acceptable, the derived mean lives are very different. Both normal and smallest extreme value distributions estimate the mean lives as within 100 years which appear to be reasonable; however the hazard plots appear to be heavily affected by the last hazard point as shown in
Figure 2-15. Furthermore it is not easy to declare a better fitted result among the two functions. On the other hand, both lognormal and Weibull distributions yield exceedingly large mean lives. The same occurs with the fitted result by the means of LSE. Looking at the hazard plot in Figure 2-15, it can be seen that lognormal and Weibull distributions fit the overall data generally well; however the hazard rate tends to be constant or decrease with age, which leads to an exceedingly large mean life estimated.

As briefly discussed in [16], limited transformer data at older ages is the cause of the discrepancy in the fitted results. This promotes further analysis of National Grid transformer life data, especially at older transformer ages. This will be discussed in Chapter 3.

2.2 Literature Review of Transformer’s End-of-life and Failure Models

2.2.1 Transformer End-of-life

Literally speaking, the term ‘transformer end-of-life’ stands for the end point of the transformer lifetime, and the transformer should be removed from operation. A strict definition of transformer end-of-life has been given by CIGRE Working Group A12.09 in [22] which defines the end-of-life of a transformer in three ways as:

*Strategic end-of-life: the transformer is considered to have unsuitable specifications in its present location and should be replaced.*

This usually involves the upgrade of the electricity network or substation. Typical examples are: the increase in local network’s load demand which leads to an unacceptably small safety margin of the connected transformer (i.e. short-circuit withstand strength); and the increase in the service voltage which implies the problem of core oversaturation in a transformer.

*Economic end-of-life: the transformer is considered to be replaced as maintaining its operation requires excessive costs.*
Typical examples are: the excessive losses resulted from the outdated materials used in an old transformer; and the unwise cost required to perform maintenance which increases with the operating time.

*Technical end-of-life: the transformer is unable to provide technical function as the electrical energy transferring device and should be replaced.*

It must be pointed out that such term can either be objective as in the case of transformer in-service failure, or subjective as in the case of preventive retirement judged by the condition of the unit. Strictly speaking, the time of a transformer’s retirement does not always represent the arrival of the unit's technical end-of-life, but only an estimate which depends on the correct engineering judgement, as the unit will probably be able to function if it remains in the system temporarily (with a lower reliability of course).

Among all transformer end-of-life definitions, technical end-of-life is directly associated with the functionality of the unit. The complete definition of transformer technical end-of-life has been suggested by CIGRE Working Group A2.18 in [23] as quoted below. Note that the prefix ‘technical’ does not appear in the original term but has been integrated in the definition.

*(Transformer technical) End-of-life: 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.*

From this point forward, only the transformer technical end-of-life will be discussed, which will be referred to as the term ‘end-of-life’ as simplification.

### 2.2.2 Transformer Failure Models

Despite the fact that transformers were invented over a century ago, complete prevention of failure is still beyond engineers’ capability due to the complex structures and operating conditions of the transformers. The basic failure concept of the transformer has been acknowledged as:
Transformer failure occurs when the withstand strength (i.e. dielectric, thermal, or mechanical) of the transformer is exceeded by the operational stresses.

This concept can be illustrated by Figure 2-16 which is re-drawn based on [23-25]. As the depiction, the transformer’s actual withstand strength (represented by the solid descending line) departs from the designed withstand strength (represented by the dotted horizontal line at the top) over the operation time. During the transformer operation, random system disturbances such as short-circuit faults or switching events occur, which may cause a sudden dip of the transformer’s actual withstand strength. As the operation time continues, the actual withstand strength will be eventually lowered to the level that is not sufficient to bear the stress from the next incoming disturbance event. The figure below could be further extended to incorporate additional features such as the occurrence of transformer fault, and the recovery of transformer withstand strength by the means of some life extension techniques. These features are not discussed here.

![Transformer failure concept diagram](image.jpg)

Figure 2-16 Basic concept of transformer failure [23-25].

It must be pointed out that the randomness of the disturbance event’s magnitude and frequency has brought a considerable degree of uncertainty into the transformer life prediction. Furthermore, since transformer is composed of numerous components, transformer failure is not necessarily due to the lowering of withstand strength in all components, but is in fact triggered by the weakest point which is regarded as being critical for the transformer’s functionality [3].
Besides operational stresses, human errors could possibly be introduced during the transformer maintenance procedure, which would lower the transformer withstand strength too [26].

Based on the concept of transformer failure mentioned above, numerous transformer failure models have been developed from different perspectives [1, 7, 25, 27-33]. Among all the models, four of them are often quoted by transformer researchers and users, which are component failure model (e.g. tap-changer, bushing etc.), cause-of-failure model (e.g. design defect, manufacture defect etc.), mechanism-of-failure model (e.g. mechanical, dielectric, and thermal), and long-term thermal failure model (i.e. thermal ageing of the bulk insulating paper). The following will discuss each failure model.

i). Component failure model

In this model, transformer failures are classified with respect to the components. The main elements and their failure mechanisms in component failure models are listed and briefly explained as follows:

**On-load tap-changer (OLTC)**

The on-load tap-changer (OLTC) has been confirmed, by utilities over the world, as the component most prone to fail within a transformer [4, 34-37]. This is expected since it is the only component in a transformer that has moving parts.

The failure of transformer OLTC can be characterised as a function of time, operating number and load current [12]. As the switching of OLTC occurs, the arcs are induced which yields elevated temperature and contaminates the insulating oil inside the tap changer compartment. By-products are generated from oil and they accumulate on the solid insulation which compromises the dielectric strength of the diverter switch insulation [38]. In the long term, when contacts are motionless, the by-products of the oil contamination will bond with the oil and form an oil-film layer on the stationary contacts which has low conductivity. The layer naturally increases the contact resistance and causes coking when load current flows, which leads to thermal runaway of the conductor [39]. In addition, the driving motor will undergo
mechanical wear which results in misalignment or incorrect timing between the selector and switch [23].

**Windings**

An international survey conducted by CIGRE Working Group A2.37 has shown that winding failure has gradually become the major contribution to transformer failure in recent years [40].

The winding failure is frequently associated with the abnormal deterioration of the localised insulation due to the inadequate transformer design [39]. In this category, the transformer fails owing to the turn-to-turn winding short-circuit that immediately occurs when the insulation is mechanically worn out due to the external disturbances or transformer vibrations [23, 30, 41, 42]. This is in contrast to the long-term thermal failure model which is associated with the long term thermal deterioration of the bulk insulating paper.

**Bushings**

The failure of bushing is another major cause of transformer failure [43]. Power transformers use oil-immersed or resin-immersed paper as solid insulation in their bushings. A high water content could be found in the bushing insulation if the seal is broken which will accelerate the paper’s degradation process [44, 45]. Furthermore, due to the brittleness of the porcelain, any poor manufacture or careless transport would result in micro cracks which allows the water from the atmosphere to breach in, which will accelerate the breakdown of the insulation [27, 46]. Under some specified conditions, solid contaminations in the atmosphere could accumulate on the bushing surface and result in high leakage current, which will potentially cause the thermal breakdown of the insulation [47].

**Core**

As the magnetic flux carrying device, the transformer core itself is very reliable in terms of the mechanical and thermal resistance. The failure of a transformer associated with core is usually attributed to the localised overheating caused by the
circulating current, which is resulted from the distorted magnetic flux by core bolt holes or pressing metal frames [7, 23].

**Cooler**

Power transformers use ancillary cooling equipment to avoid excessive temperatures on the insulating oil and paper. This includes fans to speed up the oil heat dissipation in the cooling radiator, and oil pumps to accelerate the oil circulation.

The failure of the cooling system is associated with the loss of power on single or multiple sets of the cooling equipment. The malfunctioning of the motor drive could occur owing to the mechanical wear. Under some circumstances the pump can be blocked due to the formation of oil sludge which severely decreases the oil circulation speed and leads to localised overheating [7].

**Tank**

A transformer tank is usually made of steel. It is designed as a container of the winding and insulation, and provides physical support and protection.

When an internal arcing fault occurs between turns and layers of the transformer windings, the insulating oil is vaporised under high temperature, which generate gas bubbles and increases the internal pressure of the tank. When pressure is sufficiently high, the withstand strength of the tank weak point (e.g. gaskets or other manufacture defects) will be compromised, causing tank rupture and oil leakage, or even tank explosion [48-51]. In the worst-case scenario where the circuit breaker does not operate promptly, a fire could start and cause casualties [46, 52].

**Other accessories**

The accessories other than those described above that could fail include oil preservation system, gas and oil actuated relays, radiators, oil and winding temperature indicators, tank and bushing pressure relieve devices, and etc.[7, 53, 54].
ii). **Cause-of-failure model**

In this model, transformer failures are classified according to the presumed causes. It can be summarised that a majority of the transformer failures so far are more or less induced by human errors during the stages of design, manufacture, maintenance, transport, installation etc. Some failure incidents are caused by irresistible or unpredictable factors, such as system disturbances. Typical causes of transformer failures are listed and explained below.

*Design inadequacy*

The importance of design optimisation has been greatly envisaged in order to achieve a balance between the cost and technical requirements. Transformer designs utilise every state-of-art approach; however, only as time goes by should the unforeseen weakness of a particular design emerge. Examples include the use of continuously-transposed conductors from the 1960s and the use of bolts as core clamping from the 1970s, and both have been recognised as could potentially induce the circulating currents in the windings [26].

Meanwhile, even if the problem in a design could be identified, any remedial actions tempting to correct the errors, such as design modification or the introduction of the corrective components, could possibly introduce new failure mechanisms [55].

*Manufacture defects*

The transformer manufacture is not perfect in practice. The manufacturing defects of any component due to poor workmanship and quality control would turn this component into a weak point and reduce the designed withstand strength of the transformer as a whole.

A significant number of transformer failures to-date is caused by manufacture defects [4, 23]. Examples include insufficiently dried paper insulation (water remains and accelerates the paper ageing); loosened clamping (reduces the mechanical withstand strength of the winding); and the edge burrs on transformer core (results in a localised overheating due to the extra losses) [26, 56, 57].
System disturbances

As depicted previously in Figure 2-16, excessive operational stresses could be introduced to the transformer and would reduce the transformer’s withstand strength significantly. Such disturbances include transformer switching operation, downstream system short-circuit faults, and lightning imposed overvoltage [4, 34, 35, 37].

A transformer switching incident could induce excessive inrush current which imposes electromagnetic forces to the energising winding in both axial and radial direction; causing irreversible mechanical deterioration of the cellulose paper [58].

A short-circuit event affects the cellulose paper in almost the same manner as a switching operation but with a much intense extent [59]. This has been recognised as one of the major failure causes of the transformer since the 1960s due to the increase in system short-circuit capacity [60].

Lightning imposes overvoltage on transformer insulation. A single lightning strike nearby is possible to cause a direct breakdown of the insulation and hence the transformer failure.

Overloading

Transmission power transformers are generally lightly loaded and they operate in parallel when considering the operation safety. However, under circumstances of short term emergency loading or outage of the neighbouring unit, the transformer will be forced to bear an additional load. This would greatly accelerate the insulation deterioration and makes the transformer more vulnerable to the system disturbances.

Incorrect maintenance

Transformer maintenance works both ways. Proper maintenance could prolong the functional life of a transformer; whereas errors during maintenance would push the transformer closer to the edge of failure [7, 28, 29]. Typical examples are the un-tightened or un-connected OLTC, and the moisture ingress during the maintenance process [26, 57].
Improper transport and storage

During careless transport and storage, some mechanical damages can possibly be introduced to the transformer components, such as rupture on the tank and bushing surface which leaves a weak link towards transformer failure [43, 52].

Other causes

Field experiences have demonstrated that a few transformer failures are caused by miscellaneous reasons such as improper site installation, GIC from solar activity, earthquake, animal intruding, and vandalism etc.

iii). Mechanism-of-failure model

Although transformer failure is always associated with the dielectric breakdown of the insulation and the consequent winding short-circuit, post-mortem investigation can be conducted to determine the mechanism behind the failure. In fact all transformer failures could be characterised by the mechanisms of dielectric, mechanical, and thermal [23, 33, 61, 62]. In practice, different failure mechanisms could interact with each other within a transformer and speed up the failure process [63]. The following context briefly presents each failure mechanism.

Dielectric failure mechanism

Internal faults such as arcing, sparking or partial discharge in the main tank will develop during the transformer operation, and will reduce the dielectric strength of the insulation. Once the dielectric strength reduces to the point where it is no longer capable to withstand the operational stresses, the transformer will fail.

Mechanical failure mechanism

Such failure mechanism is usually associated with the loosening of the bulk winding structure or winding clamping, possibly due to the system disturbances such as short-circuits or switching operations, and design inadequacy. If the windings displace severely or collapse, the windings could be shorted which immediately results in transformer failure.
**Thermal failure mechanism**

This is the most prominent failure mechanism for transformers, which involves localised overheating in winding insulation or leads due to the abnormal paper insulation ageing. As paper ages, its mechanical strength deteriorates rapidly. Once paper is mechanically worn up, it will be easily torn by the force induced by system disturbances. As a consequence the windings will be short circuited and cause the transformer failure.

In the long term, the bulk insulation will age and the mechanical withstand strength will degrade and lead to transformer failure without the system disturbance. The detailed discussion is presented as follows.

iv). **Long-term thermal failure model**

At this stage, three transformer failure models have been identified which classify transformer failures according to the components, presumed causes and mechanisms of failure. Most of the transformer failures so far can be described using one of these three models, as almost all transformers fail as a result of the compromise of transformer withstand strength by the random operational stress. Therefore these failures can be summarised as one common model i.e. **random failure model**.

There remains one particular failure model that has not yet been traced with much evidence in utilities at present, but is believed to be the dominating failure model in the long term for ageing population. This is known as **long-term thermal failure model**, which is specifically associated with the degradation of the bulk paper insulation caused by thermal ageing [7, 27-29].

Such a failure mode has not been found with much examples due to the long life expectancy of the transformer insulating paper [5, 64], and the National Grid Company’s proactive transformer retirement scheme. According to the National Grid transformer life data, only one transformer failure has been confirmed by the post-mortem investigation as following this particular failure model. The transformer is found to have severely aged cellulose paper, and it failed in service under normal operation stress due to the short circuited windings, without the presence of any precaution or major system disturbance [65].
Nevertheless, the long-term thermal degradation of the cellulose paper will eventually become a major failure mode if ageing assets are allowed to continue to operate without intervention, because the integrity of the paper material cannot last forever. Furthermore, since such a failure could occur suddenly without the presence of any precaution or major system disturbances, the criticality is excessively high. In this context, cellulose paper’s thermal degradation must be understood thoroughly.

2.3 Literature Review of Cellulose Paper Ageing

In electrical apparatus, the use of cellulose paper as insulation material dates back to as early as the 1920s [66]. For transformers in particular, due to the high operating voltage, Kraft paper is the most commonly used paper insulation because of its great capability of withstanding the electromagnetically induced force [67, 68]. The word Kraft means strong in German [56].

The research of the Kraft paper structure and the development of its manufacture process reached its peak in the 1940s [67]. However the understanding of the cellulose paper deterioration process has been progressing much slower. The following reviews cellulose paper’s structure, properties, indicators of the withstand strength, and the state-of-the-art knowledge in its ageing process.

2.3.1 Structure of Cellulose Paper

Cellulose is the main composition of cellulose paper, which is a unique form of fibre that richly exists in wood or cotton [69]. Figure 2-17 is an illustration of the cellulose structure from fibre down to sub-microstructure and molecular structure.
To make insulating paper, cellulose pulps are obtained from wood and are refined to fulfil the electrical requirements. Different types of insulating papers can be made out of the refined pulp according to the purpose of use. The basic manufacturing processes are, however, similar to some extent: pulp is dissolved in water and compressed to achieve high levels of density and mechanical strength. Rotating the pulp in the forming roll, papers are formed in either single ply or multiply. The manufacture of a pressboard uses additional process of moulding, calendaring and hot press drying. Figure 2-18 is a view of various solid insulation components on 220kV side in a 400/220kV transformer.

Additional treatments may be applied to the Kraft paper as needed, such as thermally upgrading, crepe paper, and diamond dot printed papers. These types of paper are out of the scope of this research.

Figure 2-17 Illustration of cellulose structure [67, 70].

Figure 2-18 Insulation components on 220kV side in a 400/220kV transformer [56].
\section*{2.3.2 Properties of Cellulose Paper}

The function of transformer cellulose paper is to insulate windings by acting as dielectric material, and to provide mechanical support of the winding, and furthermore to protect the winding from the possible physical damage \cite{71, 72}. In this context, the dielectric and mechanical strength are two important properties of cellulose paper.

\textit{Dielectric Strength}

Evidence from both ageing experiments and field experiences has confirmed that the dielectric strength of cellulose paper degrades very slowly with operation if the paper is not mechanically disturbed \cite{73}.

In \cite{74} it is shown that the dielectric strength of the cellulose paper remained stable at temperatures up to 140\degree C. It is demonstrated in \cite{75} that the paper’s dielectric strength degrades only as little as 10\% after the functional life test on a winding model exposed to 180\degree C for 620 hours. Intensive studies of deterioration on the paper’s dielectric strength at temperatures up to 100\degree C have been conducted in \cite{76} and the results show that under the presence of moderate levels of oxygen and moisture, the paper’s dielectric strength reduces 12.8\% after 1000 hours. Similar results have been found on field transformers, where the average reduction in the breakdown strength of cellulose paper has been found to be approximately 10\% after 20 years operation \cite{74}.

\textit{Mechanical Strength}

Although the dielectric strength of cellulose paper is essential to a transformer, insulation breakdown has usually been found due to mechanical wear \cite{77}. Compared with a relatively slow deterioration in the dielectric strength, cellulose paper’s mechanical strength has been found to reduce significantly during paper ageing under the combinational effects of heat, oxygen, water, acid, metal catalysts, and mechanical stresses.
The vast range of ageing experiments conducted in the laboratory has revealed that the reduction of paper’s mechanical strength involves some complex chemical reactions [72, 78], which will be further discussed.

2.3.3 Measurement of Cellulose Paper’s Withstand Strength

Since the mechanical integrity of the cellulose paper is of particular interest to the transformer researchers and users, the mechanical withstand strength is an important parameter to evaluate the condition of the cellulose paper. Two measurements are commonly used to quantify the paper’s mechanical strength. The first one is tensile strength, which indicates paper’s tolerance of the exerted physical force until it breaks [79]. The retained tensile strength in percentage has been widely used by utilities for the paper condition assessment.

The second measurement, degree of polymerisation (DP), indicates the average number of molecular rings in the cellulose. In cellulose paper, a strong correlation has been found between the retained tensile strength and DP [73, 74, 80-84]. This relationship is illustrated in Figure 2-19, in which the tensile index is the ratio of tensile strength (N/m) and the paper’s basis weight (g/m²).

![Figure 2-19 Correlation between tensile index and DP of Kraft paper in temperature range of 70ºC and 130ºC [85].](image)

The use of DP has several advantages over the use of retained tensile strength in paper assessment [73, 79]. Firstly, measuring paper’s DP is easier than measuring tensile strength. Secondly, a smaller measurement scattering is expected from the DP measurements. Thirdly, DP is an absolute measurement and is not affected by the
paper’s initial condition, whereas this must be considered with using tensile strength to assess the paper’s condition. Therefore DP has gradually been chosen as the routine measurement in cellulose paper’s condition assessment.

2.3.4 Ageing Factors of Cellulose Paper

By the means of accelerated ageing experiments, the factors contributing to the ageing of cellulose paper are found to include heat, oxygen, water, acid, metal ion in oil (acts as paper ageing catalyst), and mechanical stress.

Heat

Heat is the most prominent factor of cellulose paper ageing. The impact of elevated temperature on cellulose paper ageing was studied as early as 1930, where Montsinger made his pioneering statement that the reduction rate of oil-immersed insulating paper’s tensile strength doubles with every 7.5 to 8ºC increase of the temperature in the range of 90 to 110ºC [86].

It was then realised that the temperature needed to double the paper’s ageing rate is not constant, but rather varies between 5-10ºC over a broad temperature range [7]. The higher the temperature is, the more sensitive paper ageing is to the temperature increase [87]. As a simple rule-of-thumb, it is widely accepted that the insulating paper’s ageing rate doubles every 6ºC increase in temperature, which is usually referred to as ‘6 degree rule’ [73].

Oxygen

Oxygen contributes to the ageing of cellulose paper. In a free-breathing transformer, oxygen ingresses from the atmosphere through the breather and then the oil conservator, and eventually enters the main tank. A typical aged free-breathing transformer could have 20,000ppm of oxygen dissolved in oil, which is significantly higher than with the typical oxygen level of 300ppm in a transformer with new oil and is well sealed with membrane [56].
Ageing experiments have shown that, with the presence of oxygen, the mechanical strength of cellulose paper reduces faster [88]. A typical illustration of such an effect is shown in Figure 2-20.

![Figure 2-20 Effect of oxygen in air on paper ageing at 120°C, redrawn by Emsley et al. in [79] based on the data in [80].](image)

The effectiveness of oxygen towards paper ageing is related to the oxygen pressure in which higher pressure yields a higher ageing rate [89]. It was reviewed by Emsley et al. that under extreme conditions where the concentration of dissolved oxygen in oil reaches the saturation level of 30,000ppm, the ageing of cellulose paper is accelerated by a factor of 16 compared with an oxygen-free transformer [79]. The effectiveness of a moderate oxygen concentration on paper ageing has been reported in magnitudes of 1.4 to 4 [79, 80, 88, 90].

On the other hand, the effectiveness of oxygen is less pronounced under very high temperatures. In [87] it was found that the effectiveness of oxygen on paper ageing is more pronounced at 75°C and then significantly reduces at temperatures above 120°C. The reason was perceived as the involvement of other ageing mechanisms besides cellulose oxidation. This was later proven to be correct by chemical experiments.

**Water**

Water has been confirmed by both laboratory experiments and field experience as a major factor that significantly accelerates cellulose paper ageing. The nature of the hygroscopic property of the cellulose paper has been recognised by industry as the main disadvantage for electrical use, and the paper must be kept as dry as possible [66].
In a new transformer, the water content in the cellulose paper is generally lower than 0.5% in weight referring to the weight of the paper. Water can ingress from the atmosphere into the main tank in three ways: direct exposure of insulation to air due to the incorrect installation or repair; water vapour molecular flow due to the difference in water vapour pressure in the atmosphere and transformer oil; and the viscous flow of wet air due to the higher atmospheric pressure than the pressure inside the tank [57]. The magnitudes of the amount of water introduced under various conditions are shown in Table 2-7. The insufficient sealing on a sealed transformer in particular will introduce excessive water content and hence severely accelerates paper ageing.

Table 2-7 Upper estimate of water build-up rate from atmosphere under various conditions [57].

<table>
<thead>
<tr>
<th>Mechanism of water ingress</th>
<th>Rate of water build-up</th>
<th>Severity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct exposure of insulation to air at RH=75%, 20ºC</td>
<td>840 g/hour</td>
<td>Severe</td>
</tr>
<tr>
<td>Poor sealing under raining</td>
<td>200 g/hour</td>
<td>Severe</td>
</tr>
<tr>
<td>Free-breathing transformer</td>
<td>6000 g/year</td>
<td>Significant</td>
</tr>
<tr>
<td>Viscous flow of wet air:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Poor sealing</td>
<td>5475 g/year</td>
<td>Significant</td>
</tr>
<tr>
<td>Proper sealing</td>
<td>600 g/year</td>
<td>Moderate</td>
</tr>
<tr>
<td>Water vapour molecular flow:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Proper sealing</td>
<td>1.5 g/year</td>
<td>Minor</td>
</tr>
<tr>
<td>Poor sealing</td>
<td>30-40 g/year</td>
<td>Minor</td>
</tr>
</tbody>
</table>

Water is also generated as the by-product of cellulose paper ageing [80]. It is estimated that the water content in paper increases by 0.5% every time paper’s DP halves [85, 91]. As an estimation, a water content of 3 to 5% can be found in the paper of a typical free-breathing transformer near its end-of-life [73].

Compared to oxygen, water has been proven to be more detrimental to cellulose paper [91]. The presence of water not only results in accelerated paper ageing, but also lowers the PD inception voltage significantly [92]. The rate of paper’s DP reduction is accelerated by the increase of water content in the paper which is illustrated in Figure 2-21. Note that an additional moisture ingress was manually introduced to each of the three test subjects, as reflected by the subsequent reduction of the testing paper’s DP retention. There has been a discrepancy in estimating the
effectiveness of the presence of water on paper ageing, which varies from a factor of 2 to 20 under the paper’s water content of up to 4% [87, 91].

![Figure 2-21 Effect of water on paper’s DP reduction at 95°C [93].](image)

Lastly, it should be noted that due to the higher solubility of water in oil at a higher temperature, water tends to migrate from paper into oil at the transformer hot-spot. To some extent this alleviates the ageing of the local cellulose paper [66, 93, 94].

**Acid**

The ageing of both oil and paper produces acid but with different chemical properties [85]. Hydrophobic acid, known as high molecular weight acid, is produced mainly by oil degradation and is dissolved in oil in a large quantity. The presence of hydrophobic acid does not affect the ageing of cellulose paper much. Hydrophilic acid, on the other hand, known as low molecular weight acid, is mainly produced by the ageing of cellulose paper and is detrimental to the paper’s condition [95].

The formation of the acid is not completely understood yet, but the presence of acid, especially hydrophilic acid, is responsible in paper’s DP reduction. This is shown in Figure 2-22. Note that the first three acids are hydrophilic and their presence reduces paper DP significantly; whereas the latter two types of acid are hydrophobic and do not contribute much to paper ageing.
Individual studies on the effectiveness of three hydrophilic acids have found that the presence of formic, acetic, and laevulinic acid would accelerate paper ageing by factors of 5.6, 2.6 and 1.6 respectively under dry paper (moisture content of 0.75%). Under the paper’s moisture content of 2.5%, this factor is doubled [96].

**Metal ion in oil**

Metal ions, mainly cooper ions in oil, are found to promote the oxidation of oil and result in an accelerated production of water and acid, which will in turn catalyse the paper ageing [79, 91, 97]. It has been noted that in order to act as paper ageing catalyst, the solid copper immersed in oil needs to be converted into ion states which is a time consuming process [89].

**Mechanical stress**

Mechanical stress is possibly encountered by cellulose paper in transformer in several ways. During transformer operation, whenever system disturbance such as a short-circuit fault is encountered, the winding will bear a large induced electromagnetic force in both axial and radial force [59, 98]. Consecutive disturbances accumulate the mechanical wear on cellulose paper and eventually cause winding radial or axial damage as depicted in Figure 2-23. Field evidence indicates that many transformers which failed as the direct consequence of system
short-circuit events are found associated with historic experiences of a series of short-circuit events [99].

In addition, the occasional shipping damage is detrimental to the transformer clamping and makes the transformer vulnerable to the force induced by short-circuits or switching incidents [101].

Attempts in quantifying the effectiveness of mechanical stress on cellulose paper ageing is by far nowhere near a solution, as the impact of the system disturbance (either a short-circuit fault or a switching incident) is a function of induced current magnitude, duration, and occurrence frequency, which is not yet predictable in a large power system network [60].

2.3.5 **Ageing Mechanisms of Cellulose Paper**

Over the years of the cellulose paper ageing study, three main ageing mechanisms have been identified: oxidation, hydrolysis, and pyrolysis [73, 80]. In practice, these mechanisms most probably occur in a synergetic manner. To facilitate the investigation, each mechanism is isolated from the others and is studied separately. Figure 2-24 is a conceptional illustration of cellulose paper’s ageing mechanisms.
The ageing of a new and dry cellulose paper begins with oxidation which is initiated by the oxygen ingress from atmosphere [102]. Oxidation of oil may also make a contribution to the cellulose degradation [103]. In this mechanism, oxygen combines with heat to form hydrogen peroxide (H\textsubscript{2}O\textsubscript{2}) and organic hydro peroxides (ROOH), which decompose into hydroxyl radicals (HO\textsuperscript{*}) and depolymerise cellulose paper. The process of oxidation can be catalysed by the presence of metal ions dissolved in oil. Carbon dioxide, acid, and water are produced by cellulose oxidation, in which the later two are responsible for the initialisation of hydrolysis. Cellulose oxidation will be suppressed in an acidic environment, which means it is an auto-inhibitory process as cellulose hydrolysis starts to kick in [85].
It is noted that oxidation is the dominating ageing mechanism of the cellulose paper at a temperature range of 60ºC or less [102].

**Hydrolysis**

Hydrolysis is the major ageing mechanism of the cellulose paper, and the reaction rate of which depends on the concentration of water and acid [84, 96]. Under the presence of acid, the cellulose linkages are hydrolysed rapidly and produce more water and carboxylic acids. The acids are decomposed into H+ ions which results in paper depolymerisation. This effectively makes cellulose hydrolysis an autocatalysed process along with the accumulation of water and acid [95].

It has been shown by the experiments that during the cellulose paper ageing, hydrolysis dominates at a moderate temperature level, which is assumed to be above 60ºC [102].

**Pyrolysis**

Pyrolysis involves thermal destruction of the cellulose molecule ring, which depolymerises the paper in a direct manner. The process of pyrolysis can take place either with or without the presence of oxygen and water, and will only occur at a very high temperature range of at least 150ºC [102, 104, 105]. Since this temperature could rarely be reached by the cellulose paper in an operating transmission power transformer, the ageing mechanism of pyrolysis is usually neglected in the study of in-service transformer’s cellulose paper ageing.

### 2.3.6 Ageing Kinetics of Cellulose Paper

**DP reduction model**

The ageing kinetics model of cellulose paper has been developed upon the reduction of paper’s DP. It has been reviewed by numerous researchers in [81, 103, 106] that the development in cellulose paper’s DP reduction model dates back to 1936, when Ekamstam presented his classical equation of:
\[ \ln \left( 1 - \frac{1}{DP_t} \right) - \ln \left( 1 - \frac{1}{DP_0} \right) = -kt \]  

(2-10)

where \( DP_t \) and \( DP_0 \) represent paper’s DP at times \( t \) and initial state respectively, and \( k \) is the ageing rate. When \( DP_t \) and \( DP_0 \) are large numbers, the above expression is simplified to:

\[ \frac{1}{DP_t} - \frac{1}{DP_0} = kt \]  

(2-11)

Over the years there have been attempts to improve the DP reduction model. In [82], Emsley et al. proposed to modify the model by incorporating an additional ageing rate constant \( k_2 \) to consider the cellulose weak link, as shown by (2-12). In [107], Zervos et al. modified the model to consider the auto-catalytic depolymerisation of the cellulose paper as in (2-13). Furthermore, In [106], Ding et al. had fitted a variety of ageing experimental data and had proposed a DP reduction model based on the laboratory results as in (2-14).

\[ \frac{1}{DP_t} - \frac{1}{DP_0} = \frac{k_{10}}{k_2} \times \left[ 1 - \exp(-k_2 t) \right] \]  

(2-12)

\[ \left( \frac{1}{DP_t} - \frac{1}{DP_0} \right) \times 100 = a \left( 2^{at} - 1 \right) \]  

(2-13)

\[ 1 - \frac{DP_t}{DP_0} = \omega_{DP}^* \left[ 1 - \exp(-kt) \right] \]  

(2-14)

In (2-12), \( k_{10} \) and \( k_2 \) are ageing rate constants in cellulose paper’s normal region and weak link. In (2-13), \( a \) is auto-catalytic constant. In (2-13), \( \omega_{DP}^* \) is defined as DP degradation reservoir.

Each of the proposed models has pros and cons; however the classic model developed by Ekamstam, i.e. (2-11), is still widely used to describe the kinetics of paper’s DP reduction due to its simplicity and adequacy.
Chapter 2 Literature Review

Chemical reaction model (Arrhenius equation)

Realising that the process of cellulose paper’s ageing involves chemical reaction, in 1947, Dakin proposed that the ageing rate of the cellulose paper could be modelled by Arrhenius equation [88], which has the form of:

$$k = A \times \exp\left(-\frac{E_A}{R(T+273)}\right)$$  \hspace{1cm} (2-15)

where $A$ is the pre-exponential factor; $E_A$ is the activation energy; $R$ is the gas constant; and $T$ is the paper’s temperature in degrees Celsius. The equation can be a very useful tool in estimating the ageing rate of cellulose if the parameters of $A$ and $E_A$ are available at a given ageing mechanism. The question however remains as what should be the values of $E_A$ and $A$.

In the early days, the value of activation energy $E_A$ was determined through ageing experiments under a variety of conditions. Two separate reviews by McNutt in 1992 and Emsley et al. in 1994 showed that the value of $E_A$ derived by different researchers varied from 76 to 150kJ/mol [73, 103]. In addition, Emsley et al. plotted the data of cellulose ageing experiments from numerous laboratories in one figure and had derived a universal $E_A$ value of 111±6kJ/mol. It was only in recent years that the value of $E_A$ has been identified under a defined ageing mechanism. The values are recommended by CIGRE Working Group A2.24 in [102] and are summarised in Table 2-8.

In contrast to the less controversial values of $E_A$, the determination of pre-exponential factor $A$ under different ageing mechanisms still has discrepancies [79]. Only the provisional values are given by CIGRE Working Group A2.24 as a reference. These are also summarised in Table 2-8.

Table 2-8 Activation energy $E_A$ and pre-exponential factor $A$ under cellulose paper’s oxidation and hydrolysis [102].

<table>
<thead>
<tr>
<th>Reference</th>
<th>Oxidation</th>
<th>Hydrolysis</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Dry, no oxygen</td>
<td>Dry, oxygen access</td>
</tr>
<tr>
<td>$E_A$ (kJ/mol)</td>
<td>128</td>
<td>89</td>
</tr>
<tr>
<td>$A$ (hour$^{-1}$)</td>
<td>$4.1 \times 10^{10}$</td>
<td>$4.6 \times 10^{5}$</td>
</tr>
</tbody>
</table>
2.3.7 *Life Expectancy of Cellulose Paper*

A definite life criterion of cellulose paper is desirable in order to assist the determination of the ultimate life of a transformer. The paper’s life can be identified in terms of either electrical or mechanical aspects [73]. Since the paper’s dielectric property degrades very slowly during the transformer operation, the end point of paper’s life has been chosen as the point when paper has lost its mechanical strength to the level that it is not sufficient to withstand the operational stresses [108, 109].

As a direct representation of the paper’s mechanical integrity, a 50% retention in tensile strength was used as the paper’s, and hence a transformer’s end-of-life criterion. The functional life test indicated that under a constant temperature of 110ºC and dry, oxygen-free conditions, the 50% retention in the paper’s tensile strength corresponds to only 65,000 hours, or 7.42 years of life which appears to be pessimistic. Alternatively, if the life criterion is altered to 25% retention in the tensile strength, this would correspond to 135,000 hours, 15.41 years of life [108].

In later years, DP was found to be superior to tensile strength in representing cellulose paper’s mechanical integrity. Different values of DP were proposed by different researchers as the paper’s end-of-life criteria, ranging from 100 to 250 [73]. Among all, the DP of 200 has been widely accepted since it corresponds to the tensile strength retention of about 20% where the paper has lost almost all its mechanical strength. This corresponds to 150,000 hours, 17.12 years of life [85, 110].

To measure the paper’s mechanical condition from an operating transformer, the paper needs to be sampled, which is yet not feasible. Alternatively, there have been attempts to determine the cellulose paper’s condition based on electrical, mechanical, and thermal stresses by the means of the functional life test on a winding segment [98, 111]. However, the results cannot be scaled to real-size transformers due to the far-more complicated design and operating conditions.

As reviewed in [3], several organisations have made suggestions about a transformer’s mean-time-to-failure (MTTF). These are listed in Table 2-9. In the table, the MTTF of 50 years made by CIGRE SC 12 is believed to be the transformer
functional life expectancy, whereas all the other values most probably represent the transformer’s ultimate life expectancy determined by the paper condition.

Table 2.9 Proposed transformer mean-time-to-failure (MTTF) by different organisations [3].

<table>
<thead>
<tr>
<th>Year</th>
<th>Organisation</th>
<th>MTTF (years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1980</td>
<td>Central Electricity Generating Board</td>
<td>200</td>
</tr>
<tr>
<td>1982</td>
<td>CIGRE SC 12</td>
<td>50</td>
</tr>
<tr>
<td>1982</td>
<td>Central Electricity Generating Board</td>
<td>190</td>
</tr>
<tr>
<td>1982</td>
<td>Tokyo Electric Power Company</td>
<td>330</td>
</tr>
<tr>
<td>1995</td>
<td>Alstom</td>
<td>200</td>
</tr>
</tbody>
</table>

Referring to the table above, the discrepancy in transformer’s ultimate life expectancies derived by the different organisations, i.e. from 190 to 330 years, is probably attributed to the limited DP measurements available, and the fact that the papers were sampled from different locations which subject to different levels of degradation. Since the paper at the winding’s hot-spot experiences the fastest degradation and is regarded as the transformer’s weak link, it is of vital importance to determine the hot-spot temperature within a transformer to give the transformer’s condition and ultimate life an accurate assessment. The following reviews the determination of transformer’s hot-spot temperature.

## 2.4 Literature Review of Transformer’s Hot-spot Temperature Determination

There are two approaches in determining transformer hot-spot temperature: direct measurement using optical fibre sensors; or by the means of using a thermal model to calculate the hot-spot temperature. Each approach will be reviewed below.

### 2.4.1 Direct Measurement Using Optical Fibre Sensors

Transformer hot-spot temperature can be measured directly by embedding optical fibre sensors into the windings. The reason for choosing optical fibre over the widely used thermocouple is due to its natural resistance of the electromagnetic noise in a transformer [112].
Although optical fibres are robust in its working environment with good accuracy (error of ±1°C [112]), they are mechanically fragile devices with a bending radius of less than 0.5 centimetres typically [22]. It is possible to be damaged due to the excessive impact during manufacture, transport, or employment.

Installation of optical fibres requires caution. In principle, they should be placed in slots inside the spacers and fixed using cellulose materials to avoid any electrical interference. The spacer containing the sensor is wedged in between the winding conductors slowly without damaging the insulation. Figure 2-25 shows the attachment of the sensor on a spacer. There have been cases where the sensor has been pulled or has fallen out of the slot and is not in contact with the winding, therefore has given an incorrect temperature reading [102].

![Figure 2-25 Winding spacer with an optical fibre sensor attached (left, [113]) and wedged in between the windings (right, [114]).](image)

The location of sensor deployment is the key to a correct measurement. Due to the principle of convection, the top level of the transformer oil will obviously have a higher temperature than the bottom level. However, due to the complicated transformer structure, the temperature increases in a non-linear manner in an upward direction. The top winding disc or turn usually does not have the highest temperature because the temperature elevation is well controlled by the oil flow above [113, 115]. A typical example is shown in Figure 2-26 which clearly shows that the hot-spot is located in a vertical position at approximately 90% from the bottom coil instead of the top level. Therefore it is advised that the optical fibre sensors should cover several layers of the uppermost disc or turn with the circumferential position varied in order to secure the correct location of hot-spot [116].
The location of transformer hot-spot could change subject to load variation [113, 117]. Therefore it is necessary to deploy optical fibre sensors on both LV and HV windings. This involves the implementation of 2 to 8 optical fibre sensors on a standard transformer, and 20 to 30 for a transformer prototype, which inevitably brings cost issues into considerations.

2.4.2 Indirect Estimation Using Thermal Model

Since using optical fibre sensors to measure a transformer’s winding hot-spot temperature is costly and that the correct allocation of the hot-spot is usually unknown, as an alternative approach, the thermal model has been adopted by manufacturers and utilities to estimate the winding’s hot-spot temperature.

A thermal model is composed of a set of sophisticated differential equations to calculate the instantaneous hot-spot temperature based on a transformer’s thermal design characteristics and the dynamic operating conditions. The most widely used thermal models are the ones published by the IEC and IEEE transformer loading guides [108, 109]. There are some modified thermal models that claim to have superior performance to the IEC and IEEE thermal models. However the models are rather complex; and more importantly, all these models, including IEC and IEEE thermal models, face a common limitation which is crucial – one of the model inputs, the transformer’s hot-spot factor (HSF) is generally unknown (HSF is a term to
characterise the temperature rise of hot-spot over the top winding). Only a suggested value is used when modelling a transformer.

It is noted that the transformer thermal models discussed in this thesis are developed based on thermal principles. There are other models that are designed based on different principles, for example detailed computational modelling such as network modelling which utilises a transformer’s geometric design parameters. Computational Fluid Dynamics (CFD) has been widely used in transformer design optimisation, because it could not only estimate the magnitude of hot-spot temperature, but also determine the location of the hot-spot [118-121]. Furthermore, if sufficient oil temperature measurements are available from different locations, it is possible to use statistical approaches to develop matrices to estimate the transformer hot-spot temperature [122, 123]. These models are beyond the scope of this research study.

**Transformer thermal diagram**

The thermal model investigated in this study is developed based on the basic thermal diagram, which describes the conceptional oil and winding temperature profile in a transformer’s vertical direction. This is shown in Figure 2-27.

![Figure 2-27 Transformer thermal diagram, redrawn from the IEC loading guide 60076-7 [109].](image-url)
It is noted that above is a simplified thermal diagram with the following assumptions made:

i). The oil temperature is linearly increased from bottom to top at any circumstance, disregarding the cooling mode or load.

ii). The winding temperature is linearly increased from bottom to top disregarding the cooling mode or load, and has a constant temperature difference from the oil temperature at the same vertical position. This is known as winding-to-oil gradient ($Gr$).

iii). The hot-spot temperature is higher than the temperature of the top winding as the result of extra stray losses build-up. It exceeds the top-oil temperature by a small fraction (the IEC loading guide defines this as $Gr$ multiplied by the hot-spot factor; while the IEEE loading guide defines as the hot-spot temperature rise over the top-oil as a whole).

The temperatures at seven critical locations in the thermal diagram are obtained in the following manner during the heat-run test:

i). The ambient temperature $\theta_{amb}$, bottom oil temperature rise $\theta_{BOR}$, and top oil temperature rise $\theta_{TOR}$ are measured directly from the ambient, top oil level and bottom oil level.

ii). The mean winding temperature rise $\theta_{MWR}$ is calculated by the means of a winding resistance measurement.

iii). The average oil temperature rise $\theta_{MOR}$ is calculated by halving the sum of $\theta_{TOR}$ and $\theta_{BOR}$.

iv). The winding-to-oil gradient $Gr$ is the difference between $\theta_{MWR}$ and $\theta_{MOR}$.

v). And finally the hot-spot temperature $\theta_{HST}$ is estimated by adding the hot-spot temperature rise over $\theta_{TOR}$ and $\theta_{amb}$. It is expressed as:
\[
\theta_{HSF} = \theta_{amb} + \theta_{TOR} + HSF \times Gr
\] (2-16)

**IEC thermal model**

The procedure of using IEC thermal model to calculate the winding’s hot-spot temperature will be thoroughly presented in Chapter 4, development of transformer thermal model.

**IEEE thermal model**

**IEEE Clause 7 model**

A thermal model is published in Clause 7 of the IEEE loading guide C57.91, often referred to as ‘IEEE Clause 7 model’. In this model, the fundamental concept of hot-spot temperature calculation is identical to the IEC thermal model, in the respect that the hot-spot temperature is composed of ambient temperature, top-oil temperature rise and hot-spot-to-top-oil temperature rise. A detailed examination of the equations shows that the IEEE Clause 7 model considers the winding and oil temperature as following the exponential function which is the same as in IEC thermal model, but the equations are slightly different. The top-oil temperature rise after a load change is shown as:

\[
\theta_{TOR}(t) = \left( \theta_{TOR,u} - \theta_{TOR,i} \right) \times \left( 1 - e^{-\frac{t}{\tau}} \right) + \theta_{TOR,i}
\] (2-17)

where \( \theta_{TOR,u} \) and \( \theta_{TOR,i} \) are the top-oil temperature rise at present and previous time instances respectively, and can be calculated by the following equations:

\[
\theta_{TOR,i} = \theta_{TOR,R} \times \left( \frac{1+R \times K_i^2}{1+R} \right)^n
\] (2-18)

\[
\theta_{TOR,u} = \theta_{TOR,R} \times \left( \frac{1+R \times K_u^2}{1+R} \right)^n
\] (2-19)

where \( K_u \) and \( K_i \) are the load factors at present and previous time instances respectively; constant \( n \) is equivalent to the oil exponent \( x \) in the IEC thermal model.
The hot-spot temperature rise over top-oil temperature after a load change is characterised as:

\[ \theta_{HSR}(t) = \left( \theta_{HSR,u} - \theta_{HSR,i} \right) \times \left( 1 - e^{-\frac{t}{\tau_{\text{HSR}}}} \right) + \theta_{HSR,i} \]  

(2-20)

where \( \theta_{TOR,u} \) and \( \theta_{TOR,i} \) are the hot-spot temperature rise over top-oil at present and previous time instances, and can be calculated by the following equations:

\[ \theta_{HSR,i} = \theta_{HSR,R} \times K_{i}^{2m} \]  

(2-21)

\[ \theta_{HSR,u} = \theta_{HSR,R} \times K_{u}^{2m} \]  

(2-22)

where \( \theta_{HSR,R} \) is the rated hot-spot temperature rise over top-oil and is equivalent to the term \( HSF \times Gr \) in the IEC model; constant \( 2m \) is equivalent to the oil exponent \( y \) in the IEC model. The suggested exponents in IEEE Clause 7 model have different values from those of the IEC model, which are shown in Table 2-10 in the later section.

Differing from the IEC thermal model, the IEEE Clause 7 model suggests the use of the equivalent 12 hour prior load to calculate the initial top-oil temperature rise and the hot-spot temperature rise over the top-oil. The prior load is calculated as:

\[ K_{\text{prior}} = 0.29 \times \left( K_{1}^{2} + K_{2}^{2} + ... + K_{12}^{2} \right)^{0.5} \]  

(2-23)

Additionally, the IEEE Clause 7 model accommodates the change in the top-oil temperature rise, the hot-spot temperature rise over the top-oil, and the oil time constant at different load tap positions.

The IEEE Clause 7 model differs from the IEC thermal model in two aspects. Firstly, the oil and winding exponents used in the two models are different, which are summarised in Table 2-10 in later section. Secondly, in terms of considering the temperature change during transient period, the IEC thermal model uses three functions of \( f(1) \), \( f(2) \), and \( f(3) \) to consider the transient rise in top-oil temperature, transient rise in hot-spot temperature over top-oil, and transient drop in top-oil.
temperature respectively. The IEEE Clause 7 model on the other hand does not use similar functions, but considers the oil time constant as varying with load and top-oil temperature, and the updating process of which will in turn incorporate the transient change of the top-oil temperature.

**IEEE Annex G model**

An alternative thermal model is published in IEEE loading guide Annex G. This is often referred to as the ‘IEEE Annex G model’. The model is developed to estimate the hot-spot temperature by calculating the oil temperature adjacent to the hot-spot, and the hot-spot temperature rise over the adjacent oil. As simplification, the composition of the hot-spot temperature in the IEEE Annex G model is shown as:

\[
\theta_{HSR} = \theta_{amb} + \theta_{BOR} + \theta_{HSOROB} + \theta_{HSROO}
\]

where \(\theta_{BOR}\) is the bottom-oil temperature rise; \(\theta_{HSOROB}\) is the temperature rise of the oil adjacent to the hot-spot over the bottom-oil; and \(\theta_{HSROO}\) is the hot-spot temperature rise over the temperature of the adjacent oil. This model utilises some additional parameters comparing with the IEEE Clause 7 model, such as oil viscosity and oil’s bottom oil temperature rise, and is structurally more complex than the IEEE Clause 7 model and the IEC thermal model. The detail of the IEEE Annex G model is not reviewed here.

It must be recognised that both IEEE Clause 7 and Annex G models share the same limitation as the IEC thermal model, which is the generally unknown hot-spot temperature rise over the top-oil at the rated load (\(\theta_{HSR}\)). This is equivalent to the unknown hot-spot factor in the IEC thermal model.

It has been reviewed in [124] that the IEEE Annex G model gives a higher hot-spot temperature estimate comparing to the IEEE Clause 7 model under ONAN, ONAF, and ODAF cooling modes. Two models give similar temperature estimates at OFAF mode. Furthermore, it was concluded that the practical use of the IEEE Annex G model is limited because it requires more inputs than the IEEE Clause 7 model.
Comparison of IEC and IEEE Model

The thermal constants of oil and winding exponents in the IEC and IEEE models are different. The IEEE thermal model does not use similar parameters as $k_{11}$, $k_{21}$, $k_{22}$ as in differential equations in the IEC thermal model. Furthermore, the IEEE thermal model does not assume a constant oil time constant, and does not give suggested value of winding time constant either. The thermal constants used in the two thermal models are summarised in Table 2-10.

Table 2-10 Recommended thermal model constants under different cooling modes in IEC and IEEE thermal model (includes Clause 7 and Annex G models) [108, 109].

<table>
<thead>
<tr>
<th></th>
<th>IEC Thermal Model</th>
<th>IEEE Thermal Model</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>ONAN</td>
<td>OF</td>
</tr>
<tr>
<td>Oil exponent $x$ in IEC, $n$ in IEEE</td>
<td>0.8</td>
<td>1</td>
</tr>
<tr>
<td>Winding exponent $y$ in IEC, $2m$ in IEEE</td>
<td>1.3</td>
<td>1.3</td>
</tr>
<tr>
<td>$k_{11}$</td>
<td>0.5</td>
<td>1</td>
</tr>
<tr>
<td>$k_{21}$</td>
<td>2</td>
<td>1.3</td>
</tr>
<tr>
<td>$k_{22}$</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>Oil time constant $\tau_o$ (minute)</td>
<td>210</td>
<td>90</td>
</tr>
<tr>
<td>Winding time constant $\tau_w$ (minute)</td>
<td>10</td>
<td>7</td>
</tr>
</tbody>
</table>

The hot-spot temperature profiles estimated by the IEC and IEEE models are slightly different. This is shown in Figure 2-28. As a reference, the hot-spot temperatures measured by optical fibre sensors are highlighted.
Figure 2-28 Hot-spot temperature profiles estimated by IEC model, IEEE Annex G model and IEEE Clause 7 model, compared with the optical fibre sensor measurement [102].

It is learnt from the figure that the IEC and IEEE Clause 7 model yield extremely close estimations in winding’s hot-spot temperature, as shown by the two overlapping temperature profiles. The IEEE Annex G model does not show any advantage over the IEC and IEEE Clause 7 models as it tends to underestimates the hot-spot temperature at the optical fibre readings of approximately 85ºC, and overestimates the temperature at the optical fibre readings of approximately 110ºC. None of the three models accurately estimates the hot-spot temperature at the decreasing load.

In another study, the IEC model is compared with the IEEE Clause 7 model in terms of the winding’s hot-spot temperature estimation as shown in Figure 2-29. The temperature profile noted as ‘IEC draft’ is calculated exactly by the IEC thermal model in the loading guide 60076-7 [109] which was not officially released during the study. The profile noted as ‘IEEE method’ is referred to as the IEEE Clause 7 model. The profile noted as ‘measured’ is obtained by the optical fibre sensors.
Figure 2-29 Hot-spot temperature profiles estimated by IEC and IEEE Clause 7 model, compared with the optical fibre measurement [125].

It is shown that the difference in the ultimate hot-spot temperatures by the three approaches is small when temperature has reached stabilisation. At the transient period, the IEC thermal model yields a higher hot-spot temperature estimate than the IEEE Clause 7 model during the load increase. The difference could be up to 20ºC as one reads the y-axis at the time of 660 to 720 minute on the figure.

As far as the transformer reliability during the operation is concerned, it is rather appropriate to have a higher temperature estimate in order to give a conservative estimate of insulating paper’s ageing condition, and hence transformer’s consumed life. In this context, the IEC thermal model is favoured over the IEEE Clause 7 model.

*Alternative thermal models*

Numerous alternative thermal models have been developed by other individuals as an attempt to improve accuracy in hot-spot temperature estimation. Susa [126-129] and Swift [130, 131] have respectively proposed their thermal models based on a thermal-electrical analogous circuit. The circuit and the quantities are shown in Figure 2-30 and Table 2-11 respectively.
Figure 2-30 Thermal-electrical analogous circuit for transformer hot-spot temperature [123].

Table 2-11 Thermal-electrical analogous quantities [128].

| Through variable | Across variable | Dissipation element | Storage element |
|------------------|----------------|---------------------|-----------------
| Thermal          | Electrical     |                     |                 |
| Heat transfer rate, $q$, watts | Current, $I$, amps | Thermal resistance, $R_{th}$, °C/watt | Electrical resistance, $R_{el}$, ohms |
| Temperature, $\theta$, °C | Voltage, $V$, volts | Thermal capacitance, $C_{th}$, J/°C | Electrical capacitance, $C_{el}$, F |

A non-linear thermal resistance equation is presented below, which is the core of Susa’s and Swift’s model:

$$\theta_{HST} = R_{th,R} \times q^n$$  \hspace{1cm} (2-25)

where $\theta_{HST}$ is the hot-spot temperature; $R_{th,R}$ is the thermal resistance of the winding hot-spot at the rated load; and $n$ is the heat dissipation factor which is similarly defined to $n$ in the IEEE Clause 7 model.

The derivations of the thermal model equations are not presented here. The final equations of hot-spot temperature calculations under the varying load and ambient temperatures of Susa’s and Swift’s models have been sorted in [123] which are shown as:
\[
\theta_{HST}(t) = \theta_{HST}(t-1) + \frac{\Delta t}{\tau_w} \times \left[ K(t-1) \times P_{cu,pu}(\theta_{HST}) \right] \times \theta_{HSR}
\]

(2-26)

where all variables have been defined previously, except for \( P_{cu,pu}(\theta_{HST}) \) and \( \mu \) in (2-26), which are the load loss dependence at the specific hot-spot temperature, and the oil viscosity respectively.

Susa’s equation takes into consideration the change of oil viscosity and winding resistance with time and load. Swift’s equation is similar to the one in IEEE Clause 7 model but with three modifications. Firstly, he considers the top-oil temperature as a dependent variable, which is different to the IEEE thermal model which regards top-oil temperature rise as a dependent variable. Secondly, the ambient temperature is added during the calculation of the top-oil temperature rise at every time instant. Thirdly, the position of the exponent \( n \) is different from the equation in the IEEE Clause 7 model.

The acceptability of these two models is evaluated thoroughly in [123] which states that Swift’s model has a missing variable and hence is structurally inaccurate. Susa’s model is structurally more accurate, however it does not convey any significant improvement in terms of the hot-spot temperature estimation over the IEEE Clause 7 model.

\emph{Thermal model applications}

The application of the transformer thermal model can be classified into two aspects according to the purpose: short-term loadability assessment which mainly concerns the paper’s loss-of-life; and long-term life assessment which is based on the paper’s loss-of-life estimates.
In the short-term application, the paper’s loss-of-life is assessed by the calculating the paper’s ageing rate. Both the IEC and IEEE transformer loading guides have equations to calculate the paper’s ageing rate which are shown as (2-28) and (2-29):

\[ V = 2^{(\theta_{acc} - 98)/6} \]  
\[ F_{AA} = \exp\left[\frac{15000}{383-15000/(\theta_{acc} + 273)}\right] \]

where \( V \) and \( F_{AA} \) both stand for paper’s ageing rate. In the IEC loading guide, a reference temperature of 98ºC is defined which states that the paper has a unity ageing rate at this temperature, and every 6ºC increase in the temperature will double the rate of ageing. In the IEEE loading guide, the reference temperature is 110ºC as an accommodation to the thermally upgraded insulating paper used in the US, and the relatively higher ambient temperature.

The equations above calculate the paper’s instantaneous loss-of-life at each modelling time step. To assess the loss-of-life over a period of time, the ageing rates are accumulated as:

\[ L = \sum_{n=1}^{N} V_n \times t_n \]  
\[ F_{EQA} = \frac{\sum_{n=1}^{N} F_{AA,n} \times t_n}{\sum_{n=1}^{N} t_n} \]

where \( L \) and \( F_{EQA} \) both stand for paper’s loss-of-life over the time interval \( N \). The unit of loss-of-life depends on \( t \). For example, if the ageing rate is calculated on an hourly basis, the loss-of-life would be in hours too.

As a short-term thermal model application, the paper’s loss-of-life is calculated under different cyclic loading and/or ambient temperatures to assess the loadability of the modelled transformer at different loads or seasons [132].
Based on the paper’s loss-of-life calculation, the thermal model can be used to assess the transformer’s end-of-life in the long term too by artificially defining an end-of-life criterion.

By the means of the transformer functional life test, several life criteria have been derived. The popular ones include 150,000 hours which corresponds to a paper’s retained DP of 200, and 180,000 hours which is an interpretation from distribution transformer’s functional life test data [132, 133]. In addition, since the DP reduction model links the paper’s retained DP with time $t$ and the paper’s ageing rate $k$, the life of a transformer can be calculated by the estimating the time required to reduce paper’s DP to 200 [32].

There remain two restrictions of using the transformer thermal model for either short-term or long-term assessment despite many improvements in the model itself (as reviewed in previous section). Firstly, the calculation of the paper ageing rate using (2-28) or (2-29) is not practical, as the equations do not consider the paper’s ageing factors other than heat. Secondly, as an important model input, the hot-spot factor in the IEC thermal model, which this is equivalent to the hot-spot temperature rise over the top-oil in the IEEE Clause 7 model, is generally unknown. Using the suggested values provided by the loading guide is definitely a crude approach. To practically assess the paper’s ageing rate, and hence the transformer’s thermal life, the loading guide’s thermal models must be modified to overcome these shortages.

### 2.5 Literature Review of Furan Formation During Cellulose Paper Ageing

#### 2.5.1 Paper’s Ageing By-products

Since sampling cellulose paper from in-service transformers is not feasible, as an alternative approach, the concentrations of some paper ageing by-products in oil are investigated in order to assess paper’s condition in a non-intrusive way. These include carbon monoxide (CO) and carbon dioxide (CO$_2$), methanol (CH$_3$OH), and furan.
• **CO and CO₂**

CO and CO₂ have been found to be mainly produced by the oxidation of paper under normal operation [102]. The concentration of CO and CO₂ in oil cannot be used to directly predict paper’s lifetime, but can be used as an overheating fault indicator instead. According to the IEC standard in [134], a ratio of CO₂ over CO of less than 3 indicates there is a sudden increase in CO production due to an abnormal paper ageing. The practical use of CO and CO₂ could be argued in three aspects. Firstly, CO and CO₂ are not only produced by cellulose paper. Oil oxidation could also produce significant amounts of CO and CO₂, which makes them imperfect candidates as indicators of paper’s condition [135]. Secondly, the concentrations of CO and CO₂ produced are unstable [136]. Thirdly, at elevated temperatures, the diffusion rate of CO from paper to oil is higher which will result in misleadingly high concentrations of CO measured [137]. As a consequence, a false alarm could possibly be triggered leading to a wrong assessment of the cellulose paper’s condition.

• **Methanol**

Methanol is purely produced by the cellulose paper ageing and is regarded as a possible candidate in paper’s ageing assessment [138, 139]. The study of methanol as an ageing indicator is at the beginning phase of research and development, and it lacks field experience to guide transformer operation and maintenance. The laboratory ageing experiments show that methanol’s formation kinetics is similar to furan. At a higher DP range between 1200 and 700, the concentration of methanol has been found to be higher than furan, which makes methanol a good indicator to detect paper’s early ageing [140]. However methanol in field transformer oil is also subject to migration between paper and oil, similar to furan, which complicates its application [140, 141].

• **Furan**

Furan is one of the most important by-products of cellulose paper ageing. The study of furan formation dates back to 1980 according to [135]. A detailed review of
furanic compound properties, formation kinetics, and the correlation with paper’s DP are presented in the following.

### 2.5.1 Furan Types and Properties

Furan is the ageing product of cellulose paper. It has been shown by the ageing experiment that no furan is produced in a blank oil sample [142]. When a cellulose chain breaks down during paper ageing, the chain liberates a glucose monomer unit which undergoes a further chemical reaction to form furanic compounds [143].

Furan is rapidly produced during the paper pyrolysis at very high temperatures. At transformer operating temperatures, the main mechanism of furan formation is paper hydrolysis which is triggered by the presence of oxygen [93].

Five furanic compounds have been identified which have the names, chemical structures, and synonyms as shown in Figure 2-31.

<table>
<thead>
<tr>
<th>Name and Abbreviation</th>
<th>Structure</th>
<th>Synonyms</th>
</tr>
</thead>
</table>
| 2-Furaldehyde         | ![Structure](image1) | 2 - FURFURALDEHYDE  
                         | | 2 - FURFURAL  
                         | | FURALDEHYDE                  |
| 2-Acetylfuran         | ![Structure](image2) | 2-FURYL METHYL KETONE         |
| 5-Methyl-2-Furaldehyde| ![Structure](image3) | 5-METHYL 2-FURFURALDEHYDE  
                         | | 5-METHYL 2-FURFURAL          |
| 2-Furfurol            | ![Structure](image4) | FURFURYL ALCOHOL              |
| 5-Hydroxymethyl-2-Furaldehyde | ![Structure](image5) | 5 HYDROXYMETHYL  
                                   | | 2 FURFURALDEHYDE              |

Figure 2-31 Chemical Structure and names of the five furanic compounds [143].
Among all, 2-furfural (2FAL) is the main derivative of the furanic compounds. In [144], an ageing experiment in a sealed tube has shown that 2FAL is produced with highest concentration among all five family members. It is depicted in Figure 2-32 that the concentration of 2FAL (Figure 2-32, a) dominates and its concentration is significantly above those of 2-furfurol (2FOL), 2-acetylfuran (2ACF), and 5-methyl-2-furaldehyde (5MEF) produced by Kraft paper at 140ºC. The concentration of 5-hydroxymethyl-2-furaldehyde (5HMF) is not shown because it was extremely unstable and was only presented at an early stage of ageing. Similar results have been obtained during the ageing experiments on a transformer prototype for over 1,000 hours under the defined load pattern, in which the concentration of 2FAL at the end of the experiments has reached the magnitude of almost 8×10⁴ ppb (parts-per-billion, 10⁻⁹), whereas the concentrations of other four members are lower than 5000 ppb [145].

Looking at the stability of the furanic compounds within the temperature range of 100 to 160ºC, the concentrations of 2FAL, 2ACF, 5MEF, and 5HMF are stable up to 120ºC and will degrade slowly at higher temperatures due to evaporation. 2FOL is an exception which degrades rapidly with time [144, 146]. This is depicted in Figure 2-33.
Further investigation has confirmed that the evaporation of furans occurs significantly at temperatures higher than 160°C (except for 2FOL which evaporates at much lower temperatures) [142]. The degradation of furans can be further catalysed by the presence of metal ions in oil [146]. In [143] it is summarised that furans are ranked according to stability as 2ACF ≈ 5MEF > 2FAL > 5HMF > 2FOL.

Due to the highest concentration among all family members and its relatively high stability, 2FAL has been widely chosen as the cellulose paper ageing indicator. In the following, the kinetics of 2FAL formation, its correlation with paper DP, and the field 2FAL measurements are reviewed.

### 2.5.2 Factors of 2FAL Formation Factors

As 2FAL is the production of cellulose paper ageing, the formation of 2FAL is dependent on similar factors to the DP reduction of cellulose paper.

- **Heat**

Heat is the most obvious factor in the formation of 2FAL. The formation of 2FAL has been studied in numerous ageing experiments under the temperatures from 70°C to 180°C [142, 144]. It is however noticed that 2FAL will evaporate in temperatures of 160°C upwards as discussed previously.
• **Oxygen**

Oxygen has a strong triggering effect on 2FAL formation [136, 142, 144, 146-148]. The ageing experiment at 120°C reveals that the presence of oxygen accelerates the 2FAL formation by a factor of 4 [147]. At a lower temperature of 85°C in which oxidation is believed to dominate paper ageing process over other mechanisms, and the influence of oxygen is more pronounced. It is shown in Figure 2-34 that the concentration of 2FAL reaches 12ppm (parts-per-million, $10^6$) after 5 months with the presence of air in non-inhibited oil, which is significantly higher than the 2FAL level with an absence of air in non-inhibited oil i.e. 2ppm, and 1ppm or less with an absence of air in inhibited oil.

![Figure 2-34 Concentration of 2FAL in non-inhibited oil with presence of air (solid line), in non-inhibited oil with absence of air (dotted line in middle), and in inhibited oil with absence of air (dashed line at bottom) [90].](image)

• **Water**

The formation of 2FAL is significant when paper has high water contents [91, 136, 146, 147, 149]. In the ageing experiment under 120°C, the paper contains 8% of water would produce 2FAL with a concentration that is 3 times higher than the paper containing 0.2% of water [147].

In free-breathing transformers with oil conservators, both oxygen and water could accumulate within the oil-paper insulation system. Under this circumstance the concentration of 2FAL in oil is expected to be high, i.e. approximately 8 times more than the transformer with dry and degassed oil-paper insulation [147]. The effect of oxygen and water toward 2FAL formation is shown in Figure 2-35. The decline trend of 2FAL concentration may be due to evaporation at the temperature of 140°C.
2.5.3 **Partitioning of 2FAL in Oil-paper Insulation**

The 2FAL is a polar compound and is hydrophilic. This means that the majority of 2FAL produced will stay together with water in cellulose paper, while only a small amount is dissolved in oil [143, 150]. The solubility of 2FAL in oil is dependent on temperature i.e. the higher the temperature is, the more 2FAL will dissolve in oil [142]. In an operating transformer, partitioning of 2FAL occurs between oil and cellulose paper, and the partitioning ratio changes when the oil temperature changes because of the dynamic loading and ambient temperature.

A series of ageing experiments were conducted by CIGRE Task Force 15.01.03 to examine the 2FAL formation under the temperatures from 105 to 150°C. The ageing environment was defined in such a way that water content in paper was controlled as either dry (0.5%) or moderate (2%), with the presence of air or N₂. Under these
conditions, it is found that 80% of the total 2FAL produced is retained in the paper, whereas 20% is dissolved in the oil [136, 147]. This is in accordance with another experiment conducted at a lower temperature range of 55 to 100ºC, and it is found that the 2FAL produced will dissolve in the oil with a percentage of approximately 15% when reaching equilibrium [151], as shown in Figure 2-36.

![Figure 2-36 Residual percentage of 2FAL in oil at temperature from 55 to 100ºC [151].](image_url)

Due to the dynamic loading and ambient temperature variation, the 2FAL concentrations in oil and cellulose paper will unlikely reach an equilibrium in a field transformer. This adds a considerable degree of uncertainty in the paper’s condition assessment especially if the temperature is not measured when sampling the oil.

### 2.5.4 Correlation Relationship Between 2FAL and DP

The derivation of the correlation relationship between 2FAL concentration in oil and paper’s DP has been an objective to investigate by many researchers. The correlation relationship is particularly useful for developing the non-intrusive technique to assess the paper’s condition of an in-service transformer.

i). **Deriving by ageing experiments**

Numerous ageing experiments have been done to find the correlation relationship between the paper’s DP retention and the 2FAL concentration in oil. The results
obtained by different laboratories indicate that there exists a linear relationship between the logarithmic of 2FAL concentration in oil and paper’s DP. This is shown in Figure 2-37.

![Figure 2-37 Correlation between log(2FAL) and paper’s DP under 120ºC (triangle), 140ºC (square), and 160ºC (circle) [144].](image)

Numerous equations have been proposed trying to link 2FAL concentration in oil with paper’s DP. Some highlighted equations are summarised in Table 2-12. Most of them associate the logarithmic 2FAL concentration with paper’s DP in a first order relationship, but the physical explanations behind the fitted parameters are not clear.

An alternative form has been derived by De Pablo, which describes 2FAL formation in ppm as a result of cellulose chain scission as presented below:

\[
2\text{FAL}(\text{ppm}) = \frac{7100}{\text{DP}} - 8.88
\]  \hspace{1cm} (2-32)

The equation considers the yield rate of 2FAL formation obtained from various European laboratories which has the value of roughly 30%. The equation takes into consideration the molecular weight of the glucose units constituting the cellulose, the number of chain scissions, and the molecular weight of 2FAL. In additional, De Pablo has proposed a modified equation based on (2-32), i.e. (2-45), which assumes that 20% of the cellulose paper degrades twice as fast as the rest of it. The equation is also listed in Table 2-12.

The conditions of the ageing experiments deriving the 2FAL-DP correlation relationships are also listed in the table upon availability in the literature. The
conditions are listed in the order of: oil-to-paper ratio, temperature, water content in paper, ageing atmosphere, ageing duration, and the presence of oil inhibitor. Additionally, the 2FAL concentrations corresponding to the paper’s DP of 800, 400 and 200, which represent the paper’s status of early stage ageing, moderate ageing, and end-of-life, are calculated and listed in the table. The 2FAL concentrations in red denote the unrealistically high values.
Table 2-12 Equations of 2FAL concentration in oil and paper’s DP proposed by different researchers.

<table>
<thead>
<tr>
<th>Proposer</th>
<th>Ageing conditions†</th>
<th>Derived 2FAL-DP correlation</th>
<th>2FAL prediction (ppm) at:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>DP&lt;sub&gt;800&lt;/sub&gt;</td>
</tr>
<tr>
<td>Chendong [152]</td>
<td>24/1, 140 and 148°C, Dried oil/paper, up to 40 days</td>
<td>( \log(2FAL) = 1.51 - 0.0035 \times DP )</td>
<td>(2-33)</td>
</tr>
<tr>
<td>De Pablo et al. (collaboration work lead by CIGRE TF 15.01.03) [136, 147]</td>
<td>100/1, 120°C, 2%W, air, 56 days</td>
<td>( \log(2FAL) = 3.41 - 0.00266 \times DP )</td>
<td>(2-34)</td>
</tr>
<tr>
<td></td>
<td>100/1, 150°C, 0.5%W, N&lt;sub&gt;2&lt;/sub&gt;, 30 days</td>
<td>( \log(2FAL) = 3.57 - 0.0035 \times DP )</td>
<td>(2-35)</td>
</tr>
<tr>
<td></td>
<td>100/1, 120°C, 0.5%W, N&lt;sub&gt;2&lt;/sub&gt;, 56 days</td>
<td>( \log(2FAL) = 1.82 - 0.00166 \times DP )</td>
<td>(2-36)</td>
</tr>
<tr>
<td></td>
<td>100/1, 120°C, 0.5%W, air, 56 days</td>
<td>( \log(2FAL) = 3.61 - 0.0035 \times DP )</td>
<td>(2-37)</td>
</tr>
<tr>
<td></td>
<td>100/1, 105°C, 0.5%W, air, 240 days</td>
<td>( \log(2FAL) = 3.4 - 0.00287 \times DP )</td>
<td>(2-38)</td>
</tr>
<tr>
<td>Kachler et al. [90]</td>
<td>100/1, 85°C, 3.8%W, air, 150 days, non-inhibited oil</td>
<td>( \ln(2FAL) = 7.09 - 0.01 \times DP )</td>
<td>(2-39)</td>
</tr>
<tr>
<td></td>
<td>100/1, 85°C, 3.8%W, air, 150 days, inhibited oil</td>
<td>( \ln(2FAL) = 6.49 - 0.01 \times DP )</td>
<td>(2-40)</td>
</tr>
<tr>
<td></td>
<td>100/1, 85°C, 3.8%W, absence of air, 150 days, non-inhibited oil</td>
<td>( \ln(2FAL) = 8.75 - 0.013 \times DP )</td>
<td>(2-41)</td>
</tr>
<tr>
<td>Pahlavanpour et al.[153]</td>
<td>625/1, 70-180°C in 10°C steps, dried, sealed, 1 day per temperature step, inhibited oil</td>
<td>( \log(2FAL) = 1.4394 - 0.0046 \times DP )</td>
<td>(2-42)</td>
</tr>
<tr>
<td>Dong et al. [149]</td>
<td>With the aid of oil-paper model to simulate in-field transformers</td>
<td>( \log(2FAL) = 1.82 - 0.0025 \times DP )</td>
<td>(2-43)</td>
</tr>
<tr>
<td>De Pablo [154]</td>
<td>Derived based on cellulose chain scission theory</td>
<td>2FAL = 7100/DP - 8.88 *</td>
<td>(2-44)</td>
</tr>
<tr>
<td>De Pablo [154]</td>
<td>As above, assuming 20% of cellulose ages faster</td>
<td>2FAL = 4301/DP - 5.38 *</td>
<td>(2-45)</td>
</tr>
<tr>
<td>Burton</td>
<td></td>
<td>( \log(2FAL) = 2.5 - 0.005 \times DP )</td>
<td>(2-46)</td>
</tr>
<tr>
<td>(reviewed by [143])</td>
<td>log(2FAL) = 2.6 - 0.0049 × DP</td>
<td>(2-47)</td>
<td>0.05</td>
</tr>
<tr>
<td>-----------------------------</td>
<td>--------------------------------</td>
<td>--------</td>
<td>------</td>
</tr>
<tr>
<td>Vuarchex (reviewed by [143])</td>
<td>(2-47)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

†: In laboratory experiments, the conditions are in the order of (upon availability): oil-to-paper ratio in weight; temperature; water content in paper; ageing atmosphere; ageing duration; and presence of oil inhibitor.

*: De Pablo’s equations assume that the DP of new paper is 800.
If plotting the equations in the same figure as the paper’s DP retention against the logarithmic of 2FAL, the scattering would be great. This is shown in Figure 2-38, in which the five equations derived by CIGRE TF 15.01.03 and Dong’s equation are omitted, because the initial DP calculated by these equations are more than 1800 which are unrealistic. Indicated by the huge scattering of paper’s DP against 2FAL in oil derived by different researchers, it is learnt that any attempt to apply the 2FAL-DP correlation derived by the means of accelerated ageing experiments to the field transformer must be treated with caution because the ageing conditions can differ significantly from one laboratory to another (e.g. oil-to-paper ratio and temperature), which results in very different paper assessments.

![Figure 2-38 Plot of 2FAL and paper DP correlation proposed by various researchers.](image)

Furthermore, considering that the 2FAL concentration in oil could be affected by the partitioning effect, it is concluded that directly applying the laboratory derived 2FAL-DP correlations to the field transformers for paper’s condition assessment is not sensible.

**ii). Deriving by scrapping transformers**

The correlation between 2FAL in oil and paper’s DP can also be found by measuring the DP of the paper samples from the scrapped transformers and plotting with the 2FAL measurements. As an example, Figure 2-39 below illustrates the 2FAL concentrations measured in the oil samples of 10 transformers that have similar ages of 10-13 years old, belong to the same design family, and the papers are sampled
from the same location. A general trend of a decreasing DP associated with an increasing 2FAL measurement could be characterised [146].

![Figure 2-39 Concentration 2FAL in oil with respect to paper’s DP on 10 Canadian transformers in a same design family [146].](image)

The figure above shows a promising hope of assessing transformers’ paper conditions within a same design family using 2FAL measurements. However it must be pointed out that, since the production of 2FAL is very much dependent on the transformer’s design, oil-to-paper ratio, paper and oil type, and maintenance activities etc., one cannot apply the derived correlation relationship from this particular design family to the transformers of other design families.

### 2.5.5 Field Experiences of 2FAL Measurements

Since the correlations of 2FAL concentration in oil and paper’s DP derived by different laboratories have not yet reached an agreement, the utilities have been analysing 2FAL concentration on field transformers to trace any trend in 2FAL against the transformer’s age and specification if possible, and to set up a 2FAL threshold.

i). **China and Hong Kong**

A comparison of field transformers’ 2FAL profiles in China and Hong Kong is made in [149]. The mean, median, and maximum of 579 samples of 2FAL measured in the transformers in China are 0.318, 0.064, and 4.41ppm respectively. This is considerably lower than the ones obtained among 105 measurements in Hong Kong
i.e. 1.701, 0.977, and 9.47ppm. The reason behind this is suspected to be the different ambient environments and load patterns of the transformers.

In another study, a total number of 361 measurements of 2FAL from 310 transformers in China are investigated [155, 156]. The concentration of 2FAL is generally lower than 1ppm. Only 10% of the measurements are more than 2ppm. The 2FAL measurements are found to have no correlation with transformer rating, and they only slightly increase with respect to the increase of transformer’s service age.

In a large-scale study, a total number of 750 transformers in China have had their 2FAL concentrations in oil measured [157]. The 2FAL measurements are found to be slightly lower among the transformers having a higher voltage ratio and rating, which is attributed to the conservative operation and maintenance scheme. In addition, step-up generation transformers are found to have a stronger correlation between the 2FAL measurement and the service age than substation transformers due to the heavier and more consistent load.

ii). Japan

A study conducted by Japanese researchers has presented 2FAL measured in 98 transformers’ oil samples [141]. The highest measurement is as low as 0.31ppm. The concentration of 2FAL is found to increase slightly as service age increases. The transformers having the voltage ratio of 275kV or higher are found to have more pronounced 2FAL concentration measured.

iii). US

In a large-scale study, a total number of 12,231 samples of furan have been measured on the transformers in America from 1994 to 1997 [158]. The measurements do not distinguish 2FAL from other furanic compounds. The highest furan is found to be as high as 24.8ppm from an ancient transformer which failed soon after the furan test. Statistics show that 75% of the measurements are within 0.1ppm, 87% are less than 0.25ppm, and less than 2% of the measurements are above 2.5ppm.
iv). **UK**

According to [159], a sample set of 236 measurements of 2FAL were obtained from 200 units. It is found that the average level of 2FAL in oil is as low as 1ppm with a rising rate of 0.01ppm per year. Some transformers that are believed to have a temperature higher than the average have 2FAL of 5ppm with a rising rate of 0.1ppm per year, and transformers subject to a severe overheating could have 2FAL as high as 10ppm. It is concluded that the 2FAL level of 1 to 2ppm is regarded as an upper limit of normal concentration, and any unit with 2FAL of over 5ppm should be of concern [160, 161].

v). **Europe**

Following the collaboration work led by CIGRE Task Force 15.01.03, the 2FAL measurements on 5,005 transformers from 5 European countries are collected and analysed [147]. Among all, 95% of the measurements are within 5ppm, and only 1% exceeds 10ppm. The concentration of 2FAL is found to slightly decrease with the increase in transformer’s voltage ratio and rating. A clear increase trend of 2FAL has been spotted with the increase of transformer’s service age.

The largest scale of 2FAL study reviewed is the collaboration work led by CIGRE Working Group D1.01. In the study, approximately 30,000 2FAL records are obtained from transformers in 12 countries. The plot of 2FAL measurements against operation years as in Figure 2-40 is given, and an almost random distribution is seen as anticipated because transformers investigated have very large variations in design and operation conditions. The 90th, 95th and 98th percentile of 2FAL concentration of the entire dataset is 0.84, 1.66 and 3.08ppm which are considerably lower than the results gained from ageing experiments. The Working Group concluded from this study that by no means should one infer a universal value as either the normal or the concerned threshold level of 2FAL concentration dissolved in transformer oil.
2.6 Summary of Literature Review

The main findings in the literature review are summarised as:

i). **Statistical Analysis on Product’s Life Data**

The statistical analysis of a product’s life data must be performed upon the understanding of the product failure behaviour, as reflected by the classic bathtub curve, and the recognition of the possible data censoring problem. The biggest merit of life data analysis using statistical approaches is the utilisation of the well-developed mathematical models including normal, lognormal, smallest extreme value, and Weibull distribution. Besides, utilities could develop their own fitting functions to incorporate the failure behaviour of their own equipment. There have been innovative attempts to deal with the limited life data for particular devices such as transformers in the power system network.

An intensive statistical analysis of the UK National Grid transformer life data was conducted previously by Dr Qi Zhong. In the study, the data are fitted using a variety of functions by the means of LSE and MLE methods. By fitting the data using LSE, it has been found that the fitted functions are either statistically rejected, or accepted but with an unacceptably large mean life derived. Fitting the data using MLE, all fitted distributions are statistically accepted but the mean lives derived differ significantly. All the results have pointed to the fact that one could not confidently estimate the mean life of the National Grid transformer population by the means of ordinary statistical approaches due to the limited life data in the older transformer ages. The result of this study promotes a further investigation of the National Grid...
transformer life data, especially at the older ages where both the failure and exposing data are limited.

ii). **Transformer’s End-of-life and Failure Models**

The end-of-life of a transformer can be classified into three aspects, among which the technical end-of-life is of the major concern in managing the transformer asset.

The transformer failure models include component failure model, cause-of-failure model, mechanism-of-failure model and long-term thermal failure model. The first three types occur randomly due to the randomly occurring system disturbances exceeding the transformer’s designed withstand strength. The long-term thermal failure model of the transformer involves the thermal degradation of bulk cellulose paper.

iii). **Cellulose Paper Ageing**

The ageing of cellulose paper is dependent on various parameters i.e. heat, oxygen, water, acid, metal ions in oil, and mechanical stresses. Three explicit ageing mechanisms have been identified in paper ageing which are oxidation, hydrolysis and pyrolysis.

The life indicator of the cellulose paper is universally selected as DP over the traditionally used tensile strength. The life expectancy of the paper is widely chosen as the time for DP to reduce to 200.

iv). **Transformer’s Hot-spot Temperature Determination**

The transformer’s winding hot-spot temperature can be directly measured by optical fibre sensors but is costly and unreliable due to the uncertain location of the hot-spot. Alternatively, both the IEC and IEEE loading guides have published thermal models which have been widely used to estimate the transformer winding’s hot-spot temperature and the paper’s ageing rate.

There are two prominent restrictions in applying the model as either short-term loadability or long-term thermal life assessment. Firstly, the equation of the ageing rate calculation is over-simplified and neglects the ageing factors other than heat.
Secondly, one of the model inputs – hot-spot factor usually remains unknown for individual transformer, which greatly affects the accuracy in paper’s ageing rate assessment.

v). **Furan Formation During Cellulose Paper Ageing**

Furan dissolved in oil is regarded as one of the most promising candidates for paper condition assessment. Among all furanic compounds, 2FAL has the highest production rate and a high level of stability and hence has been used the most as the indicator for paper ageing.

The main factors responsible for 2FAL formation include heat, oxygen, and water. Subject to the change in temperature, the partitioning of 2FAL between oil and paper occurs, and this adds a considerable degree of uncertainty in determining the total amount of 2FAL produced by referring to the 2FAL concentration in oil. Due to the complexity of 2FAL formation under different conditions, the correlations between 2FAL in oil and paper’s DP derived by various laboratories differ significantly.

Throughout the literature review of the 2FAL measurements from field transformers, it is learnt that the 2FAL measurements are generally lower than those obtained from the laboratory ageing experiments. This is probably due to the much elevated temperatures during the ageing experiment which is rarely reached by transformers. Furthermore, there are many other factors influencing the field transformer’s 2FAL measurement including transformer’s design, oil-to-paper ratio, ambient temperature, loading, maintenance etc. It is not easy to set up a trustable 2FAL threshold on a large transformer population with different designs and operating conditions.

vi). **Final Remarks**

After this intensive literature review, it has been learnt that a transformer’s life expectancy cannot be easily derived by statistically analysing the life data. The reasons can be split into two folds: firstly the life data are censored; and secondly the failure mechanism is dominantly random-failure. Hence the life expectancy study needs to take an alternative approach since a transformer’s ultimate life is governed by the condition of its paper insulation. Despite that many efforts have been made in understanding the kinetics of paper degradation (via accelerated ageing experiments)
and winding’s hot-spot temperature estimation (via thermal modelling development), the previous studies seem to be independent to each other and there should be benefits to combine the outcomes of these studies for a practical assessment of transformer’s life expectancy.

The remainder of this thesis will aim to prove the inadequacy of ordinary statistical approach in transformer’s life expectancy investigation based on the existing life data (Chapter 3), to incorporate the latest knowledge gained about paper’s ageing process in laboratory into the thermal model towards a more practical transformer life estimation (Chapter 4 and 5), and with the aid of the developed thermal model, to derive a 2FAL-DP correlation coefficient for field transformers (Chapter 6).
Chapter 3  Life Data Analysis of National Grid Transformer by Statistical Approach

3.1  Introduction

In this chapter, a detailed analysis of the National Grid transformer life data is performed in order to investigate the negative impact of limited data. The section starts by presenting the National Grid transformer life data by both calendar year and transformer age, followed by the hazard plot per transformer age. Then the calculation of the hazard rate’s 95% confidence band by the use of the Binomial or Poisson distribution will be described in order to reveal the impact of the limited life data at older transformer ages. To examine the data sufficiency, the transformer life data are grouped in 3- and 5-year intervals to examine the outcome of the hazard rate’s 95% confidence band. Lastly, in order to fully utilise the existing dataset, the life data in all transformer ages are grouped to derive a general hazard rate.

3.2  Analysing National Grid Transformer Life Data

In this section, the life data of the National Grid transformers are analysed in order to reveal the uncertainties brought by limited transformer data at older ages to the statistical analysis.

3.2.1  Essentials of the Life Data

The life data of the National Grid transformer population needs to be sorted prior to the statistical analysis. The transformer life data presented and analysed hereafter is provided by the National Grid Company dated 28th September 2010.

According to the data, at the time the dataset was created, there were a total of 812 transformer units operating in the system. The oldest transformer recorded in the database was installed in 1956 and is still in operation. The population is mainly composed of the transmission power transformers with some minorities, summarised as:
• Transmission power transformers: 749 (92.2%)
• Quadrature boosters: 23 (2.8%)
• HVDC converter transformers: 8 (1%)
• Trackside transformers: 5 (0.6%)
• Others: 27 (3.3%)

Looking at the voltage level of these units, most of them have the primary voltage of either 400kV or 275kV. Very few units of special purposes e.g. trackside transformers could have the primary voltage down to 66kV. In terms of voltage ratio, 74% of the units have the voltage ratio of 400/275kV, 400/132kV, or 275/132kV.

The rating of the transformers varies from 18MVA as of trackside transformers, to 2750MVA as of quadrature boosters. 92% of the transformers have the rating within the range of 100MVA to 1000MVA.

According to the dataset, the transformers are made by 42 different manufacturers. This number has included some transformers that have had the windings rewound by a different manufacturer after winding faults. The reason of identifying such a small transformer subset is that rewinding the transformer by a different company would most probably involve different workmanship or even sometimes design, and must be treated separately from the units belonging to the same manufacturer prior to the rewinding [18].

Transformers manufactured by the same company could vary significantly in terms of design and specifications as required by the transformer user i.e. the National Grid Company. The 812 transformers in the database are counted as belonging to 205 different design families.

The failure data are sorted prior to the life data analysis. As a brief summary, 85 transformer failures have been collected, including the very first failure in 1956. The reasons of failure have been found to vary greatly and will be further discussed in the following sections. Furthermore, to avoid the field failure and to minimise the consequent costs, the transformer units having unacceptable conditions are
proactively retired by the National Grid Company. This counts as 55 transformer retirements up to 2010.

### 3.2.2 Presenting Life Data

#### i). Yearly profiles

The life data of National Grid transformers are plotted with respect to the calendar year. The installation number against the calendar year is shown in Figure 3-1.

Between 1952 and 2010, the National Grid Company installed 949 transformers in total. The installation profile of the National Grid transformers is a trajectory of the historic growth of national economy. After World War II ended in 1945, the entire nation was seeking for rehabilitation; recognising the importance of electricity supply, the development of the power system network was needed as a strong support to ensure economic recovery. As a strategy, the electricity supply industry in the UK was under public ownership, controlled by a single company i.e. the Central Electricity Generating Board (CEGB) [163]. Under the integrated statutory monopoly of CEGB, the electrification was developed rapidly. As a consequence the transformer installation experienced a boom from 1950 to 1970.

![Figure 3-1 Installation distribution of 949 National Grid transformers against calendar year.](image)

Then a change occurred, caused by the oil crisis in 1973, the electricity demand experienced an average annual fall of 0.5% in the following five years after the
crisis, in contrast to the annual increase of 4.7% in the five consecutive years before [21]. This directly resulted in a rapid drop in the number of transformer installation in the late 1970s as shown in the figure above.

Fifteen years after the oil crisis, the government decided to take steps to break the monopoly of CEGB by restructuring the electricity market. The privatisation of the energy sector was announced in the White Paper in February 1988, initiated by the Margaret Thatcher’s Conservative government, that aimed for a stimulation of investment as well as a healthy market [114]. As an immediate effect, investors’ confidence was renewed, and the installation of transformers in the transmission power system gradually increased from 1990 onwards and then levelled off till today.

As one of the most important messages delivered by the transformer installation profile, in 2010, 50% of the transformers were installed prior to 1970. The widely acknowledged transformer life expectancy of 40 years has been exceeded by these units.

According to the life data record, 85 transformers failed during the period from 1952 to 2010. The failure profile with respect to the calendar year is plotted as in Figure 3-2.

![Failure distribution of 85 National Grid transformers against calendar year.](image-url)
It is seen from the figure above that the National Grid Company has had no more than 6 transformer failures each year. In the last two years of 2009 and 2010, the failure numbers have reached the highest level of 6.

The figure above might lead to the impression that the National Grid transformer population is undergoing an increasing failure rate. This is, however, a rather unjustified statement considering that the transformer population is composed of multi-vintage units and transformers are subjected to different usage. Since, according to the previous review that the National Grid transformer life data are multiply censored, a better way to present the failure data is to re-plot the failure profile with respect to transformer age.

The failed transformer is only a small fraction of the bulk transformer population. A large number of transformers are still in service. This means that the life data of National Grid Company is time censored on the right.

As a preventative approach, by 2010 the National Grid Company has retired 55 transformers that were identified as having unacceptable conditions in order to prevent in-service failures. The retirement of service transformers was mainly carried out from 1990 onwards. Figure 3-3 is the retirement profile with respect to the calendar year.

Figure 3-3 Retirement distribution of 55 National Grid transformers against calendar year.
ii). **Age profiles**

To overcome the problem of multiply censored data in the plot of transformer installation with respect to calendar year, the National Grid transformer life data are re-plotted with respect to transformer age, such that for each individual transformer, the age is calculated by subtracting the unit’s installation year from the reference year of 2010. By doing this the concept of ‘transformer vintage’ will be eliminated from the data plot.

The number of National Grid in-service transformers in 2010 is counted as 809 in total (which is the remainder of the 949 total installations from 85 failures and 55 retirements). The in-service transformer profile with respect to transformer age is presented in Figure 3-4.

![Figure 3-4 In-service profile of 809 National Grid transformers against unit age.](image)

The figure above is almost a mirror image of the installation profile as in Figure 3-1. According to the profile, 50% of the National Grid transformer population has aged 40 years or more. This again reveals the fact that a significantly large portion of the National Grid transformers is approaching or has even passed the original designed life expectancies.

The failure profile of the National Grid transformers with respect to age is shown in Figure 3-5. Looking at the profile, it is learnt that the transformer failure occurs from
age 0, which represents those units which did not survive the first year of their operation; to age 50 which is the oldest transformer failure recorded.

According to the failure distribution, the failure of the National Grid transformers does not follow the traditional bathtub curve, which is recognised as a typical description of the product’s failure behaviour over the age. Due to strict factory test and careful transportation and installation, the failure distribution does not exhibit a high rate in the early years. A peak transformer failure of 5 occurs at the transformer age of 14. At the intermediate transformer ages of 30 and beyond, the failure number drops to the level of 2 or even lower. This should be attributed to the proactive retirement of the units conducted by the National Grid Company, which has the profile as shown in Figure 3-6 that most of the retirements (80%) were carried out beyond the transformer age of 30.

The transformer hazard rate at each age is calculated by dividing the failure number by the exposing number (i.e. the sum of survivor and failure number). As an example, the transformer exposing number at Age 0 is 949 which is the total number of transformer installations since 1956, regardless of the transformer’s installation years. At Age 1, the exposing number reduces to 948 in which a transformer failed within its first year of service has been deducted. The calculation continues at the subsequent ages to deduce the failed or retired transformer numbers from the total installation number of 949. The profile of the exposing number by transformer age is illustrated in Figure 3-7.
Chapter 3 Life Data Analysis of National Grid Transformer by Statistical Approach

Figure 3-5 Failure profile of 85 National Grid transformers against unit age.

Figure 3-6 Retirement profile of 55 National Grid transformers against unit age.

Figure 3-7 Exposing profile of National Grid transformers against unit age.
3.3 Hazard Rate of Transformer Age

At this stage the transformer failure number and the exposing number have been tabulated at each transformer age. The hazard rate \( h(t) \) is calculated by dividing the total failure by the total exposing number at any age \( t \) as:

\[
h(t) = \frac{\text{failure number in } t}{\text{exposing number in } t}
\]

To group the failures together at any transformer age, one must ensure that all the transformers grouped must have failed owing to a common failure mode. As a result of the post-mortem investigation of the 85 transformer failures, 84 transformer failures have been determined as following the random failure mode which means that the failure is attributed to design defect, system disturbance, or other causes that occurred randomly among the population and are unrelated to transformer ageing. There remains one special case of a transformer failure at age 37 which was due to the severe insulation deterioration, and failed without the presence of any sign of system disturbance. This is the only transformer failure so far that has been confirmed as ageing-related failure.

Considering the homogeneity of the life data, the transformer which failed owing to the ageing-related failure mode is excluded from the database. It will not make a significant difference in the statistical analysis. Based on 84 transformer failure data, the plot of the hazard rate over the transformer age from 0 to 57 is shown in Figure 3-8.
Figure 3-8 Plot of the hazard rates in transformer age from 0 to 57.

The hazard rates shown in the figure above appear to be within 2% over the entire age range. The plot is split into three regions for investigation:

i). Region (a) consists of ages from 0 to 46, in which the hazard rates are fluctuating within the level of 0.7%. In these ages the transformer exposing numbers are sufficient (i.e. larger than 200). The fluctuation of the hazard rate is caused by different failure numbers.

ii). Region (b) consists of ages from 47 to 50, where the hazards increase up to 1.6%, which is due to the drastic decrease of the transformer exposing number (from 160 to 82).

iii). Region (c) consists of the old transformer ages from 51 to 57. In this range the hazard rates are 0%, because in these ages the transformer population is very small (less than 60) and no failure has yet been observed.

According to (3-1), the hazard rate of any transformer age is affected by both failure and exposing number. Looking at Age 10 and 45 as examples: the hazard rates at these two ages are the same (0.37%), but the combinations of failure and exposing numbers are different (i.e. 3 failures over 811 exposures at Age 10; and 1 failure over 273 exposures at Age 45). Generally speaking, earlier transformer ages involve more life data, while, data shortage is seen at the older ages.
From a statistical point of view, only if the data is sufficient should the analysis result (e.g. the hazard rate per age) be considered as reliable and hence accepted [164]. In this sense the hazard rate at different transformer ages must yield different levels of confidence. The likelihood of the hazard rate at each individual transformer age will be analysed in the following section.

### 3.4 Likelihood and 95% Confidence Band of Hazard Rate

#### 3.4.1 Likelihood and Probability

The statistical term of ‘likelihood’ should be distinguished from the more frequently used term ‘probability’ [9]. The latter one refers to the measure of how certain, or uncertain, an outcome occurs out of an event. It can be understood as a parameter that exists or can be derived before the occurrence of the event. The term ‘likelihood’ opposes ‘probability’ in such way that it is a measure of the event’s parameter after the event occurrence. As a simple example, in coin tossing, \( P(HH|p=0.5) \) calculates the ‘probability’ of observing two heads consequently, given that the chance of having a head or a tail is fifty-fifty from this coin; whereas \( L(p=0.5|HH) \) calculates the ‘likelihood’ of head-to-tail ratio being fifty-fifty, given that the two heads have been consequently observed. In this sense, the term ‘likelihood’ can be understood as ‘the probability of probability’. In this study, it is the ‘likelihood’ of the hazard rate that will be examined.

#### 3.4.2 Calculation of Hazard Rate’s 95% Confidence Band

The evaluation of the hazard rate’s likelihood starts with the probability calculation of the transformer failure occurrence. In any transformer age, the probability of having a specified number of failures can be calculated using either Binomial or Poisson distribution as in the following equations:
Chapter 3 Life Data Analysis of National Grid Transformer by Statistical Approach

\[ P(f \mid N, h) = \frac{N!}{f!(N-f)!} h^f (1-h)^{N-f} \]  

(3-2)

\[ P(f \mid \lambda) = \frac{\lambda^f \exp^{-\lambda}}{f!} \]  

(3-3)

where in Binomial distribution (3-2), \( P(f \mid N, h) \) is the conditional probability of having \( f \) numbers of failure, given that the exposing number is \( N \) and the expected hazard rate is \( h \). In Poisson distribution (3-3), \( P(f \mid \lambda) \) is the conditional probability of having \( f \) numbers of failure, given that the expected failure number is \( \lambda \), which is the product of \( h \) and \( N \) in Binomial distribution. When \( h \) is small, both Binomial and Poisson distributions provide identical results [9, 164]. This has already been verified in the analysis of the National Grid transformer life data.

To examine hazard rate’s likelihood \( L(\lambda' \mid f) \), the use of Bayes Theorem is an effective approach, which has the mathematical expression shown in (3-4) and (3-5) depending on which distribution is used. The superscripts in \( f' \) and \( \lambda' \) denote that the hazard rate is artificially altered in a range.

\[ L(h' \mid f) = \frac{P(f \mid h')P(h')}{P(f)} \]  

(3-4)

\[ L(\lambda' \mid f) = \frac{P(f \mid \lambda')P(\lambda')}{P(f)} \]  

(3-5)

In the above two equations, \( P(h') \), \( P(\lambda') \) and \( P(f) \) are the prior probabilities of \( h' \), \( \lambda' \) and \( f \). It is assumed that:

**Without any prior knowledge of the transformer failure statistics, \( P(h') \), \( P(\lambda') \) and \( P(f) \) are uniformly distributed from 0% to 100%.**

As a result, \( P(h') \) and \( P(\lambda') \) will cancel \( P(f) \) in both equations. The calculation of the likelihoods \( L(h' \mid f) \) and \( L(\lambda' \mid f) \) are effectively made by calculating the probabilities \( P(f \mid h') \) and \( P(f \mid \lambda') \) using either Binomial or Poisson distribution. Although both approaches yield identical results, Poisson distribution has two advantages. Firstly, it offers a much simpler computing procedure. Secondly, the use of Poisson
distribution is not affected by resolution of the hazard rate. This will be discussed in detail in the following context.

At each age, the hazard rate \((h'\text{ or } \lambda')\) is increased from 0% to 100% in step of 0.05\%, and the likelihood density of \(L(h'|f)\) or \(L(\lambda'|f)\) will be calculated. The likelihood densities of each hazard rate are accumulated, and the hazard rate’s 95\% confidence band is extracted from the cumulative likelihood density in between the range of 2.5\% and 97.5\%, which are the lower and upper limit of the hazard rate of this age.

As an example, in age 0 of the National Grid transformer life data, there is one transformer failure \((f=1)\) and the exposing number is 949 \((N=949)\). Using Binomial distribution, the likelihood density \(L(h'|f)\) of the hazard rates from 0\% to 100\% are calculated as:

\[
L(0\%|1) = \frac{P(1|0\%)P(h')}{P(f)} = P(1|0\%)
= \frac{949!}{1!(949-1)!} \times 0\%^1 \times (1-0\%)^{949-1}
= 0\%
\]

\[
L(0.05\%|1) = \frac{P(1|0.05\%)P(h')}{P(f)} = P(1|0.05\%)
= \frac{949!}{1!(949-1)!} \times 0.05\%^1 \times (1-0.05\%)^{949-1}
= 4.53\%
\]

\[
\ldots
\]

\[
L(100\%|1) = \frac{P(1|100\%)P(h')}{P(f)} = P(1|100\%)
= \frac{949!}{1!(949-1)!} \times 100\%^1 \times (1-100\%)^{949-1}
= 0\%
\]

Consequently, the density and cumulative density of the likelihood density \(L(h'|f)\) is shown in Figure 3-9 and Figure 3-10 respectively. Note that the y-axis of the cumulative likelihood density has been normalised to make it equal to 1 when reading 100\% hazard rate.
As can be observed in Figure 3-9, the hazard rate of 0.105% has the highest likelihood, which is within expectation since 0.105% is very close to the true hazard rate at age 0 (1 failure divided by 949 exposing units). As revealed by the density plot, the likelihood of the hazard rate 0.105% does not greatly exceed the other hazard rates nearby. Extracting the hazard rate’s 95% confidence band in Figure 3-10, it is learnt that the hazard rate at Age 0 is statistically spread from 0.025% to 0.58%.
Figure 3-9 and Figure 3-10 are an example to show the use of Binomial distribution to examine the likelihood distribution of hazard rates, and the extraction of the hazard rate’s 95% confidence band. However, the precision on the extracted confidence band is limited by the resolution of the hazard rate which has the increment of 0.005% in Binomial distribution. Furthermore, the procedure is rather complicated such that the likelihoods must be calculated for 2000 times over the entire range from 0% to 100% in steps of 0.05%.

As an alternative approach, Poisson distribution could offer a direct calculation of the hazard rate’s 95% confidence band. In this approach, the failure number corresponding to the cumulative likelihood density of 2.5% and 97.5%, $\lambda_{lower}$ and $\lambda_{upper}$, are solved using Poisson distribution, and then they are converted to the lower and upper limit of the hazard rate. The procedure is mathematically expressed by (3-9) to (3-12).

\[
\text{Lower limit of } \lambda:\quad \frac{\int_0^{\lambda_{lower}} \frac{\lambda^j \exp^{-\lambda}}{j!} d\lambda}{\int_0^{N} \frac{\lambda^j \exp^{-\lambda}}{j!} d\lambda} = 2.5\% \quad (3-9)
\]

\[
\text{Upper limit of } \lambda:\quad \frac{\int_0^{\lambda_{upper}} \frac{\lambda^j \exp^{-\lambda}}{j!} d\lambda}{\int_0^{N} \frac{\lambda^j \exp^{-\lambda}}{j!} d\lambda} = 97.5\% \quad (3-10)
\]

Converting to hazard lower limit: $h_{lower} = \frac{\lambda_{lower}}{N}$ \quad (3-11)

Converting to hazard upper limit: $h_{upper} = \frac{\lambda_{upper}}{N}$ \quad (3-12)

In the above equations, $\lambda$ is the failure number and $N$ is the fixed exposing number. The numerators in (3-9) and (3-10) calculate the cumulative likelihood density of the failures from 0 to $\lambda$, while the denominators accumulate the likelihoods of the failures from 0 to $N$. Equating the cumulative likelihood density to 2.5% and 97.5%, the lower and upper limit values of $\lambda$ can be calculated. The corresponding hazard rate can be converted from $\lambda$ using (3-11) and (3-12).
The above equations could be re-written using the expression of Binomial distribution, but the computation is too complicated as it will involve the factorial of a large number $N$. Therefore it is shown that the use of Poisson distribution implies a much simpler procedure and a more accurate result because it is no longer limited by the hazard rate’s resolution.

### 3.4.3 Analysis of Hazard Rate’s 95% Confidence Band

The confidence band of the hazard rate over the transformer age is shown in Figure 3-11. Note that the discrete likelihood points have been connected to illustrate the band.

![Hazard Rate's 95% Confidence Band](image)

Figure 3-11 95% confidence band of the hazard rate in transformer ages from 0 to 57.

Since the confidence band quantifies the uncertainty of the transformer hazard rate, it can be seen from Figure 3-11 that the uncertainty of the hazard rate increases greatly as it approaches older transformer ages. In the last transformer age of 57, the lower and upper limits of the hazard rate are 0.36% and 52% respectively. This is however a pure statistical derivation based on 7 exposing transformers and no failure in this particular age, and must not be interpreted as the hazard expectancy of the transformer. For a better view, a zoomed illustration of the hazard 95% confidence band is shown in Figure 3-12.
The green line i.e. lower limit of the hazard rate does not change too much with the age. Looking at the red line i.e. upper limit of the hazard rate, it is seen that it has been fluctuating within the transformer age of 0 to 46. This is caused by different failure numbers at various ages. Furthermore, an increasing trend can be generally characterised on the hazard rate’s upper limit, especially beyond age 46. This is attributed to the decrease in the transformer exposing number.

To better understand how the failure and the exposing number affect the hazard rate’s upper limit, the life data are categorised according to the failure number from 0 to 5. In each failure number, the hazard rate’s upper limit against the transformer exposing number will be plotted as shown in Figure 3-13. The hazard rate’s lower limit has a similar trend and is not included in the figure, as the values are very low and are negligible.
From the figure above, it is clear that the larger the failure number is, the higher the hazard upper limit will be. More interestingly, in all failure number scenarios, as the exposing number decreases, the upper limit of the hazard rate increases exponentially. In different failure number scenarios, the increasing rates of the upper hazard rate are similar. This figure explains the negative impact of decreasing life data sample to the uncertainty in the hazard rate determination.

### 3.4.4 Discussion on Data Sufficiency

With the concern of the limited life data in older transformer ages, the question of ‘how much data is considered sufficient for a reliable statistical analysis?’ naturally arises. The answer to such a question very much relies on a statistician’s subjective judgments.

As in the case of the statistical analysis on the National Grid transformer life data, the question regarding data sufficiency shall be answered via the hazard rate’s 95% confidence band as shown in Figure 3-12 previously. In this study, it is stated that only if the transformer age involves the exposing unit number of more than 200, should the statistical analysis results (confidence of the hazard rate determined) be reliable and acceptable. This statement is based on the observation that the hazard rate’s upper limit has never exceeded 2% until Age 46 (inclusive), in which the exposing number at this particular age is 209. It must be emphasised at this point that
the hazard rate’s upper limit is not only influenced by the transformer exposing number, but also the failure number. Beyond Age 46, the exposing number drops below 200 and the upper limit of the confidence band starts to drastically increase, as indicated by Figure 3-13.

Under the control of random failure mode, the National Grid Company does not observe a lot of transformer failures at the older ages. Based on such transformer failure and exposing statistics, one shall stand firmly on the statement made above. However, in the circumstance that the transformer population enters the ageing-related failure mode of the life cycle, an increase trend will be expected on the transformer failure number. In that case, the transformer life data will be re-shuffled, and the study of data sufficiency will have to be performed on two separate transformer populations i.e. a bigger sample set that is subject to the random failure mode, and a smaller sample set that has entered the ageing-related failure mode.

### 3.5 Hazard Rate’s 95% Confidence Band of Age Groups

In the previous sections, the hazard rates at older ages have been proven to be inadequate, because the range of the 95% confidence band is too wide. The fundamental lies in the limited life data, both in failure and exposing numbers of transformers.

To further study the impact of the reduction of sample size, the transformer life data are grouped at every 3- and 5-year intervals. That is to say, the exposing numbers are added together at the transformer ages of 0 to 2, 3 to 5, 6 to 8 and onwards in the case of 3-year intervals; and the ages of 0 to 4, 5 to 9, 10 to 14 and onwards in the case of 5-year intervals. The failure numbers are treated in the same manner. The hazard rate in each interval is derived accordingly by dividing the total number of failures by the total exposing number. Then the 95% confidence band of the age interval’s hazard rate will be calculated using the procedure as presented in section 3.4.
As an example, Table 3-1 lists the life data analysis of three groups in each interval study. The likelihood plot of each group’s hazard rate is shown in Figure 3-14.

### Table 3-1 Transformer life data of re-grouped ages.

<table>
<thead>
<tr>
<th>Group</th>
<th>Transformer ages</th>
<th>Exposing number</th>
<th>Failure number</th>
<th>Hazard rate</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Three-year intervals</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>18-20</td>
<td>2006</td>
<td>3</td>
<td>0.15%</td>
</tr>
<tr>
<td>2</td>
<td>36-38</td>
<td>1437</td>
<td>4</td>
<td>0.28%</td>
</tr>
<tr>
<td>3</td>
<td>6-8</td>
<td>2583</td>
<td>10</td>
<td>0.39%</td>
</tr>
<tr>
<td><strong>Five-year intervals</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>15-19</td>
<td>3536</td>
<td>5</td>
<td>0.14%</td>
</tr>
<tr>
<td>5</td>
<td>5-9</td>
<td>4296</td>
<td>12</td>
<td>0.28%</td>
</tr>
<tr>
<td>6</td>
<td>25-29</td>
<td>2868</td>
<td>12</td>
<td>0.42%</td>
</tr>
</tbody>
</table>

Looking at the likelihood density of the hazard rates between Group 1 and 4 in Figure 3-14, it can be seen that although the group’s hazard rates are almost the same, since Group 4 has involved more life data, the likelihood distribution of the hazard rate is more restricted than Group 1. The peak likelihood of the hazard rate of Group 4 is greater than that of Group 1. The same observations can be made by comparing Group 5, 6 with 2, 3.

![Figure 3-14 Hazard rates’ likelihood density plots of the re-grouped transformer ages.](image-url)

This study has confirmed that the more life data there are, the greater confidence there would be in hazard rate determination. Therefore, for a more reliable statistical
Chapter 3 Life Data Analysis of National Grid Transformer by Statistical Approach

analysis, one should gather as much data as possible – but this must be reasoned, especially the homogeneity of the failure mode must be guaranteed in the failure sample analysed.

3.6 Derivation of General Hazard Rate of the National Grid Transformer

To eliminate the negative impact of the limited life data and to obtain the most confident statistical analysis result, the life data in all National Grid transformer ages are grouped together to derive a general hazard rate. This is a feasible approach considering the homogeneity of the failure mode in this data set (i.e. the random failure mode), which has been verified by the post-mortem investigations.

Dividing the sum of failures, 84, by the sum of exposing units, 30588, the general hazard rate of the UK transmission power transformer population is calculated as equal to 0.27%. The likelihood of the general hazard rate is calculated and plotted together with the likelihoods of the six age groups in section 3.5, as shown in Figure 3-15.

![Figure 3-15 Likelihood density of the general hazard rate 0.27% as compare to the likelihood plots of the smaller age groups.](image)

Referring to the table above, by grouping the life data together, the derived general hazard rate has the most deterministic range compared to any of the smaller age
groups. The general hazard rate is calculated as having the lower and upper limits of 0.21% and 0.33% respectively. The general hazard rate appears to be normally distributed, and the approximated standard deviation is equal to 0.03%. Considering the homogeneity of the failure mode, this general hazard rate of 0.27% with the lower and upper limits of 0.21% and 0.33% is applicable when characterising any individual transformer age as long as the population has not entered the ageing-related failure mode.

### 3.7 Summary

In this chapter, the life data of the National Grid transmission power transformers recorded in 2010 have been presented. It has been found that in 2010, over half of the transformer population has exceeded the transformer’s original designed life expectancy of 40 years. The failure number appears to be random over the transformer ages; and the hazard plot does not show an increasing trend as it approaches the older transformer ages. This is due to two-folds: the population has not entered the phase of ageing-related failure mode; and due to the National Grid’s replacement scheme in which a considerable number of transformers with poor conditions are proactively taken out of the service, and the transformer failure in service is consequently prevented.

Using either Binomial or Poisson distribution, the 95% confidence band of the hazard rate has been derived over the transformer ages, which is a quantification of the hazard rate’s statistical range. The result indicates that the range of the hazard rate expands to exceedingly high levels in older transformer ages due to the limited life data involved. Grouping the transformer life data in 3- and 5-year intervals, it has been noted that the more life data involved, the more confidently the hazard rate can be determined. As an attempt to respond to the question regarding the data sufficiency, it can be deduced that, despite the transformer age or the failure number, only when the exposing number exceeds 200 shall statistical analysis offer reliable results.

Recognising the negative impact of the limited life data in older transformer ages, the National Grid transformer’s life data should therefore be grouped together to
make a full use of the existing data given the failures share the common random failure mode. A *general hazard rate* of 0.27% with a standard deviation of 0.03% has been derived which is applicable to characterise the hazard rate of the National Grid transformers.

At this stage it has been concluded that the ordinary statistical approach does not work effectively on the National Grid transformer life data in terms of revealing a failure distribution function applicable over the life cycle of a transformer. In the following chapter, the alternative approach, i.e. transformer thermal modelling, will be presented which is able to determine the thermal life of individual transformer by evaluating the unit’s operation conditions and thermal parameters.
Chapter 4 Development of Transformer Thermal Model

4.1 Introduction

In this chapter, an improved transformer thermal model is developed based on the IEC thermal model to estimate a transformer’s thermal life. Besides, the developed model has two major improvements over the original model: the replacement of the Montsinger’s equation by Arrhenius equation when calculating cellulose paper’s ageing rate in order to consider the paper’s practical ageing mechanisms; and the incorporation of paper’s moisture accumulation effect. At the end of this chapter, a step-by-step modelling trial of a National Grid in-service transformer is presented.

4.2 IEC Thermal Model

The fundament of the thermal model published in the IEC loading guide 60076-7 is based on transformer’s thermal diagram depicted previously in Figure 2-27. Recall that the winding’s hot-spot temperature is composed by three parts:

\[ \theta_{HST} = \theta_{amb} + \theta_{TOR} + HSF \times Gr \]  

(4-1)

When a transformer operates, its load varies with time, and so does the ambient temperature it subject to. As a consequence, (4-1) is not adequate to be used to calculate the hot-spot temperature. To facilitate calculating the dynamic change in the hot-spot temperature as a function of time, load, and ambient temperature, the IEC loading guide 60076-7 presents two calculation approaches: exponential equations and differential equations.

It is declared in the loading guide that the exponential equations are only suitable for a step load profile, and the differential equations could accommodate the time-varying load and ambient profiles. The comparison of the exponential and differential equations is evaluated in [165]. It is stated that the two equations yield
identical temperature estimations during the load increase, and only slightly different results during the load decrease.

**Exponential equations**

According to the exponential equations in the IEC thermal model, as the load factor $K$ increases, the hot-spot temperature equation is extended from steady-state form (4-1) into:

$$
\theta_{HST}(t) = \theta_{amb} + \theta_{TOR}(t) + \left[ \theta_{TOR,R} \times \left( \frac{1+R \times K^2}{1+R} \right)^{x} - \theta_{TOR}(t) \right] \times f_1(t) + \theta_{HSR}(t) + \left(\text{HSF} \times Gr \times K^y - \theta_{HSR}(t)\right) \times f_2(t)
$$

(4-2)

where $\theta_{TOR,R}$ and $\theta_{TOR}(t)$ are the top-oil temperature rise at rated load and are the top-oil temperature rise at time $t$; $R$ is the ratio of full-load loss and no-load loss; $\theta_{HSR}(t)$ is the hot-spot temperature rise over top-oil at time $t$; $x$ and $y$ are oil and winding exponents.

The terms $f_1(t)$ and $f_2(t)$ are the response functions of top-oil and hot-spot-to-oil gradient respectively and have the following expressions:

$$
f_1(t) = 1 - e^{-\frac{t}{k_{11} \tau_o}}
$$

(4-3)

$$
f_2(t) = k_{21} \times \left[ 1 - e^{-\frac{t}{k_{21} \tau_o}} \right] - (k_{21} - 1) \times \left[ 1 - e^{-\frac{t}{k_{22} \tau_w}} \right]
$$

(4-4)

where $k_{11}$, $k_{21}$ and $k_{22}$ are constants; $\tau_o$ and $\tau_w$ are oil and winding time constants.

When the load factor $K$ decreases, the hot-spot temperature equation is:
\[ \theta_{HST}(t) = \theta_{amb} + \theta_{TOR,R} \times \left( \frac{1 + R \times K^2}{1 + R} \right)^x + \left[ \theta_{TOR}(t) - \theta_{TOR,R} \times \left( \frac{1 + R \times K^2}{1 + R} \right)^x \right] \times f_3(t) + \]

where \( f_3(t) \) is the response function of the relative decrease of top-oil-to-ambient gradient and has the expression of:

\[ f_3(t) = e^{-t / k_{11} \tau_o} \]

In the above equations, the oil exponent \( x \) is estimated based on the heat transfer efficiency between the winding and oil, while the winding exponents \( y \) is estimated based on the heat transfer efficiency between the air and transformer tank [131, 166]. The values of \( k_{11}, k_{21} \) and \( k_{22} \) for an individual transformer can only be accurately calculated with the aid of the optical fibre measurement on the winding hot-spot temperature [165]. As a suggestion, the IEC loading guide has offered recommendation values of \( x, y, k_{11}, k_{21} \) and \( k_{22}, \) as well as oil and winding time constants \( \tau_o \) and \( \tau_w. \) The values of the thermal constants have been shown in Table 2-10 in the previous section.

**Differential equations**

The differential equations are preferable in estimating the hot-spot temperature of an operating transformer, which take into account of the ‘overshoot’ of the temperature in case of a sudden rise of transformer load [102]. Figure 4-1 is a simplified block diagram of the differential equations with the function of each term describing the dynamic change in temperature. The Laplace variable \( s \) is the derivative operator \( d/dt. \)
In the above diagram each block can be interpreted into difference equations to facilitate the computation.

**Uncertainty in hot-spot factor**

The biggest restriction of the IEC thermal model application is the generally unknown hot-spot factor for individual transformers. The value is influenced by the loss and oil cooling efficiency which is strongly dependent on the transformer design [116]. CIGRE Working Group 12-09 had launched a survey to collect the information of attempts on determining the transformer hot-spot factor by analytical approaches, and the replies showed great discrepancies in either equation format or variables needed. As a conclusion, Working Group 12-09 does not recommend any analytical formula to calculate the hot-spot factor for any transformer [22].

The only promising way to accurately determine the hot-spot factor is to measure the winding hot-spot temperature by the use of optical fibre sensors. According to the survey in the same document [22], by the use of optical fibre sensors, 60 hot-spot temperature measurements were received on 34 transformers from 7 different countries. The calculated hot-spot factors vary from 0.51 to 2.06, among which the values less than unity are obviously errors. A linear region is located between 1 and...
1.5. The hot-spot factors are found to be independent of the transformer rating and cooling mode. The hot-spot factor distribution is shown in Figure 4-2.

Due to the scattering of the hot-spot factors collected, the IEC loading guide has only suggested 1.1 and 1.3 as recommended hot-spot factors for distribution and power transformers respectively. In chapter 5, a methodology will be presented to reversely derive National Grid scrapped transformer’s hot-spot factor by regarding the transformer’s DP predicted thermal life as a benchmark in the thermal model.

### 4.3 Thermal Model Procedure

In this section, a systematic thermal model is presented to give National Grid transformers an estimation of their thermal lives. The model is developed based on the IEC thermal model, but with two major improvements: the use of Arrhenius equation to calculate the paper’s ageing rate in order to consider the practical ageing mechanisms; and the incorporation of the paper’s moisture accumulation effect.

The procedure of the thermal model on an individual transformer’s thermal life assessment consists of four parts which are input, hot-spot temperature calculation, ageing rate assessment, and thermal life assessment. The last part is the extension of the original IEC thermal model. A flow chart is presented as Figure 4-3 to illustrate...
the modelling procedure. Note that in this study, the input of hot-spot factor no longer has the value of 1.3 as the IEC loading guide 60076-7 suggests, but will be reversely derived from scrapped units. This will be further discussed in Chapter 5.

Figure 4-3 Flow chart of transformer life assessment using the thermal model.

### 4.3.1 Thermal Model Inputs

i). **Ambient temperature**

Ideally, the ambient temperature should be measured at the location of the transformer to be modelled. As an approximation, the UK (more precisely, England and Wales in this study) is geographically split into 7 regions according to the Met Office as shown in Figure 4-4 [167]. In each region, the ambient temperature profiles
in 2009 are collected from the British Atmospheric Data Centre (BADC) which were sampled on an hourly basis [168]. In each region, the temperatures at the same hour are averaged to obtain a regional ambient temperature profile, which is assumed to be the ambient temperature profile for any transformer located within.

![Regional weather substation number and the average temperature of England and Wales.](image)

The characteristics of the regional ambient profiles are summarised in Table 4-1. As an example, the complete 2009 yearly ambient profile of the south UK is shown Figure 4-5.

<table>
<thead>
<tr>
<th>Region</th>
<th>Min (°C)</th>
<th>Max (°C)</th>
<th>Average (°C)</th>
<th>Std dev</th>
</tr>
</thead>
<tbody>
<tr>
<td>NW</td>
<td>-5.2</td>
<td>26.3</td>
<td>9.2</td>
<td>5.3</td>
</tr>
<tr>
<td>NE</td>
<td>-5.3</td>
<td>25.2</td>
<td>9.3</td>
<td>5.4</td>
</tr>
<tr>
<td>W</td>
<td>-5.4</td>
<td>24.9</td>
<td>9.9</td>
<td>4.9</td>
</tr>
<tr>
<td>M</td>
<td>-5.4</td>
<td>28.2</td>
<td>10.0</td>
<td>5.8</td>
</tr>
<tr>
<td>E</td>
<td>-4.8</td>
<td>27.3</td>
<td>10.3</td>
<td>5.8</td>
</tr>
<tr>
<td>SW</td>
<td>-6.6</td>
<td>25.5</td>
<td>10.1</td>
<td>5.0</td>
</tr>
<tr>
<td>S</td>
<td>-6.2</td>
<td>26.3</td>
<td>10.7</td>
<td>5.7</td>
</tr>
</tbody>
</table>
In the transformer thermal modelling, it is assumed that the 2009 temperature profile is valid through the entire transformer life. Although this is rather a rough assumption considering the possible anomaly in the UK’s climate over the years, in fact the average temperature of the UK has merely increased 0.75ºC from the 1970s to the 1990s and the speed of the rise has slowed down in recent years [169]. It is anticipated that such small changes in temperature should not affect a transformer’s thermal lifetime significantly if we consider the effect in a long term of transformer life.

ii). **Load**

The power supplied to the National Grid transformer is recorded every half hour in the units of megavolt ampere (MVA). The load factor of the transformer is calculated by dividing the supplied power by the rated power. The load factors are interpolated into minute intervals to increase the accuracy and resolution of the modelling steps.

The raw loading data have some blank entries and need to be manually completed. Firstly, the load data of all transformers provided by National Grid have been found to have no entry from 10:30 to 21:30 on 26th July 2009, and from 0:00 onwards on 31st December 2009. According to transformer loading experts of the National Grid
Company, this is attributed to human mistakes during the process of data acquisition. To complete the data, the empty load entries on 26th July and 31st December are filled in with the load at the same hours on the previous days of 25th July and 30th December. The coherence of load data is guaranteed, as 25th and 26th July in 2009 are Saturday and Sunday, while 30th and 31st December are both weekdays. The load completion is illustrated in Figure 4-6.

For a minority group of transformers, the load data in a time fraction, usually ranging from days to several months, have been found to have a load record of 0. The cause is suspected to be either a transformer hot-standby of a short duration, or the maintenance related works of a longer duration. In order to complete the data, since...
the neighbouring transformers which have identical specifications would have almost the same load profiles, the load of the neighbouring unit is hereby copied. In this study, the load completion is only performed on transformers having the empty load entry of no more than 10% of the total load entries in 2009, whereas the transformers having empty load entries of more than 10% of the year are excluded. As an example, Figure 4-7 illustrates the completion of a modelling transformer’s load profile by copying the data from the neighbouring transformer.

![Figure 4-7 Filling in the load blank of a modelling transformer by copying the data from the neighbouring transformer with identical specifications.](image)

A discontinuity in load is seen when copying the data from the neighbouring transformer. This is probably due to the fact that the neighbouring unit has to carry an additional load. No attempt is made to correct the completed load by artificially altering the load magnitude, as the load of the transformers could be distributed in an unknown manner within a substation.

The transformer’s load profile in 2009 is used in the thermal model and is assumed to be valid through the transformer’s entire life. There is a question mark over this assumption, as the configuration of the power system has definitely undergone significant changes over the years and the transformers were most probably loaded differently in the past.
The study of the transformer’s thermal life assessment rests firmly on this assumption due to the following reasons. From an objective point of view, the availability of historic load data does not date back far enough. Southern areas, especially London and its surroundings, are likely to have load demands that have increased in recent years, whereas northern areas are probably subject to a decrease in load demand as they were once the industrial core of the country, but there are fewer factories these days. By no means could one arbitrarily impose a universal rate of load increase or decrease per annum for each transformer. In this context a sensitivity study on modelled transformer’s load is necessary to examine the response of the life modelled.

iii). **Thermal parameters (i.e. heat-run test)**

In a transformer’s thermal life assessment, three thermal parameters are utilised which are obtained during the factory heat-run test. The parameters are full-load loss to no-load loss ratio $R$, top-oil temperature rise $\theta_{TOR}$, and winding-to-oil gradient $Gr$.

Since a large power transformer has dual cooling modes of ON and OF, which stand for oil natural-flowing without the external force and oil force-flowing with the aid of pumps, the heat-run data of $R$, $\theta_{TOR}$ and $Gr$ are derived under both cooling modes.

Furthermore, for National Grid transformers with tap windings, the heat-run test was performed on the lowest and highest tap numbers. Since the highest current was used at the highest tap number during the test, it is decided to use the heat-run data obtained under the highest tap number to give conservative temperature estimation, and hence conservative thermal lifetime assessment.

iv). **Hot-spot factor**

As discussed in the previous section, the transformer hot-spot factor is a term to describe the extra temperature increase at the winding hot-spot over the top winding to consider the extra stray loss build-up and the non-linear heat convection.

The precise determination of a transformer hot-spot factor relies on the use of optical fibre sensors to directly measure the temperature at the winding hot-spot. Conventionally this is not conducted on all transformers, hence there is no guarantee
for hot-spot temperature measurements during their heat-run tests. On the other hand, it is definitely a crude approach to use IEC loading guide’s suggested value of 1.3 on the bulk National Grid transformer population.

In Chapter 5, the hot-spot factor will be derived from the scrapping transformers and assigned to the in-service units according to the design family.

v). **Cooler setting**

Power transformers use a cooler setting to switch on the cooler system (i.e. fans and pumps) when the estimated hot-spot temperature exceeds the limit in order to prevent excessive material ageing. Since the transformer under a different cooling mode has different heat dissipation efficiency, the thermal performance will be different, as reflected by two sets of heat-run data.

Most of the National Grid transformers have a cooler setting of 75/50°C. This means the cooler system will be switched on when the estimated hot-spot temperature reaches the temperature of 75°C, and switched off when it falls to 50°C and below. In this study, all transformers modelled are defined to have the cooler setting of 75/50°C.

vi). **Miscellaneous**

This includes the oil and winding exponent \(x\) and \(y\); oil and wingding time constants \(\tau_o\) and \(\tau_w\); and thermal constants \(k_{11}, k_{21}\) and \(k_{22}\). In the thermal model, the values of these parameters will be referred to from the IEC loading guide and have been shown previously in Table 2-10.

4.3.2 **Hot-spot Temperature Calculation**

A set of differential equations are used in the IEC thermal model to calculate the instantaneous hot-spot temperature corresponding to the time-varying load and ambient temperature.

In differential equations, the time step of the input should be less than half of the time constant \(\tau_w\) to ensure a reasonable accuracy. To achieve the best estimation result, both ambient and load profiles are linearly interpolated into minute intervals.
Furthermore, in order to avoid the overshoot in the temperature estimate at the initial point, both ambient and load are kept constant for 48 hours before the modelling in order to achieve a stable initial temperature.

4.3.3  **Ageing Rate Calculation (Model Improvements)**

In paper’s ageing rate calculation, two improvements have been made in the developed thermal model over the original IEC thermal model, namely, the incorporation of the paper’s ageing mechanisms by the use of Arrhenius equation, and the incorporation of the paper’s moisture accumulation effect.

i). **Incorporation of paper’s ageing mechanisms**

As one of the major improvements in the thermal model, the originally used Montsinger’s equation is replaced by Arrhenius equation to incorporate paper’s ageing mechanisms of oxidation and hydrolysis. The values of activation energies and pre-exponential factors used at different ageing mechanisms are listed in Table 2-8.

The effectiveness of using Arrhenius equation to calculate the paper’s ageing rate is shown in Figure 4-8. Each colour denotes the ageing rate calculated by Montsinger’s equation, Arrhenius equation of oxidation, and Arrhenius equation of hydrolysis under the paper’s moisture contents of 1.5 and 3.5%. The activation energy $E_A$ and pre-exponential factor $A$ used are referred from the CIGRE Working Group 12.09 (listed in Table 2-8). It can be seen that in the temperature range of below 60°C where oxidation is the dominating ageing mechanism of cellulose paper, the ageing rate calculated by Arrhenius equation is a factor of 7 to 8 compared with the results of Montsinger’s equation. In the temperature range of 60°C and above where hydrolysis is the dominating ageing mechanism, Arrhenius equation yields an ageing rate of 5 to 7 times the ageing rate calculated by Montsinger’s equation at 1.5% of paper’s moisture content; and 8 to 11 times at 3.5% of paper’s moisture content.
### ii). Incorporation of paper’s moisture accumulation effect

Cellulose paper’s moisture content has been found to accumulate during the paper ageing with an approximation of 0.5% increase every time paper’s DP is halved [91]. Since the value of pre-exponential factor $A$ in Arrhenius equation is linearly proportional to paper’s moisture content [102], it is aimed to increase $A$ values as paper’s DP reduces from the initial stage of 1000 to paper’s end-of-life of 200 as a reflection of paper’s moisture accumulation.

According to [102], the values of $A$ at paper’s moisture contents of 1.5% and 3.5% have been determined by the means of accelerated ageing experiments on oil and paper sample. To interpolate $A$ values at other levels of paper’s moisture contents, the value of $A$ at the paper’s initial moisture content of 0.5% is quantified by combining the DP reduction model and Arrhenius equation into the following equation as:
In the above equation, $E_A$ is equal to 128kJ/mole which is the defined activation energy for hydrolysis according to [102]; $T$ is defined as 98°C, which is the hot-spot temperature yielding unity of ageing rate; $DP_t$ and $DP_0$ are defined as 1000 and 200 respectively for new paper and paper at end-of-life; $t$ is assigned with 150,000 hours. This is the life expectancy of the cellulose paper under dry condition which is assumed to be equivalent to the moisture content of 0.5% [108].

By these means, the value of $A$ at the paper’s moisture content of 0.5% is calculated as 2.81×10^{10}. Plotting the $A$ values at 0.5%, 1.5%, and 3.5% of moisture contents on the same figure, one could extrapolate the value of $A$ at the paper’s moisture contents of 1% and 2% by fitting the data using a second-order polynomial function (4-8), which are 8.67×10^{10} and 2.18×10^{11}. The extrapolation and the fitted equation are shown in Figure 4-9.
In terms of utilising pre-exponential factor $A$ in thermal modelling, recognising that paper’s moisture content increases by 0.5% every time when DP is halved [91], it is assumed in the thermal model that:

**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.**

A moisture content of 0.5% is equivalent to a dry paper in a newly installed transformer. Instead of assigning a varied moisture content and the pre-exponential factor $A$ according to a change of DP, three typical moisture content values from relatively new, moderate ageing, and end-of-life are used which reflect the average ageing rate at three stages of paper’s lifetime. A moisture content of 2% at paper’s end-of-life seems reasonable since the paper at the winding hot-spot could have moisture content lower than the bulk insulation, and the rate of moisture diffusion from paper to oil is higher at an elevated temperature [57].

As a summary, the complete values of activation energies $E_A$ and pre-exponential factors $A$ used in the developed thermal model are shown in Table 4-2.

<table>
<thead>
<tr>
<th>Oxidation</th>
<th>Hydrolysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>$E_A$ (kJ/mol)</td>
<td>$A$ (hour$^{-1}$)</td>
</tr>
<tr>
<td>Dry, oxygen access</td>
<td>1% water in paper</td>
</tr>
<tr>
<td>89</td>
<td>128</td>
</tr>
<tr>
<td>$4.6 \times 10^5$</td>
<td>$8.67 \times 10^{10}$</td>
</tr>
</tbody>
</table>

### 4.3.4 Transformer Life Assessment

In the previous stage, the ageing rate $k$ has been calculated in minute intervals based on 2009 load and ambient temperature profiles. To assess a transformer’s thermal lifetime, the yearly ageing rates are cumulated to derive $k_{year}$ which is regarded as the
cellulose paper’s yearly loss-of-life. Inserting $k_{\text{year}}$ into the DP reduction model, the DP retention after each modelling year can be derived by assuming that the initial DP is equal to 1000.

Because different $A$ values are used in Arrhenius equation at the DP ranges of 1000-500, 500-250, and 250-200 in order to incorporate the paper’s moisture accumulation effect, as a consequence, $k_{\text{year}}$ will be slightly higher every time paper’s DP is halved. This is an effective simulation of the auto-acceleratory process of the cellulose paper hydrolysis in a practical transformer.

The life of the transformer is calculated as the time $t$ required to reduce the paper’s DP retention from 1000 to the end-of-life criterion of 200.

### 4.4 Modelling Trial

In this section, a step-by-step modelling trial of a 275/132kV 120MVA National Grid field transformer is presented.

i). **Model inputs**

The transformer’s ambient temperature, load, heat-run data, cooler setting, hot-spot factor, and miscellaneous model parameters are collected as the model inputs. These are presented in Table 4-3 and Table 4-4. The ambient temperature and load profiles are not presented here. Note that the hot-spot factor of 1.8 is reversely derived from the scrapped transformer of this design family. The hot-spot factor derivation will be discussed in detail in Chapter 5.

<table>
<thead>
<tr>
<th>Ambient temperature profile</th>
<th>Equivalent load in 2009</th>
<th>Cooler setting</th>
<th>HSF (family derived)</th>
<th>Miscellaneous</th>
</tr>
</thead>
<tbody>
<tr>
<td>East UK</td>
<td>0.34 p.u</td>
<td>75/50ºC</td>
<td>1.8</td>
<td>Table 2-10</td>
</tr>
</tbody>
</table>
Table 4-4 Thermal model inputs of heat-run data.

<table>
<thead>
<tr>
<th>Heat-run data</th>
<th>ON mode</th>
<th>OF mode</th>
</tr>
</thead>
<tbody>
<tr>
<td>$R$</td>
<td>1.0</td>
<td>3.9</td>
</tr>
<tr>
<td>$\theta_{rn}$ (K)</td>
<td>29.9</td>
<td>28.6</td>
</tr>
<tr>
<td>$Gr$ (K)</td>
<td>19.5</td>
<td>28.5</td>
</tr>
</tbody>
</table>

ii). **Hot-spot temperature calculation**

The instantaneous hot-spot temperatures are calculated in minute intervals using the differential equations. Figure 4-10 depicts the profile of calculated hot-spot temperature using the family’s derived hot-spot factor of 1.8. Also shown in Figure 4-11 is the hot-spot temperature perceived by the transformer’s WTI with the ordinary hot-spot factor setting of 1.3.

![Hot-spot temperature chart](image)

Figure 4-10 Hot-spot temperatures estimates using the family's derived HSF.
It can be seen from the figures that the hot-spot temperature perceived by the WTI with the hot-spot factor set at 1.3 is considerably lower than the temperature estimated by the family’s derived hot-spot factor of 1.8. In fact, as it will be shown in Chapter 5, the hot-spot factors reversely derived from the National Grid scrapped transformers, which are counted as 35 in total, have a median value of 2.95, which is higher than the IEC loading guide’s suggested value of 1.3. This implies that the hot-spot temperature perceived by WTI with a hot-spot factor setting of 1.3 is much lower than the temperature calculated by the derived hot-spot factor.

Looking at Figure 4-11, it can be seen that the cooler system of this particular transformer was only triggered for a very short duration in January, November, and December as the WTI perceives the hot-spot temperature having reached 75°C. However, referring to Figure 4-10, the real hot-spot temperature would have already reached as high as 90°C. The difference in the two temperature profiles is delivering an important message that under the traditional hot-spot factor setting of 1.3, the cooler system will not operate when it is designed to do so, and consequently the cellulose paper goes through unnecessary high temperature and the condition will be irreversibly deteriorated. According to Montsinger’s ageing equation, a temperature elevation of 15°C will result in an ageing rate 5.7 times faster.
iii). **Paper’s ageing rate calculation**

Inserting the hot-spot temperatures into Arrhenius equation, the paper’s instantaneous ageing rate is calculated considering the different ageing kinetics brought by the paper oxidation and hydrolysis. The yearly ageing rate $k_{year}$ of cellulose paper is obtained by accumulating the ageing rates as shown in Figure 4-12. In the figure, different colours represent cumulative ageing rate of the cellulose paper having different moisture contents of 1, 1.5, and 2% within the DP range of 1000-500, 500-250, and 250-200 respectively.

![Figure 4-12 Cumulative ageing rate of the modelled transformer’s insulation paper with different moisture contents.](image)

iv). **Life assessment**

The DP reduction model is used to calculate this transformer’s thermal life by assessing the yearly ageing rate obtained from the previous stage. Due to the incorporation of the moisture accumulation effect, the reduction of the modelled transformer’s paper DP appears to have 3 stages as depicted in Figure 4-13.
The model has indicated that after 95 years the paper’s DP has reached the level of 200. Therefore the thermal life of this particular transformer has been assessed as 95 years.

4.5 Summary

In this chapter, an improved thermal model has been presented to estimate the thermal lives of the in-service transformers. The model is developed based on the thermal model published in the IEC transformer loading guide 60076-6.

The modelling process has four stages. At the initial stage, the transformer load, ambient, thermal design (i.e. heat-run data), cooler setting, hot-spot factor, and miscellaneous constants are collected as model inputs. Using the differential equations the instantaneous hot-spot temperature can be calculated at minute intervals at the second stage. Inserting the temperature into Arrhenius equation, the instantaneous ageing rates of the cellulose paper are calculated and are accumulated as the paper’s yearly ageing rate. As the last stage, with the aid of the DP reduction model, the thermal life of the transformer is assessed by calculating how many years it takes to reduce the paper’s DP from the initial point, 1000, to the end-of-life criterion of 200.
The developed model has two major improvements over the original IEC thermal model. The first one is the use of Arrhenius equation in paper ageing calculation which has quantitatively taken paper’s ageing mechanisms of oxidation and hydrolysis into consideration. Secondly, the model considers the moisture accumulation effect in the cellulose paper by defining the cellulose paper with the moisture content of 1, 1.5, and 2% within the DP ranges of 1000-500, 500-250, and 250-200 respectively. These features will aid the thermal model towards a practical and sophisticated thermal life estimation of the in-service transformers.
Chapter 5 Identification of Transformer’s Hot-spot Factor and Thermal Life Expectancy Using Developed Thermal Model

5.1 Introduction

In previous chapter, the IEC thermal model has been improved to consider paper’s practical ageing mechanisms and the effect of moisture accumulation. In this chapter, the developed thermal model is firstly applied on 35 National Grid scrapped transformers to reversely derive their hot-spot factors by regarding their DP predicted thermal lives as a benchmark. A series of sensitivity study will be performed to vary the year 2009 transformer load, winding-to-oil gradient $Gr$, and top-oil temperature rise $\theta_{TOR}$ to examine the impacts on the derived hot-spot factor. Assigning the hot-spot factors to the in-service transformer population according to the design family, the thermal lives of a total number of 106 National Grid in-service transformers will be assessed.

The modelling results of the 106 National Grid transformers are presented. The population’s thermal life expectancy, which is defined as the 50th percentile of the life cumulative distribution, will be given in this chapter. Regarding the sensitivity study, the year 2009 transformer load, winding-to-oil gradient $Gr$, and top-oil temperature rise $\theta_{TOR}$ are varied to examine the impacts on the population’s thermal life expectancy.

During the modelling exercise it is found that the cooling systems of the National Grid transformers are seldom utilised in operation. Simulations have been performed to update the original WTI’s hot-spot factor setting of 1.3 to the realistic values, i.e. the derived hot-spot factor obtained in Chapter 4, in order to examine the efficiency of the transformer’s cooling system.

Lastly, a 2-D thermal life matrix is given based on the thermal lives of the modelled and scrapped transformers combined. The matrix has simplified the control function.
of transformer thermal life, and could possibly be used as a quick tool to assess a transformer’s thermal lifetime by using only the essential information of the transformer.

## 5.2 Investigation of National Grid Scrapped Transformers

The National Grid Company has been performing forensic teardown investigations on the transformers that had either failed in service or had been proactively retired. Among all scrapping studies, the measurements of DP on paper samples are particularly useful, as they are the indicators of this particular transformer’s paper ageing status and can be used to predict the transformer’s thermal lifetime.

### 5.2.1 Scrapped Transformer’s DP Measurement

During the transformer teardown, papers are sampled from a variety of locations inside the transformer in order to gain a comprehensive view on material deterioration. Since the temperature in a transformer is not uniformly distributed, different paper locations usually have different DP values. The paper found to have the lowest DP implies the most intense degradation, and hence represents the transformer’s weak link. Therefore, ideally, the paper sampling process should be comprehensive enough to cover all the suspicious locations and to secure the location of the hot-spot.

In reality, the measurement of paper’s DP is both time consuming and costly. As a compromise, paper sampling on a scrapped transformer is a selective process that relies on engineering judgement. Looking at the locations of the paper sampled on the National Grid scrapped transformers, the sampling is usually carried out at three positions at the winding’s vertical perspective: top, centre, and bottom. In a few cases where the transformer is suspected to undergo severe insulation ageing, the sampling would be more intensive; for example the paper could be sampled at every 6 discs, or in some other transformers more discs are sampled at the top and bottom positions. Usually, the papers in all three phases on both voltage sides are sampled.
Besides series winding, additional sampling could be carried out on other windings upon necessary including common winding, tertiary winding, tap winding, or shield ring at the top and bottom of the winding. In addition, more often than not, only the outer layer of the paper is sampled.

Based on the DP measurements obtained from the National Grid scrapped transformers’ paper samples, it is assumed that:

*The lowest DP measurement obtained from any scrapped transformer is regarded as the lowest DP of all paper locations within this transformer.*

In other words, for any scrapped transformer, the lowest DP measurement obtained is used to represent the paper’s condition at this transformer’s hot-spot.

By 2009, a total number of 79 National Grid scrapped transformers have had the DP measured from their paper samples. The lowest DP measurement of each individual scrapped unit varies from 116 to 927 with standard deviation of 185. Figure 5-1 is an illustration of the lowest DP measurement plotted with respect to the transformer’s service age.
With regard to the figure above, the 79 National Grid scrapped transformers’ DP distribution can be characterised by an almost random distribution. The DP scattering is so large that no trend can be determined based on service age.

Among all the scrapped units, 14 out of 79 transformers (18%) are found to have the paper’s lowest DP measurement lower than 200 which is the widely accepted paper’s end-of-life criterion. These transformers are found to have an averaged lowest DP of 157. This is illustrated by the DP interval distribution in Figure 5-2.

![Figure 5-2 Distribution of 79 National Grid scrapped transformers’ lowest DP measurements.](image)

Having an aged insulation does not directly result in a transformer failure, but increases the probability of the transformer to fail when the next incoming system disturbance arrives, or even under the operational stress at a normal degree of magnitude.

### 5.2.2 Scraped Transformer’s DP Predicted Thermal Life

Using the DP reduction model, a scrapped transformer's thermal lifetime can be calculated from the lowest DP measurement of its paper samples. As an example, a scrapped transformer having a service life of 35 years has a lowest DP measurement of 350. The procedures to predict this transformer’s thermal lifetime are:
Chapter 5 Identification of Transformer’s Hot-spot Factor and Thermal Life Expectancy
Using Developed Thermal Model

i). Assuming the initial DP is 1000, using the DP reduction model (2-11), the ageing rate \( k \) is calculated as \( k=(1/350-1/1000)/35=5.31 \times 10^{-5} \).

ii). Further assuming the DP at paper’s end-of-life is 200, and that the ageing rate \( k \) is constant, inserting the \( k \) into the DP reduction model, the transformer thermal life \( t \) can then be calculated as \( t=(1/200-1/1000)/(5.31 \times 10^{-5})=75.4 \) years.

As a result, the estimated thermal lives of the 79 National Grid scrapped transformers vary from 16 to 2133 years with standard deviation as great as 244 years. The median life of the sample is 95 years. The thermal life distribution is shown in Figure 5-3.

In this sample, the longest thermal life of 2133 years is derived on a transformer having the lowest DP retention of 927 after 42 years of service. The unit was proactively retired due to the gassing of partial discharge fault. On the end, the lowest life of 16 years is derived on a transformer with the lowest DP retention of 117 after 31 years of service, and the unit was retired due to the gassing fault at high load.

![Figure 5-3 Distribution of 79 National Grid scrapped transformers’ DP predicted thermal lives.](image)

**Median life = 95 years**
As seen from the figure above, the thermal lives of the 79 scrapped transformers follow a bimodal normal distribution, with the boundary between two modes located at the life interval of 100-125 years. According to the knowledge on transformer’s thermal performance, the units on the left hand side of the distribution are attributed to either inadequate thermal designs or severe operating conditions, or the combination of both; and vice versa the units at the right hand side are probably subjected to good thermal designs or mild operating conditions, or both.

### 5.3 Derivation of Scrapped Transformer’s Hot-spot Factor

#### 5.3.1 Derivation Methodology

At this stage the DP predicted thermal lives of 79 scrapped transformers have been determined. Using this thermal lifetime as a benchmark, the individual scrapped transformer’s hot-spot factor can be reversely derived in the thermal model by incrementing the hot-spot factor in the iteration process. Basically, the iteration starts from an initial hot-spot factor of 1.0. The value is incremented in steps of 0.05, until a good agreement (difference being less than 5%) has been established between the modelled life and the DP predicted thermal life. This is illustrated in Figure 5-4.

Note that if the transformer was scrapped prior to 2009, the load of the transformer at the same substation with the same specification will be copied.
Chapter 5 Identification of Transformer’s Hot-spot Factor and Thermal Life Expectancy Using Developed Thermal Model

5.3.2 Hot-spot Factor Derivations

Restricted by the availability of the load and heat-run data, the hot-spot factors of 35 National Grid scrapped transformers have been derived and the distribution of the 35 hot-spot factors is plotted in Figure 5-5. The derived hot-spot factors vary from 1.3 to 9.05 with a median of 2.95.
Although the derived hot-spot factors are higher than the IEC loading guide suggested value of 1.3, after evaluation, it is found that the values are acceptable from permissible hot-spot temperature point of view, as the steady-state hot-spot temperature estimates corresponding to the derived hot-spot factors are within a reasonable level. The steady-state hot-spot temperature $\theta_{HST, SS}$ under the transformer’s yearly equivalent load factor $K$ is calculated by (5-1) in which all other parameters have been defined in the previous section.

$$\theta_{HST, SS} = \theta_{amb} + \theta_{TOR, R} \times \left(\frac{1 + R \times K^2}{1 + R}\right)^\gamma + HSF \times Gr \times K^\gamma \quad (5-1)$$

As an illustration, Figure 5-6 depicts the 35 scrapped transformers’ steady-state hot-spot temperature estimates calculated using their derived hot-spot factors using 50% of the rated load, and the transformers are under ON cooling mode. It was earlier introduced that the winding temperature indicator (WTI) perceives the hot-spot temperature with hot-spot factor set as 1.3. As a comparison, the steady-state hot-spot temperature estimated by WTI with the hot-spot factor setting of 1.3 is also plotted in the figure. The temperature estimates under OF cooling mode is neglected, because according to the thermal model, the cooler system of the National Grid
transformer rarely operates. The figure is arranged in the order of ascending hot-spot factors.

According to the figure above, the steady-state hot-spot temperatures perceived by WTI (black bars) with a hot-spot factor set as 1.3 (brown line) are below 90ºC under 50% of the rated load, which is significantly lower than the temperature estimates using the derived hot-spot factor (red bars are the temperature estimates, and pink line is the magnitude of the derived hot-spot factor). Using the derived hot-spot factor, although the steady-state hot-spot temperature estimate can be up to 130ºC under 50% of the rated load (from a particular transformer having high values of $\theta_{TOR}$ and $Gr$), this is still below the bubble inception temperature which is estimated to be 140ºC [170]. Therefore it can be concluded that although seemly high, the derived hot-spot factors are not outrageous.

The significant difference between the two hot-spot temperature profiles points out that the WTIs on the field transformers mistakenly give an optimistic hot-spot temperature estimate. Consequently, the cooling system will not operate at the time when it is designed to do so, and the cellulose paper will go through unnecessary high temperatures and the condition will be irreversibly deteriorated. This implies

Figure 5-6 Steady-state hot-spot temperature estimates at 50% rated load under ON mode, calculated by using the derived HSF and the HSF of 1.3 (in the order of ascending HSF).
that transformer’s WTI setting should be updated using the derived hot-spot factor in order to prevent the unnecessary paper deterioration.

5.3.3 Error Sources in Hot-spot Factor Derivation

The possible error sources in hot-spot factor derivation are identified as three-fold:

i). Representativeness of load profile in 2009

As described previously, the year 2009 load data is available during the study. Since it is not sensible to arbitrarily impose an annual rate of load change for the entire transformer population, only the 2009 load is used and assumed to be valid for the modelling transformer’s entire life. Therefore the validity of using only the 2009 load data to derive a transformer’s hot-spot factor is questioned and should be verified.

ii). Incorrect measurement of transformer’s top-oil temperature rise $\theta_{TOR}$

During the heat-run test, the top-oil temperature $\theta_{TOR}$ should be measured at oil inlet at the top winding. In practice however, transformers have their $\theta_{TOR}$ measured at the oil inlets of the radiator [28], which is believed to have a temperature read several degrees lower than the temperature at the top winding. Consequently the magnitude of the hot-spot temperature will be wrongly estimated.

iii). Inaccurate estimation of transformer’s winding-to-oil gradient $Gr$

The value of the transformer’s winding-to-oil gradient $Gr$ is estimated based on the top-oil, bottom oil, and mean winding temperature rise. In the transformer’s thermal diagram, it is assumed that at the same horizontal level, the winding temperature profile is parallel to the oil temperature with a constant difference of $Gr$. In practice, the distribution of the winding temperature along the vertical direction is far more complicated. By the means of direct measurement using optical fibre sensors, the value of $Gr$ has been verified as not constant [22].

The impacts of incorrect or inaccurate measurements of $\theta_{TOR}$ and $Gr$ on a transformer’s $\theta_{HST}$ are depicted in Figure 5-7.


5.3.4 **Sensitivity Study on Hot-spot Factor**

The accuracy of the derived hot-spot factor is affected by the representativeness of the transformer’s load data in 2009, the correct measurement of the winding-to-oil gradient \( Gr \), and the correct measurement of the top-oil temperature rise \( \theta_{TOR} \). In this section, a sensitivity study is performed to examine the hot-spot factor responding to the variations of load, \( Gr \), and \( \theta_{TOR} \).

Since it is not sensible to impose the transformer population with a universal load increase or decrease rate per annum, the load factor of an individual transformer is artificially varied with a factor of 50% to 150% in steps of 10%. Similarly, since there is no precise quantification of the possible error in \( Gr \) and \( \theta_{TOR} \) in practice, the values are also varied with a factor of 50% to 150% in steps of 10%. Note that in practice, the values of \( Gr \) and \( \theta_{TOR} \) are more likely to be underestimated.
Chapter 5 Identification of Transformer’s Hot-spot Factor and Thermal Life Expectancy Using Developed Thermal Model

Fig. 10 illustrates the degree of sensitivity on the median of 35 hot-spot factor derivations towards the variation of load, $Gr$, and $\theta_{TOR}$ with a broad range of factor of plus and minus 50%. The median of derived hot-spot factors at plus and minus 20% variation of load, $Gr$, and $\theta_{TOR}$ are summarised in Table 5-1.

![Figure 5-8 Derived hot-spot factors’ degrees of sensitivity under variations of load, $Gr$, and $\theta_{TOR}$](image)

Table 5-1 Median of derived hot-spot factors under the variations of load, $Gr$, and $\theta_{TOR}$.

<table>
<thead>
<tr>
<th>Variation</th>
<th>50%</th>
<th>60%</th>
<th>70%</th>
<th>80%</th>
<th>90%</th>
<th>100%</th>
<th>110%</th>
<th>120%</th>
<th>130%</th>
<th>140%</th>
<th>150%</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Load</strong></td>
<td>9.3</td>
<td>7.05</td>
<td>5.5</td>
<td>4.35</td>
<td>3.6</td>
<td>2.95</td>
<td>2.7</td>
<td>2.4</td>
<td>2</td>
<td>1.75</td>
<td>1.7</td>
</tr>
<tr>
<td><strong>Gr</strong></td>
<td>5.6</td>
<td>4.7</td>
<td>4.05</td>
<td>3.6</td>
<td>3.25</td>
<td>2.95</td>
<td>2.75</td>
<td>2.65</td>
<td>2.55</td>
<td>2.4</td>
<td>2.25</td>
</tr>
<tr>
<td><strong>$\theta_{TOR}$</strong></td>
<td>4.1</td>
<td>3.7</td>
<td>3.35</td>
<td>3.25</td>
<td>3.15</td>
<td>2.95</td>
<td>2.8</td>
<td>2.5</td>
<td>2.2</td>
<td>1.95</td>
<td>1.9</td>
</tr>
</tbody>
</table>

Generally speaking, the derived hot-spot factor decreases with the increase of all three variables. The effect of load variation on the hot-spot factor is the most significant. The value of the hot-spot factor is less sensitive to the variation of $Gr$ than load, and is least sensitive to the variation of $\theta_{TOR}$. The reason is that according to (5-1), when calculating hot-spot temperature, the impact of $\theta_{TOR}$ is attenuated with a multiplier of less than 1, and $Gr$ is multiplied with a value close to the multiplier of $\theta_{TOR}$ (i.e. $HSF \times K'$), whereas the impact of load $K$ is exaggerated because the terms containing $K$ are multiplied with much larger numbers. The magnitudes of their
multipliers determine the effectiveness of the load, $Gr$ and $\theta_{TOR}$ variations to the derived hot-spot factors.

The rate of the hot-spot factor’s decrease slows down towards higher magnitudes of load and $Gr$. The reason is that at higher load or $Gr$, the winding’s hot-spot temperature will be higher and the cooler operation will be triggered. Under the control of the cooling system, the hot-spot temperature will be maintained within the pre-defined WTI perceived level of 75°C. Consequently the hot-spot factor will be less sensitive to the increase of load or $Gr$.

The non-linearity of the hot-spot factor’s decrease against the increase of load and $Gr$ can be better illustrated by Figure 5-9, which is an example of the histogram distribution of the 35 derived hot-spot factors, with the load variation of plus and minus 20% of the base. The hot-spot factor distribution without the load variation is presented as a reference (blue bars). Having the load reduced by a factor of 20%, the hot-spot factor spans hugely from 1.8 to 12.95 with a median level of 4.35 (green bars). On the other hand if the load is increased by 20%, the hot-spot factor span shrinks into 1.05 to 6.55 with a median level of 2.4 (red bars).

![Figure 5-9 Derived hot-spot factor distribution with the load variation of plus and minus 20% of the base.](image)

<table>
<thead>
<tr>
<th>Hot-spot factor interval</th>
<th>80% load variation</th>
<th>100% load variation (original load)</th>
<th>120% load variation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1-1.5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.5-2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2-2.5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2.5-3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3-3.5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3.5-4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4-4.5</td>
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<td></td>
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<td>4.5-5</td>
<td></td>
<td></td>
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<td>5-5.5</td>
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<td></td>
<td></td>
</tr>
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<td>5.5-6</td>
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<tr>
<td>6-6.5</td>
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<td></td>
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<tr>
<td>6.5-7</td>
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<td></td>
</tr>
<tr>
<td>7-7.5</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>7.5-8</td>
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<tr>
<td>8-8.5</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>8.5-9</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>9-9.5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>9.5-10</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>10-10.5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>10.5-11</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11-11.5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>11.5-12</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>12-12.5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>12.5-13</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
In conclusion, although error sources may exist during thermal modelling, the general hot-spot factor assumption of 1.3 is far too low for the existing transformer design.

5.3.5 Hot-spot Factor Assignment

Since the value of hot-spot factor is strongly dependent on transformer design, in this study, the derived hot-spot factors will be assigned to the field transformers according to their design families. That is to say, if the modelled transformer belongs to the design family that has scrapped transformer(s), it will be assigned with the hot-spot factor derived from the family’s scrapped unit. If multiple transformers have been scrapped in a family, the derived hot-spot factors will be averaged and then assigned.

5.4 Information of Modelling Transformers

5.4.1 Summary of Basic Information

A total number of 106 transformers have been identified from the National Grid transformer population which have all the operating conditions (i.e. load and ambient temperature profiles) and thermal parameters (i.e. heat-run data) available, and are from the same design families as the 35 scrapped transformers which have had their hot-spot factors reversely derived. Consequently, each of these transformers will be assigned with its design family’s hot-spot factor in the thermal model.

The transformers to be modelled have the voltage ratio of either 275/132kV or 400/132kV. The power ratings of these units are in the range of 120 to 240MVA. The service age of the units varies from 13 to 54 years with the majority of the units ageing 40 years old or more. Among all the modelling transformers, 16 design families have been identified. Table 5-2 lists the basic information of the 106 transformers to be modelled.
Table 5-2 Basic information of the 106 National Grid transformers to be modelled.

<table>
<thead>
<tr>
<th>Power rating</th>
<th>Transformer number</th>
</tr>
</thead>
<tbody>
<tr>
<td>120MVA</td>
<td>18</td>
</tr>
<tr>
<td>180MVA</td>
<td>20</td>
</tr>
<tr>
<td>220MVA</td>
<td>3</td>
</tr>
<tr>
<td>240MVA</td>
<td>65</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Voltage ratio</th>
<th>Transformer number</th>
</tr>
</thead>
<tbody>
<tr>
<td>275/132kV</td>
<td>60</td>
</tr>
<tr>
<td>400/132kV</td>
<td>46</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Service age (ref. 2012)</th>
<th>Transformer number</th>
</tr>
</thead>
<tbody>
<tr>
<td>13 – 19 years</td>
<td>18</td>
</tr>
<tr>
<td>20 – 29 years</td>
<td>6</td>
</tr>
<tr>
<td>30 – 39 years</td>
<td>11</td>
</tr>
<tr>
<td>40 – 49 years</td>
<td>56</td>
</tr>
<tr>
<td>50 – 54 years</td>
<td>15</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Design family</th>
<th>Transformer number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Family index A – P</td>
<td>106 transformers in 16 families</td>
</tr>
</tbody>
</table>

5.4.2 *Ambient Temperature Profile*

Looking at geographical locations of the 106 transformers modelled, 26 of them locate in the North West and 38 locate in the South of the UK which respectively have the lowest and highest average ambient temperatures of the country. This geographic distribution of the modelling transformers and the average ambient temperature in each region are shown in Figure 5-10.
Chapter 5 Identification of Transformer’s Hot-spot Factor and Thermal Life Expectancy Using Developed Thermal Model

Figure 5-10 Geographical locations and the average ambient temperatures of 106 transformers to be modelled.

5.4.3 Load

At this stage, the load profiles of the transformers to be modelled are collected and manually completed if necessary. In a general view, the equivalent load spans from 0.13 to 0.46 p.u. Half of the modelling transformers are loaded lower than 0.33 p.u. The load distribution of the 106 modelled transformers is shown in Figure 5-11.

Figure 5-11 Distribution of the 106 modelled transformers’ yearly equivalent load.
The profiles of the load vary from one unit to another in an unpredictable manner. Looking at the daily load profile, the modelling transformers reasonably agree with the profile of the UK’s national demand in 2010, which is depicted in Figure 5-12 [171]. The typical winter and summer profiles were based on demand data on two weekdays of 17th November and 10th June 2010. In comparison, the daily load profiles on the similar days have been plotted from two of the modelled transformers as shown in Figure 5-13.

![Figure 5-12 The UK’s national daily profile of demand in 2010 [171].](image1)

![Figure 5-13 Profiles of daily load factor from two modelled transformers A and B.](image2)

From Figure 5-13, one could observe that the modelled transformers have similar daily load profiles to the national daily demand profiles. Both the modelling load profiles and the national load profile involve the load build-up around 6:00 and a
plateau during work hours, and then the rise-to-peak around 18:00 due to lighting and domestic loads.

Looking at the yearly load profile, the modelled transformers do not necessarily agree with the national demand profile. Due to the operation of heating devices in winter, a higher load demand is reflected in the national yearly demand profile as depicted in Figure 5-14. Only a few modelled transformers’ yearly load profiles follow the shape of the national demand profile, as represented by the profile of transformer A in upper Figure 5-15. Many other transformers modelled have differently shaped yearly load profiles; of which some units could have load overshoots in a short time period, as shown by the profile of transformer B in lower Figure 5-15.

Figure 5-14 UK national yearly demand profile in 2009 [172].
5.4.4 Heat-run Data

The heat-run data of each individual transformer, i.e. loss-ratio $R$, top-oil temperature rise $\theta_{TOR}$, and winding-to-oil temperature gradient $Gr$ under ON and OF cooling modes are collected as model inputs. The distributions of the three parameters under both cooling modes are depicted in Figure 5-16. The characteristics of each heat-run data are summarised in Table 5-3 with the comparison of the suggested values given by the IEC transformer loading guide.

Table 5-3 Comparison of the modelled transformers’ heat-run data and the suggested values in the IEC loading guide 60076-7.

<table>
<thead>
<tr>
<th>Heat-run data</th>
<th>Modelled transformers</th>
<th>IEC loading guide 60076-7</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>ON</td>
<td>OF</td>
</tr>
<tr>
<td>$R$ min</td>
<td>0.8</td>
<td>3.3</td>
</tr>
<tr>
<td>$R$ max</td>
<td>4.3</td>
<td>17.4</td>
</tr>
<tr>
<td>$R$ average</td>
<td>1.6</td>
<td>6.6</td>
</tr>
<tr>
<td>$\theta_{TOR}$ min (K)</td>
<td>29.8</td>
<td>23.4</td>
</tr>
<tr>
<td>$\theta_{TOR}$ max (K)</td>
<td>46</td>
<td>49.3</td>
</tr>
<tr>
<td>$\theta_{TOR}$ average (K)</td>
<td>37.7</td>
<td>34.9</td>
</tr>
<tr>
<td>$Gr$ min (K)</td>
<td>5.7</td>
<td>14.9</td>
</tr>
<tr>
<td>$Gr$ max (K)</td>
<td>26.8</td>
<td>42.2</td>
</tr>
<tr>
<td>$Gr$ average (K)</td>
<td>11.2</td>
<td>22.2</td>
</tr>
</tbody>
</table>
Referring to the table above, the value of loss ratio $R$ of the modelled transformers under ON mode is 1.6 which is significantly lower than the suggested value of 6 in the IEC loading guide. The averaged value of $R$ under OF mode is 6.6 and reasonably agrees with the loading guide’s suggested value of 6. The averaged $\theta_{TOR}$ under ON and OF mode and the averaged $Gr$ under ON mode of the modelled transformers are much lower than the suggested values of IEC loading guide. Exceptionally, 40 out of 106 modelled transformers have values of $Gr$ under OF mode higher than the suggested values in the IEC loading guide.

Based on the 106 modelled transformers’ averaged heat-run data, assuming the ambient temperature is 20K and the transformer’s hot-spot factor is 1.3, the rated hot-spot temperatures of the modelled transformers are calculated. The paper’s
ageing rate $k$ is by using Montsinger’s equation. Regarding 150,000 hours as the paper’s life expectancy at rated temperature, the modelled transformers’ life expectancy under the averaged heat-run data are calculated. The results are presented in Table 5-4 comparing with the suggested values in the IEC loading guide 60076-7. Note that the load factor of 0.33 p.u is the average load factor of the 106 modelled transformers. Overall, as reflected by the tables above, the modelled transformers imply superior thermal designs to the perspective of the IEC transformer loading guide.

Table 5-4 Averaged heat-run data, rated hot-spot temperature, ageing rate, and paper’s life expectancy of the modelled transformers comparing with the values in IEC loading guide 60076-7.

<table>
<thead>
<tr>
<th>Design family</th>
<th>$\theta_{amb}$ (K)</th>
<th>$\theta_{TOR}$ (K)</th>
<th>$Gr$ (K)</th>
<th>$HSF$</th>
<th>Load (p.u)</th>
<th>$\theta_{HST}$ ($^\circ$C)</th>
<th>$k$</th>
<th>Life expectancy (year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>IEC (ON)</td>
<td>20</td>
<td>52</td>
<td>20</td>
<td>1.3</td>
<td>0.5</td>
<td>98</td>
<td>1.0</td>
<td>17.12</td>
</tr>
<tr>
<td></td>
<td></td>
<td>56</td>
<td>16.9</td>
<td></td>
<td>1.0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ave_106 (ON)</td>
<td>37.7</td>
<td>11.2</td>
<td></td>
<td></td>
<td>0.5</td>
<td>72.3</td>
<td>0.0514</td>
<td>333</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.33</td>
<td>55.3</td>
<td>0.0072</td>
<td>2381</td>
</tr>
<tr>
<td>Ave_106 (OF)</td>
<td>34.9</td>
<td>22.2</td>
<td></td>
<td></td>
<td>1.0</td>
<td>83.8</td>
<td>0.1939</td>
<td>88</td>
</tr>
</tbody>
</table>

### 5.4.5 Hot-spot Factor

The hot-spot factors derived from 35 scrapped transformers are assigned to the 106 modelled transformers according to the design families. The assignment of the derived hot-spot factors are presented in Table 5-5, and the distribution of 106 modelling transformers’ hot-spot factors are shown in Figure 5-17.

Table 5-5 Assignment of the derived hot-spot factors from scrapped units to modelled units.
Figure 5-17 Distribution of hot-spot factors of the 106 modelled transformers compared with the scrapped transformers.

Note that the highest hot-spot factor derived from the scrapped sample, i.e. 9.05, does not appear on the modelled sample set, because this hot-spot factor has been averaged with the second derived hot-spot factor (i.e. 4.85) within this design family during the assignment.

Due to the similar ratios of the modelled sample set to the scrapped sample set in each design family, the distribution of the hot-spot factor after assignment appears to be similar to the distribution of the scrapped sample. The difference between the two distributions is that the hot-spot factor of 2.1 and 6.95 in family P and K has been
assigned to a large number of modelled transformers, and this elevates the CDF of the modelling sample’s hot-spot factor at the corresponding locations.

5.5 Modelling Thermal Lives

With the aid of the developed thermal model, the thermal lives of 106 National Grid in-service transformers have been estimated. The life modelled varies from several years to more than 400 years with the distribution shown in Figure 5-18.

![Figure 5-18 Distribution of 106 National Grid in-service transformers’ modelled thermal lives.](image)

The distribution could be roughly split into two regions. The units having modelling lives within 100 years, which make up over 50% of the entire sample, are of particular interest to the asset manager as these units must be subject to either severe operating conditions, or inadequate thermal design, or the combination of both. Consequently the thermal lives estimated are relatively short, indicating that they have higher probabilities of failure in the near future and deserves attention.

It is noted that some transformers have modelled thermal lives lower than their service lives, which seems not logical at first sight. This is shown in Figure 5-19.
where 37 out of 106 modelled transformers (35%) have a ratio of service year and modelled life as greater than 1.

The discrepancy in the ambient profiles of the modelled and scrapped transformers within the same design family is a theoretically possible explanation. However the climate across the UK differs insignificantly and therefore this can be disregarded.

After a closer investigation, the reason is determined as the discrepancy in load magnitude between the modelled transformer and the scrapped transformer in the same design family. Since the family’s hot-spot factor was derived based on the load profile of the scrapped transformer, if the modelled transformer has a much higher load magnitude, a lower thermal lifetime will be modelled when the derived hot-spot factor is directly assigned.

To verify this, the magnitudes of 2009 equivalent loads are compared between modelled and scrapped transformers within the same family. It is found that for the 37 transformers having the modelled lives lower than the service lives, the 2009 equivalent loads of theirs exceed the scrapped transformers’ loads within the same design family by 36% on average. This implies that a sensitivity study on transformer’s load is needed to examine the response on modelled thermal life.
Recognising that the confidence of an individual transformer’s modelled life could be affected by the transformer’s load level within the design family, the utilisation of the individual modelled lives may not be appropriate. Instead, a conclusion on the thermal life expectancy of the 106 transformers could be drawn.

In this study, the thermal life expectancy is defined as the median life of the 106 modelled transformers, which is derived as 84 years. This number demonstrates that 50% of these 106 transformers will have their papers reaching the end-of-life criterion of 200 within this time duration.

### 5.6 Sensitivity Study on Modelled Thermal Life

The process of thermal life modelling is subject to the same errors as the process of hot-spot factor derivation, i.e. the representativeness of the year 2009 load; the incorrect measurement of top-oil temperature rise $\theta_{TOR}$; and the inaccurate estimation of winding-to-gradient $Gr$.

Although the possible errors could be identified above, any attempt to correct the above mentioned three parameters is not sensible without the support of the actual data. Instead, sensitivity studies are performed to examine how modelled life will be affected if variations are imposed on them. The load factor, $Gr$, and $\theta_{TOR}$ of an individual transformer is artificially varied with a factor of 50% to 150% in steps of 10%. Note that in practice, the values of $Gr$ and $\theta_{TOR}$ are more likely to be underestimated. The response of the 106 modelled transformers’ thermal life expectancy is illustrated in Figure 5-20. The values of life expectancies are summarised in Table 5-6.

According to the figure and table above, the modelled thermal life expectancy climb to exceedingly high levels as the load is decreased. On the other hand, as the load is increased, the modelling lives are reduced substantially but have a decelerated rate with the load increment.
Figure 5.20 Response of 106 modelled transformers’ thermal life expectancy towards variations of load, \(Gr\), and \(\theta_{TOR}\).

Table 5.6 Thermal life expectancies at different variation factors of load, \(Gr\), and \(\theta_{TOR}\).

<table>
<thead>
<tr>
<th>Variation</th>
<th>50%</th>
<th>60%</th>
<th>70%</th>
<th>80%</th>
<th>90%</th>
<th>100%</th>
<th>110%</th>
<th>120%</th>
<th>130%</th>
<th>140%</th>
<th>150%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load</td>
<td>1102</td>
<td>718</td>
<td>409</td>
<td>219</td>
<td>124</td>
<td>84</td>
<td>58</td>
<td>44</td>
<td>32</td>
<td>26</td>
<td>19</td>
</tr>
<tr>
<td>(Gr)</td>
<td>306</td>
<td>262</td>
<td>171</td>
<td>120</td>
<td>93</td>
<td>84</td>
<td>72</td>
<td>56</td>
<td>52</td>
<td>43</td>
<td>36</td>
</tr>
<tr>
<td>(\theta_{TOR})</td>
<td>360</td>
<td>250</td>
<td>163</td>
<td>123</td>
<td>99</td>
<td>84</td>
<td>71</td>
<td>64</td>
<td>57</td>
<td>53</td>
<td>49</td>
</tr>
</tbody>
</table>

The modelled lives of individual transformers could exhibit different degrees of sensitivity responding to the load variation. The reason is that some transformers have either a relatively high load magnitude or an inferior thermal design, therefore the winding temperature is more elevated than the others. As a consequence, the cooling system operates more frequently to control the highest temperature, and hence the modelled life is less sensitive towards the increase of load variation factor. This can be illustrated by Figure 5.21.
The load variation affects the modelling life in a non-linear way. In short, the thermal life of the 106 transformers will be prolonged by a factor of 13 if the load is decreased by 50%; while the life will be reduced to one fifth if the load is increased by 50%.

The modelled lives increase as $Gr$ and $\theta_{TOR}$ are decreased, but with a smaller degree of sensitivity compare to the decrease of load. Similar to Figure 5-21, individual transformers exhibit different degrees of sensitivity responding to the variations of $Gr$ and $\theta_{TOR}$ which depend on the frequency of the modelled cooler system operation. As can be read from Table 5-6, if the transformers have a 50% reduction in $Gr$ or $\theta_{TOR}$, the thermal life expectancy will be prolonged with a factor of 3.7 and 4.3 respectively. On the other hand, if the $Gr$ or $\theta_{TOR}$ is increased by 50%, the thermal life will be reduced respectively to 0.4 and 0.6 from the base value.
5.7 Thermal Life Extension Using Updated WTI Setting

The WTI settings of the 106 modelled transformers have been updated from the original setting of 1.3 to the families’ hot-spot factor derivations. The cooler setting is not changed from the default of 75/50°C. As a direct result, the cooling system operates with a longer time. The effectiveness of the updated WIT setting on the cooling system operation time is summarised in Table 5-7.

<table>
<thead>
<tr>
<th>Yearly percentage of cooler operation</th>
<th>Traditional WTI setting of 1.3</th>
<th>Updated WTI setting with derived HSF</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum</td>
<td>15.7%</td>
<td>64.8%</td>
</tr>
<tr>
<td>Average</td>
<td>1.8%</td>
<td>12.3%</td>
</tr>
<tr>
<td>Thermal life expectancy (years)</td>
<td>84</td>
<td>158</td>
</tr>
</tbody>
</table>

Under the original WTI setting of 1.3, the operation time of the cooling system is almost negligible with an average percentage of 1.8% of the transformer operation time. After updating the WTI setting, the operation time has been increased as anticipated, to an average level of 12.3% of the transformer operation time.

The thermal life expectancy under the new WTI settings has been prolonged by a factor of 1.9, from 84 years to 158 years. The life distribution has been shifted to the right under the updated WTI setting as shown in Figure 5-22. The updating of the WTI setting mainly extends the thermal life of transformers on the left end of the figure, because these transformers have higher hot-spot temperature estimates. Under a higher WTI setting, the cooler operations of these transformers will be more frequently, and hence the transformer thermal life will be prolonged.
It was shown in the previous section that by updating WTI setting with the derived hot-spot factor, the modelling life expectancy of 106 National Grid transformers are prolonged by a factor of 1.9 because the cooler system operates more frequently. This naturally brings an ambition such that whether, under the updated WTI setting, the transformer could carry an additional load without having excessive thermal ageing.

Driven by the desire for a higher loadability, under the updated WTI setting, the transformer load is artificially varied with a factor of 110% to 150% in steps of 10%. The corresponding population thermal life expectancies are summarised in Table 5-8. Also included in the table is the operation time of the cooler system under each load variation.

As can be read from the table, when the transformer’s WTI setting is updated, the load of 106 transformers could be increased by a factor of up to 40% without having the population’s thermal life expectancy significantly lowered, i.e. 80 years. In other words, under the updated WTI setting, the benefit of the cooler system is brought
into the play to maintain the same rate of material degradation while the transformer is bearing an additional load.

Table 5-8 Population’s thermal life expectancy subjecting to load increase under the updated WTI setting.

<table>
<thead>
<tr>
<th>WTI's HSF setting</th>
<th>Load variation</th>
<th>Thermal life expectancy (years)</th>
<th>Average percentage of cooler operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>WTI=1.3</td>
<td>No variation</td>
<td>84</td>
<td>1.8%</td>
</tr>
<tr>
<td></td>
<td>No variation</td>
<td>158</td>
<td>12.3%</td>
</tr>
<tr>
<td></td>
<td>110%</td>
<td>132</td>
<td>18.5%</td>
</tr>
<tr>
<td>Family's derived HSF</td>
<td>120%</td>
<td>122</td>
<td>25.9%</td>
</tr>
<tr>
<td></td>
<td>130%</td>
<td>98</td>
<td>33.1%</td>
</tr>
<tr>
<td></td>
<td>140%</td>
<td>80</td>
<td>39.6%</td>
</tr>
<tr>
<td></td>
<td>150%</td>
<td>53</td>
<td>45.6%</td>
</tr>
</tbody>
</table>

### 5.9 Enlarged Life Sample Set of Modelled and Scrapped Units

At this stage, a total number of 106 National Grid in-service transformers have had their thermal lives modelled. In order to obtain a larger life sample for a more confident estimation of the National Grid transformers’ thermal life expectancy, the modelled life sample is combined with the thermal lives of 79 National Grid scrapped transformers that are predicted by the paper’s lowest DP measurement. In fact, the process of combining two samples is feasible, as the lives in both samples are estimated based on the same end-of-life criterion i.e. the DP retention of the cellulose paper.

The distribution of the combined life sample is shown in Figure 5-23 as a stack histogram. To distinguish different samples, the modelled samples are shown in green bars, whereas the scrapped samples are shown in pink bars. The CDF is drawn based on the combined life sample set.
Chapter 5 Identification of Transformer’s Hot-spot Factor and Thermal Life Expectancy Using Developed Thermal Model

It can be seen from Figure 5-23 that the distributions of both sample sets have similar shapes i.e. a skewed distribution with two modes. In both sample sets the boundary locates near the thermal life interval of 100-125 years. Based on current knowledge of paper ageing, in both life sample sets, the units with short lives (on left-end of the distribution) must be subject to severe operating conditions, or inadequate thermal design, or the combination of both. Vice versa, the samples with long thermal lives (i.e. on right-end of the distribution) must be subject to either mild operating conditions, or good thermal design, or both.

In terms of the transformer number at each life interval, the number of the modelled transformers exceeds the number of scrapped transformers at both ends of the distribution. This indicates that the sample of 106 modelled transformers have included more extreme operating conditions and thermal designs that were not covered in the scrapped sample.

The thermal life expectancy of the 185 combined samples is 88 years, which appears to be a compromise between the modelled thermal life expectancy of the 106 field transformers (84 years) and the DP predicted thermal life expectancy of the 79 scrapped transformers (95 years). This value is provisionally declared in this study as Median life = 88 years.
the thermal life expectancy of the National Grid transmission power transformers, until it is revised by modelling more transformers in the future.

5.10 Thermal Life Matrix of National Grid Transformers

Based on thermal modelling exercise, it is learnt that the thermal life of a transformer is determined by multiple parameters that include the ambient temperature, load, heat-run data, hot-spot factor, cooler setting, and miscellaneous thermal constants. Among these parameters, the former four parameters vary from transformer to transformer and need to be collected before modelling.

Even if the transformer’s ambient, load, heat-run data, and family’s derived hot-spot factor are available, it is not possible to directly estimate the unit’s thermal life because of the complexity of the multi-parameter driven function used in the thermal model.

To simplify the problem, a visually straightforward presentation of the transformer thermal life is produced, based on the 106 field transformers’ modelled lives and the 35 scrapped transformers’ DP predicted lives, in order to reveal the combinational effect of the ambient temperature, load, heat-run data, and hot-spot factor. The presentation format proposed here is a 2-D thermal life matrix.

In this plot, the x-axis is the transformer’s per-unit equivalent load in 2009. The y-axis is the rated hot-spot temperature of the transformer, which is calculated by (4-1) where the ambient temperature is the yearly average value, top-oil temperature rise and winding-to-oil gradient are measured in the heat-run test at 50% of the rated load under the ON cooling mode, and the hot-spot factor is the family’s derived hot-spot factor. Note that the hot-spot temperature under OF cooling mode is neglected as the transformer seldom operates with this cooling mode. When mapping the modelled and DP predicted lives into the thermal matrix, the multiple thermal lives falling into each grid will be averaged. The grids will be coloured according to the thermal life interval.
By these means, a 2-D thermal life matrix has been plotted based on the 106 modelled lives and the 35 DP predicted lives. The matrix is plotted in Figure 5-24.

![Thermal life matrix based on thermal lives of 106 modelled and 35 scrapped transformers.](image)

From the figure above, a diagonal trend in transformer’s thermal life can be identified such that the thermal life decreases from bottom to top in the vertical aspect (i.e. towards poorer thermal designs) and extends from right to left horizontally (i.e. towards lower loadings). Looming boundaries seem to exist between the grids of different colours.

Through the development of this thermal life matrix, the complicated function of transformer thermal life has been greatly simplified by integrating the transformer operating conditions and thermal parameters into a 2-D plot. As a perspective, if the load and the hot-spot temperature (derived based on the ambient temperature, heat-run data, and family’s derived hot-spot factor) of a particular transformer are known, one can easily identify the range of this transformer’s thermal life by using the plot above.

Such a thermal life matrix could not be developed without the aid of the thermal modelling. It is anticipated that as more transformers are modelled, the plot will be enriched and can be sophisticated enough to have life parabolas drawn in between
the differently coloured grids, and serve as the quick and initial guidance of transformer thermal life assessment.

### 5.11 Summary

In this chapter, the hot-spot factors of 35 scrapped transformers have been reversely derived by regarding the transformers’ DP predicted thermal lives as a benchmark in the thermal model. Although the median value of the derived hot-spot factor is 2.95 and is considerably higher than the originally assumed value of 1.3, they have been proven to be thermally acceptable and are assigned to the field transformers according to their design families. A series of sensitivity studies have been performed to examine the response of derived hot-spot factors on variation of load, top-oil temperature rise $\theta_{TOR}$, and winding-to-oil gradient $Gr$ with variation factors from 50% to 150% in steps of 10%. The results have indicated that although the load variation has the greatest impact on a transformer’s derived hot-spot factor, the derived values are still significantly higher than 1.3 no matter the error of load is as high as 50% from the base level.

The thermal lives of 106 National Grid field transformers have been estimated by using the developed thermal model. The thermal life expectancy of the modelled population is 84 years and is considerably longer than the service year of the transformers currently existing in the power system network. As a sensitivity study, individual transformer’s load, winding-to-oil gradient $Gr$, and top-oil temperature rise $\theta_{TOR}$ are imposed with variation factors from 50% to 150% in steps of 10% to examine the response of the modelled life. It was found that the modelled life is most sensitive to the load variation, and less sensitive to the variation of $Gr$ and $\theta_{TOR}$. Decreasing the load by 50% will prolong the thermal life by a factor of 14, while increasing the load by 50% will greatly reduce the thermal life to one fifth of the original life. On the other hand decreasing the $Gr$ or $\theta_{TOR}$ with 50% will prolong the thermal life by a factor of 3.7 and 4.3, while increasing the $Gr$ or $\theta_{TOR}$ by 50% will reduce the thermal life to 0.4 and 0.6 from the base.
The modelled transformer’s WTI setting has been updated with the family’s derived hot-spot factors. As a result, the transformers’ average percentage of the cooling operation time has been increased from 1.8% to 12.3% of the transformer operation time. Consequently, the population’s thermal life expectancy has been prolonged by a factor of 1.9. After evaluation, under the updated WTI setting, the National Grid transformer could spontaneously carry an additional load of up to 40% of the original level without having a major reduction in thermal life expectancy.

With the aid of thermal modelling, a 2-D thermal life matrix has been developed. The matrix could serve as a quick and initial tool for identifying the thermal life range of the transformers by utilising essential parameters only, including the yearly equivalent load and the hot-spot temperature calculated by the yearly average ambient temperature, rated top-oil temperature rise, winding-to-oil gradient, and family’s derived hot-spot factor.
Chapter 6  National Grid Transformers’ Paper Condition Assessment Using Furan Measurement

6.1 Introduction

In this chapter, a large-scale analysis is performed on the furan data of 342 National Grid field transformers, which counts as totally 1269 furan measurements. The concentrations of all five furanic compounds will be analysed, and the measurement outliers will be investigated individually for the causes. The relationships between the 2FAL concentration measured and the transformer ratio, rating, load, and age are studied in order to find a possible parameter that positive correlates with the 2FAL formation.

With the aid of transformer thermal modelling, the paper’s DP can be estimated at the transformer age when oil is sampled. The 2FAL concentrations measured in 56 National Grid field transformer’s oil samples are plotted with the paper’s DP estimates in order to derive a 2FAL-DP correlation relationship. Three functions, i.e. logarithmic equation, De Pablo’s equation, and linear equation, are used to fit the data and are evaluated to find the best fitted function format.

6.2 Furan Analysis on National Grid Transformers

6.2.1 Basic Information

Furan measurement results have been collected from 342 National Grid transformers. As the basic information, in 2012 the ages of the studied transformers vary from 10 to 58 years. Nearly 80% of the sampled transformers are aged 40 years or more. The power ratings vary from 120MVA to 276MVA. The voltage ratio of the transformer is either 400/132kV or 275/132kV. The transformers are found to
belong to 66 different design families which imply a huge design discrepancy. The basic information are summarised in Table 6-1.

Table 6-1 Basic information of the 342 National Grid transformers investigated.

<table>
<thead>
<tr>
<th>Service age (ref. 2012)</th>
<th>Transformer number</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 – 19 years</td>
<td>2</td>
</tr>
<tr>
<td>20 – 29 years</td>
<td>33</td>
</tr>
<tr>
<td>30 – 39 years</td>
<td>29</td>
</tr>
<tr>
<td>40 – 49 years</td>
<td>223</td>
</tr>
<tr>
<td>50 – 58 years</td>
<td>49</td>
</tr>
<tr>
<td>Unknown</td>
<td>6</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Power rating</th>
<th>Transformer number</th>
</tr>
</thead>
<tbody>
<tr>
<td>120MVA</td>
<td>41</td>
</tr>
<tr>
<td>180MVA</td>
<td>49</td>
</tr>
<tr>
<td>220MVA</td>
<td>3</td>
</tr>
<tr>
<td>240MVA</td>
<td>248</td>
</tr>
<tr>
<td>276MVA</td>
<td>1</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Voltage ratio</th>
<th>Transformer number</th>
</tr>
</thead>
<tbody>
<tr>
<td>275/132kV</td>
<td>204</td>
</tr>
<tr>
<td>400/132kV</td>
<td>138</td>
</tr>
</tbody>
</table>
According to National Grid, the oil sampling and furan measurement were conducted in between 2006 and 2011. The transformers were sampled with rather different frequencies, varying from only one measurement over 5 years, to 5 measurements within one year. In terms of the sampling location, most of the oil samples were obtained at the bottom level of the main tank. In very few cases, the oil was sampled from the top and middle of the tank which should not yield significant difference in furan measurements.

As a total, 1269 oil samples have been obtained from 342 transformers. In each oil sample, the concentrations of all five furanic compounds have been measured i.e. 5HMF, 2FOL, 2FAL, 2ACF, and 5MEF. The information on oil sampling and furan measurement are summarised in Table 6-2.

<table>
<thead>
<tr>
<th>Oil sampling date</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Earliest</td>
<td>Nov 21 2006</td>
</tr>
<tr>
<td>Latest</td>
<td>Dec 22 2011</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Oil sampling frequency</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Highest</td>
<td>14 samples (44 years, 240MVA, 400/132kV)</td>
</tr>
<tr>
<td>Lowest</td>
<td>1 sample (53 years, 120MVA, 275/132kV)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Oil sampling location</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Main tank, bottom (majority)</td>
<td></td>
</tr>
<tr>
<td>Main tank, top and mid (minority)</td>
<td></td>
</tr>
</tbody>
</table>

Total number of oil samples 1269
Field transformers could have oil reclaimed or changed to improve the insulation’s condition. This would temporarily remove considerable amount of furan dissolved. In this study, the furan database has been searched to track any oil process in the past. As a result, during 2006 and 2011, 4 transformers have had their oil reclaimed, and 2 transformers have had their oil changed. Further looking into the furan concentrations of these 6 transformers, 3 transformers are found to have a sudden dip in their furan concentration after the oil processes. As a correction, the furan concentration after the oil processes is added with the previous value before the dip. An example of the correction in furan concentration after the oil change is shown in Figure 6-1.

![Figure 6-1 Concentration of total furan dissolved in oil before and after oil change.](image)

### 6.2.2 Concentration of Total Furanic Compounds

As the first step of furan investigation, the total furan concentration is the sum of all five furanic compounds measured; the transformer’s service age is calculated by subtracting the transformer installation date from the sampling date. The total furan
concentration versus the transformer’s age from the 342 transformers’ oil samples is shown in Figure 6-2.

![Figure 6-2 Concentration of total furan dissolved in oil versus transformer’s age, sampled from 342 transformers.](image)

At the first glance at the plot, the total furan concentration generally maintains at a stable level of less than 5ppm until the transformer age of 40. Some exceptionally high measurements were obtained around Age 20 and 40 which will be further discussed later. From Age 40 onwards the measurement of total furan increases and reaches the peak at Age 45, and then decreases. The expansion of the furan envelope from Age 40 to 50 could be attributed to the large amount of the samples within this range i.e. 65.2% of the 1269 samples.

The concentrations of the five furanic compounds, i.e. 5HMF, 2FOL, 2FAL, 2ACF, and 5MEF, have been explicitly measured in each of the 1269 oil samples. The pie chart below illustrates the average percentages of each furanic compound.

![Figure 6-3 Average percentage of each furanic compound in 1269 oil samples.](image)
Observing the pie chart above, it is learnt that the portion of 2FAL measured from the oil outweighs other furanic compounds by taking up over 90% of the total furan concentration, followed by the concentration of 5HMF which is 3.4%. The rest of the furanic compounds only take up approximately 3% of the entire composition. The concentration level of the five furanic compounds are ranked as 2FAL>> 5HMF>5MEF>2FOL>2ACF.

In terms of the possible correlation between furanic compounds, the correlation coefficients have been calculated on the bulk measurement by regarding one compound as reference. The results are summarised in Table 6-3, which indicate that no correlation can be determined between different furanic compounds. However it will be shown in the later section that some exceptionally high measurements in 5HMF, 2FOL, 2ACF, and 5MEF appear to be associated with high measurements in 2FAL.

<table>
<thead>
<tr>
<th>5HMF</th>
<th>2FOL</th>
<th>2FAL</th>
<th>2ACF</th>
<th>5MEF</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ref.</td>
<td>0.01</td>
<td>0.03</td>
<td>0.00</td>
<td>0.02</td>
</tr>
<tr>
<td>0.01</td>
<td>Ref.</td>
<td>-0.02</td>
<td>0.00</td>
<td>0.06</td>
</tr>
<tr>
<td>0.03</td>
<td>-0.02</td>
<td>Ref.</td>
<td>0.05</td>
<td>0.17</td>
</tr>
<tr>
<td>0.00</td>
<td>0.00</td>
<td>0.05</td>
<td>Ref.</td>
<td>0.01</td>
</tr>
<tr>
<td>0.02</td>
<td>0.06</td>
<td>0.17</td>
<td>0.01</td>
<td>Ref.</td>
</tr>
</tbody>
</table>

### 6.2.3 Concentration of Minor Furanic Compounds

#### i) Concentration of 5HMF

As a minority of the furanic compound family, the concentration of 5HMF has been isolated from the total furan measured in transformer oil and studied individually. Figure 6-4 depicts the plot of the 5HMF concentration against the transformer’s age.
The concentrations of 5HMF dissolved in oil measured on 342 transformers are found to be very low with an average of 0.02ppm. A majority of the oil samples could only be detected with a trace of 5HMF, which can be shown by the 5HMF distribution as shown in Figure 6-5. In the figure, 95.5% of the 5HMF measurements is lower than 0.1ppm, and 99.8% of the measurements is within 1ppm. Note the break on x-axis after 1ppm. Three measurements are found to be greater than 1ppm which compose the last 0.2% of all measurements and therefore are regarded as outliers.
The three measurement outliers of 5HMF are found to be 4.78ppm, 3.8ppm and 1.54ppm and are obtained from three different transformers. The reason for causing such high 5HMF is not certain. However the measurements of 2FAL on these three transformers have been found to be significant as summarised in Table 6-4. The 2FAL measured from the same oil sample are 1.38ppm, 2.09ppm, and 0.99ppm. The averaged 2FAL measurements of these three transformers are 1.9ppm, 2.64ppm, and 1.31ppm. This indicates that the high measurement in 5HMF does not occur randomly, but is an evidence of abnormal paper ageing, as supported by the high 2FAL measurement in the same oil.

It is concluded that the concentration of 5HMF has been found to be a minor furanic compound dissolved in the oil. Although some high measurements in 5HMF have been found in accordance with the high measurement of 2FAL, the concentration of 5HMF is not sensitive enough to be used as an insulation ageing indicator.

**ii). Concentration of 2FOL**

As another minority derivative, the concentration of 2FOL is isolated from the total furan measurement and plotted with the transformer age as shown in Figure 6-6.
The measurements of 2FOL concentration dissolved in oil are found to be even lower than 5HMF with an average value of less than 0.01ppm for the 342 transformer. As indicated by Figure 6-7, the percentage of 2FOL reaches 97.4% within 0.1ppm, and 99.5% within 0.2ppm. Very few measurements have been found in the database beyond 0.2ppm. Three measurements are found to be greater than 0.5ppm which compose the last 0.2% of all measurements and therefore are regarded as outliers.

The three 2FOL outliers, 0.94ppm, 0.68ppm, and 0.54ppm are from three different transformers. Interestingly, looking at other furanic compounds measured from these transformers.
three oil samples, it is found that the concentration of 2FOL is dominating over other compounds. This is summarised in Table 6-5. The 2FAL measured in three samples are respectively 0.13ppm, 0.38ppm, and 0.001ppm. None or trivial amounts of other furanic compounds were measured. The average 2FAL measurements of three transformers are not very high either, with values of 0.14ppm, 0.49ppm and 0.44ppm. This indicates that the high 2FOL measurement should not be correlated to the abnormal paper ageing.

Table 6-5 Outliers in 2FOL measurement.

<table>
<thead>
<tr>
<th></th>
<th>2FOL outlier 1</th>
<th>2FOL outlier 2</th>
<th>2FOL outlier 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>2FOL in oil sampled</td>
<td>0.94ppm</td>
<td>0.68ppm</td>
<td>0.54ppm</td>
</tr>
<tr>
<td>2FAL in oil sampled</td>
<td>0.13ppm</td>
<td>0.38ppm</td>
<td>0.001ppm</td>
</tr>
<tr>
<td>Average 2FAL of all samples</td>
<td>0.14ppm</td>
<td>0.49ppm</td>
<td>0.44ppm</td>
</tr>
<tr>
<td>Other furanic measurements</td>
<td>0ppm</td>
<td>0.12ppm of 5MEF</td>
<td>0ppm</td>
</tr>
</tbody>
</table>

According to the measured data, 2FOL is produced as a minor furanic compound dissolved in the oil. Recall that 2FOL is the least stable furanic compound among all family members, it is concluded that the concentration of 2FOL should definitely not be used as an insulation ageing indicator.

iii). 2ACF concentration

The concentration of 2ACF has been isolated from the total furan dissolved in oil and is plotted with transformer age as shown in Figure 6-8.
The magnitude of 2ACF concentration measured is similar to 2FOL i.e. generally lower than 0.01ppm. According to the 2ACF distribution in Figure 6-9, the measurement has reached 99% within the 2ACF level of 0.1ppm. Some measurements have been found between 0.1ppm and 0.5ppm, which compose 99.8% of the measurements. Note the break on x-axis after 1ppm. Two measurements are found to be 1ppm or higher, which compose the last 0.1% of all measurements and therefore are regarded as outliers.
The two 2ACF outliers, 5.77ppm and 1ppm, are from two different transformers. From the same oil sample, it is found that the 2FAL concentrations are significant too, which are 2.76ppm and 1.09ppm, as summarised in Table 6-6. Additionally the average 2FAL measurements of these two transformers are significant with the values of 1.73ppm and 1.02ppm.

Table 6-6 Outliers in 2ACF measurement.

<table>
<thead>
<tr>
<th>2ACF outlier 1</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>2ACF in oil sampled</td>
<td>5.77ppm</td>
<td></td>
</tr>
<tr>
<td>2FAL in oil sampled</td>
<td>2.76ppm</td>
<td></td>
</tr>
<tr>
<td>Average 2FAL of all samples</td>
<td>1.73ppm</td>
<td></td>
</tr>
<tr>
<td>Other furanic measurements</td>
<td>0ppm</td>
<td></td>
</tr>
<tr>
<td>2ACF outlier 2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2ACF at oil sampled</td>
<td>1ppm</td>
<td></td>
</tr>
<tr>
<td>2FAL at oil sampled</td>
<td>1.09ppm</td>
<td></td>
</tr>
<tr>
<td>Average 2FAL of all samples</td>
<td>1.02ppm</td>
<td></td>
</tr>
<tr>
<td>Other furanic measurements</td>
<td>0.04ppm of 5HMF</td>
<td>0.01ppm of 2FOL</td>
</tr>
</tbody>
</table>

The data have confirmed that the production of 2ACF is generally trivial in National Grid transformers. Some oil samples are found to have high concentrations of 2ACF dissolved in oil and are accompanied by high concentration of 2FAL. Recall that 2ACF has the highest stability among all furanic compounds, a high measurement in 2ACF could possibly be used as a backup parameter in insulation assessment.

iv). 5MEF concentration

The concentration of 5MEF plotted with a transformer’s age is shown in Figure 6-10. The overall concentration of 5MEF is as low as 0.01ppm. 96.1% of the measurements are within 0.1ppm. Some measurements are found as up to 0.4ppm. The distribution of 5MEF is shown in Figure 6-11. One measurement is found to be greater than 0.9ppm which is regarded as an outlier.
Chapter 6 National Grid Transformers’ Paper Condition Assessment Using Furan Measurement

![Figure 6-10](image1.png)

**Figure 6-10** Concentration of 5MEF dissolved in oil versus transformer’s age from 342 transformers.

![Figure 6-11](image2.png)

**Figure 6-11** Distribution of 5MEF measurement on 342 transformers.

The oil sample with the highest 5MEF concentration is found to have almost no other furanic compounds dissolved. The only measurement beside 5MEF is 2FAL with the amount of 0.001ppm. Furthermore, this transformer is found to have an average 2FAL of 0.09ppm which shows no indication in significant insulation ageing. This is summarised in Table 6-7.

Since the concentration of 5MEF is found to be very low in the oil of National Grid transformers, it is considered as a minor furanic derivative during cellulose paper ageing. The high measurement of 5MEF dissolved in oil is found to be not in
accordance with high measurement of 2FAL, which makes it not a suitable indicator of insulation ageing.

Table 6-7 Outlier in 5MEF measurement.

<table>
<thead>
<tr>
<th>5MEF outlier</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>5MEF in oil sampled</td>
<td>0.91ppm</td>
</tr>
<tr>
<td>2FAL in oil sampled</td>
<td>0.001ppm</td>
</tr>
<tr>
<td>Average 2FAL of all samples</td>
<td>0.09ppm</td>
</tr>
<tr>
<td>Other furanic measurements</td>
<td>0ppm</td>
</tr>
</tbody>
</table>

6.2.4 **Concentration of Major Furanic Compound (2FAL)**

As the main furanic derivative of paper ageing, the concentration of 2FAL is isolated from the total furan measurement for investigation. The measurement of 2FAL is plotted with a transformer’s age as shown in Figure 6-12.

It is seen from the plot that the concentration of 2FAL is much higher than all the four minor compounds listed previously, as indicated by the average measurement of 0.8ppm. The measurement level maintains stable till Age 40, then increases and reaches the peak at Age 45, and decreases again.

Looking at the 2FAL distribution as shown in Figure 6-13, the distribution shape is not as biased as the distribution of minor furanic compounds presented previously. Only 15% of the measurements are below 0.1ppm. Over half of the measurements
(52.6%) are within 0.5 ppm. A majority of the measurements (99.2%) is within 5 ppm. Ten measurements are higher than 5 ppm, which are composed of the last 0.8% of the distribution, and are regarded as the outliers. The maximum measurement is as high as 12.35 ppm.

Among the ten measurement outliers, seven of them, ranged from 8.44 ppm to 12.35 ppm, were obtained from the same transformer. The averaged 2FAL measurement of this particular transformer is 9.63 ppm which suggests that the cellulose paper has severely aged. Apart from 2FAL, only 0.14 ppm of 5MEF was measured from one oil sample. Further investigation has shown that the transformer has an unusual cooler setting of 80/50°C, which is higher than the correct setting of 75/50°C. This leads to unnecessary temperature elevation. In addition, the oil sample was suspected to be contaminated which is believed to cause an incorrect 2FAL measurement. As a further note, the cooler setting of another neighbouring transformer was verified to be incorrect too, however the average 2FAL measurement is found to be as low as 0.06 ppm which is attributed to the different design type.

The measurement outlier of 7.82 ppm is found to be a one-off spike in 2FAL measurements of a particular transformer. The three subsequent measurements taken
within the following two years were below 0.3ppm. According to the National Grid transformer expert, this outlier is most probably attributed to the measurement error.

A transformer is found to have a high 2FAL measurement of 5.17ppm. This particular transformer is found to suffer from high moisture content in insulation which accelerates the formation of 2FAL as discussed in the previous literature review.

The last measurement outlier of 5.12ppm is found in a transformer with an unusual cooler setting of 90/65°C which could self-explain this abnormal 2FAL value. The average 2FAL measurement of this transformer is 1.64ppm, which is close to the 2FAL level of 1.32ppm of the neighbouring transformer with the same design, although the correctness of cooler setting was not specified for this neighbouring transformer.

As a summary, the ten outliers in 2FAL measurements and the presumed causes are listed in Table 6-8.

Table 6-8 Outlier in 2FAL measurement.

<table>
<thead>
<tr>
<th>2FAL outlier 1-7</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>2FAL in oil sampled</td>
<td>(in time order) 8.66, 8.44, 8.44, 10.46, 12.35, 9.6, 9.43ppm</td>
</tr>
<tr>
<td>Average 2FAL of all samples</td>
<td>9.6 ppm</td>
</tr>
<tr>
<td>Average 2FAL of neighbouring units</td>
<td>0.06ppm (different design)</td>
</tr>
<tr>
<td>Presumed cause</td>
<td>Unusual cooler setting 80/50°C, possibly contaminated oil sample</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>2FAL outlier 8</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>2FAL at oil sampled</td>
<td>7.82ppm</td>
</tr>
<tr>
<td>Average 2FAL of all samples</td>
<td>2.12ppm</td>
</tr>
<tr>
<td>Average 2FAL of neighbouring units</td>
<td>0.22ppm (same design) 0.78ppm (different design)</td>
</tr>
<tr>
<td>Presumed cause</td>
<td>Measurement error</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>2FAL outlier 9</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>2FAL at oil sampled</td>
<td>5.17ppm</td>
</tr>
<tr>
<td>Average 2FAL of all samples</td>
<td>3.12ppm</td>
</tr>
<tr>
<td>Average 2FAL of neighbouring units</td>
<td>0.45, 0.47, 1.45ppm (different design)</td>
</tr>
<tr>
<td>Presumed cause</td>
<td>Suspect to have excessive moisture content in paper insulation</td>
</tr>
</tbody>
</table>
### 2FAL outliers

<table>
<thead>
<tr>
<th>2FAL at oil sampled</th>
<th>10.12ppm</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average 2FAL of all samples</td>
<td>1.64ppm</td>
</tr>
<tr>
<td>Average 2FAL of neighbouring units</td>
<td>1.32ppm (same design) 0.09, 0.92ppm (different design)</td>
</tr>
<tr>
<td>Presumed cause</td>
<td>Unusual cooler setting 90/65°C</td>
</tr>
</tbody>
</table>

As a summary, most of the 2FAL measurement outliers are caused by unusual cooler setting, or oil contamination, or measurement error. One transformer is found to have a high level of 2FAL due to the paper’s moisture accumulation.

Since the 2FAL formation process in a transformer is multi-parameter controlled, in following sections, the 2FAL concentration will be evaluated against the transformer’s age, voltage ratio, rating, and load to find the possible parameters which are positively correlated with the 2FAL formation.

#### 6.2.1 Tendency of 2FAL Concentration

i). **2FAL versus transformer age**

The plot of 2FAL measurements with respect to the transformers’ ages is fitted with the Gaussian distribution to characterise the rise of 2FAL concentration as transformer ages. The measurement outliers 1 to 8 are omitted in the database, as these oil samples were either contaminated or had errors in measurement process.

Throughout the fitting process, it is found that the raw data could not be fitted well due to the huge data scattering. As a compromise, the 2FAL measurements at each transformer age are averaged and then fitted. Additionally, the maximum 2FAL measurements at various ages are plotted and fitted to provide a conservative evaluation of 2FAL concentration against the transformer’s age.

After examining several functions, the 2-mode Gaussian is found to best fit the average 2FAL measurement against transformer age, but still has $R^2$ being as low as 0.14. The plot and the fitted equation are shown below.
According to the fitted function, the concentration of 2FAL reaches two peaks at transformer ages of 22 and 50. The fitted curve has inherited the decrease trend within the age of 25 to 35, and 50 afterwards from the raw data, which is caused by a relatively small sample size.

The two climbing regions of the fitted curve indicate that the average 2FAL concentration of the UK transmission power transformers increase with a rate of approximately 0.03 ppm per year. This is slightly higher than the derivation of 0.01 ppm per year made by Ali et al. in 1996 [159].

The best fitting function of maximum 2FAL against transformer age is determined as 1-mode Gaussian with the value of $R^2$ being 0.3. The fitted equations and plot are shown below.
2FAL_{\text{max}} = 3.546 \exp \left[ -\left( \frac{t-45.88}{15.67} \right)^2 \right] \quad (6-2)

The fitted result is interpreted as a conservative estimation of the 2FAL concentration in the National Grid transformer’s oil against age. In the case of a transformer suspected to have high operating temperature, the concentration of 2FAL increases with an average rate of 0.09ppm per year. This is in accordance with the value derived by Ali et al. in 1996 which was 0.1ppm per year [159].

ii). 2FAL versus transformer voltage ratio

Among the 1269 2FAL measurements, 58% of them are from the transformers having a voltage ratio of 275/132kV, and the rest are from the transformers having a voltage ratio of 400/132kV. Plotting the 2FAL distribution under different transformer voltage ratios as shown in Figure 6-16, it is seen that the CDF of two sample sets are very close, except that the sample of 400/132kV has more measurement outliers.

![Figure 6-16](image)

Figure 6-16 Distribution of 2FAL measurement against transformer voltage ratio.

The average 2FAL measurement of the 400/132kV sample set is 0.91ppm which is slightly higher than 0.74ppm of the 275/132kV sample set. However if the measurement outliers (5ppm or higher) are disregarded from both sample sets, the
average measurements are much closer i.e. 0.78ppm in 400/132kV sample set and 0.72ppm in 275/132kV sample set. This can be illustrated by Figure 6-17. It is concluded that for National Grid transformers, the voltage ratio of 400/132kV and 275/132kV do not yield significant difference in the 2FAL concentration dissolved in oil.

![Figure 6-17 Average concentration of 2FAL under different transformer ratios, with and without the measurement outliers.](image)

iii). 2FAL versus transformer rating

The sampled transformers have five different power ratings of 120MVA, 180MVA, 220MVA, 240MVA, and one particular transformer of 276MVA which was up-rated from 240MVA. This unit is grouped into the sample of 240MVA. Additionally, due to the small sample size, the measurements from transformer with the rating of 220MVA (makes up only 1% of the entire sample) are grouped with the sample of 240MVA for a better statistical significance.

Figure 6-18 is the distribution of 2FAL concentrations under different transformer power ratings. The transformers having the rating of 220-276MVA have taken up almost three fourths of the total 2FAL measurements. As a consequence the sample set has more 2FAL measurements than the other two sample sets in every interval of 2FAL concentration. The sample set of 180MVA has more 2FAL measurements which are lower than 1ppm than the other two sample sets.
Looking at the average 2FAL concentrations of each sample set as shown in Figure 6-19, the transformers with the rating of 220-276MVA have the highest value of 0.84ppm. The transformers with the lowest rating of 120MVA have a moderate 2FAL level of 0.73ppm. The transformers with the rating of 180MVA have the lowest average 2FAL concentration of 0.7ppm. If the measurement outliers of 5ppm and above are disregarded, the average 2FAL concentrations of 180MVA and 220-276MVA sample sets reduce to 0.64ppm and 0.77ppm respectively. At this stage, it is concluded that there is no obvious tendency in 2FAL concentration with respect to National Grid transformer’s power rating.
iv). **2FAL versus transformer age in a design family**

The 2FAL measurements are classified according to the transformer design families. Since different numbers of measurements are involved in each design family, the family with the largest number of 2FAL measurements (69 measurements from 19 transformers) is discussed here. The 2FAL measurements of this family are plotted against the transformer age as illustrated in Figure 6-20 and the fitted function using the exponential function.

According to the figure above, within the same design family, the envelope of the 2FAL measurements seems to expand with the increase of transformer age, which suggests that a higher 2FAL measurement can be expected as the transformer ages. However looking at the measurements of individual transformers, it is found that not all transformers will follow this trend. As two examples, the 2FAL measurements of transformer A and B within this design family are explicitly plotted as shown in Figure 6-21.
As shown by the figure above, two transformers have very different trends in terms of 2FAL measurement. The measurements of transformer A are fluctuating with age which is obviously in contrast to the consistent increase of the 2FAL measurements with age as in transformer B. According to the database, neither of the two transformers has had oil reclaimed, therefore the furan content must have been staying in both transformers. Under this context the fluctuation of transformer A’s 2FAL measurement must be caused by the partitioning of 2FAL between oil and paper under different loading and ambient conditions.

Recalling Figure 6-20, it is found that within this design family, it is possible that a randomly distributed 2FAL concentration in oil is expected from the transformers aged 42 years old or less, whereas an increasing trend in 2FAL concentration could be found from the transformers aged more than 42 years old.

Based on the analysis of 2FAL concentration within the same transformer family, it is concluded that the plot of 2FAL measurement in a transformer family can only be referred to when estimating the upper limit of the family transformers. The actual measurement of an individual transformer is likely to fluctuate with the transformer age due to the furan partitioning between oil and paper.
v). **2FAL versus transformer load**

The 2009’s yearly equivalent load factor of the National Grid transformer is plotted against the 2FAL measurement obtained in 2009 to find the possible correlation in between them. Multiple measurements in 2009 are averaged to represent a typical value throughout the year. The plots are shown as in Figure 6-22 which has included the data from 166 National Grid transformers with the fitted exponential function (the four data at load higher than 0.5 p.u have been omitted).

![Figure 6-22 Individual transformer’s averaged 2FAL measurement against 2009 equivalent load, disregarding the transformer design.](image)

According to the plot, the envelope of 2FAL concentration expands as the equivalent load factor increases from 0.1 to 0.5 p.u. Most of the transformers had the load level of 0.3 to 0.5 p.u in 2009, and the measurements of 2FAL concentration in this load region tend to randomly vary below 4ppm. Four transformers had load of higher than 0.5 p.u, and the 2FAL measurements were lower than 1ppm which should be attributed to the temperature control by the cooler operation at OF mode.

If one omits the four 2FAL data at the load of 0.5 p.u above and fits the rest of the data with transformer load using an exponential function, one shall characterise the

\[
2\text{FAL}(\text{ppm}) = -58742.6 \times \exp\left[\frac{K}{(-20119.6)}\right] - 58742.6 \quad (6-4)
\]

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correlation with an almost linearly increasing relationship as plotted in the figure. It is concluded that there is a general tendency of having a high 2FAL measurement from the transformer subjected to the heavy load. However it is not easy to determine the precise concentration of 2FAL in oil at a specific load factor, due to the data scattering.

6.3 Derivation of 2FAL-DP Correlation Relationship

As reviewed previously, due to the differently defined ageing conditions, the correlation of 2FAL dissolved in oil and paper’s DP derived by different laboratories differ significantly. Under this circumstance, directly applying the laboratory derived 2FAL-DP correlation to the field transformers is not a sensible approach.

Now with the aid of the developed thermal model as described in Chapter 4, the DP of a transformer’s insulating paper at the time when oil was sampled can be estimated. Plotting the estimated paper’s DP with the 2FAL concentration, a correlation relationship between 2FAL in oil and paper’s DP can be established for field transformers.

6.3.1 Summary of Transformers Analysed

As presented in Chapter 5, a total number of 106 National Grid field transformers have been modelled using the developed thermal model. Among these transformers, 85 units are found to have the 2FAL measured in oil.

Some of these transformers have modelled thermal lives lower than their service lives. As a consequence, the DP estimates at the time when oil is sampled could be lower than the end-of-life criterion of 200. A filtration process is performed to filter the transformers with an unacceptably low DP estimate, and the DP filtering threshold is set as 116, which is the lowest DP measured from the National Grid scrapped transformers. After filtration, there remain 56 transformers in the sample, which are the analysis subjects for deriving the 2FAL-DP correlation relationship.
6.3.2 **Paper’s DP Estimation at Oil Sampling Time**

Using the built-in DP reduction model in the thermal model, the transformer’s DP retention of the cellulose paper can be estimated at the time when oil is sampled by substituting time \( t \) in the DP reduction model with the age of oil sampling. As an example, Figure 6-23 illustrates the paper’s DP estimates at age 20, 21, and 22 of a particular transformer when the oil was sampled.

![Graph showing paper’s DP retention over transformer age](image)

**Figure 6-23 Example of paper’s DP estimates at the ages oil was sampled.**

6.3.3 **Plot of Paper DP with 2FAL**

A total of 248 measurements of 2FAL dissolved in oil have been collected from the 56 transformers. With the aid of developed thermal model, the paper’s DP retention has been estimated at the time when oil was sampled. Figure 6-24 illustrates the plot of the 2FAL measurements and the paper’s DP estimates against the transformer’s per-unit life, and the per-unit life is obtained by dividing the transformer’s service life by the modelled life.
In the figure above, 2FAL measurements are represented by the green squares, and the paper’s DP estimates are represented by the orange circles. The data scattering of the 2FAL measurements is significant, which is anticipated since it has been shown previously in the plot of 2FAL against the transformer’s age when analysing the 342 National Grid transformers. At the transformer’s life of up to 0.7 per unit, the averaged 2FAL measurement is fairly low i.e. 0.8ppm. This is based on a sufficient amount of data (193 out of 248). Within the transformer’s life range of 0.7 to 0.8 per unit, the 2FAL measurements increase dramatically, and the average level has reached 2.1ppm. However this observation is based on a limited amount of data (18 out of 248). At the life beyond 0.8 per unit (which have 37 data out of 248), the averaged 2FAL measurement drops to 0.7ppm. The observations made at the transformer’s life of 0.7 p.u and beyond are probably not representative considering the less data available.

It is noted that in the figure above, 26 measurements of 2FAL were obtained from 7 transformers which have the per unit life of greater than 1. The lowest DP of these transformers is estimated as 122. These transformers represent the portion of units that have paper DP of lower than 200 but still remains in service.
To establish the 2FAL-DP correlation relationship, the data in the figure above are re-plotted in the manner of regarding the 2FAL measurement as x-axis and the paper’s DP estimates as y-axis. This is shown in Figure 6-25.

The raw scattered data are represented by the blue squares. In addition, as represented by the red squares connected with solid line, the DP estimates are averaged at 2FAL intervals of 0.5ppm for a better view of the trend. Despite the 2FAL scattering, a downward sliding of the DP estimates can be characterised when the 2FAL concentration increases.

6.3.4 Fitted Function of DP-2FAL Correlation

The data in Figure 6-25 are fitted to derive a correlation relationship between the field transformers’ 2FAL measurement and the paper’s DP estimates. As the most popular function used to describe the relationship between 2FAL measurement and paper’s DP, the logarithmic equation is used to fit the 2FAL-DP data. Also used is De Pablo’s 2FAL-DP relationship which is derived based on the theory of cellulose chain scission. Furthermore, considering the data scattering, a linear function is also tried in this study. The formats of the three fitting functions are written as:
log(2FAL) = A_1 - B_1 \times DP \quad (6-5)

2FAL = \left( \frac{23703.71}{DP-29.64} \right) \times C \quad (6-6)

\frac{2FAL}{B_2} = \left( \frac{A_2 - DP}{B_2} \right) \quad (6-7)

where \( A_1, B_1, A_2, \) and \( B_2 \) are constants and do not have physical interpretation, \( C \) is the reaction yield rate in De Pablo’s equation. As a result, the fitted functions and curves are shown as:

\log(2FAL) = 19.73 - 0.04132 \times DP \quad (6-8)

2FAL = \left( \frac{23703.71}{DP-29.64} \right) \times 5\% \quad (6-9)

2FAL = \left( \frac{553.1 - DP}{56.07} \right) \quad (6-10)

Figure 6-26 Fitted functions of the 56 transformers’ paper DP estimates against the 2FAL measurements.

There are no physical interpretations available on the parameters in logarithmic and linear function. On the other hand, the variable in De Pablo’s equation, yield rate of 2FAL formation, is derived as 5\%. This is considerably lower than the originally proposed value of 30\% [154]. According to [154], the 2FAL yield rate is a quantification of the 2FAL production rate as cellulose paper degrades; and a yield rate of 30\% represents that every 3 cellulose chain scissions will produce 1 molecule of 2FAL. In this study, a derived yield rate of 5\% means that it will take 50 cellulose
chain scissions to produce 1 molecule of 2FAL. This is 6 times slower than what De Pablo has derived in the laboratory.

Further investigation has managed to find the possible explanations to this exceptionally low yield rate derived. According to a series of accelerated ageing experiments in [142], it was found that as temperature decreases from 120 to 70°C, the yield rate of the furfural production decreases rapidly from 70% to 0%. In addition, according to the furan formation experiments conducted in [147], the lowest 2FAL yield rate of 13% was obtained under a temperature of 105°C, whereas the yield rate of higher than 50% was obtained on temperatures equal to or higher than 150°C.

These results have pointed to the fact that during cellulose paper ageing, the yield rate of the 2FAL would be considerably lower at lower temperatures. Considering that the operating temperature of the National Grid field transformers is fairly low according to the thermal modelling, which is roughly 80°C, the derived yield rate of 5% appears to be very reasonable.

In additional, referring to Table 2-12, the oil-to-paper ratio in the laboratory ageing experiments ranges from 24:1 to 625:1, which is higher than the ratio of the field transformers which is approximately 4:1 [159]. In this circumstance, per every unit of 2FAL produced by the paper, in the laboratory experiments, more 2FAL will dissolve in oil and will be measured, and consequently the yield rate of 2FAL formation derived would be higher than expected from field transformers.

6.3.5 Evaluations of Fitted Functions

The three fitted functions are evaluated to decide which one is better in describing the National Grid field transformers’ 2FAL formation. In terms of the goodness of fitting from statistics point of view, none of the fitted functions yield $R^2$ value of higher than 0.1 which indicates a poor fitting from first sight. Observing from the figure, it can be seen that probably none of the popularly used functions would yield a satisfying goodness of fitting.
From engineering point of view, it is possible to make the judgement on the fitted functions by looking at the fitted curves. The logarithmic equation is firstly rejected due to the following reasons. According to the fitted logarithmic function, the paper’s DP is estimated down to 500 as 2FAL concentration increases to 0.1ppm, and then levels off thereafter. When the DP retention reaches the level of 200, the corresponding 2FAL concentration reaches an unreasonably high level (3×10^{11} ppm). Additionally, the initial DP (at 2FAL of 0ppm) is estimated as approximately 622 which is much lower than the widely acknowledged value of 800 to 1000 in a new transformer. None of these properties is coherent with the engineering experiences.

The linear equation seems to give a reasonably well description of the data trend. However similar to the logarithmic function, the initial DP predicted by the linear function is too low, which is 553. Therefore the linear function could not be accepted either.

Looking at De Pablo’s equation, first of all the equation itself is supported by the sophisticated theory of cellulose chain scission. Secondly, the fitted function follows the data trend reasonably well. The initial DP is defined by the function as 800 which is acceptable among all three fitted functions. The concentration of 2FAL at DP of 200 is estimated as 4.56ppm, which is coherent with the 56 National Grid field transformers’ 2FAL data such that none of the 2FAL measurements has exceeded 4.5ppm (except for the outliers). Therefore the De Pablo’s equation is selected as the best fitting function to describe the correlation relationship between the National Grid field transformer’s 2FAL concentration in oil and the paper’s DP estimates.

As a summary, Table 6-9 lists the estimated 2FAL concentration at the paper’s DP of 800 (early ageing stage), 400 (moderate ageing stage), and 200 (end-of-life point) and their 95% confidence levels.
Table 6-9 Estimation of 2FAL concentrations (in ppm) corresponding to the critical DP levels by different fitted functions.

<table>
<thead>
<tr>
<th>Fitted function</th>
<th>DP=800 (early stage)</th>
<th>DP=400 (moderate stage)</th>
<th>DP=200 (end of life)</th>
</tr>
</thead>
<tbody>
<tr>
<td>De Pablo (accepted)</td>
<td>&lt;0.001</td>
<td>1.52</td>
<td>4.56</td>
</tr>
<tr>
<td></td>
<td>(1.18, 1.86)</td>
<td>(3.54, 5.58)</td>
<td></td>
</tr>
<tr>
<td>Logarithmic (rejected)</td>
<td>N/A</td>
<td>2×10^3</td>
<td>3×10^11</td>
</tr>
<tr>
<td></td>
<td>(3.9, 7×10^9)</td>
<td>(7×10^3, 1×10^19)</td>
<td></td>
</tr>
<tr>
<td>Linear (rejected)</td>
<td>N/A</td>
<td>2.73</td>
<td>6.3</td>
</tr>
</tbody>
</table>

### 6.4 Summary

In this chapter, the 1269 furan measurements of 342 National Grid field transformers have been intensively analysed. It is found that 2FAL is the major derivative among all furanic compounds. The concentration of 2FAL has taken 93.4% of all the furanic compounds detected in the oil sample. The average concentration of 2FAL from 1269 oil sample is quantified as 0.8 ppm, while none of the four minor compounds (i.e. 5HMF, 5MEF, 2FOL, and 2ACF) has the average concentration of above 0.02 ppm.

Focusing on the concentration of the four minor compounds, the exceptionally high measurements of 5HMF and 2ACF are found to be in accordance with high measurements of 2FAL, which makes them possible backup indicators in detecting the paper ageing. The measurements of 5MEF and 2FOL are on the other hand found to be isolated and are hence not particularly useful.

Ten 2FAL measurements are particularly high, i.e. above 5 ppm, and the highest one reaches the value of as high as 12.35 ppm. Further investigations have indicated that most of the outliers were caused by unusual cooler setting, or human errors such as oil contamination and measurement error. Only one particular measurement is suspected to be caused by the aged insulation of the transformer.

The 2FAL measurements are averaged according to the transformer age intervals and are fitted with Gaussian function. The results indicate that on an average scale, the 2FAL concentration in oil for National Grid transformers increases with a rate of
approximately 0.03ppm per year. For transformer suspected to have a higher operating temperature, the rate is 0.09ppm per year.

The 342 transformers are classified according to voltage ratio, rating, and load in order to find parameters which are positively correlated with the 2FAL formation. The results have indicated that there is no obvious correlation between the 2FAL concentration and the transformer’s voltage ratio and rating. Within the same design family, the envelope of the 2FAL measurement expands as the age increases; however an individual transformer’s 2FAL measurement does not necessarily follow the simple increase trend as the unit ages. A similar conclusion is drawn on the relationship between the load and 2FAL, such that an expansion of 2FAL envelope can be seen as transformer load increases.

With the aid of the thermal model, the paper’s DP has been estimated for 56 transformers at the time when oil is sampled. Three functions are used to fit the 2FAL-DP relationship which are logarithmic equation, De Pablo’s equation, and linear equation. The fitted results indicate that although none of the functions imply a satisfying goodness of fitting due to the data scattering, De Pablo’s equation is better than the others from engineering point of view. The shape of the fitted De Pablo curve follows the data trend generally well, and the estimated 2FAL concentrations at the start and end point of the paper’s DP are very reasonable and are in accordance with the field measurement.
Chapter 7 Conclusions and Future Work

7.1 Conclusions

This thesis presents the work of life assessment, taking the transformer fleet of National Grid transmission power transformers as an example, from the following three aspects: analysing the historic life data of the transformer population; improving the IEC thermal model for thermal life evaluation based on examining the transformer’s operating conditions and thermal parameters; and using furan data to correlate with transformers paper’s DP. The main findings of the study are summarised as follows:

A thorough statistical analysis has been performed on the National Grid transformer historic life data. The hazard plot does not show the increase sign of hazard rate with age, which indicates that the National Grid transformer population has not entered the ageing stage of life cycle and is still within the phase of the random failure mode. The 95% confidence band of the hazard rate at individual transformer age has been quantified using either Binomial or Poisson distribution. The result has indicated that due to the limited life data available, the statistical range of the transformer’s hazard rate is exceedingly large at the older ages. Grouping the life data at multiple transformer ages, it is verified that the more life data are involved, the narrower statistical range the hazard rate will have. Therefore the life data in all transformer ages are summed to derive a general hazard rate of 0.27% with a standard deviation of 0.03%. Regarding the data sufficiency, at any transformer age, only if the exposing transformer number is larger than 200 should the statistical analysis result be regarded as reliable. It is concluded that ordinary statistical analysis is not capable to predict the transformer’s ageing-related failure rate or lifetime in the future based on the life data, because of the limited data available at the older transformer ages.

As an alternative approach, it is proposed to use transformer thermal models to evaluate a transformer’s thermal lifetime. An improved thermal model has been developed based on the existing thermal model presented in the IEC transformer
loading guide 60076-7. The DP reduction model is used to estimate the transformer’s thermal lifetime by obtaining paper samples from a scrapped transformer and the paper’s DP retention. The developed model has two major modifications of the IEC thermal model. The first one is the use of Arrhenius equation in ageing rate calculation in order to consider the paper’s ageing mechanisms of oxidation and hydrolysis and their dominant temperature ranges. Secondly, the model has incorporated the paper’s moisture accumulation effect and the gradually increasing ageing rates with increased moisture contents in aged paper. **The developed thermal model used in this study is much more practical than the original IEC thermal model in terms of the field transformer’s thermal life assessment.**

With the aid of the developed thermal model, the conventionally unknown hot-spot factors of 35 scrapped transformers have been reversely derived by using their DP predicted thermal lives as a benchmark and applying iterations to the thermal modelling procedure. The median hot-spot factor derived is 2.95. Although it appears to be greatly higher than the IEC loading guide’s suggested value of 1.3, it has been proven to be thermally acceptable in terms of the steady-state hot-spot temperature. It has been identified that the modelled transformer’s load, winding-to-oil gradient, and top-oil temperature rise as three possible error sources in the hot-spot factor derivation.

The thermal lives of 106 National Grid field transformers have been estimated. As a result, the thermal life expectancy of the population is derived as 84 years. The transformer’s load, winding-to-oil gradient, and top-oil temperature rise are respectively imposed with a variation factor ranged from 50% to 150% in steps of 10% to examine the response of the modelled life. It is found that the thermal life derived is most sensitive to the load variation, and is least sensitive to the top-oil temperature rise variation. Investigations have been conducted to update the transformer’s WTI setting with the family’s derived hot-spot factor to examine the possible improvements on transformer’s thermal performance. The results indicate that under the updated WTI setting, the population’s thermal life expectancy can be prolonged by a factor of 1.9. In another operational scenario, the transformers could carry an additional load of up to 40% of the original level without a major reduction in the population’s thermal life expectancy. A 2-D thermal life matrix has been
developed based on transformers’ modelled lives, which is expected to be used as a quick tool for identifying the approximate range of a transformer’s thermal life by utilising only the essential information. The practical use of the developed thermal model has been presented in this part of work. As the result, the median of hot-spot factors is derived as 2.95, and the thermal life expectancy of 185 field transformers is quantified as 88 years. These results offer an opportunity to re-evaluate the thermal performances of the in-service transformers.

A total of 1269 furan measurements of 342 National Grid field transformers have been intensively analysed. As expected, the concentration of 2FAL is the main derivative of furanic compounds with an average percentage of 93.4%, over other members of 5HMF, 2FOL, 2ACF, and 5MEF. The average concentration of 2FAL from 1269 oil sample is quantified as low as 0.8ppm. It is found that the concentration of 2FAL in oil is independent of transformer’s voltage ratio and rating, and the envelope of which increases with respect to the increase of transformer’s load, and transformer’s age within a design family. The average 2FAL measurements are found to increase at a rate of approximately 0.03ppm per year. For a transformer that is suspected to be hot, the average 2FAL measurement increases at a rate of 0.09ppm per year.

With the aid of the thermal model, the paper’s DP has been estimated at the time when oil is sampled. The DP estimates of 59 transformers are plotted against the 2FAL measurements, and three functions are used to fit the 2FAL-DP data which are logarithmic equation, De Pablo’s equation, and linear equation. The fitted results indicate that the De Pablo’s equation could better describe the relationship between the 2FAL concentration in oil and the paper’s DP estimate from engineering point of view. Using the fitted equation, the 2FAL concentration in oil at the paper’s end-of-life is estimated as 4.56ppm. The fitted 2FAL-DP correlation is regarded as a tangible progress towards the study of field transformer’s 2FAL measurement and the paper’s DP estimate for the purpose of insulation condition assessment.

### 7.2 Future Work
The following presents the possible future work which may help to solve the questions raised during this research work.

**For statistical analysis of the National Grid transformer life data:**
The result of the life data analysis is only as timely as the data itself. Since this part of work was done during the starting period of this PhD research, the life data is considered dated at this moment. Although the two-year period is too short to see the change of the life data, however new evidence of ageing-related failure could possibly emerge in the future which would help to complete the life data analysis. Therefore the statistical analysis is expected to be kept to date with the latest life data available.

**For transformer thermal model development and its use on field transformers:**
It is a crude assumption to regard the transformer load in 2009 as valid throughout the entire transformer life. Since the historic record of load does not go back far, as a potential approach, alternative resources should be used to trace back a transformer’s load. For example the investigations on the migration of industrial activities and the UK’s population could offer an understanding of the change in the regional load demand, and hence provide a reliable method to estimate the historic load possible.

Besides load, considering that a significant number of transformers in service were manufactured many years ago and do not have heat-run data available, and the fact that the heat-run data cannot be copied from other designs, there is a desire to fill in the blanks. With the help of online monitoring techniques and engineering experiences, it is possible that the unknown heat-run data of the aged units could be reversely derived from the monitored temperature, oil ageing, and furan/methanol data, or alternatively they could possibly be approximated by the available data from the younger units when considering the loading conditions as well. If more transformers could be modelled because of the completion of the missing heat-run data, the statistical significance of the thermal life expectancy derived would reach to a higher level.

**For transformer furan analysis and the correlation with paper’s DP estimates:**
The results presented in this work do not consider the 2FAL partitioning effect during transformer operation, which is a major factor to cause an unreliable assessment of the ageing of insulating paper. As a possible work refinement, if the oil temperature and moisture measurements are available, they should be considered to calibrate the existing 2FAL measurements to minimise the partitioning effect. In this sense the ‘true’ 2FAL concentration retained in the paper could possibly be estimated, which would lead to a less scattered 2FAL plot. In addition, the precision of the 2FAL-DP correlation relationship would also be improved.
Reference


F. Clark, "Factors affecting the mechanical deterioration of cellulose insulation," *Transactions of the American Institute of Electrical Engineers*, vol. 61, pp. 742-749, 1942.


[115] D. Kweon, K. Koo, J. Woo, and Y. Kim, "Hot spot temperature for 154 kV transformer filled with mineral oil and natural ester fluid," *IEEE*


Appendix

List of publications:


