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Health Indexing of Norwegian Power Transformers

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Abstract

In this thesis, a health index model for condition evaluation of power transformers is proposed. A health index is a tool that processes service and condition data into a score which describes the overall health of an asset. The motivation behind this is to objectively and confidently assess the condition of power transformers so that reinvestment and maintenance decisions might be justified. This way, the technical lifetime of healthy assets might be safely increased, while risky assets can be identified and taken care of before they fail. Health indexing is particularly useful for evaluation of large transformer fleets, since it makes it easy to identify the assets most in need of additional attention. An important prerequisite for a health index to be useful is, however, that the availability of data is considered in the model design. A health index intended for use in Norway will thus have to be customized to the data availability faced by most Norwegian utilities and transformer users.

In order to identify which assessment methods that are suited for use in a Norwegian health index, four existing health index models have been reviewed. Based on these reviews and the general data collection practices of Norwegian utilities, a health index model has been proposed. Its main inputs for assessment are: Dissolved gas analysis, oil sample analysis, temperature or load history, maintenance history and particular design data. This information is processed through assessment modules that each evaluate different subsystems of the transformer. For these assessment modules to reflect the degradation of transformers in a best possible way, emphasis has been put on identifying the most important failure modes and aging mechanisms.

In order to test the performance of the proposed model, it has been applied to seven different transformers. The results from this analysis show that the model is capable of differentiating between assets in different conditions and that the health index score appears to be a rough, but reliable, indication of the actual condition of a transformer.

Sammendrag

I denne masteroppgaven presenteres et forslag til en helseindeksmodell for tilstandsvurdering av krafttransformatorer. En helseindeks er et verktøy som benytter drifts- og tilstandsdata for å beregne en score som beskriver en transformators generelle tilstand. Motivasjonen bak dette er å, på en objektiv og sikker måte, vurdere tilstanden til krafttransformatorer slik at vedlikeholds- og reinvesteringsbeslutninger kan underbygges. På denne måten kan levetiden til transformatorer i god stand trygt forlenges, mens transfortmatorer i dårlig stand kan tas hånd om før en feil oppstår. Helseindeksering er særlig nyttig for å evaluere et større antall transformatorer siden det gjør det enkelt å oppdage hvor vedlikeholdsbehovet er størst. En viktig forutsetning for at en helseindeks skal være nyttig er imidlertid at tilgjengeligheten på data er tatt med i betraktning når denne designes. En norsk helseindeks må derfor tilpasses norske nettselskapers og transformatorbrukeres datatilgjengelighet.

For å finne passende vurderingsmetoder for en norsk helseindeks har fire eksisterende modeller blitt vurdert. På grunnlag av denne vurderingen, samt generell praksis for datainnsamling hos norske nettselskaper, er en norsk helseindeksmodell foreslått. De viktigste inputdataene for denne modellen er: Analyse av oppløst gass i olje, analyse av oljeegenskaper, temperatur- eller lasthistorikk, vedlikeholdshistorikk og utvalgte designdata. Denne informasjonen blir behandlet gjennom spesielle vurderingsmoduler som hver evaluerer de ulike delsystemene til transformatoren. For at disse modulene på en best mulig måte skal gjenspeile transformatorens tilstand og gi et godt bilde av aktuelle nedbrytningsmekanismer har en redegjørelse av de viktigste feilmoder og aldringsprosesser blitt vektlagt.

For å undersøke den foreslåtte modellens pålitelighet har den blitt testet på syv forskjellige transformatorer. Resultatene fra denne testen viser at modellen er i stand til å skille mellom transfortmatorer i ulik tilstand. I tillegg later helseindeksen til å være en grov, men pålitelig, indikator på en transformators faktiske tilstand.

Preface

This thesis is the result of the final semester of a master's degree in Electric Power Engineering at the Norwegian University of Science and Technology. The thesis has been written in cooperation with SINTEF Energy Research and Statnett SF, and has been supervised by professor Hans Kristian Høidalen. The work was conducted during spring 2015.

The background for this thesis is a request made by several members of the Norwegian Group for Users of Power and Industrial Transformers for a tool that can aid transformer maintenance decisions. The development of such a tool has been administered by SINTEF Energy Research, and is performed by a dedicated project group. This thesis has been written in cooperation with this group and should be regarded as a first draft of a transformer decision aiding tool. To take part in the work of this group has for my part been very rewarding. The support received especially from Lars Lundgaard and Thomas Welte has contributed greatly to the work with this thesis.

Additionally, important contributions to the thesis have been given by Statnett. The necessary data have been provided by Trond Ohnstad, while Owe Stubberud and Kjetil Ryen have both willingly answered transformer related questions.

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Problem Description

The power transformer is an essential component in the power grid. It is also one of the most costly components to reinvest in. For these reasons, it is crucial to assess the condition of power transformers in service so that maintenance and reinvestment can be scheduled. Internationally, health indexing has become an increasingly popular method for performing such assessments on larger groups of assets. Norwegian utilities have therefore requested that such a health index be developed for use on Norwegian power transformers.

Health indexing is performed by processing service and condition data into a score that describes the overall condition of the transformer. To construct such a tool does hence require a thorough knowledge of the transformer and its potential failure modes and aging mechanisms. Furthermore, a health index is limited to evaluating data that are actually available for a majority of assets. This is an important limitation that dictates which quantities that can be evaluated. In order to assess a transformer in the best possible way, it is therefore important that assessment methods are chosen with care.

The main tasks to be conducted in this master's thesis are:

- Identify the most important failure modes and aging mechanisms with respect to transformer lifetime.
- Review already existing models for health indexing of transformers in order to find appropriate methods for assessment.
- Construct a health index model customized to Norwegian needs and test its performance on real transformers.

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1 | Introduction

The power transformer is not only one of the most important components in the power system, but also one of the most expensive in terms of reinvestment. In order to fully utilize assets, and thus postpone reinvestments, asset owners continuously seek ways to increase the lifetime of their power transformers. It is, however, important that transformers are not operated to the point where they begin to pose a threat to their environment. Unexpected transformer failures are often associated with severe consequences and substantial costs, and assets in a poor condition should therefore be identified and taken care of before a failure occurs. Appropriate measures in such cases include both maintenance and reinvestment, and a course of action is decided upon based on factors such as the asset condition and importance. However, because acquisition times for power transformers are very long, it is important that future maintenance and reinvestment is properly scheduled. For this, condition assessment is a prerequisite.

To ensure a safe and economically optimized operation, asset managers must find ways to direct resources to where they are needed the most. This is a comprehensive task that requires both deep knowledge about the transformer and a good overview of the fleet. In recent years the concept of health indexing has been proposed as a tool to aid such decisions. A health index allows for a quick and efficient way to evaluate and compare the overall condition of all the transformers in a fleet. In general, such evaluations are based on service data, which are processed into a score that describes the overall condition of an asset. This way asset managers can easily detect risky units and make well informed decisions in a relatively short time. There are, however, several approaches as to how health indexing should be performed. Some health indexes base themselves on a relatively small amount of data that are regularly collected by utilities or asset owners, while others have chosen to utilize more detailed data. Another matter is how the collected data are processed in order to produce a score that reflects reality in a good way. To be an efficient and reliable tool, a health index should be able to link input data to all the most prominent failure modes and aging mechanisms that affect a power transformer.

This thesis will focus on health indexing from a Norwegian point of view. In 2008 half of the Norwegian power transformer fleet had an age of 30 years or more, and Norwegian utilities have therefore been expecting a wave of reinvestment in the years to come [1]. A health index customized to Norwegian needs and conditions has therefore been requested by utilities. In this thesis, such a health index will be proposed based on reviews of currently existing models and of the most important failure mechanisms described in transformer literature.

2 | Transformer Stresses

This chapter will present the main components of a power transformer in addition to giving an overview of the most important stresses acting on them. The goal is to give a thorough understanding of the different degradation mechanisms and failure modes that a transformer might encounter during its operational lifetime. Identifying all failure modes and deterioration or degradation mechanisms is listed as the first step towards creating a health index in [2] since such knowledge is essential for establishing reasonable criteria for assessment. Because the main goal of this thesis is to create a tool for condition assessment through health indexing, this recommendation is followed.

The failure modes and aging mechanisms presented below are collected from literature on transformer maintenance such as the *ABB Service Handbook* [3], *the J&P Transformer Book* [4], *Transformers: Basics, Maintenance, and Diagnostics* by the US Bureau of Reclamation [5] and the *Transformer Handbook* by the Norwegian Group for Users of Power and Industrial Transformers [1, 6–10]. The term failure mode is here defined as a present and detectable abnormality within, or on, the transformer, whereas the term aging mechanism refers to a process which over time reduces the qualities of a given part of the transformer. An aging mechanism does not have to be detectable or present at first, but will, given the right circumstances and enough time, result in a failure mode. Lists of the most important failure modes and aging mechanisms are found in Tables A.1 and A.2. To verify the relevance of the listed stresses, and to ensure that no important stress factors have been left out, the list has been presented to a group of transformer experts for revision. As a consequence, minor corrections have been made.

2.1 Core

The main function of the core of a transformer is to lead the magnetic flux from one winding through the other with as low losses as possible. To achieve this, the core has to have a low magnetic reluctance to lead the magnetic flux and a high electrical resistance to counteract eddy current losses. The core construction is therefore made of several layers of core steel with a thickness of around 0,2-0,3 mm per layer. There exist several technologies to increase the magnetic permeability of the steel. Some focus on adding different chemical compounds to the steel, such as silica, manganese-sulfide or aluminum-nitrate. Others focus on the way the steel is rolled and how the steel laminations are joined together in the core joints. To counteract eddy current losses, the steel laminations are coated with an insulating material. This way, the electrical cross section of the core is significantly reduced. This will effectively reduce eddy currents, as they are proportional to the square of the cross section [11].

The core laminations can, due to transport or construction errors, receive damages to the insulating layer between the laminations. This might lead to a short circuit between the laminations, resulting in circulating currents and heat generation. Over time, this might develop and can lead to a further degradation of the insulating layer due to the temperatures generated. Ultimately, this can cause severe local overheating of the core, which can possibly damage the core itself and nearby paper insulation. Another cause to overheating can be additional, but unintentional, grounding of the core. This will allow for circulating currents, which will generate heat and might lead to a local overheating. Conversely, if the initial grounding of the core is lost, this might lead to partial discharges in the core. If a transformer has either partial discharge activity or overheating problems, this can be detected by DGA sampling [8].

The transformer laminations might, during its lifetime, experience considerable mechanical stresses due to high currents in the winding. Such forces can cause small inaccuracies in the core construction, especially in conjunction with the joints, to grow. If these forces separate laminations and create gaps between them, this might lead to partial discharge activity and circulating currents.

2.2 Winding

The windings of a power transformer are commonly made of several copper conductors that are electrically insulated from each other in order to reduce eddy currents. Commonly, the conductors are covered by a layer of varnish and then spun with paper for insulation. The smaller conductors are then joined and the bundle is spun with paper to form the complete winding conductor. The final layer of paper insulates the winding from the neighboring two phases in addition to neighboring winding turns and the grounded transformer core [7]. In this thesis, the term winding is considered to include leads from the bushings and from a potential tap changer.

Winding failures are considered to be the most critical type of failure that a transformer can experience. Such failures will not only prevent the transformer from performing its required function, but may also pose a serious safety risk when they occur. Additionally, repair of winding failures is often very costly and time consuming, and requires that the transformer is taken out of service for an extensive period of time. If no back up is available, such failures can lead to significant additional costs as a consequence of lost production. Because of this, replacing the entire transformer is often considered instead of repair following winding failures. In the following, an overview of failure modes and aging mechanisms affecting the windings will be listed. Because aging of the winding insulation is of utmost importance to the transformer lifetime, thermal and aging related aspects will receive particular attention.

2.2.1 Failure Modes

The winding can, as a consequence of the electromechanical forces produced by large currents, be deformed in several ways. Such high currents can be caused by lightning, earth faults or switching operations. How large an impact these events will have on a transformer and its winding depends on both the location of occurrence and the design of the transformer. Mechanical forces can then act either radially or axially on the winding due to the axial and radial leakage flux, respectively. Radial forces will attempt to either compress or expand the winding construction, depending on the direction of the current. Without sufficient mechanical support and withstand strength, radial compression might lead to buckling of the winding, while expanding forces might tear the conductors or their isolation apart. Axial forces will on the other hand compress or expand the windings along the direction of the core. Winding deformation is likely to result in a serious failure where short circuit between winding layers, phases or phase to earth might occur [7].

Electrical breakdown of the winding insulation might occur in parts of the isolation where the electrical field strength is particularly high, or where the dielectric strength of the insulation is reduced. Such areas are typically cavities in the solid insulation or gas bubbles within the liquid insulation. The seriousness of electrical breakdown can vary from relatively harmless partial discharges to a complete breakdown with devastating consequences. Electrical breakdown is also a condition that can worsen over time, and can thus be regarded as both a failure mode and an aging mechanism. This is the case when partial discharges damage the solid insulation and gradually reduce its insulating qualities. The partial discharges might then develop into more serious failures with higher discharge energy. It is, however, important to remember that the consequences of such failures are not only given by the energy of the discharge, but also the location of the failure [7].

A too high content of water within the transformer is, in addition to increasing the aging rate of the insulation system, potentially harmful for two reasons: Water vapor bubbles might be formed as a consequence of rapid heating of the cellulose insulation. Water will then be released from the cellulose insulation and into the oil, where it, if the temperature is sufficiently high, will boil. Conversely, if the oil has been heated for a long time and is rapidly cooled, its ability to dissolve water will decrease quicker than the ability of the cellulose to absorb water. As a result, free water might be released into the oil. Both cases are associated with a substantial risk of flashover between windings [7].

For transformers using oil produced between 1990 and 2008, the problem of copper corrosion has been observed [7, 12]. This is due to corrosive sulfur in the oil, and the problem is hence regarded as an oil deficiency. Nevertheless, the failures due to this kind of aging will to a large degree affect the windings. Corrosive oils can form semi-conducting copper sulfide which might deposit on the winding insulation to form conducting paths. Such paths might ultimately lead to short circuit failures, and can develop over time. The problem with corrosive sulfur appears to be most prominent for transformers with high temperatures and low oxygen content. Such conditions are typically encountered within highly loaded transformers using a membrane expansion system [7]. A more detailed description of this phenomenon is given in section 2.5.

2.2.2 Aging Mechanisms

Paper contributes not only to the dielectric withstand strength of the windings, but also to the mechanical withstand strength since it is wound very tightly around the conductors. This way the windings are kept in place during mechanical stresses. When the cellulose of the paper insulation ages, this will not impact its dielectric strength, but rather the mechanical strength [7]. If the windings then are stressed by high electromagnetic forces, the paper insulation might yield and the conductors can obtain electrical contact. The mechanical strength in the paper is gradually reduced due to a scissioning of the cellulose molecules. Cellulose is a polymer which in chemical terms is written $(C_6H_{10}O_5)_n$, where $C_6H_{10}O_5$ is called the monomer unit [3]. The factor n is the number of monomers chained together to form the polymer, and is usually referred to as the degree of polymerization (DP). From experiments conducted at SINTEF Energy Research a relationship between the tensile index and DP has been found, and DP measurements can thus be used to determine the ability of the windings to withstand mechanical stresses [13].

Degradation of paper in terms of DP can be described mathematically as a first order reaction, using the Arrhenius equation. A model described by Lundgaard et al. where temperature is assumed to be the dominating cause of paper degradation is seen in Equation 2.1:

$$\frac{1}{DP_t} - \frac{1}{DP_0} = A \cdot e^{\frac{-E}{RT}} \cdot t \tag{2.1}$$

In this equation, A is a constant depending on the chemical environment. It has the dimension [time^{-1}]. E is the activation energy of the reaction in [kJ/mol], R is the molar gas constant in [J/mol/K], T is the absolute temperature in [K] and t is the time in [h]. The A and E coefficients attain different values for different types of paper, as well as for different chemical environments. Values for different moisture and oxygen levels for kraft and thermally upgraded paper are shown in Table 2.1 and 2.2.

Table 2.1: *A and E values for kraft paper under different chemical environments [13].*

Parameter	Dry, no oxygen	1,5% moisture	3,5% moisture	Dry with oxygen
E_A	128	128	128	89
A	$4 \cdot 10^{10}$	$1,5 \cdot 10^{11}$	$4,5 \cdot 10^{11}$	$4,6 \cdot 10^{5}$

Table 2.2: *A and E values for thermally upgraded paper under different chemical environments [13].*

Parameter	Dry, no oxygen	1,5% moisture	3,5% moisture	Dry with oxygen
E_A	86	86	86	82
A	$1,6 \cdot 10^{4}$	$3,0 \cdot 10^{4}$	$6,1 \cdot 10^{4}$	$3,2 \cdot 10^{4}$

Paper degradation is considered to be a combination of the degradation processes hydrolysis, oxidation and pyrolysis. Of these, hydrolysis and oxidation are the main causes of degradation under normal operation. Hydrolysis is a process which is strongly dependent on the acidity and the moisture content of the paper insulation. Thermally upgraded paper appears to be more resistant to hydrolysis than kraft paper, and will thus age at a lower rate under the same conditions at the same temperature. For oxidation to take place at significant rates, a threshold content of oxygen has to be exceeded. If the oxygen content is below this threshold value, the oxidation contribution to paper aging is low compared to that of the hydrolysis. This threshold is idicated to be around 5000 ppm in [14]. Oxidation will therefore be more prominent in free breathing transformers than sealed ones. The aging rate of kraft and upgraded paper due to oxidation appear to occur at similar rates [13].

Pyrolysis, on the other hand, will happen regardless of oxygen and moisture, but only if the temperature of the paper greatly exceeds normal operation temperatures. For very high temperatures, the rate of aging due to pyrolysis will be dominant compared to hydrolysis and oxidation. Such high temperatures might be caused by overheating of joints and connections in the winding conductors, and might over time carbonize the paper completely. A problem when it comes to estimation of the paper aging rate is the fact that the hydrolysis and oxidation processes interact with each other. Oxidation is a process which produces CO_2 and water, which thus increases the moisture of the winding and accelerates hydrolysis [14]. Because these processes are not yet fully understood, caution must be shown when calculating the aging rate of a given environment. For rough estimates regarding the insulation condition, it might however be sufficient to assume that the processes work independently of each other [14].

In order to assess the condition of the solid insulation of a transformer, it is important to know how its degradation rate is affected by environmental conditions.

In this regard, moisture, acidity and access to oxygen are important factors. However, the single most dominating factor is the temperature at which degradation occurs. To measure, or at least estimate, this temperature is therefore essential when it comes to evaluating the state of the solid insulation. The temperature might be measured through fiber optic measuring devices installed in the winding. Such devices are, however, only available for new assets, since this has to be installed during construction. For older assets the temperature of the winding must therefore be measured from the top oil or be estimated from the load. Because the temperature distribution within the transformer is not uniform, some areas of the insulation will experience higher temperatures than other. These areas, usually referred to as hot-spots, are where the insulation is expected to have degraded the furthest. This will represent a "weakest link" of the solid insulation and estimates of the insulation condition through Equation 2.1 should therefore aim to assess the hot-spot insulation.

IEC 60076-7 presents a way of calculating the hot-spot temperature through an exponential equation. This allows the hot-spot temperature to be described as a function of time, load and ambient temperature. The equation does also take into account the design and cooling arrangement of the transformer. The steady state expression for the hot-spot temperature is shown by Equation 2.2.

$$\theta_h(t) = \theta_a + \Delta\theta_{or} \cdot \left[\frac{1 + R \cdot K^2}{1 + R}\right]^x + H g_r K^y \tag{2.2}$$

In this equation, $\theta_h(t)$ is the hot-spot temperature, θ_a the ambient temperature, $\Delta\theta_{or}$ the difference between the top oil temperature and ambient for nominal load, R the ratio between rated losses and no load losses , K the load in per unit, x the oil exponent, H the hot-spot factor, g_r the temperature rise from the oil to the winding and y the winding exponent. The constants R, x, H, g_r and y are transformer specific and depend on design and cooling mode. Suggested values for these, as well as for $\Delta\theta_{or}$, are given by IEC 60076-7 [15]. The value of these can be seen in Table 2.3.

To illustrate the principles behind this calculation, Figure 2.1 is considered. The illustration displays the assumed temperature distribution within a transformer.

Table 2.3: *Calculation parameters used to calculate the hot-spot of a transformer as described by IEC 60076-7 [15].*

Cooling mode	**x**	**y**	**R**	**H**	g_r	$\Delta\theta_{or}$
ONAN	0,8	1,3	6	1,3	20	52
ONAF	0,8	1,3	6	1,3	20	52
OF...	1	1,3	6	1,3	17	56
OD...	1	2	6	1,3	22,3	49

Temperature is given along the x-axis, whereas the y-axis represents the vertical position within the transformer. This is, however, a simplified model where the following assumptions are made:

- Oil temperature within the tank increases linearly towards the top.
- The temperature difference between oil and windings is a constant g_r.
- The hot-spot is assumed to be somewhat higher than that of the top winding. $\Delta\theta_{hr} = H \cdot g_r$.

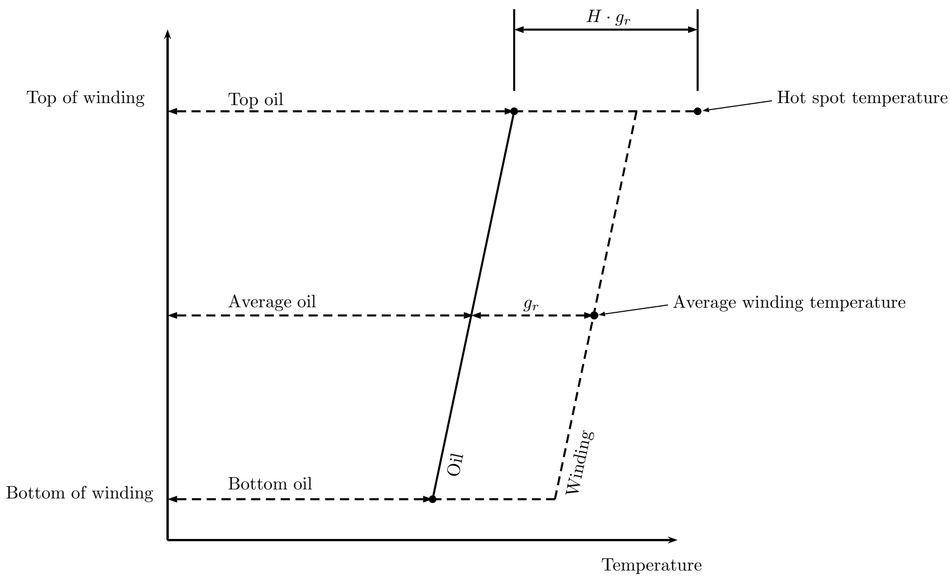

Figure 2.1: *Thermal diagram showing the vertical temperature distribution for oil and windings as described by IEC 60076-7. The horizontal axis represents temperature while the vertical axis represents the vertical position within the transformer.*

From Equations 2.1 and 2.2, the current DP value of the winding hot-spot can be estimated, provided that either temperature or load data are available.

Another mechanism that might affect the paper insulation over time is the loss of winding pressure due to moisture variations. The winding pressure will increase with increasing moisture, but will decrease below the initial level as a consequence if the moisture content is reduced. Such moisture reduction is typically caused by drying of the solid insulation, and care must therefore be taken when such maintenance is performed.

2.3 Tap Changer

Tap changers are used to adjust the voltage of the secondary side of a transformer. Such adjustments can be necessary for a number of reasons, such as compensating voltage variations or to provide flexibility with respect to a system voltage. Tap changers are mainly found in transformers used for transmission and industry, as these are dependent on controlling the output voltage of the transformer. Generator step up transformers used for power production can be operated without a tap changer as the voltage output of these to a great extent can be controlled by magnetization of the generator. Tapping is performed by mechanically selecting the number of low voltage winding turns being active, and thus changing the turn and voltage ratio of the transformer. The tap changer is commonly regarded as one of the most critical components of a transformer, as it is both frequently subject to failure and because tap changer failures might require that the transformer is taken out of service for expensive repairs to be made [3, 6].

Tapping can be performed either while the transformer is energized or when it is de-energized. Tap changers where switching is performed while the transformer is loaded are called on-load tap changers (OLTC), while tap changers that require the transformer to be de-energized are called de-energized tap changers (DETC). Today the OLTC type is by far the most common and DETCs are, according to Norwegian utilities, mainly found in conjunction with older assets[1]. Although OLTCs and DETCs are similar in function, they are quite different when it comes to failure modes and degradation and the two will therefore be handled separately in the following.

De-Energized Tap Changer

Since this type of tap changer requires that the transformer must be disconnected before operation, the stresses experienced by a DETC are less than those for an OLTC. The most prominent failure mode for DETCs is the risk of contact coking as a result of operation on the same tap for a long period of time. This condition is initiated by deposit of carbon particles on the contact surface if the contacts are left in the same position for a long time. Because of the heat generated from the increased contact resistance, the carbon will coke and further increase the contact resistance and decrease the cooling. Ultimately, the DETC might experience thermal runaway and gases might be produced. To avoid this, the transformer should regularly be operated through all taps to clean the contact surfaces of pollution [3, 16]. The formation of coke can in severe cases cause the tap changer to get locked in its current position and thus make operation impossible. If operated while the contacts are locked in position, the tap changer might be damaged.

1. Stated by utility representatives during a meeting in Oslo, 14th of April 2015. This meeting is more closely described in Chapter 5

On-Load Tap Changer

Because OLTCs are operated while the transformer is still loaded, they are more exposed to stresses than DETCs. Of course, OLTCs can experience the same coking problems as described for DETCs, but OLTCs are usually operated automatically and are rarely left in the same position for a long period of time. However, because they are frequently operated, the mechanical wear of the switching mechanism is a considerable source to tap changer failures. Operation of the OLTC is performed by a complex mechanical system composed of several components. The tapping process is driven by a motor arrangement located on the outside of the transformer, while the switching takes place within the main tank of the transformer. How the switching is performed within the transformer depends on the tap changer design, but generally the switching operation is carried out by the diverter and selector. These components are located within the transformer tank, and can either be placed in the same oil volume as the transformer windings or within their own oil-filled compartment [3, 6]. It is important to be aware that current interruption in an OLTC leads to arcing, which in turn will lead to a production of gases. These gases are the same as those created by dielectric faults within the main tank. If the tap changer shares oil volume with the active part of the transformer, these gases can therefore be falsely interpreted as an internal dielectric fault [6, 7].

2.4 Bushings

The bushings of a power transformer are essential components for operating the transformer. Their main function is to lead the current from the external electrical grid to the active part of the transformer. The current must hence pass through the main tank of the transformer, and it therefore important that the bushings allow this without compromising the tightness of the tank. Generally, transformer bushings are cheap components that can easily be replaced in the case of failure. Their importance to the transformer health is therefore limited. However, serious bushing failures might cause extensive damages to other and more expensive components. For this reason it is important to be aware of the failure modes and degradation mechanisms that affect the bushings.

According to the Transformer Maintenance Handbook issued by SINTEF Energy Research, there are three particular conditions that should be monitored closely to ensure optimal bushing operation [10]:

- The outer porcelain surface of the bushing is susceptible to pollution from air. This is especially important in case of heavy rain or proximity to sources to pollution such as the sea or industry. The bushings should therefore be regularly cleaned in order to avoid arcing.

- The bushing should regularly be checked for oil leaks. The oil level of the bushing should not have to be refilled during its lifetime. Oil leaks are therefore a serious defect that will require the bushing to be repaired, and it should under no circumstances be operated if the internal oil level is too low. This might cause serious damage to both the bushing and transformer, as well as to any personnel in the proximity [3].

- Bad connections within the bushing might lead to local temperature increase. This can be detected using thermovision. In such cases, the bushing should be dismantled and reassembled.

Other defects that might affect the bushings are loose field distributors (shields) and physical damage to the bushing body during transportation or maintenance. Loose shields might cause uneven distribution of magnetic flux, which in turn might lead to overheating of specific areas and the formation of gas. Physical damage to condenser insulated bushings might cause the condensers to be short circuited. This might lead to uneven field distribution and subsequently increased electrical stresses on the bushing [3].

Bushings are additionally prone to many of the same failures that both windings and the oil insulation system is. For bushings where an oil-paper insulation system is used, both the oil and the paper can degrade as a consequence of moisture and high temperatures. The insulation might also be damaged by partial discharges that can occur as a consequence of high moisture. In extreme cases, discharges might lead to a buildup of pressure that can cause the porcelain to burst.

2.5 Oil

Power transformers do largely use mineral oil as insulation between windings and tank. Oil has both great insulating properties and the advantageous feature of being a liquid. This has several practical implications: Natural convection causes the oil to flow past the active part of the transformer and thus function as a cooling agent. Additionally, the content of gases and chemical compounds in the oil is an important source of information about the inner condition of the transformer. Since oil is a liquid it can be sampled for lab analysis. These analyses can detect failure modes on important components that might otherwise have been overlooked.

Failure modes concerning the oil itself will in most cases be related to its gradual degradation. Over time, the insulating and cooling properties of the oil will be reduced. Once these qualities have reached a level which is no longer acceptable, the oil can be said to have a failure mode. Such aging caused failure modes are, however, predictable and can be counteracted by a proper maintenance scheme [3]. They are therefore not regarded as the most critical failure modes the oil can experience. Far more serious is the relatively new problem of corrosive sulfur in the oil. Corrosive sulfur appears to be connected to mineral oils produced between 1990 and 2006, and is considered a serious risk. Corrosive sulfur in the oil can react with metals such as copper or silver to form semi-conducting compounds which might deposit on the inner surfaces of the transformer, resulting in a substantial risk of short circuit failures. This will happen on different places, depending on whether the oil is corrosive towards copper or silver. If the oil is corrosive towards copper, the deposits will be formed where copper is available. Copper sulfide formation will, for this reason, mostly affect the winding and its insulation. Because the copper sulfide can be absorbed into the paper insulation of the winding, a conducting path might be formed between conductors. Silver corrosion behaves similarly, but affects silver surfaces which are typically found in contact points within the transformer [7, 12].

Whether the oil is corrosive or not can be determined by a laboratory analysis where this is specified, and is hence fairly easy to discover. However, mineral oils can be potentially corrosive, meaning that non-corrosive oils might turn corrosive in the future. One way corrosivity might be triggered is through regeneration of the oil. If exposed to too high temperatures during the regeneration process, this might cause the oil to become corrosive [12]. Additionally, high temperatures and low oxygen content within the transformer appear to trigger copper corrosion. Hence, membrane-sealed transformers where high temperatures occur are especially exposed. Covering the conductors with a varnish will protect them from corrosive sulfur, but uncovered areas such as joints might still be exposed. Adding a so-called passivator is also a way of preventing corrosion of the copper conductors.

Mineral oil degradation is important to the transformer condition for especially two reasons. Aging of the oil will over time reduce its holdfastness and hence lead to an increased probability of severe short circuit failures. Reduction of the holdfastness can be due to particle contamination of the oil, increased water content or formation of gas bubbles in the oil. Particles are created as by-products as both the paper insulation and the oil insulation is oxidized. Oxidation of oil will further lead to the formation of acids and sludge. Acids, and especially low-molecular acids, further accelerate the aging of the paper insulation. Sludge will stick to the windings and deposit in the cooling ducts, causing cooling to be less efficient. Oxidation is normally counteracted by adding a so called inhibitor to the oil. In Norway dibutulparacresol (DBPC) is used for this purpose. The inhibitor will be consumed over time and should be kept above a threshold level of 0,10% to prevent accelerated aging. Refilling should normally result in an inhibitor content of 0,30% [7].

The content of water in the oil is a very important parameter when it comes to the oil quality. Normally, nearly all of the water in a transformer will be stored in the cellulose. However, since there will be an equilibrium between the oil and cellulose, some of the water will also be dissolved in the oil. The ability of the cellulose to store water is very dependent on temperature and the water content of the oil can thus vary considerably depending on load and ambient temperature. A too high content of water within the transformer is, in addition to increasing the ageing rate of the insulation system, potentially harmful for two reasons: Water vapor bubbles might be formed as a consequence of rapid heating of the cellulose insulation. Water might then be released into the oil and will, if the temperature is sufficiently high, boil. Conversely, if the oil has been heated for a long time and rapidly is cooled, its ability to dissolve water will decrease and free water might be released. Both cases are associated with a substantial risk for flashover between windings [7].

Gases can also be formed as a consequence of discharges or overheated areas within the transformer. Heating of the oil causes formation of several hydrocarbons, while electrical faults produce mainly hydrogen and acetylene [3]. The kind of failures that can cause such gas formation are typically partial discharges or hot metal surfaces due to bad electrical contact or stray flux currents. Carbon monoxide and carbon dioxide are on the other hand associated with degradation of the cellulose. Because different gases are produced at different temperatures and from different failure mechanisms, the gas content of the oil can provide much information on both the condition of oil and paper insulation. As a general rule, the higher the energy of the fault, the higher the number of bonds in the gases formed [17]. Based on this, gas ratios are often considered when trying to identify faults within the transformer. Table 2.4 explains how gas ratios may be used to identify a failure mode according to IEC 60599 [17]. Although this method might reveal the fault mechanism being the cause of gas production, the location of the fault remains unknown.

Table 2.4: *Fault identification using gas ratios as described in [17].*
** Not significant*
T1 fault: T<300 °
T2 fault: 300 °C<T<700 °C
T3 fault: T>700 °C

Probable fault	$\mathbf{C_2H_2/C_2H_4}$	$\mathbf{CH_4/H_2}$	$\mathbf{C_2H_4/C_2H_6}$
Partial discharges	*	<0,1	<0,2
Low energy discharges	>1	0,1-0,5	>1
High energy discharges	0,6-2,5	0,1-1	>2
Thermal fault T1	*	>1	<1
Thermal fault T2	<0,1	>1	1-4
Thermal fault T3	<0,2	>1	>4

In addition to the hydrocarbon gas ratios shown in Table 2.4, two more ratios should be mentioned. These are the ratios $\frac{CO_2}{CO}$ and $\frac{O_2}{N_2}$, which are related to the degradation of paper and oil. If the ratio $\frac{CO_2}{CO} < 3$, this is usually considered an indication of paper involvement in a fault. If $\frac{O_2}{N_2} < 0,3$, this indicates that oxygen is being consumed, either from paper or oil degradation. It is important to emphasize that these ratios are not absolute, but might be used as indicators of the condition of the transformer insulation system. For the calculation of all gas ratios, it might be an idea to calculate the ratios based on the difference between the most recent samples. This can prevent that the fault gases are concealed by the gas content in the transformer prior to the fault [17].

2.6 Tank and Auxiliary Equipment

The tank of a transformer plays an important role in protecting the active part and its insulation system from external factors such as mechanical damage and ingress of moisture. Additionally, it allows the oil to expand and contract without bursting and contributes to cooling through its construction. The two main failures that regard the tank of a transformer are damage to the outer coating and aging of gaskets and seals. The paint coating on the tank is intended to protect the tank from corrosion and rust. If damaged, this might over time lead to leaks. The seals and gaskets of the transformer are intended to keep the mineral oil inside of the tank while moisture is kept out. Over time, they will however lose their elasticity and become more and more brittle. Oil can then leak out and moisture might enter the main volume. Seals and gaskets should preferably be replaced before such degradation has occurred [9].

A power transformer does normally have large amounts of accessories, but the most important with respect to its lifetime are the cooling system and the expansion system. As pointed out in section 2.2, the lifetime of the transformer is highly dependent on the temperature which the winding insulation is exposed to. Transformer cooling systems are generally divided into an internal and an external cooling system. Internal cooling uses oil as cooling medium, and the oil might be flowing either naturally or forced. Natural flow will take place automatically when the oil is heated by the windings. Hot oil then flows to the top of the transformer and cold oil goes to the bottom, thus creating a natural circulation. Forced oil flow is pump driven and is more efficient in terms of cooling. Similarly, the external cooling system can consist of a natural or a forced flow. The most commonly used external cooling medium is air, which in the case of forced flow requires the use of fans. For generator step up (GSU) transformers used in conjunction with hydro power, water might also be used as an external cooling medium. To easily separate between the different cooling systems, abbreviations of four letters are used. The first and third letters describe the internal and external cooling mediums, respectively. The second and fourth letters describe how the flow is driven. The most commonly used cooling systems in Norway and their abbreviations can be seen in Table 2.5 [7]. Common failures are related to the motors propelling the fans or oil pumps. Defects on drives can either be detected due to a temperature increase or as an unusual noise coming from the transformer.

The expansion system of a transformer impacts its lifetime because it in some cases allow moisture and oxygen from the air to come in contact with the transformer oil. There exist several systems that are designed to allow oil expansion, but only two are mentioned here. In free breathing transformers, a conservator is used to provide a volume in which the oil might expand. The conservator is

Table 2.5: *The most commonly used cooling systems of Norwegian power transformers.*

Abbreviation	Internal cooling system	External cooling system
ONAN	Oil, Natural	Air, Natural
ONAF	Oil, Natural	Air, Forced
OFAF	Oil, Forced	Air, Forced
OFWF	Oil, Forced	Water, Forced

usually mounted on top of the transformer and the oil is here in contact with air at atmospheric pressure. Oxygen and moisture from the air will then be absorbed by the oil until an equilibrium is established. To prevent too high water uptake by the oil, silica gel is used to dry the air as it enters the conservator. This gel will have to be regularly replaced as it is saturated with water over time. An alternative and commonly used solution is to use an elastic and water proof membrane between oil and air. This way, the oil is allowed to expand without coming in contact with air. These are the two most commonly used systems in Norway [7].

2.7 External Stresses

In addition to the many factors on, or within, the transformer that are important to its condition, external factors do also cause a stress to the transformer. External factors can be of both an electrical, mechanical, chemical or thermal character and are in this text defined as all events happening either on the outside of the transformer tank (for mechanical, chemical or thermal events) or on the outside of the transformer bushings (for electrical events). To approach these factors in a systematic manner, a distinction is made between electrical and non-electrical external factors. The impact of these factors is largely dependent on the geographical position of the transformer, as well as its electric position within the grid, and might therefore vary considerably from transformer to transformer. Although the effects of external stresses might not be reflected in the current condition of a transformer, they may be significant when it comes to the probability of failure in the future.

2.7.1 Electrical External Stresses

External stresses of an electrical nature are generally the most critical with respect to the risk of transformer failure. How serious these stresses are depend largely on the transformer position in the grid, the transformer construction, its protection equipment and the climate of the location. Examples of such stresses are lightning surges, switching overvoltages and earth faults.

Lightning surges are among the most critical external stresses that a transformer might experience and one of the most common reasons for disturbances in the electricity grid. In 2013, the Norwegian TSO Statnett SF, recorded that 18,9% of all service disturbances in the transmission grid were due to lightning [18]. For power transformers, lightning represents a serious threat mainly when there is a risk that surrounding overhead lines might get struck. If this should happen, voltage and current waves will travel along the lines until they reach the substation where the transformer is located. Lightning currents vary considerably in magnitude, but typical values lie between 10 and 50 kA [19]. Significantly higher currents might however also occur. Such high currents will also cause overvoltage waves which will travel along the transmission lines. These waves are characterized by their front rise time, by their amplitude and by the time it takes for the voltage to be reduced to half of the peak value.

When voltage waves reach a transformer, a reflection of the voltage will occur due to the high impedance of the transformer. The magnitudes of the currents and voltages will in these cases depend strongly on the network configuration. In the case of transformers, the entire voltage wave will be reflected, resulting in a doubling of the voltage in the point of reflection [19]. The stress a transformer experiences due to lightning is very dependent on how large voltages the transformer is dimensioned to withstand, how its protection equipment is dimensioned, how far the voltage wave has to travel and on how the grid is configured at the point in question. Additionally, the lightning frequency in the area of a transformer is of importance, since it will determine how often the transformer is stressed due to lightning.

Switching overvoltages are caused by the sudden current interruption performed by circuit breakers. As the system is forced from a steady state to a transient state, voltage transients of high amplitude might occur. These voltages will behave similar to those caused by lightning. However, because the magnitude of the voltage will be lower than those of lightning overvoltages, switching overvoltages are considered a less critical stress factor than lightning overvoltages [19].

Earth faults might occur unexpectedly and are often caused by external factors such as weather or vegetation. An earth fault is essentially a short circuit of the power system and will result in the flow of extremely high currents until the fault is cleared. This might be critical to a transformer since the induced electromagnetic forces acting on the winding will increase by the square of the current [11]. High short circuit currents might therefore lead to serious winding deformation. Additionally, high currents lead to high resistive losses which produce heat. This might damage both the conductors and the insulation system [11]. The magnitude of the earth fault current is dependent on the system voltage, as well as the short circuit impedances of both the transformer and the system. The RMS value of the short circuit current is given by Equation 2.3.

$$I_k = \frac{U_S}{\sqrt{3}\,(Z_T + Z_S)} \tag{2.3}$$

Here, I_k is the short circuit current in [kA], U_S is the system voltage in [kV], Z_T is the short circuit impedance of the transformer and Z_S is the impedance of the electrical system, both in in Ohms. The theoretical maximum current is, however, given by Equation 2.4. This is because the dimensioning stress is given by the peak value of the current. In addition, the short circuit current will be dependent on the relationship between the system resistance and reactance. This R/X ratio is represented by a factor κ and has to be multiplied to the expression in Equation 2.3. The theoretical maximum short circuit current is therefore given by Equation 2.4 [11].

$$\hat{\mathrm{I}}_k = \sqrt{2}\kappa I_k \tag{2.4}$$

$\hat{\mathrm{I}}_k$ is the theoretical maximum short circuit current in [kA]. The value of the κ-factor is given by the R/X relationship of the network configuration, but can according to the IEC be assumed to be 1,8 for transformers below 100 MVA and 1,9 for transformers above 100 MVA [20].

Protection

Generally, a power transformer will be protected against surges by one or more surge arresters. A surge arrester is an instrument that will begin to conduct current only if it is subjected to voltages higher than a certain level. This voltage level is usually referred to as the lightning impulse protective level U_{pl} and is the voltage that will reside over the arrester while it is conducting. In addition to U_{pl}, surge arresters are characterized by several other quantities that describe their ability to withstand and handle different stresses. The most important surge arrester quantities from a transformer protection point of view are, however, U_{pl} and the distance from the earth terminals of the arrester to the transformer terminals. An incoming wave at the arrester terminal will keep its shape and continue to move towards the transformer. Because of the steep front of lightning waves and the high impedance of the transformer, which causes all incoming waves to be reflected, a voltage rise according to Equation 2.5 is observed at the transformer terminals.

$$U_T = U_{pl} + \frac{2 \cdot k \cdot l_{AT}}{n \cdot c} \tag{2.5}$$

In this equation, U_T is the voltage observed at the transformer terminals, U_{pl} is the lightning impulse protective level, k is the wavefront steepness, l_{AT} is the distance from the arrester grounding to the terminals of the transformer, n is the number of incoming lines at the station and c is the speed of light. Equation 2.5 is exact for $n = 1$ and approximate for $n = 2$ [19]. Because this voltage rise, in addition to U_{pl}, is proportional to the distance between the surge arrester and the transformer, the surge arrester should be placed as close to the transformer as possible. In Norway, this is especially relevant for GSU transformers since these are often located within excavated mountain where space is limited [19].

2.7.2 Other External Stresses

Typical examples of non-electrical external stresses that affect the condition of a transformer are corrosion and pollution of its outer surface. Corrosion and rust are well known mechanisms that attack metal surfaces where iron is present. Because rust is catalyzed by moisture and the presence of salts, the environment around the transformer will be of significance. This is especially important in case of heavy rain or proximity to sources to pollution such as the sea or industrial plants. Pollution might besides form conductive layers on the outer surface of the transformer. Such layers might give rise to arcing and should therefore be avoided by regularly cleaning these surfaces [3].

3 | Health Indexing

A health index is a tool that allows asset managers to make quick and well-informed decisions by aggregating and processing available information for an asset into an overall condition evaluation. This way, both the maintenance need of individual assets and fleets as a whole can be investigated through a ranking of assets. Such a ranking is usually based on one or several scores, which in turn are found from a set of algorithms especially designed to evaluate both service and condition data. These algorithms typically assess separate subsystems of the transformer and are eventually merged to form a final score, which represents the overall condition of the transformer. Based on either this score or the partial scores obtained for each subsystem, decisions regarding condition and maintenance need can be made [21].

An important motivation for health indexing of assets is the increasing demand for optimal resource distribution which is faced by many asset managers [2]. This includes the ability to schedule maintenance and reinvestment in an economically optimal way. Additionally, asset owners are aware that large amounts of capital can be saved if reinvestments can be safely postponed. As a result, the timing of maintenance actions will be an economical trade-off with postponing reinvestment on one side and the cost of a potential failure on the other. In order to achieve optimal maintenance scheduling, information about asset condition is essential. Obtaining such information is, however, also resource demanding. Health indexing can therefore not only reveal where maintenance and reinvestment is needed, but also where collection of additional condition data is required.

3.1 General Concepts of Health Indexing

Health indexing of power transformers is often performed with a special emphasis on assessing the long term reliability of an asset, rather than its short term functionality [2]. Health index models are therefore normally constructed to consider factors that affect the useful lifetime as more serious than those that can be reversed by maintenance. This is important to be aware of, both for users and developers of health indexing tools, so that both have a common understanding of what the output from a health indexing tool actually means. In [2], the objectives of a health index are described as follows:

- The index should be indicative of the suitability of the asset for continued service and representative of the overall asset health.
- The index should contain objective and verifiable measures of asset condition, as opposed to subjective observations.
- The index should be understandable and readily interpreted.

From these objectives it is understood that a health index is no exact way of calculating the condition of an asset, but rather a way of quantifying it so that it might easily be represented and compared on a large scale.

Because a transformer consists of several subsystems, separate modules that describe the degradation of each subsystem can be developed. Health indexes are therefore sometimes referred to as composite health indexes [2]. How these modules affect the final health index verdict depends on the different failure mechanisms the transformer might experience, which in turn depends on manufacturing design, environment and operating conditions. Although considerable variations exist when it comes to design and construction details, most power transformer follow the same basic construction principles. This makes it possible to design a tool that to a large extent is able to assess the technical condition of transformers of various ratings and for various fields of application. Different designs are however also important to incorporate in the model where these are known to, or expected to, play a significant role on the technical condition of the transformer.

A principled illustration of how a health index might be constructed is shown in Figure 3.1. In this figure it can be seen that the input data are processed into a score by assessment function modules. These scores are further weighted relatively to each other and finally summarized to calculate a final health index score.

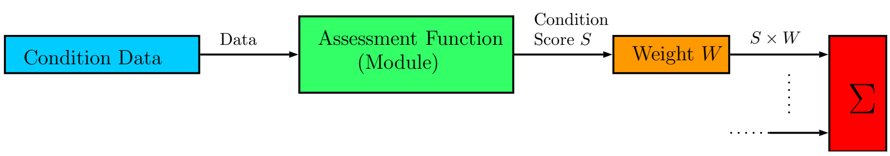

Figure 3.1: *Principled schematic of a health index model. Condition data is processed into scores by assessment function modules. These scores are further weighted relatively to each other and summarized to calculate a final health index score.*

In Norway, as in most other parts of the world, most power transformers are subject to a maintenance scheme where several routine measurements are conducted.

Routine measurements can be performed on one or several of the components of the transformer and will in most cases be the main source of information about the transformer condition. Naturally, special measurements might also have been conducted to obtain better or additional information, but this will normally only be the case for a smaller group of assets. In a health indexing context, condition data are often referred to as indicators of condition. In order to rank and compare assets on the same basis, the data, or indicators, used as input to the health index model should be available for as many assets as possible [22]. This does not mean that special measurements can not be added to a health index, but rather that it is important to know on which grounds a health index score is obtained. Another aspect of data availability is the end user experience. If a health index requires data that the user does not have access to, either because they are expensive or technically challenging to obtain, it will be of no use. On the other hand, a health index will give no information unless the input data actually contain some information about the condition of the transformer. With this in mind, a reasonable choice is to use condition data that utilities already collect on a regular basis as a part of their maintenance scheme. An overview of common practice among Norwegian utilities when it comes to data collection can be seen in Table 3.1. This table is based on the reported maintenance and data collection frequencies from eight Norwegian utilities [23].

Table 3.1: *Condition data collection - Overview of Norwegian practice:*
**) Not recorded by all utilities.*
***) Special measurements. Not conducted regularly.*
****) Varies between continuous measurements and regular, manual registration.*

Condition data	**Intervals [years]**
Dissolved Gas Analysis	1-2
Oil sampling	1-2
Infra red scan	1-3*
Tap changer audit	6-8*
Furans	8*
SFRA	**
PD	**
Dielectric response	**
Service data	
Inspections	1-6 times/year
Load history	***
Top oil temperature	***

Identifying all relevant failure and degradation mechanisms, as well as their consequences and practical implications, is in [2] listed as the first step towards creating a health index model. This includes identifying which stresses that cause irreversible deterioration, which stresses might lead to immediate failure, which parts of the transformer that are especially exposed to failure and how measured data should be interpreted to give reliable and relevant information. Having good knowledge of the transformer and its components is also necessary in order to determine which situations that should be considered serious and which should not. This will subsequently determine how strongly the health index is influenced by each indicator. The relative importance of each indicator will hence be decided based on both statistics, experience and expected consequence in case of failure.

3.2 Experience and Reliability

Few studies of the reliability of health indexing have so far been conducted. This is probably due to the fact that investigating the actual condition of transformers requires them to be opened. Since this is normally only performed when assets are taken out of service, such investigations take a long time to conduct for a significant amount of transformers. However, if sufficient time is spent, the reliability of a health index might be measured in two ways; through the failure rate of the transformer fleet where the health index is applied or through a post-mortem investigation of assets that are taken out of service due to a poor health index rating [24].

One such study has been performed by Doble Engineering and National Grid [24]. In this study, thirty transformers scrapped during 2011 and 2012 were thoroughly investigated after they had been taken out of service. The findings were subsequently compared to the initial health index estimates for the transformers, which divided the transformers into six different condition categories. Of the investigated transformers, twenty were found to have been classified within the correct category, seven showed a better condition than estimated and three were in a poorer condition than expected. The main reasons for deviations between the expected condition and the actual condition were incorrect estimation of the solid insulation aging and incorrect classification of thermal faults. The conclusion of the study was, however, that the health index had prevented a significant number of transformer failures [24].

4 | Review of Models for Health Indexing

In this chapter, four different health index models from literature will be presented and reviewed. The aim of this review is to highlight how the models are constructed with respect to data requirements, calculation models, reliability of the output and how this is presented to the user. Additionally, the applicability of the models to Norwegian transformers will be evaluated. The conclusions made from this review will later serve as a basis for the development of a health index model customized to Norwegian needs. The selected models have been chosen because they appear to offer a good balance between thoroughness and simplicity. Furthermore, the methods have been proposed by renown companies within the transformer or energy sector. Two of the presented models are only described in a general manner and can therefore only be qualitatively evaluated, whereas the remaining two models contain a more detailed methodology where calculation methods are shown.

4.1 Model 1 - DNV KEMA

4.1.1 Description

This model, presented in Cigré paper "*Asset management decision support modeling, using a health index, for maintenance and replacement planning*", provides a methodology intended to simplify power transformer asset management decisions [21]. The method is described in a qualitative manner and can therefore not be reproduced. The paper does however give good insights on different elements and considerations that could or should be included in a health index for power transformers. The model works by estimating an expected remaining lifetime from a large set of input parameters. Depending on this remaining lifetime, assets are ranked and divided into four condition categories. Additionally, the uncertainty of these estimates is indicated.

4.1.2 Input

Both failure statistics, utilization data and condition data are used as input in the model. The model does also have a special methodology to handle missing data where this is encountered, as will be explained later. Since the main purpose of the model is to rank assets by replacement need, the model needs to establish the time frames in which replacement and maintenance must be conducted. The user is therefore asked to submit a *reference period* and a *critical time*. The reference period is the time horizon in which asset analysis is performed and is typically set from ten to fifteen years. The critical time is the standard time required for a complete replacement to take place and is typically set between one and five years. Based on these times, four condition categories are established:

- Good condition
- Additional maintenance required within reference period
- Replacement expected within reference period
- Immediate replacement required

4.1.3 Assessment Method

Calculation of remaining life is carried out by three separate function blocks named assessment functions. These functions use different input data to estimate the remaining life of an asset and are eventually combined to form a reliable and conservative output estimate. The functions are named according to their input: Statistical function, degradation function and condition function.

Statistical Function

This function uses the failure statistic of an asset owner as a basis for estimating an expected remaining life of different groups of assets. Such groups can for instance be transformers with the the same rated voltage level or the same rater power. Together with expert knowledge, failure statistics is used to develop a probability density function for the specific asset groups as a function of age. The failure definition used in the paper is not explicitly stated, but appears to be the asset end of life. The density function is obtained through curve fitting of recorded failure data, whereas expert knowledge is used to handle the issue of inaccurate or missing information. In the paper, a normal distribution is usedto illustrate this principle. If probability density functions are developed for every group of assets, an initial expected lifetime for every asset group can be derived. However, this method will only show the expected lifetime for new assets. Since most of the assets under investigation will be far from new, and possibly even approaching their end of life, the initial remaining life can not be used directly. The calculation must therefore take into account the fact that an asset has survived up to its current age and that its probability density function thus is changed. As a consequence, the probability density function of assets in service will be conditional, and will thus have to be modified [21].

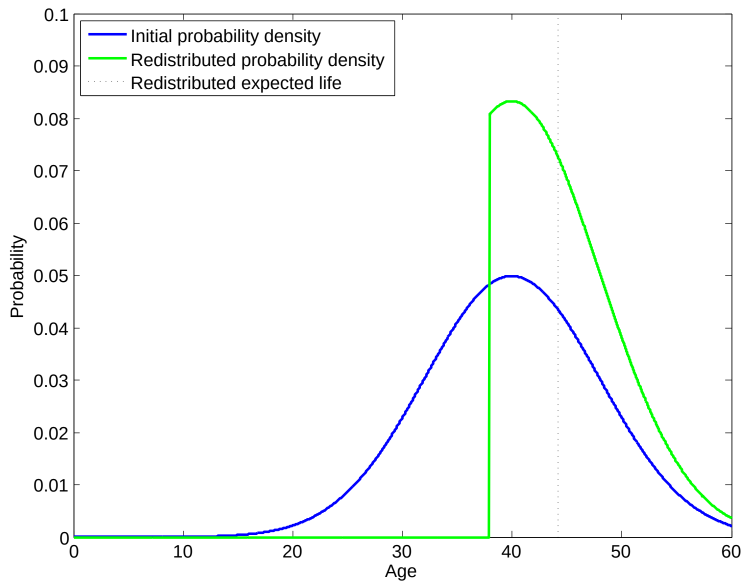

Figure 4.1: *Illustration of redistribution of the failure probability density function of a transformer. Initial probability density function shown in blue has an expectancy of 40 years and a standard deviation of 8 years. Green line shows the redistributed probability density function of a 38 year old asset, whereas the vertical dotted line shows the expected lifetime of the asset after redistribution.*

The modified (redistributed) probability density function represents the probability that an asset will fail at a certain point in time, given that it already has reached its current age. The probability density function is assumed to retain its original shape, but is scaled so that the area under the curve equals 1, as this is a requirement for all probability density functions. Scaling of the probability density function is performed according to Equation 4.1, where k is the scaling factor and $F(t)$ is the cumulative probability function of the initial distribution. A detailed derivation of this factor can be found in Appendix B.1.

$$k = \frac{1}{1 - F(t)} \tag{4.1}$$

To perform calculations on remaining life, the statistical function uses the concept of mean time to failure (MTTF), which is given by Equation 4.2. Here, x is the mean time to failure, t is the age and $f_r(t)$ is the redistributed probability density function. The remaining life is further found from Equation 4.3, where x is the mean time to failure, t is the current age of the asset and $F_r(t)$ is the redistributed cumulative density function.

$$x = \int_t^{\infty} f_r(t) \cdot t \, \mathrm{d}t \tag{4.2}$$

$$Remaining\ Life = \frac{x}{1 - F_r(t)} - t \tag{4.3}$$

The process of redistribution and calculation of remaining life is illustrated in Figure 4.1. Blue line shows the Normal distributed initial failure probability density function for a fictitious group of assets with an expected lifetime of 40 years and a standard deviation of 8 years. Green line shows the redistributed probability density function for a specific asset which is currently 38 years. The vertical dotted line indicates the expected lifetime of that particular asset after redistribution has been performed. The expected lifetime of this asset is then found to be 44,2 years, which means that the asset has an expected remaining life of 6,2 years. This way the initial failure probability density function which is valid only for a group of assets can be individualized.

Degradation Function

To assess the impact of known degradation mechanisms on transformer life, a so called degradation remaining life function is used. This function will combine utilization data and design parameters with models that are developed to describe various degradation mechanisms. A complete description of this function is not given in the paper, but from the text it is evident that the function assesses at least the two following mechanisms:

- Degradation of paper.
- Wear of OLTC.

The degradation of paper over time is a well known aging mechanism, which often acts as the limiting factor for transformer life. The degradation function used by DNV KEMA uses the IEC loading guide model for transformer lifetime modeling in its assessment [25]. This model calculates a per unit loss of life based on the winding paper quality and the winding hot-spot temperature [15]. If historical data on temperature exist, a remaining lifetime can be calculated for individual components. If such data do not exist, estimates can be made, but with a higher degree of uncertainty. Additional input that can increase the degree of certainty is measurement of furans in the transformer oil or direct measurements of DP.

Assessment of the OLTC degradation is performed based on the number of switching operations. If the tap changer is subject to a typical switching pattern, the wear over time can be estimated. The OLTC degradation function will further let the user know when the OLTC is nearing the specified number of operations and is due for maintenance. There is, however, no mention in the paper of how, or if, the tap changer degradation function impacts the remaining lifetime estimate of the degradation function.

Condition Function

To fine-tune and to further individualize the lifetime estimates obtained from the statistical assessment function, a so called condition function is used. This function takes information from inspections, diagnostic testing and maintenance as input and will this way provide the most certain and up to date results of the three assessment functions. The condition function works by adjusting the statistically expected remaining lifetime depending on the condition of an asset. If the data from condition assessment reveals that the asset is in a good state, the expected remaining lifetime is increased according to a set of predefined rules. Conversely, if condition assessment reveals a poor state, the expected remaining life is decreased. There is also a possibility that the condition data reveals an unacceptable condition for a transformer. In this case, a knock-out alert will be triggered to signal that the transformer should be replaced or maintained immediately. How large the change in expected remaining lifetime is depends on how good or bad the condition is found to be, and is handled according to a set of predefined rules. These are constructed so that data from inspections, maintenance and diagnostics can be compared against threshold values and graded accordingly. The paper provides an example of how a condition function might be constructed for a tap changer. This example can be seen in Appendix B.2.

Transfer Functions

A common problem for asset managers is the inaccuracy or lack of data. In the DNV KEMA health index model, this challenge is handled through so called transfer functions. Transfer functions are meant to fill gaps in information by using available information. The model presents two ways of doing this:

- Deduction: Assumptions are made based on knowledge of other parameters. The level of humidity in a transformer can for instance be deducted from knowledge on location, housing, cleaning practice, heating etc. Rough estimates of humidity levels can then be made and categorized as e.g. low, moderate, high. This way, humidity dependent quantities can be estimated. In theory, this can be carried out for any parameter, but a good understanding of correlations is needed.

- Statistical: From the assumption that similar assets will have similar properties, estimates can be made from statistical knowledge of assets where all required information is known. These assets are considered as statistical samples, and can hence be used to construct missing data where this is needed.

Such transfer of information might in many situations prove very helpful when assessing transformers that are nearing their end of life. Such assets are more likely to lack both historical and condition data than new ones, and transfer might therefore be the only possible way to estimate the remaining life. Obviously, such estimates come at the price of a reduced level of certainty.

4.1.4 Output

When all the assessment functions have been run, they are combined to give the remaining life estimate of the model. As shown in Figure 4.2, this is performed by running the degradation function in parallel with the statistical and condition functions. The final remaining life estimate of the model is then chosen as the lowest of the two estimates given by the paralleled branches.

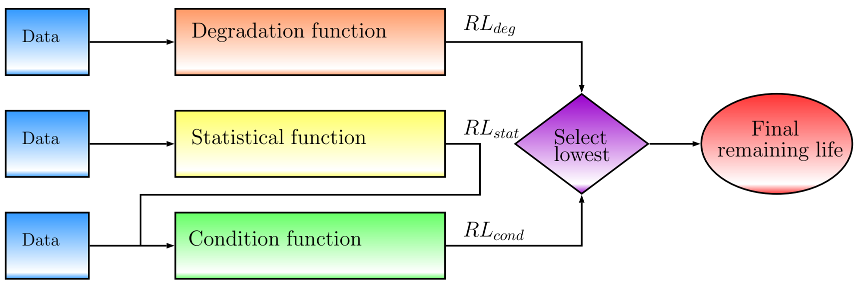

Figure 4.2: *Schematic of how the assessment functions are combined to give a final remaining life estimate.*

4.1.5 Confidence

For a remaining lifetime estimate to be truly helpful to an asset manager, the estimate certainty has to be known. While a high degree of certainty can assure the asset manager that the output is reliable, a low degree of certainty might promote collection of the data required to reach a higher level of confidence. A sensitivity analysis is therefore performed by using Monte Carlo simulations. In this process, the input parameters are fed to the model as probability density functions. The model is further run 1000 or 10000 times to obtain an output distribution. The mean of the output distribution will then represent the final remaining life estimate, while the standard deviation of the distribution will signal the uncertainty of the estimate. In the function output, the remaining life is indicated by a color code from green to red. As mentioned earlier, the asset is placed in one of four condition categories depending on the reference period and critical time.

4.2 Model 2 - Hydro-Québec

4.2.1 Description

In Cigré papers "*Use of Health Index and Reliability Data for Transformer Condition Assessment and Fleet Ranking*" and "*Strategies for Managing an Aging Transformer fleet*", asset management methods and strategies used by Hydro-Québec, Canada, are presented [22, 26]. These papers explain, in a general manner, how entire transformer fleets are assessed and ranked through the use of statistics and a health index model. The aim of the procedure is to simplify the work of asset managers. The output of the method will let asset managers know which assets represent the highest risk so that maintenance and reinvestment decisions are more well-informed and easier to make. To link statistical aspects and the health indexing, the concept of apparent age is introduced. This concept aids the asset comparison by calculating an equivalent age for assets based on their condition. This can be used to estimate individualized failure probabilities and to position assets in a risk matrix from which maintenance and reinvestment decisions are made.

4.2.2 Input

The data used for transformer assessment by this model are of both a statistical and diagnostic nature. The statistical material used originates from service records for Hydro-Quebec transformers over several years. For the health index calculation, Hydro-Québec has chosen to include only those condition data that are available for more than 75% of the assets in their transformer fleet. As a consequence, the following condition data, or indicators, have been selected to serve as input for the health index:

- **Failure rate of similar transformers.** Transformers are divided into families based on factors such as manufacturer, specifications, age, etc. Families with a high failure rate can further be identified and ranked as poorer than those families with low failure rates.

- **Solid insulation aging.** The degree of paper aging is estimated from markers such as methanol, furans and the content of dissolved gases in the transformer oil.

- **Dissolved gas analysis.** An index is calculated based on the gas values found in the most recent DGA sample. Each type of gas is weighted in the final calculation and consideration is also taken to trending over time.

- **Tap changer condition.** Tap changer is ranked based on model reliability and maintenance data.

- **Bushing condition.** Bushings are ranked based on model reliability and maintenance data.

- **Moisture content in oil.** Water in oil is measured so that the water content in the paper insulation might be estimated.
- **Oil tests.** An index is derived from the qualities shown by the oil in the most recent oil sample analysis. The index is comprised of the quantities acidity, interfacial tension, dielectric strength and power factor.
- **Accessories reliability.** An indicator which reflects the need for maintenance on the auxiliary equipment of the transformer. The score is derived from the performed number of repairs related to the transformer accessories.
- **Oil leaks.** This indicator is derived from the performed number of minor repairs related to oil leaks.

4.2.3 Assessment Methods

Statistical Estimates

To investigate how transformer survivability and failure rates are affected by an increasing asset age, statistical material is investigated through the non-parametric Kaplan-Meier product limit estimator [22]. A non-parametric estimator is used to avoid any unjustified assumptions or biases regarding the shape of the failure probability distribution of a transformer. The Kaplan-Meier estimator is further chosen because data in survival analysis often will be right censored, i.e. they are incomplete because several of the objects under investigation are still in service and have not yet failed. The ability to deal with this type of censoring is one of the properties that makes the Kaplan-Meier estimator suited for such analysis [27]. The Kaplan-Meier estimator can be written as shown in Equation 4.4. Here, j is the index of the interval following a failure at time t_j, where $t_j \leq t$. For each interval there are n_j remaining units that are functioning and in observation. $\hat{S}(t)$ is the survivor estimator, showing the survival rate at time t.

$$\hat{S}(t) = \prod_{j \in J_t} \frac{n_j - 1}{n_j} \tag{4.4}$$

By using this estimator, curves showing the actual failure rate and survivability as functions of age can be produced. These curves can further be used for comparison with parametric distributions for which the statistical properties are known. By using curve fitting, a Weibull distribution is found to be consistent with the Kaplan-Meier estimator and is hence regarded as the most appropriate distribution for describing the survivability of Hydro-Québec's transformers. The parameters for this Weibull distribution are, however, not given.

Health Indexing

As part of the asset management strategy, Hydro-Québec uses a health index module where assets are scored depending on their condition. The basis for calculation of this score is asset specific condition data, as listed in section 4.2.2. Depending on the condition of the components under investigation, the indicators are given a score of 0, 1 or 2. The indicators are also weighted differently from each other in the final calculation to reflect their relative importance. Generally, indicators whose condition can not be improved by maintenance are weighted heavier than those that can. These weights have been chosen by transformer experts, but are not given in the paper. Nor are the procedures for selecting or calculating the score of each indicator provided, so reproduction of the method is not possible. A schematic of the health index calculation can be seen in Figure 4.3.

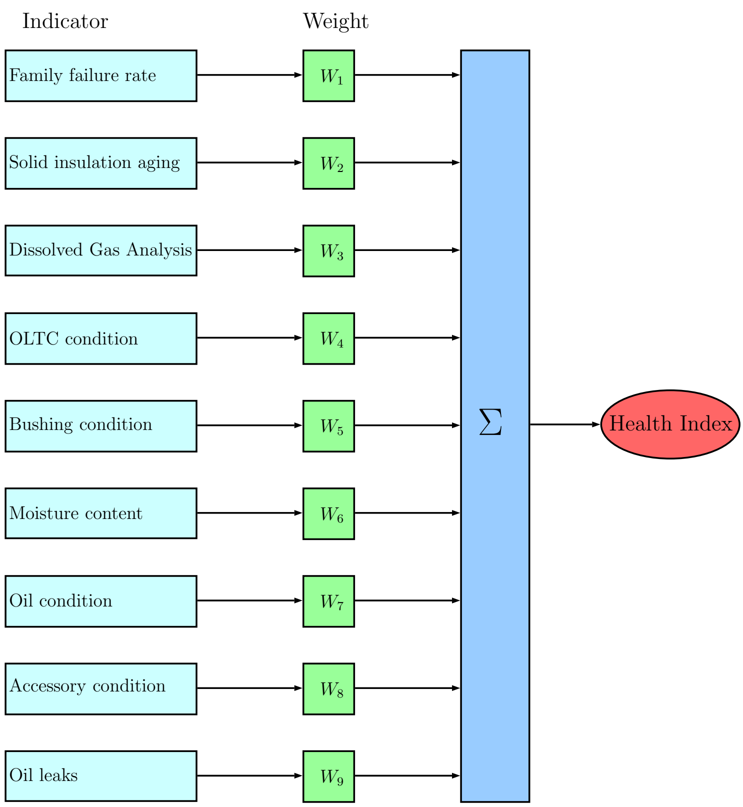

Figure 4.3: *Schematic of the Hydro-Québec health index module.*

4.2.4 Output

The output of the Health index model is given as a score from 0 to 50, where 0 represents the best possible condition. When assessing transformer fleets, this score can for each transformer be plotted in a diagram with asset age along the x-axis and health index score along the y-axis. When a large group of transformers are assessed, a regression line can be drawn to indicate the average fleet condition to age relationship. Assuming that new units are in a perfect condition forces this line to pass through the origin. Units above this line are consequently in a worse condition than the fleet average, whereas units under the line are in a better condition. An illustration of the output is given in Figure 4.4. It is emphasized that this is just an illustration and that the health index values are fictitious. A regression line has been added to indicate the average condition of the fleet.

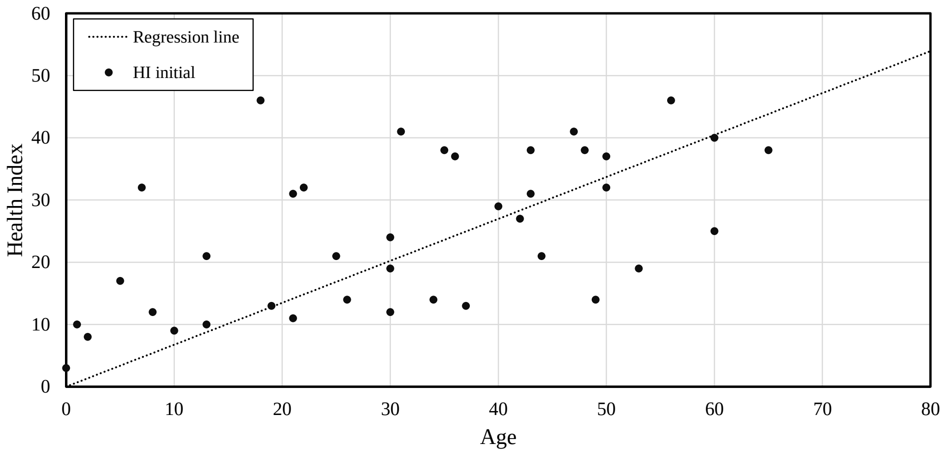

Figure 4.4: *Illustration of the output from the Hydro-Québec health index module. A regression line which passes through the origin is drawn to indicate the average condition of the fleet.*

Apparent Age and Risk Assessment

Because it is challenging, or even impossible, to directly relate a health index score to a failure probability, the authors of the paper have introduced the concept of apparent age [22, 26]. The principle is that all assets are assigned an apparent age which is determined from the regression line in the output. The apparent age is the age which gives the regression line the same health index score as the asset in question. The regression line can be written as $h(x) = a \cdot x + b$, where x is the asset age, a the slope of the curve and b is equal to 0 since the line passes through the origin. From this it can be seen that an asset i with health index score h_i will receive an apparent age x_{app} according to Equation 4.5:

$$x_{app} = \frac{h_i}{a} \tag{4.5}$$

This method alone can sometimes give extreme deviations between actual age and the calculated apparent age. To avoid this, limits of maximum 15 years above or a minimum of 10 years below the actual age are set. These limits can be represented by lines that lie parallel to the regression line, but are shifted +15 or -10 years along the x-axis. Before apparent age calculations are performed, all health index values are shrunk vertically between these limits. The upper and lower extreme values will then be located on their respective limit line, while the remaining values will be scaled between the regression line and the limit lines, as shown in Figure 4.5.

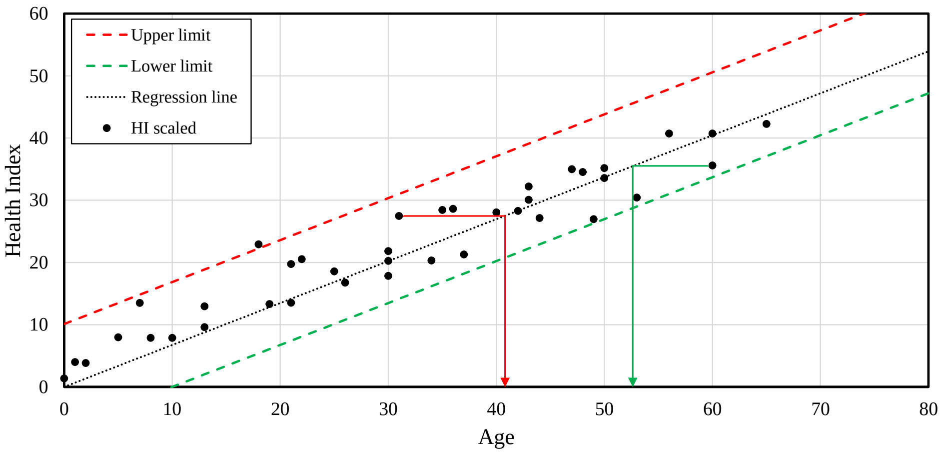

Figure 4.5: *Illustration of how health index scores are shrunk vertically between upper and lower limit before apparent age is calculated. Apparent age calculation is shown by red and blue arrows.*

Once the apparent age is found, it can be used in combination with the failure rates obtained from the statistical mean aging model to estimate the failure probability of an asset. Assets can then be positioned along the probability axis of a risk matrix.

4.2.5 Confidence

The uncertainty associated with each indicator used in the health index depends on the data type, as well as the data age. Additionally, if data is missing for an indicator the condition will be assumed good. The uncertainty is, however, set to a maximum to promote collection of the missing data. The statistical distribution for the probability of failure will also be associated with a uncertainty which will affect the final evaluation. Although the paper gives the mentioned guidelines for uncertainty management, there is no representation of the uncertainty in the health index output. How the uncertainty further affects the result of the model is therefore unknown.

4.3 Model 3 - Kinetrics

4.3.1 Description

This method, developed by Kinectrics Inc., Canada, is presented in [28,29] and proposes a scheme for evaluating the overall condition of a transformer. The method uses service and diagnostic data as input and assigns scores to the different subsystems of the transformer through customized evaluation algorithms. The method differs from the previous two since it does not contain any statistical elements, but only focuses on condition data. It does also provide a more detailed explanation of how the assessment is conducted. Several of the condition data that are being used are normally not collected in Norway, but these might be seen as measurements that in the future potentially should be included in a Norwegian health index.

4.3.2 Input

The model does only take service and condition data as input in the evaluation of a transformer. The required data, as well as a schematic of how these are processed, can be seen in Figure 4.6.

4.3.3 Assessment Method

The following will explain how the different input parameters are converted to scores in the health index model. The modules for assessment of each condition parameter will be presented one at the time.

Dissolved Gas Analysis

The contents of gas in the oil is compared against the grading values in Table C.1 and each gas is given a score. The scoring values are based on recommendations by international standard bureaus such as Dorenburg, IEC, IEEE and Bureau of Reclamation. From the concentration of these gases, a total Dissolved Gas Analysis Factor (DGAF) is calculated by using Equation 4.6.

$$DGAF = \frac{\sum_{i=1}^{7} S_i \cdot W_i}{\sum_{i=1}^{7} W_i} \tag{4.6}$$

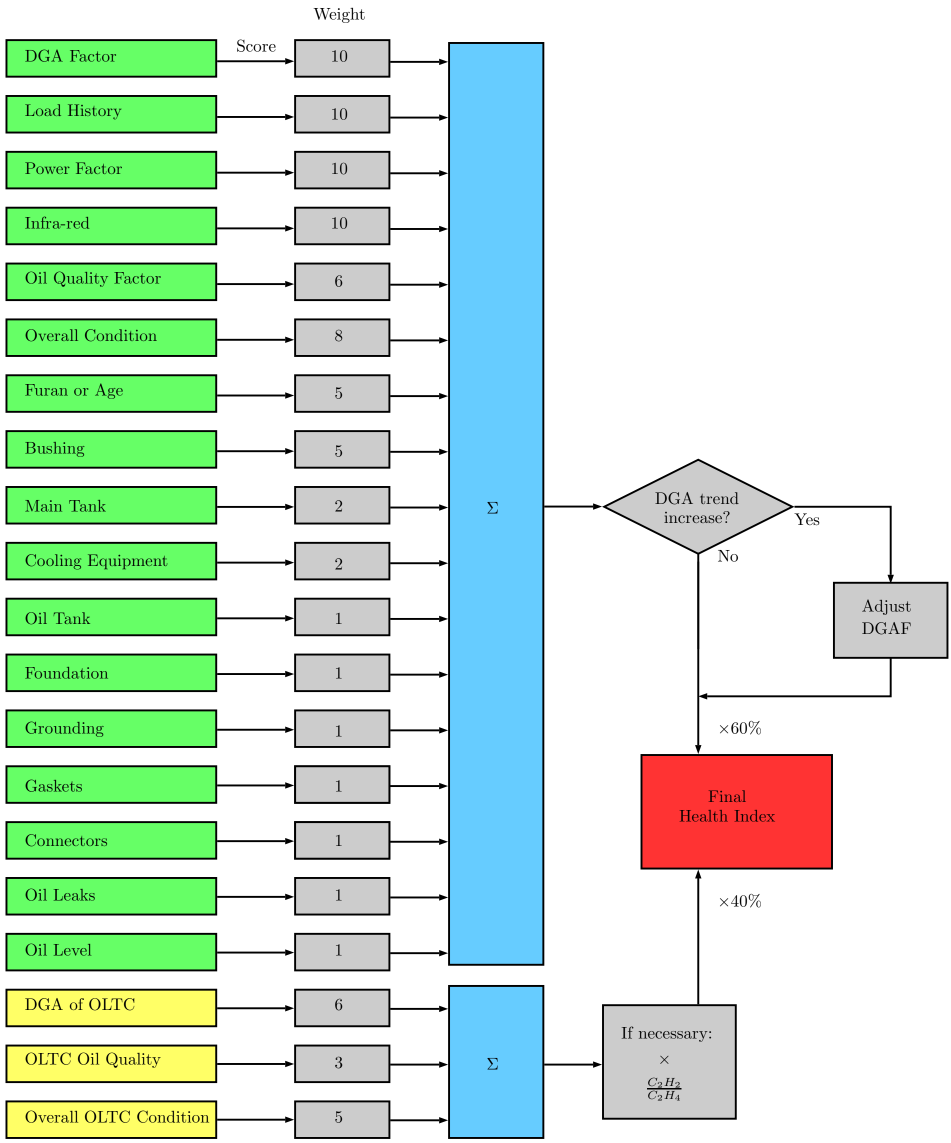

Figure 4.6: *Flowchart showing the Health Index required input data and calculation procedure.*

In this equation, S_i is the score of each gas and W_i is the weight factor of each gas. From the DGAF a rating is assigned according to Table 4.1.

It is emphasized that the method is not meant as a diagnostic tool, but as a tool to evaluate the long term quality of the oil. The rate of gas production is also of importance, and a reduction of the final health index score is recommended if three consecutive gas samples show a 30% increase or more, or if a 20% increase or more is found for five consecutive samples. This is shown in Figure 4.6.

Table 4.1: *Transformer rating based on DGA Factor.*

Rating Code	**Condition**	**Description**
A	Good	DGAF$\leq$1.2
B	Acceptable	1.2$\leq$DGAF$<$1.5
C	Need Caution	1.5$\leq$DGAF$<$2
D	Poor	2$\leq$DGAF$<$3
E	Very poor	DGAF$\geq$ 3

Oil Quality

Similarly to how the DGA Factor was determined, an Oil Quality Factor (OQF) is obtained through scoring of the most important properties of the oil. These properties can be seen in Table C.2. The OQF is calculated through Equation 4.7, where S_i is the score of the different properties and W_i is the corresponding weight according to Table C.2. The final oil quality rating is obtained from in a similar way as for the DGAF, but scoring values are not provided. It should be noted that the dissipation factor and breakdown voltage limits used in this model are based on other standards of measurements than those used in Norway. Dielectric dissipation factor is referred to 25°C (IEEE standard), while laboratories in Norway refer this measurement to 90°C (IEC standard). Additionally, the dielectric breakdown voltage limits used in this method are measured using an electrode gap of 2 mm according to IEEE C57.106-2006. In Norway, this value is measured according to IEC 60156 with a gap of 2,5 mm. It should also be noted that the values presented in Table C.2 are intended for use on service-aged oil.

$$OQF = \frac{\sum_{i=1}^{6} S_i \cdot W_i}{\sum_{i=1}^{6} W_i} \tag{4.7}$$

Furfural

Furan analysis has been used as a method for estimating the DP of paper insulation made from kraft paper [13]. Based on the concentration of the aging indicator 2FAL in the transformer oil, a score is given according to Table 4.2. It is pointed out in [28] that research is still being done on this field and that the interpretation of results might change as a consequence of this. As an alternative to where no furan analysis is available, age is proposed as an indicator of the condition of the winding insulation. It is however important to note that Table 4.2 does not imply any direct relationship between age and content of furanic compounds and that an age criterion should only be used if no other data is available.

Table 4.2: *Furfural concentration test rating or age rating where test results are not available.*

Rating Code	Furaldehyde [ppm]	Age [years]
A	0-0.1	Less than 20
B	0.1-0.25	20-40
C	0.25-0.5	40-60
D	0.5-1.0	≥60
E	≥1.0	-

Power Factor

In this health index model, the highest measured value for the power factor pf_{max} is used to determine a score [28]. The scores are proposed as shown in Table 4.3.

Table 4.3: *Power factor rating.*

Rating Code	Maximum Power factor [%]
A	$pf_{max} < 0.5$
B	$0.5 \leq pf_{max} < 0.7$
C	$0.7 \leq pf_{max} < 1.0$
D	$1.0 \leq pf_{max} < 2.0$
E	$pf_{max} \geq 2.0$

Tap Changer

In [28,29] a method for ranking the condition of the tap changer is developed based on the experience of Kinectrics Inc. and literature on transformer gases. The method is developed to differentiate between resistive, reactive and vacuum type tap changers. However, since most European tap changers are of resistor type [3], only the threshold values related to these will be shown. The ranking method is based on the DGA results of the gases CH_4, C_2H_6, C_2H_4 and C_2H_2 in the tap changer oil. Score is obtained in a similar way to the DGAF, based on the threshold values given in Table 4.4. Additionally, if the ratio $C_2H_2/C_2H_4 \geq 1$, the weight of the OLTC condition in the final health index calculation is multiplied by the inverse of this ratio, i.e. C_2H_4/C_2H_2. This can be seen in Figure 4.6. Furthermore, oil quality is used as another parameter in the health index calculation, but how this parameter is calculated is not shown. In addition, a condition rating called "Tap changer overall condition" is introduced, but not explained.

Table 4.4: *Scoring and weight factors for resistive type tap changer gas levels [PPM].*

Gas	**Score (S_i)**				W_i
	1	2	3	4	
CH_4	≤50	50-150	150-250	≥250	3
C_2H_6	≤30	30-50	50-100	≥100	3
C_2H_4	≤100	100-200	200-500	≥500	5
C_2H_2	≤10	10-20	20-25	≥25	3

Load History

As discussed in Chapter 2.2, temperature, and thus load, plays a significant role when it comes to the condition of the solid insulation of the windings. In the Kinectrics health index model the load history is represented by the load factor (LF), which takes into account the load peak S_i of every month. The ratio between the monthly load peak and the rated loading S_B of the transformer is then calculated for every month. The number of instances where the monthly peak load falls into one of the categories listed below is then recorded and Equation 4.8 is used to calculate a load factor for the transformer. The rating of the load history based on the load factor is obtained from Table 4.5. From this procedure, transformers that are heavily loaded will receive a low LF while lightly loaded transformers will receive a high load factor.

- N_0: Number of instances where $S_i/S_B < 0.6$
- N_1: Number of instances where $0.6 < S_i/S_B < 1$
- N_2: Number of instances where $1 < S_i/S_B < 1.3$
- N_3: Number of instances where $1.3 < S_i/S_B < 1.5$
- N_4: Number of instances where $1.5 < S_i/S_B$

$$LF = \frac{\sum_{i=0}^{4} (4 - i) \cdot N_i}{\sum_{i=0}^{4} N_i} \tag{4.8}$$

Table 4.5: *Load factor rating.*

Rating Code	Load factor
A	LF $\geq$ 3.5
B	2.5 $\leq$ LF $<$ 3.5
C	1.5 $\leq$ LF $<$ 2.5
D	0.5 $\leq$ LF $<$ 1.5
E	LF $\leq$ 0.5

Maintenance History

The impact of the maintenance history of an asset is evaluated based on the number of corrective maintenance work orders during the last five years. Such work orders for the different components on the transformer are counted and compared to the scoring criteria in Table 4.6.

Table 4.6: *Individual component rating criteria based on number of corrective maintenance work orders.*

Rating Code	Bushings	Oil leaks	Oil level	Infra-red	Cooling	Main tank	Oil tank	Foundation	Grounding	Gaskets	Connectors
A	0	0-2	0	0	0-3	0	0	0	0	0	0
B	1-2	3-4	1-2	1	4-6	1-2	1-2	1-2	1-2	1-2	1-2
C	3-4	5-6	3-4	2-3	7-10	3-4	3-4	3-4	3	3-4	3
D	5-7	7-8	5-6	4-5	11-15	5	5-6	5	4-6	5-6	4
E	>7	>8	>6	>5	>15	>5	>6	>5	>6	>6	>4

In addition to the number of corrective work orders on the individual components, a separate score is calculated to capture negative trends in an asset's need for maintenance. From the rate of increase of corrective maintenance work orders during the last five years, a separate condition rating called *Overall condition* is obtained. This rating is obtained from the criteria listed in Table 4.7, where an OR-logic between criterion 1 and 2 is used.

Table 4.7: *Overall condition based on the trend in total corrective maintenance work orders. A rating applies as long as one out of the two criteria is satisfied (Criterion 1 or Criterion 2).*

Rating Code	Criterion 1	Criterion 2
A	< 3 WOs last 2 years	< 10% increase last 5 years
B	> 3 WOs last 2 years AND > 10% increase last 5 years	> 5 WOs last 2 years
C	> 5 WOs last 2 years AND > 30% increase last 5 years	> 10 WOs last 2 years
D	> 10 WOs last 2 years AND > 50% increase last 5 years	> 15 WOs last 2 years
E	> 15 WOs last 2 years AND > 80% increase last 5 years	> 20 WOs last 2 years

4.3.4 Output

The health index score is calculated by weighting the several condition ratings relative to their importance for the general condition of the transformer. Next, for each component the actual score is divided by the maximum possible score and then multiplied by 100. This way the sum of scores will be normalized to a maximum score of 100, which indicates perfect condition. The procedure can be described through Equation 4.9, and the weights of the different condition ratings proposed in [28, 29] are shown in Table C.3. For calculation purposes each condition rating (A,B,C,D,E) is converted to a health index factor between 4 and 0, respectively. In Equation 4.9, the two different fractions represent the condition of the transformer and the condition of the tap changer, respectively. The factors 60% and 40% are used to reflect the proportion of tap changer failures relative to other types of failures as indicated by the major survey on transformer failures conducted by Cigre in 1983 [30]. This is a factor that can easily be changed for utilities that experience a different failure distribution for their tap changers. Based on the health index, a description of the general condition as well as an estimate of the expected remaining lifetime of the transformer is shown in Table 4.8. An overview of the entire calculation procedure is shown in Figure 4.6.

$$HI = 60\% \frac{\sum_{j=1}^{17} K_j \cdot HIF_j}{\sum_{j=1}^{17} 4K_j} + 40\% \frac{\sum_{j=18}^{20} K_j \cdot HIF_j}{\sum_{j=18}^{20} 4K_j} \tag{4.9}$$

Table 4.8: *Health index scoring for the Kinectrics model.*

Health Index	Condition	Description	Approximate Expected Lifetime
85-100	Very Good	Some aging or minor deterioration of a limited number of components	More than 15 years
70-85	Good	Significant deterioration of some components	More than 10 years
50-70	Fair	Widespread significant deterioration or serious deterioration of specific components	Up to 10 years
30-50	Poor	Widespread serious deterioration	Less than 3 years
0-30	Very poor	Extensive serious deterioration	At End-of-Life

4.4 Model 4 - EDF method

4.4.1 Description

The following method is a modified version of a model proposed by Électricité de France (EDF) for evaluating both the technical condition and the strategic importance of a transformer [31]. The modified model is developed by the Norwegian TSO, Statnett SF, and aims to assess the same elements as the EDF model. The EDF method was however developed for use on generator step up (GSU) transformers in particular. Since Statnett SF only owns transmission transformers and no GSUs, the method has been modified so that it also might be used to assess transmission power transformers.

The model results in a final score, representing the criticality of an asset. The criticality is a term used to describe the risk associated with an asset when both the probability of failure and the potential consequences of a failure are considered. These two factors are assessed through the indicators named General Technical Condition (GTC) and General Strategic Importance (GSI), respectively. Both these indicators are found from several criteria that are weighted and summed up to a score between 0 and 16. A GTC of 0 represents a transformer with a very low probability of failure, while a GSI of 0 represents an asset where a potential failure will cause a minimum of consequences. It is important to note that the model is under development and that several of the indicators referred to in this chapter are still subject to discussion. What is presented in the following does, however, give a good description of the main principles of the approach [32].

Because the focus of this thesis is on condition assessment, only the parts of the model related to this will be discussed. Aspects concerning cost of maintenance and the evaluation of strategic importance will therefore not be covered. The following sections will give a further description of the GTC indicator and the criteria of which it is comprised. These criteria are: Transformer health (C_1), Technological risk (C_2), The weight of the past (C_3) and Operating conditions (C_4).

4.4.2 Input

Because the assessment criteria of this model evaluate entirely different aspects of the transformer, the required input to the model include both condition data, observations and service experience. The main parameters used in the assessment by this model are:

- Inspection observations
- DGA
- Oil sample analysis
- Paper samples

- Component reliability experience
- Age
- Operating conditions

4.4.3 Assessment Method

Transformer Health

This criterion is developed to assess both the external and internal health of the transformer. The external health is evaluated based on the maintenance history and inspection of the auxiliary equipment of the transformer. Depending on the observed condition and the statistical reliability of these components, an evaluation is made. Because regular measurements of auxiliary equipment are usually not conducted, the available information might vary considerably from asset to asset. Evaluation of the external health criterion might therefore have to be an overall evaluation performed by an asset manager, rather than a comparison of measured data against threshold values.

The internal health criterion is more comprehensive than the external, but does also hold more possibilities for data collection. DGA and oil sample analysis is conducted regularly and will hence be the most important sources of information for this criterion. Additionally, other indicators such as DP measurements and furan analysis might be used to further conclude on the internal health of the asset. The main condition indicators used for this criterion are however DGA and oil sample analysis. The five condition indicators which are identified as particularly important to the internal health of the transformer are excessive heating of joints or leads, discharges within the transformer, aging of the paper insulation, the moisture content of the insulation and aging of the oil [32].

Excessive heating might be identified from either an increase in the dissolved gas in the oil or from the set of gas ratios proposed by IEC 60599, as described in Chapter 2.5. These ratios might also be used to identify discharges within the transformer. The criteria for scoring the transformer based on these considerations are given in Table 4.9.

Paper degradation is in this model also assessed through dissolved gas analysis. Increased gas levels of CO and CO_2 are indications of aging of paper or oil as these gases are formed as by-products when paper or oil is degraded. Further indication might be given by the gas ratios CO_2/CO and O_2/N_2. If $CO_2/CO < 3$, this is seen as an indicator of paper aging. The ratio $O_2/N_2 < 0,3$ might indicate an underbalance of oxygen caused by oxidation of paper or oil [17].

Moisture content of the transformer insulation is in the Statnett model assessed depending on the voltage level of the transformer in question. A distinction is made between units above and below 132 kV. The different scoring criteria based

Table 4.9: *Scoring criteria as described by Statnett SF. As long as one criterion or more is fulfilled, the associated score is assigned to the transformer internal health [32].*

Score	**Condition**	**Criteria**
10	Very poor	-High energy discharge faults (D2 fault) -High temperature thermal faults (T3 fault) -Critical paper degradation (DP<300) -Moisture: >2,5 % for U_N>132 kV, >3,5 % for $U_N \leq$132 kV -Unacceptable values for oil degradation
6	Questionable	-Medium temperature thermal faults (T2 fault) -Excessive paper degradation (DP ca. 350) -Moisture: >2,0 % for U_N>132 kV, >3,0 % for $U_N \leq$132 kV -Poor values for oil degradation (OI<200)
2	Acceptable	-Low energy discharge faults (D1 or PD fault) -Low temperature thermal faults (T1) -Aged paper (DP>400) -Moisture (M): 1,5 %<M<2 % for U_N>132 kV, 2,0 % <M<2,5 % for $U_N \leq$132 kV -Acceptable values for oil degradation (OI>400)
0	Good	No known defects

on moisture level are shown in Table 4.9.

Aging of the transformer oil is assessed through the so-called oxidation index. When the oil ages, its interfacial surface tension will be reduced and its acidity will increase because acids are formed as by-products. The ratio between the interfacial surface tension and the acidity is often referred to as the oxidation index and is normally in the range of 400-1000 for oil of good quality [5]. The model proposed by Statnett uses the oxidation index to score transformers as shown in Table 4.9.

Technological Risk

Because a large proportion of power transformers reach ages of up to 30 and 40 years, a typical fleet will include assets from different technological eras. Different technologies might over time show different performance when it comes to reli-

Table 4.10: *Scoring of assets based on their expected technological risk.*

Score	Criterion
10	Technology known to pose a very high risk
6	Technology known to pose a high risk
2	Technology where particular elements are known to pose increased risk
0	Technology which does not pose any increased risk

Table 4.11: *Scoring of assets based on their age.*

Score	Age
10	$Age \geq 50$
6	$50 > Age \geq 35$
2	$35 > Age \geq 25$
0	$25 > Age$

ability and maintainability. Additionally, fleets will often consist of assets from different manufacturers. These might use both different technology and technical solutions in the manufacturing process. If a specific technology or manufacturer is found to systematically perform below the fleet average, this should be reflected in the condition evaluation of a transformer. To be able to establish such a criterion, both failure statistics and the experience and knowledge of asset managers is essential. Scoring of this criterion is proposed as shown in Table 4.10.

The Weight of the Past

This criterion uses the age of an asset to score it according to Table 4.11. It is important to note that this criterion only assesses the age of an asset, regardless of its technical condition. Although age is expected to be a poor indicator of actual condition, the criterion is included based on the assumption that older units have a higher failure frequency than newer ones [32].

Operating Conditions

How a transformer is operated greatly impacts its deterioration rate. As described in Chapter 2, both high load and frequent load variations might be harmful for the transformer. To assess the loading of the transformer, a scoring system based on the transformer utilization time is suggested as an indicator. The utilization time is defined according to Equation 4.10. Here, E is the total energy transferred through the transformer over a specified period of time t and S_n is the rated capacity of the transformer. This will give the number of hours that the transformer would have

Table 4.12: *Scoring of assets based on their utilization time.*

Score	**Utilization time [h]**
10	$UT \geq CCCC$
6	$CCCC > UT \geq BBBB$
2	$BBBB > UT \geq AAAA$
0	$AAAA > UT$

to be fully loaded in order to transfer the same amount of energy. If the utilization time is high, this indicates that the transformer is heavily loaded. The model does however not provide any recommendations as to which threshold values should be used for scoring this criterion. Threshold values should be able to differentiate between what is regarded as normal for a system and what is not. Hence, setting these threshold values is a task for experts who know the system under investigation well. Once these threshold values are established, Table 4.12 might be used to score the asset.

$$UT = \frac{E}{S_n} \frac{[MWh]}{[MW]} \tag{4.10}$$

4.4.4 Output

When all the separate criteria have been calculated or found, they are weighted to reflect their relative importance to the transformer condition. In [32], the GTC is expressed by Equation 4.11:

$$GTC = \frac{1}{10} \cdot (8 \cdot C_1 + 2 \cdot C_2 + 3 \cdot C_3 + 3 \cdot C_4) \tag{4.11}$$

The coefficient $\frac{1}{10}$ is used since each of the criteria are assigned scores between 0 and 10. By using this scaling factor, the final GTC score is kept between 0 and 16. From the GTC, the transformer might be positioned along the probability axis of a risk matrix.

4.5 Model Comparison

In this section, the models presented in the previous sections of this chapter will be reviewed with respect to aspects such as their ability to give a good evaluation of asset condition, the reliability of the output and their requirements to input data. As a first step, the interpretation of the function of a health index will be discussed. This is performed to limit the further discussion to subjects that are relevant for condition assessment of Norwegian power transformers.

The ability to give a reasonable and as good as possible evaluation of asset condition is naturally one of the most important qualities of a health index. This is a comprehensive requirement of which the meaning might be widely discussed. However, as a baseline for discussion, the objectives listed in Chapter 3.1 will be used. The main objective of the health index with respect to condition assessment is therefore to indicate the suitability of the transformer for continued service and to be representative of its overall health. From this formulation it might be understood that the health index is not expected to come up with a condition evaluation considered to be correct, but rather representative. This difference is important because the output from a composite health index will not be accurate enough to single handedly determine the condition of a transformer. Power transformers are too complex for one score alone to assess the complete set of components, sub-components and the stresses affecting them. Maintenance and replacement decisions should therefore rely not only on a health index score, but also on more thorough investigations. These investigations might, however, be performed as a consequence of the health index score. It is therefore pointed out that a health index can be a strong indicator, but not an absolute measure of condition.

In order to limit the comprehensiveness of this section to a useful minimum, the models will not be reviewed in their entirety. Instead, a general discussion around the critical aspects *input*, *assessment methods* and *output* will be given. This way, it may be highlighted which solutions that can be adopted into a Norwegian health index model and which should be avoided. Evaluating the functionality and efficiency of the models is however avoided, as this would require testing of their reliability over time. Additionally, since many of the important calculation procedures are unknown, reproduction of the results is not possible.

4.5.1 Data Availability

The entire concept of health indexing is dependent on the availability of condition data and it is thus reasonable to discuss the data requirements of the models in question. As previously stated, it is important that the required data is available for a majority of the assets in a fleet for them to be compared on the same grounds and for the model to be useful. On the other hand it is important that the input data contains information with strong relevance for the asset condition. The required input data of a model is for this reason one of the most important criteria when it comes to evaluating whether it is suited for use in Norway or not. Common practice among Norwegian utilities when it comes to collection of condition data can be seen by Table 3.1. From this table, DGA, oil sample analysis, load and/or temperature history and reliability experience seem to comprise the most relevant inputs in a Norwegian health index. These input data are used by all of the reviewed models.

Input data that, based on the data collection practices of Norwegian utilities, are difficult to incorporate in a Norwegian health index are special measurements such as power factor, core to ground resistance, turns ratio measurements, and DGA and oil sample analysis of tap changer oils. In addition, statistical data seem hard to include because of the lack of a Norwegian failure statistic for power transformers.

4.5.2 Assessment Methods

For a health index to be able to indicate the condition of an asset in a good way, there are particularly two elements which need to be given special attention: How scores are calculated from service data and how these scores further are weighted relative to each other. These elements are decisive for how well a health index is able to evaluate the health of an asset. In the following, the assessment methods used to process this data in the the presented models will be discussed.

Dissolved Gas Analysis

DGA is not an indicator of the condition of one any particular component within the transformer, but rather of the general internal condition. In addition, DGA might be helpful for detecting specific defects, as explained in Chapter 2. The ability of a health index DGA module to evaluate the state of the transformer is, however, dependent on the amount of information utilized by the module. A single DGA sample provides at least two important pieces of information: The current gas levels within the transformer and the presence or absence of internal faults. Additionally, if DGA samples have been collected over time, the trend of gassing comprises a third piece of information. Ideally, assessment of the DGA values of a transformer should include criteria related to each of these three pieces of information.

The only model that reveals how scoring based on both gas values and trending is performed is the one suggested by Kinectrics. The suggested scoring scheme is simple, elegant and in accordance with IEC 60599. The same can be said for the evaluation of gas trending. The scheme is also flexible in the case that a company experiences different typical values than those suggested by Kinectrics or the IEC. This solution does therefore appear suitable for use in a Norwegian health index. Use of gas ratios in the assessment is, however, only performed by the EDF/Statnett model. Kinectrics states that the DGA factor is designed to reflect the long term suitability of a transformer, rather than its short term reliability, and that assessment through gas ratios therefore is omitted. It is however known that Norwegian transformers are occasionally left in service for long periods even though low energy faults such as PD and T1 are present. For this reason it appears reasonable to include a gas ratio criterion in the DGA module, just as for the EDF/Statnett model.

Liquid Insulation Assessment

Of the presented models, the Kinectrics and EDF/Statnett models are the only that explain how the assessment of the liquid insulation system is performed. The approaches used by these two are very similar, except the fact that Kinectrics utilizes more of the measured values obtained from a standard oil sample analysis than the EDF/Statnett model. Because good knowledge about the interpretation of these values exists [3, 5], it must be considered an advantage to utilize as many as possible of these values. This will both increase the confidence of the evaluation and make sure that as many failure modes and aging mechanisms as possible are indicated by the health index.

Solid Insulation Assessment

Assessment of the solid insulation is performed by all of the presented models, but through quite different assessment models. As previously stated, measurement of furans and methanol are rarely conducted in Norway. Furans are also only reliable for use on transformers where the solid insulation is made from kraft paper. Because of this, these measurements are hardly appropriate as indicators of the solid insulation in a Norwegian health index model. They may, however, be used as a supplement to other indicators. This can not be said for the load factor proposed in the Kinectrics model. Kinectrics presents a simple and coarse way of scoring transformers based on their monthly peak load. The approach does only take the peak load of each month into account, and does thus make the score independent of how the transformer is otherwise loaded. A consequence of this is that transformers that are normally unequally loaded, but have the same load peaks during a month, receive the same score. Compared to alternative methods, this is not a suitable way of indicating the aging of a transformer in the long run.

The solid insulation assessment method considered to be best suited for use in a Norwegian health index, both with regard to input requirements and output reliability, is the IEC equations used by the DNV KEMA model. This method evaluates the solid insulation through the equations provided by IEC 60076-7. The method is considered to be suited for assessment of Norwegian power transformers because the required input data to a great extent are available, and because the output is believed to be an accurate indicator of the solid insulation condition. It should, however, be noted that the equations given by the IEC are linearizations of Equation 2.1, and that they do neither take moisture content nor oxidation into account. Measurement of DP from dedicated paper compartments within the transformer is a measurement technique that can be used as a supplement to or correction of the paper degradation models.

Reliability Assessment

Both DNV KEMA and Hydro-Québec use statistical assessment modules in their health indexes. These modules are quite similar and utilize the age of an asset as well as failure statistics for similar assets to calculate a remaining lifetime or a failure rate. This is an interesting approach which might be particularly useful for asset managers in charge of large transformer fleets. If statistics are systematically collected, these modules might provide a useful way of evaluating both the fleet as a whole and particular assets. In a Norwegian context, a statistical assessment might however prove difficult because no detailed national statistic on transformer failures exists. Developing such an assessment method would therefore have to be performed by each utility, as these are in a good position to create failure statistics for their own assets. Using statistics as input should nevertheless not be disregarded, as this is a very descriptive and easily understood way of describing the expected lifetime of a transformer. If proper failure statistics are developed, these methods could prove efficient modules of future health indexing tools.

A way to avoid the use of statistics, but still address the expected reliability of a transformer, might be to evaluate the historic maintenance need of assets. This can either be carried out based on the maintenance record of an asset, as performed by Kinectrics, or from knowledge of components that are particularly prone to failure. The latter sort of knowledge is, however, often accumulated over a long period of time and might be hard to quantify. The maintenance record of a transformer is, on the other hand, easily quantified and hence a more suitable choice for assessing the expected maintenance need of a transformer.

4.5.3 Output

When it comes to the output of the presented models, three different solutions are used. DNV KEMA calculates a remaining lifetime, Hydro-Québec calculates an expected failure rate and the remaining two calculate a score which, relatively to the top and bottom limits, describes the expected asset condition. These differences are important because they to a certain degree dictate how the user of the health index should interpret the output. For instance, giving output as a remaining lifetime has at least two practical implications:

- The responsibility of estimating a useful remaining lifetime is transferred from the asset manager to the model developers.
- Remaining lifetime estimates are made based on assumtions regarding the future operating conditions of a transformer.

By calculating a remaining lifetime, the model relieves the asset manager from the task of deciding when the useful technical lifetime of an asset is reached. However, since a transformer is such a complex system, no model will be able to predict its exact time of failure and this output must hence be associated with a substantial degree of uncertainty. The remaining life estimate from the DNV KEMA model should therefore be interpreted as an indication of the remaining life rather than the actual remaining life. Many asset managers will however appreciate having such an indication, rather than a non dimensional score.

Another implication of the remaining life estimate is that the future service conditions of an asset are assumed. This is not problematic in itself, as utilities normally have good knowledge of how load demand is expected to change over time. However, by calculating the expected remaining life under the assumed circumstances, the current condition of the asset is not visualized properly. When considering different options for the future service of an asset, it would be useful to the asset manager to know not only how fast the transformer degrades, but also how far it has currently degraded. Visualizing this difference could be a meaningful supplement to the health index.

In the Hydro-Québec model, the output is given as an apparent age, which is further used to calculate an expected failure rate for the transformer. This is, mathematically speaking, very similar to calculating a remaining lifetime estimate. While a failure probability offers many opportunities for further post-processing of the output, it might not be as intuitive as a remaining lifetime estimate. The remaining two models have chosen to indicate their outputs through a dimensionless score. The models do hence not claim to know when an asset will fail and leaves this responsibility to the asset manager. By focusing on the current condition of the transformer, rather than its remaining lifetime, future operating conditions are not included in the ranking of the transformer. This way, the operating conditions can be adapted to the transformer to maximize its usefulness. The most important property of the output is, however, that it might be used to rank transformers. This is the case for the output of all the investigated health index models.

5 | Norwegian Health Index Model

In this chapter, a model for health indexing of Norwegian power transformers will be proposed. The model presented will be thoroughly explained in a step by step manner with emphasis on justification of the selected methods. At first, an overview of the model design will be presented to give the reader a thorough understanding of the general principles being used. Next, the different assessment modules used in the model will be explained. This part aims to answer which data is being used as input, how the limit values for scoring are obtained, how calculation of important quantities are performed and how the different assessment modules are weighted in the final calculation of a health index. At the end, the output and its representation is explained. In Appendix H, the performance of this model is demonstrated through a case study.

It should be mentioned that the model presented in this thesis is to be regarded as a fist draft of a health index for an ongoing project at SINTEF Energy Research. This project will continue the work begun in this thesis to further develop a health index model customized to Norwegian conditions. The presented model is also available in an excel-format. This is further explained in Appendix J.

5.1 General Description

The motivation for developing a health index model adapted to Norwegian needs and conditions has been been two-sided: The availability of data differs from country to country, and a model designed to take into consideration the data collected by Norwegian utilities was therefore required. On one side, the model should not require more data than the utilities have available. On the other side, the model should be able to utilize as much information as possible to give an as precise as possible output. A compromise between the two, customized to Norwegian practice for data collection, is therefore necessary. In addition to this, it is important that the Norwegian owners of power transformers, who in the end will be the users of a health index, have trust in the assessment models. It is therefore important that these have the possibility to participate in the making of the health index. As a part of the development of the model proposed in this thesis, Norwegian utilities were urged to give their opinions on which failure modes and aging processes that they considered to be most critical.

As stated in Chapter 3, Hjartanson and Otal emphasizes the need for identifying all relevant failure modes and deterioration mechanisms that might affect a transformer [2]. As a first step, a list of failure modes and aging mechanisms that can or will affect the transformer was therefore constructed based on a literature study. This list attempted to connect the most prominent failure modes and aging mechanisms, their possible causes and the components most likely to be affected. To verify the relevance of this list, a meeting with several utility representatives was was arranged in Oslo on the 14th of April 2015 under the auspices of SINTEF Energy Research. An attempt was also made to rank the different failure modes and aging mechanisms by criticality from the perspective of the utilities. This proved to be a complex and difficult task. No criticality ranking of the different failure modes and aging mechanisms was therefore established, but a strong impression of which components and failure types were regarded as the most critical was given. A simplified version of the list as it stands after this meeting can be seen in Appendix A.

Figure 5.1: *Schematic of a model design where the health index is calculated as the weighted average of condition factors.*

For the principle layout of the model, two designs were considered. The first was to let the final health index score be the weighted average of scores and weights. This is the same approach as performed by Kinectrics and Hydro-Québec. This design makes it easy to see the direct impact of each condition score on the final evaluation. It will also make it easy to add and remove modules to the model if required. The disadvantage of this design is that assigning weight factors to each condition score becomes more difficult. Because there are so many assessment functions which each result in a condition score, it is hard to base the weight factors on hard evidence. However, if the condition scores are given a relative importance that the asset manager believes to be correct there is nothing wrong with this approach. The principal structure of such a design is illustrated in Figure 5.1.

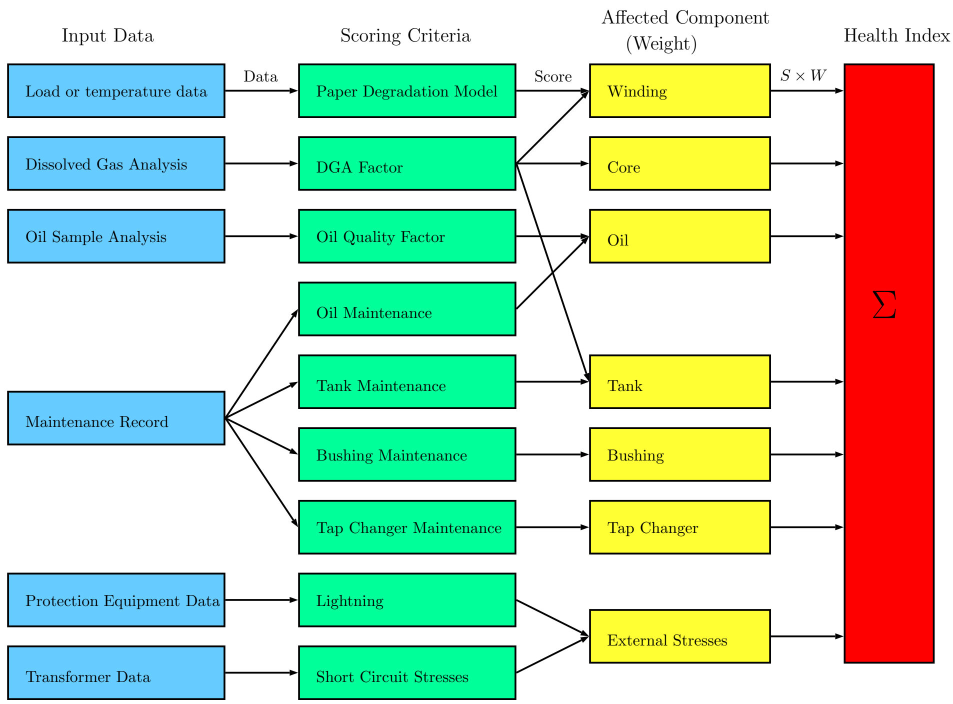

Figure 5.2: *Schematic of a model design where assessment of the subcomponents of the transformer is included. Health index is calculated as a weighted average of the subcomponent scores.*

An alternative approach was to assign a relative importance to each component rather than to each assessment function. This might be an easier way to handle the concept of relative importance because the costs and consequences of a component failure are more evident than those of a condition score. In addition, failure statistics can play a significant role in determining the relative importance of components. As failure statistics from Cigré is usually given for the six components core, winding, tap changer, tank, bushing and oil, this categorization seems appropriate [30]. A disadvantage of this approach is that this adds another calculation step to the model. Additionally, the relative importance of each assessment function for each component has to be determined. It is, however, possibly easier to relate a condition score to a component rather than the entire transformer. In conclusion, by splitting the process of assigning relative importance into two separate steps, it might be easier for an asset manager to assign a relative importance that is believed to be correct. For this reason, this design is chosen for the proposed model. A principal structure of the design can be seen in Figure 5.2.

As previously discussed, the assessment functions of a Norwegian health index should reflect the available condition data. Based on the typical data collection practice shown in Table 3.1 and the evaluations made in Chapter 4.5, the following assessment functions are selected: A paper degradation module, a DGA factor module, an oil quality factor and a factor to account for the maintenance history for each of the tap changer, bushings, tank and oil. In addition, a factor to account for external stresses is added. All of these modules and how they are connected can be seen in Figure 5.2. These will be thoroughly explained in the following sections of this chapter.

5.2 Interpretation of Dissolved Gas Analysis

Dissolved gas analysis (DGA) is one of the most important measurements when it comes to detection of abnormalities within the transformer. Because DGA is usually performed every one to two years, results will often be able to reveal such abnormalities before they grow into more serious failures. Such abnormalities might be indicated by either a high content of gas or from the set of gas ratios described in Chapter 2.5. Additionally, results from the most recent sample can be compared to previous samples to determine if there is a visible trend in the gas production rate of the transformer. This means that DGA sampling offers at least three different aspects for detection of abnormalities within the transformer. In order to create a DGA module that is able to assess both the long term effects of gassing as well as critical situations occurring within a shorter time frame, the DGA factor has been chosen to include all of these three aspects.

Today, there exist several recommendations on how to interpret results from a DGA sample. Among the most notable recommendations are those given by the IEEE and IEC [17, 33]. Both these institutions provide methods and guidelines for evaluating a transformer based on its DGA results. These guidelines take into account the total content of gas, the rate of gas increase and the ratio between particular gases. On a general basis, there is a large degree of correspondence between the two guidelines. However, for some particular quantities a significant difference is observed. As a guide for reference, these recommendations will be considered when key parameters for the model are selected.

Concentration of Gas

As previously stated, the concentration of gas constitutes one of the three quantities that will be evaluated in order to form the single factor which describes the DGA. The concentration will, however, serve as the base quantity with respect to calculation. This means that the other two quantities, the rate of gas increase and the ratios between gases, simply will be used to modify the gas concentration evaluation outcome. From IEC and IEEE standards, suggestions are given as to which gas levels that might be considered normal. These values, often referred to as the L1 level, are shown in Table 5.1 (IEC) and Table 5.2 (IEEE, Condition 1). As long as the gas content is below these values, experience shows that no detectable or incipient faults are likely to be present within the transformer [17, 33]. As soon as one or more gas concentrations rise above these values, the transformer should be considered for increased supervision. It is however emphasized by both institutions that typical values might vary considerable from transformer to transformer without necessarily being an indication of any abnormalities. Preferably, utilities should collect and determine their own values for typical gas concentrations.

Table 5.1: *Typical gas concentration values as reported by the IEC [17].*
**) No communicating OLTC.*
***) Communicating OLTC.*

Gas	Concentration [ppm]
H_2	50-100
CH_4	30-130
C_2H_6	20-90
C_2H_4	60-280
C_2H_2	2-20 *
	60-280 **
CO	400-600
CO_2	3800-14000

The L1 values listed in Table 5.1 and Condition 1 of Table 5.2 represent the limit between a gas content considered to be perfectly normal and a gas content which might indicate abnormalities. Gas concentrations below these values should therefore, from a health indexing point of view, lead to the best possible condition score of the dissolved gas analysis. The worst possible condition score should be assigned to gas concentrations exceeding the so called alarm concentrations. Such values will vary considerably from transformer to transformer and utility to utility

Table 5.2: *Gas concentrations used to classify transformers according to the IEEE four-condition categorization system. Condition 1 represents normal and satisfactory operation, whereas Condition 4 is a strong indication of excessive degradation of paper and/or oil. [33].*

Gas	Condition 1	Condition 2	Condition 3	Condition 4
H_2	100	101-700	701-1800	>1800
CH_4	120	120-400	401-1000	>1000
C_2H_6	65	66-100	101-150	>150
C_2H_4	50	51-100	101-200	>200
C_2H_2	1	2-9	9-35	>35
CO	350	351-570	571-1400	>1400
CO_2	2500	2501-4000	4001-10000	>10000

and are therefore not suggested by the IEC. An indication of such alarm concentrations can however be found from the IEEE four-condition DGA classification system shown in Table 5.2. Depending on the desired level of conservativeness, Condition 3 or Condition 4 might be used as a reference for a worst possible condition score for each gas. The IEEE describes these conditions as strong indicators of a high level of decomposition (Condition 3) and excessive decomposition (Condition 4) of paper and/or oil.

In Chapter 4.3, the Kinectrics DGA factor was explained. The scoring limits for this factor are given in Table C.1. A comparison of these values with the recommendations from the IEC and IEEE shows a good correspondence. The limits leading to the best possible condition score are similar to the L1 values of Tables 5.1 and 5.2 and the limits for assigning the worst possible score correspond to either Condition 3 or 4 in Table 5.2. The scoring limits proposed by Kinectrics do therefore seem appropriate for evaluation of the suitability for continued service of the transformer with respect to the DGA results. For this reason, the Kinectrics scoring system is adopted in the Norwegian model. However, for calculation purposes, the scoring order is reversed. This means that gas concentrations below the lowest scoring level are awarded a score of 6 instead of 1. Conversely, concentrations above the maximum limits are awarded a score of 1. The weights assigned to each gas are kept the same since these seem reasonable with respect to the energy required to create each of the different gases [17]. The modified scoring criteria can be seen in Table 5.3. When each gas is assigned a score, the DGA factor (DGAF) is calculated from Equation 5.1.

$$DGAF = \frac{\sum_{i=1}^{7} S_i \cdot W_i}{\sum_{i=1}^{7} W_i} \tag{5.1}$$

Table 5.3: *Scoring limits and weight factors for gas levels for the Norwegian model [ppm]. Limits and weight factors are adopted from the model proposed by Kinectrics [28].*

Gas	**Score (S_i)**						W_i
	6	5	4	3	2	1	
H_2	≤100	100-200	200-300	300-500	500-700	≥700	2
CH_4	≤75	75-125	125-200	200-400	400-600	≥600	3
C_2H_6	≤65	65-80	80-100	100-120	120-150	≥150	3
C_2H_4	≤50	50-80	80-100	100-150	150-200	≥200	3
C_2H_2	≤3	3-7	7-35	35-50	50-80	≥80	5
CO	≤350	350-700	700-900	900-1100	1100-1400	≥1400	1
CO_2	≤2500	≤3000	≤4000	≤5000	≤7000	≥7000	1

Rates of Gas Increase

In addition to the concentrations of gas, the rate at which gas is produced is an important quantity for evaluating the current condition of a transformer. As mentioned previously, typical gas concentration values might vary significantly between different transformers. Transformers with a high gas content might therefore be considered as perfectly healthy as long as the concentrations remain stable. A sudden increase of one or more gases is considered more alarming and as a clear indication of abnormalities within the transformer [17]. Investigating the trend shown by each gas between consecutive DGA samples is therefore important. Of the health index modules presented in Chapter 4, trending of gas is mentioned as a parameter that should impact the health index by both by Kinectrics and Hydro-Québec. While the latter does not describe how this should be conducted, the model proposed by Kinectrics recommends that the DGA factor be reduced if three consecutive DGA samples show a 30 % or more increase from the previous sample or if a 20 % increase is found for five consecutive samples. How much the DGAF should be reduced is, however, not stated.

It must be assumed that the approach given by Kinectrics is intended for DGA samples collected annually, or at least at fixed intervals. This is not the case for all utilities in Norway, where DGA sampling intervals vary between one and two years. Additionally, under special circumstances the intervals between each DGA sample might be reduced to six or three months. An assessment model for this parameter should therefore use the average rate of increase over a given period of time as scoring criterion. IEC 60599 states that an increase of 10 % or more per month above typical concentrations is a prerequisite for pronouncing that there is an active fault within the transformer [17]. IEEE does, on the other hand, once more use the four-condition evaluation system to evaluate the proper maintenance action based on gas rates. From Table 3 in [33] it can be seen that all production rates of combustible gas above 30 ppm/day are recommended to trigger additional maintenance. The extent of this additional maintenance is determined by the rate of gas increase. As a reference, the maximum total concentration of combustible gas required to classify a transformer by Condition 1 is 720 ppm [33].

Based on the above mentioned considerations, establishment of the scoring criteria for a trend factor for gas production should take the following notions into account:

1. The best possible condition score must be awarded to assets where gas levels are stable and a gas production close to zero is observed. This is the best possible behavior a transformer can exert with respect to gas production.

2. The worst condition score should be assigned to assets showing a clear indication of active internal faults. This means that a trend factor will not differentiate between extremely critical situations and moderately critical situations. As long as there is a clear indication of an internal fault, the condition will be evaluated as not suited for continued operation and hence be given the worst possible score. This approach is chosen to make sure that the long term perspective of the health index evaluation is maintained according to the guidelines given in Chapter 3. Any active faults present in the transformers are not consistent with continued operation for a long period of time without maintenance. Hence, the worst condition score limit is set at 10 % gas increase above the L1 values per month.

3. Because of the sampling intervals of DGA, scoring limits for the trend factor should be referred to yearly rates rather than to monthly, weekly or daily rates. If rates are given at a monthly, weekly or daily basis, this indicates that the production is substantial and that a serious fault might be present within the transformer. Yearly gas rates given in percent will be within the proposed extremes and will be easy for asset managers to relate to. As a consequence, the active fault limit mentioned in the above paragraph is adjusted to a 120 % increase above L1 values per year.

Based on these notions, proposed scoring criteria for the trend factor for gas production are given in Table 5.4. The same weight factors as for the DGA factor have been used. In addition, to evaluate cases where significant gas production has been present for a long period of time, criteria similar to those suggested by Kinectrics are included in the final evaluation. An OR-logic is used between the three criteria, so that a score is obtained as long as one of the criteria is fulfilled. Finally, the trend factor is calculated as a weighted average of the individual gas scores according to Equation 5.2. The resulting factor will be a number between 0 and 1, which is further multiplied with the DGA factor to adjust this according to trends in gas increase as shown by Equation 5.3.

Table 5.4: *Scoring criteria for rates of gas production for the Norwegian model. Scoring limits are given as a yearly percentage increase above the L1 levels. Scoring is performed for the same gases as the DGA factor and with the same weight factors.*

Score	**Last year [%/year]**	**OR Last three years [%/year]**	**OR Last five years [%/year]**
4	<30		
3	<60		
2	<90	>30	
1	<120	>60	>30
0	≥120	>90	>60

$$TF = \frac{\sum_{i=1}^{7} S_i \cdot W_i}{4 \cdot \sum_{i=1}^{7} W_i} \tag{5.2}$$

$$DGAF' = DGAF \cdot TF \tag{5.3}$$

Gas Ratios

Because oil decomposes to different gases under different conditions, it is possible to indicate the cause of gassing from the relative concentrations of gas, as described in Chapter 2.5. The ratios and conditions listed in Table 2.4 can be used to determine the presence of faults of a thermal or dielectric nature, whereas the ratios CO_2/CO and O_2/N_2 are indicators of aging. Of the health index models presented in Chapter 4, these indicators are only explicitly included in the Statnett/EDF method. This might be because serious faults are inconsistent with the continued service of a transformer and that the health index is no longer useful if such faults are discovered. Another reason might be the time perspective of such faults. While the health index usually is expected to assess the long term health of the transformer, these faults might occur quite sudden and are therefore hard to predict by a health index.

Including gas ratios might, however, have several beneficial effects to the health index. T1 and PD faults are generally considered the least serious of the faults listed in Table 2.4. Some transformers might therefore be kept in service for a period of time even though the DGA samples reveal these faults. In case the transformer is kept in service it seems appropriate to indicate the presence of such faults in the health index since these are a strong signal that the health of the transformer is significantly reduced. More serious faults will often require immediate or imminent maintenance actions and it will probably mean little to an asset manager whether they are included or not. However, for the sake of visualization of potential faults, they are included in the proposed model. To reflect the severity of these faults, the DGA factor is automatically set equal to zero (worst condition) if they are found to be present. If no fault is detected, the DGA factor remains unchanged. Mathematically, the fault factor can be seen as a factor equal to 1 under normal operation and 0 if any faults are detected. This factor is further multiplied with the DGA factor explained in the previous two sections.

Another aspect of the fault code system shown in Table 2.4 is the fact that this can be used to give an indication of where a fault is localized. As previously stated, it is impossible to say which particular component within the transformer that is responsible for a fault code. However, the set of components that can be the cause of such a fault are known and can hence be used to rule the others out. This fact will be used in the final evaluation of the DGA factor. Table 5.5 shows which components that are most likely to be affected by the different fault categories. This table is based on information about the different fault conditions and their causes from [3,17,34]. It is emphasized that the table is only suggestive as to which components are most likely to be affected by the respective faults and that it by no means should be used for failure localization.

Table 5.5: *Relationship between fault codes and components that potentially can cause these faults.*

Component	**PD**	**D1**	**D2**	**T1**	**T2**	**T3**
Core				•	•	•
Windings	•	•	•	•	•	•
Oil	•					
Tap changer		•		•	•	•
Tank				•	•	•
Bushing	•	•			•	

Final Evaluation

The calculation of a DGA factor where concentration levels, the trend in gas production and gas ratios are taken into account is illustrated in Figure 5.3. This DGA factor is further compared to Table 5.6 in order to obtain a final condition score.

As explained in section 5.1, a model structure is chosen where the total health index evaluation is obtained from a weighted average of the condition scores of the transformer main components. This was illustrated in Figure 5.2. A consequence of this is that each condition score needs to be linked to one or more components.

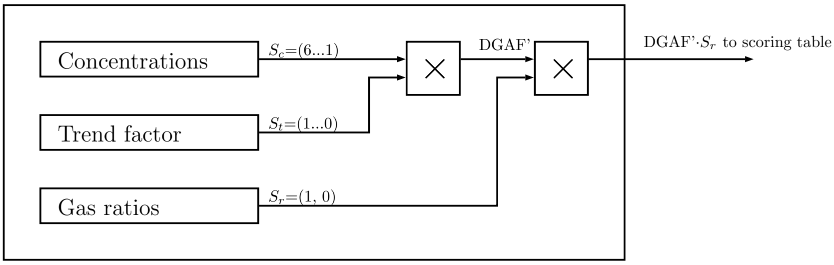

Figure 5.3: *Schematic of how the final DGA factor is calculated. The concentration level factor is multiplied with both the trend factor and the fault presence indicator obtained from the gas ratio module. The product of these three is compared to Table 5.6 to obtain a final condition score which is used in the final evaluation of the transformer.*

Table 5.6: *Scoring of the DGA factor for the Norwegian model.*

Condition Score	Condition	Criterion
4	Good	DGAF>5,8
3	Acceptable	5,8≥DGAF>5,5
2	Need Caution	5,5≥DGAF>5
1	Poor	5≥DGAF>4
0	Very poor	DGAF≤ 4

For the DGA factor, this is a difficult task since the recorded gas values can be caused by so many different reasons. The impact of the DGA factor during normal circumstances (no faults present) is especially challenging to link to any particular component. However, as an attempt to do so, it is assumed that the gas production during normal operation can be related to either the windings, the core or the tank. This is an assumption based entirely on the fact that gases are created as a consequence of heat, and that both the core, the tank and the windings are likely sources of such heat. The impact of the DGA condition score will therefore be split between these three components. How much the DGA condition score impacts the total assessment of each component is, however, dependent on how many other scores that are used in the evaluation of these components.

The destination components for the DGA condition score might, however, be changed if the operating conditions suggest this. The three circumstances that lead to a change in the destination of the DGA condition score are the CO_2/CO-ratio, the O_2/N_2-ratio and any of the IEC fault codes. If the CO_2/CO-ratio is found to be less than 3, the DGA factor is directed in its entirety to the winding. This means that the winding is the only component affected by the DGA condition score. If the O_2/N_2-ratio is found to be less than 0,3, the DGA factor is directed in its entirety to the oil. If both ratios are below their limit values, the DGA factor is split between the winding and oil. These ratios do not decrease the DGA score in any way. In the case of an IEC fault code being detected, the DGA factor is divided equally between the components which potentially are the cause of this fault according to Table 5.5. The presence of such fault codes will reduce the DGA factor to zero. It is important to emphasize that the DGA factor is divided equally between the components affected.

5.3 Quality of the Liquid Insulation

The condition of transformer oil is an important quantity both with respect to probability of failure and the aging rate of the transformer. Assessment of the oil condition is performed through a so called general oil test (GOT), where several key qualities are measured. Collection of oil samples for such measurements are in Norway normally conducted every other year. Results from such oil sample analysis are usually easier to interpret than those of a dissolved gas analysis. This is because the results from an oil sample analysis is linked to the condition of the oil itself while the results from a dissolved gas analysis describe the internal conditions of the transformer. Oil sample analysis does therefore give a good indication of the current condition of the oil with a high degree of confidence.

To assess the condition of the oil, the approach presented in the Kinectrics model of Chapter 4.3 has been adopted. This method provides a simple way of comparing the measured values with predefined limit values to further assign a score to each of the measured quantities. However, because the Kinectrics model is based on American standards, some of the limit values are incompatible with those measured by Norwegian laboratories. In addition, Norwegian laboratories measure some quantities which are not included in the Kinectrics model. A few additional quantities will therefore be added to the oil quality assessment module of the proposed model. To assign suitable scoring values for each parameter, IEC 60422 [35] will be used as a reference. In this standard, a system where each of the measured parameters of the oil can be categorized as either "Good", "Fair" or "Poor" is presented. Parameters showing acceptable values are here classified as "Good" while assets where additional maintenance is soon needed are categorized as "Poor". However, because the mentioned categories in IEC 60422 in practice range from "acceptable" to "poor", an additional condition class is used in the proposed Norwegian model. This allows assets which are in an extraordinary good state to be scored higher than those that are only in an acceptable state. Because the IEC "Poor" category in fact represents a quite urgent need for maintenance, these limits are generally used in the proposed model to score the worst possible condition. A complete overview of the selected condition parameters, limit values and weight factors is shown in Table D.1. In the following, the different parameters used to assess the quality of the oil will be listed and explained.

The breakdown voltage of an oil sample is an important parameter for the oil quality as this indicates the insulating capability of the oil. Measurement of this quantity is performed for different measurement configurations in America and Europe and the limit values provided by Kinectrics are for this reason not compatible with the values provided by Norwegian laboratories. Suggested limit values from IEC 60422 are therefore used in the proposed model. However, to allow assets with particular good values for this parameter to be scored higher than the rest, an additional category is added to the IEC suggestions. Scoring limits do also, as recommended by the IEC, depend on the nominal voltage of the transformer in question. The weight factor for the breakdown voltage is adopted from the Kinectrics model.

Moisture in the oil is also an important factor with respect to the insulating capabilities of the oil, as well as an indicator of aging speed for the solid insulation. Except from an additional condition level for scoring of exceptional good moisture levels, the IEC limits for moisture are adopted in the Norwegian model. A comparison of the scoring criteria for the Norwegian model (Table D.1) and the Kinectrics model (C.2) reveal that these are quite similar. The weight factor for moisture is adopted from the Kinectrics model.

The acidity of the oil is important mainly because high acid levels potentially can lead to increased aging rates of both the solid and liquid insulation. The scoring limits given by the IEC are for this parameter equal to the bottom three condition scores suggested by Kinectrics. Kinectrics do, however, use four, instead of three, condition categories for scoring. The fourth category indicates an exceptional condition. Because of the correspondence between the two and because a fourth condition category promotes conservativeness in the assessment, the Kinectrics scoring limits have been adopted in the proposed model.

Dielectric dissipation factor is very temperature dependent and is in America and Europe referred to different temperatures. Limit values for this parameter from Kinectrics can therefore not be used in the Norwegian model. The scoring values are therefore obtained from IEC 60422. A scoring criterion is added to indicate exceptional condition, as is done for the other parameters. The limit between the best and the second best condition is set at 0,05 % for all three voltage levels. This relies on the fact that new transformer oil should have a dielectric dissipation factor below 0,01 % [7], while a dielectric dissipation factor of 0,1 % is regarded as acceptable [35]. The limit value between the best and next best conditions is therefore set at 0,05 %.

The color of the transformer oil is a good indicator of the formation of carbon particles and soot within the transformer. The color should normally be clear and bright and free from debris. An oil with a clear and bright color is indicated by a color number below 1,5, whereas a dark and clearly contaminated oil is given a color number of 8. An alarm level for the color is usually set at 3,5 [7]. IEC does not provide any scoring criteria for the color number and the Kinctrics scoring scheme is therefore adopted.

The inhibitor content is one of the quantities which are not scored by the Kinectrics model. However, since the use of inhibitors in the transformer oils is common practice in Norway, this is a quantity that should be included in a Norwegian health index model. ABB reports that the oil will be subject to accelerated aging when the inhibitor content of the oil is reduced below 0,12 % [3]. This corresponds to the IEC guidelines, which recommend that the inhibitor should not be reduced below 40 % of the initial concentration. In Norway, the recommended initial concentration is 0,30 % [7]. A linear scoring scale between 0,30 % and 0,12 % with four condition levels as shown in Table D.1 is therefore used for the evaluation of this parameter. Because this parameter is important to the aging of the transformer, but not critical with respect to operation, a weight factor of 2 is selected.

The interfacial surface tension (IFT) of the oil is regarded as a good indicator of the aging of oil. For new oil this parameter will be in the range of 40-50 mN/m [3]. Different recommendations exist for the lower acceptance level for this parameter. ABB suggests an alarm level of 30 mN/m, while the IEC classifies values below 28 mN/m as "Fair" and values below 22 mN/m as "Poor" for all voltage levels. According to the US Bureau of Reclamation, an IFT value of 22 mN/m or below will almost certainly be synonymous with the formation of sludge [5]. The Bureau therefore suggests that an IFT value of 25 mN/m should trigger reclamation of the oil. For the Norwegian model, these suggested values are used to create the scoring criteria for IFT shown in Table D.1. An upper limit of 35 mN/m ensures that assets with particularly good values are identified, whereas a lower scoring value at 25 mN/m aims to avoid the formation of sludge.

As described in Chapter 2.5, corrosive oil has in recent years become a critical problem for some transformers. The inclusion of this is only mentioned by one of the health indexing models presented in Chapter 4. Because of the potentially fatal consequences associated with corrosive oil, it is decided that a Norwegian health index needs to assess this problem. Because a parameter of such importance should dramatically affect the OQF, the corrosivity parameter is assigned a weight factor of 4. As a consequence of the nature of this failure mode there are only two possible scoring options; "Corrosive" and "Not corrosive". Corrosive oil is therefore assigned the wost condition score, while non-corrosive oil leads to the exclusion of the parameter from the oil quality factor calculation. This is because non-corrosivity is not a sign of high oil quality. Lack of corrosivity should hence not impact the OQF in a positive direction. This parameter can therefore only affect the OQF in a negative direction.

Passivator is used as a means for protection of the transformer against corrosive oil. This parameter is for this reason only included in the calculation of the OQF if the oil is found to be corrosive. IEC recommends that the passivator content of the oil should be around 100 ppm by weight, while a passivator content below 50 ppm is recommended to trigger treatment of the oil. A linear scoring scale between these two limits is therefore selected. The passivator parameter is assigned a weight of 1. A low weight has been selected to prevent the passivator content from disguising the severe problem that corrosive oil represents. Scoring limits for both corrosivity and passivator content is shown in Table D.2.

When each parameter is given a score, Equation 5.4 is used to calculate an oil quality factor (OQF). Here, S_i and W_i are the score and weight factor of parameter i, respectively. A final condition score for the oil quality is obtained from comparing the OQF to Table 5.7.

$$OQF = \frac{\sum_{i=1}^{9} S_i \cdot W_i}{\sum_{i=1}^{9} W_i} \tag{5.4}$$

Table 5.7: *Scoring of the oil quality factor for the Norwegian model.*

Condition Score	Condition	Description
4	Good	OQF>3,6
3	Acceptable	3,6≥OQF>3,2
2	Need Caution	3,2≥OQF>2,8
1	Poor	2,8≥OQF>2,4
0	Very poor	OQF$\leq 2,4$

5.4 Quality of the Solid Insulation

Degradation of the solid insulation of a transformer is generally considered as the end of life criterion for a transformer. All of the health index models presented in Chapter 4 do therefore have a way of indicating the condition of the solid insulation. The model proposed by KEMA has chosen to use the equations for paper degradation described in IEC 60076-7, whereas Hydro-Québec and Statnett have chosen to use indicators such as furans, methanol and gas content to indicate the condition of the solid insulation. Kinectrics does, on the other hand, indicate the gradual degradation of the transformer through its load history. Despite the differences of these models, they all attempt to highlight the following two aspects:

- How far, in terms of DP, has the degradation come?
- What is the remaining lifetime of the transformer?

The accuracy in the output of the mentioned models is, however, likely to vary significantly with respect to both their evaluation and credibility.

5.4.1 Method

In the proposed model, assessment of solid insulation degradation is performed using a model developed at SINTEF Energy Research [13]. This model is believed to describe the degradation of cellulose in a relatively accurate manner, given that sufficient knowledge of the environment is provided. In order to explain how this model is used for assessment of the solid insulation it is necessary to investigate Equation 2.1 in Chapter 2.2 more closely. This equation provides a way of calculating the current DP value of the insulation as a function of temperature. This equation can, however, be re-arranged and represented in an alternative way as described by Equation 5.5.

$$\eta_{Tot} = DP_{new} \cdot \left(A_{Oxi} e^{\frac{-E_{Oxi}}{RT}} + A_{Hyd} e^{\frac{-E_{Hyd}}{RT}} \right) \cdot t \tag{5.5}$$

Here, η_{Tot} is the average number of chain scissions that have taken place for the cellulose molecules in the solid insulation. This is an alternative way of stating the DP value, since the initial DP value is halved for each chain scission. DP_{new} is the initial DP value of the insulation and is usually considered to be about 1000 for a new transformer. A is a constant depending on the chemical environment. It has the dimension [time^{-1}]. E is the activation energy of the reaction in [kJ/mol], R is the molar gas constant in [J/mol/K], T is the absolute temperature and t is the time. The subscripts Oxi and Hyd indicate that there are two active degradation processes and that the value of the A and E constants are different for the two. A more detailed description of the constants involved in this equation is found in Chapter 2.2.

An important aspect of Equation 5.5 is that the aging rate k is given by the term within the brackets. This may be written as [14]:

$$k = A_{Oxi} e^{\frac{-E_{Oxi}}{RT}} + A_{Hyd} e^{\frac{-E_{Hyd}}{RT}} \tag{5.6}$$

$$k = k_{Oxi} + k_{Hyd} \tag{5.7}$$

The aging rate k describes the amount of aging experienced by the insulation for a given period of time and has the dimension $[1/h]$. If the parameters for A and E are known, temperature data for a given period of time can be used to calculate the aging rate of the paper for this paper. The total aging for the period is then given by the integral of the aging rate over the given period of time. This is illustrated in Figure 5.4. Here, hourly values for the winding temperature from a 120 MVA transformer are used to calculate corresponding hourly aging rates. It is assumed that both oxidation and hydrolysis are active. The moisture of the winding is, based on the moisture content in oil, assumed to be 1,5 % and the paper quality is assumed to be of kraft type. The resulting reduction of DP is also indicated. It should however be noted that the initial DP value of 1000 is set for illustrative purposes only.

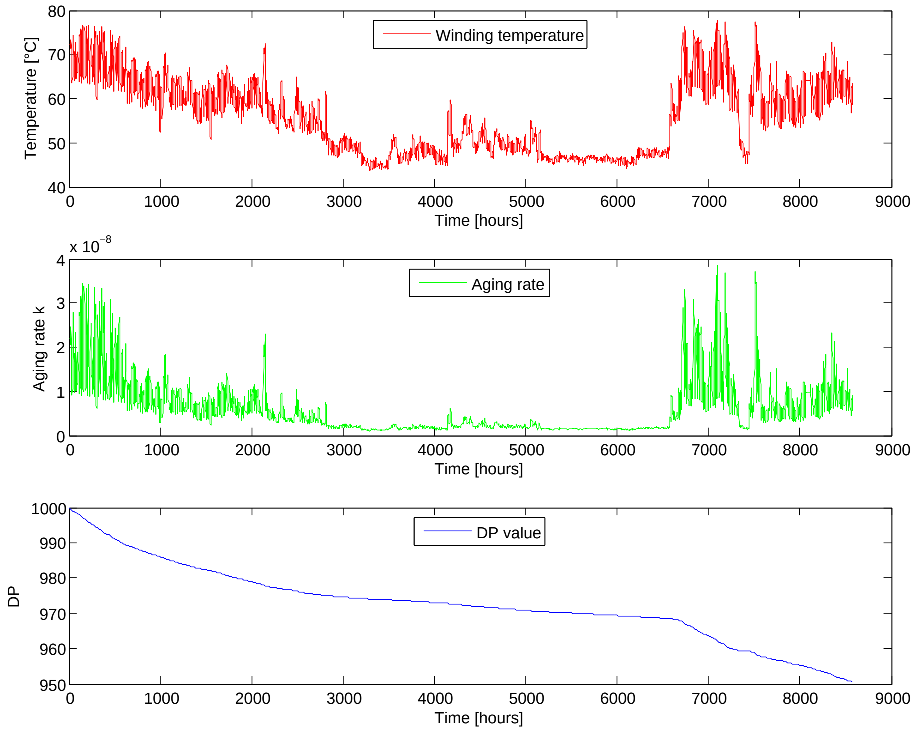

Figure 5.4: *Illustration of how aging rates and DP reduction are functions of temperature according to Equation 5.5. It is assumed that the solid insulation is made out of kraft paper and that both hydrolysis and oxidation are active. The winding moisture is assumed to be 1,5 %. The temperature data used in this example are hourly readings of winding temperature from a 120 MVA transformer. It should be noted that the initial DP value of 1000 in this example is set for illustrative purposes only.*

As shown in Figure 5.4, historic temperature data might be used to estimate the current DP value as long as all the calculation parameters of Equation 5.5 are known. These must, however, be estimated from the available condition data. In the proposed model, two assumptions adopted from [14] are used to select appropriate A and E values from Tables 2.1 and 2.2:

- The moisture content of the oil is assumed to be representative of the moisture content in the winding at the temperature of the oil at the time of sampling.

The equilibrium curves shown in Figure E.1 are further assumed to be decent indicators of the relationship between oil and winding moisture.

- Oxidation is assumed to take place if the O_2 content in the most recent DGA sample is above 6000 ppm. For O_2 values below this, hydrolysis is assumed to be the only aging process.

In addition to these assumptions, the selection of appropriate calculation parameters depend on the paper quality of the winding. The user of the model must therefore select whether kraft paper or thermally upgraded paper is used in the winding. In case this is unknown, kraft paper is assumed since this will give the most conservative estimate. The model must also decide whether to use A_{Hyd} and E_{Hyd} values for dry paper, 1,5 % moisture or 3,5 % moisture. To do so, the paper is assumed to be dry if the winding moisture content is estimated to be below 0,5 %. A_{Hyd} and E_{Hyd} values corresponding to a 3,5 % moisture level are used if the winding moisture is estimated to be above 2 %. The 1,5 %-values are used for values between 0,5 and 2 %. Estimation of the winding moisture is performed by using the equilibrium curves in Figure E.1 from. These curves are taken from [14].

When appropriate calculation parameters have been found, Equation 5.5 can be used in combination with temperature data to calculate aging rates and the resulting DP-loss, as previously explained. A limitation of this approach is, however, the very varying extent to which temperature data are collected by Norwegian utilities. Because many transformers have been in service for a long period of time, no temperature data have been recorded for a large proportion of their life. For these assets, occasional readings from a temperature gauge might be the only available data about the internal temperature. For newer assets the possibilities are more. These might have fiber optic measurements of the winding temperature, or at least a digital recorder of the top oil temperature. However, common practice has been to only store temperature data for the last year [23]. In addition the location of the temperature measurement might vary from asset to asset. For these reasons, the paper degradation module of a health index should be able to use several different temperature measurements or observations as input.

In the model proposed in this thesis, the paper degradation module is designed so that the user might use the following as input:

- Hourly temperature data for a representative year measured for the winding.
- Hourly temperature data for a representative year measured for the top oil.
- Hourly load data for a representative year.
- An average winding temperature estimate.
- An average top oil temperature estimate.
- An average load estimate.

Of these, the upper two are the preferred input to the model. Such data will allow the calculation of the aging rate of the insulation for typical operating temperatures for the transformer. Historic load data might also be used as an alternative to temperature, although with less reliability. All of these three rely on Equation 2.2 for calculation of the hot-spot temperature of the transformer for each hour of the given year [36]. These temperatures are then combined with Equation 5.5 for calculation of the total aging of that year.

The model should be able to estimate the aging of the insulation for the entire lifetime of the transformer. To do so, two methods might be chosen: The temperature data curve might be assumed representative for the entire transformer lifetime and duplicated for both previous and later years. Another option is to calculate an equivalent temperature which causes the same amount of aging of the insulation during the year as the estimated hot spot temperatures do. This constant temperature has to be calculated numerically due to the complexity of Equation 5.5. In theory the two methods are equivalent. However, since the first method would require processing of large amounts of data, the second method is chosen. When an equivalent temperature is obtained, this is used to calculate the aging of the transformer for 200 years after its commissioning. Calculations are performed under the assumption that all calculation parameters remain unchanged. This way, both the current DP value and its expected development can be investigated.

In case no recorded temperature or load data are available, the user has the possibility of estimating a representative constant temperature for either the winding or the top oil of the transformer. To calculate a hot-spot temperature from this estimate by means of Equation 2.2 it is also necessary that the a representative load is estimated. The hot spot temperature obtained from Equation 2.2 will then be used in the exact same way as the equivalent temperature. However, since the hot-spot temperature is merely based on estimates, the results will naturally be associated with a much higher uncertainty than those originating from actual measurements. In Figure 5.5, the output of the paper degradation model in terms of current DP and expected deterioration trend is shown. These values were obtained from the same winding temperatures as shown in Figure 5.4.

Table 5.8: *Scoring of both the current DP and the expected remaining life of transformers.*

Condition Score	Current DP	Remaining Life [years]
4	≥700	≥40
3	≥500	≥20
2	≥400	≥10
1	≥300	≥5
0	<300	<5

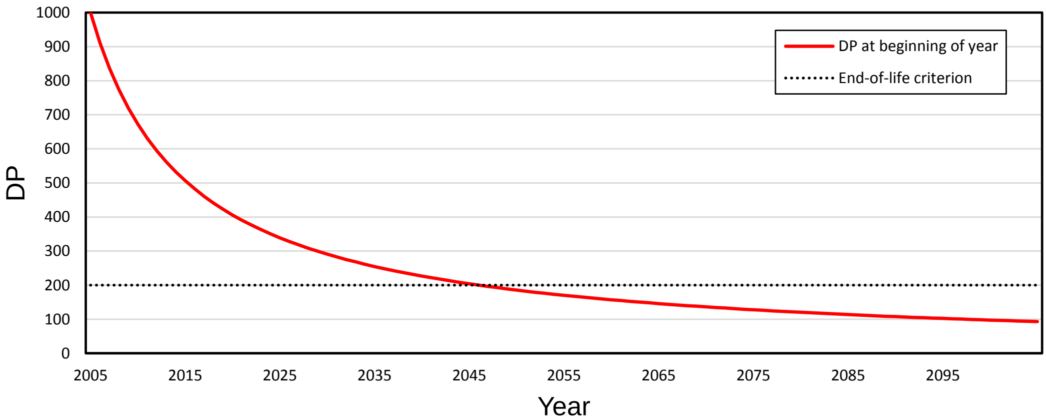

Figure 5.5: *Development of DP for the life of a 120 MVA transformer as estimated by the paper degradation module of the proposed model. The degradation is calculated for a moisture value of 1,5 % and with the assumption of active oxidation. The calculation is based on the hourly temperature data that are shown in Figure 5.4.*

For the output of the degradation module to answer both of the two questions mentioned in the beginning of this section, the output from the module is two-sided. One score is given based on the estimated current state of the insulation and one score is given based on the expected remaining lifetime of the asset. Table 5.8 is used for assigning both scores. On a component level, both these scores are used to assess the condition of the winding. The current state score is, however, weighted twice as heavy as the trend score to make sure that the health index is primarily representative of the current condition of the transformer.

5.5 Assessment of the Tap Changer

In the models presented in Chapter 4, several methods for assessment of the tap changer are mentioned. These use both results from direct measurements and service experience to estimate the reliability of this component. Among the measurements being highlighted are DGA and oil sample analysis of the tap changer oil, resistance measurements and load monitoring. Experience with the reliability of the technology is also mentioned as a possible assessment criterion by three of the four presented models, while the maintenance history of the tap changer is mentioned in two of the models.

In Norway, tap changer condition assessment is mainly performed through a tap changer audit every sixth to eighth years. Thorough checks of important functions such as the switching mechanism and the motor drive are then performed. These functions are checked through a set of measurements and inspections. Measurements such as separate DGA and oil sample analysis are however rarely performed. The condition data available for use in a Norwegian health index model are therefore in principle limited to the findings from the tap changer audits. In the proposed model, scoring of the tap changer on component level is therefore based on three different indicators: The general evaluation from the last tap changer audit, an evaluation of the tap changer maintenance scheme and an evaluation of its maintenance history. Of these, the first two will be described in this section. The maintenance history evaluation is performed for all of the transformer components and is for this reason described in a separate section.

Tap changer audits will usually be the most reliable indicator of the condition of a tap changer. During such audits, several measurements of mechanical and electrical nature are performed as part of a thorough inspection of the component. In theory, the results from these measurements could be used in a health index to assess the condition of the tap changer. However, because no good models for assessment of the measured quantities are known, the overall condition evaluation of the tap changer from the audit will be used in the proposed health index model. Scoring is then performed according to Table 5.9. Such an evaluation will usually be available from the audit report, but might require the user of the health index to decide which of the scoring categories that are most fitting. This is unfortunate, since health indexing is initially a tool used to avoid subjective evaluations. However, because of the limited condition data and accompanying assessment models found for the tap changer, this approach seems necessary. To minimize the impact of subjective evaluations, guidelines for assessment could be created.

From the previously mentioned meeting with utility representatives conducted on the 14th of April 2015, an impression was given that tap changers subject to a proper maintenance scheme were considerably less likely to experience failures than those that were not. Such a maintenance scheme should include both frequent inspections and regular audits of the tap changer. Furthermore, as stated in

Table 5.9: *Scoring of the overall condition evaluation from the tap changer audit.*

Condition evaluation	**Score**
Good as new	4
Notable wear	3
Significant wear	2
Critical wear	1
Failed	0

Chapter 2.3, it should ensure that the entire range of taps are operated regularly to keep them clean of carbon deposits. This is especially important for de-energized tap changers, since these are more prone to this problem. For an OLTC, the frequency of tapping is an important parameter with respect to wear. To avoid that tapping is performed more frequently than necessary it is important that the voltage regulator is calibrated properly. As indicators of the maintenance scheme, these elements are therefore scored according to Table 5.10. This is a very coarse approach which will most likely not reflect the condition of the tap changer. The intention is, however, to let assets that are suffering from an inadequate maintenance scheme to be ranked lower than those that are not. The total score of the maintenance scheme is given as the sum of criteria that are fulfilled.

Table 5.10: *Scoring of the tap changer maintenance scheme. For each of the four criteria a score of 0 or 1 is given. A score of 0 indicates that the criterion is not met while a score of 1 indicates the opposite. The total score of the maintenance scheme is given as the sum of the criteria scores. For DETCs, a score of 2 is given if the taps are operated regularly.*

Criterion	**OLTC**	**DETC**
Frequent inspections?	Yes = 1 No = 0	Yes = 1 No = 0
Regular audits?	Yes = 1 No = 0	Yes = 1 No = 0
All taps operated regularly?	Yes = 1 No = 0	Yes = 2 No = 0
Voltage regulation properly calibrated?	Yes = 1 No = 0	
Maintenance scheme total score	Sum of above scores	Sum of above scores

5.6 Assessment of the Maintenance History

The tendency of a transformer to need corrective maintenance is, either through statistical or experience based evaluation schemes, used as an indicator of the transformer health by all of the health indexing models presented in Chapter 4. For this reason it has been decided that the maintenance history of a transformer should be included in the proposed model. Another important factor in this regard is the availability of such data. Every power transformer being subject to a proper maintenance scheme will have its own maintenance record. Obtaining data for this condition indicator is therefore relatively easy.

As a baseline for developing a maintenance history module, the approach suggested by Kinectrics (Chapter 4.3) is considered. In this module, the total number of work orders related to specific corrective maintenance actions is used as scoring criterion. The module does, however, not take into account the seriousness of the fault being corrected. Because a serious failure will impact the health of the transformer considerably, whereas a minor failure might be insignificant to the transformer health, the severity of the corrected faults should be reflected in the maintenance history condition score. The impact of corrective maintenance in the proposed model is therefore dependent on the severity of the initial fault. In addition, faults that have not yet been corrected have a significantly larger impact on the maintenance score than those that have. As a consequence of the model composition, scoring based on the maintenance history is performed per component. This means that failures affecting the tap changer, tank, bushings, oil or auxiliary equipment will be reflected in the score of the respective component. The scores of the winding and core are not affected by the maintenance history, since no maintenance is performed on-site for any of these components.

In order to classify the severity of a fault, a fault grading system used by Statnett SF has been adopted. This system gives each fault a priority ranking from 0 to 4, where 4 is the most serious. A generalized version of this system is shown in Table 5.11. This system can be used on a general basis to determine the severity of a fault. It should be noted that the strategic importance of an asset this way might impact how serious a fault is considered to be. However, as a practical and easily understood method to rank fault severity, the method is believed to be adequate for its purpose. To assess the maintenance history of each component, a scheme is

Table 5.11: *Generalized severity ranking of faults used in the maintenance history module of the proposed model.*

Fault Description	**Severity**
No fault	0
Fault which only requires monitoring	1
Fault that should be repaired within one year	2
Fault which should be repaired within one month	3
Fault which requires immediate outage and repair	4

used where all faults are assigned an impact factor according to Table 5.12. The sum of impact factors, called the maintenance factor (MF), for all faults which have affected a component over the last five years will further be compared against Table 5.13 to obtain a final maintenance history score for that component. In Table 5.12 a distinction is made between 'Active' and 'Repaired' faults and the corresponding impact factors. The idea is that faults that have not yet been repaired should impact the maintenance history score heavily. From Tables 5.12 and 5.13 it can be seen that any severe fault which is not yet repaired will instantly lead to a low maintenance history score. When the fault has been repaired its impact is reduced by 90%. This remnant impact factor is meant to represent both the possibility of maintenance induced failures and a weakened condition as a consequence of the initial fault. The impact of repaired faults lasts for five years. If five years go by without the occurrence of any failures, the maintenance history score of all components will be the best possible. The maintenance factor might be mathematically described by Equation 5.8.

$$MF = \sum_{i=1}^{n} I_i \left(H(t - t_{Fi}) - 0,9 \cdot H(t - t_{Ri}) \right) \tag{5.8}$$

Here, MF is the maintenance factor, n is the total number of faults that have occured over the last five years and I_i is the impact factor of each fault. The unit step function H is further used to separate between faults that have been repaired and those that have not. t_{Fi} and t_{Ri} are thus the time of failure and repair for fault i, respectively.

Table 5.12: *Impact of faults depending on their severity used in the maintenance history scoring scheme.*

Severity	**Impact factor (Active fault)**	**Impact factor (Repaired)**
0	0	0
1	10	1
2	30	3
3	60	6
4	100	10

5.7 The Effect of External Stresses

External stresses of an electrical nature are by far the most important with respect to the continued operation of a transformer. Such stresses might be caused by lightning, switching or earth faults and can potentially cause great damage to the transformer. Of the four models presented in Chapter 4, none assesses the effect of external electrical stresses directly. This might be due to the fact that it is

Table 5.13: *Scoring of the maintenance history condition score. This applies to all of the components where maintenance history is used as a condition indicator.*

Final maintenance history score	Maintenance factor
4	<10
3	<20
2	<30
1	<40
0	≥40

hard to quantify the impact of such stresses on the transformer condition. Besides, external stresses might be regarded to not belong in a health index since they do not directly describe the condition of a transformer. Nevertheless, there can be no doubt that these factors are of great importance to the continued operation of the transformers. For this reason, it has been decided that the proposed model should include a module which reflects the effect of external stresses on the transformer.

The external stresses that will be analyzed and scored by this module are restricted to earth faults and lightning surges. These factors impact the transformer in two different ways: Lightning surges might cause overvoltages that lead to a breakdown of the transformer insulation. Earth faults might on the other hand cause mechanical deformation of the winding and overheating to take place. The scoring of these stresses is performed with a focus on the ability of the transformer to withstand them. Details regarding the design of the transformer and its protection equipment is therefore used in the calculation. Different models are used to assess the ability of the transformer to withstand lightning surges and earth fault currents.

Lightning Withstand Capacity

Assessment of the ability of the transformer to withstand lightning surges is conducted by calculating the ratio between the basic insulation level (BIL) of the transformer and the voltage levels caused by a potential lightning surge. The basic insulation level is the voltage level for which the transformer is tested by the manufacturer and which it is guaranteed to withstand. The BIL is very dependent on the voltage level of the transformer. Typical values for this quantity can be seen in Table F.1. The voltage on the transformer terminals as a consequence of lightning surges is often referred to as the coordination withstand voltage U_{cw} and is given by Equation 5.9. This equation is an alternative representation of Equation 2.5 in Chapter 2.7.1 [37].

$$U_{cw} = U_{pl} + \frac{A}{n} \cdot \frac{l_{AT}}{l_{sp} + l_a} \tag{5.9}$$

U_{cw} is here the coordination withstand voltage, U_{pl} the residual voltage of the surge arrester, A the corona factor according to IEC 60071-2, l_{AT} the distance from the transformer terminals to the ground arrangement of the surge arrester, l_{sp} the length of the overhead line span closest to the station and l_a the representative distance from the transformer to the lightning strike. This distance is by the IEC assumed to be given by the ratio between the acceptable failure rate due to lightning R_a and the actual failure rate due to lightning R_{km} [37]. IEC suggests a value of one failure per 400 years for R_a, while statistics from Statnett show that the actual failure rate is around 0,2 failures per 100km per year [19]. Values for A are given in Table F.2. As a result, the coordination withstand voltage can be calculated as long as the parameters U_{pl}, l_{AT} and l_{sp} are known.

Scoring is further based on the ratio between the transformer BIL and U_{pl} according to Table 5.14

Table 5.14: *Scoring of the ability of a transformer to withstand lightning stresses.*

Lightning withstand score	**BIL/U_{pl}**
4	≥2
3	≥1,75
2	≥1,5
1	≥1,25
0	<1,25

Earth Fault Withstand Capacity

Assessment of the earth fault withstand capacity is performed based on the ratio between the maximum short circuit current for the transformer and its rated current. As explained in Chapter 5.7, the theoretical maximum earth fault current a transformer can experience is dependent on both the system short circuit power and the transformer short circuit reactance. These are therefore required as input in the model. In the case that the short circuit power is unknown, standard values as reported by the IEC 60076-5 are used. These might be found in Table F.3. From this, the maximum short circuit current is calculated as described by Equation 2.4 and compared to Table 5.15 to obtain a score.

Table 5.15: *Scoring of the ability of a transformer to withstand short circuit stresses.*

Lightning withstand score	$\hat{\mathbf{I}}_k/I_N$
4	<15
3	<20
2	<25
1	<30
0	≥30

5.8 Output Representation

When all the different condition scores have been calculated, these need to be assigned to their respective components. Each component will thus receive one or more condition scores which are weighted relatively to each other in order to calculate a final score for that component. The component score is calculated according to Equation 5.10, where W_i and S_i are the weight and score, respectively, of condition score i. In this regard, external stresses are also treated as a component. The relative weights assigned to each condition score are shown in Table G.1.

$$CS = \frac{\sum\limits_{i=1}^{n} W_i \cdot S_i}{\sum\limits_{i=1}^{n} W_i} \tag{5.10}$$

The importance of each component is further weighted in order to calculate the final health index score of the transformer. From the list of failure and aging mechanisms shown in Table A.1, as well as from the general impression given by transformer experts during the meeting mentioned in section 5.1, a good understanding of the relative importance of each component was acquired. This impression, combined with international failure statistics [30], forms the basis for the weighting of each component. The weights proposed in this model are shown in Table G.1. The final health index score is calculated according to Equation 5.11 and will be given as a score between 0 and 100, where 100 indicates perfect condition. In this equation, W_i and S_i is the weight and score, respectively, of component i. External stresses are treated as a component in the calculation.

$$HI = \frac{\sum\limits_{i=1}^{n} W_i \cdot S_i}{\sum\limits_{i=1}^{n} W_i} \cdot 100 \tag{5.11}$$

To the user of a health index, it is essential to know how the model output should be interpreted. For the proposed model, no condition categorization based on the health index score has so far been proposed. Such a categorization is however useful with regard to population studies and should therefore be established. A main challenge in this regard is to determine how low the health index score should be allowed to go before the transformer is classified as unsafe and at its end of life. Since establishing such categories requires knowledge about the behavior of the health index for assets of various condition, the model should be tested before condition categories are defined.

6 | Results

To test its performance, the proposed model has been applied to seven Norwegian power transformers owned by Statnett SF. The output of the model on module level, component level and transformer level will further be presented. To thoroughly demonstrate the behavior of the model, a case study for one of these transformers is shown in Appendix H. The data used in the health index calculation for the selected transformers are given in Appendix I.

6.1 The Transformers

The transformers evaluated by the proposed model are shown in Table 6.1. These transformers were selected in order to investigate how the model would perform for units of different expected condition, age and geographic location. The expected condition of transformers T5, T6 and T7 is based on their evaluation in the Statnett SF reinvestment plan for power transformers. The expected condition of T1 is based on its short time in service (2 years). The remaining three units were selected to include assets of all age groups and geographic locations in the analysis. T6 is the only transformer without a tap changer.

Table 6.1: *Age, nameplate data and expected condition for the transformers used to test the proposed health index model.*
**) Has only been two years in service.*

Transformer	Age	Voltage [kV]	Power [MVA]	Expected condition
T1	5*	138	80	Very good
T2	13	300	300	Unknown
T3	28	305	160	Unknown
T4	39	300	200	Unknown
T5	44	300	300	Very poor
T6	52	304	125	Poor
T7	58	144	30	Acceptable, but old

6.2 Results

In this section, the results from each of the modules are shown for each of the seven transformers investigated. Results both on module level, component level and transformer level are shown. Module scores are given in Table 6.2. In Table

Table 6.2: *Results from the different modules of the health index model for each of the seven transformers. A score of 4 represents the best condition and 0 the worst.*

Module	**T1**	**T2**	**T3**	**T4**	**T5**	**T6**	**T7**
DGAF	4	4	1	0	0	0	0
OQF	4	3	4	3	0	2	4
RL	4	4	4	4	4	4	4
DP	4	4	4	4	4	4	4
Tap changer audit score	4	3	3	2	0	-	4
Tap changer maintenance scheme	4	3	4	4	2	-	3
Tap changer maintenance	4	4	4	4	4	-	3
Tank maintenance	4	4	4	3	4	4	4
Oil maintenance	4	4	4	4	4	1	4
Bushing maintenance	4	4	4	4	4	4	4
Auxiliary equipment maintenance	4	4	4	3	4	4	4
Lightning protection	2	1	2	2	2	4	2
Short circuit withstand capacity	1	2	1	2	2	2	2

6.3, the resulting scores for the component and stress factors for the seven transformers are shown. The final health index scores of the seven transformers are shown in Table 6.4. For comparison, the expected condition and the age of the transformers are also shown in this table. Additionally, Figure 6.1 is included to illustrate the relationship between health index and age for the investigated transformers.

Based on the results obtained for transformer T5 in this thesis, a rough estimate of a condition categorization might be made. In the reinvestment evaluation of this

Table 6.3: *Component and stress factor scores for the seven transformers investigated. A score of 4 represents the best condition and 0 the worst.*

Component	**T1**	**T2**	**T3**	**T4**	**T5**	**T6**	**T7**
Winding	4,0	4,0	2,8	2,4	2,7	1,3	2,4
Tap changer	4,0	3,3	3,4	2,9	1,6	1,3	3,6
Tank	4,0	4,0	2,3	1,3	2,0	4,0	1,7
Oil	4,0	3,4	4,0	3,2	0,8	1,8	4,0
Bushing	4,0	4,0	4,0	4,0	2,0	4,0	4,0
Core	-	-	1,0	0,0	0,0	-	0,0
Auxiliary equipment	4,0	4,0	4,0	3,0	4,0	4,0	4,0
External stresses	1,5	1,5	1,5	2,0	2,0	3,0	2,0

Table 6.4: *Age, expected condition and health index score for the transformers used to test the proposed health index model.*
**) Has only been two years in service.*

Transformer	**Age**	**Expected condition**	**Health index score**
T1	5*	Very good	93
T2	13	Unknown	87
T3	28	Unknown	74
T4	39	Unknown	63
T5	44	Very poor	45
T6	52	Poor	54
T7	58	Acceptable, but old	70

transformer, Statnett describes its condition as "lousy" and emphasizes that the transformer should immediately be replaced. From this, it might be reasonable to define the end of life around a health index score of 45. The condition categorization shown in Table 6.5 is therefore proposed, as this also appears to give a reasonable verdict for the remaining assets where the condition is known. The categorization is a modified version of the one proposed in the Kinectrics model.

Table 6.5: *Condition categorization based on health index scores.*

Health Index	Condition
85-100	Very Good
70-85	Good
55-70	Fair
40-55	Poor
0-40	Very poor (At end of life)

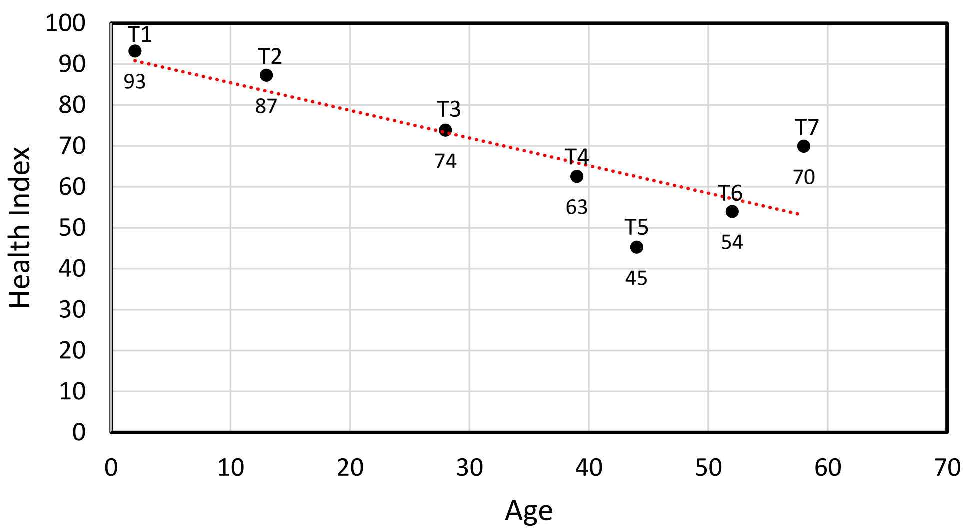

Figure 6.1: *Plot of the relationship between age and health index score of each asset.*

7 | Discussion

In order to evaluate the qualities of the proposed model, this chapter will give a discussion on both the results presented in the previous chapter and the method used to obtain these. Important subjects that will be highlighted are interpretation and reliability of the model output, the model composition and the expected strengths and weaknesses of each assessment module used in the model. This will finally be summed up in a discussion regarding the suitability of the model for use by Norwegian utilities and power transformer users.

7.1 Health Index Output

In the previous chapter, the proposed model was applied to seven transformers owned and operated by the Norwegian TSO, Statnett SF. For four of these transformers, a condition estimate was obtained prior to testing the model. For transformers T5, T6 and T7, these estimates were based on the condition evaluations performed by Statnett in conjunction with reinvestment planning. For T1, the condition was assumed to be very good because of its short time in service. The condition of the remaining three transformers was unknown. The results from this analysis are shown in Table 6.4 and Figure 6.1.

Comparison of the health index score and the expected condition for the assets where this was known shows a strong correlation between the two. The number of assets investigated is, however, not sufficient to conclude on whether or not the health index score is representative of the asset condition. It should also be remembered that the condition evaluation of T5, T6 and T7 performed by Statnett most likely is based more or less on the same data as is used in the health index calculation in this thesis. It is therefore reasonable that the two investigations lead to similar results. Nevertheless, the significant differences in score between the transformers T1, T5, T6 and T7 indicates that the health index is able to differentiate between assets of various condition.

Another interesting aspect from the results presented in the previous chapter is the relationship between age and health index score. How the condition of a transformer develops throughout its life is a frequently debated subject in transformer literature. Traditionally, the age of a transformer has been regarded as a key parameter when determining its condition, while newer literature tends to put more emphasis on the aging of the transformer. This difference is especially important when it comes to reinvestment decisions: Should an old, but apparently healthy transformer be replaced? Although the results obtained for this thesis offer no clear answer to this question, it is observed that considerable differences in condition exist between assets of a similar age. Another observation is that, although variations exist, the condition of assets in general seem to decrease significantly over time. These observations indicate that age might be used to rule out that older transformers are in a "Very good" condition. However, from of the large variations in health index score shown for the three oldest assets it is obvious that age is poorly suited as an indicator of *which* condition the transformer is in. To be able to conclude more confidently about this, an investigation should be performed for a larger group of assets.

7.2 Model Considerations

The proposed health index model is comprised of several assessment modules that evaluates different subsystems of the transformer. These assessment modules each represent an uncertainty in the final evaluation and a review of the performance of these does therefore seem appropriate. Additionally, the composition of the model and the proposed weighting of components will be discussed.

7.2.1 Model Composition

As described in Chapter 5.1, it was selected that the model should first calculate a score for each of the major components and an external stress factor before these were subsequently used to calculate the final health index score. The alternative solution was to calculate the health index score directly from the set of condition scores obtained from the assessment modules. The first solution was selected since this was believed to be an easier way of assigning a meaningful weighting to the condition scores. To first determine the importance of a condition indicator for one component and then determine the importance of this component to the transformer health is believed to make it easier for asset managers to assign weights that are based on experience instead of speculations. An additional advantage with this approach is that the condition of each component can easily be visualized to the user of the health index.

Although the selected model composition has several benefits, it does also have some drawbacks that should be pointed out. The most prominent of these is that one of the components does not have a condition indicator which exclusively points to it. This is the case for the transformer core, which is only evaluated through the DGA module. Because the DGA module can change which component it evaluates based on the input, the core might end up without any indicators of its condition. This is a complicating and inaccurate approach that leads to the exclusion of the core in the final calculation. Without any condition indicators that exclusively evaluate the condition of the core, the selected model layout becomes less meaningful. A diagnostic measurement that for this purpose could be included in the model is the resistance from core to ground. This way, the core would always have at least one indicator of its condition. Whether or not this measurement is conducted frequently enough for it to be a meaningful addition to the health index, remains unknown.

Another disadvantage of the selected model layout is revealed when a condition indicator, such as the DGA, does not point directly towards a single component. This forces the result from this condition indicator to be directed to the component(s) from which it is most likely to originate. This is an imprecise and somewhat confusing practice which would be avoided if the alternative model layout had been chosen. Although the total health index score is not significantly affected by this, the scores of each component might become seriously misleading. This greatly undermines the usefulness of visualizing the score of each component. It might, however, be argued that the main objective of the health index is to assess the transformer as a whole. A low health index score will most likely trigger further investigation of the transformer that will anyhow discover components that are in a potentially weakened state.

7.2.2 Modules

The performance and reliability of the health index model is primarily determined by the performance and reliability of the different assessment modules being used. The following will therefore evaluate the strengths and weaknesses of these and suggest further improvements where this is appropriate.

DGA Module

The DGA assessment module proposed as a part of the health index model is based on the recommendations of internationally acknowledged institutions such as the IEC and IEEE. Scoring of the DGA factor based on gas content and trending is therefore believed to be performed in a reasonable manner which reflects the common practice for interpretation of DGA results, even though typical values might vary from transformer to transformer. The gas ratio assessment used in this module does, however, have a potential for improvement. Low content of particular gases might cause the gas ratios to erroneously indicate a fault. IEC 60599 suggests that gas ratios should only be used if at least one gas exceeds the typical values. Furthermore, for particularly low gas levels the uncertainty of the DGA measurement must be taken into account. These precautions are not implemented in the DGA module and do therefore represent a weakness in the module. Although it is often possible to tell whether or not a fault code is questionable due to low gas concentrations, the DGA module should nevertheless be able to handle this automatically.

From the module results found in Table 6.2,it is observed that the obtained DGA scores range from 4 to 0. However, there is only one transformer where the score is not either 4 or 0. This on/off-characteristic is caused by the detected presence of faults for transformers T4, T5 and T6, and by the trend factor for T7. Although this characteristic is not a problem, it might be important to be aware of. If the model is tested for larger groups of assets and this characteristic is still present, adjustments of the DGA module should be made in order to use the entire specter of DGA scores.

Oil Quality Module

The oil quality assessment module used in the proposed model is, like the DGA module, based on scoring limits suggested by the IEC and IEEE. The validity of the scoring scheme applied by this module is therefore believed to be representative of common practice. The suggested weights for each of the oil quality parameters are, with a few exceptions, adopted from the Kinectrics model. How these weights initially have been determined is accounted for, but from a health indexing point of view they seem reasonable with regard to the severity of each parameter. In addition to these parameters, the proposed model has introduced inhibitor content, corrosivity and passivator content as condition parameters for the oil. These are parameters with high relevance to Norwegian transformers that can be crucial to the transformer health and failure probability. Corrosivity of oil is, due to its tremendous importance, given a high weight in the final calculation.

Paper Aging Module

This module has already been thoroughly described in previous chapters, and a further elaboration will therefore be avoided. There are, however, two aspects related to the performance of this module that need to be highlighted. The first regards the use of ambient temperature in the calculation: Hot spot temperatures are calculated for one load year under the assumption that the ambient temperature remains constant throughout the year. Although the yearly average temperature has been used in the calculation, this is presumably a too rough simplification since the ambient temperatures during a year might vary considerably. Because the yearly average temperatures in Norway generally are low, the hot-spot calculations render quite low temperature estimates. Subsequently, because of the exponential temperature dependence of paper aging, inaccuracies in the estimation of temperature will be amplified in the paper aging calculations. Meteorological data are easily available for most parts of Norway and the ambient temperature could therefore have been represented by daily averages instead of a yearly average temperature. The combination of low loading and low ambient temperatures causes the calculated paper degradation to be negligible for most of the investigated assets. This picture will most likely change if more accurate data are used for the ambient temperature.

The second aspect of the paper degradation module which needs to be discussed regards the use of Equation 2.2. This equation is used to calculate the steady-state temperature of the transformer hot-spot, which is further used to calculate the aging rate of paper. The assumption that calculation of the steady-state temperature would be sufficient appears to be questionable. For transformers where significant load variations occur frequently, as for T1, the calculated hot-spot temperature will fluctuate. This is not representative of the actual hot-spot temperature, which will remain much more stable for such conditions. As a consequence, the calculated paper aging will show an on/off-characteristic where significant degradation of paper only occurs during load peaks. Because of the differences in the oil and winding time constants given in IEC 60076-7 the error for paper aging during heating and cooling of the transformer will not cancel out. As a general comment, the proposed paper aging module is not capable of taking frequently varying load data as input. In such cases, it might be better to use an estimated average load for the transformer if temperature data are not available.

Although Norwegian transformers generally are subject to relatively low ambient temperatures, it is unlikely that all the transformers that have been tested have a DP and a remaining lifetime which qualifies for top scores. Based on this and the above considerations, it can be concluded that a model for paper aging should most definitely be based on more accurate temperature calculations than those performed in the proposed model. More detailed dynamic models for this are proposed in IEC 60076-7. Implementation of these should , however, consider using simulation tools such as SIMULINK instead of Microsoft Excel for increased flexibility. This, in combination with more accurate ambient temperature data, will most likely lead to more accurate DP and remaining life estimates.

Maintenance Module

The maintenance module proposed in the model scores the components of transformers based on their maintenance need during the last five years. The usefulness of this module is, however, very dependent on the subjective user evaluation. Since the user is asked to determine the severity of each corrective maintenance operation, the objectiveness of the health index is lost. This might cause transformers with similar defects to be scored differently depending on the user. However, as long as the national statistical material remains unsatisfactory for calculation of reliable failure rates, alternative methods have to be found. The historic maintenance record of a transformer is for this reason also assumed to be representative of the future maintenance need of the transformer. Because of the relatively low weight of the maintenance module in the final health index calculation, the loss of objectivity is not regarded to be a significant problem.

External Stress Module

The external stress module used in the proposed model uses both the lightning withstand capacity and the expected short circuit currents as criteria for scoring. This way, the potential effect of lightning overvoltages and short circuit currents is roughly evaluated. A limitation to this model is, however, its inability to take into consideration the frequency of such events. This important factor was left out of the model because of the limited access to this kind of data. This leads to the automatic assumption that all transformers are equally exposed to such stresses, which is naturally wrong. If the frequency of both lightning surges and short circuit currents was incorporated into the model, this would allow for differentiation between assets that are particularly exposed to external stresses and those that are not.

Another weakness of this module as it stands, is the fact that the external stress scores will remain constant over time. This means that the score will not differentiate between assets of various conditions, but only indicate their withstand capability against external stresses. Although this information is also interesting, the module counteracts the idea that assets that clearly are in a poor condition should score lower than those in a good condition. A solution for this might be to include the number of lightning surges and short circuit occurrences experienced by the transformer. This way, the score would both decrease over time and be representative of the stresses that have actually affected the transformer. If current data availability allows the inclusion of such an indicator is, however, unknown.

7.2.3 Uncertainty Management

Two of the reviewed models in Chapter 4 mention ways of indicating the confidence associated with the output. In the proposed model, however, this is not indicated in any way. Instead, uncertainty is consequently handled by assuming the worst. This might cause the model to both be unreasonably harsh and to appear more reliable than what is the case. Although the model has been designed with the data availability of Norwegian utilities and transformer owners in mind, its output will always be associated with some degree of uncertainty. For this reason, an indicator of the certainty should ideally accompany the health index score. One way to include such an indicator could be to calculate a confidence index in parallel with the health index. The output of the model could then be given both as a health index and a confidence index. To calculate such a confidence index, the same approach as for the health index could have been used. Through a set of predefined rules the confidence of each condition score could be evaluated. These rules could for instance be based on the input data age or quality.

7.3 Overall Quality of the Model

The model proposed in this thesis is a first draft of a health index customized to Norwegian needs. For this reason, the data collection practices of Norwegian utilities have been essential to the design of the model. An important question is, however, whether or not the model is reliable enough for asset owners to put trust in it. In an attempt to answer this question, the above discussed aspects will be taken into account. Because of the previously explained weak performance of the paper aging module, using load data as input for this module should be avoided. For such a functionality to be reliable, more accurate thermal models would need to be utilized. If, however, winding or top oil temperature is used as input, the inaccuracies of the thermal model are ommitted.

Although it might be argued that experienced asset managers will be able to interpret the condition data of single transformers just as well as a health index, the real advantage of an index lies in its ability to assess numerous transformers simultaneously. By making sure that every asset is evaluated by the same criteria, a ranking of assets by condition is made possible. This ranking will allow asset managers to see where maintenance or reinvestment is required simply by comparing the scores of the assets in a fleet. From the results presented in Chapter 6, it appears that the health index is able to provide reliable scores for ranking of assets. Additionally, based on the presented results, a decent relationship between the actual condition of an asset and the health index score appears to exist. It might therefore be said that the health index score is indicative of the condition of a transformer. However, to accurately determine this condition, more thorough investigations than those utilized in the health index must be performed.

When it comes to the usability of the proposed model, it is believed that most asset managers will have access to the required input data. This is expected to be a large advantage since this allows all assets of a fleet to be assessed and since it minimizes the effort associated with such assessments. Additionally, the model is able to select appropriate values based on IEC standard values for some of the quantities that are not in frequent use. This functionality is believed to be very important in order to make the health index an easy-to-use tool. In the opposite case, the asset manager has to provide all the information and health indexing might be seen as too time consuming and troublesome to be worth while. After all, health indexing is initially performed for increased efficiency.

8 | Conclusions

In this thesis, a model for health indexing of power transformers is proposed. This model is based on identification of the most important failure modes and aging mechanisms for power transformers, as well as on reviews of four existing models for health indexing. Customizing the model to Norwegian needs has been an important goal and the model has therefore been designed with special emphasis on the data availability faced by most Norwegian utilities. This is important to ensure that all transformers are evaluated on the same basis. The model input data have for this reason been limited to DGA analysis, oil sample analysis, load or temperature data, maintenance history and selected design data. Special measurements that are not conducted regularly in Norway have been left out. Based on the reviewed models and the available input data, appropriate assessment models have been found. These have been designed corresponding to international standards on transformer maintenance. The output of the model is given as an overall score which describes the condition of the transformer.

The proposed model has been tested on seven power transformers of various age and condition. This test showed that the model was able to differentiate between transformers in different conditions. Furthermore, the model appears to give good estimates of the actual condition of each transformer and can hence be used to identify potentially risky assets. The model output is too rough to be used as a sole basis for reinvestment decisions, but might be used as an indicator of where more thorough investigations are needed. The main model limitation is believed to be the paper aging assessment module of the model. This module is designed to handle both temperature and load data as input, but shows an unsatisfying performance when the latter is used. Additionally, consideration should to a greater extent be taken to the ambient temperature of the transformer. The models for assessment of dissolved gas analysis and oil sample analysis are generally believed to reflect common practice.

Further Work

Because of the unsatisfying performance of the solid insulation assessment module of the proposed model, a natural field of further work is to improve this. Such improvements might be made by implementation of the dynamic thermal models proposed in IEC 60076-7. Furthermore, establishing a confidence indicator should be considered in order to let users of the model know the reliability of a condition estimate.

In order to determine the performance of the proposed model more confidently, it should be tested on larger groups of assets where the condition is known. This way, the relationship between health index score and actual condition of a transformer might be found more clearly. Such testing would also be helpful with respect to the implementation of a confidence indicator. Comparing the output of the proposed model to that of similar health index models should also be considered. Finally, it might be desirable for each user of the health index model to adjust either scoring limits or weights in the proposed model according to their own service experiences.

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Appendices

A | List of Failure Modes and Degradation Mechanisms

In this appendix, the list of failure modes and aging mechanisms described in Chapter 5 is provided. The list is a result of a litterature review condicted on transformer degradation mechanisms. Important sources of information have been the SINTEF Energy Research Transformer Handbook [1, 6–10], the ABB Service Handbook [3], the J&P Transformer Book [4,11] and the US Bureau of Reclamation Transformer Book [5]. To verify the validity of the list, a meeting with several transformer experts took place in Oslo on the 14th of April 2015 under the auspices of SINTEF Energy Research. This meeting resulted in minor corrections of the list.

Table A.1: *List of failure modes which might impact the health of power transformers.*
E=Electrical, M=Mechanical, T=Thermal, C=Chemical

Component	**Failure mode**
Core	Short circuited laminations (E)
	Broken ground condition (E)
	Unintentional ground (E)
Winding	Deformation of winding (M)
	Breakdown of insulation (E)
	High moisture (C)
Oil	Formation of sludge (C)
	Corrosivity (C)
	Contamination of particles (C)
	Water in oil (C)
Tank	Overheating from stray flux or circulating currents (T)
	Leaks (M)
DETC	Coking of contacts (E/C/T)
	Jammed mechanism (M)
OLTC	Coking of contacts (E/C/T)
	Burnt resistor (E)
	Jammed mechanism (M)
Bushings	Corona and internal discharges (E)
	Loose field distributor (E/M)
	High resistance in connections (E/T)
	Puncture of capacitive insulation (E/M)
	Cracks in outer coating (M)
	Leaks (M)
	Pollution of outer surcafe (C)
Cooling	Loss of gasket sealing (M)
	Failure of fans or pumps (M/E)

Table A.2: *List of aging mechanisms which might impact the health of power transformers.*
E=Electrical, M=Mechanical, T=Thermal, C=Chemical

Component	**Aldring**
Core	Loss of lamination pressure (M)
Winding	Aging of paper insulation (M/C)
	Loss of winding pressure (M)
	Carbonization of paper (T)
	Overheating of contacts and joints (E/T)
	Copper corrosion (C)
	Discharges or partial discharges (E)
Oil	Oxidation of oil (C)
	High moisture (C)
Tank	Aging of gaskets (C)
	Corrosion (C)
	Loss of sealing pressure (M)
DETC	Aging of insulation (C)
OLTC	Aging of oil (C)
	Aging of insulation (C)
	Wear of mechanical parts (M)
	Silver corrosion (C)
Bushings	Partial discharges (E)
	Degradation of paper insulation (C)
	Moisture ingress (C)
Cooling	Corrosion (C)
	Clogging of heat exchangers (C)
	Clogging of water coolers (M)

B | Assessment Functions

In this appendix, the assessment functions developed by DNV KEMA, described in Chapter 4.1 will be described more in detail. The functions are originally described in [21].

B.1 Statistical Assessment Function

Redistribution

Let $f(t)$ be the probability density function obtained for a group of assets from the failure statistic of an asset owner. $F(t)$ is then the cumulative density function for the same group of assets. In the following it can be assumed that $f(t) = n(t, \mu, \sigma)$. Per definition, the integral of $f(t)$ from minus infinity to infinity must be equal to 1.

$$\int_{-\infty}^{\infty} f(t)\,\mathrm{d}t = 1 \tag{B.1}$$

Now, consider a sepcific asset of age x. This asset has survived this far, and can hence not fail for any time $t < x$. Its probability density function $f_r(t)$ must therefore be 0 for all values of t up to its current age x. It is assumed that $f_r(t)$ will retain its original shape for any time $t \geq x$, i.e. it is Normal distributed with the same μ and σ as for the initial distribution. Since it is an absolute requirement that the area under any statistical density function must be equal to 1, Equation B.2 applies.

$$\int_{-\infty}^{\infty} f_r(t)\,\mathrm{d}t = \int_{-\infty}^{x} 0\,\mathrm{d}t + \int_{x}^{\infty} f_r(t)\,\mathrm{d}t = 1 \tag{B.2}$$

Since $f_r(t)$ is zero for all $t < x$, the remaining curve for all $t \geq x$ must be scaled for Equation B.2 to be true. From the assumption that $f_r(t)$ retains its shape for all $t \geq x$ and the fact that the integrals of $f(t)$ and $f_r(t)$ from minus infinity to infinity are equal, a scaling factor can be derived:

$$f_r(t) = k \cdot f(t) \tag{B.3}$$

$$\int_{-\infty}^{\infty} f(t)\,\mathrm{d}t = \int_{t}^{\infty} f_r(t\,\mathrm{d}t \tag{B.4}$$

Combining Equations B.3 and B.4 then gives

$$\int_{-\infty}^{\infty} f(t)\,\mathrm{d}t = \int_{t}^{\infty} k \cdot f(t)\,\mathrm{d}t \tag{B.5}$$

Solving Equation B.5 gives the cumulative density functions as shown by Equation B.6.

$$F(\infty) - F(-\infty) = k \cdot (F(\infty) - F(t)) \tag{B.6}$$

Since $F(-\infty) = 0$ and $F(\infty) = 1$, the expression can be rewritten and solved for k to yield Equation B.7:

$$k = \frac{F(\infty)}{F(\infty) - F(t)} = \frac{1}{1 - F(t)} \tag{B.7}$$

B.2 Condition Assessment Function

In Table B.1 and B.2, the condition function for a tap changer is illustrated. This is one out of several condition functions used by the method presented in [21], but is also the only example which is given. The function evaluates the long term effect of the condition parameters shoen in Table B.2 and uses the functions in Table B.2 to adjust the statistically expected remaining lifetime obtained from the statistical function as explained in section B.1.

Table B.1: *Example of how the condition assessment function is constructed. The following parameters and their value are used as input for the functions shown in Table B.2.*

Input parameters	**Values**
Tap changer type	Brass, Silver
Load	Low, Moderate, High
Sulphur	Yes, No
Resistance	Poor, Fair, Good
DGA (C_2H_4)	Poor, Fair, Good
Statistical remaining life	RL_{stat}

Table B.2: *Example of how the condition assessment function is constructed. The following functions are used to adjust the statistically estimated remaining lifetime of individual assets. To identify particularly poor assets, knock-out criterions are used to trigger an alarm which indicates that the asset is in need of immediate attention.*

Function Condition	**Result**
if (DGA=poor)	Knock-out
elseif(Resistance=poor)	Knock-out
elseif(Resistance=fair)	$RL_{cond} = RL_{stat} - 50\%$
elseif(Type of TC=silver & Sulphur=Yes & Load=High)	$RL_{cond} = RL_{stat} - 50\%$
elseif(Type of TC=silver & Sulphur=Yes & Load=Low or Moderate)	$RL_{cond} = RL_{stat} - 25\%$
elseif(Type of TC=brass & Sulphur=Yes & Load=High)	$RL_{cond} = RL_{stat} - 75\%$
elseif(Type of TC=brass & Sulphur=No & Load=High)	$RL_{cond} = RL_{stat} - 50\%$
elseif(Type of TC=brass & Sulphur=Yes & Load=Low or Moderate)	$RL_{cond} = RL_{stat} - 50\%$
elseif(Type of TC=brass & Sulphur=No & Load=Low or Moderate)	$RL_{cond} = RL_{stat} - 25\%$
else	$RL_{cond} = RL_{stat}$

C | Scoring Tables for Kinectrics Health Index Model

The following appendix contains the tables used as scoring criteria for the health index model presented by in Chapter 4.3.

Table C.1: *Scoring and weight factors for gas levels [PPM].*

Gas	**Score (S_i)**						W_i
	1	2	3	4	5	6	
H_2	≤100	100-200	200-300	300-500	500-700	≥700	2
CH_4	≤75	75-125	125-200	200-400	400-600	≥600	3
C_2H_6	≤65	65-80	80-100	100-120	120-150	≥150	3
C_2H_4	≤50	50-80	80-100	100-150	150-200	≥200	3
C_2H_2	≤3	3-7	7-35	35-50	50-80	≥80	5
CO	≤350	350-700	700-900	900-1100	1100-1400	≥1400	1
CO_2	≤2500	≤3000	≤4000	≤5000	≤7000	≥7000	1

Table C.2: *Scoring and weight factors for oil quality parameters.*

	U≤69 kV	**69 kV<U<230 kV**	**230 kV≤U**	**Score (S_i)**	**Weight (W_i)**
Dielectric Strength [kV] (2mm gap)	≥45	≥52	≥60	1	3
	35-45	47-52	50-60	2	
	30-35	35-47	40-50	3	
	≤30	≤35	≤40	4	
Interfacial tension [dyne/cm]	≥25	≥30	≥32	1	2
	20-25	23-30	25-32	2	
	15-20	28-23	20-25	3	
	≤15	≤18	≤20	4	
Acid number [mg KOH/g oil]	≤0.05	≤0.04	≤0.03	1	1
	0.05-0.1	0.04-0.1	0.03-0.07	2	
	0.1-0.2	0.1-0.15	0.07-0.1	3	
	≥0.2	≥0.15	≥0.1	4	
Water content [ppm]	≤30	≤20	≤15	1	4
	30-35	20-25	15-20	2	
	35-40	25-30	20-25	3	
	≥40	≥30	≥30	4	
Color	≤1.5			1	2
	1.5-2.0			2	
	2.0-2.5			3	
	≥2.5			4	
Dissipation factor [%] (at 25°C)	≤0.1			1	3
	0.1-0.5			2	
	0.5-1.0			3	
	≥1.0			4	

Table C.3: *Condition criteria weights for scoring.*

i	**Transformer Condition Criteria**	**Weight** K_i	**Condition Rating**	**HIF**
1	DGA	10	A,B,C,D,E	4,3,2,1,0
2	Load History	10	A,B,C,D,E	4,3,2,1,0
3	Power Factor	10	A,B,C,D,E	4,3,2,1,0
4	Infra-red	10	A,B,C,D,E	4,3,2,1,0
5	Oil Quality	6	A,B,C,D,E	4,3,2,1,0
6	Overall Condition	8	A,B,C,D,E	4,3,2,1,0
7	Furan or Age	5	A,B,C,D,E	4,3,2,1,0
8	Bushing Condition	5	A,B,C,D,E	4,3,2,1,0
9	Main Tank Condition	2	A,B,C,D,E	4,3,2,1,0
10	Cooling Equipment	2	A,B,C,D,E	4,3,2,1,0
11	Oil Tank Condition	1	A,B,C,D,E	4,3,2,1,0
12	Foundation	1	A,B,C,D,E	4,3,2,1,0
13	Grounding	1	A,B,C,D,E	4,3,2,1,0
14	Gaskets	1	A,B,C,D,E	4,3,2,1,0
15	Connectors	1	A,B,C,D,E	4,3,2,1,0
16	Oil leaks	1	A,B,C,D,E	4,3,2,1,0
17	Oil level	1	A,B,C,D,E	4,3,2,1,0
18	DGA of OLTC	6	A,B,C,D,E	4,3,2,1,0
19	OLTC Oil Quality	3	A,B,C,D,E	4,3,2,1,0
20	Overall OLTC Condition	5	A,B,C,D,E	4,3,2,1,0

D | Scoring Tables for Oil Quality Module of the Norwegian Health Index Model

This appendix contains the tables used for scoring of the oil quality in the Norwegian health index model. Table D.1 is used for scoring of non-corrosive oil. If the oil is corrosive, Table D.2 is used as a supplement for scoring. The tables are explained more thoroughly in Chapter 5.

Table D.1: *Scoring and weight factors for oil quality parameters used in the Norwegian health index model.*

	U≤72,5 kV	**U≤170 kV**	**170 kV<U**	**Score (S_i)**	**Weight (W_i)**
Dielectric Strength [kV] (2,5mm gap)	≥50	≥60	≥70	4	3
	<50	<60	<70	3	
	<40	<50	<60	2	
	<30	<40	<50	1	
Water content [ppm]	<20	<15	<10	4	4
	<30	<20	<15	3	
	<40	<30	<20	2	
	≥40	≥30	≥20	1	
Acid number [mg KOH/g oil]	<0.05	<0.04	<0.03	4	1
	<0.1	<0.1	<0.07	3	
	<0.2	<0.15	<0.1	2	
	≥0.2	≥0.15	≥0.1	1	
Dissipation factor [%] (at 90°C)	<0.05		<0.05	4	3
	<0.1		<0.07	3	
	<0.5		<0.1	2	
	≥0.5		≥0.1	1	
Color	<1.5			4	2
	<2.0			3	
	<2.5			2	
	≥2.5			1	
Inhibitor content [%]	≥0.24			1	2
	<0.24			2	
	<0.18			3	
	<0.12			4	
Interfacial surface tension [mN/m]	>35			4	2
	>30			3	
	>25			2	
	≤25			1	

Table D.2: *Addition to Table D.1 in case of corrosive oil. If the oil is found to be corrosive, these two parameters are included in the oil quality factor. If the oil is not corrosive, the parameters are left out to not distort the oil quality factor.*

	U≤72,5 kV	**U≤170 kV**	**170 kV<U**	**Score (S_i)**	**Weight (W_i)**
Passivator content [mg/kg]	>90			4	1
	>70			3	
	>50			2	
	≤50			1	
Corrosivity	Non-corrosive			4	4
	Corrosive			1	

E | Equilibrium Curves

The following equilibrium curves are used to estimate the winding moisture content in the Norwegian health index model. Water content in paper insulation [%] is described as a function of oil moisture content [ppm] for different temperatures. The curves are initially taken from [14].

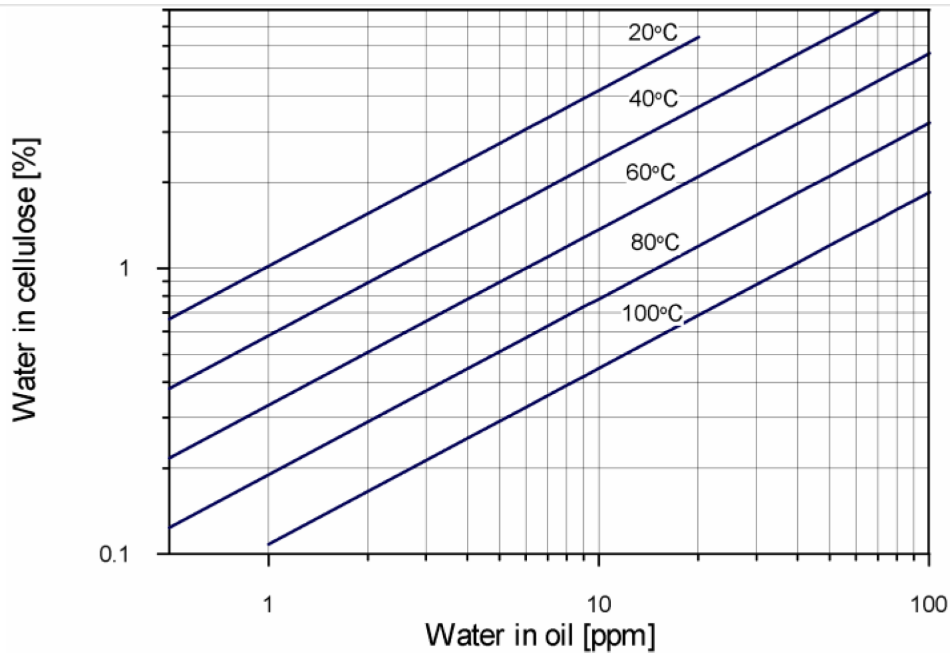


__Figure E.1:__ Equilibrium curves for a paper-oil insulation system used to estimate winding moisture content in the Norwegian health index model. Figure taken from [14].

F | Tables Used to Calculate Impact of External Stresses

In this appendix, IEC standard values for basic insulation (BIL), overhead line corona factor and short circuit power are given. The values are originally given by IEC standards 60071-2 and 60076-5. These values are used in the calculations regarding the ability of transformers to withstand external stresses if no other data are available.

Table F.1: *Standard upper basic insulation level (BIL) for transformer with different rated voltages as given by IEC 60071-2 [37].*

Highest system voltage [kV]	BIL [kV]
36	170
52	250
72,5	325
123	550
145	650
170	750
245	1050
300	1050
362	1175
420	1425

Table F.2: *Corona factor for different types of transmission lines as given by IEC 60071-2 [37].*

Corona factors for transmission lines	**A** [kV]
One conductor	4500
Two conductors	7000
Four conductors	11000
Six and eight conductrors	17000

Table F.3: *Typical European schort circuit powers for different voltage levels as given by IEC 60076-5 [20].*

Voltage level [kV]	**Short circuit power [MVA]**
36	500
72,5	1000
123	6000
170	10000
245	20000
300	30000
362	35000
420	40000

G | Weight Tables for Norwegian Health Index Model

Table G.1 shows the proposed weighting of each component and the relative weights for each condition score. The latter is used for calculation of a component score, whereas the component weights are used to calculate the final health index score. External stresses are in this regard treated as a component. It should be noted that the condition score weight factors are relative only to the the other condition scores for that component. The DGA factor is, however, an exception since it might be split between several components as described in Chapter 5.2. For a no-fault situation it will be split between the winding, tank and core, resulting in a weight of 4 to each.

It should be noted that the core is only evaluated through the contribution from the DGA factor in this model. In cases where the DGA factor is not directed towards the core (such as for a PD fault), the core is excluded from calculation. The remaining component weights will thus have to be adjusted so that the relative weight of each component remains the same. The same might happen if the transformer does not have a tap changer. The tap changer is then excluded from calculation and the remaining scores adjusted accordingly. These two incidents might also occur at the same time.

Table G.1: *Relative weight factors for each component. Note that the weights are only relative to the other condition scores of that component.*

**) The DGA factor is initially weighted 12, but the factor might be split between several components as described in Chapter 5.2. For a no-fault situation, it will be split between the winding, tank and core, resulting in a weight of 4 to each.*

Component weight [%]	**Component**	**Condition score**	**Relative weight**
		DGA Factor	12*
30	Winding	Insulation remaining life	2
		Insulation DP value	4
		DGA contribution	*
20	Tap changer	Maintenance factor	3
		TC maintenance scheme	1
		TC audit score	5
		DGA contribution (Main tank)	*
5	Tank	Maintenance factor	3
		DGA contribution	*
15	Oil	Maintenance factor	3
		Oil quality	12
		DGA contribution	*
10	Bushing	Maintenance factor	3
		DGA contribution	*
8	Core	DGA contribution	*
2	Auxiliary equipment	Maintenance factor	1
10	External stresses	Lightning protection score	1
		Short circuit withstand capacity	1

H | Case study: T7

To demonstrate the behavior of the different modules and the model as a whole, a case study is performed. T7 is chosen as test object because of its interesting expected condition, which is described as "Acceptable" despite its high age.

DGA Factor

The DGA factor of T7 is calculated based on the data in Table I.31. By using Equation 5.1, a DGA factor of 5,44 is calculated based on the values of the different gases. The same data are used to calculate the trend factor of 0,72 according to Equation 5.2. These factors are then multiplied to include trending in the DGA evaluation. This gives a DGA factor of 3,93. Scoring of this factor is performed according to Table 5.6, resulting in a score of 0. The different scores are summed up in Table H.1

It should be mentioned that a D1 fault was initially reported by the DGA module for this transformer. This fault code is however ignored in the calculation because the low concentrations of certain gases for T7 makes fault detection through gas ratios a questionable practice. The fault factor is hence set to 1. The DGA factor score is, however, calculated to be 0 regardless of this fault code. Because the DGA factor score is obtained for "normal operation" (no fault), the impact of this factor is split between the winding, tank and core.

Table H.1: *DGA module sub-scores and final score for transformer T7.*

DGA factor	**Trend factor**	**Fault factor**	**DGAF·TF·FF**	**Score**
5,44	0,72	1	3,93	**0**

Oil Quality Factor

The oil quality factor (OQF) of the transformer is calculated based on the data in Table I.32. Equation 5.4 then results in an OQF of 3,88, which results in an OQF score of 4 according to Table 5.7.

Paper Aging Assessment

Figure I.7 shows one load year for the transformer. Based on this load year, an equivalent hot spot temperature of 45°C is calculated. This is the constant temperature which causes the same amount of aging during one year as the varying temperatures for that year. During this year, the hot spot temperature is calculated to vary between the extremes 27°C and 70,8°C as shown in Figure H.1. An equivalent temperature of 45°C is further assumed to be representative of previous and future years. Through Equation 5.6, a current DP value and an expected remaining life is found. The ambient temperature of the transformer location is set to 4°C, which is the yearly average temperature according to climate statistics from the Norwegian Meteorological Institute [38]. The transformer is located in Northern Norway, and the average ambient temperature is hence low.

Determination of appropriate parameters for Equation 5.6 is performed by investigating the oxygen and moisture content in the DGA and oil sample analysis, respectively. Oxidation is assumed to take place since the O_2-level is above 6000 ppm. The diagram shown in Figure E.1 is further used to assume a moisture level for the paper. From the oil sample analysis, a moisture content of 4,7 ppm at 18°C is found. This results in an estimated moisture level of 3,5 %. Because no information on the paper quality of the transformer has been found, the paper is assumed to be of kraft type. This will result in the most conservative estimate. The paper degradation curve obtained from these calculations is shown in Figure H.2. The current DP value is estimated to be 823, while the remaining life is estimated to be 1002 years. Based on these numbers a score of 4 is obtained both for the current DP value criterion and the remaining life criterion.

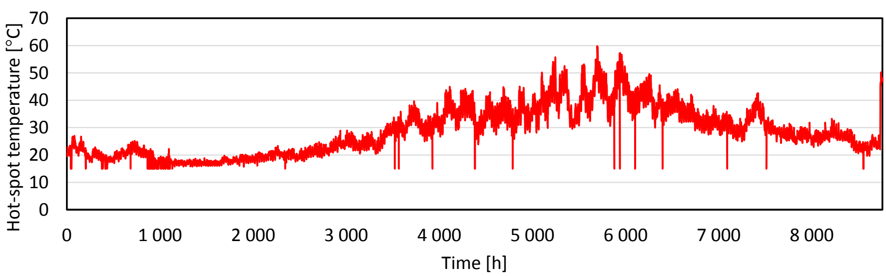


Figure H.1: *Hot spot calculated for one load year for T7. The calculation is performed from summer to summer and the highest temperatures do hence occur during winter.*

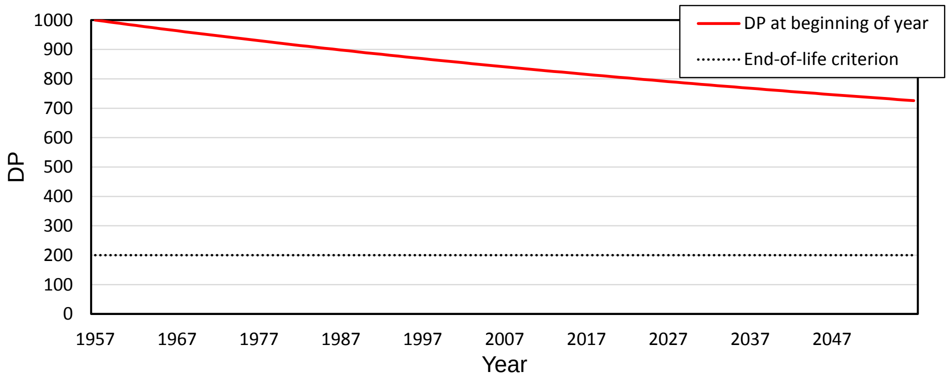


Figure H.2: *Estimated DP value development over the life of T7.*

Table H.2: *Paper aging calculation parameters and scores for transformer T7.*

T_a	T_{HS}	Moisture	Oxidation?	DP	DP score	Remaining life	RL score
4°C	45°C	3,5%	Yes	823	**4**	1002 years	**4**

Maintenance Need

The maintenance scores of the different components were calculated based on the maintenance record shown in Table I.33. The only component which does not score 4 based on its maintenance history, is the tap changer. The tap changer of this transformer was of OLTC type and did in 2012 have a serious defect which led to its replacement. The current tap changer is therefore relatively new and most likely in a good condition. Nevertheless, the maintenance history score of this component is decreased because of the previous defect and its score is calculated to be 3. Because the current tap changer is relatively new, it has been given a score of 4 for the audit criterion. The tap changer maintenance scheme criterion resulted in a score of 2, since regular calibration of the voltage regulator and regular operation of all taps could not be verified.

Table H.3: *Tap changer sub-scores and final score for transformer T7.*

Maintenance history	Audit score	Maintenance scheme	Final TC score
3	4	2	3,6

External Stresses

The ability of the transformer to withstand lightning stresses was calculated through Equation 5.9. U_{pl} for the transformer surge arrester was found to be 395 kV. Parameters which regarded distances and design, i.e. the location of the surge arrester, the length of the span closest to the station and the number of conductors of this line, were estimated based on photos from the transformer station. From this, the surge arrester ground was assumed to be 5 meters from the transformer terminals, the length of the closest span to be 300 meters and the number of conductors for the lines of this span to be two. These parameters should, however, ideally have been based on data and do represent an element of uncertainty in the calculation. The number of incoming overhead lines for the station is assumed to be 1, since this represents the worst case scenario. Furthermore, the accepted failure rate was set equal to one failure per 400 years per, as suggested in [37]. A failure rate of 0,2 failures per 100km per year, which is based on statistics from Statnett, is used for the actual failure rate coefficient R_{km}. This resulted in a coordination withstand voltage of 418 kV.

To score the lightning withstand ability of the transformer, the coordination withstand voltage is compared to the basic insulation level (BIL) of the transformer. The BIL was not known, but assumed to be according to the standards given by the IEC in Table F.1. A BIL of 650 kV was therefore assumed. This resulted in a BIL/U_{cw} ratio of 1,56, which gives a lightning withstand score of 2 according to Table 5.14. The ability of the transformer to withstand short circuit is calculated based on its short circuit reactances. These are given in Table I.35. The resulting primary to secondary maximum short circuit current is calculated to be 23,6 per unit, resulting in an earth fault withstand score of 2.

Table H.4: *Lightning withstand ability of transformer T7.*

BIL	U_{cw}	BIL/U_{cw}	Lightning withstand score
650 kV	418 kV	1,56	**2**

Table H.5: *Earth fault withstand ability of transformer T7.*

Voltage level	Short circuit reactance (P-S)	$\hat{I}_{SC}$	Earth fault withstand score
144 kV	0,129 pu.	23,6 pu.	**2**

Results for T7

From the presented scores, a final health index is calculated through Equations 5.10 and 5.11, as explained in Chapter 5.8. The different components of the transformer are scored as shown in Table H.6. The final health index score of the transformer is found to be 70.

Table H.6: *Component and stress factor scores for transformer T7. A score of 4 represents the best condition and 0 the worst.*

Winding	**Tap changer**	**Tank**	**Oil**	**Bushing**	**Core**	**Auxiliary equipment**	**External stresses**
2,4	3,6	1,7	4	4	0	4	2

I | Transformer Data

This appendix contains all the different data for the transformers evaluated in the thesis. The results based on these data are shown in Chapter 6.

I.1 T1 Data

Table I.1: *DGA data for T1.*

	Date:	**26.05.2015**
[ppm]	Hydrogen	3,9
[ppm]	Oxygen	5000
[ppm]	Nitrogen	16000
[ppm]	Carbon monoxide	160
[ppm]	Carbon dioxide	110
[ppm]	Methane	1,1
[ppm]	Ethene	1
[ppm]	Ethane	1
[ppm]	Ethyne (Acetylene)	1
[ppm]	Propane	0,065
[ppm]	Propene	0,2

Table I.2: *Oil sample analysis data for T1.*

Date:	**26.02.2015**
Top oil temperature [°C]	20
Breakdown voltage [kV]	86
Water content [mg/kg]	4,3
Neutralization value [mg KOH/g]	0,01
tan(δ) [% ref 90°C]	
Color	0
Surface tension	48
Inhibitor content	0,29
Corrosive towards copper	No
Corrosive towards silver	No
Passivator content:	

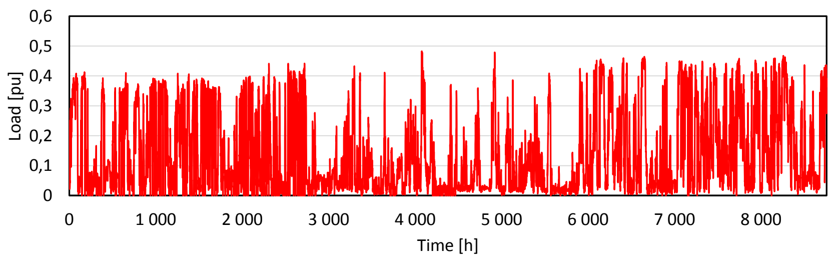


Figure I.1: *Hourly load values for one year for transformer T1.*

Table I.3: *Maintenance data for T1. *) Priority of the initial fault is given as a number from 0 to 4, where 0 represents no fault and 4 represents a major failure which requires immediate outage and repair.*

Failure detected date:	**Priority* for the affected component**					**Failure corrected date**
	Tap changer	**Bushing**	**Tank**	**Oil**	**Auxiliary equipment**	
14.10.2013	3					22.10.2013

Table I.4: *Parameters used in the calculation of the coordination withstand voltage U_{cw} of transformer T1.*

BIL [kV]	650
Distance between arrester and transformer [m]	0
Length of span closest to station [m]	300
Overhead line number of conductors	2
Corona coefficient [kV]	7000
Number of lines connected to station	1
Accepted failure rate [failures/year]	0,0025
Overhead line outage rate [failures/year/100km]	0,000002
l_a [m]	1250
Surge arrester lightning impulse protection level U_{pl} [kV]	395

Table I.5: *Short circuit reactances of transformer T1.*

Transformer short circuit reactances		
Primary - Secondary	0,1137	pu.
Secondary-Tertiary	0,02222	pu.
Primary - Tertiary	0,0667	pu.

I.2 T2 Data

Table I.6: *DGA data for T2.*

	Date:	06.03.2014	02.04.2013	24.05.2012	20.07.2011
[ppm]	Hydrogen	25	27	27	27
[ppm]	Oxygen	6900	1300	3900	270
[ppm]	Nitrogen	33000	11000	26000	12000
[ppm]	Carbon monoxide	330	320	410	430
[ppm]	Carbon dioxide	390	380	410	430
[ppm]	Methane	6,5	6	6	5
[ppm]	Ethene	1	1	1	1
[ppm]	Ethane	1	1	1	1
[ppm]	Ethyne (Acetylene)	1	1	1	1
[ppm]	Propane	1	1	1	1
[ppm]	Propene	1,8	2	2	2

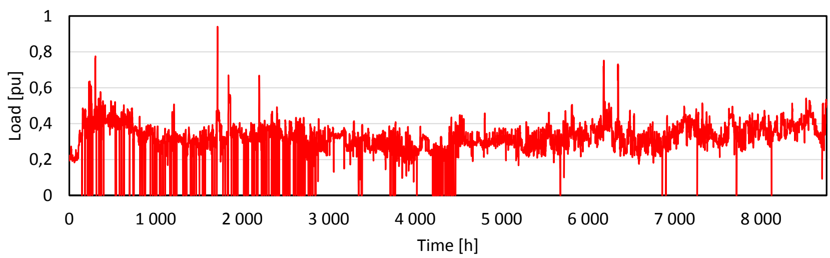


Figure I.2: *Hourly load values for one year for transformer T2.*

Table I.7: *Oil sample analysis data for T2.*

Date:	**06.03.2014**
Breakdown voltage [kV]	85
Water content [mg/kg]	3
Neutralization value [mg KOH/g]	0,01
tan(d) [% ref 90°C]	0,0005
Color	0
Surface tension	45
Inhibitor content	0,3
Corrosive towards copper	Yes
Corrosive towards silver	No
Passivator content:	0

Table I.8: *Maintenance data for T2. *) Priority of the initial fault is given as a number from 0 to 4, where 0 represents no fault and 4 represents a major failure which requires immediate outage and repair.*

Failure detected date:	**Priority* for the affected component**					**Failure corrected date**
	Tap changer	**Bushing**	**Tank**	**Oil**	**Auxiliary equipment**	
24.03.2014					2	17.09.2014
13.11.2012					2	15.11.2012
05.01.2012	2					09.04.2013

Table I.9: *Parameters used in the calculation of the coordination withstand voltage U_{cw} of transformer T2.*

BIL [kV]	1050
Distance between arrester and transformer [m]	10
Length of span closest to station [m]	300
Overhead line number of conductors	4
Corona coefficient [kV]	11000
Number of lines connected to station	1
Accepted failure rate [failures/year]	0,0025
Overhead line outage rate [failures/year/100km]	0,000002
l_a [m]	1250
Surge arrester lightning impulse protection level U_{pl} [kV]	726

Table I.10: *Short circuit reactances of transformer T2.*

Transformer short circuit reactances		
Primary - Secondary	0,1249	pu.
Secondary-Tertiary	0,1699	pu.
Primary - Tertiary	0,1699	pu.

I.3 T3 Data

Table I.11: *DGA data for T3.*

	Date:	**28.06.2012**	**12.05.2011**
[ppm]	Hydrogen	2	2
[ppm]	Oxygen	22000	24000
[ppm]	Nitrogen	52000	58000
[ppm]	Carbon monoxide	250	290
[ppm]	Carbon dioxide	4600	5400
[ppm]	Methane	2	2
[ppm]	Ethene	460	520
[ppm]	Ethane	1	1
[ppm]	Ethyne (Acetylene)	1	1
[ppm]	Propane	2	3
[ppm]	Propene	11	12

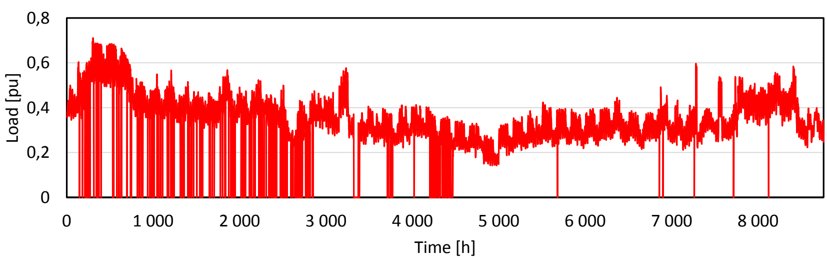


Figure I.3: *Hourly load values for one year for transformer T3.*

Table I.12: *Oil sample analysis data for T3.*

Date:	**29.05.2014**
Breakdown voltage [kV]	81
Water content [mg/kg]	3,3
Neutralization value [mg KOH/g]	0,01
tan(d) [% ref 90°C]	0,0019
Color	1,5
Surface tension	47
Inhibitor content	0,4
Corrosive towards copper	No
Corrosive towards silver	No
Passivator content:	

Table I.13: *Maintenance data for T3. *) Priority of the initial fault is given as a number from 0 to 4, where 0 represents no fault and 4 represents a major failure which requires immediate outage and repair.*

Failure detected date:	**Priority* for the affected component**					**Failure corrected date**
	Tap changer	**Bushing**	**Tank**	**Oil**	**Auxiliary equipment**	
05.01.2015					2	25.02.2015
03.10.2013					2	03.10.2014
25.07.2013					2	05.03.2014

Table I.14: *Parameters used in the calculation of the coordination withstand voltage U_{cw} of transformer T3.*

BIL [kV]	1050
Distance between arrester and transformer [m]	10
Length of span closest to station [m]	300
Overhead line number of conductors	2
Corona coefficient [kV]	7000
Number of lines connected to station	1
Accepted failure rate [failures/year]	0,0025
Overhead line outage rate [failures/year/100km]	0,000002
l_a [m]	1250
Surge arrester lightning impulse protection level U_{pl} [kV]	592

Table I.15: *Short circuit reactances of transformer T3.*

Transformer short circuit reactances		
Primary - Secondary	0,118	pu.
Secondary-Tertiary	0,09	pu.
Primary - Tertiary	0,0055	pu.

I.4 T4 Data

Table I.16: *DGA data for T4.*

	Date:	**12.06.2012**	**04.04.2011**
[ppm]	Hydrogen	8	54
[ppm]	Oxygen	22436	17522
[ppm]	Nitrogen	49496	64183
[ppm]	Carbon monoxide	119	225
[ppm]	Carbon dioxide	900	1666
[ppm]	Methane	40	92
[ppm]	Ethene	114	194
[ppm]	Ethane	22	37
[ppm]	Ethyne (Acetylene)	2,7	7
[ppm]	Propane		
[ppm]	Propene		

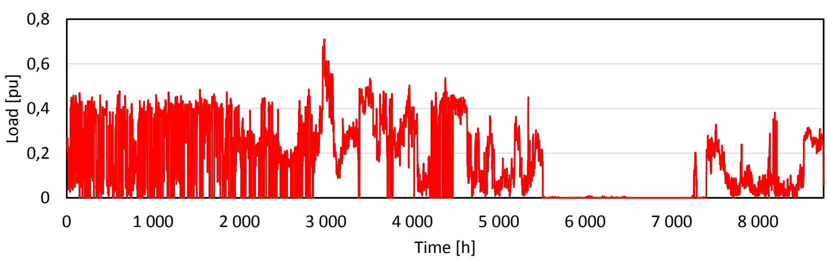


Figure I.4: *Hourly load values for one year for transformer T4. The period without load was found for two consecutive years and therefore assumed to be representative for the loading of the transformer.*

Table I.17: *Oil sample analysis data for T4.*

Date:	**12.06.2012**
Breakdown voltage [kV]	75
Water content [mg/kg]	3,8
Neutralization value [mg KOH/g]	0,02
tan(d) [% ref 90°C]	0,0096
Color	2,5
Surface tension	30
Inhibitor content	0,25
Corrosive towards copper	No
Corrosive towards silver	No
Passivator content:	

Table I.18: *Maintenance data for T4. *) Priority of the initial fault is given as a number from 0 to 4, where 0 represents no fault and 4 represents a major failure which requires immediate outage and repair.*

Failure detected date:	**Priority* for the affected component**					**Failure corrected date**
	Tap changer	**Bushing**	**Tank**	**Oil**	**Auxiliary equipment**	
15.04.2015					2	17.04.2015
29.12.2014					3	06.01.2015
15.09.2014					2	25.09.2014
20.08.2012			4			31.08.2012
18.10.2010			2			15.12.2010

Table I.19: *Parameters used in the calculation of the coordination withstand voltage U_{cw} of transformer T4.*

BIL [kV]	1050
Distance between arrester and transformer [m]	8
Length of span closest to station [m]	300
Overhead line number of conductors	2
Corona coefficient [kV]	7000
Number of lines connected to station	1
Accepted failure rate [failures/year]	0,0025
Overhead line outage rate [failures/year/100km]	0,000002
l_a [m]	1250
Surge arrester lightning impulse protection level U_{pl} [kV]	646

Table I.20: *Short circuit reactances of transformer T4.*

Transformer short circuit reactances		
Primary - Secondary	0,1315	pu.
Secondary-Tertiary	0,1276	pu.
Primary - Tertiary	0,053	pu.

I.5 T5 Data

Table I.21: *DGA data for T5.*

	Date:	25.03.2014	07.05.2013	23.04.2012	08.11.2011
[ppm]	Hydrogen	210	200	49	33
[ppm]	Oxygen	3700	1800	550	770
[ppm]	Nitrogen	60000	56000	55000	56000
[ppm]	Carbon monoxide	1400	1600	1600	1400
[ppm]	Carbon dioxide	5600	6800	8000	7200
[ppm]	Methane	1100	7800	99	59
[ppm]	Ethene	1400	700	32	24
[ppm]	Ethane	1000	500	62	42
[ppm]	Ethyne (Acetylene)	1	1	1	1
[ppm]	Propane	530	220	120	110
[ppm]	Propene	2600	800	160	150

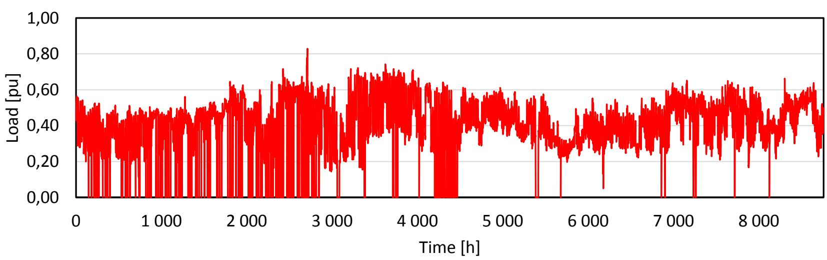


Figure I.5: *Hourly load values for one year for transformer T5.*

Table I.22: *Oil sample analysis data for T5.*

Date:	**25.03.2014**
Breakdown voltage [kV]	75
Water content [mg/kg]	36
Neutralization value [mg KOH/g]	0,52
tan(d) [% ref 90°C]	0,27
Color	8
Surface tension	17
Inhibitor content	0,06
Corrosive towards copper	No
Corrosive towards silver	No
Passivator content:	

Table I.23: *Maintenance data for T5. *) Priority of the initial fault is given as a number from 0 to 4, where 0 represents no fault and 4 represents a major failure which requires immediate outage and repair.*

Failure detected date:	**Priority* for the affected component**					**Failure corrected date**
	Tap changer	**Bushing**	**Tank**	**Oil**	**Auxiliary equipment**	
04.07.2011	3					04.07.2011

Table I.24: *Parameters used in the calculation of the coordination withstand voltage U_{cw} of transformer T5.*

BIL [kV]	1050
Distance between arrester and transformer [m]	10
Length of span closest to station [m]	300
Overhead line number of conductors	4
Corona coefficient [kV]	11000
Number of lines connected to station	1
Accepted failure rate [failures/year]	0,0025
Overhead line outage rate [failures/year/100km]	0,000002
l_a [m]	1250
Surge arrester lightning impulse protection level U_{pl} [kV]	545

Table I.25: *Short circuit reactances of transformer T5.*

Transformer short circuit reactances		
Primary - Secondary	0,126	pu.
Secondary-Tertiary	0,076	pu.
Primary - Tertiary	0,044	pu.

I.6 T6 Data

Table I.26: *DGA data for T6.*

	Date:	06.06.2014	09.07.2012	14.02.2012
[ppm]	Hydrogen	3	10	12
[ppm]	Oxygen	26000	22000	23000
[ppm]	Nitrogen	61000	54000	58000
[ppm]	Carbon monoxide	280	310	320
[ppm]	Carbon dioxide	5600	6600	7600
[ppm]	Methane	3	5	7
[ppm]	Ethene	55	69	78
[ppm]	Ethane	2	4	6
[ppm]	Ethyne (Acetylene)	82	92	110
[ppm]	Propane	10	7	8
[ppm]	Propene	41	39	43

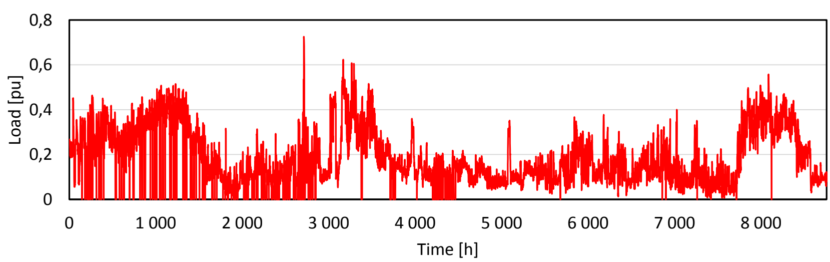


Figure I.6: *Hourly load values for one year for transformer T6.*

Table I.27: *Oil sample analysis data for T6.*

Date:	**06.06.2014**
Breakdown voltage [kV]	88
Water content [mg/kg]	4,8
Neutralization value [mg KOH/g]	0,03
tan(d) [% ref 90°C]	0,013
Color	2
Surface tension	33
Inhibitor content	0,29
Corrosive towards copper	Yes
Corrosive towards silver	Yes
Passivator content:	0

Table I.28: *Maintenance data for T6. *) Priority of the initial fault is given as a number from 0 to 4, where 0 represents no fault and 4 represents a major failure which requires immediate outage and repair.*

Failure detected date:	**Priority* for the affected component**					**Failure corrected date**
	Tap changer	**Bushing**	**Tank**	**Oil**	**Auxiliary equipment**	
11.11.2011					2	14.12.2011
01.08.2011					2	13.12.2011
21.09.2010				2		

Table I.29: *Parameters used in the calculation of the coordination withstand voltage U_{cw} of transformer T6.*

BIL [kV]	1150
Distance between arrester and transformer [m]	8
Length of span closest to station [m]	300
Overhead line number of conductors	4
Corona coefficient [kV]	11000
Number of lines connected to station	1
Accepted failure rate [failures/year]	0,0025
Overhead line outage rate [failures/year/100km]	0,000002
l_a [m]	1250
Surge arrester lightning impulse protection level U_{pl} [kV]	528

Table I.30: *Short circuit reactances of transformer T6.*

Transformer short circuit reactances		
Primary - Secondary	0,156	pu.
Secondary-Tertiary	0,1075	pu.
Primary - Tertiary	0,076	pu.

I.7 T7 Data

Table I.31: *DGA data for T7.*

	Date:	02.06.2014	24.06.2013
[ppm]	Hydrogen	23	16
[ppm]	Oxygen	22000	12000
[ppm]	Nitrogen	61000	28000
[ppm]	Carbon monoxide	120	53
[ppm]	Carbon dioxide	2000	1300
[ppm]	Methane	3	1,3
[ppm]	Ethene	5	2,6
[ppm]	Ethane	1	0
[ppm]	Ethyne (Acetylene)	14	7,8
[ppm]	Propane	1	0,56
[ppm]	Propene	3	1,8

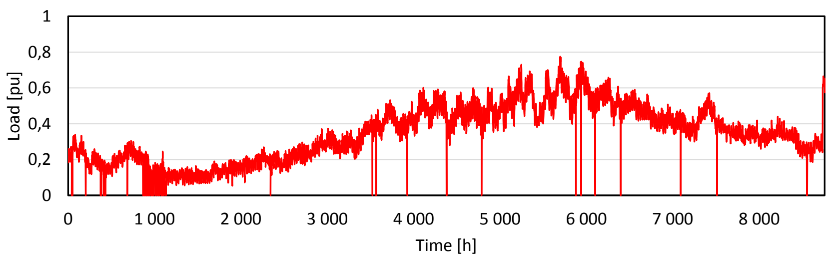


Figure I.7: *Hourly load values for one year for transformer T7. Note that the data span from summer to summer.*

Table I.32: *Oil sample analysis data for T7.*

Date:	**02.06.2014**
Breakdown voltage [kV]	85
Water content [mg/kg]	4,7
Neutralization value [mg KOH/g]	0,01
tan(d) [% ref 90°C]	0,0016
Color	0
Surface tension	35
Inhibitor content	0,43
Corrosive towards copper	No
Corrosive towards silver	No
Passivator content:	

Table I.33: *Maintenance data for T7. *) Priority of the initial fault is given as a number from 0 to 4, where 0 represents no fault and 4 represents a major failure which requires immediate outage and repair.*

Failure detected date:	**Priority* for the affected component**					**Failure corrected date**
	Tap changer	**Bushing**	**Tank**	**Oil**	**Auxiliary equipment**	
24.08.2012	4					03.09.2012
03.09.2012				2		24.10.2012
26.10.2010					2	26.10.2010
30.11.2005					2	30.11.2005
12.06.2002	2					12.06.2002

Table I.34: *Parameters used in the calculation of the coordination withstand voltage U_{cw} of transformer T7.*

BIL [kV]	650
Distance between arrester and transformer [m]	0
Length of span closest to station [m]	300
Overhead line number of conductors	2
Corona coefficient [kV]	7000
Number of lines connected to station	1
Accepted failure rate [failures/year]	0,0025
Overhead line outage rate [failures/year/100km]	0,000002
l_a [m]	1250
Surge arrester lightning impulse protection level U_{pl} [kV]	395

Table I.35: *Short circuit reactances of transformer T7.*

Transformer short circuit reactances		
Primary - Secondary	0,129	pu.
Secondary-Tertiary	0,111	pu.
Primary - Tertiary	0,0315	pu.

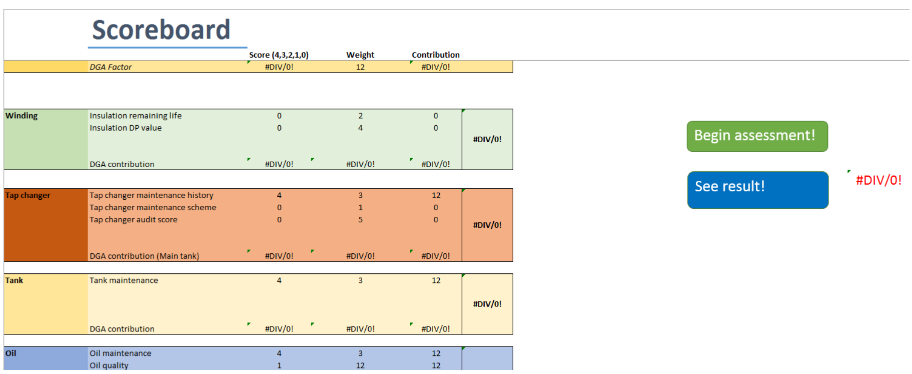
J | Excel Health Index Model

In order to test the health index model presented in this thesis, it has been implemented in Microsoft Excel. This Excel model is comprised of six files and is available for download from the following link: `http://1drv.ms/1MlezEF`

The above URL leads to an uploaded version of the Excel model that can be downloaded. The downloaded zip-file consists of two sub-folders. One of these contains an empty model which can be used for assessment of new transformers, while the other is an example assessment of a fictive transformer. The model consists of six files that are located within the same folder. For every assessment of a new transformer, the empty model folder should be copied. This is important to preserve the connections between the six files of which the model is comprised.

The assessment is started when the file named "Interface.xlsx" is opened. This is the assessment "dashboard" and is where the final score of the transformer is displayed. To begin the assessment, the user must simply press "Begin assessment!". An illustration of the empty interface file is shown in Figure J.1. When the assessment is begun, the program will guide the user through several pages where input to the model is requested. The user can then navigate through these pages using simple "Back" and "Next" buttons. In practice, the program then navigates

Figure J.1: *Picture from the interface file of the proposed model.*



through the six files of the model. For each of these, the model asks for the exact same input as is described in Chapter 5. A detailed explanation of this is not necessary, as this is given both in the Excel files and in Chapter 5.

General Notes

For each of the six files, there are several tabs. Some of these tabs are intended for input and are hence given a green color, while some merely contain calculations. The latter are indicated by a red color. This is illustrated in Figure J.2. By using the "Back" and "Next" buttons, the user will only be guided through the tabs used for input.

Figure J.2: *Illustration of tabs that are intended for input and tabs that are not. DGA and oil sample analysis data are used as input in the green tabs, while calculation algorithms are located in the red ones.*