Insulation diagnosis for low-voltage electrical machines

A method to determine the state of insulation material

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INSULATION DIAGNOSIS FOR LOW-VOLTAGE ELECTRICAL MACHINES

A METHOD TO DETERMINE THE STATE OF INSULATION MATERIAL

by

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Trust in the LORD with all your heart
and lean not on your own understanding.

In all your ways acknowledge Him,
and He will make your paths straight.

Proverbs 3:5-6

Preface

In this MSc thesis results of the research on the possibility of a lifetime expectancy method for LV- and MV-machines are given. This research would not have been possible without the help of several people and companies, who I want to thank.

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A. T. Sluimer
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Abstract

Electrical machines are used more often for many applications. This has caused the number of motors and generators to rise over the years. Reliability of these machines is an increasing demand, for industry relies heavily on the use of these machines. Maintenance is the best option to ensure reliability over the lifetime of these assets. Nowadays the popularity of condition based maintenance is rising, for this strategy can reduce costs and still guarantees reliability.

The current state of the equipment is important information for condition based maintenance to be successful. However no methods that give information on the current condition of low voltage electrical machines exists. ABB developed a lifetime expectancy method that provides information on the machines current condition, as well as a remaining expected lifetime. Sadly this method is limited to machines with a nominal voltage of 3,3kV and above.

In this study the possibility of a lifetime expectancy model for LV- and MV-machines (up to 3,3kV) is investigated. This thesis contains an extensive literature study on the stresses, failures, causes of failures and offline measurements that can be performed on electrical machines. A number of measurements have been picked for use in a practical setup. With this setup, trends in measured values have been found during an accelerated (thermal) aging process. These trends indicate that it might be possible to develop a lifetime expectancy model. The trends are presented and a generalized version of expected trend values is presented. However much more research is necessary to validate the generalized formulas, investigate influences of other stress factors and to make a complete model that provides information on the condition and remaining lifetime of electrical machines.

Contents

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Introduction

1.1. Maintenance of electrical machines

Over the last decades electrical machines are being used in most aspects of life. The number of motors and generators have therefore increased. Industry relies heavily on the use of electrical machines to improve efficiency of work or to be able to perform certain tasks. Unexpected outage causes trouble for users and may lead to high costs. Especially in the petrochemical industry these costs can be in the range of millions of dollars, for a long outage of machines can spoil days of work. For end-users it is therefore critical to achieve a minimum of down-time in order to reduce economical losses [1, 2].

The basic idea on how to minimize unwanted and unexpected outage of machines is to maintain all equipment frequently and repair or replace parts if needed. In service the three most important maintenance strategies according to [3] are:

- Planned maintenance, which means for instance that every year maintenance will take place.
- Corrective maintenance, which basically means that maintenance takes place after an error has occurred.
- Condition-based maintenance, where equipment is serviced based on the current condition.

The use of condition-based maintenance has been rising over the last years, as managers begin to understand the benefits of this strategy. A few of the benefits are:

- Less costs and down-time due to prevention of maintenance that was not yet needed
- Possible prevention of failures for a certain time
- The possibility to get an indication of the state of the equipment
- Maintenance managers get the possibility to make budgets for repair or replacement of the equipment

With these benefits research in this field is stimulated, for better ways of measuring may give more useful results [4].

Nowadays there are a number of measurements that can be performed on insulation material of electrical machines. However it turns out to be very hard to interpreted collected data and give qualitative information on the condition of a machine. More research is currently happening on systems to make this interpretation of the data easier and thus making condition-based maintenance better available for asset managers [5–7].

1.2. Problem definition

Quite some effort has been put into measurements on different electrical machine aspects. These measurements are not very difficult to perform in most cases. However the interpretation of what is measured is very hard and sometimes impossible. As a result most reviews of machines result in a go no-go situation based on experience. Any real diagnostic value on longer term is therefore rare [4, 5, 8].

ABB developed a structured method for coupling long term diagnostic value to a predefined set of measurements. By doing this, an expected lifetime of the machine is calculated and a specific type of maintenance can be suggested. The main drawback of this method is the limited range of electrical machines that is covered. This method is limited to electrical machines with a voltage rating of 6.6kV and above. According to the designers of the method the lower boundary can be decreased to 3.3kV with less certainty as result, but machines below 3.3kV are not covered [9].

The objective of this thesis is to investigate if a similar method can be designed for LV- and MV-machines in the range of 400V up to 3.3kV. Since the structure of machines with this rating is significantly different from that of HV-machines, most of the used measurements in case of HV must be re-investigated or alternative measurements must be found. A (small) research on the failure mechanisms and failure statistics of LV- and MV-machines is done to verify the causes of machine failures and how often they occur. With this information several tests have been chosen for data collection. This data has been used to investigate the possibility for developing of a method that gives information on expected lifetime.

1.3. Methodology

To investigate the possibility for a lifetime expectancy model the following methodology has been used. At first a literature survey has been performed to achieve good basic knowledge on the topic of machine failures and measurements. This way an indication is given on the aspects and failures that need to be taken into account when looking at an expected lifetime. After this a small investigation on failure statistics for electrical machines has been made. The results of the statistics have been used to determine what tests should be done on which parts for the practical part of the thesis.

With use of both the literature survey and statistical information found, a practical test setup has been designed to look for trending indications in values that can be measured. During this thesis a set of stators have been aged using a thermal aging process and all possible values that can be measured have been measured. Over the time of testing on the practical setup several external influences on the measurements are shortly investigated as well. With the data collected from the practical setup, trendlines are made to indicate the changes in measured values over the time of of aging.

A number of LV electrical machines from the field have been measured as well. This has been done to validate the assumption that measured values will differ for different machines.

Last conclusions are drawn on the question if a lifetime expectancy model can be made. A number of recommendations on further research that needs to be performed is added after the conclusion.

1.4. CONTRIBUTION

Up till now no significant research on the condition of low-voltage machines has been performed. There is however a large demand for a method to determine the condition of these machines, as it is critical information when applying condition-based maintenance. In this thesis a tip of the veil is lifted on the possibility of lifetime expectancy for LV- and MV-machines. The found results show that it is possible to monitor machine conditions even for small electrical machines. The results also show that possible trendlines can be made over the lifetime of the small machines. Using these findings, an indication is found that the possibility to design a lifetime expectancy model exists. However to much more research is necessary to make a model that complies to the aging of machines in field.

1.5. STRUCTURE OF THE THESIS

This thesis is divided in several chapters. At first a theoretical basis is made in chapter 2. This chapter contains a summary of the literature survey made on machine failures, insulation stresses and state of the art measurements available for indicating the condition of insulation. The literature survey is given in Appendix A and Appendix B. In chapter 3 statistical data found on machine failures is summarized. chapter 4 covers the design of the practical test setup, based on the information gained in previous chapters. It also covers some remarks on the measurements that have been performed. Data collected with the test setup is presented and discussed in chapter 5. In chapter 6 trendlines are given based on the collected data. This chapter also discusses the possibility of lifetime expectancy models. The thesis will end with chapter 7, which holds conclusions and recommendations for future research in this field of work.

2

Literature survey

Since the topic of this thesis is very broad, the literature survey is divided in three parts. These parts cover the topics that must be understood before designing a method to define the state of a machine. First, the stresses that insulation material faces are explained in section 2.1. Secondly the most common failure causes of machines are mentioned in section 2.2. These causes and induced failures are discussed in more detail in Appendix A. After that, several measurements to identify the condition of motors are given in section 2.3. The mentioned measurements are discussed in Appendix B.

2.1. Stresses on insulation system

Insulation material suffers a high amount of stress during its life time. According to literature the stresses on an insulation system can be split into four separate stresses called: Thermal, Electrical, Ambient and Mechanical stresses. These are also referred to as TEAM-stresses. In most situations each separate stress induces other stresses and eventually a failure of the insulation system occurs [10–12]. Each of these stress factors will be briefly discussed.

2.1.1. Thermal degradation of insulation material

Thermal degradation of insulation material is a well known principle and it is said to be the most dominant factor in the aging of insulation systems. It is based on the knowledge that insulation material ages faster at a higher temperature. In most (larger) machines the temperature is constantly monitored, since a sudden rise in temperature may indicate a failure. But a history on the temperature of the machine can also give valuable information on the insulation condition. This is because thermal stresses have a negative effect on the lifetime of an insulation system. There are a number of causes for thermal overloading, the most occurring causes are: voltage variations, unbalanced phase voltages, thermal cycling, overloading of the machine, obstructed ventilation and a high ambient temperature [1, 13].

According to [1, 14] operation at every 10 degrees above rated temperature decreases the lifespan of insulation material by 50%. This rule of thumb is used in a lot of situations since it is easy to apply.

Another way to estimate the lifetime of insulation is the Arrhenius rate law as used in [10–12]. Arrhenius describes the thermal aging process as a chemical reaction. Arrhenius equation holds for many uncomplicated aging processes within restricted temperature intervals and is mostly written as given in Equation 2.1.

$$L \approx A \cdot e^{\frac{-E}{k} \cdot T} \tag{2.1}$$

Where:

L = Expected lifetime

A = Constant

E = Activation energy

k = Boltzmann constant

T = Thermodynamic temperature [K]

An expected life at a specific temperature can be found by extrapolation of the graph which plots $log(L)$ against $\frac{1}{T}$. More information on this estimation, including its derivation is given in [15].

In [10, 12] it is stated that both the rule of thumb and Equation 2.1 give similar results within restricted temperatures (see table Table 2.1). In most situations aging temperatures will not exceed the restricted temperatures therefore the rule of thumb is normally used in practice.

Table 2.1: Thermal aging temperatures according to [12]

Service temperatures °C	**55**	**75**	**90**	**105**	**120**	**130**	**155**	**180**	**200**	**220**	**250**
Thermal class	**55**	**75**	**90 (Y)**	**105 (A)**	**120 (E)**	**130 (B)**	**155 (F)**	**180 (H)**	**200 (N)**	**220 (R)**	**250**
Aging temperatures °C	135	155	170	185	200	210	235	260	280	300	330
	125	145	160	175	190	200	225	250	270	290	320
	115	135	150	165	180	190	215	240	260	280	310
	105	125	140	155	170	180	205	230	250	270	300
	95	115	130	145	160	170	195	220	240	260	290
	85	105	120	135	150	160	185	210	230	250	280
	75	95	110	125	140	150	175	200	220	240	270

There are two reasons why both Equation 2.1 and the rule of thumb do not give exact results on expected lifetime. First, the results are only valid for relatively high operating temperatures, since below a certain threshold no thermal aging will occur. Secondly, both situations assume only one chemical reaction while normally multiple reactions happen simultaneously. Therefore a first order equation would, strictly speaking, not cover every reaction that occurs. However both approximations are firmly entrenched in standards, which provides little motivation to make this model more accurate [10].

2.1.2. ELECTRICAL STRESS ON INSULATION SYSTEM

Electrical aging of the insulation system normally happens due to the presence of partial discharges (PD for short) in the insulation material. These partial discharges occur mostly in cavities where the local electric field gets too high. This high electric field causes a discharge over the cavity in the material. A single PD by itself is not harmful for an insulation system, but a high repetition of PDs is. Each discharge causes an electron to crash onto the the positive side of the gap. When more discharges occur, more electrons crash and a part of the material is slowly 'eaten' away. After a large number of PDs the cavity in the material grows and eventually the insulation system will be weakened to a level where breakdown occurs at or below the rated voltage level of the machine. PDs normally happen at AC-voltages and its repetition is dependent on the power frequency of the source. Effects such as tracking, treeing, dielectric losses and space charges play a role in the electrical aging of insulation as well. However most of these effects have PD or bad manufacturing prior to the occurrence of the effects [11, 16].

Electrical aging has little impact on the insulation system for stator windings rated below 1000 V. For these machines the thickness of the insulation material is primarily determined based on the mechanical considerations. In these applications the required insulation thickness of the material is thicker based on mechanical stresses than based on electrical stresses. In stator windings rated above 1000 V, the insulation thickness is primarily based on the electrical stresses that are expected in the machine [10]. There is however some discussion on the voltage level that indicates electrical aging as an important deterioration aspect. The voltage levels where electrical aging starts is even stated to be as high as 5 kV [1, 17].

A number of different laws have been derived that give an indication on electrical aging or expected lifetime. All laws do not include temperature as a contributing factor. This may be done deliberately, keeping in mind that only the electrical aging should be covered. In all situations the constants a, b, c and n should be determined based on the material used.

Equation 2.2 gives an indication on insulation lifetime, based on the idea that the number of voltage fronts the material can handle can be calculated based on the applied voltage [18]. This approximation seems very easy to apply, but it also raises the question if the equation may not be too simple, since no relation between time, expected life and the remaining voltage fronts is indicated. For this formula to be of use in practice, all the voltage fronts applied to a machine must be counted. The remaining number of voltage fronts can be calculated by subtracting the counted fronts from the calculated maximum number of voltage fronts. However the number of voltage fronts applied to a machine is seldom counted in practice, for this would need extra equipment and may lead to high costs.

$$N = V^{-n} \tag{2.2}$$

Where:

N = Maximum number of voltage fronts expected till failure

V = Applied voltage

n = Power law constant

According to [11] the relation between electrical stress and lifetime should be described as given in Equation 2.3, based on the inverse power law. In this equation the remaining lifetime is dependent on the time that the electrical field is applied.

$$L_r \approx E^{-nt} \tag{2.3}$$

Where

L_r = Expected remaining life time

E = Electrical field strength

t = Time the electrical field is applied

n = Power law constant

In [10, 19] a different version of the inverse power law is given which is described in Equation 2.4. In this equation the lifetime is dependent on the electric field, but it does not indicate any effect on the time the field is applied. On the contrary a range for n is given, which is usually in the range from 9 to 12.

$$L_e = cE^{-n} \tag{2.4}$$

Where

L_e = Expected life time

E = Electrical field strength

c = Constant

n = Power law constant

There are also reports that indicate a change of the power law constant with stress level. It means the factor is no longer a constant and can not be implemented in the equation as such. As a consequence an exponential model may be used for the estimation of the insulation lifetime, one of these models is given in Equation 2.5 [10].

$$L_e = ae^{-bE} \tag{2.5}$$

Where

L_e = Expected life time

E = Electrical field strength

a = Constant

b = Constant

The last important note on electrical stress is that due to the faster switching of drives using IGBT's, the voltage surges on electrical machines become steeper and thus more dangerous. To the authors knowledge, no model on this aspect has been developed yet. It is therefore advised to double check insulation properties of the machine before installing a new and faster drive.

2.1.3. AMBIENT STRESSES IN INSULATION MATERIAL

Ambient stresses are, in most cases, caused by contamination of the insulating material, such as oil, water, chemicals and dirt. Normally the contribution of these factors can easily be minimized by proper maintenance and cleaning of the machine. A special situation of ambient stress is caused by radiation. When a machine operates in spaces containing radiation, little can be done to prevent deterioration of the insulation material.

Stresses caused by ambient circumstances do, in most situations, not cause aging themselves. The contamination present on the insulation material can however increase the effect of electrical or thermal stresses. For example a conductive material may lay on top of the surface decreasing the electric strength or dirt may block an air inlet of the cooling system. Even though these stresses do not cause the aging themselves, they have a huge influence on the deterioration of the insulation material. It is therefore important to minimize the ambient stresses for each machine to maximize its lifetime [10].

2.1.4. MECHANICAL STRESSES ON INSULATION SYSTEM

Mechanical insulation stresses have roughly three different sources. First are the high centrifugal forces that are exposed to the rotor during operation. These forces do not cause vibrations but tend to crush the insulation. For most situations the options for the insulation material are simple. Either the insulation material survives the expressed forces or it does fail under the pressure. This means aging is not really applicable for this situation, although there are some materials that can experience 'cold flow' also referred to as creepage or deformation. This occurs if such a material is put under constant high pressure. The solid material slowly moves toward an area with a lower pressure. This phenomenon becomes worse when the material is heated but at a temperature still under its melting point [20].

The second mechanical stress is due to the magnetic force induced by the power frequency current. This force may cause vibrations of the cores when they are loose in the stator slot, e.g. due to thermal expansion or contraction. These vibrations cause abrasion of the cores that can damage the insulation material.

The third important cause of mechanical stress is switching motors on or out-of-phase synchronization of synchronous machines. Both these situations lead to large transient currents that may be more than six times greater than the normal stator operating current. This massive current will magnetically induce mechanical forces that are 25 times larger than during normal operation. Due to the large forces, coils or bars may bend or even break under the stress.

To the authors knowledge no models exist that give a proper indication on mechanical stresses applied to the insulation material in rotating electrical machines. Since no models are available it is relatively hard to speak of aging in this matter since no information on the decay is present. Some diagnostic value can be obtained by measuring vibrations, but this can not be expressed in a lifetime expression [10].

2.2. FAILURE MECHANISMS IN ELECTRICAL MACHINES

Failures in electrical machines can be divided based on their location and cause. The most common roots of break down are based on thermal, environmental, mechanical and electrical effects, also called TEAM-stresses in section 2.1. However most failures occur due to a combination of these effects. Therefore machine failures are normally specified on the location of the first failure that caused breakdown of the machine [1, 14, 21].

This section will mention most of the failures in electrical machines. To limit the size of this thesis an explanation of each failure is given in Appendix A. Appendix A also gives a plausible cause of the failure if this is known, however this does not mean all possible causes are mentioned. Motor drives will not be covered in the literature survey since they are, technically speaking, not part of a machine.

2.2.1. MECHANICAL RELATED FAILURES

There are multiple mechanical faults that may contribute to failures of electrical machines. The major mechanical faults are: Airgap irregularities, bent shafts, misalignment, bearing and gearbox failures, broken rotor bars or cracked rotor short circuit rings, vibration problems, an out of balance system, critical speed, resonance and corrosion [14, 22].

Of all the faults mentioned, bearing failures have the largest contribution to the mechanical faults. According to [23] about 40% of all failures in induction machines are due to bearing related failures. Most other mechanical faults are due to bad alignment of the machine, wrong engineering during the design phase and mistreatment of the equipment.

In Appendix A the mechanical failures are discussed in more detail based on the following causes:

- Bad alignment of the machine
- Engineering errors during the design phase
- Mistreatment of the equipment
- Bearing related failures

The section Bearing related failures discusses the different types of bearings used in machines. It also summarizes and explains information on the known damages of rolling element bearings, which are mostly used in LV-machines. The bearing damage types discussed are:

Primary damage to bearing

- Flaking
- Wear
- Indentations
- Smearing
- Surface distress
- Corrosion
- Electric Current damage

Secondary damage to bearing

- Flaking
- Cracks

There are two types of damage mentioned, based on the level of danger. Primary damage gives rise to secondary damage, which is also called failure-inducing damage. This means that a machine can still operate when primary damage is present. If the primary damage causes secondary damage to increase a critical failure will occur, forcing the machine to stand-still. Flaking is marked as both primary and secondary damage. In early stages flaking is considered as primary damage, since it does not directly cause critical damage. When the process of flaking is further evolved or initiated by other types of primary damage, the danger level is much higher and critical damage is likely to happen. For this reason the process of flaking is regarded both primary as secondary damage.

2.2.2. STATOR RELATED FAILURES

Most of the electrical failures in electrical machines are related to the stator. According to [23] around 38% of all induction machine failures were caused due to failures in the stator. This means that stator failures are more or less occurring as much as bearing related failures. Other sources say that especially for machines with a lower rated voltage, bearing related failure are more likely to occur, but still stator related failures are the next greatest contributor to machine failures [24].

The most common causes of failures known to happen to machine stators are summarized below. The causes and failures will not be discussed in this chapter. In Appendix A, a more detailed explanation can be found. Possible known reasons that initiate these causes and failures are given as well. Also a number of ways to detect the induced faults are given. The most frequently occurring failure causes to machine stators are:

- Thermal Deterioration
- Thermal Cycling
- Slot Discharges
- Voltage Surges
- Electrical Tracking
- Abrasive Particles
- Chemical Attacks
- End Winding Vibrations
- Poor Electrical Connections

Each of these causes can lead to critical failure and can cause a machine to stop operation. Often indications of multiple faults are visible during normal operation, since the machine is normally used under changing conditions and demands. Therefore the stresses to the system change as well, which gives rise to multiple wear patterns. However when a failure occurs it is caused by one of the summarized phenomena initially. In some cases the failure causes another failure to initiate as well and multiple failures are found upon investigation. This is also a reason why the diagnosis of failed machines can be difficult, for it is not possible to find the first fault if multiple failures are found.

2.2.3. ROTOR RELATED FAILURES

Electrical failures in rotors of machines are relatively rare in practice. According to [23] only 10% of all induction machine failures are caused by rotor failures. One of the reasons for this is the limited change in rotor design over the years. Since design has barely changed most research on rotors and found solutions is still valid. This causes the prevention of numerous electrical rotor faults, as remedies are still applicable to modern rotors [22].

There are broadly two types of rotors used in modern electrical machines. The first is a squirrel cage rotor, which is used in most induction machines due to its robustness. The second type of rotors are wound rotors that can be applied on both induction and synchronous machines. Wound rotors have a much longer surface area of insulation material. Therefore these types of rotors tend to fail more often. Some of the summarized failure causes are also mentioned as stator faults, for failure of insulation material is the main reason of the fault. The most occurring failure causes for machine rotors are:

- Thermal Deterioration
- Thermal Cycling
- Copper Dusting
- Electrical Tracking
- Repetitive Voltage Surges
- Too High Centrifugal Forces
- High Resistance Connections
- Slipring Insulation Shorting
- Operation Without Field Current

One individual induced failure can cause the machine to stop operation, but often indications of multiple faults can be found due to the various stresses applied to the rotor. A number of these faults may cause synchronous machines to lose synchronization, which will in turn cause other failures to rise. The causes and induced failures are discussed in more detail in Appendix A. When causes for the initiated failure causes are known, they will be mentioned and if possible some ways to indicate these faults are given. For rotor related failures it is also common that after an initial failure, multiple other failures may be triggered as well. Due to this, it remains difficult to pinpoint the first failure that initiated a machine stop.

2.3. MEASUREMENTS FOR INDICATING THE CONDITION OF THE INSULATION SYSTEM

There are three ways known to indicate the remaining life of machine insulation. The first one is monitoring of stresses that are known to cause deterioration. This is actually an approach that makes sure that no situations occur that may decrease lifetime over and above normal conditions. The second option is to perform test procedures and based on the results of these procedures a lifetime estimation based on experience can be made. The third option is to determine the remaining life by modeling the deterioration processes of the insulation system [2, 5, 8, 25].

In this thesis the possibility to combine the second and third option is investigated. To be able to do this in the best way possible, both mechanical and electrical measurements should be investigated. However, due to time constraints the rest of this thesis will focus mostly on the electrical aspects in the machine.

2.3.1. MECHANICAL/BEARING RELATED MEASUREMENTS

Mechanical or bearing related failures are often monitored with the use of vibration measurements. It is commonly known that more than 50% of all machines fail due to mechanical (mostly bearings) issues. This is one of the main reasons why many people and companies researched methods to monitor the mechanical condition of machines. All the research done on these mechanical aspects lead to a relatively good understanding of how mechanical failures originate, but also on how the condition of the elements can be monitored.

Table 2.2 summarizes the most common monitoring techniques used to monitor the condition of gearboxes and bearings. More information on this can be found in Appendix B. The appendix will also give more explanation on vibration measurements on bearings and other monitoring techniques.

2.3.2. STATOR WINDING TEST MEASUREMENTS

There are a number of measurements that can be performed on stator windings. The types of measurements are generally known to give some information on the state of the insulation. However drawing proper conclusions based on these measurements is very difficult. One of the reasons for this is that no records of measurements were taken on a regular basis and processed in an organized way. This means that no knowledge is available on which values indicate a proper working machine and which values indicate possible failure or weak spots.

In this section only Table 2.3 containing possible offline measurements on stator windings is given. During this thesis the focus is laid on offline measurements for various reasons, such as accuracy and safety. In Appendix B a table containing a number of online alternatives is presented as well. Appendix B also discusses the offline measurements mentioned in Table 2.3.

2.3.3. ROTOR WINDING TEST MEASUREMENTS

Apart from tests that can be performed on the stator windings, measurements on rotors are also developed. With these measurements an indication on the state of the rotor insulation can be acquired, but drawing a conclusion, based on the measured values, still proves to be difficult. In Table 2.4 the set of offline measurements that can be performed on LV rotors is given. These measurements are looked after in more detail in Appendix B.

Table 2.2: Typical gearbox and bearing condition monitoring techniques according to [23]

Sensing scheme	Monitored Components	Advantages	Disadvantages
Vibration	Gearbox Bearing Shaft	Reliable Standardized in ISO 10816	Expensive Intrusive Subject to sensor failures Limited performance for low speed rotation
Torque	Rotor Gear	Direct measurement of Rotor Load	Expensive Intrusive
Oil Analysis Debris Analysis	Bearing	Direct characterization of bearing condition	Limited to bearings with closed-loop oil supply system Expensive for online operation
Temperature	Bearing	Standardized in IEEE 841	Embedded temperature detector required Other factors may cause similar temperature rise
Acoustic Emission	Bearing Gear	Able to detect early-stage fault Good for low-speed operation High signal-to-noise ratio Frequency range far from load perturbation	Expensive Very high sampling rate required
Stator Current Stator Power	Bearing Gear	No additional sensor needed Inexpensive Non-intrusive Easy to implement	Displacement based rather than force based Difficult to detect incipient faults Sometimes low signal-to-noise ratio

Table 2.3: Summary of offline stator winding measurements, source: [1, 10]

Method	Description	Effectiveness	Performance Difficulty
Winding Resistance/ DC conductivity Test	Measure resistance of the windings at a low DC voltage	Finds bad connections or turn shorts	Easy
Insulation Resistance (IR)/ Megohm	Measure leakage current after applying DC voltage for 1 minute	Finds contamination or defects in phase-to-ground insulation	Easy
Polarization Index (PI)	Look at the ratio of IR values after 1 and 10 minutes	Finds contamination or defects in phase-to-ground insulation	Easy
DC High Potential Test (DC HiPot)	Apply high DC voltage for 1 minute	Finds contamination of defects in phase-to-ground insulation	Easy
AC High Potential Test (AC HiPot)	Apply high AC voltage for 1 minute	Finds contamination or defects in phase-to-ground insulation better than DC version	Moderate due to large transformer
Capacitance	Measure the capacitance between phase and ground	Detects phase-ground faults	Moderate
Inductive Impedance	Measure inductance of windings	Detects shorted turns	Moderate
Dissipation-Factor / Power-Factor	Measure the dissipation factor / power factor of phase-to-ground or phase-to-phase insulation	Detects deterioration of the phase-to-ground and phase-to-phase insulation	Moderate
Surge Test	Applies steep voltage front and looks at the measured response	Detects weak turn-to-turn insulation	Difficult
Offline partial Discharge	Measure PD activity when HV is applied	Detects deterioration of the phase-to-ground and phase-to-phase insulation	Difficult

Table 2.4: Summary of Offline Rotor Measurements, source: [10, 26]

Method	Description	Effectiveness	Performance difficulty	Applicable for rotor types
Insulation Resistance (IR)	Measure leakage current after applying DC voltage for 1 minute	Finds contamination or defects in phase-to-ground insulation	Easy	All wound rotors
Polarization Index (PI)	Look at the ratio of IR values after 1 and 10 minutes	Finds contamination or defects in phase-to-ground insulation	Easy	All wound rotors
DC High Potential	Apply high DC voltage for 1 minute	Finds contamination of defects in phase-to-ground insulation	Easy	All wound rotors
AC High Potential	Apply high AC voltage for 1 minute	Finds contamination of defects in phase-to-ground insulation better than DC version	Moderate due to large transformer	All wound rotors
Impedance test	Apply AC voltage and measure I and V to find turn shorts	Detects shorted turns	Moderate	Rotors with slip rings
Pole Drop	Apply AC current and measure the voltage drop across each pole	Detects shorted turns	Easy	Salient pole rotors
Rotor RSO & Surge Test	Measure any discontinuities in the surge impedance of windings	Effective for indicating 'hidden' short circuits	Difficult	Round rotors
Rotor Single Phase Rotation Test	Apply AC voltage to two stator windings and measure drawn current when the rotor is turned	Finds broken rotor bars or short-circuit rings	Moderate	Squirrel cage rotors

3

STATISTICS ON MACHINE FAILURES

Surprisingly little statistical information is available on the failures that occur within machines. Most information found is specific for only one type of machine or a single application. There are surveys that cover a broader scope of machines, but these originate from the 80's. Altogether it can be concluded that there is no off-the-shelf information to be used. In this chapter the information from different sources is taken and summarized. Empirical conclusions from field engineers and a few papers are used to validate the collected statistical data. In section 3.1 several statistics on different field areas have been collected from different papers and are summarized. section 3.2 summarizes the information from found statistical surveys performed in the past. Last a validation on the collected statistical data found is given in section 3.3.

3.1. STATISTICS FROM DIFFERENT FIELD AREAS

There are a lot of papers that give fault distributions in order to make the essence of their research clear. Each author presents different failure distributions depending on their field of work. In Table 3.1 an overview on failure distributions in different areas is given based on multiple papers found. In this table the contribution to all failures of the investigated machines is given in percentages. On the first column the source of each failure is given and for each next column the failure contribution of this source is given. This means that, looking at the second column, 69% of all failures are mechanical or bearing failures, 21% of the failures are occur in the stator winding ect.

Most authors of papers investigate a different group and type of machine. To get an idea on average failures of machines the last column of Table 3.1 presents a calculated average based on the information from the papers. Surprisingly the calculated average has a relatively high deviation from the distributions stated in some of the papers. This makes it clear to see that machines used for different purposes tend to fail on different aspects.

The main difference between the statistics on different field areas collected from papers and the statistical data presented in surveys is the amount of background information given. For instance, surveys normally mention the group size from which the failure distributions have been calculated, while this is seldom the case for the information given in papers. When only a small group of samples is surveyed, the failure distribution found may not represent the failure rate of all the mentioned machines, since the sample space may be too small. This information can give information on the reliability of the found failure

Table 3.1: Overview failure statistics given in multiple papers

Source	[7]	[22]	[14]	[23]	[27]	[28]	[21]		[24]	Calculated average
Machine types	Squirrel cage induction motors	All motors	All machines	Induction machines	HV Hydro Generators	LV and MV machines rated 15MW and above	Wind turbine Generators <1MW (550V-690V)	Wind turbine Generators >2MW (550V-690V)	Motors in Petro-chemical industry	
Mechanical / Bearing	69%	50%	65%	40%	27%	41%	20%	60%	51%	47%
Stator winding	21%	40%		38%	44%	36%	25%	20%	16%	27%
Rotor	7%	10%		10%	12%	9%	50%	10%	5%	13%
Other/Unknown	3%		35%	12%	17%	14%	5%	10%	28%	14%

distribution. Therefore it is assumed that statistics presented in surveys can be considered more reliable. Most surveys have a broader scope on failure distributions as well, since multiple machine types are investigated.

3.2. SUMMARIZED STATISTICS FROM PREVIOUS STATISTICAL SURVEYS

There are a few surveys on the failures of machines, mostly performed during the 80's. The only sources found containing a survey that covers the whole range of electrical machines in field is [29–31]. In Table 3.2 an overview on failures in multiple machine types is given. By comparing the stated results with the average calculated in Table 3.1, it shows that the calculated values are comparable with the statistics for induction motors. Since induction motors are used in the majority of industry this was to be expected.

Table 3.2: Component failures against motor types. Source [29]

Failed component	Induction motors		Synchronous motors(small group)		Wound rotor motors(small group)	
	numbers	percentage	Numbers	percentage	Numbers	percentage
Bearing	152	50,00	2	4,88	10	34,48
Windings	75	24,67	16	39,02	6	20,69
Rotor	8	2,63	1	2,44	4	13,79
Shaft	19	6,25		0,00		0,00
Brushes or sliprings		0,00	6	14,63	8	27,59
External device	10	3,29	7	17,07	1	3,45
Unknown	40	13,16	9	21,95		0,00
Total	304	100	41	100	29	100

The failure distribution for synchronous machines is surprising to say the least. It seems like bearings contribute little to the failures of synchronous machines. It is likely to believe that this non-logical distribution is a cause of the small group of synchronous machines surveyed. The failure distribution of the windings is similar to the averaged value calculated in Table 3.1.

In [32] the information from [29–31] and some other sources is summarized in a few tables. These tables are given in Table 3.3 - 3.5.

In Table 3.3 an overview of when most failures are found is given. As suspected bearing failures are mostly noticed during maintenance periods when the machines are in stand still and partly dismantled. Most other errors are primarily found during operation, when the nominal electric field is applied to the insulation material. This shows the importance of this research. Failure of the machine during operation is always a bad case. When a better indication on the insulation material is given prior to recommissioning, the number of unexpected failures can be minimized.

In Table 3.4 a comparison is made between two studies on machine failures. As expected both studies find similar failure distributions. The main differences between the two sources are because slightly different criteria or failure origins were used.

The last table that summarizes the information from [32] is Table 3.5. This table is probably the most useful for this thesis because the cause of bearing and winding failures and failures of several machine types are summarized. The amount of 'other causes' given is surprisingly high, but a clear indication is given that most winding failures have insulation breakdown as an initiator. The other causes stated could have been expected since they follow the line of failures described in chapter 2.

Table 3.3: Component failures in percentage against the moment they are found. Source [32]

	Time discovered		
Failed component	Normal operation	Mainenance or test	Other
Bearing	36,6%	60,5%	50,0%
Winding	33,1%	8,3%	28,6%
Rotor	5,1%	1,8%	0,0%
Shaft of coupling	5,8%	8,3%	14,3%
Brushes or slip rings	3,1%	7,3%	0,0%
External device	5,0%	3,7%	0,0%
Not specified	11,3%	10,1%	7,1%
Total Percent	100,0%	100,0%	100,0%
Total nr. of failures	257	109	14

Table 3.4: Comparison in found failure rates between an IEEE study and an EPRI survey. Source [32]

IEEE Working group		EPRI phase 1	
Bearings	44%	Bearing related	41%
Windings	26%	Stator related	37%
Rotor/shaft/coupling	8%	Rotor related	10%

In [33] an other summary of multiple surveys is given. The results are displayed in Table 3.6. In this table it can be seen that the failure statistics vary with the types of machines and their rating. For machines with a higher voltage rating more failures are related to the stator and rotor. This makes sense, since in these type of machines the insulation material suffers higher electrical stress. However the contribution of bearing failures is very high in the case of low voltage machines. This is probably caused by the high amount of squirrel cage induction motors in these groups.

3.3. VALIDATION OF THE STATISTICAL DATA

The statistical information found is old or mainly based on collected (older) data. This might be a reason to question whether the information given is still representative for the machines currently used. In this section arguments are given from which can be concluded that the statistical data found is still representative.

Looking at the results of a similar study described in [24] shows that the failure rates in different machine designs have undergone little change. In this study three types of machines, commonly used in the USA, have been compared. These machine types were primarily build during different time periods. The oldest types were mostly build before 1992. The next type of machines were build between 1992 and 2000 and the newest machine types are from 2000 and newer. It can be concluded from [24] that even though machine designs have changed to improve efficiency, the operating temperatures did not change accordingly. This means that little change has been found in the operating temperatures of the machine while the efficiency of the machines has increased over time. As a consequence the conclusion is drawn that the thermal life and service factor capability have changed too little to influence the reliability of the machines significantly. Another safety margin on the temperature mentioned is embedded in the design of the machines which

Table 3.5: Failure causes against bearing/winding failures and Motor type (above 200hp). Source [32]

	All motor types failed components				
Causes of failure	Bearings %	Windings %	All types of motors %	Induction motors %	Synchronous motors%
Failure initiator					
Transient overvoltage	0,0%	4,1%	1,5%	1,4%	0,0%
Overheating	12,4%	21,4%	13,2%	14,7%	0,0%
Other insulation breakdown	1,9%	36,7%	12,3%	11,9%	21,1%
Mechanical breakage	50,3%	10,2%	33,1%	37,4%	5,2%
Electrical fault or malfunction	3,7%	11,2%	7,6%	5,8%	23,7%
Stalled motor	0,0%	2,1%	0,9%	0,7%	2,6%
Other	31,7%	14,3%	31,4%	28,1%	47,4%
Total %	100%	100%	100%	100%	100%
Total nr. of failures	161	98	341	278	38
Failure contributor					
Persistent overloading	1,4%	6,5%	4,2%	4,9%	2,7%
High Ambient temperature	0,7%	7,6%	3,0%	3,4%	0,0%
Abnormal moisture	2,7%	18,5%	5,8%	6,7%	2,7%
Abnormal voltage	0,0%	5,4%	1,5%	1,5%	2,7%
Abnormal frequency	0,0%	1,1%	0,6%	0,7%	0,0%
High vibration	21,8%	8,7%	15,5%	17,6%	5,4%
Aggressive chemicals	5,4%	6,5%	4,2%	4,5%	2,7%
Poor lubrication	31,3%	5,4%	15,2%	16,9%	8,1%
Poor ventilation of cooling	0,0%	7,6%	3,9%	2,2%	2,7%
Normal deterioration with age	20,4%	18,5%	26,4%	24,0%	51,4%
other	16,3%	14,1%	19,7%	17,6%	21,6%
total %	100%	100%	100%	100%	100%
total nr. of failures	147	92	330	267	37
Failure underlying cause					
Defective component	17,8%	10,9%	20,1%	20,3%	22,2%
Poor installation/testing	14,5%	10,9%	12,9%	15,9%	0,0%
Inadequate maintenance	27,6%	19,6%	21,4%	22,8%	11,1%
Improper operation	2,0%	6,5%	3,6%	3,3%	2,8%
Imporoper handling/shipping	0,7%	0,0%	0,6%	0,8%	0,0%
Inadequate physical protection	7,9%	7,6%	6,1%	6,5%	2,8%
Inadequate electrical protection	2,6%	15,2%	5,8%	5,3%	11,1%
Personnel error	7,2%	5,4%	6,8%	5,7%	5,6%
Outside agency - not personnel	2,0%	3,3%	3,9%	2,8%	13,9%
Motor-driven equipment mismatch	5,9%	4,3%	4,9%	4,9%	0,0%
Other	11,8%	16,3%	13,9%	11,8%	30,6%
total %	100%	100%	100%	100%	100%
total nr. of failures	152	92	309	246	36

Table 3.6: Overview on failures given in [33]

Subassemblies	Predicted by an OEM through FMEA techniques, 1995-7	MOD survey, Tavner, 1999	IEEE large motor survey, 1985, O'Donnell, 1985	Motors in Utility Applications, Albrecht, 1986	Motor Survey Offshore and Petrochemical, Thorsen, 1995	Proportion of 80 Journal Papers published in IEEE and IEE on these subject areas over the past 26 years
Types of machines	Small to medium LV motors and generators <150 kW, generally squirrel cage induction motors	Small LV motors and generators <750 kW, generally squirrel cage induction motors	Motors greater than 150 kW generally MV and HV induction motors	Motors greater than 75 kW generally MV & HV induction motors	Motors greater than 11 kW generally MV & HV induction motors	All machines
Bearings Stator related Rotor related Other	75% 9% 6% 10%	95% 2% 1% 2%	41% 37% 10% 12%	41% 36% 9% 14%	42% 13% 8% 38%	21% 35% 44% -

backs up these conclusions. Most motors are built with a class F insulation material or better, but under normal operating conditions the temperature rise is seldom higher than 120°C. This means that the insulation material is mostly over-designed, since theoretically speaking a class B insulation material would suffice. This over-designing might be one of the contributors to the little change in temperature found. For the cooling system is designed to cool the insulation at the rated temperature, so 155°C in case of class F insulation.

In [29, 32, 34] machine statistics are also based on failures per year. The differences between the failure rates is however remarkable. In [29] it is stated that the failure rate is dependent on the quality of the maintenance. Logically this makes sense, but the statement of 0,0045 failures per year for good maintenance and a failure rate of 0,0175 for fair maintenance seems very optimistic. Comparing these rates with the rates given in [32] (0,07-0,08 for induction and synchronous motors) and [34] (0.04-0.2 for wind turbines) gives rise to questions on the mentioned rates. Either most of the machines are poorly maintained or the failure rate given in [29] is too optimistic. These differences however also prove that there are big differences in machine failures depending on their use. Similar differences have been found in the statistical data given in Table 3.1. Since differences are similar, it is likely that the calculated average on failures for all machine types in Table 3.1 represents the total failure distribution in machines.

Some of the statistics can be verified with the experience of field engineers. According to a former service engineer of marine based equipment most machines in the marine environment stall due to two problems. The first cause of failure has bearing failures as the main contributor. In marine applications most machines do not operate at a solid foundation. Movements of the ship due to numerous reasons may cause forces on the bearings in unexpected directions. These forces can cause multiple wear patterns on the bearing and will eventually result in breakdown of the bearings. The second major problem is the contamination in the machines (mainly water). These contaminants create low resistance paths where (electrical) tracking occurs.

Service engineers for other machine applications state that most failures found are bearing related. These bearing failures mostly originate from wear or a misalignment between the machine and other components. The majority of other failures are located in the stator. Electrical breakdown of insulation material is the main contributor for these faults. This is normally caused by voltage spikes that are too high for the insulation to withstand or because (electrical) insulation properties have decreased. The degradation of the insulation material is commonly caused due to normal aging processes or high local temperatures (hotspots).

4

Practical setup

For designing a method that can be used to estimate the condition of insulation, a practical setup has been designed to perform measurements on a machine stator. First a description of the test samples and test procedure is given in section 4.1. The setup build for the measurements is described in section 4.2. Last section 4.3 describes the most extraordinary problems faced during the measurements. In this section some remark on the setup used are placed as well.

4.1. Description of the test procedure

The purpose of the test is to investigate a trend in values measured against the state of the insulation material. For a reliable set of measurements it is necessary to age the insulation material of the test samples in a structured way. It is important as well to have good control over the aging process. The best control on an aging mechanism is obtained by using a (single factor) thermal aging process, thus by heating the insulation [2, 12]. This statement is backed up by the large amount of standards that have been written on the accelerated aging of insulation material. In [35] it is claimed that the thermal factor is the dominant aging factor for electrical insulation systems with an input voltage below 1.000 V. This means that for most LV-machines the major failure contributor is covered.

4.1.1. Test samples used

For collecting measurement data three stators have been used. All stators are production parts from commercially available ABB motors. The motors provided are three-phase induction motors rated at 1.1 kW. The maximum voltage rating is 460 V at 60 Hz. The insulation class of the machines is class F, so the recommended maximum temperature of 155°C should not be exceeded during operation.

The motors were completely assembled upon arrival. Since only the stators were used in the thermal aging procedure the motors have been disassembled prior to testing. More information on the motors, such as nameplate information, is available in Appendix C.

During the tests, two stators have undergone an accelerated aging process and the third stator has been used as reference. This way errors in measurements or environmental influences have been detected in order to minimize measuring errors. The first stator will be aged and a number of measurements are performed, but none of them are possibly destructive for machines that should still work properly under normal conditions. The second stator that is aged will undergo the same measurements and some possible destructive measurements that simulate over-voltages that may occur during normal operation as well.

4.1.2. THERMAL AGING TEMPERATURE USED

As mentioned in subsection 2.1.1 the lifespan is halved for every 10°C above the rated temperature. This statement is backed up by [2, 10, 24, 36–38]. There is however some difference in the stated lifetime at rated temperature. According to [2] the insulation will last for 40.000 hours at rated temperature. However according to [10, 36, 37] this is only half, so 20.000 hours. Since there is a difference the rated lifetime the lifetime according to the IEC standards has been used, i.e. 20.000 hours at rated temperature for insulation materials commonly used [38].

Combining the lifetime stated in the IEC standard and the rule of thumb gives expected lifetimes shown in Table 4.1, and is also backed up with Figure 4.1. By looking at the information in Table 4.1 it is clear that the remaining lifetime decreases exponentially with a rise in temperature. For testing a limited amount of time was available, therefore an aging temperature of 215°C was chosen. At this temperature the expected lifetime decreases to only 312 hours, which is equal to 13 days. According to [35, 38] the minimal time for an aging test should be between 100 and 500 hours and the the temperature needs to be at least 5 K below the melting point of the insulation material.

According to internal notes at ABB, the motors are able to withstand over-temperatures of 200°C for a number of time periods per year without aging. This indicates that the insulation material will not melt at similar temperatures and aging at 215°C is possible. Results from heating sessions on multiple components show that the system will not melt at a test temperature of 220°C, therefore it is assumed that the insulation material does not melt during the test period. Next to this IEC standards have recommended aging temperatures that should be withstood if the machine complies to the IEC standard. These temperatures are given in Table 2.1. According to the standard the thermal aging tests can be at temperatures as high as 235°C. The test machines comply to the IEC standards and thus should be able to withstand 235°C as well. Therefore it can be assumed that accelerated aging at 215°C may not result in problems.

Table 4.1: Lifetime versus the temperature of the insulation material.

Lifetime in hours	Temperature in C°
20.000	155
10.000	165
5.000	175
2.500	185
1.250	195
625	205
312	**215**
156	225

Since measurements have been performed on the test samples over time, the stators have been removed from the oven on a regular basis. The stators have been in an oven mostly for time cycles of 18 or 25 hours. After the time cycle the oven is turned off and

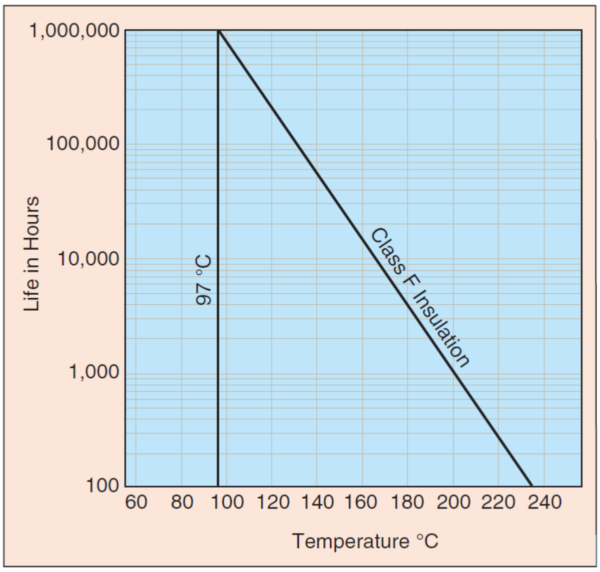

Figure 4.1: Lifetime of a class F rated insulation material plotted against temperature. Source [24]

the door is opened during the cooling period. When the test samples have cooled down to room temperature the defined number of measurements have been performed.

4.1.3. MEASUREMENTS PERFORMED

The following set of non-destructive measurements have been performed to identify degradation of the insulation system.

- Winding conductivity test
- Insulation resistance measurement (IR)
- Polarization index (PI)
- Capacitance measurement
- Inductive impedance measurement
- Power factor or tan(δ)

On the stator that has been subjected to (possible) destructive tests, the following extra tests have been performed.

- DC high potential Test
- Surge test

During normal testing the (destructive) test voltages went up to 1000 Volts (two times rated voltage), since this is the most common overvoltage the insulation system will face. After four measurements the test voltage has been increased in steps of 500 Volts up to 3000 Volts (six times rated voltage) for one cycle of testing. This is done to simulate the worst kind of induced overvoltages caused by for example inrush currents or transient phenomena [10, 26].

4.1.4. TEST PROCEDURE

The test procedure used is summarized below:

1. Measurements on all stators and data collection
2. Two stators that have been aged are placed in the oven
3. The oven and samples are heated to 215°C
4. Each aging cycle lasts 18 or 25 hours
5. When the aging cycle is completed the oven is turned of and the door is opened
6. The stators cool down to room temperature
7. Procedure is repeated starting at step 1

4.2. PRACTICAL TEST SETUP

In this section the practical setup is discussed. Some aspects that were important during the first 2 heating cycles are discussed as well. First the difference between an assembled and disassembled machine is investigated in subsection 4.2.1. Limitations of commercial equipment is discussed in subsection 4.2.2. Last in subsection 4.2.3 the used equipment and measuring circuits are given.

4.2.1. DIFFERENCE BETWEEN ASSEMBLED AND DISASSEMBLED MACHINE

For the ease of heating, the machines have been disassembled and only the stators were subjected to the thermal aging process. However in field applications, machines will remain assembled while the set of measurements is performed. In this subsection it is investigated whether the presence of the rotor will influence the values measured. This is done by performing a set of measurements on two identical machines. One is completely assembled and ready for operation, the second object is only the stator of the machine.

First $\tan(\delta)$ measurements have been performed on both situations. The measured capacitive values and corresponding $\tan(\delta)$ are shown in Table 4.2. In this table it is clearly

Table 4.2: Measured tan delta values for assembled and a disassembled situation

Capacitance measured	Assembled machine		Disassembled machine (stator)	
	Capacitance at 50Hz	$\tan(\delta)$ at 50Hz	Capacitance at 50Hz	$\tan(\delta)$ at 50Hz
$C_{UVW-Ground}$	2973 pF	0.255%	3022 pF	0.168%
$C_{U-Ground}$	1186 pF	0.392%	1282 pF	0.264%
$C_{V-Ground}$	1179 pF	0.389%	1276 pF	0.249%
$C_{W-Ground}$	1202 pF	0.369%	1295 pF	0.255%
C_{U-V}	96.86 pF	1.18%	135.8 pF	0.599%
C_{U-W}	94.32 pF	1.00%	134.8 pF	0.686%
C_{V-W}	103.5 pF	0.897%	141.7 pF	0.473%

visible that the presence of the rotor influences the values measured. This is to be expected since the windings are surrounded by more grounded parts and the rotor in inside the stator. The capacitive values measured between windings show this effect best. When the rotor is inside an easier path to ground is available for the electric fieldlines to follow. It is for example easier for the field to flow from one winding to an other (grounded) wire via the metal of the rotor instead than to travel through air. The easier path may cause the capacitance to decrease when the rotor is inside the stator, which is clear to see in the values of Table 4.2. The lower capacitance measured also results in a higher $\tan(\delta)$. This is easy to understand, since the resistive current in the insulation material is not influenced by the extra shielding. As a result the resistive current stays the same and the capacitive current is lower and thus the calculated $\tan(\delta)$ is higher. This can also be seen in Equation B.6.

Resistive measurements performed on both situations were: Winding resistance, insulation resistance and polarization index. For each of these methods the measured values were comparable, with deviations less than one percent. With these results, it is safe to assume that the presence of the rotor does not influence the measurements of winding or insulation resistance. This is to be expected since the presence of the rotor or caps does not change the resistivity of the winding or insulation. When using AC voltages instead of the DC voltages used some parasitic capacitance may influence the values slightly. This may also be the reason why these resistance measurements are always performed with DC voltages.

The inductance of the windings has been investigated in both situations as well. It turns out that the presence of the rotor has a large contribution to the measured inductance. If the machine is completely assembled the measured inductance is twice the value as when measured on only the stator. Just as with the capacitance this was to be expected since the presence of the rotor will influence these measurements. In this case there is an extra (better) path for the flux to follow, through the rotor. This influence can also be made clear with simple coil design. When there is an air-core, the inductance is normally lower than when a ferrite core is used in the coil. Current through the coil magnetizes the core material. The field of the magnetized material contributes to the field produced by the wire, which in turn cause the inductance to rise. In the situation of an added rotor an extra (induced) coil is added, instead of an ferrite core. The current inducted in the rotor will create a magnetic field which contributes to the field induced by the stator coils. Therefore the measured inductance increases due to the contribution of the rotor field. With this background information it makes sense that a higher value is measured, since there is an aluminium/iron core that influences the inductance beneficially.

For the use of the surge test it is suggested by manufacturers to alter the test slightly. For a stator the windings are tested, compared at different voltages and compared to other phases. When the rotor is in place the position of the rotor may influence the response of the surge test in some cases. This can be solved by repeating the test multiple times while rotating the rotor. Since this proves to be difficult in practice, the analysis is minimized. When the rotor is in place, it is suggested by manufacturers to compare the response for a single phase only with measurements at lower voltages at the same phase. This minimizes the diagnostic value of the test and is therefore not recommended by the author. According to the author it is suggested to perform the same test for stators and assembled machines. When measured readings deviate too much the test should be repeated after turning the rotor slightly to pinpoint the measured fault. During practical validation no difference between a stator and an assembled machine has been found while comparing the results of the surge test. In the test the result of each winding has been compared to the results of other windings and no significant differences were found.

Altogether it has been made clear that the presence of the rotor inside the machine has some influence on the measured values during some tests. However, except for a capacitance, tan(δ) and winding inductance measurement, results show very little difference for both situations. It can be concluded from this results that some care must be taken when comparing results from a stator and a motor. When comparing capacitance, tan(δ) and winding inductance measurements, it might be best to only compare machines with the same setup. The differences in measured values between an assembled motor and stator do however not mean that the principle of trending values will differ. Although different values will be measured, the fundamentals that cause the change of the insulation system do not change. When a database is built, a clear distinction between motors and stators should be made due to this reason. For the surgetest, differences between an assembled and disassembled machine are minimal. The test is used to find weak spots in the insulation material. Whether the machine is assembled or not should not influence the presence of weak spots. Other methods can be compared for both situations, but extra care has to be taken when (small) differences between values measured are found.

4.2.2. LIMITATIONS AND COMPARISON OF COMMERCIAL AVAILABLE EQUIPMENT

LIMITATIONS OF THE EQUIPMENT

During the reference measurements and the day-0 measurements a clear limitation of commercial available equipment has been made visible. For new machines the insulation resistance is too high and therefore the equipment could not measure a proper value. This means that this equipment is not capable of measuring well insulated machines.

To be able measure the high insulation resistance values, specialized equipment has been used make accurate measurements on the insulation resistance. A comparison has been made on a reference resistance of 312MΩ to validate the results of values measured by the commercial equipment. The results show that commercial equipment can measure these lower values quite well with only a small difference.

COMPARISON BETWEEN COMMERCIAL EQUIPMENT

During the period of testing, multiple commercial motor analysers have been used. To compare the testers, the same tests have been performed on the same test object and the results are given in Table 4.4. As can be seen the tests are not performed on the test motors used in the thermal aging process. For testing an old synchronous motor was used with the nameplate information given in Table 4.3

From the data summarized in Table 4.4 can be concluded that each motor analyser has more or less the same performance. The largest difference in values are for high insulation resistance values. These faults might be caused by limitations of the current sensing element or calibration errors. For one of the machines the calibration certificate indicates that for this application calibration stopped at 1 GΩ. When calibration for higher values is necessary the tester must be send to the factory for further calibration.

A measurement on a reference resistance with a lower value has been performed as well, to indicate accuracy for lower IR ranges. The used reference resistance is rated at 319.1 MΩ and has been measured with each analyser. Each analyser measured values in the proper ohmic range, but the AWA-IV was slightly more off the expected value. On further inspection the calibration period of this machine has been expired, which may be the cause for

Table 4.3: Nameplate information on the old synchronous motor used during the comparison tests

Nameplate Information		Motor ID: Old Test Motor	
Location	HV LAB TUDELFT	Building	EWI
Model	synch.motor	Manufacturer	Heemaf
Serial Number		HP/KW	3.4
Volts-Rating	500	Volts-Operating	415
Amps-Rating	6	Amps-Operating	0
RPM	6000	Service Factor	0
Frame	Fe	Freq-Hz	50
NEMA Design	F	Max Amb °C	20
Description	Old test motor for comparing different motor analysers		

Table 4.4: Comparison of measurements with different analysers

	Baker AWA-IV	Schleich MC2	Schleich Motor analyser 2
Winding resistance in Ω			
R_{1-2}	2.936	2.916	2.914
R_{2-3}	2.936	2.918	2.919
R_{3-1}	2.939	2.915	2.915
Insulation resistance in GΩ	5.321	5.2	5.645
Measurement of reference resistance (319.1 MΩ)	340 MΩ	316 MΩ	314.5 MΩ

the difference found. The other measuring devices have a valid calibration certificate and measured the reference quite accurate. Differences in the measured value for the calibrated machines complied to the specified accuracy stated for the equipment. The AWA-IV is only been used for measuring winding resistance, to perform a DC HiPot test and to perform a surgetest for the first two measurements in the practical setup. The expired calibration certificate does therefore not influence the data collected during the test setup, since all these values do not indicate a trend or are go no-go tests.

Apart from resistance measurements a comparison between the surge voltages of each machine has been made. The comparison results show that there is some difference between the motor analysers. Relevant differences were found in the risetime of the surgewave that is applied. The overvoltages caused by reflections have been measured as well. These results show that the analysers have similar overshoots when the steepest wavefronts possible are applied. The exact results can however not be published due to confidentiality reasons. The surgetest is normally used to simulate a motor connected to a PWM drive which switches at a high frequency. For this simulation it is important to have a surge test with a rise time as short as possible. There are differences measured between rise times, but differences on the voltage overshoot are found as well. These differences are related to the components used inside the testers and the way the components are controlled. Basically it can be said that a voltage overshoot is highest when the rise time is as short as possible.

In Figure 4.2 the voltage overshoot of an IGBT switching at 15 kHz is given, this is the green line in the figure. This same principle hold for the switching elements inside the

Figure 4.2: Switching of characteristic of an IGBT

analysers during a surge test. When switching speeds come close to the maximum switching speed of the component the overshoot will be highest. If the speed of switching is lowered, a lower overshoot will be visible.

During the surge tests transient phenomena are found as well. This is due to reflections caused by an impedance mismatch between the tested motor and the connected cables. The reflections inside the cable caused the voltage to be higher than expected at the motor terminal. In the the application of the surge voltage during the tests performed for this thesis these reflections are of minor importance. However when looking at tests that indicate a voltage level at which a fault occurs a separate oscilloscope and high voltage probe should be used to verify the applied voltage on the machine terminals. This is to validate the voltage at which the machine insulation breaks down. To give this voltage level, it is important that all reflections are included. This way the actual voltage on the terminals of the machine during breakdown can be presented.

4.2.3. Setup used during testing

Equipment used

The equipment used during the period of testing is given in Table 4.5. More information on this equipment can be found in Appendix C.

The first resistive measurements have been performed with the use of the AWA-IV, the other measurements are performed using the motor analyser 2. Since the value of IR was out of scale for both these analysers, dedicated megohmmeters have been used. Both the HM3A and Radiometer have been calibrated each time before measuring the IR. The Radiometer has a more accurate scale for reading the resistive values, therefore this device has been primarily used for measuring values of IR. Equipment from Megger (for capacitance and $\tan(\delta)$) and the Binder oven were used during the complete testing period.

All measurements have been performed in the following order to structure the measurements as much as possible. The following structure has been used:

1. Winding resistance and inductance, IR and PI. Using AWA-IV or motor analyser 2

Table 4.5: Equipment used during the period of testing

equipment	Used for/to
Megger IDAX 300 Megger VAX020	Measure capacitance and tan(δ)
Binder FD53 drying oven	Aging the stators thermally
SKF Baker AWA-IV/12 motor analyser Schleich Motor analyser 2 (MA2)	Measure winding resistance, winding inductance (only MA2), capacitance (only MA2). Perform DC HiPot test and surge test
Hipotronics HM3A megohmmeter Radiometer Megohmmeter	Measure IR and PI

2. If applicable: DC HiPot and surgetest. Using AWA-IV or motor analyser 2
3. IR with Radiometer. Starting from the second measurement PI has been measured as well
4. Capacitance and tan(δ) with Megger IDAX300 and VAX020

MEASURING CIRCUITS

In this section the (equivalent) circuits that are used for the measurements are shown. The circuits are shown in Figure 4.3 - 4.11. While most of these figures do not need any extra explanation, some explanation is given on the figures when needed.

Figure 4.3 shows a block "multiplier + Analog meter". This block visualizes the extra circuits that are between the current sensor and the analog meter used for taking the reading. The cable used on the top side of the figure is enveloped with a "dotted line". This is to indicate that a shielded cable is used and the shield of the cable is connected to ground. By doing this, external influences that cause a wrong current measurement do not flow through the current sensor but will flow through ground instead.

In the figures that show the circuit for measuring capacitance and tan(δ), Figure 4.4 - 4.10, all possible capacitances are shown. However the setup does not measure all values at once. The setup is made in such a way that all capacitances are shorted except the one that is to be measured. On first glance this may be confusing but only the capacitance and tan(δ) selected is measured.

Figure 4.11 shows the connection circuit used for the commercial motor analysers. In the figure the motor analyser is pictured as the 'black-box' at the left of the picture. From this device a connecting wire for each phase and one for the ground connection are used to connect the analyser to the test subject. The test stators are connected in star on one end during the measurements. This way measurements are performed trough 2 phases each time or from all three windings simultaneously to ground. for example, a DC HiPot test is performed from all three phases to ground, but a surgetest is executed from one phase to the other.

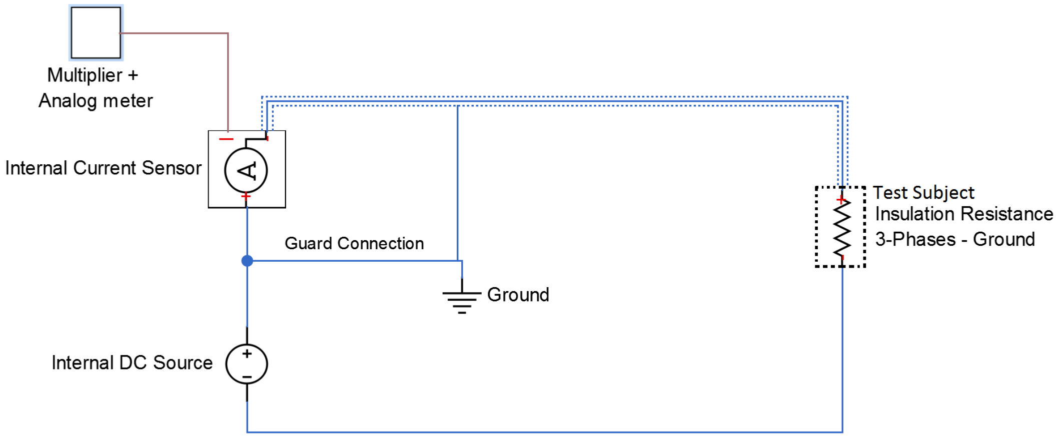

Figure 4.3: Circuit used for measuring the IR and PI

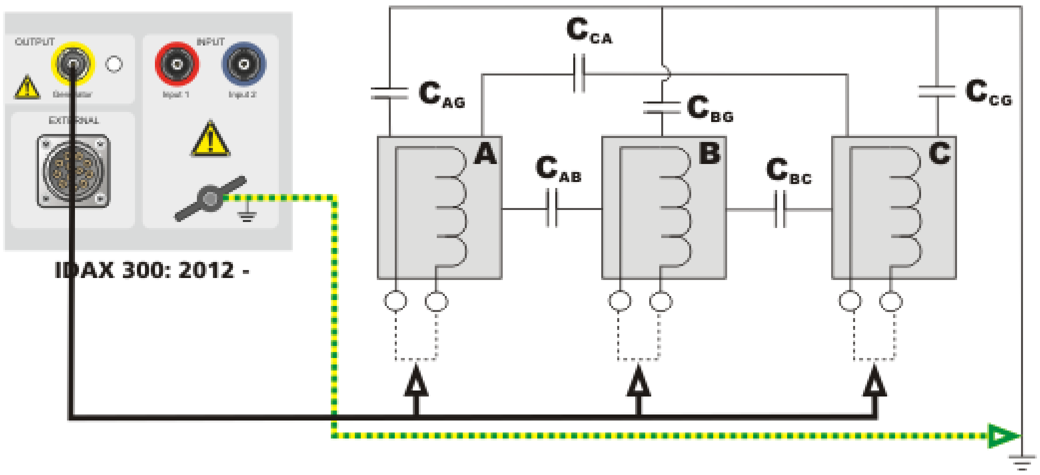

Figure 4.4: Connection circuit for measuring $C_{ABC-Ground}$ and $tan(\delta)_{ABC-Ground}$

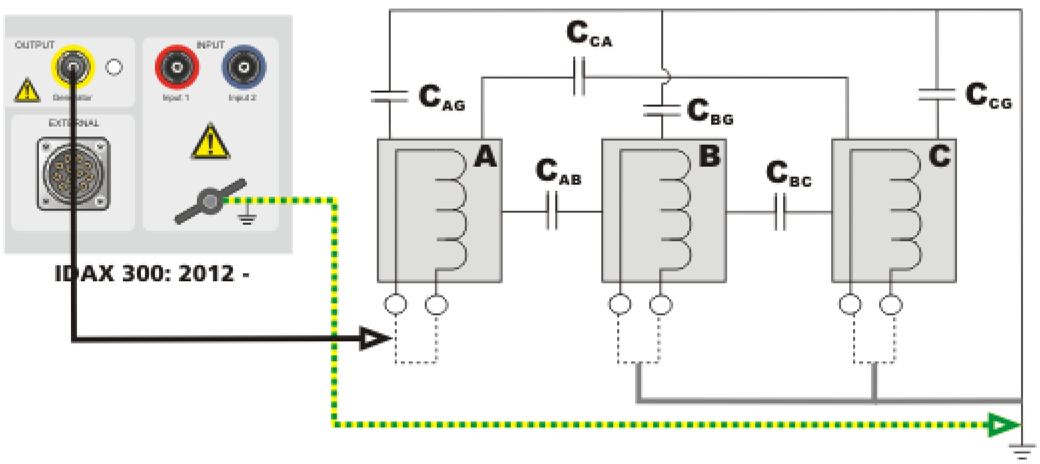

Figure 4.5: Connection circuit for measuring $C_{A-Ground}$ and $tan(\delta)_{A-Ground}$

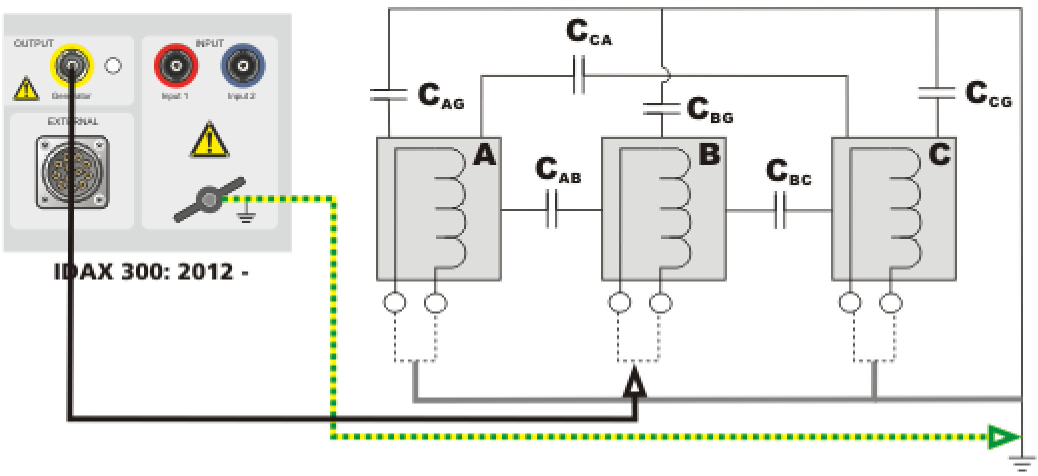

Figure 4.6: Connection circuit for measuring $C_{B-Ground}$ and $tan(\delta)_{B-Ground}$

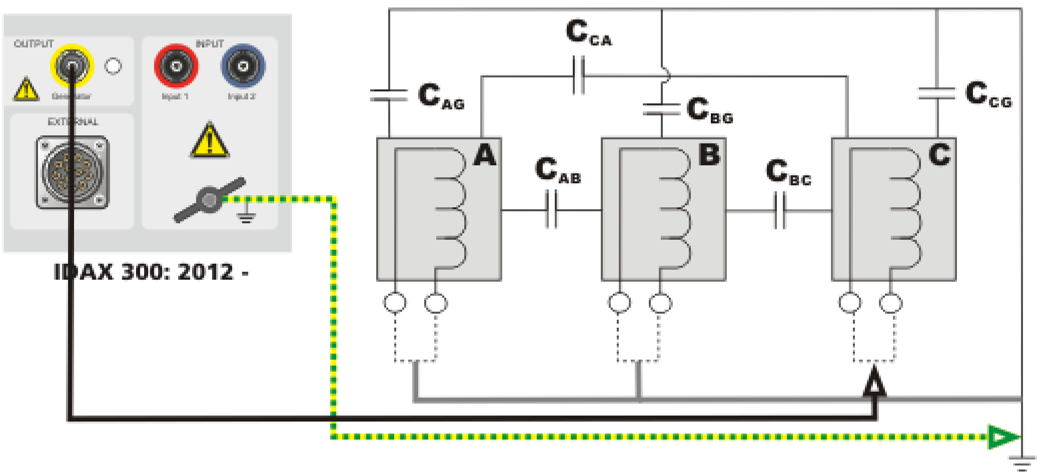

Figure 4.7: Connection circuit for measuring $C_{C-Ground}$ and $tan(\delta)_{C-Ground}$

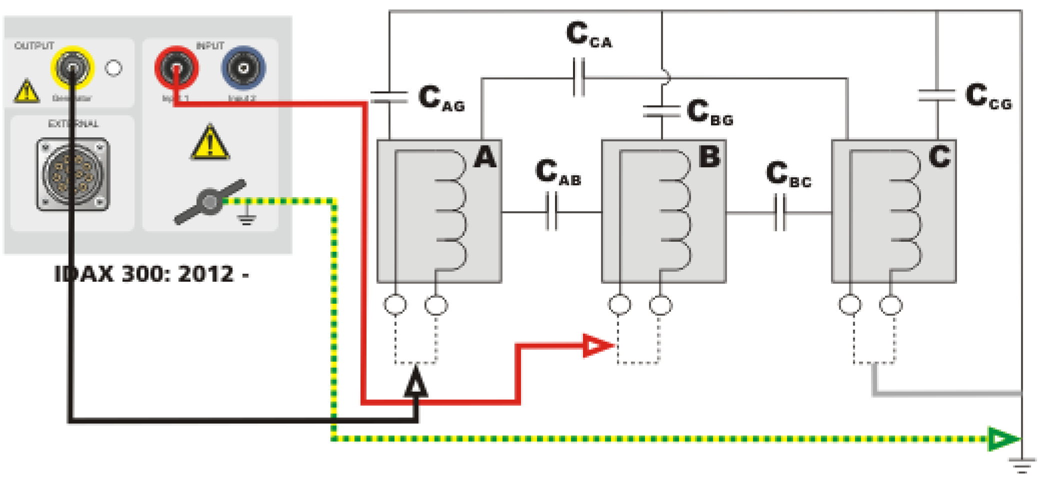

Figure 4.8: Connection circuit for measuring C_{A-B} and $tan(\delta)_{A-B}$

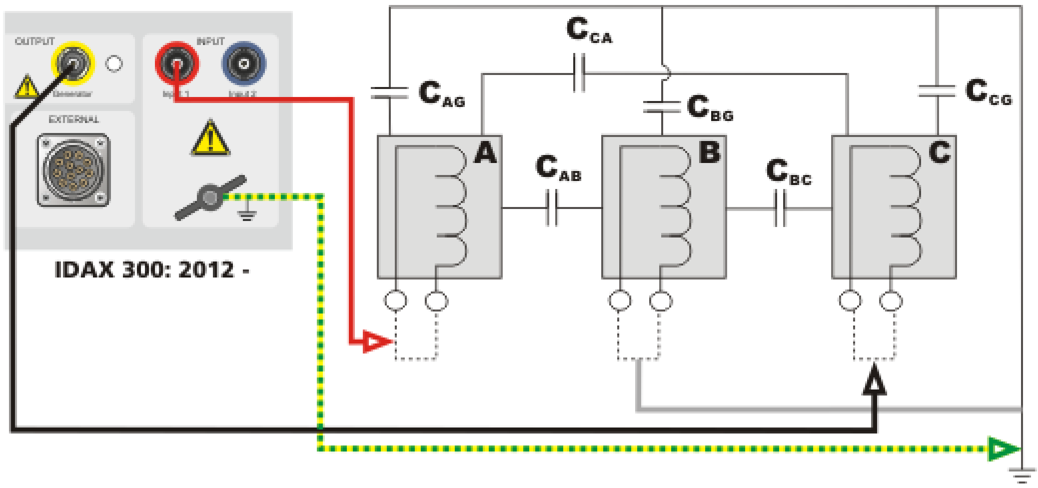

Figure 4.9: Connection circuit for measuring C_{A-C} and $tan(\delta)_{A-C}$

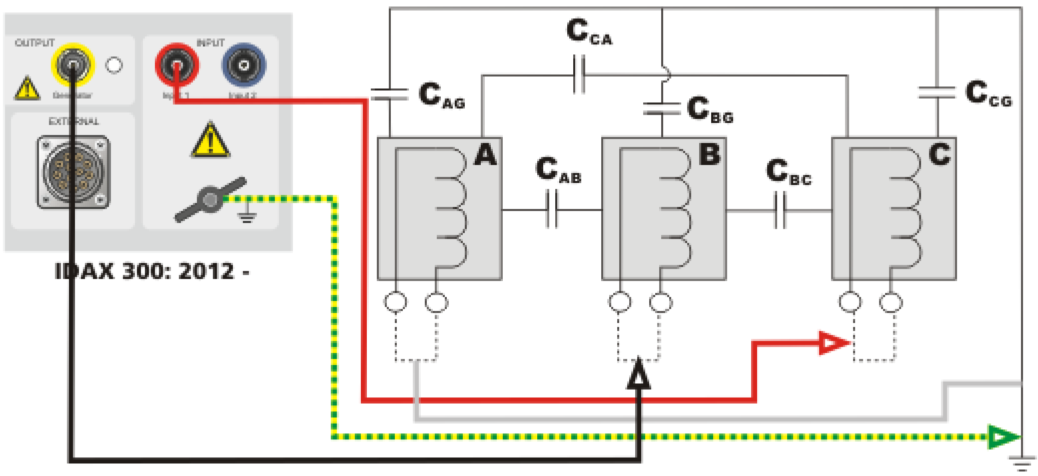

Figure 4.10: Connection circuit for measuring C_{B-C} and $tan(\delta)_{B-C}$

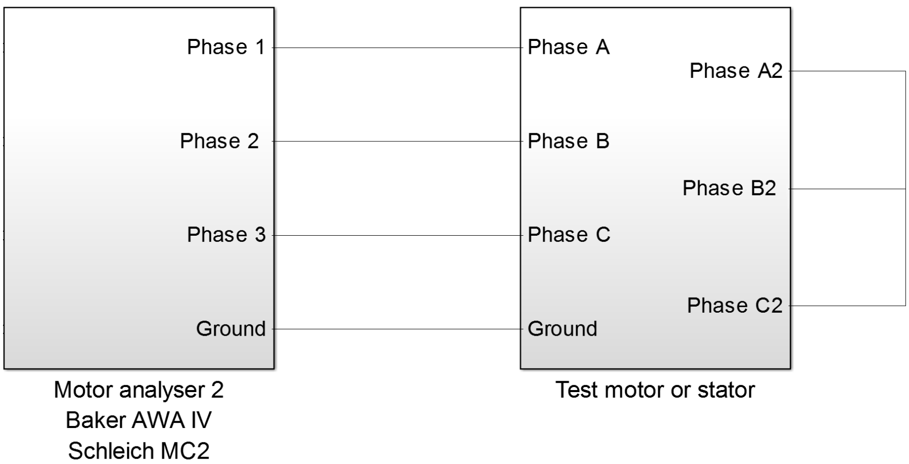

Figure 4.11: Circuit that shows how the motor analyser has been connected to the stators

4.3. PROBLEMS DURING TESTING AND AGING

When performing measurements on a test setup it is very rare that no problems occur. In this section the most extraordinary problems during the testing period are described.

4.3.1. MEASURING ERRORS CAUSED BY CONNECTION PROBLEMS

Measuring tan(δ) and the corresponding capacitance has been done on different frequencies. These different frequencies are used to look for differences in measured values at different frequencies. When measuring tan(δ) at frequencies below 1 Hz the measured values are sometimes wrong. In Figure 4.12 an example of such a wrong measurement is given. By reconnecting the clamps and by making sure the connections are as far away from each other as possible the measurement would give proper results again.

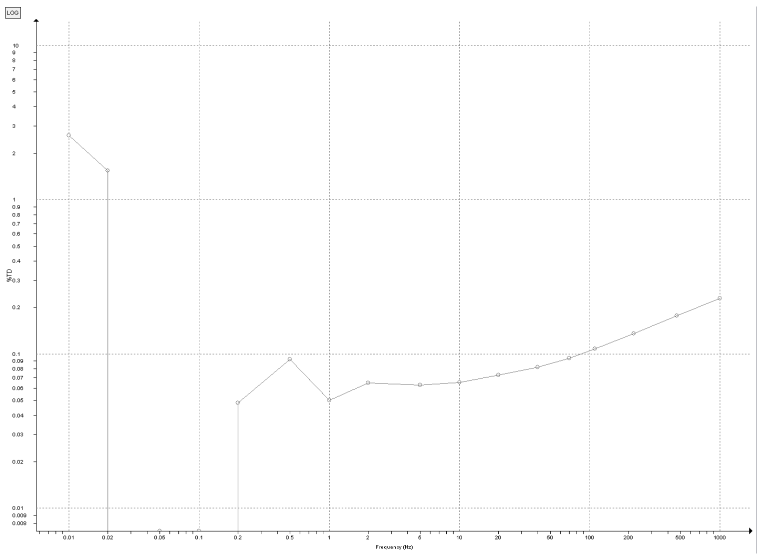

Figure 4.12: Faulty tan(δ) measurement of $C_{ABC-ground}$

This phenomena is probably caused by a bad connection or a parasitic capacitance outside the machine. Since the currents that need to be measured are very low (in the order of pA) a bad connection or parasitic capacitance can influence the measured values significantly. The problem occurs primarily when using low frequencies and therefore it is most likely that parasitic capacitance have little influence. Therefore it is expected that this fault is caused by a bad connection which causes a higher resistance that influences the current measurement.

During the period of testing the connections to the windings have been replaced for reasons explained in subsection 4.3.2. By comparing results before and after the replacement of the connections it has been verified that the different connections do not influence the measurements (see also "Influence of terminal block on IR and PI"). The main difference was in the ease of connecting measuring equipment and errors due to a (possibly) wrong connection occurred less often. Another possible reason for the wrong measurements might be caused by limitations of the IDAX measuring system. In subsection 4.3.4 this is discussed in more detail.

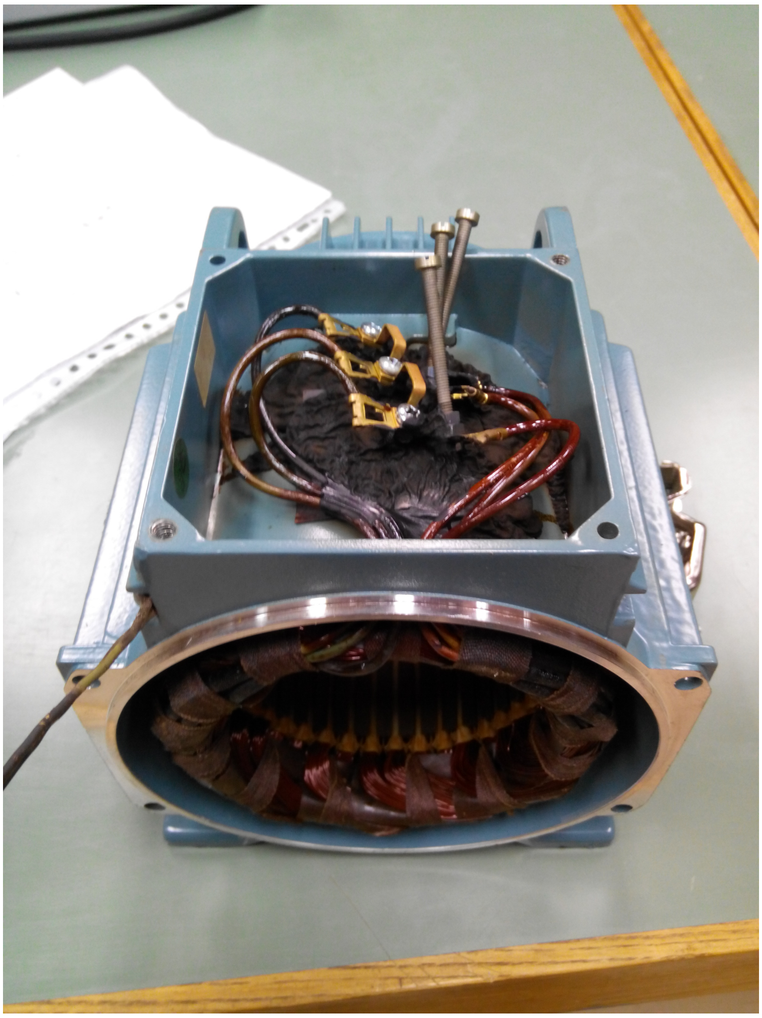

Figure 4.13: Picture of the melted terminal block after the first heating cycle

4.3.2. MELTING OF MACHINE PART

Although the used machines were labeled to comply to the IEC standard, not all parts of the machine did comply to the standard. While all parts should be able to withstand the aging temperature of 215°C, the terminal block of the motor melted during the first aging cycle. After this heating cycle the terminal block looked as depicted in Figure 4.13 and Figure 4.14.

During normal operation these temperatures are not reached, but according to certification the component should not have melted. After verifying that the rest of the machine has not been damaged, the machine has been cleaned and ceramic clamps have been installed. These clamps can withstand the thermal stress during the aging cycles and the quality of connections has been improved. In Figure 4.15 a picture of the connections with the ceramic blocks used for the rest of the practical period is given. To insure that the new blocks would not influence the measurements, the set of measurements was performed before and after installing the ceramic clamps. The results obtained are the same for both situations, therefore it can be concluded that the different connections do not influence the measurements.

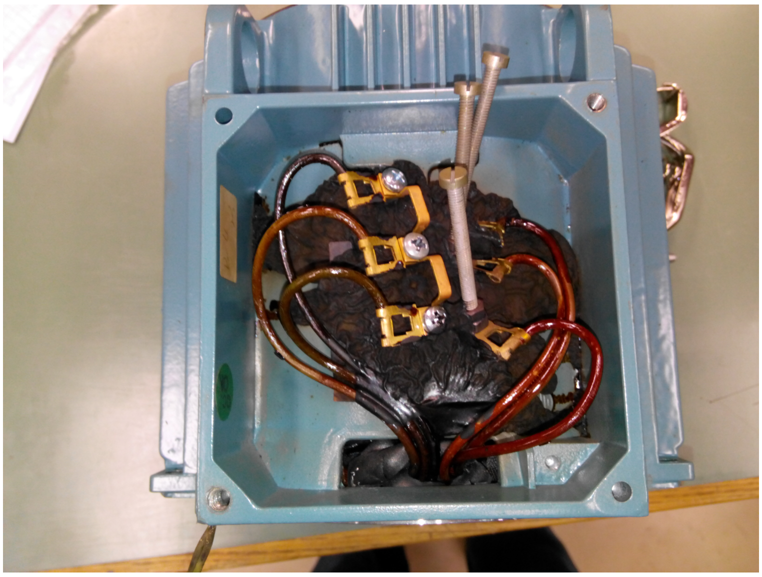

Figure 4.14: Melted terminal block after the first heating cycle

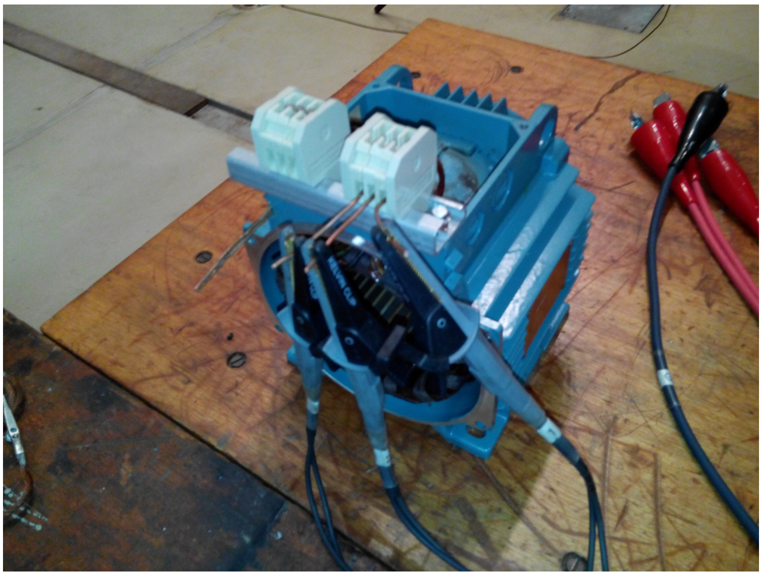

Figure 4.15: Picture of the new connections with the ceramic block

4.3.3. INFLUENCE OF TERMINAL BLOCK ON IR AND PI

The terminal block of the machine is, in practice, one of the major contributors of wrong IR and PI measurements. Dirt on the block may create a path to ground with a lower resistance than the insulation material. Therefore it is necessary to inspect the terminal block carefully before performing IR an PI measurements. However the material of the terminal block is also an important factor, since the block is attached to the (earthed) mass of the stator. If the material is less resistive than the machine insulation the IR and PI measurements will only indicate the "condition" of the terminal block. Together with the steep rise of measured IR after the first aging cycle, the need has been made clear to investigate if the terminal block has had any effect on the measured IR and PI. Since after the first heating cycle, melting and replacing of the block, the IR values changed so much, it might also indicate that the first day-0 measurements were wrong and only the IR of the terminal block was measured.

To investigate the effect of the terminal block the IR and PI has been measured with and without the terminal block. The results from these measurements can be found in Table 4.6. The contribution of the terminal block to the measured value is also investigated. This is done by measuring the resistance of the new terminal block to ground while the windings are disconnected. In the last column of Table 4.6 these values are given.

Table 4.6: Measured values of IR and PI with and without a terminal block

Measurement	With terminal block	Without terminal block	terminal block to ground
IR	3,5TΩ	3,2TΩ	58TΩ
PI	3,429	3,438	3,156

In Table 4.6 it is visible that the values with and without the terminal block show no significant change. The measured values are not exactly the same. This is because of the very high order of magnitude and the limited scale make it difficult to get an accurate reading. It is also visible that the resistance to ground of the terminal block only is several orders higher than the IR of the windings. Also the value of PI is roughly in the same order, which means that the resistance rises with the same factor over time. Therefore it is safe to conclude that in this case the terminal block does not influence the reading of IR and PI.

There are however some remarks on this conclusion. The measurements have been performed while the terminal block was clean and thus the effect of contamination, with for example oil, is not taken into account. It is also good to keep in mind that this conclusion holds only for the type of material used in this terminal block. To be able to draw this conclusion for other cases, a similar test should be performed for each different material that is used.

Altogether it can be concluded that the steep rise in IR and PI measured in the test setup, is not caused by the different terminal block. Therefore it is safe to assume a different effect caused this measured rise in the values. However this will not be discussed in this chapter, since conclusions based on measurements are given in chapter 5.

4.3.4. REMARK ON RESISTANCE MEASUREMENTS WITH IDAX

During the testing period some questions have risen on the measurements performed by IDAX. The root of these questions is the high insulation resistance measured, which means that a very low current must be measured properly. Especially for the measurement of tan(δ) the measured resistive current is important, since this influences the value of tan(δ) directly. For this reason a small test has been performed to investigate the quality of the resistive current measurement during the tests for tan(δ).

As test a object, one of the aged stators has been used for measurements. The machine has been connected in star, so a measurement of all three phases to ground is performed. To validate the measured data a IR and PI measurement has been performed twice in for of the following setups:

- Radiometer, three phase to ground. (Will be further noted as "Radiometer")
- IDAX, setting rotating machine and selected mode phase ABC-Ground. (Will be further noted as "IDAX ABC-G")
- IDAX, setting general specimen connected to measure three phase to ground. (Will be further noted as "IDAX General Specimen")

The measurements have been performed at 500V_{DC} and an ambient temperature of 19°C. Between measurements the test object has been completely grounded for 5 minutes to insure no left over charge is present inside the material. In Table 4.7 the results of the measurements are given.

Table 4.7: Measured IR and PI at 500V_{DC} with different setups

nr. of	Radiometer		IDAX ABC-G			IDAX General Specimen		
measurement	IR	PI	IR	PI	C_{ABC-G}	IR	PI	C_{ABC-G}
1	3,8TΩ	4,737	837,1GΩ	1,263	2,954nF	2,548TΩ	3,922	2.951nF
2	3,0TΩ	4,000	774,1GΩ	1,442	2.954nF	2,136TΩ	5,503	2,951nF

Table 4.7 shows that there is a significant difference between all setups. Some difference is to be expected due to the different charging rate between the Radiometer and IDAX. As long as values are in the same range this should not prove a problem. The difference between the two modes used on IDAX is however unexpected. A cause of this difference might be the difference in the chosen setup and mode. In case of IDAX ABC-G the measurement is performed using the ground as a return path, which might be a reason why the measurement is much lower. For in this situation the current can be distorted due to for example other earthed equipment. Since the measured currents are very low (in the order of pico amperes), other equipment might easily influence the current and thus the measured resistance. The measurement of IDAX general specimen is performed using two isolated wires that are connected to the device. This means influence from the outside is minimized and therefore the measured value is less influenced.

As a consequence the reading of the measured tan(δ) will need extra attention before drawing any conclusions. Since the measured capacitance is for both setups almost the same the measured capacitive current during tan(δ) measurement is also roughly the same. However the measured resistive current is different and thus the tan(δ) calculated using both currents will differ as well. The setup used during the accelerated aging test (IDAX ABC-G) gives as a result a higher value of tan(δ) than actually measured, since influence from the outside distorts the resistive current reading. This means that the reading of tan(δ)

might not be correct, since the accuracy at the lower boundary is too low. During the accelerated aging test the IDAX ABC-G setup has still been used, because this will simulate an environment similar to infield measurements.

Another conclusion that can be drawn from Table 4.7 is about the spread in readings on the same device. For all measurements a relative large difference is visible between the first and the second measurement. This has been expected because of the very low currents that must measured.

The influence of the applied voltage is briefly looked into as well. In this situation the IDAX general specimen setup has been used and the IR and PI is measured at both $200V_{DC}$ and $500V_{DC}$. From the results in Table 4.8 it can be concluded that the voltage supplied is an important factor during a measurement. The difference in calculated PI also shows that the material polarizes differently for both voltages. It can be concluded that for trending values it is important to use the same settings, such as applied voltage and connections, for each measurement. During testing a voltage of 200V has been used. At this voltage the IDAX could make a more accurate measurement on the tan(δ).

Table 4.8: Measured IR and PI at different voltages

	200V	500V
IR	3,479TΩ	2,548TΩ
PI	2,523	3,922

5
Data collected from practical tests

During the period of thermally aging the test stators, a predefined set of measurements has been performed on the stators between heating cycles. In section 5.1 the results of the measurements are presented in a set of figures. The collected data is used in chapter 6 to make plausible trend-lines that can be used for modeling the insulation lifetime when a model is made. It is to be expected that measured values on the test subjects will differ from other machine types in field. To validate this expectation, a number of machines in field have been measured and the results can be found in section 5.2.

5.1. Data from practical test setup

The results of the measurements on the thermally aged machines are shown in Figure 5.2 - 5.5. The legends in these figures state two different stators, called 'stator 001' and 'stator 005'. This refers to the last three digits of the serial number of the stators. During the tests stator 001 has been subjected to the potential destructive tests at higher voltages, while stator 005 has not been stressed over 500V.

During testing the contribution of electrical, ambient and mechanical stress has been minimized. Therefore effects such as PD's, electrical tracking or cracks in the material, caused by the contribution of electrical, ambient and/or mechanical stresses, have little to no contribution to the change in measured values. However these contributions may influence the values measured in practice. Therefore it is suggested to investigate how the other stresses influence these values before making or tuning an lifetime expectation model.

5.1.1. Failure of a stator

During the period of testing the stator that was subjected to the surgetest failed after 334 hour of aging. A flashover occurred during the surgetest at a surgevoltage of 3kV and after this the stator failed at the surgetest every time and at all voltages. Figure 5.1 pictures the response of the surgetest after the failure occurred.

When all windings have not failed the graphs should all lay on top of each other. In this case 3 different graphs can be seen. The response of phase 3-1 (blue) clearly shows an error in one of these phases. It can be seen that the resonant frequency is roughly half of the other phases. Because of the LCR-loop this means that the product of L and C must be four times lower. Since voltage is applied with a steep front (equivalent to high frequency behaviour), the capacitive element has the most contribution in the circuit. The frequency

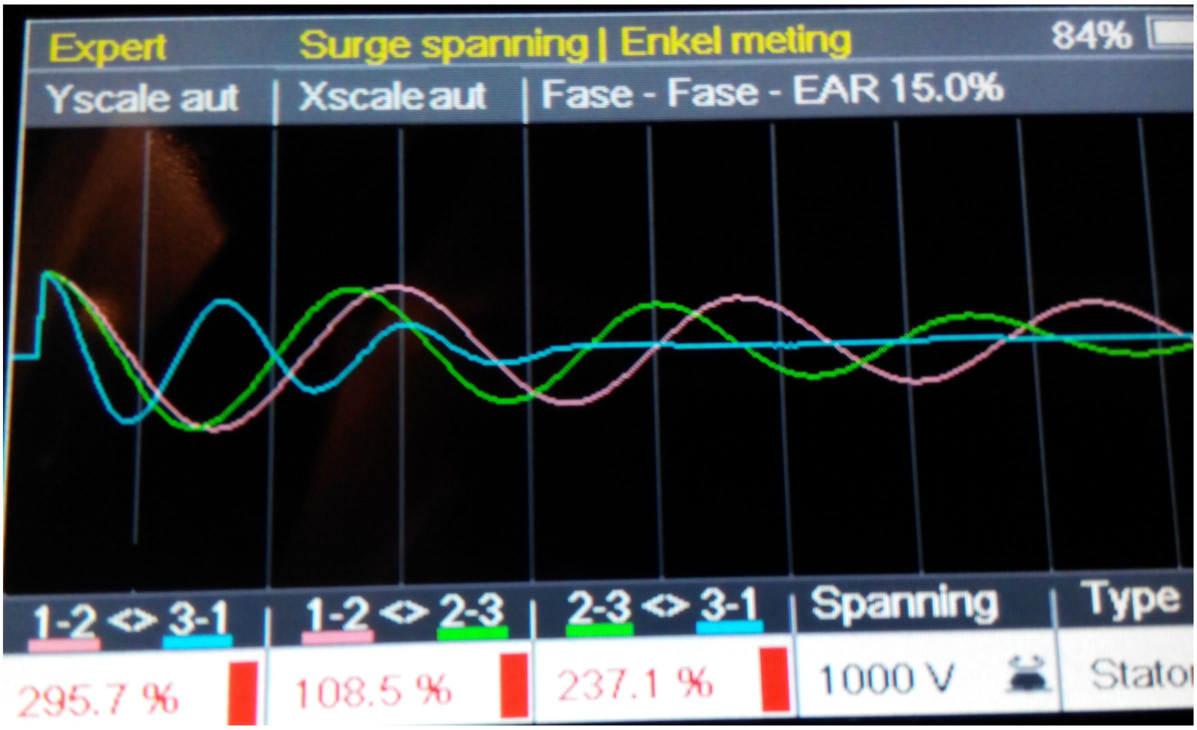

Figure 5.1: Response of the surgetest after a failure has occured

of the oscillation is increased for the tests 3-1 and 2-3. This makes it likely that the fault has occurred somewhere in the beginning of phase 3.

Another aspect that can be concluded from this figure is the type of fault. The rate of damping is very fast for the measurement of phase 3-1. From this result is can be concluded that the failure is most likely a failure to ground. Since the currents are likely to have leaked to ground, which caused the fast damping of the signal. This assumption is backed-up with the error message the IDAX gives when the stator is connected for tan(δ) and capacitance measurements. The error message explains that there is a leakage path somewhere in the sample because the measured voltage is unexpectedly low.

As just mentioned, the set of measurements for tan(δ) and capacitance cannot be performed anymore on this stator. For one of the phases the device gives the same error on the possible leakage somewhere in the connections or in the object. Since not all measurements can be performed anymore and the other measurements on this stator produced very inconsistent results these measurements have not been performed on the failed stator after the failure. The other measurements gave however still plausible and consistent results, therefore the measured values of IR and PI are still measured even after the failure. Measured values of the winding resistance and winding inductance showed no significant difference. From these measurements it cannot be concluded whether a measuring error or an failure has occurred. This proves the use of a surgetest for diagnosis of insulation systems. Even though it does not give diagnostic information for lifetime expectancy, it shows faults in the system that are not found using other tests.

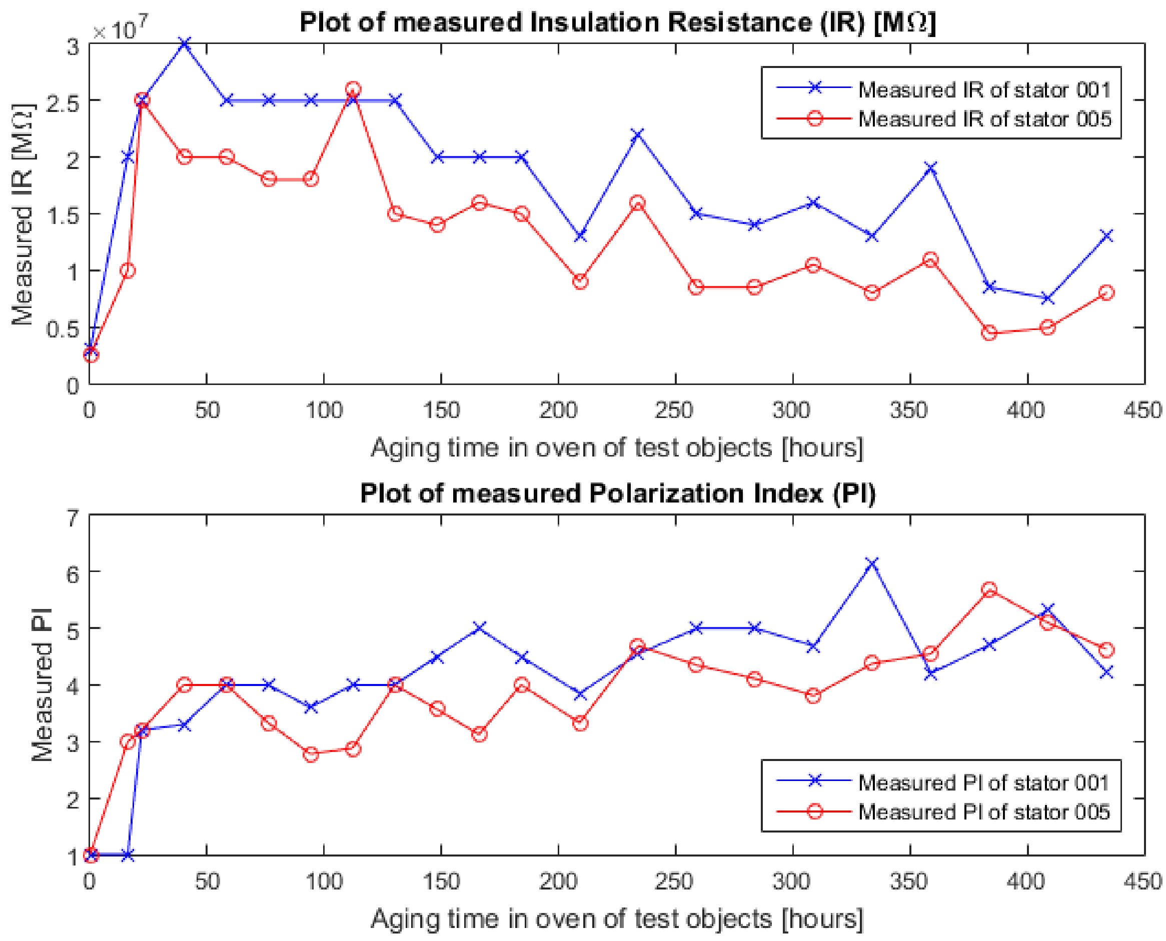

Figure 5.2: Figures of the collected data on IR and PI.

5.1.2. ANALYSIS OF INSULATION RESISTANCE AND POLARIZATION INDEX

The results given in Figure 5.2 show that the insulation resistance rises during the first aging cycles. Although, at first, it was expected that the IR would decrease over time this different phenomenon can be explained. During manufacturing, the machines are insulated with a lacquer. When the machines come out of the factory, the lacquer still needs to harden more until the insulation is completely hardened. This is also referred to as post curing. Normally this process will take place during the first years of operation and after these years the IR will gradually decrease. The process of hardening is visible in the first aging cycles.

In the first heat cycles the material has moisture trapped inside as well. During the first aging cycles the moisture inside the material is evaporated. This is another factor that contributes to the sudden rise of IR at the first aging cycles. The effects of moisture absorbed by the material is visible in the IR value over time as well. When the stators are outside the oven the material absorbs some moisture from the air. Between aging and measuring the machines have cooled down for different time periods. During this time periods the material has time to absorb moisture from the air, which explains the IR value that is less constant than expected. In subsection 5.1.4 the effect of moisture is explained in more detail.

Prior to the measurements the following hypothesis on the IR and PI values has been made: "The insulation resistance will gradually decrease over time. This decrease will be caused by the aging process inside the material. Aged material will have higher conduction losses and thus a lower resistive value. The Polarization Index will decrease as well, since contamination will have more influence on the aged material. These contaminants are likely to be more polar, which will cause the PI to decrease. When a failure in one of the machines if detected it is expected that the insulation resistance will have a much lower value than during the time without failure. Because of the lower resistance and the failure the PI will be very close to one, since the failure is not likely to have a polarization current."

During the measurements this hypothesis has turned out to be not entirely correct for this setup. Insulation Resistance has decreased over time, but with a much slower slope than expected. The decreasing slope proves that the material has indeed been aged. Over the time of aging it is likely that the insulation material has developed some cracks in the material. These cracks are likely to be the cause of higher conduction losses and thus the decrease of IR. The cracks are probably filled with air, moisture or dirt which cause the insulation resistance to decrease. Since the aging process has kept the stators extremely dry and other contaminants are minimized as well, air has probably filled all the spaces inside the insulation. Air is by itself a relative bad conductor and will therefore causes the insulation resistance to only drop slightly. When the stators are given more time outside the oven, more moisture is absorbed and this will cause the IR to decrease drastically because water is a better conductor. The absence of moisture and/or dirt inside the material is visible in the plot of PI from Figure 5.2 as well. In this figure the value of PI increases over time, while it expected to decrease when moisture or dirt is present inside the material. Since the values increase over time it is expected that (dry) air filled the cracks and gaps inside the insulation material.

After the detected failure, during the surgetest, the values of IR and PI have been determined again. Against expectations the values of IR and PI are still out of the ordinary high. This implies that the failure is frequency dependent and that some space between the shorted sections is likely to be present. To insure the fault is (for DC voltages) not voltage dependent a HIPOT DC test has been performed up to 2kV to verify if the fault can be detected with DC voltage. During the HIPOT DC test the drawn current has been measured. The current drawn was in this case extremely low, which implies that this fault cannot be found using DC-voltages. From these results it can be concluded that the surgetest can detect other flaws in the machine material than the DC-voltage tests. With use of the surgetest, frequency dependent faults can be detected, which cannot be found using IR and PI measurements. Weak insulation, that tends to fail when steep voltage fronts are applied, can be found with the surgetest as well. This provides ways to 'simulate' the behaviour of PWM drives and gives the possibility to look at the response of a motor supplied by such a drive in a controlled way.

5.1.3. ANALYSIS OF CAPACITANCE AND TAN(δ)

MEASURED TAN(δ) AND CAPACITIVE VALUES

The measurements of tan(δ) and capacitance have been performed with different circuits as shown in subsection 4.2.3 but at different frequencies as well. It is known that different frequencies cause certain losses to increase based on the type of loss. For this test the results of the measurements at the frequencies 1000Hz, 50Hz and 10mHz are taken. The results of the measurement over the aging period are therefore shown in different subplots.

Figure 5.3 shows the capacitance and tan(δ) measured for the situation of all three

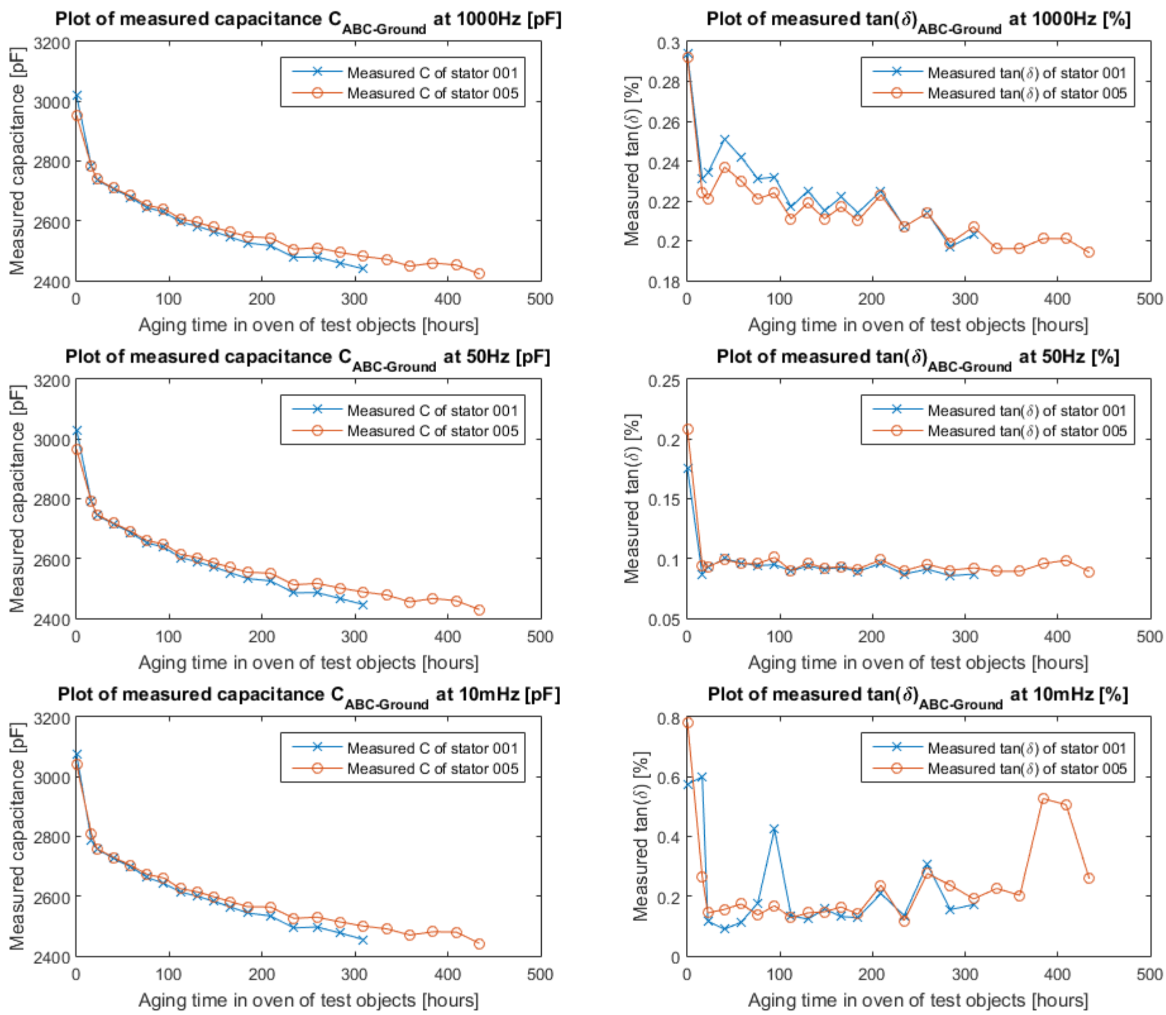

Figure 5.3: Plots of the capacitance and tan(δ) measured from three phases to ground.

phases to ground. Figure 5.4 shows the values measured from the setup that is used to indicate single phase to ground values. In Figure 5.5 the capacitance and tan(δ) between separate phases over time is given. These figures show a steady decrease of capacitance against the aging of the material. The values of the capacitance have decreased by almost 20% over the period of aging. It is also likely to conclude that the capacitance decreases linearly over time after the effects of post-curing and drying are over. The measured values do not give a clear indication that the capacitance of the material will stabilize at a certain value. Therefore it is likely that this process will continually take place until a failure has occurred and the machine is revised or recycled. The figures also show that the capacitance of the stator that experienced more electrical stress during testing decreases slightly faster than that of the other stator. This might indicate that electrical stress on the insulation system causes extra deterioration of the material, even when it is kept to a minimum. Last it is clear to see that the capacitance between phase A and C of stator 005 is much lower than the capacitance between other phases. It is likely that this is a flaw from the construction process. In practice this winding will most likely be a weak-spot in the motor and a failure is likely to occur the fastest between these windings.

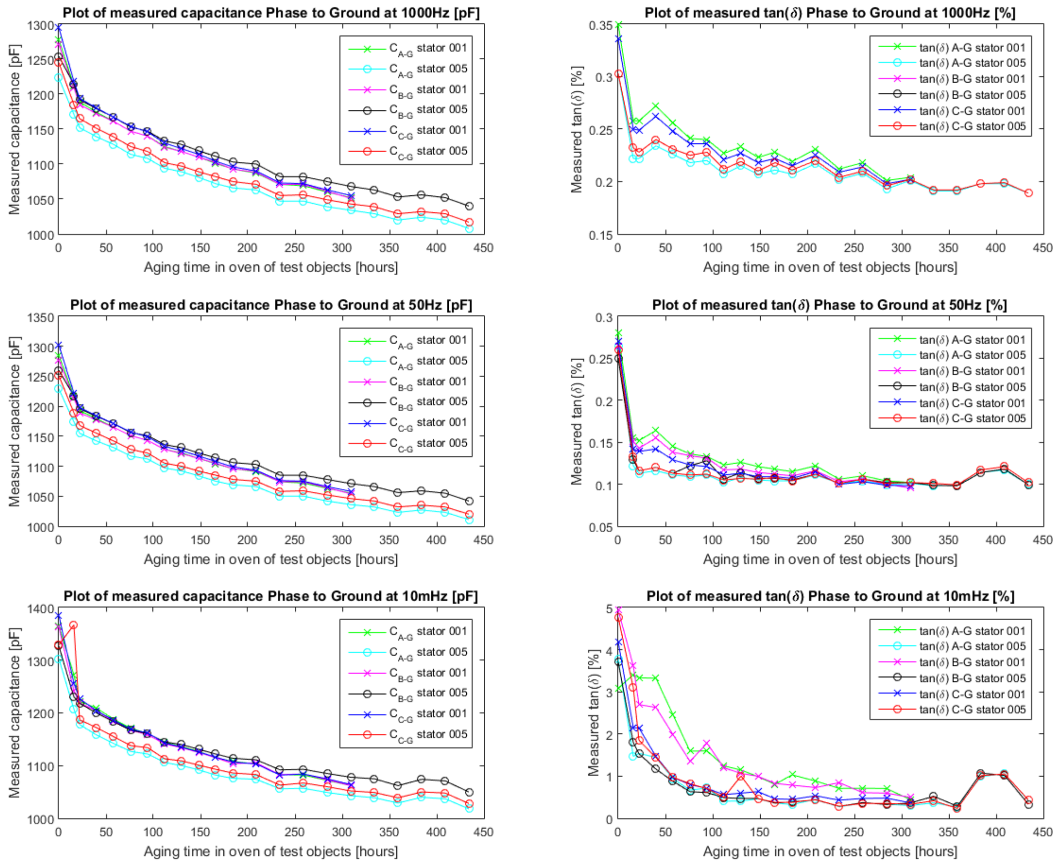

Figure 5.4: Plots of the capacitance and tan(δ) measured from a single phase to ground.

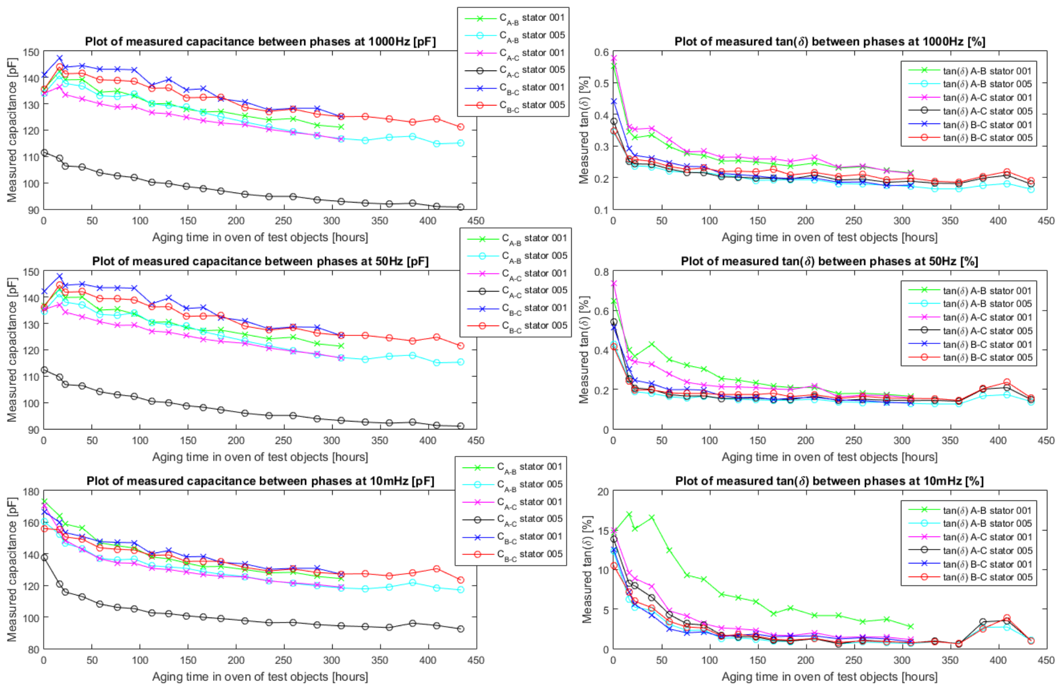

Figure 5.5: Plots of the capacitance and tan(δ) measured between separate phases.

The small change in $\tan(\delta)$ after the first few aging cycles is however unexpected. The insulation material has been aged over time the condition of the material should worsen. This deterioration of the material should be visible in an increase in $\tan(\delta)$, but this is not clear. There are a two plausible reasons given why the expected trend is not followed. First the unexpected absence of decease in IR may cause the $\tan(\delta)$ not to rise. Since the IR does not decrease much, the resistive current does not increase as well. Because the value of $\tan(\delta)$ is calculated from the ratio between the capacitive and resistive current little difference in the results is visible. The second reason is mentioned in subsection 4.3.4 as well. The currents to be measured are so low that the device has trouble to perform an accurate measurement. As a consequence the values measured might just be the limitation of the device, which could explain the little change in $\tan(\delta)$ over the period of aging.

The last measurements show a rise in the measured $\tan(\delta)$, except for the last measurement. One of the reasons for this sudden rise is the expected decrease in insulation resistance, which is visible in Figure 5.2 as well. However there is one other aspect that contributes to the rise in measured value. Prior to the measurements, the stator windings have been exposed to the environment for a longer period time than normal. During this period the material has had more time to absorb moisture from the air, which causes the conduction losses to increase. This phenomenon is explained in subsection 5.1.4 in more detail.

The measurements performed at the lowest frequency (10mHz) show that for this measurement the $\tan(\delta)$ started with a relative high value. This value decreases over the aging period and reaches values close to the values at other frequencies. Since the used frequency is very low, an almost DC like state is created. Because the IR is relatively low at the first cycles of aging, the measured value of $\tan(\delta)$ is high. Over the aging period post-curing and drying have taken place, which caused a rise of IR and thus a decrease in $\tan(\delta)$. The low frequency gave rise to another problem as well. At these low frequencies the measured value is distorted easily. This has caused multiple repetitions of the measurements during the period of testing. For infield applications this low frequency is therefore not recommended.

Although exact values are of less importance when looking for a trend, it might be good to give the measured values some attention as well. When looking at the capacitive values between phases, much lower values are measured than in the case of a measurement between phase and ground. This is likely due to the place where the capacitance is dominant. In case of the measurement between phases, the dominant capacitance is in the end-windings. In the end-windings a single layer polymer insulation is used which contributes to the low capacitance, since there is little material between two phases. The small surface area (only in the end-windings) is also a contributor to the low capacitance.

When looking at the capacitance measured between one phase and ground, much higher values are measured. This is mainly due to the larger surface area inside the stator slots. But an extra layer of material is used inside the slots as well, which very likely causes the ϵ to increase. The combination of these aspects are most likely responsible for the higher value of the capacitance measured.

The last difference in capacitance that will be mentioned is an observation on the measurement of 3-phase to ground. It is to be expected that this value would be three times the value of a single phase to ground. However this is not exactly true. The 3-phase to ground values are slightly lower than expected. This difference is probably caused in the

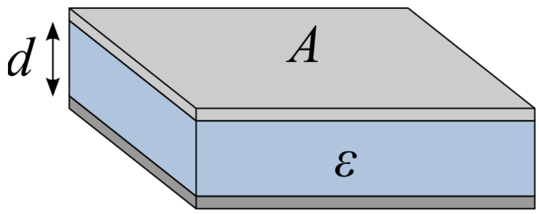

Figure 5.6: Representation of a parallel plate capacitance. Source: [39]

end-windings. During the single-phase to ground measurements the other windings are grounded, but this is not possible for the 3-phase to ground measurement. This means that a longer surface area is applicable in the single phase measurement. This extra surface area causes the 3-phase to ground value to be slightly lower than three times the single-phase to ground value.

CAUSE OF CHANGE IN CAPACITANCE AND TAN(δ)

The capacitance and tan(δ) given show a decrease over time. This decrease has been expected with knowledge from Appendix A and Appendix B. However the reason for this decrease is not yet explained in detail. With use of Equation 5.1 and Figure 5.6 a plausible explanation is given.

$$C = \frac{\epsilon A}{d} \tag{5.1}$$

From Equation 5.1 it can be found that in order for the capacitance to decrease, either ϵ or A needs to decrease or d has to increase. Since there is expansion and contraction of the materials due to the heat cycles there might be some slight differences in A and d. However it is more likely that a change in ϵ is the main contributor to the change in capacitance. Due to the high thermal stress the large polymer molecules are split into smaller polymer molecules with a lower weight. These lower weight molecules are more polar and therefore decrease the dielectric strength (ϵ) of the material. This assumption is backed up by [40, 41]. In [40] the process of post curing is mentioned as an other source of the difference in capacitance and tan(δ). The increase of IR also causes the resistive current to rise. As a consequence the ratio between the capacities and resistive current changes, which in turn causes the value of tan(δ) to change. Evaporated moisture from the insulation material has some influence as well, since this causes the dielectric strenght to change as well. This effect is found in subsection 5.1.4 as well.

5.1.4. INFLUENCE OF MOISTURE ON MEASURED VALUES

Since most of the performed measurements are very sensitive, effects from the outside must be looked after as well. Humidity in air for example can have a big influence on the values measured. For the insulation material might absorb some of the moisture which influences its insulating behaviour. When more moisture is absorbed by the material, the conductivity will increase and thus the resistance will drop. To investigate the influence of outside humidity two tests have been performed. The first test is used to investigate if the insulation material absorbs moisture from the air and what influence it has. The second test has been used to determine the influence of relative air humidity on the measurements performed. Each test will be discussed in a separate section.

MOISTURE ABSORPTION OF THE INSULATION MATERIAL

If materials are heated for a longer period of time, the moisture inside evaporates. The material is therefore extremely dry after heating compared to the environment outside the oven. Since the used insulation is (partly) hydrophilic, moisture in the air is absorbed by the material to a certain degree. Moisture inside insulation material has a large influence on the values measured. It is therefore important to have an idea on how hydrophilic the material is in practice, since interpretation of results will otherwise be very difficult.

For this reason the the test stators have been measured two times. The first set of measurements is performed one day after the oven has turned off and the stators had have enough time to cool down. The second set of identical measurements is performed 8 days later. During these days the stators are subjected to several environmental changes, such as changing temperatures and changing air humidity. By comparing the results of the two sets of measurements, an indication on the hydrophilic properties of the material is made. In Table 5.1 the results of the performed measurements are given.

Most of the measured values have changed significantly between the first and second measurement. This means that the insulation material has absorbed some moisture from the air during the period the stators were outside the oven. The insulation resistance is very dependent on the amount of moisture that is absorbed, since the value of IR has dropped in both cases by 8TΩ. For the value of PI this dependency is not visible. This probably is because the PI is calculated using the resistive value after both 1 and 10 minutes. During this time the amount of moisture inside the material does not change significantly. Therefore the dependency of moisture is divided out of the equation.

Over all, the capacitive values have increased slightly over time. For most situations the change is about 0,5% to 1%, which is much lower than the relative difference in IR. The change in capacitance is likely caused by the moisture that is absorbed, which has a higher permittivity than dry air that was inside prior to the absorption of moisture. A rise in most $\tan(\delta)$ values is also visible. This is mainly caused by the higher losses (thus lower IR), but it is partly compensated by the rise in capacitance. It has been expected that both the capacitance and $\tan(\delta)$ would rise, since this complies to the statement made in section B.2.

The measured $\tan(\delta)$ values show more remarkable behaviour. Since the change in values is much larger at low frequencies than at high frequencies. The impression rises that $\tan(\delta)$ measurements at different frequencies may give valuable information on the amount of moisture absorbed. It is likely to assume that older insulation materials have more cracks in the material than relatively new insulation materials and that the amount of cracks will increase over aging time. When more cracks are in the material, more moisture can be absorbed in these cracks. This would mean that the change in $\tan(\delta)$ values, caused by absorbed moisture, will increase when insulation systems get older. However at high frequencies the change in values is much lower than at low frequencies. The ratio between these (relative) differences may be an indicator of material aging. If further research can explain and prove these assumptions and remarks, the results can be an important indicator for the condition of insulation material. Eventually this could be another factor in a lifetime expectancy method to be designed.

From this data it can be concluded that some care has to be taken while doing the measurements. To be able to perform reliable measurements, environmental aspects (such as temperature and humidity) should be taken into account and corrected for if possible.

Table 5.1: Measured values after 1 and 8 days outside the oven

Value measured		Stator 001 1st measurement	Stator 001 2nd measurement	Stator 005 1st measurement	Stator 005 2nd measurement
IR [TΩ]		22	14	16	8
PI		4.55	5.00	4.69	4.375
C_{ABC-G}	1000Hz	2478	2499	2505	2527
in	50Hz	2485	2506	2512	2534
$[pF]$	10mHz	2494	2523	2526	2549
$tan(\delta)_{ABC-G}$	1000Hz	0.207	0.207	0.207	0.205
in	50Hz	0.0869	0.0866	0.0897	0.0907
[%]	10mHz	0.135	0.176	0.118	0.266
C_{A-G}	1000Hz	1071	1079	1047	1054
in	50Hz	1074	1082	1050	1057
$[pF]$	10mHz	1083	1091	1056	1065
$tan(\delta)_{A-G}$	1000Hz	0.212	0.211	0.202	0.200
in	50Hz	0.106	0.108	0.101	0.101
[%]	10mHz	0.710	1.091	0.274	0.470
C_{B-G}	1000Hz	1071	1071	1082	1092
in	50Hz	1074	1074	1085	1095
$[pF]$	10mHz	1083	1083	1092	1103
$tan(\delta)_{B-G}$	1000Hz	0.209	0.207	0.204	0.203
in	50Hz	0.103	0.105	0.101	0.103
[%]	10mHz	0.846	0.804	0.285	0.453
C_{C-G}	1000Hz	1073	1081	1055	1064
in	50Hz	1076	1084	1058	1067
$[pF]$	10mHz	1082	1093	1063	1075
$tan(\delta)_{C-G}$	1000Hz	0.207	0.205	0.204	0.202
in	50Hz	0.0998	0.102	0.101	0.104
[%]	10mHz	0.430	0.557	0.288	0.449
C_{A-B}	1000Hz	123.9	125.3	121.2	122.7
in	50Hz	134.2	125.7	121.5	123.0
$[pF]$	10mHz	127.9	129.8	123.0	124.7
$tan(\delta)_{A-B}$	1000Hz	0.230	0.235	0.181	0.183
in	50Hz	0.178	0.193	0.137	0.139
[%]	10mHz	4.174	4.171	0.585	0.968
C_{A-C}	1000Hz	120.3	120.8	94.82	95.56
in	50Hz	120.7	121.2	95.08	95.82
$[pF]$	10mHz	122.8	123.7	96.36	97.52
$tan(\delta)_{A-C}$	1000Hz	0.232	0.236	0.192	0.193
in	50Hz	0.161	0.176	0.143	0.153
[%]	10mHz	1.405	1.718	0.609	1.122
C_{B-C}	1000Hz	127.7	127.5	127.1	129.0
in	50Hz	128.0	127.9	127.5	129.4
$[pF]$	10mHz	130.2	130.2	129.1	131.5
$tan(\delta)_{B-C}$	1000Hz	0.185	0.185	0.204	0.206
in	50Hz	0.146	0.148	0.154	0.168
[%]	10mHz	1.225	1.467	0.772	0.972

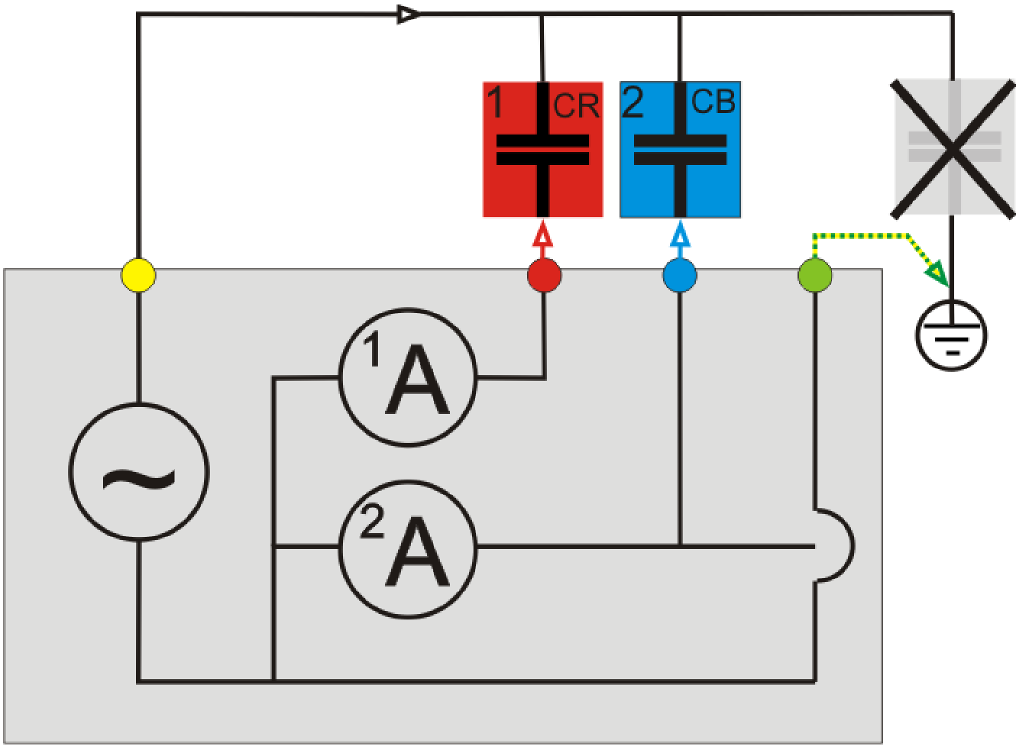

Figure 5.7: Setup used during the investigation of RAH influence on the measurements

INFLUENCE OF HUMIDITY IN AIR

The conditions during machine testing are seldom the same. Especially relative air humidity (RAH) is in practice almost impossible to keep at a constant level, since outside humidity changes constantly. To investigate how much influence the RAH level has, a set of measurements have been performed on both an aged stator (after the aging cycles have been finished) and the (new) reference stator. Both these stators have been placed into a chamber where the climate can be controlled. Since connections could not be changed without opening the chamber, thus changing the humidity level, only one setup could be used at different humidity levels. The setup used is shown in Figure 5.7.

For this setup both stators have been tested simultaneously to insure the conditions during the measurements have been the same. In Figure 5.7 the stators are regarded as general specimens depicted as 'CR' and 'CB'. Specimen 'CR' is the aged stator and object 'CB' represents the new reference stator. Both stators are connected such that measurements between all three phases and ground are performed. With this setup the IR, PI, C (freq. sweep) and tan(δ) (freq. sweep) have been measured. The results of the measurements are given in Table 5.2 and Figure 5.8 - 5.10. In the figures, the lines plotted in red correspond to the aged stator and the plots in blue correspond to the new stator. The almost constant lines with the filled dots represents the measured capacitance and the curved lines with circles represents the measured tan(δ).

From these results it can be seen that little difference between measured values is visible at relatively low RAH. It is likely that at these humidity levels the moisture in air has little influence. When at a high RAH level, the moisture in the air seems to influence the

Table 5.2: Measured values from the RAH setup

RAH	20%		47%		88%	
	Old stator	New stator	Old stator	New stator	Old stator	New stator
IR	93,30 GΩ	-1,406 TΩ	96,38 GΩ	-1,414 TΩ	80,51 MΩ	104,7 GΩ
PI	1,058	0,684	1,03	0,722	1,905	1,145
C_{1kHz}	2410 pF	2895 pF	2412 pF	2896 pF	2432 pF	2904 pF
C_{50Hz}	2416 pF	2907 pF	2417 pF	2909 pF	2460 pF	2919 pF
C_{10mHz}	2427 pF	2963 pF	2431 pF	2968 pF	38715 pF	2983 pF
$tan(\delta)_{1kHz}$	0,192%	0,325%	0,193%	0,328%	1,019%	0,355%
$tan(\delta)_{50Hz}$	0,085%	0,193%	0,087%	0,205%	6,830%	0,233%
$tan(\delta)_{10mHz}$	7,112%	0,751%	7,178%	0,805%	1804,600%	1,531%

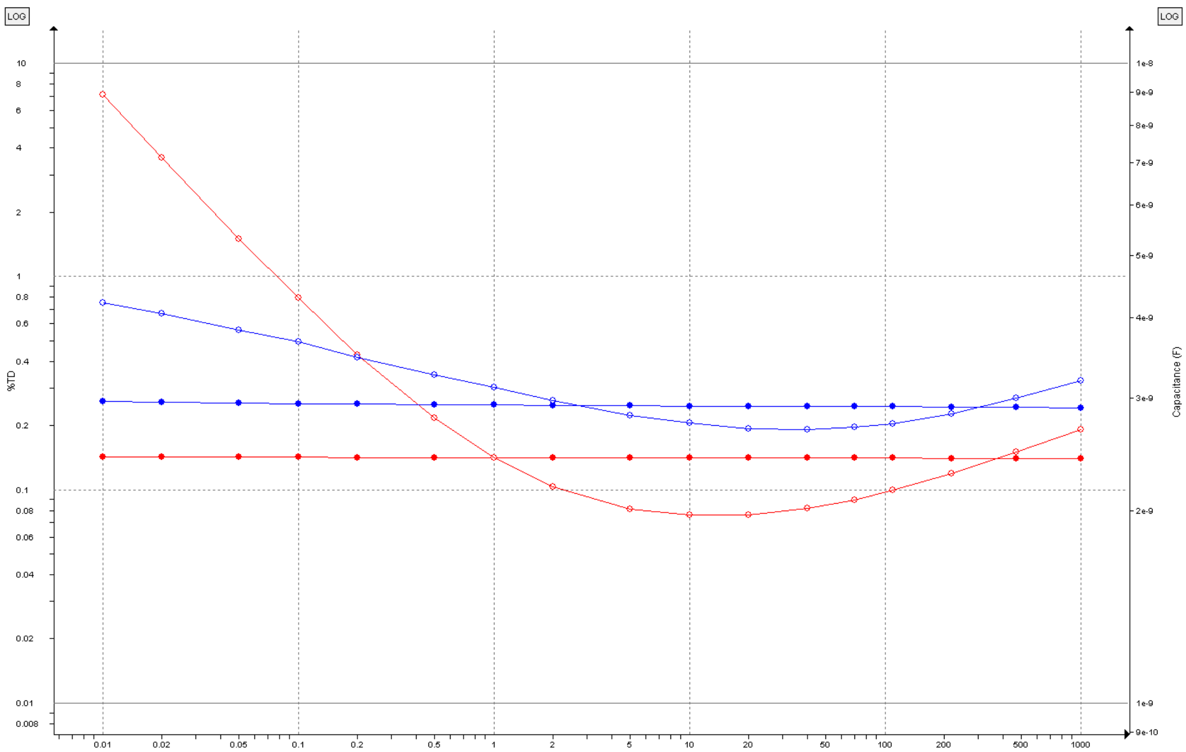

Figure 5.8: Measured C and tan(δ) over a frequency sweep between 10mHz and 1kHz with RAH=20%

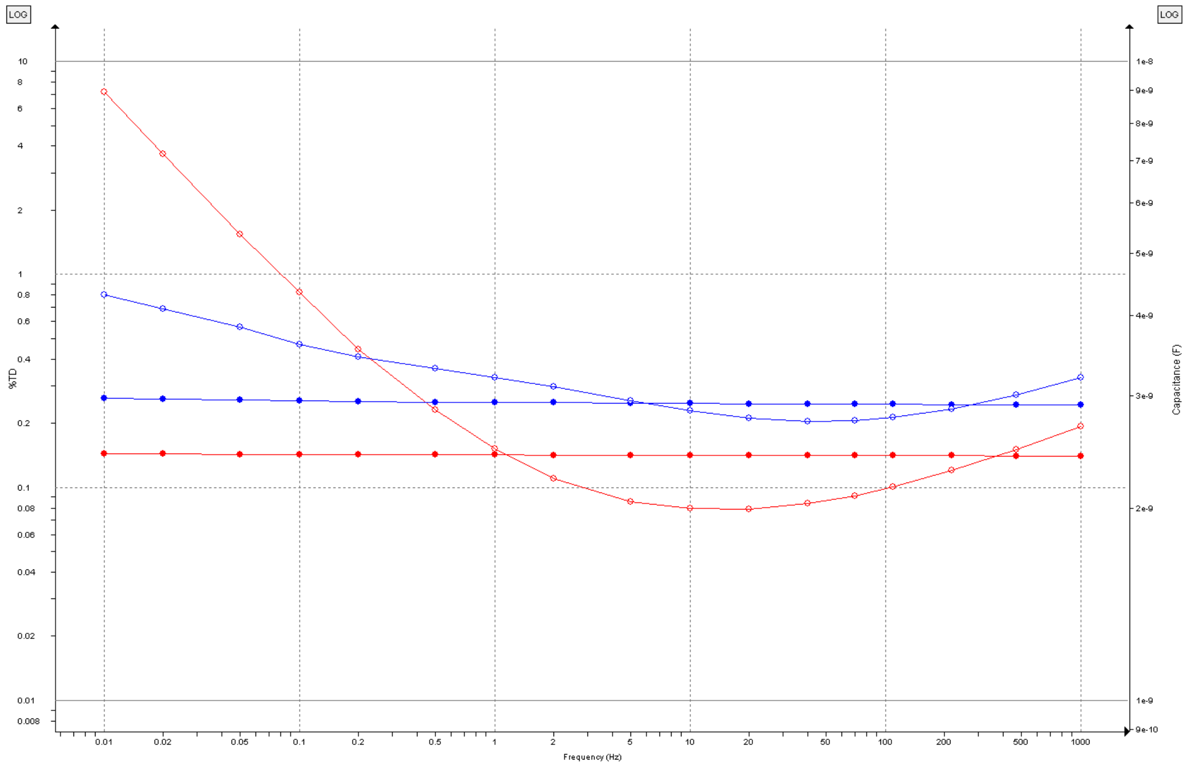

Figure 5.9: Measured C and tan(δ) over a frequency sweep between 10mHz and 1kHz with RAH=47%

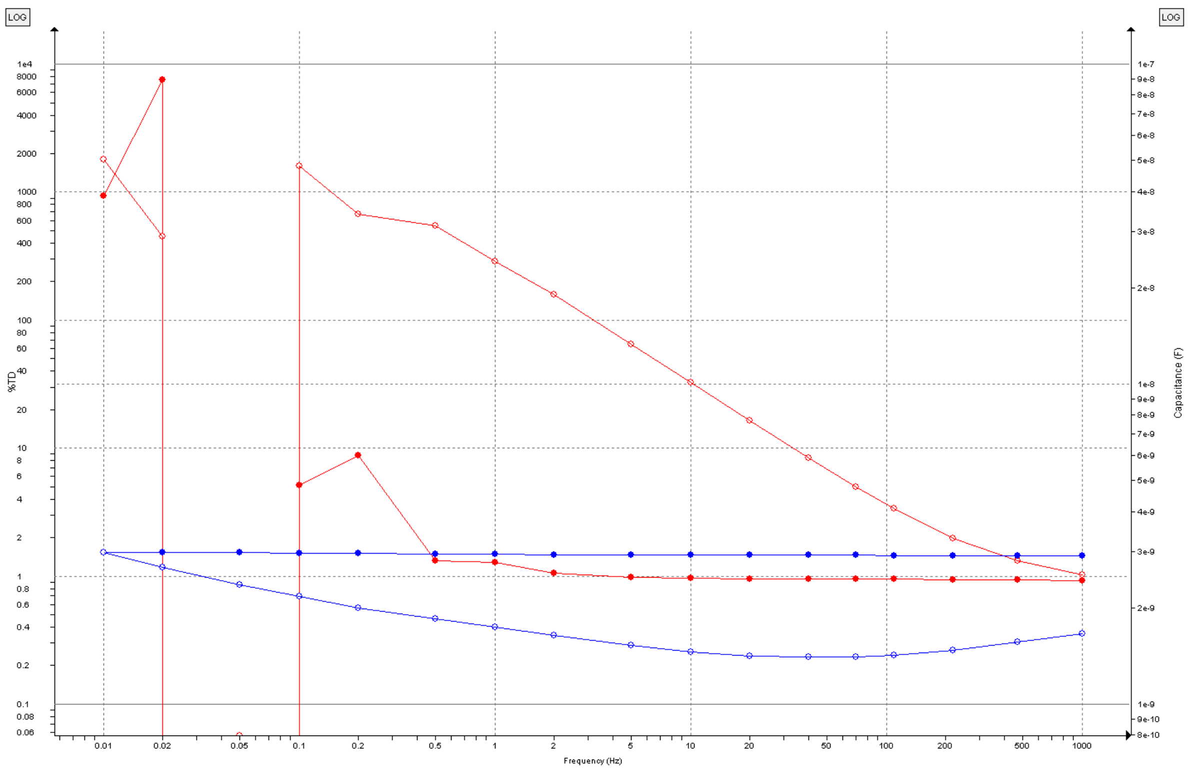

Figure 5.10: Measured C and tan(δ) over a frequency sweep between 10mHz and 1kHz with RAH=88%

measurements a lot, for most measured values have changed significantly.

At the high humidity level insulation resistance has dropped much. There are a number of plausible reasons for this. Due to the high amount of moisture in the air, some moisture may have condensed on (parts) of the stators. When moisture is condensed on windings or connecting terminals, resistance to ground is likely to drop since current will flow (partly) trough the moisture. Another reason for the difference in measured IR might be the amount of absorbed moisture by the insulation material. The high RAH would in this case cause the insulation material to absorb more moisture, since there is an excess of moisture in the air. Both of these reasons do however not explain the unexpected rise in measured PI value.

The measured capacitance is only influenced a little by the difference in air humidity. The capacitive values measured at both low and high RAH differ about 2% maximum. For this indication the measurement at 10mHz at high humidity for the old stator is not included, since the measurement is likely to be inaccurate. The dependency of the capacitance over the frequency range is comparable at different humidity levels. A difference in machine condition can also be detected by the value of capacitance measured. As concluded in subsection 5.1.3 the capacitance decreases over the lifetime of the machine. This difference is clearly visible with these measurements as well.

Tan(δ) gives for this situation the most significant information. There is little difference in measured value between lower RAH levels. At higher RAH the tan(δ) of the old stator is completely different over the whole frequency range. This shows that the older stator is influenced a lot at such a humid environment. The new stator is however barely influenced by the differences in RAH. Both the shape over the frequency range and the measured values are close to each other at different RAH levels. The measured values of the old stator are much more frequency dependent, but the tan(δ) is lower at normal operating frequency. The change in frequency dependency and measured values indicate significant differences based on a machines age. Such differences could be used when doing further research on lifetime expectancy models. This shows the need to perform tan(δ) measurements at different frequencies as the results can possibly indicate machine aging as well.

However some remarks must me made on the results found. The insulation resistance of the new stator is negative and the corresponding PI is very low. It is likely that the value to be measured is out of the equipments range and therefore wrong values are displayed. An other remark must be made on the measurement of C and tan(δ) of the old stator at high humidity level. Although the measurements have been performed several times, readings were not stable at frequencies below 1Hz. This suggests that measurements should not be performed when the humidity is very high. Although the equipment manual states that the equipment should work fine at humidity levels up to 95%, it is not recommended. More research is needed to determine the exact level at which measurements prove to be unstable. With the results found during such a research, a maximum humidity level for accurate measurements can be given.

5.2. DATA MEASURED FROM MACHINES IN FIELD

Since the goal of a life-time expectancy method is to indicate future lifetimes of LV-machines in general, other machines need to be looked after as well. This is done to validate the hypothesis that every different machine will have different measured parameters. For this purpose a number of used, revised and broken machines have been measured at "van Bodegraven elektromotoren, Dordrecht". In total 5 machines with a different rating, size and history have been measured. Prior to the results each motor will be discussed and some remarks on the tests performed are given. Afterwards the results of the measurements are given in a table and will be discussed briefly.

5.2.1. TEST OBJECTS MEASURED

During the measurements 5 different motors have been measured. Each motor is discussed in a separate paragraph.

Motor 1 is a 3 phase induction motor built by Hyundai. The motor has been build for use in marine environment, which means the motor is build for a 60Hz supply voltage. The machine is rated for 440V with a maximum power rating of 380KW. During the 8 years that the motor has been constructed it is never used in practice, since it is kept as a spare machine. This means very little electrical stress has been applied to the motor over its lifetime. Even though the machine has experiences little stress not all measurements gave an accurate reading. This shows that stashing a machine is not very good for its condition as well.

Motor 2 is a defected 3 phase induction motor from which the windings have been burned. This machine, built by Schorch, used to have a nominal voltage of 440V and a power rating of 370kW. The machine has been designed for operation at 60Hz and has been used in marine environment. Not all the measurements performed could provide a reading because the failure caused a short to ground. The measurements that could not be performed due to the failure are marked with '-' in Table 5.3.

Motor 3 is a revised 3 phase induction motor made by Schorch. The revised machine has a power rating of 132kW and a nominal voltage of 380V. This machine is supplied by a 50Hz voltage supply and its operation has been verified after the revision.

Motor 4 is a defective DC-motor built by the manufacturer Lammers. The nominal voltage of the machine is 440V with a maximum power rating of 44,5kW. This motor has been designed for marine purpose and is supplied with a 60Hz source. It is suspected that the motor has been floated with (salty) water and this is most likely the cause of the failure. The condition of this machine is so bad that the IR and PI could not be measured at the usual 500V. To at least get an indication on the condition of the insulation material the test to measure IR and PI has been performed at 250V which resulted in a (inaccurate) reading. Some measurements could not be performed at all on this motor due to its bad state. The tests that could not be performed are marked with '-' in Table 5.3.

Motor 5 is the smallest 3phase motor that is measured in field. This motor, build by Nord, has a nominal voltage of 400V at 50Hz and a rated power of 3kW. The machine has been disassembled during the measurements. It is said that the motor is still working fine when it is assembled again. Sadly it was not possible to measure tan(δ) on this stator because of its small size. The missing measurement is marked with '-' in Table 5.3.

During the measurements not all different test circuit mentioned in item 4.2.3 have been performed. The measurements used are measurements which are normally used in field when measuring electrical machines. While normally the measurements are performed with the equipment explained in chapter 4, these measurements were performed with equipment from ABB Nederland which is normally used for high voltage testing. The tests which are normally performed in field are: Winding resistance, IR, PI, capacitance three phase to ground (at 50Hz) and tan(δ) three phase to ground (at 50Hz). Since these tests are normally performed for HV machines it is known that readings might be inaccurate. For the set of measurements, used to get an indication, this should not pose a problem. However more specific equipment might be needed when accurate measurements need to be performed. All measured motors are connected in Δ and therefore the used measuring setup is similar and measured values can be easily compared.

5.2.2. RESULTS OF MEASUREMENTS IN THE FIELD

The results of the measurements performed infield are given in Table 5.3.

Table 5.3: Obtained values from the motors measured at van Bodegraven elektromotoren

measurement performed	Motor 1	Motor 2	Motor 3	Motor 4	Motor 5
Winding resistance 1-2	5.973mΩ	8.176mΩ	24.806mΩ	0.176Ω	3.566Ω
Winding resistance 1-3	5.713mΩ	9.185mΩ	23.805mΩ	0.173Ω	3.571Ω
Winding resistance 2-3	5.693mΩ	9.438mΩ	24.583mΩ	0.171Ω	3.590Ω
Insulation Resistance	22.1GΩ	-	7.22GΩ	3.6MΩ	186.2GΩ
Polarization Index	5.52	-	5.82	1.49	4.12
Capacitance (@4kHz)	0.1μF	14.9μF	24.3nF	19.7nF	4.9nF
Capacitance (@50Hz)	99.19nF	-	25.36nF	-	-
tan(δ)	-0.206%	-	6.052%	-	-

From these results it can be concluded that machines of different size and rating will have different reading on the measurements. It is likely that the measured values change with differences in build size, insulation class, voltage rating and power rating. The following generalizes assumptions are made on these changes:

- If the build size of the machine is larger, the winding resistance measured will be lower. The measured value of the insulation resistance is likely to be higher for machines that have a smaller size.
- Different insulation classes or insulation types used in a machine will influence the values measured for all machines.
- When the voltage rating and/or power rating is increased, it is likely that the measured insulation resistance and capacitance will be higher.
- A measurement of tan(δ) on a LV-machine with a relatively high insulation resistance is most likely to be inaccurate. The boundary of the IR that causes an inaccurate reading will depend on the sensitivity of the equipment used.

These assumptions are however not verified, but the information has been used for recommendations given in chapter 6 and chapter 7.

6

LIFETIME EXPECTANCY

In this chapter the data presented in chapter 5 is collected in a set of trendlines. The formulas of these trendlines can be used when the deterioration of insulation in electrical machines is modeled. In section 6.1 the trendlines made with the data from the practical setup are presented. A way to generalize the found formulas based on initial machine parameters is discussed in section 6.2. Based on the results of chapter 5, section 6.1 and section 6.2 the possibility for a lifetime expectancy model is discussed in section 6.3.

6.1. TRENDLINES OF COLLECTED DATA

With the data collected from the practical setup trendlines have been made. The formula's of these lines can be used to simulate degradation of insulation material over time. Since there were multiple measurements on similar test samples, such as measurements on a single phase to ground winding, the results of these tests must be combined to reach a single trendline. To do this the average of all the measured values is calculated. The averaged values are used to make a trend formula, which indicates the change in measured values. The first two measurements have not been included in the data for the trendline, since effects other than aging play a significant role in the change of values.

There are no trendlines made for the behaviour of $\tan(\delta)$, due to two reasons. First is the high dependency of moisture absorbtion by the material. The moisture causes much change in measured values, which is explained in subsection 5.1.4. Since the material is extremely dry when the measurements have been performed, unrealistic values have been measured. This is one of the reasons why the values of $\tan(\delta)$ appear to be almost constant in Figure 5.3 - 5.5 after a few aging cycles. The second reason is explained in subsection 4.3.4. It is unclear if the resistive current measured and used for calculating $\tan(\delta)$ is accurate. Since measured currents are very low, it is plausible that the indicated values are dominated by the device limitations. This in turn might cause an almost constant value of $\tan(\delta)$. Altogether the trendlines for the values of $\tan(\delta)$ have not been included due to the suspicion of inaccurate readings.

Figure 6.1 - 6.4 show the results of the calculated averages with the circle-points. The lines drawn through these points are the trendlines that have been formulated. In Figure 6.2 - 6.4 three averages and trendlines are visible. Each of these lines represents the trendline for when the measurements are performed at different frequency. It can be seen that there are some differences between frequencies used and therefore the trendlines at

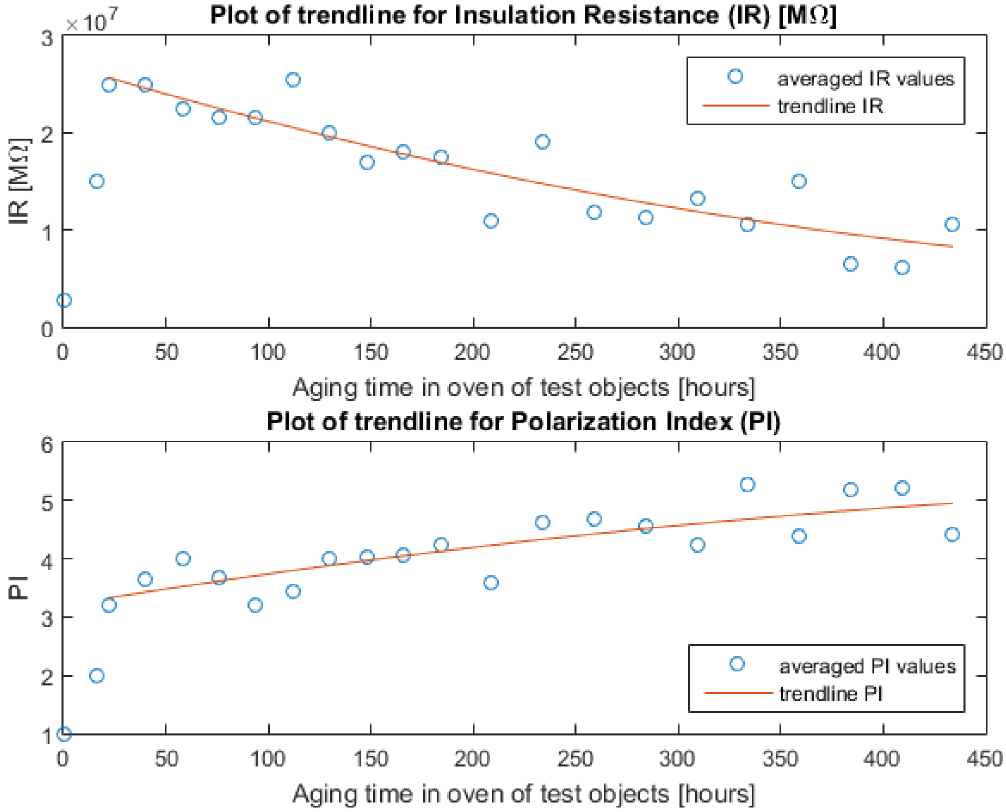

Figure 6.1: Trend made for IR and PI

different frequencies have been put in a single figure. This way it is made clear that the frequency at which capacitance and tan(δ) are measured have a significant influence.

The trends calculated for the IR and PI are given in Figure 6.1. Although the measured values of IR are very high a decrease in resistance is still visible. This is a clear indication of deterioration over time, since the properties degrade. The rising trend in PI is however unexpected, for a decreasing trend was expected prior to testing. This increasing trend of PI might be the cause of equipment limitations as well because the values measured after 10 minutes are very close to the equipments end of scale. Equation 6.1 and 6.2 have been made to indicate the change in measured IR and PI values over deterioration time. With IR_{exp} as the expected IR in [MΩ], PI_{exp} as the expected PI and x as aging hours inside the oven. According to the assumptions made in chapter 4, one aging hour inside the over equals 64 hours at rated temperature. Assuming lifetime is 10 higher at normal operating temperatures one our of aging inside the oven correspondences to 640 hours at normal operating temperatures.

$$IR_{exp} \approx 46.76x^2 - 63550x + 27 \cdot 10^6 \tag{6.1}$$

$$PI_{exp} \approx -3.96 \cdot 10^{-6} x^2 - 5.7 \cdot 10^{-3} x + 3.2 \tag{6.2}$$

In Figure 6.2 - 6.4 the found trendlines for the capacitance are shown. On first glance these lines seem to have roughly the same shape. This could have been expected, since the degradation process is the same at all places in the stators. For every (dominant) capacitance a trendline is made for the frequencies 1000Hz, 50Hz and 10mHz. The general trend

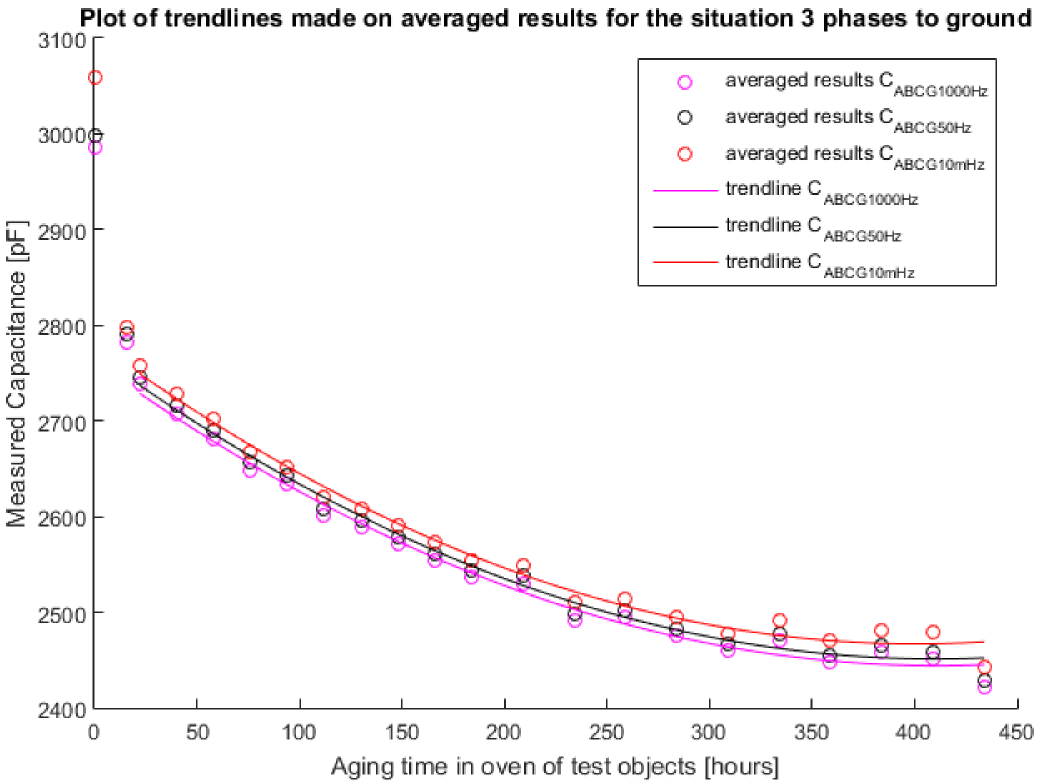

Figure 6.2: Trend made for the capacitance of 3 phases to ground

for the formulas at different frequencies is however the same, which implies that trending these values should be possible at all frequencies. In Equation 6.3 - 6.11 the calculated expected capacitance is given in [pF] and x is the number of aging ours inside the oven.

The formulas of the trendlines for the capacitance between all three phases and ground, shown in Figure 6.2, are given in Equation 6.3 - 6.5.

$$C_{exp,1000Hz} \approx 1.9 \cdot 10^{-3} x^2 - 1.55x + 2762 \tag{6.3}$$

$$C_{exp,50Hz} \approx 1.9 \cdot 10^{-3} x^2 - 1.56x + 2771 \tag{6.4}$$

$$C_{exp,10mHz} \approx 2.0 \cdot 10^{-3} x^2 - 1.58x + 2783 \tag{6.5}$$

The formulas of the trendlines for the capacitance between each single phase and ground, shown in Figure 6.3, are given in Equation 6.6 - 6.8.

$$C_{exp,1000Hz} \approx 6.9 \cdot 10^{-4} x^2 - 0.67x + 1190 \tag{6.6}$$

$$C_{exp,50Hz} \approx 7.0 \cdot 10^{-4} x^2 - 0.68x + 1194 \tag{6.7}$$

$$C_{exp,10mHz} \approx 9.4 \cdot 10^{-4} x^2 - 0.81x + 1218 \tag{6.8}$$

The formulas of the trendlines for the capacitance between phases, shown in Figure 6.4, are given in Equation 6.9 - 6.11.

$$C_{exp,1000Hz} \approx 3.0 \cdot 10^{-5} x^2 - 0.076x + 136 \tag{6.9}$$

$$C_{exp,50Hz} \approx 3.3 \cdot 10^{-5} x^2 - 0.078x + 136 \tag{6.10}$$

$$C_{exp,10mHz} \approx 1.4 \cdot 10^{-4} x^2 - 0.140x + 146 \tag{6.11}$$

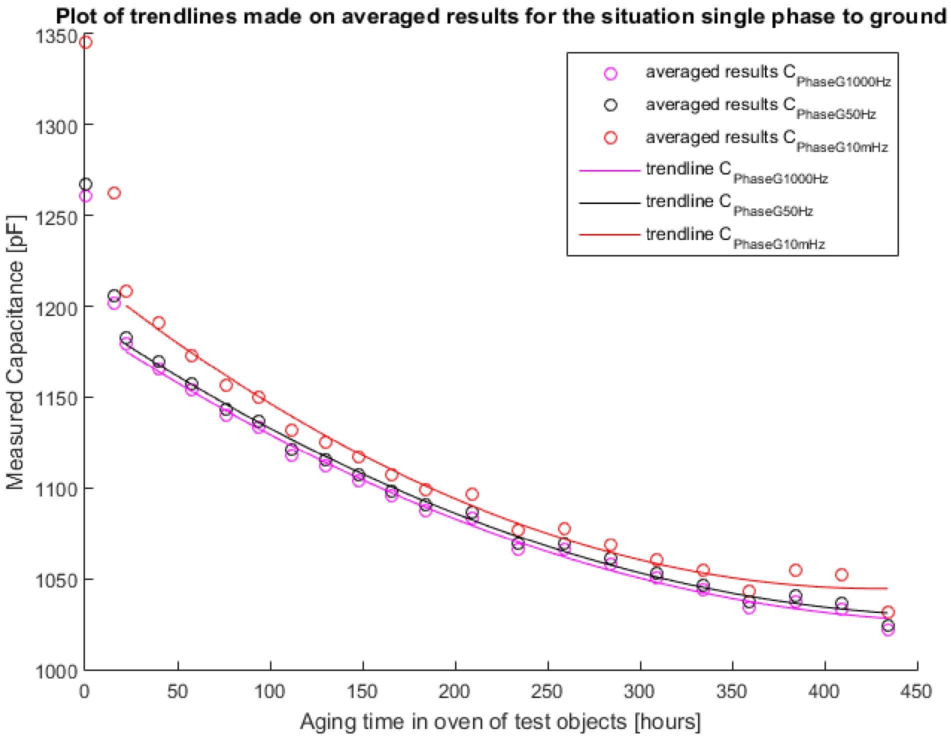

Figure 6.3: Trend made for the capacitance of a single phase to ground

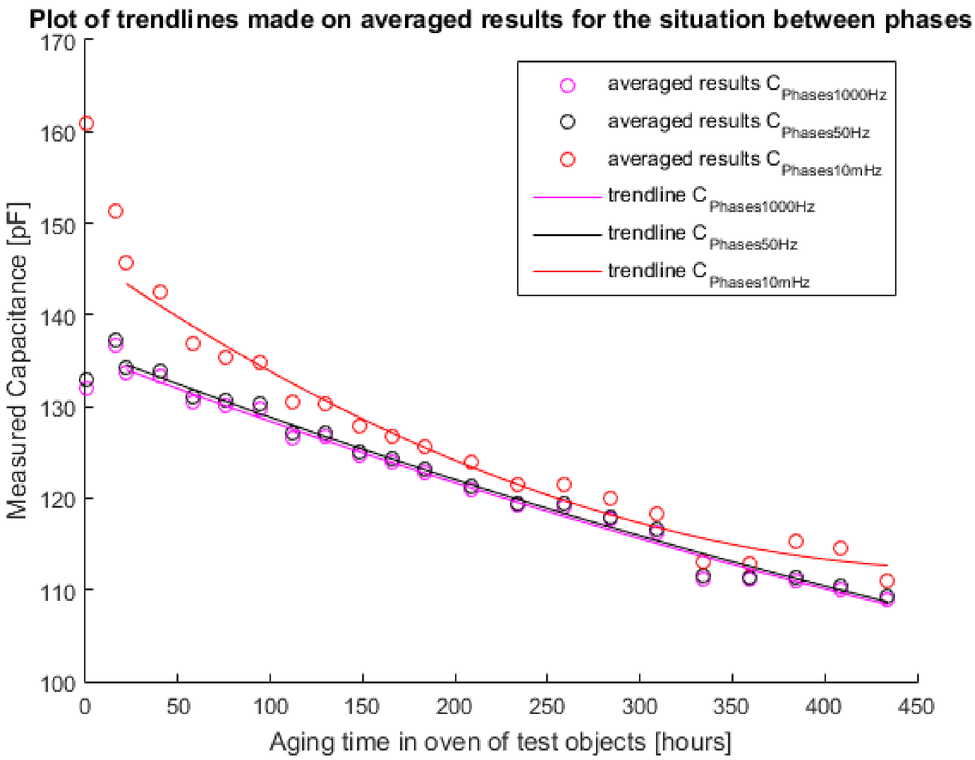

Figure 6.4: Trend made for the capacitance between phases

These trending formulas are only valid for these types of stators and under the conditions used during the aging process. Due to the relatively unstable measuring conditions a high deviation of the trendlines can be found for several points. Also the formulas have initial values based on the measurements performed on the test samples. In section 5.2 it is mentioned that measured values change with machine differences, this means initial values change for each of those machines as well. In section 6.2 a generalization of the formulas based on initial parameters (after post-curing) are presented.

6.2. GENERALIZATION OF TRENDLINES

The trendlines found in section 6.1 are only valid for stators that are nearly identical to the test objects used. Since a lifetime expectancy model should be applicable to a large scope of machines, generalized equations have been designed. The generalized equations describe the deterioration of the insulation over time, but they have not been verified yet.

For the generalization initial values have been altered, based on the initial values to be measured just after the post-curing process has taken place. The time of aging has been changed as well. In Equation 6.1 - 6.11 the aging time 'x' corresponds to the number of hours inside the oven at 215°C. For Equation 6.12 and Equation 6.13 the aging time has been normalized to days at normal temperature (given as 't'). This normalization is based on the assumption that an electrical machine has an expected lifetime of 23 years at normal operating temperatures, so ten times longer than at rated temperature.

Equation 6.12 gives a generalized version for the expected insulation resistance. It is assumed that the IR will follow a similar trend when other (constant) conditions are used. The formula shows that the initial IR measured after the post curing process, influences the decay of the value over time. The amount of moisture absorbed should however remain relatively constant over the time of monitoring, since absorbed moisture influences the measured values significantly. Based on these starting points Equation 6.12 has been made.

$$IR_{exp,gen} = 7.22 \cdot 10^{-7} \cdot IR_{ini} \cdot t^2 - 1.0 \cdot 10^{-3} \cdot IR_{ini} \cdot t + IR_{ini} \tag{6.12}$$

Where:

$IR_{exp,gen}$ = Expected Generalized Insulation Resistance value in [mΩ]

t = The age of the machine in days

IR_{ini} = The initial Insulation Resistance in [MΩ] calculated using:

$$IR_{ini} = IR_{pc} + \left(IR_{pc} - (7.22 \cdot 10^{-7} \cdot IR_{pc} \cdot t_{pc}^2 - 1.0 \cdot 10^{-3} \cdot IR_{pc} \cdot t_{pc} + IR_{pc})\right)$$

With:

IR_{pc} = The Insulation Resistance in [mΩ], measured after the post curing process

t_{pc} = The age of the machine after post curing has taken place in days

In Equation 6.13 a generalized version of the expected capacitance is given. When comparing the trendlines of each situation, it is found that the equations relate to each other based on the initial capacitance measured. This has been used to generalize the equation that gives the expected capacitive value. By using this simple way to generalize the found trendlines, the expected value for the capacitance can be estimated.

Figure 6.5: Comparison of Equation 6.12 and the averaged results from the measurements of IR

$$C_{exp,gen} = 2.44 \cdot 10^{-7} \cdot C_{ini} \cdot t^2 - 2.37 \cdot 10^{-4} \cdot C_{ini} \cdot t + C_{ini} \tag{6.13}$$

Where:

$C_{exp,gen}$ = Expected Generalized Capacitive value in [pF]

t = The age of the machine in days

C_{ini} = The initial capacitance Capacitance in [pF] calculated using:

$C_{ini} = C_{pc} + \left(C_{pc} - (2.44 \cdot 10^{-7} \cdot C_{pc} \cdot t_{pc}^2 - 2.37 \cdot 10^{-4} \cdot C_{pc} \cdot t_{pc} + C_{pc}\right)$

With:

C_{pc} = The Capacitance in [pF], measured after the post curing process

t_{pc} = The age of the machine after post curing has taken place in days

The generalized functions made have been checked briefly using the averaged values presented in section 6.1. For this purpose the time 't' has been compensated such that the formula fits for aging time inside the oven again. Figure 6.5 - 6.8 show the results of the comparison of the generalized functions and averaged practical results.

With the use of Figure 6.5 it can be concluded that the generalized version for calculating the expected IR seems to fit well. However the generalized function has been made using the exact same dataset. The practical value of the comparison is therefore questionable, since results cannot be compared with different machines or setups.

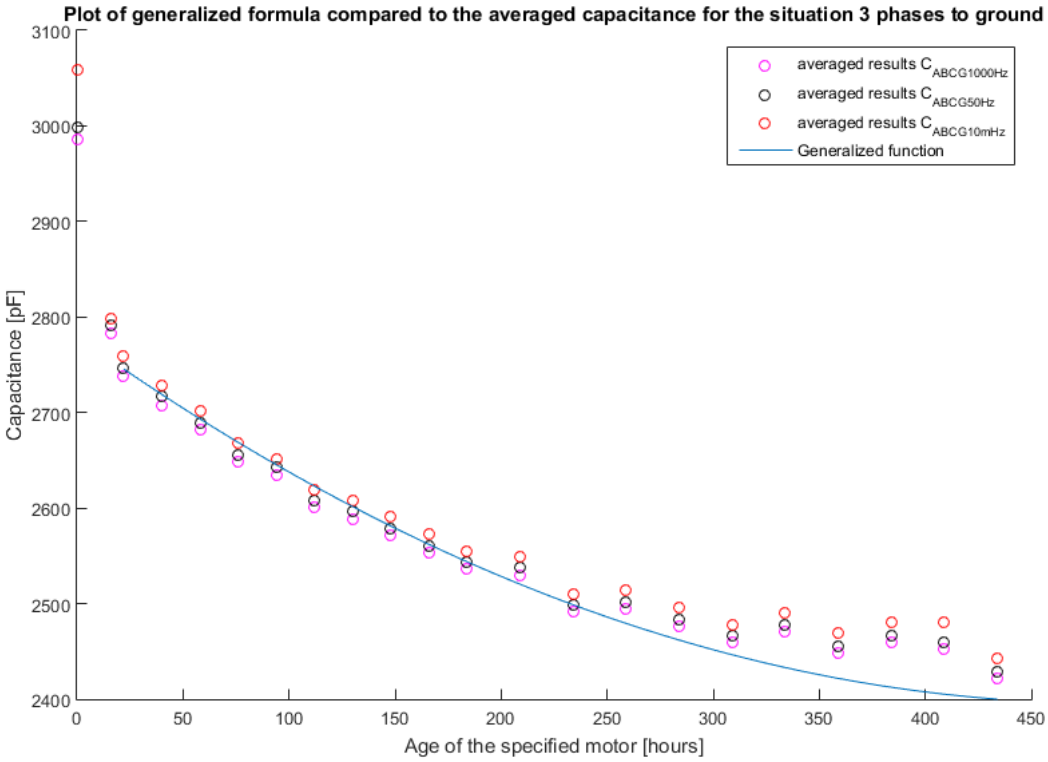

Figure 6.6: Comparison of Equation 6.13 and the averaged results from the measurements of the capacitance between three phases and ground

The comparison of Equation 6.13 is of more practical use, since the formula has been compared for different setups and thus different initial values. The results of these comparisons are shown in Figure 6.6 - 6.8. These figures show that the generalized equation is most reliable during the first half of a machines lifetime. It is also clear to see that Equation 6.13 gives bad results for very low capacitive values. For calculating expected capacitive values between a single phase and ground the results are very accurate. One of the causes might be that the generalized equation is based on the trendline of these results. The results for the situation of three phases to ground are relatively accurate as well, mainly in the first halve of the machines lifetime. During the second half of the expected life the expected capacitive values are lower than expected. This might result in pessimistic expectations near the end of life of machine.

6.3. POSSIBILITY FOR LIFETIME EXPECTANCY METHOD

The purpose of this thesis is to investigate the possibility of a lifetime expectancy method for LV- and MV-machines. With the research that is performed it can be concluded that the possibility of such a method exists. However much more research is needed to make an accurate model. In this section some possibilities for such a model are discussed, based on the achieved results. A number of remarks, limitations and recommendations on the possibilities are given as well. This way research on this topic can be easily continued.

Based on the results of this research it can be concluded that a lifetime expectancy method is possible for electrical machines with a low voltage rating, when only thermal aging is considered. The measured values, given in chapter 5, clearly show a possible trend

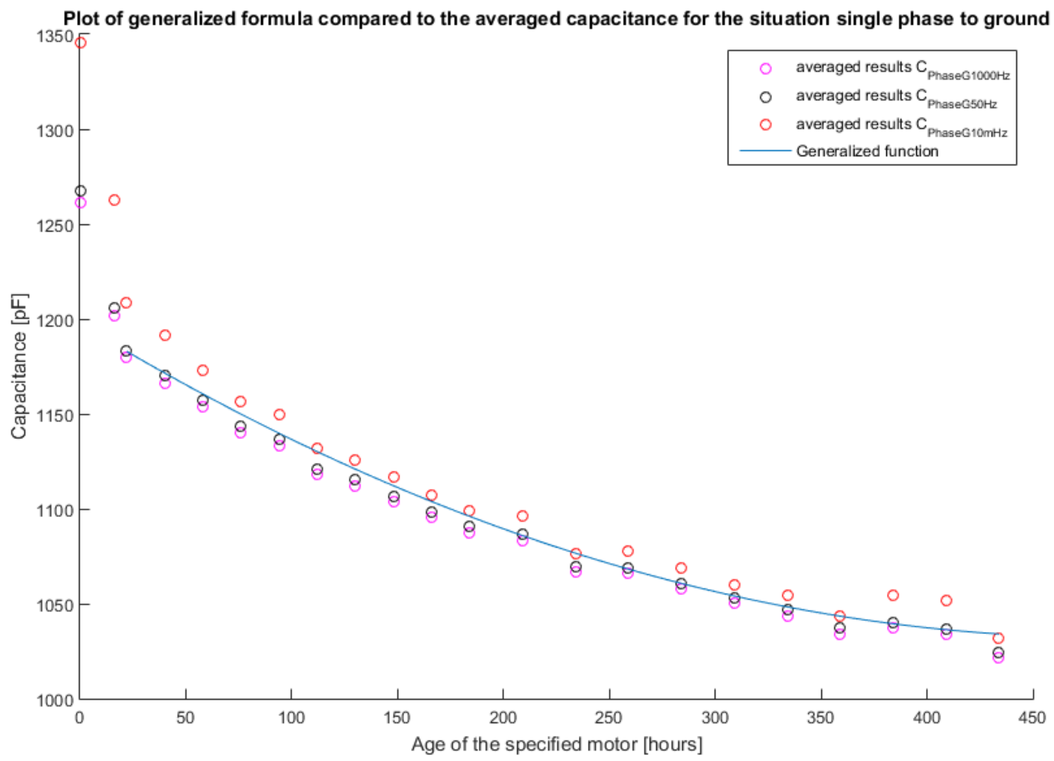

Figure 6.7: Comparison of Equation 6.13 and the averaged results from the measurements of the capacitance between a single phase and ground

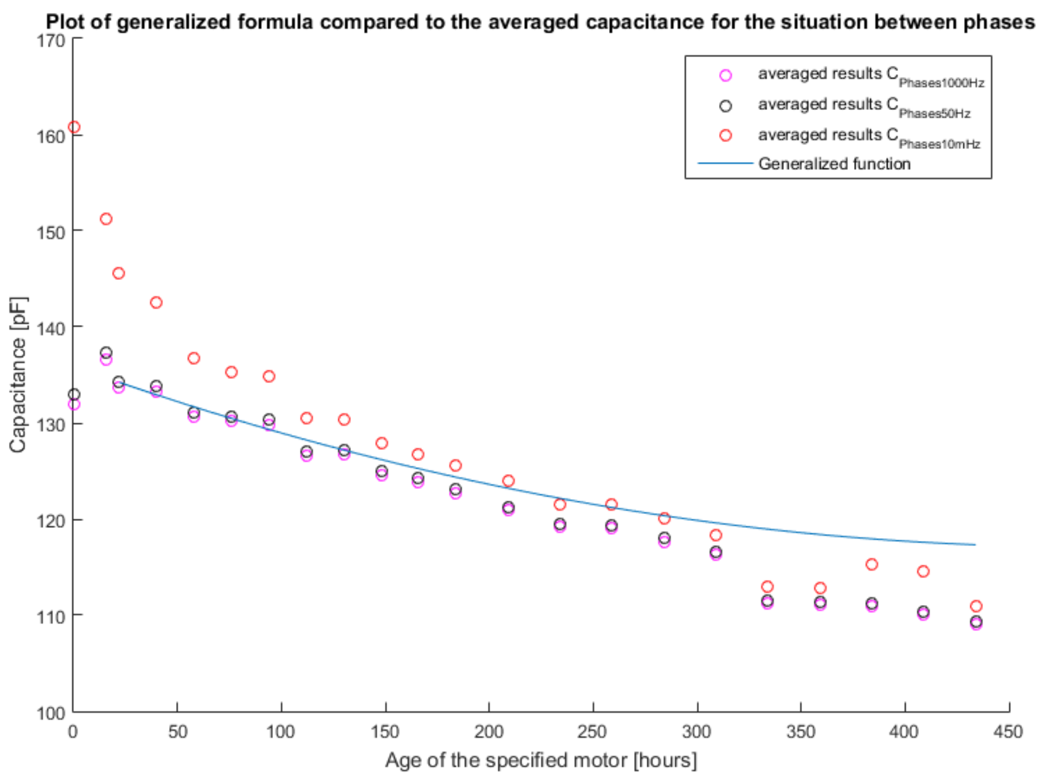

Figure 6.8: Comparison of Equation 6.13 and the averaged results from the measurements of the capacitance between two phases

over the aging time of the machine. This trend has been made in section 6.1 and a generalized version of the trend is given in section 6.2. To be able to design a generalized and practical lifetime expectancy model, the decay caused by other stresses must be investigated and modeled as well.

The generalized equations for a trendline can theoretically be used to make a rough estimation on a machines condition. With the use of values measured, an expected plot of the IR and capacitance can be made when the age of the machine is known. By using extrapolation, a trendline can be made on the expected decrease of both the capacitance and insulation resistance. This method can be implemented in a model when more information is available on the effects of other TEAM-stresses. With such a model expected lifetime can accurately be calculated. However for a model to be accurate, much more research is needed, since all types of stresses must be implemented.

Using the values measured before the electrical breakdown of 'stator 001', a broad indication on a machines condition can be given. This indication is made based on the ratio between measured values before aging and the last values measured just before breakdown. An indication is made for the capacitive value of the machine. It is however not possible to do this for the insulation resistance since the measurements for this value have been too inaccurate. Before breakdown at overvoltage has taken place, the capacitive values have dropped by about 20% of the initial value. For the capacitance between two phases this was about 13%. These levels can be used as a so-called 'danger level', since potential overvoltage could destroy the machine. When machines enter the 'danger level' it should be advised to revise or replace the machine when its function is critical for a plants operation. If a machine is not critical for a plants operation it can be advised to save budget and (pre-)order a spare machine. For better implementation of a 'danger level' system in advisement on maintenance strategy it is suggested to look into the following items:

- Measure the decay in values when machines are 'very likely' to fail.
- Validate Equation 6.13 on different machine sizes.
- Validate Equation 6.13 on multiple machines in field
- Investigate effects of other stress factors on capacitive values.

Altogether it can be concluded that it is possible to make a lifetime expectancy method for LV- and MV-machines. At the moment a very rough indication on a machines condition can be achieved, using the not yet verified general equations. It is however suggested that the general formulas that can be used for this indication should be validated using different conditions. When this validation is performed and the results are positive, a 'danger level' system can be used to get an indication on the condition of an electrical machine. The indication can be made much more accurate when more research is performed on the contribution of other stresses and other effects that play a role in the deterioration of machine insulation. When more research is performed on the aging and failures of electrical machines, the indicative 'danger level' system can be replaced with a detailed model. This model should contain all (major) effects that play a role in the aging of electrical machines and should predict what happens in the remaining time period. When such a model is made, it can be fine-tuned and a lifetime expectancy model can be achieved, giving expected remaining working hours.

7

Conclusion and Recommendations

The goal of this thesis has been to investigate the possibility of a lifetime expectancy model for electrical machines with a voltage rating below 3,3kV. The to be researched possibility of a method should be applicable for a large scope of machines and does not necessarily need monitoring over the machines total lifetime. ABB Nederland preferred that measurements used would be commercially available and that the used measurements can be performed in field. In this chapter conclusions drawn on these goals are given, as well as recommendations for further research.

7.1. Conclusions

Based on the research performed for this thesis the following conclusions are drawn:

- The results found during the research show that measured values show a decay over the lifetime of a machine. This decay follows a certain trend. With the knowledge that decay of insulation material follows a certain trend, there might be a possibility to develop a lifetime expectancy method based on these trends.
- Since all machines have an insulation system, it is likely that trendlines on the decay of the insulation material can be found for all machines.
- When more research is performed on the correlation between different trends followed and machine parameters, the possibility exists that expected trendlines can be used in the (to be designed) lifetime expectancy method. This means that expected lifetimes can be estimated without knowledge of the machines history.
- Most measurements performed on HV machines are applicable on LV- and MV-machines as well.
- Measured values will differ for each different machine. These differences are likely depending on build size, voltage and power rating, insulation class.
- Standard commercially available equipment cannot be used for accurate measurements on a broad scope of machines. The accuracy of this equipment is not good enough to perform accurate measurements on smaller electrical machines.

- When accurate measurements need to be performed on (smaller) machines, specialized equipment should be used to perform the measurements. Such equipment can be used in field, but noise levels may be higher than in a laboratory environment.
- Absorption of moisture from the air by the insulation material has a significant influence on insulation measurements to be performed.
- Humidity in the air has little influence on the performed measurement when the humidity is relatively low. At high humidity levels the performed measurements are influenced significantly.
- An old and new stator can be identified with use of capacitance and $\tan(\delta)$ measurements performed over a frequency range between 1kHz and 10mHz.
- Results of $\tan(\delta)$ measurements at multiple frequencies can provide valuable information on the condition of insulation systems. For example, contamination of insulation material can easily be found by performing these measurements at relatively high and low frequencies.

7.2. RECOMMENDATIONS

There are two sets of recommendations made. The first set is a set of recommendations to make a 'danger level' system for use on short term. This part will hold a number of suggestions to validate the formula's made in chapter 6. Recommendations on expanding such a method are given as well. The second set holds a number of recommendations for further research on this topic.

7.2.1. RECOMMENDATIONS FOR A 'DANGER LEVEL' SYSTEM

In chapter 6 generalized versions of trendlines are presented based on the trendlines found from the measurements performed on the practical setup. When these trendlines are validated and possibly expanded, a very rough indication on the condition of an electrical machine may be given. This rough indication is based on a 'danger level' system, where machines can be divided into 'good', 'moderate' and 'bad' groups. For such a system it is assumed that machine insulation values follow a similar trend over the lifetime as the trends found in this research. Before applying such a system the following work is recommended:

- More general equations must be made to indicate trends over lifetime of measurements that can be performed.
- Measure the relative difference in values when machines are 'good', 'likely to fail' and 'very likely to fail'.
- Validate the found general equations on different machine sizes.
- Validate the found general equations when different stresses are applied to the machine.
- Validate the found general equations on multiple machines in field.
- Investigate effects of other stress factors on measured values.

Since it is time consuming and expensive to perform the recommended research on all different kinds of machines, it is suggested to set up a database containing machine data from machines in field. With the use of enough data from a database, general equations can be made, verified and improved. This database should be organized based on the types of machines. It is suggested to make the following categories in the database:

- Machine build size
- Nominal voltage rating
- Nominal power rating
- Insulation class used
- Age of the machine
- Operation hours of the machine

When a 'danger level' system is validated and completely set up, the system can be used for condition based maintenance. Managers will be helped by the system, since the found condition can place machines in a 'good', 'moderate' or 'bad' group. This method can be applied on short term when a database containing enough useful machine data is available. When such a database is not available, the database should be made prior to improving and validating the 'danger level' system.

7.2.2. RECOMMENDATIONS FOR FUTURE RESEARCH

Performed research in the field of lifetime expectancy on LV- and MV-machines is still very limited and in an early stage. There are however indications of a possibility that a lifetime expectancy method for these machines can be designed. For such a lifetime expectancy method to be accurate and successful, much more research is needed. In this thesis only the thermal aging effect has been investigated briefly and more research is needed to validate the generalized equations that give an expected trend. The effects of other TEAM-stresses should be investigated and similar generalized equations on trends should be made and validated. Since it is still unknown how different stress affects the values measured. The effect that separate stresses have on other stresses is still unknown as well. Altogether the contribution to the deterioration caused by all stresses should be investigated and modeled in detail.

When the contribution of all stresses and combinations of stresses are known and modeled, machines in field should be researched. This research should give insights in the ways how machines are used, what kinds of stress are applied during its use and how much stress is applied. Modern machine models may already give a some information on this topic. When possible, it is recommended to expand existing machine models such that stress levels are given as an output of these models. With the designed simulated stress levels and their influence, a lifetime expectancy model can be used to accurately simulate the remaining life of a machine.

Executing these recommendations will likely be more difficult than expected. Manufacturers keep improving their machine designs, thus changing the parameters for machine models. The continuous research for better insulation materials contributes to the difficulty in execution as well. Since every type of insulation is likely to behave (slightly) different, detailed models must be updated based on every type of insulation. A solution for this could be generalization of models with less accuracy as a consequence. The best ratio between accuracy and generalization should be investigated for such methods to be successful.

A

Literature survey on machine failures

Failures in electrical machines can be divided based on their location and cause. The most common roots of break down are based on thermal, environmental, mechanical and electrical effects, also called TEAM-stresses in section 2.1. However most failures occur due to a combined effects. Therefore the failures on machines are normally specified on the location of the first failure that caused breakdown of the machine. [1, 14, 21]

This section will cover most of the failures in electrical machines. If a plausible cause of the failure is known it will be stated, but it does not mean that it is the only cause of the failure. Motor drives will not be covered in the literature survey since they are, technically speaking, not part of a machine.

A.1. Mechanical/Bearing related failures

There are multiple mechanical faults that may contribute to failures of electrical machines. The major mechanical faults are: Airgap irregularities, bent shafts, misalignment, bearing and gearbox failures, broken rotor bars or cracked rotor short circuit rings, vibration problems, an out of balance system, critical speed, resonance and corrosion [14, 22].

Of all the faults mentioned, bearing failures have the largest contribution to the mechanical faults. According to [23] about 40% of all failures in induction machines are due to bearing related failures. Most other mechanical faults are due to bad alignment of the machine, wrong engineering during the design phase and mistreatment of the equipment.

A.1.1. Bad alignment of the machine

Misalignment of the machine can lead to troublesome situations. Apart from extra wear of the bearings, dangerous situations may occur. If a machine runs at operating speed severe vibrations can be applied to the machine. If vibrations exceed an overall level of eight millimeter per second, bearings can be destroyed and the insulation system will be damaged [14].

When the system is out of balance due to for example misalignment, vibrations are caused. The out of balance system may also cause airgap irregularities which will contribute to even bigger vibrations of the machine. Too much vibrations due to misalignment are a major cause to bearing and gearbox failures. Gearbox failures will not be discussed in detail and bearing failures will be covered in 'bearing related failures'.

Another problem in the same league as bad alignment is an out of balance rotor. When a rotor is out of balance, high centrifugal forces are applied to the machine. According to [14] the following five phenomena must occur when the system is out of balance, when one or more phenomena are not present, the problem must have an other cause. The mentioned observations are:

- A vibration frequency equal to the running speed
- A constant phase angle
- The radial amplitude will always be greater than the axial amplitude
- The amplitude will always be inversely proportional to the bearing support stiffness
- The amplitude will always be proportional to the square of the running speed

A.1.2. ENGINEERING ERRORS DURING THE DESIGN PHASE

When a rotating electrical machine is designed, a lot of aspects are to be reckoned with. If some of those aspects are forgotten or when calculated values are wrong, a number of mechanical errors may happen. From the major occurring faults mentioned critical speed and resonance are a few errors that can happen when the design aspects are not completely covered during the design phase. When one or both these failures occur, large vibrations may be present during normal operation, being the cause of several other errors such as bearing failures.

When machines face a lot of vibrations during stand-by or when they are stored, bearing damage is likely to happen. This bearing damage will lower the critical speed of the machine. It is therefore important to have the critical speed far off the operational speed.

Another important design aspect is the eccentricity of the airgap. When e.g. couplings are used that are too flexible, a lot of vibrational forces will be applied on the bearings, leading to failure. To be able to eliminate the vibrations the eccentricity of the airgap must be below 5% [14].

A.1.3. MISTREATMENT OF THE EQUIPMENT

During the transportation of machines a lot of care is given to the conditions of the machine. If there are large vibrations during transport, bearing damage may already have occurred before commissioning. But apart from vibrations during transport other external forces must be kept in check. If large forces are suddenly applied, welts that were already weak may fail under the pressure and serious faults may occur. Multiple faults such as broken rotor bars or cracked rotor short circuit rings are faults that can happen. Further bend shafts are caused by applying a too large force to the shaft. If this force is large enough the shaft may bend and be the cause of misalignment. More faults on the rotor will be discussed in more detail in section A.2.

Excessive corrosion is also a clear example of mistreatment because when proper maintenance would be applied, the corrosion would be fought before it grows towards dangerous levels. However it proves to be difficult to maintain every piece of the machine properly, since some spots are difficult or impossible to reach.

By using the machine when it turns at over-speed, large mechanical forces are applied to the machine. Normally the design is made such that a machine running at 130% of the rated speed should not get damaged. When running at speeds that exceed 130% of the normal rotational speed, the forces exerted will be too high and the insulation material may get crushed. It is therefore of importance that machines rotating speeds do not exceed the rating of the machine too much. [14]

A.1.4. BEARING RELATED FAILURES

For electrical machines there are two types of bearings that are commonly used. These are 'rolling element bearings' and 'sleeve bearings'.

Rolling element bearings are mostly used in smaller machines. They have a large contribution to the failures that occur in electrical machines. A picture of a rolling element bearing is given in Figure A.1. These bearings use rolling elements (mostly cylindrical or round elements) that slide between the two shells (the cage) of the bearing. If there are damages to any aspect of these bearings, vibrations will occur. By precisely monitoring these vibrations and filtering back-ground noise, useful information about the state of the bearing can be acquired.

In larger machines sleeve bearings are used as depicted in Figure A.2. The rating of these machines is in the range of about 300kW and higher. These bearings have a rotating shaft inside a cage filled with a fluid, mostly oil. The shaft will not hit the outer wall of the bearing because the oil gets compressed by the motion of the shaft and a high pressure (over $2 \cdot 10^6 \frac{N}{m^2}$) film will be created preventing the collision between the wall and the shaft. These bearings have a higher cost because a fluid is to be kept inside and therefore seals have to be applied. This is the reason why these types of bearings are only used for larger machines. In normal situations sleeve bearings tend to fail less often than rolling element bearings and thus these bearings are more reliable. But due to the oil film and limited flexibility of the bearing, measured vibrations will be small. This means that it is harder to get in indication of the bearing state this way. [14, 33]

According to [14] bearings get damaged when the overall vibrations of a machine exceed 8 $\frac{mm}{s}$. It is therefore of importance to minimize vibrations since damage to the bearings can shut down the machine during unexpected times.

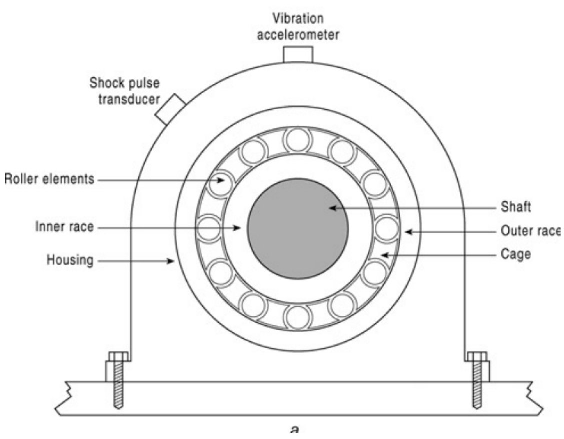

Figure A.1: A rolling element bearing inside a machine. Source:[33]

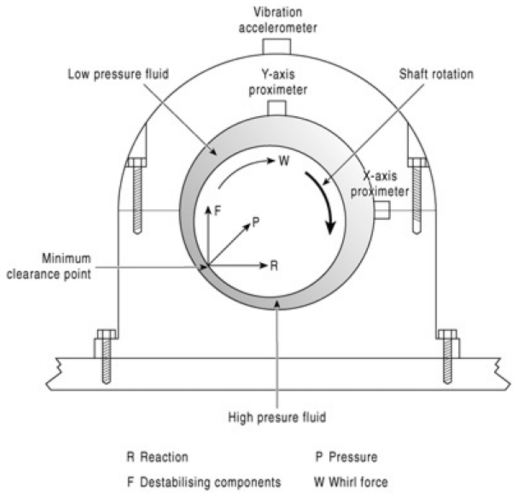

Figure A.2: A sleeve bearing inside a machine. Source: [33]

Bearing failures in machines is the most frequent occurring failure. Even when a failure is initiated from an other cause, such as winding failures, it is likely that bearing failure will be a consequence of the fault [14, 22]. According to [23] about 40% of all failures in induction machines are bearing failures, but other sources claim the contribution of bearing failures to overall machine failures is even higher.

Rolling element bearings are used in almost every type of low-voltage machines, since those are mostly smaller machines. Therefore when talking about bearings without further specification, rolling element bearings are meant. The following information is based on files stored in the database of SKF, the files used are [42–44].

There are normally two steps of damage to bearings they are mostly called primary and secondary damage. Primary damage gives rise to secondary damage, which is also called failure-inducing damage. An overview on both types op damages is listed below.

Primary damage to bearing

- Flaking
- Wear
- Indentations
- Smearing
- Surface distress
- Corrosion
- Electric Current damage

Secondary damage to bearing

- Flaking
- Cracks

Wear is in normal situations not appreciable for rolling element bearings. But when there are foreign particles inside a bearing, wear may occur due to the debris. The quantity of the abrasive particles is dependent on how far the avalanche effect is progressed, the particle quantity increases as material is worn away from the running surface of inside the bearing. This wear gets worse when there is more debris and since the effect causes particles to form inside the bearing the effect will get worse over time.

There are three different types of wear in bearings: Wear caused by abrasive particles, wear caused by inadequate lubrication and wear caused by vibrations. Wear by abrasive particles is a problem that gets accelerated over time. The particles wear the bearing down and during the process more particles are worn away from the bearing's surface. It is important to service a bearing with debris inside as soon as possible, since after a time the particles wear the bearing towards levels that leave the bearing unserviceable and the replacement will be the only option such a situation. When there is not enough lubricant or the lubricant lost its properties, the oil film has not sufficient capacity to carry the bearing elements. If this happens both metal parts contact each other wearing the bearing down. If a bearing is not turning there is no lubricant film between the rolling elements and the raceways. Since there is no lubricant film, a metal-to-metal contact is present. Vibrations produce small relative movements of the rollers and rings and during these movements small particles break away from the surface providing a source to wear caused by abrasive particles.

Raceways and rolling elements may become dented if the mounting pressure is applied incorrectly or when an abnormal load is applied to the bearing while at stand still. An other cause of **indentations** are foreign particles present in the bearing. Indentations in the rolling elements and their raceways are created when there is an abnormal heavy load applied while the machine is not running. The heavy load will stress a small section of the bearing so much that the metal will deform and so called indentations are created. Since the raceway is not smooth anymore, vibrations will be present during operation giving rise to other causes of failures. When foreign particles are present inside the bearing indents can also be created. This is due to the force that the bearing has to cope with. The large force will press the particles into the metal surface, which will again deform the raceway slightly. The deformations are mentioned as indentations and will cause vibrations during operation.

Apart from keeping the bearing clean and not overloading it, proper lubrication is a crucial part for a bearings lifetime. If there is not enough lubricant between two surfaces, they slide against each other under load. During this sliding, material may be transferred from one surface to the other. This event is known as **smearing** and the surfaces will look torn and will become ripped up. Four different types of smearing are known to happen in bearings, which will shortly be named. Smearing and roller ends guide flange occurs when heavy axial load acts in one directions for a long time period while there is inadequate lubrication. Skid smearing of rollers and raceways is caused during the start of the rotational movement. During start-up the rings will start moving but the rollers will have slight delay before they follow. During this delay the rollers slide across the bearing ring and smearing may occur. This can also happen when a rotor is suddenly stopped or very fast accelerations happen. When a bearing is very lightly loaded (under the recommended minimum load) the clearance in the bearing may be too big giving room for smearing in the bearings. It is important to minimize fast accelerations or decelerations to prevent this type of smearing. Smearing streaks may be found in in the raceways of spherical roller bearings. These are a result of careless handling or incorrect mounting of the bearing and are caused by applying too much force or impacts to the wrong ring without rotating the bearing. The external surface of a bearing can also be smeared when bearings are heavily loaded. The smearing is a result of the outer ring moving relative to its housing or shaft. This can only be prevented by making sure the bearing fits are tight enough and thus can be seen as a design feature.

Surface distress happens when the film between the rolling elements and the raceways becomes too thin, this can be due to inadequate or improper lubrication. During this time both surfaces momentarily contact each other and small cracks will form in the surface. This is called surface distress. Cracks caused by surface distress are very small and gradually increase in size until they start interfering with the running of the bearing. The cracks must however not be confused with fatigue cracks that will be mentioned later on. Fatigue cracks originate form beneath the surface instead of surface distress where the cracks start at the surface and deepen over time.

In bearings two different types of **corrosion** can be present, these are 'deep-seated rust' and 'fretting corrosion'. Deep-seated corrosion occurs when water or corrosive elements penetrate through the protective oxide film on the surface. The contact with the steel surface will result in patches of etching. This development is so called deep-seated rust. This type of corrosion is a great danger to bearings since it can initiate flaking or cracks in the bearing. The presence of acid liquids and salt water is highly dangerous for bearings because they increase the corrosion speed. Fretting corrosion will happen when the oxide film is penetrated. Oxidation of this type will proceed deeper into the material. It is most likely to occur when there is a small relative movement between a bearing ring and a shaft when a fit is too loose. This corrosion is relatively deep and will not be evenly spread. The bearing may not be evenly supported in this situation leading to problems with the load distribution of the bearings.

Bearing currents are electric currents that run through the bearing and may damage bearings quite a lot. The surface contacts will experience stresses that are equal to electric arc welding, since surface discharges may occur inside the bearing. Frequently the passage of the electric current leads to the formation of fluting (also called corrugation) inside the bearing raceways and rollers. Even low currents that are both alternating or direct are dangerous to the bearing, since the electric field strength is leading for the occurring discharge. The only way to avoid bearing currents is to make sure that no current can pass through the bearing.

Flaking is something that can happen as a result of normal fatigue, for instance the bearing reached the end of its normal life span. However in most situations the end of life is not the cause of flaking, since proper bearings are designed to last as long as other machine components. It is therefore more common that flaking is caused by other factors, but that means it is not less dangerous. When flaking is detected at an early stage, where there is little damage, it is possible to diagnose the cause of flaking and preventative actions can be taken. When flaking has proceeded to a certain threshold level a warning is given, in the form of noise and vibrations, that indicate the bearing has to be replaced.

Cracks in bearing rings are formed due to various reasons. It is most common that they are caused by rough treatment during mounting of demounting of the bearings. There are a number of other causes for cracks in the bearing, the most common other causes are: excessive drive-up, smearing and fretting corrosion.

Cage damage is in many cases difficult to track, in most situations it is detected when the bearing has to be removed due to a bearing failure. Even though it is hard to track cage damage a number of causes for the damage are known namely, vibrations, excessive rotational speeds, wear and blockage. After a long time of applied vibrations on bearings fatigue cracks may form in the cage material. These cracks will eventually lead to a cage failure. Vibrations that cause cage damage can be divided in two types. The first type is due to eccentric motion of the bearing. This motion will generate vibrations that lead to heavy accelerations and eventually fatigue of the cage bars will occur. The second type is caused outside the bearing. Due to vibrations from other machine parts or from the surroundings peak accelerations are generated. These vibrations lead to hammering of the cage pockets and eventually the shakedown limit for the cage material is exceeded leading to deformed cage bars. Eventually the hammering may lead to fractured cage bars after a period of time.

Inadequate lubrication, excessive roller skew, high temperatures or abrasive particles are causes of **cage wear**. Since there is always some friction between the rolling elements and the cage this is often the first component that is affected when lubrication is not good enough. Cages are always made of softer material than other bearing components and therefore they tend to wear quickly compared to other bearing components. When operating temperatures exceed 200°C the strain hardened zones of the cage softens and the amount of wear will increase even more. When hard particles such as fragments of flaked material gets wedged between a cage and a roller, the roller is prevented from rotating around its axis. This means that the roller will slide over the cage (surface distress) and since the cage material is softer than the roller material the cage will be damaged. Thus the blockage leads to a cage failure.

Last there are three measures mentioned that may offer a **reduction in the risk** of generating indentations. The first is to maintain the lubricant in the cleanest condition. This can be done with the use of a good particle filtration for the oil, using clean grease and making sure that all seals are undamaged. The second measure is following the mounting recommendations of the bearing manufacturers, since indentations can be produced by mounting bearings incorrectly. Last measure is to keep a good lubricating film inside the bearing. This can be assured by selecting a lubricant with the proper viscosity for the bearings operating condition. Using the proper lubricant the created film minimizes surface distress around indentations and by doing that the lifetime of the surface can be extended.

A.2. ROTOR RELATED FAILURES

Electrical failures in rotors of machines are relatively rare in practice. According to [23] only 10% of all induction machine failures are caused by rotor failures. This is because squirrel-cage rotors are used for most motor applications and few faults happen with these rotors. There are however machines (mostly synchronous machines) where wound rotors are used which need to be covered as well. Another reason why there are fewer number of rotor failures is because rotor design has changed little over the years. This means that most investigations on rotor failures in the past are still valid and possible causes have been prevented. [22] In this section rotor failures that may happen will be discussed. When symptoms or optional remedies for these failures are described in literature, they will be mentioned briefly.

This section follows the ideas described in [10, 26]. A lot of information is used from these references, but to improve the readability, references to these sources will not be placed again after the discussion of each failure mechanism. When other sources are used as reference for a section the reference is placed at the end of the section. An exception will be made when only a specific (small) part is paraphrased from a reference.

A.2.1. THERMAL DETERIORATION

Thermal deterioration can lead to failure in every wound machine rotor, regardless of how they are build. The thermal stresses will eventually lead to a failure of the insulation system and thus a fault in the machine. It is the most studied and best understood failure type for rotors. This is possibly due to its high contribution to rotor failures with older types of insulation. Especially during the time period when tapes were applied by hand, a limited number of turn shorts were acceptable and often tolerated. However these shorts cause an unbalanced heating of the rotor and excess vibrations due to thermal bowing of the rotor. Thermal deterioration is less likely to happen on hydrogen-cooled rotors because there is a lack of oxygen. The lack of oxygen decreases the chemical reaction speed that ages the insulation material and therefore thermal degradation will be slower. Apart from thermal aging under normal conditions (which takes multiple decades) a number of factors may lead to an unacceptably high rate of the aging mechanism:

- An overload operation or high temperatures of the cooling-medium, leading to operating temperatures above the designed values
- Inadequate cooling due to e.g. insufficient cooling air, dead-spots in the cooling design or blockage of the cooling systems
- Usage of materials with the wrong thermal properties
- Over-excitation of rotor windings for long time periods
- Under-excitation of rotor windings for a time period. This may cause synchronous machines to loose synchonism or to start working as an induction motor
- Negative sequence currents in the stator winding due to unbalanced system voltages leading to circulating currents in the rotor
- Repetitive start-stop actions without enough time for the machine to cool down.
- Sudden load changes for squirrel cage induction motors

Apart from visual inspection, thermal degradation can be signaled with one of the following symptoms. There will be a low insulation-resistance, a low impedance or during a surge test a spike is shown. These symptoms can be measured with the proper equipment. Equipment and/or measurements will be discussed in section 2.3. [4, 7, 22, 33, 45]

A.2.2. THERMAL CYCLING

Along the line of thermal deterioration are failures caused by thermal cycling. Temperature will change according to e.g. load changes or start-stop actions of the machine. Due to heat the copper windings will expand and when they cool down they shrink back to their former form. This event can happen hundreds of times but eventually the ground insulation will abrade by the repeated movement back and forth. In the end this thermal cycling will result in mechanical aging and eventually in failure. Thermal cycling is more likely to occur with machines that have a high number of start-stops since for each start-stop a thermal cycle or large load variation will happen. For longer rotors this problem results in a higher danger level, since a larger amount of extension and thus relative movement is likely to happen. Thermal cycling is possible because there are multiple different materials used in a machines design. During multiple cycles the spatial relationship between these materials may be altered, since each material will expand different than the other. The expansion will cause components to undergo one or more of the following displacement mechanisms:

- Each component has a difference in expansion coefficient and thus expands differently. This is most of the times the first level of displacement
- Critical components e.g. end-winding interturn connections and radial leads run in different directions. The two components will lead to stresses on their connections, this is a so-called second level of displacement
- The third level of displacement can happen when the rotor cools down again. During cooling components may be prevented to return to their original place due to e.g. distortion or wear

As a consequence of thermal cycling mechanical stresses are increased. Insulation damage, interference with the cooling system, displacement and looseness of the components may occur due to these stresses. These problems are more likely to occur when fast load changes and fast excitation current changes happen inside the machine. Therefore it must be kept in mind to minimize these contributions as much as possible.

Apart from a number of visual inspections little measurements can be done to get an indication of the thermal cycling in a machine. If unexpected turn-shorts occur, cycling may have had a contribution to the fault. An other measurement that may possibly give a slight indication is the measuring of the wedge tightness, however this requires removal of the rotor and decommissioning of the machine for a period of time. [4]

A.2.3. COPPER DUSTING

Abrasion due to imbalance or turning gear operation is a failure that mostly occurs for round rotor designs. Since these rotors have a considerable weight up to 100 tons, it is very important to let them run smoothly wit minimal vibrations during operation. Therefore considerable effort is required to make sure the rotor system is mechanically balanced. This effort is applied over the whole lifetime of the machine, starting with design, going to assembly and followed by operation conditions. Considering the possible mechanical failures it is easy to understand that a balanced rotor is not always to be expected. A lot of factors contribute to disbalance of the rotor and thus to the amount of vibrations during operation.

Although rotor vibrations are a mechanical problem, the origin can be thermal or electrical in nature. During operation thermal and electrical stresses are build up and are superimposed on top of the weight distribution of the rotor. Over longer time periods these superimposed forces may grow large enough to influence the weight distribution of the rotor. Changes in weight distribution have a large influence of the dynamic performance of the rotor. This is especially the case for long and thin rotor designs often called 'turbo rotors'. Large turbine generators are operated on turning gear at low speeds to prevent damage during shutdown. Low centrifugal forces on the windings due to the slow turning gear speed may cause copper dusting abrasion. These copper particles will set off against the surface and can lead to turn to ground shorts.

As already mentioned rotor vibrations are one of the causes of abrasion. When a machine is operating mechanical, thermal or magnetic imbalances exhibit high rotor vibrations due to movement of components or turn shorts. These vibrations can lead to the abrasion of the insulation inside the machine. There is some degree of free movement of components applied in the machines design, but when this degree is exceeded the free movement of the components is distorted. This distortion in turn causes compromising of the weight distribution of the rotor. The rotor gets unbalanced giving rise to an increase of vibrations.

When running at normal operation speeds the centrifugal forces prevent relative movement between conductors. These high centrifugal forces are mostly absent when operating at low speeds. This lack of force will give rise to relative movement between two adjacent copper conductors and fretting (abrasion) is likely to occur. Fretting is the cause of small copper particles that will migrate to the top of the slot. Most of the particles will fall out of the slot and act as contamination on the inside of the machine. There are however particles that get trapped inside the slot. If enough particles are trapped, the electrical field strength decreases to a level where turn-to-ground or turn-to-turn faults can occur. This can be prevented by making a design where fretting is not possible and at the same time the forces on the rotor will not be too great during operation.

An increase of bearing vibrations over time may give an indication that relative movement of components occurs. Eventually shorted turns due to abrasion may be present. This can be detected by multiple techniques but when the state can be measured the damage is already considerable. The field to ground protection may give an indication as well, for instance when the ground insulation of the rotor has failed. When a rotor is dismantled the presence of small copper particles is a sign of copper dusting during earlier operation. [22, 33]

A.2.4. TRACKING

Tracking is a problem that occurs for rotors where the rotor turns are exited, as well as in stators. In these applications the insulation has to electrically separate copper windings at several hundreds Volts from the grounded rotor body. When the insulation material is clean, the creepage distance is long enough to prevent a discharge. However when pollution is present the creepage path may be shortened and eventually turn-to-turn shorts will develop in a short to ground. When multiple discharges are repeated, a path is worn deeper and wider into the insulation material. This path damages the insulation material and the "burned-in" track is commonly referred as tracking. In most situations excitation voltages between 500 and 600 Volts prove to be high enough for tracking to occur.

The root cause of tracking is pollution of the surface, but chemicals that attack insulation give similar results. Common types of pollution are e.g. carbon dust from brushes, dust in cooling air and copper dust from abrasion. The absorption of moisture by the insulation material is an other cause for tracking. In both cases the insulation material has its insulating ability weakened by foreign particles. In combination with moisture or oil mist, the particles create a partly conductive coating on the surface over time. When the conductive coating is large enough, small currents can flow along the surface of the rotor and surface discharges may occur. These discharges will eventually be the cause of tracking. In particular open-type machines are vulnerable to tracking since a lot of exposure to the outside and thus pollutants is present in these designs.

Until serious faults such as turn-to-ground faults occur, very little symptoms of tracking are apparent. When the rotor is removed from the machine the burn-in prints may be visible. This is the only early indication of tracking before serious faults are present, however the rotor is removed only on rare occasions and thus tracking is rarely found in its early stage. When turn-to-turn faults or turn-to-ground faults are already present, an indication can be given by flux and vibration monitoring. An easier indicator of the machines state is the amount of pollution inside the machine. When the rotor appears to be greasy or wet, pollution is found using visual inspection. There are two electrical measurements that give an indication of the pollution in the machine as well. If the surface is polluted a low insulation resistance will be measured or a failure will be found during the voltage drop test will occur. [1, 14, 22, 33]

A.2.5. REPETITIVE VOLTAGE SURGES

Under stationary conditions the insulation materials used in a rotor can last almost for an infinite amount of time. However applied voltages are never stationary and transient (over)voltages are supplied from the excitation supply. These voltages can be multiple times higher than rated voltages and may thus degrade the insulation material. Internal or external events to the excitation system can induce large transient voltages in the windings of the rotor. Insulation material is designed to withstand occasional spikes, but repetitive spikes can lead to a repetition of partial discharges which lead to gradual deterioration of the insulation material. The principle is the same as in stator windings and in the end the insulation material will get 'eaten' away.

Voltage surges are created by the wave-chopping circuitry inside excitation systems also called drives. In conventional drives about six voltage surges occur per AC cycle, which means about 300 surges per second based on a 50 Hz frequency. But in some PWM driven drives the amount of surges as high as the switching frequency. Due to voltage reflections and oscillations caused by (parasitic) inductance or capacitance the magnitude of the voltage surges can be even higher than expected. Especially older motors designed for a drive that uses e.g. GTO's are damaged frequently when the drive is exchanged for a new one using IGBT's. This is because IGBT's switch a lot faster and therefore steeper voltage fronts are applied to the machine. Older machines may use insulation material that cannot handle these type of steep voltage changes and they may break down as a consequence. When insulation material ages the dielectric strength is lowered as well. In these situations the insulation system may break down because of the wave fronts. The stator can also be a source of voltage surges inside rotor windings. If disturbances on the system such as breaker actions, equipment errors or lightning strikes occur on the stator side, the disturbances are transferred via the airgap to the rotor. Since machines are not designed for these events to happen multiple times, the voltage across the insulation may exceed the rated voltage by orders of magnitude. There are also cases of transient overvoltages that are caused by the power system (grid) outside the machine. Events such as missynchronization, motoring of synchronous generators and load shedding can give rise to overvoltages that can exceed ten times the excitation voltage.

A high repetition of voltage surges can give rise to turn-to-turn shorts. These shorts are not very dangerous if there are just a few in the machine, but as the number of shorts increase, vibration levels may increase and more damage to the rotor occurs. When a rotor is examined (and thus removed), this problem is visible by signs of overheating or abrasion at a punctured insulation spot. [14, 18, 45]

A.2.6. CENTRIFUGAL FORCES

During operating speeds large centrifugal forces are generated by the rotor. These forces can exceed 1.500 tons at the wedges and even reach 15.000 tons at retaining rings. During start-up and shutdown of a motor or generator, large tangential forces are present as well. Both forces can cause cracks or yield of the rotor insulation system, leading to faults between turns or faults to ground. When the rotor is turning at normal speed during operation, centrifugal forces are developed that exceed 8000 times the weight of the component. Quality stock insulation materials applied with proper margins are used in machine design, since they can endure these massive forces over long time periods. However if flaws in the material are present due to inadequate quality control or aging mechanisms, the insulation can bend, crack or buckle under the influence of the large forces. As a consequence of the insulation damage turn-to-turn and turn-to-ground faults will occur inside the rotor.

The high continuous stresses can cause phenomena like yielding, distortion or movement of windings or insulation material. Because of this 'wear', windings may become loose and the mentioned faults are likely to occur. Also the connections of the winding conductors may fracture or be distorted causing open circuits in the winding. The cylindrical forces may cause loosening of the winding insulation system with similar results as induced by over-stressing.

Evidence of damage caused by centrifugal forces may be determined during rotor overhaul. The extent of the disassembly is also the limiting factor for early indication factors to be found. The following signs may indicate development of a failure:

1. When the retaining ring is removed, the interface of the rind insulation and end-winding bars can provide important information. Indentations in the surface of the end-winding are normal, but they should not exceed 25% of the insulation thickness. If an indentation at any point is more than 25%, an indication is given that there were high centrifugal forces present. In these situations any variation of the high centrifugal loads should be investigated. The same holds if cracks emanate form the edges of the indentations.

2. The slot armor may show fretting, cracking or chipping caused by the high forces that push the liner against the retaining rings. Cycling stresses can contribute to fasten any damage to the liner as well. This may also give an indication that the slot liner in inadequately blocked.

3. End-winding turn insulation is likely to be damaged by high centrifugal forces. This is particularly the case on the joints between straight sections and sections which are curved near the end winding. To provide enough creepage distance lap joints are used, but this means that only the top turn section can be inspected. For better inspection all the windings should be removed, but this is not likely to happen in practical situations.

4. When wedges are removed from the slots it is useful to inspect the top pad of the packing strips. These may show abrasion or cracking in the circumferential direction which correspondent to the end of the wedges.

5. When the outer edges of the end-winding blocks are chipped or cracked damage due to centrifugal forces is indicated as well.

In the early stages of operation with high centrifugal forces it is not likely that any of the mentioned failure mechanism occurs. Since these indications are all visual, it is difficult to monitor aspects of a (running) machine for a proper indication. If the damage has progressed enough to influence the operational behaviour, the rotor will likely produce higher vibrations and shortened turns will be present. [7, 22, 33]

A.2.7. HIGH RESISTANCE CONNECTIONS

When joints between conductors are poorly soldered or brazed, the connection will have a high resistance. This high resistance will produce excessive overheating of the insulation material when currents flow through the connection under load. This is especially the case for shorted rotors or squirrel cage rotors in induction machines. The high temperature will age the insulation until an insulation fault is developed. For a lot of situations the temperatures may rise enough to melt the solder or brazing material used to connect the joint.

Normally all joint connections will go through quality control during the manufacturing process, but sometimes a poorly soldered or brazed connection will pas through this procedure. This is the most common cause of high resistance joints. Another situation that may cause failure of the joint is low-cycle fatigue during frequent starting. These type of faults can be found with the use of surge tests or similar methods. This phenomenon also makes itself known by the presence of molten solder of brazing material that will be distributed due to the centrifugal forces acting inside the machine.

A.2.8. SLIP RING INSULATION SHORTING

Wound-rotors in asynchronous machines are normally used in combination with slip rings which are separated from the shaft using a layer of insulation. The spacing between both rings should provide enough creepage distance to provide proper electrical insulation. When the slip ring enclosure is contaminated, shorts between rings or the shaft can occur leading to serious damage. The damage can extend over a large portion of the rotor such as the shaft, windings or the slip rings. These problems may occur when the insulation fails due to stresses that cause aging.

When machines are properly maintained these failures are not very likely to occur unexpected, because most root causes are covered during an inspection. The following causes will likely cause a problem with the slip rings:

- Failure to clean the carbon dust from the brushes periodically
- Ingress of dust, bearing oil or moisture into the enclosure of the slip ring
- Mechanical or thermal stresses that cause the insulation of the slip ring to fail
- Mechanical failure of the slip ring connection stud insulation, with a phase-to-phase fault as a consequence

A.2.9. OPERATION WITHOUT FIELD CURRENT

When the stator windings are connected to the power system and there is no DC current flowing through the rotor windings the rotor can be seriously damaged. This situation is most likely to occur due to one of the following causes.
A loss of field during normal operation, due to e.g. break down of an exciter. During this situation the machine will act as a induction generator with a running speed slightly higher than the synchronous speed. This difference in speed will induce currents in the rotor body at slip frequency. The currents can cause arcing between components of the rotor leading to serious damage.
The other cause is sudden closure of a three phase circuit breaker of generator stator windings, inadvertently connecting the stator to the power system. At this situation the rotor is still at stand still and thus the machine will act as an induction motor. When the rotor still needs to speed up there will be high currents in the rotor giving room to a high temperature rise. This high temperature may lead to several other problems mentioned above.

When this phenomena has occurred it can be detected by one of the following symptoms: There will be evidence of overheating of several components in the rotor. There should be evidence of arcing between two or multiple components of the rotor. Components such as diodes and firing-tyristors will most likely be damaged. Cracked slot wedges or rotor teeth are found on inspection of the rotor. For inadvertent stator breaker closure cracked retaining rings may also be present.

A.3. STATOR RELATED FAILURES

Of all the electrical failures in machines most of them are related to the stator. According to [23] around 38% of all induction machine failures were caused due to failures in the stator. This means that stator failures are more or less occurring as much as bearing related failures. Other sources say that especially for machines with a lower rated voltage bearing related failure are more likely to occur, but still stator related failures are the next greatest contributor to machine failures [24]. Since the scope of the thesis is on machines that are already designed and have operated for multiple years or decades, failures that are purely design or manufacture related will not be mentioned in this section.

For this section [22, 26] were important sources. These two references will not be placed after the description of each failure mechanism for the ease of reading. Other references that were used to collect information will be mentioned at the end of the discription of each failure. An exception will be made when only a specific (small) part is paraphrased from a reference.

A.3.1. THERMAL DETERIORATION

Thermal deterioration is probably the most common reason for stator windings to fail, air-cooled machines are especially vulnerable to this type of failure. The degradation can be caused due to various processes depending on the nature of the insulation and the operating environment.

For air-cooled machines that have a thermoset insulation material (epoxy or polyester) or a film on magnet wire, thermal deterioration is essentially a chemical reaction giving rise to oxidation. When this reaction occurs at sufficiently high temperature, the bonds inside the polymer are broken into shorter, weaker bonds. This will cause the insulation to become brittle and thus it gets likely that the insulation will fail.

In form-wound stators the reduced bonding strength may cause mica layers to separate. These separated layer lead to delamination and will give rise to one of the following critical failures:

- Vibration of the copper conductors caused by the magnetically induced forces. This becomes possible since the copper conductors are not held tightly together by the insulation material anymore. The vibrations give rise to short circuits between turns and eventually to a turn-to-ground fault.

- When coils are operated at a higher voltage than about 3kV, partial discharges (PD) may occur in delaminated insulation. Eventually after a lot of PDs a hole in the insulation material is eroded, giving rise to a critical ground failure. However in this study the focus is on low voltage machines therefore PDs will not be covered in detail.

The thermal strength of the stator insulation system is also depending on the type of material that is used. Most older machines made before the 70's have a Class B (Class 130) insulation system. This means that the insulation will have a lifetime of 20.000 hours, which is about 2,3 years, at an operating temperature of 130°C. Nowadays machines are made with Class F or Class H insulation material, which means they last 2,3 years at 155°C respectively 180°C before becoming brittle. As already mentioned in section 2.1 the thermal lifetime of the insulation will half every 10°C above the rated temperature, since the chemical reaction will be faster due to the higher temperature. However up to certain degree the insulation lifetime is increased when lower operating temperatures are present. If the insulation is operated at a temperature that is 30°C lower than rated, the lifetime is roughly extended eight times. This means the material will last somewhere between 20 and 30 years, the normal expected lifetime of an electrical machine.

There are a lot of reasons why high winding temperatures can occur. To make the list of reasons not too long, causes that originate from design or manufacturing failures are not mentioned. This leaves the following reasons:

- Overload operation of the machine. The temperature will increase with the square of the current.

- Too little time between starts for induction motors. During start inrush currents up to six times the operational current can occur. These high currents generate a lot of heat due to losses in the machine. If too many starts occur in a short time the machine is still hot from the previous start and the heat will be increased even more till it breaks down the insulation material.

- High harmonic currents caused by drives that increase losses inside the machine.

- Negative sequence currents due to voltage imbalance. An imbalance of 3,5% in voltage can lead to a increase of 25% in temperature.

- Dirt that prevents proper functioning of cooling systems inside the machine.

- Loose coils/bars inside the slot. This reduces the heat conduction of the conductors to the core.

- Under excitement of synchronous machines during operation. This creates axial magnetic fluxes at the end of the stator core which in turn induces currents that circulate in the stator core ends. Due to the currents local hot-spots are created.

Apart from visual inspection and measuring the temperature inside the machine the following aspects may give an indication of thermal deterioration. The insulation resistance will be low, there will be a low-surge breakdown voltage, the capacitance of the insulation will be lower (a trend over time can be useful for this situation) and PDs may occur given that the operating voltage is high enough.

A.3.2. THERMAL CYCLING

Thermal cycling is the same principle as described in section A.2, its principle will therefore not be discussed. However the problems that may rise are slightly different than in the rotor, therefore these will be discussed in brief. In stators there are three known variations of thermal cycling.

- Girth cracking or tape separation are special variations of thermal cycle deterioration. It happens in thermoplastic insulation materials such as asphalt an mica. These materials expand slower than the copper conductors and therefore the tape layers are stretched and after a number of cycles they will crack.

- Conventional thermoset deterioration is a failure that can occur for epoxy-mica insulation which are conventionally used. It also originates from the problem that the copper core heats faster than the insulation material and thus the copper will stress the insulation mechanically. When the field strength gets high enough because of the deterioration, PDs may occur as well speeding up the degradation process.

- For large VPI windings mostly used in large turbine rotors of 300MVA and above, rapid removal of a load will cause the cores to cool and shrink faster than the groundwall. This process will cause stresses between the copper, the groundwall and the stator core. Because of these stresses, cracks may occur after a number of cycles and eventually the cracks may lead to a failure.

As already mentioned the root causes for these problems are: load changes that are too fast, operation at too high a temperature and flaws during the design phase of the machine. If thermal cycling is happening inside the machine, a power factor tip-up and a PD tests can give an indication with the greatest sensitivity. However these test assume that PDs will always occur in a machine suffering from this failure. [4]

A.3.3. SLOT DISCHARGES

Loose coils in the slots give rise to discharge phenomena are also referred as slot discharges. Normally this type of failure is associated with form-wound stators that are not manufactured with the VPI process. The forces on the bars or coils increase according to the MVA-rating. When everything is held tightly in the slot, the forces have little impact. However when the coils are not held tight, they start to vibrate and the insulation material gets worn away against the steel laminations of the stator coil. When about 30% of the insulation material is abraded, a stator ground fault is likely to happen. During this process two stages can be defined. The first stage is when most of the coating is still intact. The bar or coil is already vibrating during this step and some (contact) sparking might occur. Slot discharges occur during the second stage. At this time the coating is already rubbed away and the surface of the coil is not grounded. As a consequence PDs will occur, since there is not enough insulation to withstand the electric field. Due to the high intensity of PD, the process will accelerate deterioration of the insulation and eventually a failure will occur.

Slot discharges are normally a cause of production errors. Thermal cycling and looseness of wedges in salient pole machines are other possible causes that can lead to loose coils inside the slots. If the rotor is removed this phenomenon is easy to spot since a powder of the insulation material will be visible inside the stator. Also loose wedges are easy to detect when the rotor is removed. Without disassembly of the machine an indication can only be achieved with the use of PD test. However for low voltages it is very difficult to detect PDs since they occur quite rarely.

A similar failure is the presence of 'high intensity slot discharges'. These are caused when semiconductive coating gets isolated from the stator core over entire slot-length. When contact between both separate sections occurs, a very large discharge happens. In machines designed for lower voltages semiconductive coatings are seldom used, therefore these failures are not discussed any further.

Vibration sparking, also referred to as spark erosion, is related to the problem with loose coils and thus with slot discharges as well. It occurs when the surface coating conducts too well and shorts the stator core laminations. The high conductive coating creates a path for currents that are induced by the flux. Due to vibrations of the bars or cores, sparks or PDs may occur, therefore the name vibration sparking. Fortunately it is a problem that occurs rarely, since it is only caused by poor design.

A.3.4. VOLTAGE SURGES

Voltage surges can be divided in two groups. The first group consists of transient voltage surges that are normally non-recurring and the second group contains repetitive voltage surges mostly caused by drives. In both situations voltages higher than the rated machine voltage occur and therefore the electrical stress is increased.

Transient voltage surges can be caused by lightning strikes, the closure of a generator breaker when the generator is out of phase, opening or closure actions of motor circuit breakers and ground faults of the power system. These surges do not deteriorate the insulation system, but either causes the insulation system to fail or to continue without further effects. When the insulation material degrades over the years the electric strength of the material decreases. Eventually the system will fail due to a transient voltage that is too high for the state of the insulation. However it would not occur if there were no other aging mechanisms that degraded the insulation material. Transient voltages are therefore only "the last straw that broke the camels back".

The severity of a voltage surge is not only in the amplitude of the first wave, but also in the rise-time of the voltage. When the rise-time is too short an uneven electric field may occur and the field may get too high on specific points. On these points a breakdown can happen.

The cause of these surges are mostly disturbances in the power system e.g. phase-to-ground faults, switching events and lightning strikes. Since it is unlikely that these faults can be completely eliminated, machines have to be designed to withstand such stresses during the expected lifetime. This type of failure is a go-no go situation there are no tests that can give a proper indication of when it will occur. To give an impression on the systems condition an AC or DC voltage high potential test or a surge test is performed. During this test the voltage applied will normally be twice the rated voltage plus 1 kV. If the machine is capable to withstand the test voltage it is assumed that the insulation system will hold till the next time maintenance is prescribed.

The effect of transient voltage surges can be minimized by placing a surge arrestor before the machine. The surge arrestor will minimize the effects of the transient voltage wave thus minimizing the danger. Surge capacitors may also be used to minimize the voltage that will appear across the turn insulation. Because of the characteristics of a capacitor the high frequency components are likely to flow through the capacitor and not through the machine. Both these components to limit the effect of transient voltage surges lead to extra costs, therefore most users prefer an insulation design that is robust enough to withstand the surges to be expected.

Repetitive Voltage Surges, caused by (faster) switching of drives, gradually age the material used in mostly older machines. This is because most older machines are designed to survive surges caused by GTOs which are multiple times slower than modern IGBTs [46]. Insulation in random-wound motors with a rating between 400V and 1000V is especially vulnerable since these types of machines are likely to experience very high voltage surges with short rise-times. Also semiconductive and grading coatings used in higher voltage machines starting from 3,3kV are subject to rapid degradation due to the surges. Repetitive voltage surges can induce degrading of turn insulation, groundwall and phase insulation and semiconductive and grading coatings. The first two will be discussed, but the last one will be left out, since semiconductive coating is rarely applied in low-voltage machines.

Turn insulation deterioration due to repetitive surges is most likely to occur in random-wound stators because the insulation used in form-wound stators is more resistant to PDs. The PDs happen due to the fast rise of interturn voltages caused by the fast switching of the drive. Most random-wound stators have cavities in the insulation or organic insulation material. Especially these two insulation systems are likely to grow to a failure caused by the PDs.

Ground and phase insulation suffers a lot more electrical stress when fed by inverters than when connected to a 50 Hz power frequency supply. The short rise-times may induce reflections along the transmission line or the windings. Due to the reflections the voltages can be 40% higher than under normal conditions. These higher voltages induce PDs that accelerate the aging of the insulation material until breakdown occurs.

Turn insulation deterioration in stators is caused by the following reasons that start the degrading process:

- A fast rise-time, usually less than 200ns
- An impedance mismatch between the motor and connection cable
- Cavities inside the insulation
- Turn insulation that is not resistant to PDs. These are mostly organic materials.
- A lot of recurring surges (thousands per second), since PD occurs rarely. Therefore many surges are needed to degrade insulation material.

This problem can be indicated with the use of PD measurements. However PDs are not easy to measure, especially for lower voltages. In form-wound stators ozone may be present due to the discharges that occurred.

Form-wound stators should be made according the the values mentioned in IEC 60034-18-42, but due to the lack of formal optimization studies, most manufacturers increase the voltage class level by one to be sure the insulation will hold the repetitive voltage surges. [45]

A.3.5. ELECTRICAL TRACKING

Electrical tracking is one of the problems that is caused by contaminated windings or moisture that is present. When tracking occurs, currents are able to flow over the surface of the insulation, which is most likely to happen in end-windings. The currents degrade the insulation and eventually a groundwall failure will happen. Even though this problem is more likely to happen with high operating voltages, this phenomenon also occurs at low voltages. Machines operated at voltages even as low as 120V may fail due to electrical tracking. The degree of dirt or moisture present is of great influence on the occurrence of electrical tracking. There are two processes that lead to failure in a machine, depending on how the stator is wound.

In form-wound stators tracking is most likely to occur in the end windings. When the resistivity of the layer on top of the insulation is low enough, currents will flow from places with a high electric field to spots that have a low electric field (see also Figure A.3). Normal designed systems are resistant enough to prevent this tracking of currents, but contamination or moisture (dark grey top layer in Figure A.3) lowers the resistance. When no excessive contamination or moisture is present in the machine the tracking process is very slow. It often takes more than 10 years before a wet or dirty winding fails.

For random-wound stators the electrical tracking process is somewhat different. Electrical tracking in the used windings is not the main aging mechanism, although it can occur due to repetitive voltage surges. In this situation pinholes or cracks in the magnet wire are required before deterioration is likely to occur. When cracks or pinholes are present, a (partly) conductive path can be formed between turns. Since the distance between turns is very small in random wound windings compared to the form-wound situation, the currents that flow may be larger than for form-wound situation. When currents flow along the

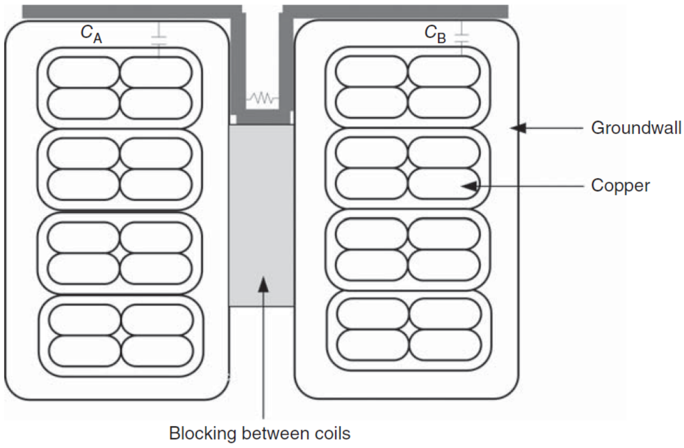

Figure A.3: Cross-section of two coils form different phases and a possible tracking path. Source: [26]

surface, the resistance of the conductive path is lowered even more and eventually circulating currents flow between turns. This develops into turn shorts and after a short period of time a ground fault will happen. The number of pinholes and cracks in combination with the level of pollution and moisture is leading for the time it takes until a failure occurs. Depending on the quality of the magnet wire, failure may occur within weeks but might as well happen after 30 years.

This type of failure can be indicated with a large variety of tests and with a high reliability. In both types of stators, insulation resistance and Polarization index test can be used. Form-wound machines can be tested with the capacitance, power factor and PD tests as well, but these measurement need a reference from when the windings were completely clean.

By making sure the contribution of pollutants and moisture is minimized this problem can be minimized as much as possible. However it is impossible to completely remove all pollutants and moisture in air and thus all machines will be susceptible to tracking eventually. When contamination is present inside the machine it can be solved easily by cleaning the machine completely. This is best possible during maintenance, revision or overhaul of the machine. Moisture is slightly more difficult to remove. The best options to remove moisture are to place the machine in an oven or heating the machine with a small current that flows thought the windings of the machine. [45]

A.3.6. ABRASIVE PARTICLES

If abrasive particles are present in the cooling gas stream they can grind away the winding insulation of the stator. All kind of foreign hard particles that are present in a machines can damage the insulation. When insulation material is worn enough that the copper conductors are exposed, a turn-to-ground failure will occur. If the particles are (partly) conductive, electrical tracking may occur as well, accelerating the deterioration of the insulation material. The end windings are the most likely place where abrasion occurs but when contamination is severe the ventilation ducts of the stator core will be exposed to extensive wear as well.

Apart from abrasion due to contamination inside the machine, abrasion can also be caused during the cleaning process of the stator. Some methods use materials such as nutshells or dry ice that is blown under pressure to clean encrusted dirt. When the nozzle is held over one spot for too long the "cleaning materials" may wear the insulation of the stator.

Sadly there are no diagnostic tests that can identify this problem in an early stage. When the insulation is already completely worn away shorts are present in the machine and the failure is easily detected using an insulation resistance, polarization index or high potential test.

A.3.7. CHEMICAL ATTACKS

Chemical attacks on the insulation system can occur when the machine is exposed to chemicals present in the environment. These chemicals can vary from acids or paint to oil and even water. Older types of insulation are especially vulnerable to this type of contamination. When exposed to certain chemicals, insulation may soften, swell or lose its mechanical and/or electrical strength. When insulation is softened, cold flow is likely to occur and eventually the material may migrate enough so that it can not withstand normal operating voltages. Swelling leads to another problem inside the stator. Because the material expands it can cause delaminations or peeling of the insulation in magnet wires. When mechanical and electrical strength is decreased significantly due to the chemicals, voltage surges can cause a puncture of the insulation. After the puncture, a turn or ground-short is very likely to occur. Over the years a lot of research has been performed to increase the resistance insulation materials to chemical attacks. Therefore most modern materials are less susceptible to this problem.

There are a few tests to diagnose if a machine is subjected to a chemical attack. By analyzing samples of the insulation in combination with the contamination inside the machine chemical reactions can be found rather early. This method however is quite extensive and relatively expensive compared to the alternative. As alternative test the insulation resistance and polarization index tests can be performed. When measured values are low, it indicates deterioration of the insulation material, possibly due to a chemical attack. Sadly this is only possible when the problem is already advanced to a more severe state. A very rough, but early indication may also be given by the filters installed on the machine. If these filterers are extremely dirty an indication of environmental pollution is given. When the filters are full of dirt for a longer time period it is likely that there will be some debris or dirt inside the machine as well.

A.3.8. END WINDING VIBRATIONS

End winding vibrations occur when the end windings are not supported enough. During this period of time, the coils start vibrating and eventually the insulation will be abraded. The problem is most likely to occur in large form-wound two- and four-pole machines since they can have natural frequencies close to the frequencies used to operate the machine. Nowadays due to the appliance of VPI, these types of failures are less likely to occur with high amplitudes. But this does not imply that the vibrations are not present. When the end windings are not properly supported any type of machine will fail due to the vibrations.

When copper strands break due to end winding vibrations, the current flow in other strands will increase and make the good strands more likely to crack. The increased temperature caused by the higher current causes the resistance in other strands to increase, which will in turn lead to more temperature rise. Eventually more strands will break due to the temperature rises and a runaway condition occurs. The thermal runaway will continue until the entire bundle melts and a plasma will be created between parted conductors, causing a failure.

Apart from design or manufacture failures a few other causes for these vibrations are known.

- A previous out-of-phase synchronization or excessive motor starting current. These situations create large magnetic forces which may break the lashing or allows blocks to become loose.
- Long term operation at high temperatures cause thermal aging of the insulation and support materials. Due to the aging, materials will shrink and thus room for vibrations will be present.
- Excessive oil in the end windings may cause some lashing materials to slack and thus vibrations may occur.

With the use of a 'bumb' test the natural frequency of the end windings can be measured. When this frequency is near the operating frequencies it is likely that end winding vibrations occur during operation. Also vibration sensors can be placed on the end windings, which is mostly done in machines that are likely to suffer from end winding vibrations. By executing a high potential test some information can be achieved on cracked copper strands. This is only possible for form-wound machines. In random-wound machines the problem can only be detected with a visual inspection.

A.3.9. Poor electrical connections

Since there are thousands of electrical connections in stator windings a few poor connections that cause a high resistance are likely to occur. The high resistance connections causes temperatures to increase and eventually a failure occurs. All kind of stators are vulnerable to this problem, but form-wound stators are even more vulnerable due to the large number of joints.

For form-wound stators the connections between leads and bars are usually brazed or soldered. When the connections have too much resistance they will become warmer than expected. The increase in temperature will cause the resistance to rise and thus the temperature will increase even more. If this avalanche continues, the copper may get warm enough to melt and cause a failure of the machine. Generally there are fewer connection in random-wound machines, but there are still a large number of connections. Because the insulated connections are mostly near the core or other coils a failure may occur if the temperature rises to such levels that the insulation material is melted.

Poor electrical connections are in most situations caused by poor workmanship. Apart from this cause, wear or cracks may increase the resistance of the connections as well. Thermal sensors or camera's are the only measures that can indicate the presence of high resistive regions caused by poor connections. By keeping a trend of the winding conductivity over time, severe bad connections may be indicated, however these results are far less accurate than with the use of thermal detection.

B

LITERATURE SURVEY ON MACHINE MEASUREMENTS

There are three ways known to determine the remaining life of machine insulation. The first one is monitoring of stresses that are known to cause deterioration. This is actually an approach that makes sure that no situations occur that may decrease lifetime over and above normal conditions. The second option is to perform test procedures and based on the results of these procedures a lifetime estimation based on experience can be made. The third option is to determine the remaining life by modeling the deterioration processes of the insulation system. [2, 5, 8, 25]

In this thesis the possibility to combine the second and third option is investigated. To be able to do this in the best way possible, both mechanical and electrical measurements should be investigated. However, due to time constraints the rest of this thesis will focus mostly on the electrical aspects in the machine.

B.1. MECHANICAL/BEARING RELATED MEASUREMENTS

Mechanical or bearing related failures are monitored with the use of vibration measurements. It is commonly known that more than 50% of all machines fail due to mechanical (mostly bearings) issues. This is one of the main reasons why many people and companies researched methods to monitor the mechanical condition of machines. All the research done on these mechanical aspects lead to a relatively good understanding of how mechanical failures originate, but also on how the condition of the elements can be monitored. Since bearings are the main reason why machines fail mechanically, most of the focus is on this aspect. These failures are almost always monitored with the use of vibration measurements.

The gearbox is another component that tends to fail often, especially in wind turbines. Earlier in the thesis it was stated that gearboxes would not be covered, but here an exception is made. In [23] a clear overview on condition monitoring techniques for gearboxes is given. In Table B.1 the overview is given as well. Since the original paper does include a lifetime expectation of the gearbox, the mentioned techniques will not be explained in further detail. When more detailed information on gearbox condition monitoring is needed it is suggested to read the source of the information.

Table B.1: Typical gearbox and bearing condition monitoring techniques according to [23]

Sensing Scheme	Monitored Components	Advantages	Disadvantages
Vibration	Gearbox Bearing Shaft	Reliable Standardized in ISO 10816	Expensive Intrusive Subject to sensor failures Limited performance for low speed rotation
Torque	Rotor Gear	Direct measurement of Rotor Load	Expensive Intrusive
Oil Analysis Debris Analysis	Bearing	Direct characterization of bearing condition	Limited to bearings with closed-loop oil supply system Expensive for online operation
Temperature	Bearing	Standardized in IEEE 841	Embedded temperature detector required Other factors may cause similar temperature rise
Acoustic Emission	Bearing Gear	Able to detect early-stage fault Good for low-speed operation High signal-to-noise ratio Frequency range far from load perturbation	Expensive Very high sampling rate required
Stator Current Stator Power	Bearing Gear	No additional sensor needed Inexpensive Non-intrusive Easy to implement	Displacement based rather than force based Difficult to detect incipient faults Sometimes low signal-to-noise ratio

Other mechanical failures can be monitored with the use of mechanical vibration monitoring. By measuring vibrations present in the machine, even electrical faults in the stator and rotor can be monitored to a certain degree. For the monitoring of bearings, the use of vibration measurements is by far the most common used method. By looking at specific vibration frequencies, the location of the fault can be narrowed to the outer- or inner-ring, a rolling element or a train defect. However when damages are still very small, they may get lost in the background noise. When looking at the vibration velocity an overall indication of the machine is given. One of the standards where such allowable levels are stated is the German Vibration Standard VDI2056 also given in Table B.2. The measurements can be performed with simple instrumentation on the stator and is therefore common in many installations. The sensitivity however is quite low, especially when the fault is in an early stage. An other drawback is the lack of diagnostic information with this method. [22, 33]

Table B.2: Vibration standard VDI2056, source [33]

<table>
<tr><th>Vibration velocity, mm/s rms</th><th>Vibration velocity, dB, ref 10^{-6} mm/s</th><th>Small machines</th><th>Medium machines</th><th>Large machines</th></tr>
<tr><td>45</td><td>153</td><td rowspan="5">Not Permissible</td><td rowspan="4">Not Permissible</td><td rowspan="3">Not Permissible</td></tr>
<tr><td>28</td><td>149</td></tr>
<tr><td>18</td><td>145</td></tr>
<tr><td>11,2</td><td>141</td><td rowspan="2">Just Tolerable</td></tr>
<tr><td>7,1</td><td>137</td><td rowspan="2">Just Tolerable</td></tr>
<tr><td>4,5</td><td>133</td><td rowspan="2">Just Tolerable</td><td rowspan="2">Allowable</td></tr>
<tr><td>2,8</td><td>129</td><td rowspan="2">Allowable</td></tr>
<tr><td>1,8</td><td>125</td><td rowspan="2">Allowable</td><td rowspan="6">Good large machines with rigid and heavy foundations whose natural frequency exceeds machine speed</td></tr>
<tr><td>1,12</td><td>121</td><td rowspan="5">Good medium machines 15-75 kW or up to 300 kW on special foundations</td></tr>
<tr><td>0,71</td><td>119</td><td rowspan="4">Good small machines up to 15 kW</td></tr>
<tr><td>0,45</td><td>117</td></tr>
<tr><td>0,28</td><td>109</td></tr>
<tr><td>0,18</td><td>105</td></tr>
</table>

Companies like SKF have divisions that are specialized in the condition monitoring of bearings. They developed multiple tools that give the condition of the measured bearing for people to use. In [47] some of their equipment is discussed, which gives an indication on the bearing condition based on measured accelerations. The indications are divided in three groups. First when no problems are found, a second where first indications of wear are indicated in a warning and last the state where serious damage is measured. There are multiple other techniques such as "Time Waveform Analysis", "FFT Spectrum Analysis", "High Frequency Detection", "Envelope Detection" and "Spectrum Analysis" described in [44] for monitoring the condition of bearings.

There are also tools developed to let non-professional users know about the condition of the bearings. On of those tools is the "Root Cause Analysis" (RCA) that is mentioned in [48]. When RCA is combined with other analysis programs, predictive and preventive maintenance programs are made with a main focus on "Reliability Centered Maintenance". [48]

As already mentioned, this thesis will be focused on electrical aspects and therefore the pure mechanical measurements will not be discussed in more detail. More detailed information can be found in e.g. the database of SKF or the repository of the TU Delft.

B.2. STATOR WINDING TEST MEASUREMENTS

There are a lot of electrical measurements that can be performed on the stator of a machine. All measurements give some indication on the state of the machine insulation, but drawing a proper conclusion from the information proves to be very difficult. One of the reasons for this difficulty is that no records of measurements were taken on a regular basis and processed in an organized way. This means that no knowledge is available on which values indicate a proper working machine and which values indicate possible failure or weak spots.

Measurements that can be performed can be divided into invasive or noninvasive and online or offline measurements. It is important to keep these differences in mind, since most owners of motors will not allow some measurements to be performed. Since invasive measurements require dismantling of the machine or additional sensors it is not a popular method. Therefore nonintrusive methods are always preferred, since they only use voltages and current that can be measured from the motor terminals. Making a pure distinction between online and offline measurement is more difficult. This is also dependent on the requirements of the owner. Some want the ability to see "inside" the machine at all times, for these situations online methods should be used. This is most likely to happen in continuous processes such as water treatment or petro-chemical processes. The other option is offline measurements. These measurements are normally more direct and accurate and therefore preferred by many people. Other benefits of this method are that it can be easily applied during maintenance, it does not require operation of the machine and thus it might be safer and only one set of test equipment is needed to perform measurements on multiple machines. [1]

For this thesis the focus will be on offline measurements, because they are more proven and more accurate. The practical side of offline measurements needs some consideration as well. Since the method to be researched will most likely be applied during maintenance stops, it will be more easy to perform the measurements when they are offline. Last but not least is the financial aspect. With the use of offline measurements only one set of equipment needs to be bought to perform the method on a large group of machines.

An overview of online measurements is given in Table B.3, but they will not be discussed. This is done to let the reader know there are online options. When the reader prefers online measurements, for their own reasons, it is suggested to read [1] or other sources for more details.

There are a lot of offline measurements that can be performed on stator windings of electrical machines. Most can be performed from the connections on the stator terminals, but some can only be done on special occasions, such as when the rotor is removed. Also the applied voltage in combination with the voltage rating of the machine may be a limiting factor for some measurements. Due to these reasons a number of measurements will not be mentioned, for either they cannot be performed on machines with a low voltage rating or they are impractical to perform. First practical measurements will be described and

Table B.3: An overview on online measurements that can be performed on stator windings, source: [1]

Method	Insulation Monitored and Diagnostic Value	Attributes
Temperature monitoring	Detects deterioration in phase-to-ground and faults in turn -to-turn insulation	(-)invasive if sensors are required, (-)a lot of data and additional information like ambient temperature required
Condition Monitors and Tagging Compounds	Detects faults and problems with phase-to-ground and turn-to-turn insulation	(-)invasive (equipment for detection of particles required and chemicals have to be applied to machine)
Leakage Currents	Detects deterioration of the phase-to-ground and phase-to-phase insulation	(+)non-invasive, (+)capable of determining the cause of deterioration
High Frequency Impedance / Turn-to-turn Capacitance	Detects deterioration of the turn-to-turn insulation	(-)Invasive (search coil), (-)not tested widely yet, (++)capable of monitoring the deterioration of turn-to-turn insulation
Negative Sequence Current	Detects turn-to-turn faults	(+)non-invasive, (-/+)non-idealities that complicate fault detection / methods available to take non-idealities into account
Sequence Impedance Matrix	Detects turn-to-turn faults	(+)non-invasive, (-/+)non-idealities that complicate fault detection / methods available to take non-idealities into account
Zero Sequence Voltage	Detects turn-to-turn faults	(+)non-invasive, (-/+)non-idealities that complicate fault detection / methods available to take non-idealities into account, (-)neutral of the machine has to be accessible
Pendulous Oscillation Phenomenon	Detects turn-to-turn faults	(+)non-invasive, (+)able to compensate for non-idealities
Axial Leakage Flux, Airgap Flux Signature	Detects turn-to-turn faults	(-)invasive (search coils), (-)results strongly depend on the load
Current Signature Analysis	Detects turn-to-turn faults	(+)non-invasive, (-)interpretation of results subjective, (-)further research advised to generalize results
Vibration Signature Analysis	Detects turn-to-turn faults	(-)invasive (accelerometer), (-)further research advised to generalize results
AI-based	Detects turn-to-turn faults	(+)no model for fault or system required, (+)automation of diagnostic process, (+/-)can be non-invasive/invasive based on required input quantities
Online Partial Discharge	Detects deterioration of the phase-to-ground and turn-to-turn insulation system	(-)additional equipment required, (-)not applicable to low-voltage machines, (-)difficulty in interpretation of the data, (+)good practical results
Ozone	Detects deterioration of the phase-to-ground and turn-to-turn insulation system	by-product of PD, (-)invasive (gas analysis tube or electronic instrument)

summarized at the end of the section Table B.6 is given. This table gives a summary of the measurements mentioned.

This section follows the line given in [10]. A lot of information is used from this source. To improve readability, references to this source will not be placed again after discussing each measurement. When other sources are used as reference for a section the reference is placed at the end of the section. An exception will be made when only a specific (small) part is paraphrased from a reference.

B.2.1. WINDING RESISTANCE / DC CONDUCTIVITY TEST

The winding resistance or DC conductivity test is meant to find copper strands in winding coils or ring busses that are broken or cracked. It can also be used to check if the brazed or soldered connections are deteriorating, since that would lead to a high resistance.

When copper strands are cracked or broken the cross section of the copper conductors will be reduced. The resistance of the windings will increase since the same current has to flow through the winding. The same reasoning holds for when brazed or soldered connections are in bad shape. When the measurement is performed at the connecting cables, poorly connected cables may be detected as well.

For these measurements it is best to use DC instead of AC with an exception for detecting shorted turns in insulated rotor windings. This is because when applying AC the inductive reactance of the winding will be measured as well. The reactance may vary with e.g. the rotor resistance or due to noise from outside. It is therefore almost impossible to measure the exact same situation with AC and therefore DC should be used.

The measurement is performed by passing a DC current through a winding and measuring the induced voltage across the winding. Using Ohms law it is easy to calculate the resistance afterwards. However the resistance of windings is low, mostly in the range of 10Ω down to $10^{-3}\Omega$. Therefore special equipment is required to measure such low voltages and thus resistances.

It is common knowledge that resistance values are temperature dependent. To be able compare multiple results over time a temperature correction needs to be applied, before values can be compared. A measured copper resistance at a certain temperature can be corrected to the equivalent copper resistance at 20°C with Equation B.1.

$$R_{20} = \frac{R_T}{1 + (T - 20)/255,5} \tag{B.1}$$

Where

T = Absolute temperature [K]

R_T = Measured resistance at temperature T

R_{20} = Resistance corrected to 20°C

The best diagnostic information from the winding resistance measurement is by trending the measured values over time. This way differences between measured values can be distinguished and an idea on the state of the machine is given. Another possibility for interpretation is by comparing values between phases of the same machine. By comparing measured values with identical machines elsewhere or by making a comparison with factory data available on the machine. Acceptable deviations between measured resistances are:

- 1% for form-wound windings
- 3% for random-wound windings
- 5% for identical machines

If a winding is rewound it is likely to have a different resistance than the original winding. However to insure proper functioning of the machine, resistance balance is needed. Therefore the above criteria should still hold.

For trending the resistance value a deviation of 1% should give rise to a warning. It is important to repeat this measurement over the years. That way an early detection of possible faults may prevent expensive repair costs if a large failure occurs.

B.2.2. INSULATION RESISTANCE (IR) & POLARIZATION INDEX (PI)

Measuring the insulation resistance is probably the most commonly used diagnostic test for electrical machines. The main benefit of the tests is that they can be performed on all machines since every machine has insulation between the windings and ground. The tests can indicate and even locate pollution and contamination problems in windings. For older insulation systems even thermal deterioration can be detected. The IR test is combined with a PI test, since both measurements are performed with the same instrument.

For the IR test the resistance of the electrical insulation between the copper windings and the earthed core is measured. In an ideal situation the measured resistance should be infinite, since no current flows through the insulation material. In practice there is always a small current flowing and the insulation resistance is therefore not infinite, but very high. When the measured resistance is low, it is likely that there is a problem with the insulation e.g. a ground fault.

A variation of the IR test is the PI test. For PI the ratio of the measured IR is taken after voltage is applied for one and ten minutes. A typical PI is be calculated with Equation B.2.

$$PI = \frac{R_{10}}{R_1} \tag{B.2}$$

with

R_{10} = Insulation resistance after 10 minutes

R_1 = Insulation resistance after 1 minute

When a low PI is found it may indicate that a winding is contaminated or wet.

For the tests a relatively high DC voltage is applied between the conductor and the grounded core. The current that will flow is measured and again with the use of Ohm's law the resistance is calculated. It is important to make a time reference to the measured current, since the current is normally not constant. When a current flows, the sum of multiple currents is measured and it consists of minimally four currents. It is only possible to measure the sum of the currents, but only two currents are of interest are of interest for determining the winding condition. The currents needed are the leakage current and the conduction current. The four currents that at least play a role are:

- Capacitive current. This current flows for the first seconds since the parasitic capacitance needs to be charged.

- Conduction current. This is the current that flows through the insulation material because the resistance is not infinite.
- Leakage surface current. This current will flow over the surface of the insulation. It is caused by contamination that is (partly) conductive. When the current is large electrical tracking may occur.
- Absorption current. This is the current that causes polar molecules to align with the magnetic field induced by the current. The current is relatively large just after applying voltage and will decay to zero when multiple minutes (around 10) have past

Just as the conduction resistance test the IR is heavily dependent on temperature. To minimize the dependency of temperature and to be able to trend data the PI test was developed, since that way most of the temperature dependence is divided out of the measurement. For this statement to hold it needs to be assumed that the temperature will not differ during the PI test.

When the PI is about one, leakage and conduction currents are large enough for electrical tracking to occur. On the other hand if the PI is higher than two, it is almost certain that no electrical tracking can take place and the windings are dry and clean. For trending the PI it need to be kept in mind that the same time ratios are used. That way the contribution of the capacitive and absorption current is in every situation more or less the same and will not deceive the user.

A sensitive ammeter in combination with a high-voltage DC supply can be used to measure IR and PI. The "megohmeters" that are commercially available are sometimes called Megger Testers as well. This is in remembrance of the first company that developed instruments for this purpose. For the best results it is recommended to measure as close to the windings as possible, preferably one phase at a time at the machine terminal. However due to practical reasons the test is often preformed from the switchgear, meaning that the insulation of the cable and the connections are tested as well. When a failed reading occurs in this situation, the test is to be repeated at the terminal box to conclude whether the fault is in the winding or in the cable connecting the machine and the switch gear. Obviously when surge capacitors are present, they need to be removed since they influence the results of the test and a PI value of one is likely be the result of the test.

For the test it is very important that the windings are warm enough. When the winding temperature is below the dew point, the PI can not be corrected because the windings are too humid from the ambient humidity. If a winding is normally in very humid conditions, before testing it might be necessary at first to heat the windings until moisture has condensed or evaporated.

The voltages that need to be applied to the windings depend on the rating of the machine. In Table B.4 recommended voltages to be applied are given according to the standard given in IEEE 43-2000. The rated voltage is dependent on the type of machine. For three-phase machines the line-to-line voltage is taken and for other machines the line-to-ground voltage should be taken.

Apart from a very high resistance when cracks are present a few other phenomena may give some information on the windings:

- If the measured R_1 is very high (in the order of multiple giga-ohms), the PI will not likely indicate any information on the windings. Therefore the test can be aborted when such values are measured.

Table B.4: Recommended voltage levels for IR test according to IEEE 43-2000, source: [10]

Winding rated voltage [V]	IR test voltage [V]
<1000	500
1000 - 2000	500 - 1000
2501 - 5000	1000 - 2500
5001 - 12000	2500 - 5000
>12000	5000 - 10000

- For modern windings a IR or PI below the minimum value indicates contamination.
- A high PI in older windings indicated the occurrence of thermal deterioration, because the insulation structure is changed by the heat.

According to IEE 43-2000 the minimum resistance value differs for some designs. The reason is that after the 70's the type of insulation material used changed. The minimum stated resistances is given in Table B.5.

Table B.5: Minimum resistance levels after 1 minute according to IEEE 43-2000, source [10]

Minimum insulation resistance after 1 min [$M\Omega$]	Group applicable
100	Most form-wound stator windings build after 1970
5	Most machines with random-wound stator coils and form-wound coils rated below 1 kV
$\frac{V_{rated}}{1000}+1$	Most windings made before 1970, rotor windings and other (not described) windings

B.2.3. DC HIGH POTENTIAL TEST

The DC high potential test (DC HiPot) should not be performed if it is not clear that the results of the IR and PI test are good. During this test a high DC (over)voltage is applied to the windings. The idea of this test is that if the insulation will hold the high DC voltage, the insulation will not likely fail due to the aging of insulation material until the next maintenance. However if the insulation does not hold, the groundwall insulation is punctured and a repair or rewind is mandatory. The DC HiPot test is therefore possible destructive and not always preferred by the owners of machines. This test is normally only performed on stator windings, but can be applied to rotor windings as well. Also because it is possibly destructive it is recommended to do this test when spare parts are available.

IEC 60034 recommends a DC voltage level of 1,7 times the AC HiPot level ($2E+1$kV), with E as the rated rms phase-to-phase voltage of the winding in kV. In practice a voltage of about $2E$ is mostly used. This is because the highest overvoltage that is likely to occur (in a phase-to-ground failure) is about two times the rated voltage. This way the 'worse possible' overvoltage a stator is likely to endure is reproduced in a controlled fashion. When the voltage is withstood the system is likely to withstand voltage surges in real life.

The main benefit of the DC HiPot is that during this test the windings are not aged, while at an AC HiPot aging of the insulation will take place. This is because PDs are likely to take place when AC is applied, but they rarely happen while DC is applied. When the test is executed from the switch gear side, the condition of the cables have to be kept in mind. When the connecting cables are soaked in water, water treeing is likely to occur and might damage the cable. If cables are kept dry this should not pose a problem. After performing the test, the test subject should be grounded for a time to be sure no electric shocks are given to personnel due to the polarization of the molecules in the winding.

The test is preformed by applying a high DC voltage with a relatively steep front. After the insulation holds for a number of minutes the voltage is quickly lowered and the winding is grounded. When no failure is present, no high currents will flow and the circuit breaker of the power supply will not trip. If a failure is present the power supply breaker will trip because of the high current that flows from the winding to the grounded core. This is an indication that the windings need repair or replacement. When the leakage current during a DC HiPot test is trended over the years some diagnostic information can be gathered. For an increase in current over time normally indicates contamination of the machine. However the resistance (and thus the current) is heavily dependent on the temperature and humidity of the atmosphere. Therefore it is difficult to trend this data in a proper way.

B.2.4. AC HIGH POTENTIAL TEST

The AC high potential test (AC HiPot) is similar to the DC HiPot test. The only difference is the frequency used, this is mostly 50Hz and sometimes 0.1Hz. It is performed on form wound stator windings in most situations. In the essence it is a go-no go test just like the DC version and the description is more or less the same as with the DC situation. The difference between both test is in the type of stress distributions along the insulation material. However with epoxy-mica insulation some flaws may be missed by the DC HiPot. For these situations the AC HiPot is better since the flaws are detected due to the applying of the AC voltage.

Because AC HiPot tests simulate the in-service situation better, this test is considered superior compared to the DC version. The main drawback of the test is the large transformer needed to supply the required voltage. This makes the test equipment more bulky and thus sometimes harder to bring close to a machine for testing. It is therefore rarely performed as a simple maintenance test.

In the standards NEMA MG1 and IEC 60034 the suggested voltage for the AC HiPot test is defined as "$2E + 1$kV", where E is the rated rms phase-to-phase voltage of the stator. The IEEE 56 suggests a lower voltage of a maximum of $1,5E$, which is significantly lower than the other standards. This may be done to minimize the number of partial discharges during the test and therefore minimize the degradation of lifetime. During the tests partial discharges may occur and these will lower the life of the insulation material slightly. A 1-minute test of $1.5E$ is equivalent to roughly 235 hours which is about ten days of operation and for the situation of $2E$ the lifetime will be decreased by roughly 20 days. Life is not significantly reduced with these test, since machines are designed to last at least 25 years.

In the authors opinion the DC HiPot test should be used during normal maintenance testing. This is due to the fact that applying DC voltage will not age the insulation and thus does not age the machine When a better reading and accuracy is needed an AC HiPot test is recommended. However more research on both test is needed to determine the difference between the accuracy achieved for both test options.

B.2.5. CAPACITANCE TEST

By measuring winding capacitance, problems such as thermal deterioration or saturation of the insulation by moisture can sometimes be indicated. The test is most useful on smaller form-wound and random-wound stators. Further use of the test is during the manufacturing process for quality inspections.

The principle behind this measurement is the change of the nature of insulation material during the deterioration process. During the deterioration process the dielectric constant of the insulation layer will lower due to the change of the material. In most situations, gas will be inside the insulation material which has a dielectric constant way lower than solid material.

By trending the changes of the winding capacitance over time, it can be distinguished if thermal deterioration or problems with moisture or contamination occurs inside the machine or not. If the capacitance decreases, it is likely that the winding experienced thermal deterioration. When the capacitance increases, it may indicate the presence of absorbed moisture or electrical tracking. Since both these indications can only be made clear with the trend of the capacitance value is is already obvious that a single measurement will not hold any diagnostic value.

The test is best performed directly at the windings or as close as possible. When cables are used the capacitance of these cables influences the results. In the case of small motors, cables with a length of 100m or more will contribute so much to the measurement that the measurement results in useless results on the motor.

When looking at the trend of the capacitance values a drop of 1% on the capacitance value over the years indicates thermal deterioration that happened. When the winding is very wet the capacitance will increase by approximately 5%. The test is not sensitive enough to find only a few spots. Therefore the measurements are of best use when looking at the entire winding state.

A variation of the capacitance test is the capacitive impedance test, which is actually another way to measure the winding capacitance. For measuring the capacitive impedance specialized instruments were introduced in the 90's. Most of those tools perform this measurement in combination with a set of other tests such as IR, PI, conductivity and inductive impedance.

The impedance test is performed with the use of the voltage, current and two calculations given in Equation B.3 and Equation B.4.

$$X_c = \frac{V}{I} \tag{B.3}$$

$$C = \frac{1}{2\pi f X_c} = \frac{I}{2\pi f V} \tag{B.4}$$

Where

f = frequency in Hz

V = Measured voltage

I = Current through the winding

X_c = capacitive impedance

The frequency used can vary between 10Hz to 100kHz depending on the manufacturer. When higher frequencies are used, higher currens are measured and less interference of the power-frequency current is measured. To be able to produce results that are significant the measuring of voltage and current should have an accuracy better than 0,1%.

B.2.6. INDUCTIVE IMPEDANCE TEST

The inductive impedance test is sometimes also referred as a low-voltage version of the surge test performed on stators and can be applied to any three-phase stator winding. As mentioned the test is mostly performed in combination with other tests that complement each other. During the test a high frequency 'f' (in the range of 1 kHz) and a voltage 'V' (a few volts) are applied to a pair of phase terminals and the AC current 'I' is measured. The inductive impedance and inductance can be calculated with use of Equation B.5.

$$X = \frac{V}{I} = 2\pi f L \tag{B.5}$$

The inductance is measured three times in total, each time between different phases. The measured inductance is dependent on the number of turns between the phase terminals and the permeability of the surrounding steel. In good conditions the measured values should be equal to each other with a difference of 1%. When this is not the case the following reasons are likely to be the cause:

- There are shorted turns in one of the phases.
- The rotor is in a slightly different position in respect to the coils in each phase.
- Influence of steel end shields and other steel parts around the machine.

Sadly the last two effects affect the inductance measured far more than the first one. This makes the interpretation very difficult. When a lot of turns are shorted the first reason will be measured, but an exact amount of shortened turns remains difficult to give.

In the authors opinion, the effect of the second reason could be minimized by measuring for a longer time, while turning the rotor by a constant speed. When the measured value is averaged, a value of the inductance independent on the position of the rotor can be given. If the measurement is performed after proper cleaning of the machine the third effect can be minimized as well.

B.2.7. DISSIPATION- OR POWER-FACTOR

Both the dissipation factor and the power factor are measurements used to indicate the dielectric losses of the insulation. Since thermal deterioration and moisture absorption cause the dielectric losses to rise, this test can be used for these detection purposes perfectly. There are mainly two ways to measure dielectric losses inside the insulation: The first one is the dissipation factor (also referred to as tan(δ)) and the second one is the power factor. Both tests are most relevant for stator windings and are usually applied to form-wound stators only.

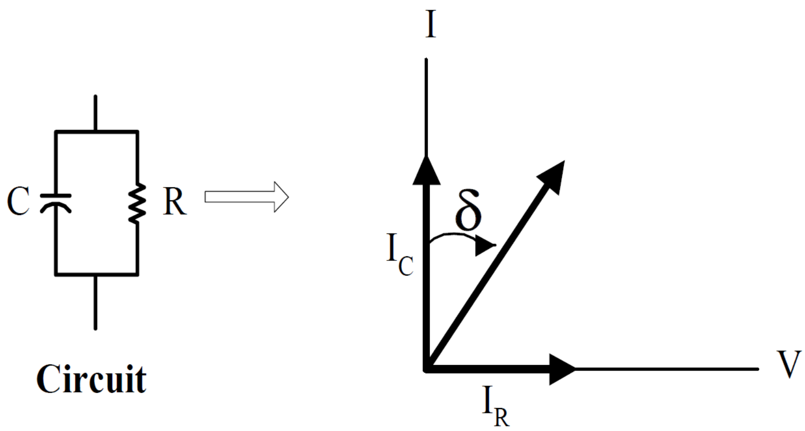

Figure B.1: Example of the calculation of the phase angle for the tan(δ) measurement, source:[49]

These tests are in a way comparable to the insulation measurements mentioned before, since both previous tests and these tests look at the power dissipated in the insulation material. In the ideal case the winding insulation will behave as a pure capacitor, only storing energy and not dissipating it. In practice the insulation material always has a resistive component and thus cannot act as a pure capacitor. Since AC is used during these measurements, the main losses will be caused by polar molecules aligning with the electric field. However it must be kept in mind that the dielectric loss is a material property and it can not be used for a quality indication of insulation. For indicating the aging of insulation due to overheating it is best to look at the trend of dielectric losses in the insulation material over time. Normal aging over time is likely to let the losses increase gradually. When a sudden rise of dielectric losses is found this may indicate a serious error due to overheating, but it may also indicate that the winding is soaked with water.

The two ways mentioned to measure the dielectric loss both use a similar principle. The approach of the methods is that the winding insulation is in essence a capacitor with a small dielectric loss. Both methods will be shortly discussed.

1. Dissipation Factor (DF) which is also referred as tan(δ) measures the loss with the use of a balanced bridge-type instrument. It uses a resistive-capacitive network that is varied until the same voltage and phase angle is measured across the winding. A result of such a situation as well as the equivalent circuit is given in Figure B.1. The DF is then calculated from the currents or the R and C values used in by the bridge to achieve the null voltage. With this method an accuracy of 0.01% is easily achieved.

   With the use of Equation B.6 the loss angle can be calculated with the measured values.

$$tan(\delta) = \frac{I_R}{I_C} = \frac{1}{2\pi f CR} \tag{B.6}$$

   Where

   δ = the angle in radians

   I_R and I_C = the current of the resistive or capacitive component of the insulation material

f = the frequency in Hz

C = the capacitive value of the material or bridge

R = the resistive value of the material or bridge

2. Measuring of the power factor (PF) is less renown than DF. For most windings the PF and DF are about the same, since they have low dielectric losses. Therefore most people don't even care about the fact that they are actually two different tests. The PF is measured by accurately measuring the voltage applied between the copper conductor and the core and detecting the current that will flow. With the use of a wattmeter the power factor is calculated with Equation B.7. This method is less expensive than the DF, since a bridge-type instrument is not needed. However the test is also less accurate in measuring the dielectric loss.

$$PF = \frac{W}{VI} \tag{B.7}$$

Where

W = the measured real power

V = the applied voltage

I = the current that flows

Since the measurements are performed at a low AC voltage, there might be some power-frequency currents induced by other energized systems that can interfere with the measurement. These induced signals can result in false results of the measurement. To minimize induced signals that interfere with the results often frequencies other than the power-frequency are used. For the best effect the occurrence of harmonics on the net should also be taken into account when choosing a frequency.

As already mentioned the DF and PF are in most situations more or less the same. Equation B.8 gives a formula that can be used to convert the DF to PF. In normal situations the DF will be very small which results in a PF that is more or less the same after conversion.

$$PF = \frac{DF}{\sqrt{1+DF^2}} \tag{B.8}$$

When performing one of these methods, it is best to measure as close to the terminals as possible. This is because any connected cables may have losses that add up to the losses inside the machine. When using cables, it needs to be insured that the used materials have very low losses (below 0,01%). This means that older cables, such as oil-paper or rubber-insulated cables, should not be used to connect the equipment with the machine. For the best results each phase should be measured separately, but this is not always possible due to a neutral connection inside the machine.

Incidental measuring of the dissipation is of little relevance. For normal epoxy and polyester impregnated insulation a DF of about 0,5% is acceptable. For mica insulated windings acceptable rates are between 3 and 5%. When the measuring of the DF is occurring at regular basis an indication of the material is obtained. When the measured values are constant over time, no thermal aging or contamination has happened to the winding. If the DF increased more than 1% above the initial value it indicates that a significant amount of contamination is present on the material or long periods of overheating have occured. If combined with a capacitance measurement thermal aging can be found. If this happens the trend of the measured capacitance decreases, while the DF is increasing. When both the capacitance and DF have an increasing trend, the absorbtion of moisture or contamination is indicated. [49–51]

B.2.8. SURGE TEST

Of all test that can be performed the surge test is only one which provides information on the integrity of the insulation during the first test cycle. During this test a relatively high voltage is applied between the turns. This means that the insulation may fail during the test. However if this should happen the quality of the insulation material was already in bad shape prior to the test. The surge test can be used on all winding-types and is described in a number of standards.

In the description of some failure mechanisms it was mentioned that the insulation material often fails due to the fast risetimes of voltage surges. When the risetime is short enough and the voltage is sufficiently high, the turn insulation will puncture. The puncture in the turn insulation is likely to evolve quickly to a phase-to-ground fault resulting in failure of the machine. This failure mechanism is (partly) responsible for about 80% of all electrical failures in the stator. With the surge test, these voltage surges are duplicated and therefore real life situations are replicated in a controlled way.

Instead of the HiPot DC or AC test, where the impedance is monitored, the surge test looks at changes in the resonant frequency of the windings. When a short in a winding is present the resonant frequency changes and this will be detected. The resonant frequency of a winding can be approximated with Equation B.9.

$$f = \frac{1}{2\pi\sqrt{LC}} \tag{B.9}$$

If no faults are present a fixed frequency of oscillation will be measured. When a turn fault is present the inductance will be lowered and the resonant frequency will increase. It is therefore important to look for the increase in frequency when the test is performed. Since the increase in frequency is only a few percent, the increase is difficult to detect. With the use of digital equipment the detection of the increase in frequency is made significantly easier.

Older surge testers were also referred as 'Surge comparison testers'. These testers were based on the principle that two phase windings are ideally identical. Due to this assumption the waveforms of two windings were compared to each other and when one of the waveforms changed, it was likely that a turn puncture occurred in the phase that changed. This method is less accurate, since two windings will always differ slightly and thus a measuring error is present during the test. For this reason the comparison test is used less over the years and modern surge testers are often used.

In IEEE 522, NEMA MG1 and IEC 60034-15 a description of the surge test as acceptance test is given. In these standards the voltage wave is recommended to have risetime of 100 ns and a maximum magnitude of 3,5-3,7 times the rated voltage.

IEEE 522 is the only standard that describes waves for maintenance tests as well. For testing windings that are already in service the same front of 100ns should be used but the amplitude of the voltage will be a maximum of 2,6 times the rated voltage.

Both tests should be applied as close to the machine terminals as possible to be most effective. It is also recommended to increase the surge voltage gradually to its maximum. This way the change in waveform can be found without overstressing the (already bad) insulation too much.

If a failed coil is found in a form-wound winding it needs to be located and isolated. It is most likely that the fault will be present in a phase end coil. When the location is found the damaged section can be cut out and replaced. When a coil has failed in a random-wound winding the easiest way to locate the fault is by turning the light of and look for any signs of discharges in the machine. For these types of windings cleaning and (re-)dipping in varnish is enough to restore the fault in most cases. It is not acceptable to recommission the winding when a puncture has been found and it is not yet restored. During the first significant surge the failure will show up and the machine will break down due to a failure to ground.

Basically the surge test is a go-no go test, since there are only two options. Either the insulation will hold and pass the test or a puncture or other fault is found and the winding will not pass the test. Combined with information on partial discharges that might occur, information on voids inside the insulation material may be detected as well. However there is no equipment developed that can handle the voltage surges and is accurate enough to measure the PDs with enough accuracy for LV-machines. [52]

B.2.9. OFFLINE PARTIAL DISCHARGES

It is already mentioned that Partial Discharges (PDs) do not happen often in machines supplied with a lower voltage. Even if PDs occur it is very hard to detect them. It is said that machines rated below 3kV cannot be diagnosed for PDs because they happen rarely.

However research is being done to make it possible to measure partial discharges at lower voltages. This way discharges caused by drives and other occurring PDs can be measured in machines. Sadly the results of these researches still need to be commercialized in reliable equipment.

Therefore the measurement of PDs on the machines will be kept out of the thesis's scope. When enough research proves that PD measurements on LV-machines are possible and equipment for these measurements is available, the test should be included in the set of measurements to be performed. This is due to the high level of information that can be achieved with proper PD measurements. [16, 17, 51, 53]

B.2.10. SUMMARY OF OFFLINE STATOR WINDING MEASUREMENTS

Table B.6: Summary of offline stator winding measurements, source: [1, 10]

Method	Standard	Insulation tested and diagnostic value	Attributes	Performance Difficulty
Winding Resistance/ DC conductivity Test		Detects shorted turns, no predictive value	(+)easy to perform, (-)only detects faults	Easy
Insulation Resistance (IR)/ Megohm	IEEE43, NEMA MG1	Finds contaminations and defects in phase-to-ground insulation	(+)easy to perform, (+)applicable to all windings except for the rotor of a squirrel cage IM, (-)result strongly temperature dependent	Easy
Polarization Index (PI)	IEEE43	Finds contaminations and defects in phase-to-ground insulation	(+)easy to perform, (+)less sensitive to temperature than IR-test	Easy
DC High Potential Test (DC HighPot)	IEEE95, IEC34.1, NEMA MG1	Finds contaminations and defects in phase-to-ground insulation	(+)easy to perform, (+)if test does not fail, the insulation is likely to work flawlessly until the next maintenance period –> more predictive characer than IR and PI, (-)in case of failure repair required (destructive test)	Easy
AC High Potential Test (AC HighPot)	IEC60034, Nema MG1	Finds contaminations and defects in phase-to-ground insulation	(+)more effective than DC HighPot, (-) not as easy to perform as DC HighPot	Moderate, due to large transformer needed
Capacitance		Detects phase-ground faults	(-)undesired foreign influence on result, (-)not as easy to perform as the Insulation Resistance (IR) test	Moderate
Inductive Impedance		Detects shorted turns, no predictive value	(-)undesired foreign influence on result, (-)not as easy to perform as the Winding Resistance test	Moderate
Dissipation-Factor / Power-Factor	IEEE286, IEC60894	Detects deterioration of the phase-to-ground and phase-to-phase insulation	(-)measurements on a regular basis required in order to trend the data over time, (+)able to determine the cause of deterioration	Moderate
Surge Test	IEEE522, NEMA MG1, IEC61000-4-5	Detects deterioration of the turn-to-turn insulation	(+)only offline test that measures the integrity of the turn insulation, (-)test can be destructive	Difficult
Offline partial Discharge	IEEE1434	Detects deterioration of the phase-to-ground and phase-to-phase insulation	(+)good practical results, (-)not applicable to low-voltage machines, (-)difficulty in interpretation of the data	Difficult

B.3. ROTOR WINDING TEST MEASUREMENTS

Apart from tests that can be performed on the stator windings, measurements on rotors are also developed. With these measurements an indication on the state of the rotor insulation can be acquired, but drawing a conclusion, based on the measured values, still proves to be difficult. Most measurements that can be performed on the stator can be used on the rotor as well. To prevent repetition of these measurements they will only be mentioned, but not explained again. Measurements that can be used on rotors only will be discussed in this part, since they may be used to complement the total set of measurements. When measurements can not be used due to too high voltages or practical issues, they will not be discussed in this section. The same reasoning about online and offline measurements holds as given in the section on stator measurements. Therefore only offline measurements will be discussed. No reliable source on online rotor measurements is available to the author, therefore no overview on these measurements can be given. However when online measurements are preferred, a user can look for online alternatives off the discussed offline measurements.

The different measurements will be mentioned or discussed first and at the end of this section an overview on the measurements is given.

This section based on information found in [10] and a similar line is followed. To improve the readability, references to this source will not be placed again after discussing each measurement. When other sources are used as reference for a section, the reference is placed at the end of the section. An exception will be made when only a specific (small) part is paraphrased from a reference.

B.3.1. MEASUREMENTS IDENTICAL TO STATOR MEASUREMENTS

As mentioned a number of the stator measurements can be used on rotors as well. However not all measurements have been investigated to prove whether the results have the same accuracy.

For the measurements mentioned below, it is suggested that these tests are regularly performed on rotors. Therefore it may be assumed that a validation of cases between the stator and rotor has taken place.

- Insulation resistance
- Polarization index
- DC HiPot
- AC HiPot
- (Inductive) Impedance test

Other tests seem to have not been validated, but should be possible to use according to the author:

- Winding resistance test
- Capacitance test
- Dissipation factor

Since no references are found to indicate that these tests are performed on rotors for diagnostic value, these tests will not be included in the overview at the end of the section. By looking at the nature of each test, there is no prove that these measurements will give wrong results or damage the rotor.

B.3.2. POLE DROP

The pole drop test is mostly referred as a rotor voltage drop test. The test can be used on all salient pole windings of a rotor to look if any shorted turns are present. Performing this measurement is relatively easy since no special equipment needed. A drawback is that not all faults can be found, since the rotor is a stand still. If the centrifugal forces on the rotor cause turn shorts only during operation, the faults will not be measured during an offline situation when these forces are not present.

The principle used is that the inductive impedance will drop significantly when AC is applied and a shorted turn is present. When an AC voltage is applied to the terminals of each pole, the voltage across the coil is measured. If no faults are present all coils have almost the same impedance and all measured voltages are similar. When a turn fault is present, the impedance of that coil will be much lower and that coil will have a much lower voltage drop.

It is important to have good access to the individual pole connections to be able to perform this test. Especially in smaller machines this may mean that the rotor has to be removed before the test can be used. Access to the ends of the rotor has to be available as well, but normally this is available via the sliprings for asynchronous machines or via the exciter after the diodes for brushless synchronous machines. As already stated the equipment needed is simple. A combination of commonly available meters and a 120/240V variac is enough excecute the measurement. If a voltage drop is measured that deviates more than 10% from the average voltage, a turn fault is indicated. Any smaller deviations may be caused by differences in the coils, since it is impossible to make all coils exactly the same.

B.3.3. ROTOR RSO & SURGE TEST

Both the Recurrent Surge Oscilloscope (RSO) and Surge test are methods that can detect turn shorts, ground faults and high resistance connections in synchronous machine rotors. It is even said that the RSO can be used for identifying the location of the fault. The surge test is similar to the surge test performed on the stator windings. It is even possible to use the same equipment for performing the measurement. Therefore the surge test will not be discussed any further. The RSO is slightly different than the surge test, therefore this method will be discussed further.

The RSO is based on the same principle as the previously discussed surge test. The idea is that healthy rotor windings are symmetrical in electrical aspect. Any faults present will distort the symmetry and can therefore be found. The main difference between both tests is the voltage used for testing. Instead of a high voltage with the surge test, the RSO is performed at voltages below 100V. At this voltage identical high frequency electrical pulses are injected at both ends of the winding. In the case that the winding is healthy the travel time for both pulses is identical. When faults are present, the impedance that each pulse will see is different and reflections will take place in the winding. As a consequence, the faults cause the wave-forms to differ from each other. The only exception on the faults that can be detected is when the fault is exactly in the middle of the winding. In this case the fault will interfere the same for each pulse and will therefore not be detected.

The main benefits of the RSO are the low voltage that is used and the possibility to locate faults. There are however also a few difficulties with the test. The interpretation of the results can be difficult and according to [54] the test can only be performed for low impedance situations.

The RSO can detect ground faults that have caused the resistance to be below 500Ω. Since most other (easier) tests can detect such ground faults as well, this test can basically be used as a way to confirm faults detected previously. Turn faults are detected when the resistance is less than one ohm. This means that some faults that only occur during operation can not be detected, because these faults have a too high resistance during stand still.

B.3.4. ROTOR SINGLE PHASE ROTATION TEST

The single phase rotation test is often used to detect broken rotor bars, broken short-circuit rings and broken joints between bars and rings. This means that the test can only be performed on squirrel cage induction motors. The main benefit for this test is that the rotor can stay inside the stator.

The test is performed by applying a single-phase 50 Hz voltage across only two of the stator windings (the third one is floating). As a result of the applied voltage a non-rotating sinusoidal flux will be present in the airgap inducted by the current through the winding. Broken sections in the rotor cage cause a non-uniform impedance. When the rotor with broken sections is rotated, the non-uniform impedance will interfere with the airgap flux that is created. This interference causes significant fluctuations in the current drawn form the source.

Normally this test is performed by applying 10 to 25% of the rated voltage to the stator windings. When the voltage is applied, the rotor is turned slowly and the drawn stator current is monitored. If the current fluctuates more than 5%, a broken rotor bar or short-circuit ring is indicated. Sadly only broken sections can be detected in this way. Cracks or brakes that occur due to large centrifugal forces can not be detected, since they have very little influence on the rotor winding impedance.

For this test it should be noted that a lot of heat will be produced. Because the rotor is turning very slowly, fans mounted will barely work and therefore the machine cannot be cooled enough. For this reason it is important to minimize the test time in order to minimize the heat induced in the machine.

According to the author a similar test could be used on machines where the rotor windings are excited. In this situation the rotor winding must be excited and the induced voltage on the stator windings must be measured. In the ideal situation the induced voltage on each stator winding is the same. When turn faults are present in the windings, the measured voltage on the stator windings will differ from each other and the winding that holds the fault can be indicated. Since no reference of such a test has been found, more research should be done to learn about the details on the results measured.

In a way the idea of this method may be compared to an open circuit test as described in [55]. The main difference is the purpose of both tests. Open circuit test are mainly used for measuring machine parameters and the suggested method is focused on measuring the condition of the machine at the time.

B.3.5. OVERVIEW OF OFFLINE ROTOR MEASUREMENTS

Table B.7: Summary of Offline Rotor Measurements, source: [10, 26]

Method	Description	Performance difficulty	Aplicable for rotor types	Effecitiveness
Insulation Resistance (IR)	Measure leakage current after applying DC voltage for 1 minute	Easy	All wound rotors	Finds contamination or defects
Polarization Index (PI)	Look at the ratio of IR values after 1 and 10 minutes	Easy	All wound rotors	Finds contamination or defects
DC High Potential	Apply high DC voltage for 1 minute	Easy	All wound rotors	Finds defects
AC High Potential	Apply high AC voltage for 1 minute	Moderate, due to large transformer	All wound rotors	Finds defects better than DC version
Impedance test	Apply AC voltage and measure I and V to find turn shorts	Moderate	Rotors with sliprings	Finds turn shorts
Pole Drop	Apply AC current and measure the voltage drop across each pole	Easy	Salient pole rotors	Finds turn shorts
Rotor RSO & Surge Test	Measure any discontinuities in the surge impedance of windings	Difficult	Round rotors	Effective for indicating 'hidden' short circuits
Rotor Single Phase Rotation Test	Apply AC voltage to two stator windings and measure drawn current when the rotor is turned	Moderate	Squirrel cage rotors	finds broken rotor bars or short-circuit rings

C

EQUIPMENT INFORMATION

In this appendix information on the equipment used is given. The information varies from information of the test samples to nameplate information of the tests equipment.

C.1. TEST SAMPLE INFORMATION

Three motors are used are ABB induction motors with motor type: M2AA 090LB-4 IE2 production year 2014. The serial numbers of the motors are: (21)3G2C143609023001, (21)3G2C143609023005 and (21)3G2C143609023031. Insulation used is class F insulation and motors comply with IEC60034-1.

Nameplate information of each motor is identical (except the serial number) and is given in Table C.1

Table C.1: Nameplate information test motors

3 Motor M2AA 090LB-4 IE2			Cl. F	IP 55	IEC60034-1
3GAA092214-ASE				IM 1001	
$N°$ 3G2C1436090230xx					2014
V	Hz	r/min	kW	A	$cos(\phi)$
230 D	50	1435	1.1	4.1	0.78
400 Y	50	1435	1.1	2.4	0.78
460 Y	60	1740	1.1	2.1	0.76
IE2-50Hz-83.7(100%)-84.1(75%)-83(50%)					
IE2-60Hz-84.6(100%)					
6205-2Z/C3 6204-2Z/C3				16 Kg	

C.2. EQUIPMENT USED FOR MEASUREMENTS

The following equipment has been used to perform measurements on the test subjects.

Megger IDAX300 Insulation Diagnostic Analyzer in combination with a **Megger VAX020** High Voltage Amplifier as can be seen in Figure C.1. This equipment has been used to perform $\tan(\delta)$ measurements in combination with capacitance measurements.
Further information on IDAX300 in Table C.2.
Further information on VAX020 in Table C.3.

Table C.2: Specifications Megger IDAX 300

Software version used	IDAX 5.0 SW
Serial nr.	1300439
Operating temperature	-20°C - +55°C
Maximum humidity	95%
Mains voltage	100 - 240V ±10%, 50/60Hz
Max power consumption	250VA
Capacity range	10pF - 100μF
Inaccuracy	0.5% + 1pF
Dissipation factor range	0 - 10 (when within capacity range)
Max output voltage	0 - 200V_{peak}
Max output current	0 - 50mA_{peak}
Frequency range	DC - 1kHz

Table C.3: Specifications Megger VAX020

Serial nr.	1300132
Operating temperature	-20°C - +55°C
Maximum humidity	90%
Mains voltage	100 - 240V ±10%, 50/60Hz
Max power consumption	120VA
Max output voltage	2kV_{peak}
Max output current	50mA_{peak} above 50Hz derating linearly to 30mA_{peak} below 10Hz
Frequency range	DC - 1kHz
Capacitive load capability	0 - 20μF, 80nF at 2kV, 50Hz

Figure C.1: Megger IDAX 300 and VAX020

BINDER FD53 drying oven with forced air ventilation as can be seen in Figure C.2 and Figure C.3. This has been the oven used for aging the test stators thermally.

Further information on Binder FD53 is given in Table C.4.

Table C.4: More information on Binder FD53

Serial nr.	09-11949
Input voltage	230V
Maximum input current	5.3A
Maximum power	1,20kW
Interior volume	53L
Interior height	400mm
Interior width	400mm
Interior Depth	340mm
Temperature range	5°C above ambient - 300°C
Temperature variation @ 150°C	$\pm 2^{\circ}C$
Temperature variation @ 300°C	$\pm 3,7^{\circ}C$
Heating time to 150°C	24min
Heating time to 300°C	60min

Figure C.2: Outside of Binder FD53 Oven

SKF Baker AWA-IV/12 static motor analyser as is shown in Figure C.4. This motor analyser has been used to perform a series of test on the motor during the first two aging cycles. The following test methods were performed using this device: Winding resistance, Insulation resistance, Polarization index, DC HiPot and surge test.
Further information on Baker AWA-IV can be found in Table C.5.

Hipotronics HM3A megohmmeter as shown in Figure C.5. This has been used to perform measurements on the insulation resistance of the material inside the machine.
Further information on the HM3A is given in Table C.6.

Schleich Motor Analyser 2 was used as an alternative to the Baker AWA-IV. A figure of the motor analyser is given in Figure C.6. The motor analyser has been used to perform the

Figure C.3: Inside of Binder FD53 Oven

Table C.5: Specifications on SKF Baker AWA-IV/12

Serial nr.	10539 70710
Range winding resistance	0.001 - 800 Ω
Max insulation resistance	50000MΩ
Accuracy insulation resistance	±10%
Accuracy voltage and current measurement	±5%
DC test	
Output voltage	0 - 12000V
Max output current	5000μA
Current resolution	0.1, 1, 10, 100 μA/Div
Surge test	
Output voltage	0 - 12000V
Max output current	600A
Pulse energy	2.88J
Storage capacitance	0.04μF
Sweep range	2.5 - 200μF/Div
Accuracy voltage measurement	±12%

following tests: Winding resistance, insulation resistance, polarization index, winding inductance, DC HiPot and surge test. More information on this machine is given in Table C.7

Radiometer Megohmmeter was used for measuring insulation resistance as well and is pictured in Figure C.7. More information on this Megohmmeter is given in Table C.8

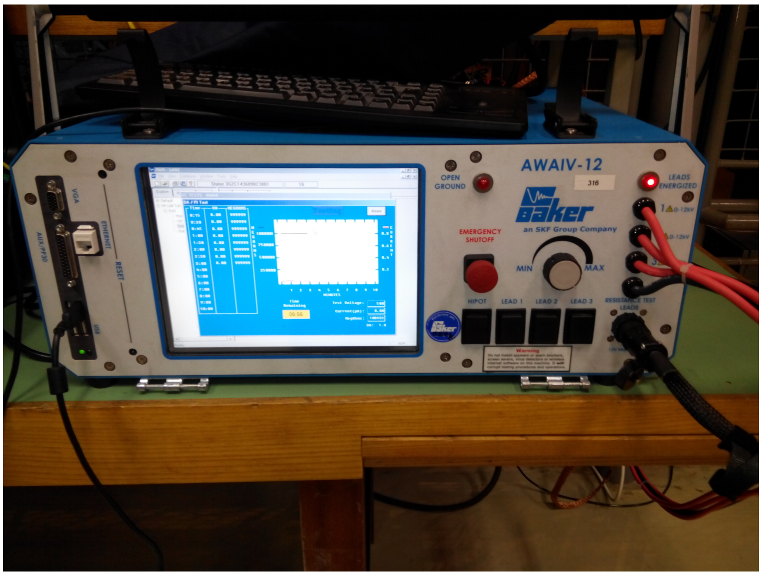

Figure C.4: Front side of Baker AWA-IV/12

Table C.6: Specifications on Hipotronics HM3A

Serial nr.	003331-008632
Input voltage	220V @ 50Hz
Output voltage	50, 100, 500, 1000V
Range	0.1 - 20000000MΩ (20TΩ)
Scale range	(50, 100V) 1-100M
	2-200M
Resistive Multiplier switch	(50, 100V) $10^{-1}, 10^{0}, 10^{1}, 10^{2}, 10^{3}, 10^{4}$
	(500, 1000V) $10^{0}, 10^{1}, 10^{2}, 10^{3}, 10^{4}, 10^{5}$
Accuracy	3/22" of Scale <1000000M
	1/8" of Scale >1000000M

Figure C.5: Front of Hipotronics HM3A

Table C.7: Specifications on Schleich Motor Analyser 2

Serial nr.	11850
Range winding resistance	0.001Ω - 499Ω
Accuracy winding resistance	±0.3% ±1 digit
Range Insulation resistance	1 - 100000MΩ
Induction and capacitance measurement	
Range Induction	0.05mH - 5H
Range Capacitance	0.001 - 24μF
Accuracy	±2-3% ±1 digit
Frequency	50 - 4000Hz
Test Voltage	0.5 - 10V
Max test current	1A
DC test	
Output voltage	0 - 6000kV
Max output current	3mA
Surge test	
Output voltage	0 - 3000V
Surge capacitance	100nF
Surge energy	0.45J

Figure C.6: Motor Analyser 2 form Schleich

Table C.8: Specifications on the Megohmmeter from Radiometer

Serial nr.	120298
Type	IM 5e
Input voltage	220V @ 50Hz
Output voltage	5, 10, 20, 50, 100, 200, 500, 1000V
Range	0.1 - 100000000MΩ (100TΩ)
Scale range	1 - 100MΩ
Resistive Multiplier switch	$10^0, 10^1, 10^2, 10^3, 10^4, 10^5, 10^6$

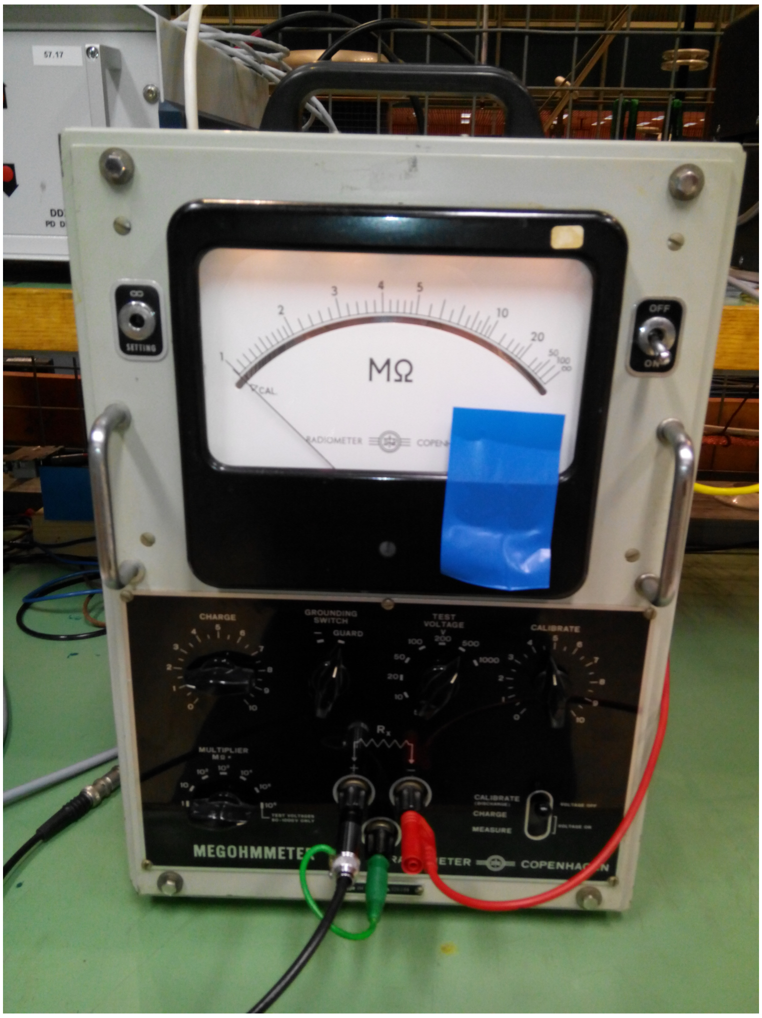

Figure C.7: Megohmmeter used made by Radiometer

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