Lars Ivar Ulvestad Raanaa

Condition Monitoring of Power Transformers in Digital Substations

Master's thesis in Energy and Environmental Engineering
Supervisor: Hans Kristian Høidalen
June 2020

Master's thesis

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Norwegian University of Science and Technology
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Abstract

Ageing power transformers in the power system increase the need for maintenance and reinvestments. There is currently a shortage of adequate data and analysis systems for estimation of condition and residual lifetime, to facilitate decision-making. It is a challenge to restructure asset management with regard to collect relevant data and to introduce new systems for handling and analysing the data. There is a large potential for increased value creation with condition monitoring systems.

This thesis examines potential opportunities for better management of condition data and utilisation of condition monitoring systems for power transformers. The aim is to improve maintenance and reinvestment decisions, with the purpose to increase cost efficiency. Power transformers are expensive and implementation of condition monitoring will improve the monitoring, which can be used to adjust the load, to adapt the capability of individual power transformers, and to plan maintenance and reinvestment activities.

Natural processes degrade power transformers. A breakdown occurs when the degree of degradation has reached a certain level. By using various diagnostic techniques, it is possible to monitor parameters that indicate the degree of degradation. A condition monitoring system can report when a power transformer has reached a severely reduced state, and thus enable the user to take action before a breakdown occurs.

A new type of substation referred to as digital substation, introduces a new substation automation system that reduces the amount of copper cables between the field and the substation, by using an Ethernet cable known as the process bus. Similarly, an Ethernet cable is utilised between the bay level and the station level, known as the station bus. This thesis proposes ways of integrating condition monitoring systems into the digital substation.

Communication in digital substations is based on the IEC 61850 standard. The standard aims to achieve interoperability between devices from different vendors, and is intended to be a complete standard that will cover the entire substation automation system and the network between the substation and the control centre. The thesis presents the standard's data model, communication mappings and cyber security aspects. A practical piece of code for an RTU is shown to demonstrate the standard.

After the fundamental framework is a short vendor survey of condition monitoring systems commercially available presented. It examines what components and monitoring facilities these systems have implemented, and provides a rough price estimate for various condition monitoring systems.

Sammendrag

Aldring av krafttransformatorer i kraftsystemet øker behovet for vedlikehold og reinvesteringer. Det er i dag en mangel på tilstrekkelige data- og analysesystemer for estimering av tilstand og restlevetid av krafttransformatorer. Det er en utfordring å omstrukturere anleggsforvaltning med hensyn til å samle inn relevante data og å innføre nye systemer for å håndtere og analysere dataene. Det er et stort potensiale for økt verdiskapning med tilstandskontrollsystemer.

Denne oppgaven undersøker potensielle muligheter for bedre håndtering av tilstandsdata og bruk av tilstandskontrollsystemer for krafttransformatorer. Målet er å kunne forbedre vedlikeholds- og reinvesteringersbeslutninger med det formål å øke kostnadseffektiviteten. Krafttransformatorer er kostbare og innføring av tilstandskontroll vil medføre bedre overvåkning av tilstand som kan legge til rette for å justere belastningen, for å tilpasse ytelsen til hver enkelt krafttransformator, og planlegge vedlikeholdsarbeid.

Naturlig aldring medfører nedbrytelse av krafttransformatorer. Når en nedbrytelse har nådd et visst nivå, vil krafttransformatorer havarere og et brudd i nettet kan oppstå. Ved hjelp av ulike måleteknikker kan man måle parametre som indikerer graden av aldring. Et tilstandskontrollsystem kan rapportere når en krafttransformator når en kritisk svekket tilstand, og dermed kan man få gjort tiltak før et havari oppstår.

En ny type transformatorstasjon kalt digitalstasjon, innfører et nytt koblingsanlegg som erstatter tradisjonelle kobberkabler mellom felt og stasjon med en Ethernet kabel kalt prosessbuss. På samme måte brukes en Ethernet kabel mellom reléer og stasjonsenheter, kalt stasjonsbuss. Ulike måter å integrere tilstandskontroll i slike koblingsanlegg er presentert og diskutert i denne oppgaven.

Kommunikasjon i digitale stasjoner er baset på IEC 61850 standarden. Den har som mål å sikre interoperabilitet mellom enheter fra ulike leverandører, og er ment å være en komplett standard som skal dekke hele koblingsanlegget og nettverket mellom driftssentral og stasjoner. Oppgaven beskriver standardens oppbyggning, kommunikasjonsprotokoller og datasikkerhetsapekter. En praktisk anvendt programkode for en RTU er gitt for å demonstrere standarden.

Etter å ha presentert det grunnleggende rammeverket, er en kort leverandørundersøkelse av tilstandskontrollsystemer på markedet gitt. Den undersøker hva slags komponenter og måleteknikker disse systemene består av, og gir et grovt prisoverslag for ulike tilstandskontrollsystemer.

Preface

This Master's thesis is the conclusion of my Master of Science degree in Energy and Environmental Engineering with the Department of Electric Power Engineering at the Norwegian University of Science and Technology (NTNU). The work was carried out during the spring semester of 2020, and has been performed in collaboration with SINTEF Energy Research. The thesis is a continuation of my specialisation project, and involves examining opportunities and challenges obtained by introducing condition monitoring in digital substations.

The assumed background knowledge expected of the reader is that of a 5th-year electric power engineering student.

Firstly, I would like to thank my supervisor Hans Kristian Høidalen at NTNU. He has been my main source of guidance and support during the work with this thesis. I would also like to thank Hans Kristian Hygen Meyer at SINTEF Energy Research for providing support to my work. In addition, I would like to thank Espen Eberg and Maciej Grebla at NTNU for helpful contribution and advice.

I am also grateful for being a part of the project "Engineering and Condition Monitoring in Digital Substations (ECoDiS)" for giving me the opportunity to undertake this work.

Finally, I would to thank my family and friends for their love, support and motivation through my whole time as a student.

Trondheim, June 2020

Lars Ivar Ulvestad Raanaa

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Abbreviations

ECoDiS	=	Engineering and Condition Monitoring in Digital Substations
RTU	=	Remote Terminal Unit
IEC	=	International Electrotechnical Commission
LAN	=	Local Area Network
NCIT	=	Non-Conventional Current Transformers
OCT	=	Optical Current Transformers
MU	=	Merging Unit
SCADA	=	Supervisory Control and Data Acquisition
IED	=	Intelligent Electronic Device
OLTC	=	On-Load Tap Changer
ONAN	=	Oil Natural Air Natural
ONAF	=	Oil Natural Air Forced
Cigré	=	International Council on Large Electric Systems
DGA	=	Dissolved-Gas-In-Oil
PD	=	Partial Discharge
CIT	=	Conventional Instrument Transformer
NCIT	=	Non-Conventional Instrument Transformer
WAN	=	Wide Area Network
HMI	=	Human Machine Interface
RS (232/422/485)	=	Recommended Standard (232/422/485)
DNP 3	=	Distributed Network Protocol 3
DAU	=	Data Acquisition Unit
OSI	=	Open Systems Interconnection
MMS	=	Manufacturing Message Specification
ACSI	=	Abstract Communication Service Interface
SV	=	Sampled Value
GOOSE	=	Generic Object Oriented Substation Event
MAC	=	Media Access Control
SMV	=	Sampled Measured Value
SCL	=	Substation Configuration Language
XML	=	eXtensible Markup Language
DoS	=	Denial of Service

Chapter 1

Introduction

1.1 Background

Utility companies have an increasing amount of ageing power transformers in the power grid system leading to a growing need for maintenance and reinvestments. Transformer failures and outages cause loss of energy supplied and a lack of stability and reliability of the power grid that can result in significant costs as well as inconveniences to society.

Time based maintenance has been the traditional form of maintenance carried out at defined intervals that are solely defined by the experience of the utilities, or by recommendations of the transformer manufacturer. It is associated with inefficiency and inaccuracy as intervals may be carried out to often, to find no signs of degradation, or to seldom, after a fault has occured [1].

The evolution of maintenance practices now moves in the direction from time based to condition based maintenance. In this way, asset management decision processes will be a structured process that emphasises that more intrusive replacement and overhauls only need to take place when a measurable wear of ageing occurs. Condition based maintenance is initiated when deterioration has gone beyond a prescribed limit.

Condition based maintenance is based on continuous online monitoring of transformers using modern technology. This includes using various types of sensors for detection of different deterioration processes along with a network infrastructure for data transmission. In addition, a properly implemented condition based system will not only acquire and present data, but can also evaluate and analyse the data, to autonomously identify degradation of the monitored transformers and provide necessary actions to avoid failures.

The market now offers plenty of condition monitoring systems, however there is no common practice on how to manage the whole process and convert the data into useful and relevant information [2]. A common design would enable utilities more easily to implement condition monitoring systems. In addition as more and more experience is gained, the best practice can be developed and verified over time.

If condition monitoring systems prove to be successful and cost effective, it is likely that condition monitoring will be a natural integrated part of substation automation systems as control and protection is already today. In this way, condition monitoring will consequently be an integral part of power transformers.

The digital substation is a new emerging type of substation automation system which changes the substation automation system in terms of data transmission. Digital substations are based on Ethernet technology by deploying the IEC 61850 process bus for data transmission between process level devices and bay level devices, instead of wired copper cables. The challenge is to integrate condition monitoring into the digital substation, and to evaluate possibilities as well as limitations with this system.

Today, a multiple of different protocols exists for substation automation systems, many of which are proprietary. Interoperability of devices from different vendors would be an advantage, and therefore IEC Technical Committee 57 created the IEC 61850; an international standard defining communication protocols for devices in substations in order to achieve interoperability [3].

An important aspect of communication is cyber security. There are restrictions imposed by the Norwegian government[1] on how to handle, merge, transmit, and present data. Means of meeting the restrictions is an important challenge for the success of condition monitoring.

The ongoing SINTEF/Statnett project ”Engineering and Condition Monitoring in Digital Substation (ECoDiS)” aims to gather experience and competence on condition monitoring systems in digital substations. As a part of this, three pilot substations are implemented which can evaluate the maturity of the technology. In addition, a platform is built to test different aspects of the IEC 61850 standard, including interoperability and cyber security, as part of the National Smart Grid Laboratory at NTNU [4].

An important remark is that condition monitoring systems can be implemented to other components than power transformers as well, such as switchgear, lines, cables, and generators. However, covering different types of components is too extensive for this thesis,

[1] Norges vassdrags- og energidirektorat NVE and Direktoratet for samfunnssikkerthet og beredskap DSB.

and to narrow down the scope, the focus is on power transformer exclusively, as it is a comprehensive power component consisting of many subparts with corresponding ageing mechanisms and diagnostic techniques.

Finally, condition monitoring is a part of the long-range plan for electrical networks that is the ”smart grid”. The smart grid is a fully automated power system that can be achieved by integrating information technology, communication, control and condition monitoring, to gain increased cost efficiency and reliability pf the power system [5].

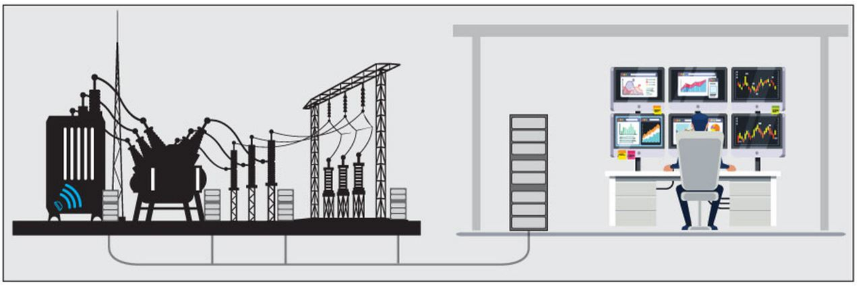

Figure 1.1: Power transformer condition monitoring in digital substation graphics [4].

1.2 Problem Description

This thesis is a part of the ECoDiS research project and involves examining potential solutions for power transformer condition monitoring systems in digital substations for asset management purposes. This is done in order to determine if condition monitoring is an alternative to conventional methods. It can optionally be one of several tools used.

The motivation is to develop a standardised approach for condition monitoring that achieves interoperability between components from different vendors and is safe to operate in terms of cyber security.

The aim is that such system can be able to use realtime data and historic from power transformers in order to predict the state of the given transformer in a more efficient, safe, cost effective way then already existing methods to reduce failures and following outages. A step further is to merge condition data and operational data so that the condition can be evaluated in terms of the load situation. Finally, such a system needs to be optimised by means of finding the simplest and most cost-efficient system that provide sufficient functions and information and meet all restrictions and requirements.

Vendors have already designed a range of systems that are commercially available. When implementing a condition monitoring system, the utility would probably buy a finished system instead of designing their own system. Therefore, it is useful to investigate in more detail what vendors offer. However this can only be properly done by knowing theory and principles behind such systems.

The objectives of this thesis are:

- To describe the method of asset management involving condition monitoring.
- To describe typical ageing mechanisms and failure modes of power transformers.
- To obtain information about diagnostic test methods for power transformers.
- Investigate sensor technologies.
- Investigate solutions for how to merge condition and operational data.
- To obtain information about the IEC 61850 data model and communications mapping.
- The development of a digital substation system for condition monitoring based on IEC 61850.
- Evaluate IEC 61850 in terms of interoperability and cyber security.
- Evaluate available vendor condition monitoring solutions.

1.3 Approach

To meet the stated objectives, the thesis work started with a literature review, and the study of relevant theory for power transformers, asset management, condition monitoring, substation automation systems and communication with emphasis on IEC 61850. In this work, it has been important to use both Norwegian and international sources and standards to get access to information. Despite the international scope, focus has been on Norwegian conditions. Books, articles, research papers, web-pages and conversations with my supervisors, SINTEF Energy Research scientists and engineers from both utilities and vendors, have been sources of information. Utilities include Statnett, Hafslund Nett[2], Skagerak Nett, and BKK, and vendors include ABB, Siemens, Altanova, and 8 others. The NTNU university online library ”Oria”, the Norwegian user group for power transformers[3], the

[2]Now called Elvia.
[3]Called *Brukergruppen for kraft- og industritransformatorer* in Norwegian.

web-page ”Standard.no”, the Google academic search engine ”Google Scholar”, and the IEEE *Xplore* Digital Library have been platforms for finding relevant information. The IEC and Cigré have in particular been good sources of information. Online sources including tutorials and videos have also been used as background material. Information acquired from earlier courses at NTNU which the undersigned has taken, is also included.

The thesis work builds on the theory and literature review carried out as part of my specialisation project [6], and there is an extensive usage of the content therefrom.

Remark: The work with this thesis was conducted during the Corona/covid-19 virus outbreak of spring 2020. Unfortunately, this virus had implications on the work, as NTNU Gløshaugen had to close its doors as a measure to prevent spread of the disease. A laboratory work was planned to be conducted to test RTU capability and IEC 61850 functionality and interoperability, but had to be cancelled. The lab work involved creating a Python/-MATLAB source code to analyse data acquired from an OPAL-RT simulator, that was intended to mimic power transformer behaviour.

The thesis became therefore a synthesis work, and is a collection of knowledge from various fields. The aim of this thesis is therefore to provide fundamental knowledge about power transformers, digital substations, communication, IEC 61850, and vendor solutions, to serve as a guide for condition monitoring practices.

1.4 Outline

The outline of the thesis is built around understanding the various aspects of condition monitoring systems and means of integrated such systems in digital substations.

Chapter 2 presents a brief literature review and theory of the main aspects of condition monitoring comprising asset management, digital substation, and the condition monitoring process, and also includes description of commonly used jargon to aid clarity.

Chapter 3 presents the power transformer in detail by describing its construction in terms of its subparts, then followed by related ageing mechanisms, diagnostic techniques to monitor the ageing mechanisms, and recommendations for monitoring. Understanding the underlying principles and theory provide valuable knowledge that can be utilised in the creation of a condition monitoring system.

Chapter 4 presents the fundamentals of condition monitoring systems. It describes the various types of substation devices and their communication channels, and describes very briefly models used to evaluate condition data.

Chapter 5 discusses data aspects related to condition monitoring, and focuses on the IEC 61850 data model, communication mappings, system configuration, the process bus, security, and includes pieces of code from a RTU that was bought in for lab work. The code aims to demonstrate in a practical manner, how the IEC 61850 works.

Chapter 6 provides a presentation of condition monitoring solutions from 11 vendors. The systems were analysed in terms of monitored parameters, devices used, communication channels, interoperability, security and presentation of data. No economic evaluation was performed. The intention is not to favour any of the systems, however, their pros and cons are discussed.

Chapter 7 is a discussion on condition monitoring systems and focuses on possibilities and challenges associated with them.

Chapter 8 then finally presents the conclusion and gives some recommendations for further work.

Chapter 2

Literature Review and Theory

2.1 Asset Management

Power transformer asset management involves balancing costs, opportunities and risks against the desired performance to achieve the utility objectives. It enables the application of analytical approaches towards managing a transformer over the different stages of its life cycle. This includes the conception of the need for the transformer, through to its disposal [7].

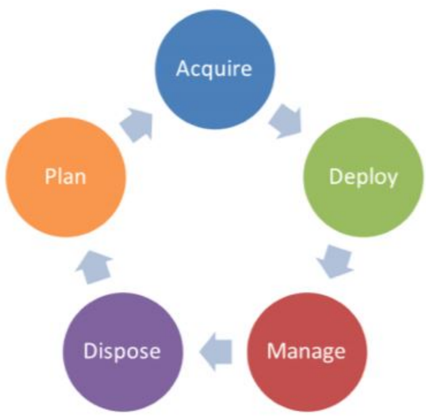

Figure 2.1: General life cycle of an asset [8].

Some of the benefits of asset management include improved financial performance, improved services, managed risk and informed asset investment decisions. It gives the utility the opportunity to improve its decision-making and effectively balance costs, risks, opportunities and performance. Asset management involves making the right decisions and optimising the delivery of value based on monitoring.

A more specific example of a transformer life cycle is shown in Figure 2.2. The figure illustrates the technical condition of an asset over time, with maintenance and reinvestment performed after a certain time to avoid any failures and outages. The condition monitoring system should tell when it is time for maintenance or reinvestments. The topic is more important today than ever as the power system infrastructure, mainly built in the 1950s and 60s, is ageing and consumers' have expectations of a reliable and constant power supply.

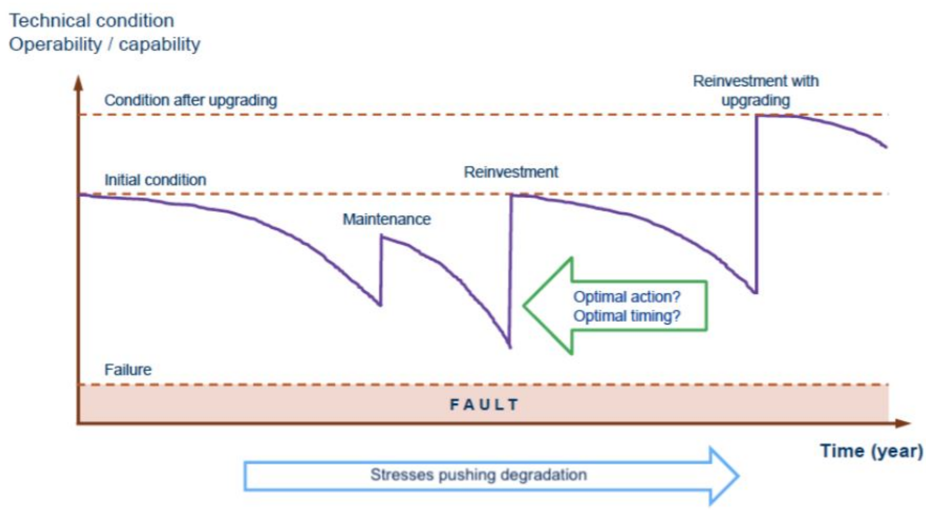

Figure 2.2: Life cycle of an asset [8].

The justification for online condition monitoring is driven by the need to increase the availability of transformers, to facilitate the transition from time-based to condition-based maintenance, to improve asset and life management, and to enhance failure-cause analysis. The use of condition monitoring allows maintenance to be scheduled, or other actions to be taken to prevent consequential damages and avoid its consequences.

However, it is important to underline that continuous on-line condition monitoring is a cost-adding alternative to maintenance and reinvestment strategies, and may not necessarily be the most cost-effective solution as the cost of such a system may outweigh the savings [9]. Savings are obtained by changing the maintenance activities in terms of reducing the frequency of onsite "manned" inspections and by obtaining longer lifetimes of the transformer. Moreover, benefits include better safety by preventing injuries to workers or the public in the event of a catastrophic failure, improved protection of power transformers, and avoiding the potentially large impact by system instability, loss of load, cost of not supplied energy, environmental cleanup, etc.

2.2 Digital Substation

The term *digital substation* has no definition, but refers to substations where data from process level devices is digitised at the source. The exchange of data as well as commands and signals between the process level and the bay level is managed via a communication network where IEC 61850 defines the format for the data and methods for data access and exchange[1]. This communication network is referred to as the *process bus* [10]. The process bus is used to transmit operational data such as current and voltage measurements, control and protection messages and to distribute an accurate time reference to time synchronise the substation devices.

The process bus is basically an Ethernet LAN-network that replaces the copper cables used for measuring and control circuits, which run from the control building to the separate high voltage bays in conventional substations. In digital substations the only copper cables left between the control building and the high voltage bays will be those used for AC and DC power supply circuits.

The interface between the station level and the bay level is a communication network referred to as the *station bus*. The station bus connects the bay level devices to the station level devices, thereby enabling the communication between the two levels as well as peer-to-peer communication between bay level devices. Similar to the process bus, the station bus is an Ethernet LAN-network.

Digital substations also open up for the application of Non-Conventional Instrument Transformers (NCIT), such as Optical Current Transformers (OCT), were current and voltages are measured with other principles than traditional magnetic coupling. In order to integrate conventional instrument transformers into digital substations, Merging Units (MU) are required, which digitize the currents and voltages. This happens close to the field, and MUs are therefore found out in the coupling yard. The topology of a digital substation is shown in Figure 2.3, with the station bus and the process bus marked in dark and light blue respectively. Collection points on the process bus and the station bus are network devices, typically switches, gateways or routers.

[1] The substation levels are explained in Section 4.1.

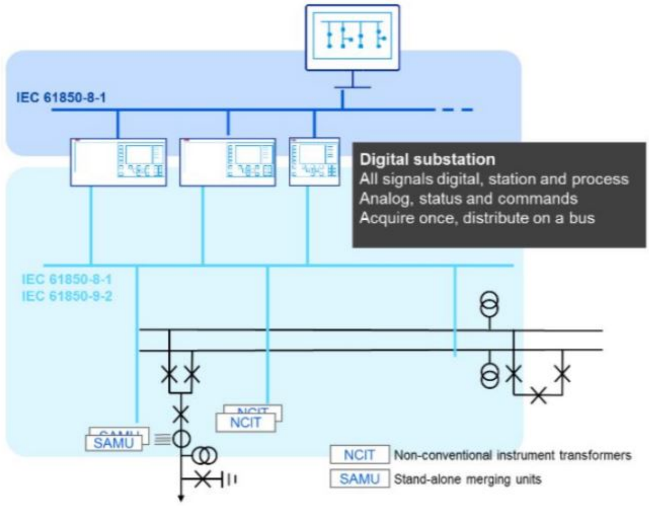

Figure 2.3: Topology of a digital substation [11].

The digital substation brings several benefits:

- Reduces wired copper wires between process and bay devices.
- Makes the work of electrical room panels safer by eliminating high energy signals.
- Reduces the required size of panels and thus also the size of the electrical room in substations.
- Reduces engineering and construction time in addition to less effort is needed for drafting, installation and testing of such systems.

The digital station is still in the development phase, and very few substations today are of this type, both in Norway and abroad, although the concept was introduced more than 10 years ago. In Norway, however, a few pilot digital substations are emerging that include Furuset substation in Oslo operated by Statnett, Tørdal substation in Drangedal operated by Skagerak Nett, and Heggdal substation in Asker operated by Elvia, in addition to a vendor-independent test facility in the National Smart Grid Lab in Trondheim.

2.3 The Condition Monitoring Process

There are basically four criteria that must be fulfilled for condition monitoring

- There is measurable parameter that can indicate failure.
- There is a monitoring technique available.
- Monitoring allows sufficient time to take action after detection of incipient failure.
- There are methods for interpretation of monitoring data.

A complete condition monitoring system will not only gather and present data, but also analyse the data, using intelligent computational methods, to proactively identify pending deficiencies in the monitored equipment.

According to [2] the process of condition monitoring goes through a number of stages that are shown in figure 2.4. Furthermore, the process is described as ”using transformer fundamental knowledge, sensing, data acquisition and processing systems to collect raw or pre-processed data, store it, and translate it to a common actionable output, that describes the unit’s and/or component’s condition, with the use of analytical techniques”.

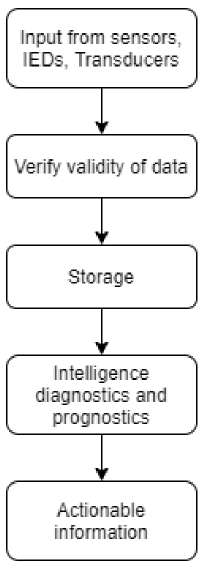

Figure 2.4: Stages in condition monitoring.

Essentially, sensors collect some physical quantity, such as temperature, gas content, moisture concentration etc., and transform the physical quantity to a representative signal in amperes or volts. The data need some primary processing such as conversion or digitisation and must be checked for consistency, to correct for measurement errors and to exclude false information. Distortions, for example due to electromagnetic interference may be identified and removed and missing data may be added. Then, the data must be stored and made available for later use and analysis. Computational intelligence can take this data and further diagnose and come up with prognostics for incipient faults for the transformer, and also execute triggers and alarms in case of a value reaching a threshold. This stage includes models and algorithms, and is based on physical, empirical or statistical relationships between the condition parameters to be determined on the one hand, and the measured data on the other hand. At last, the data must be presented and made available for reporting. The aim is to give the user a list of actions for maintenance, replacement and operation.

2.4 Terminology

Some important jargon for understanding condition monitoring terminology are:

- **Condition** is an expression of the state of the equipment which takes into account its aged state as well as any inherent faults. According to [12], the condition can be categorised into four categories:

  - Normal: no problems and signs of degradation.

  - Defective: no significant impact, but lifetime may be affected in the long term unless maintenance is carried out.

  - Faulty: can remain in service, but short-term reliability likely to be reduced.

  - Failed: Cannot remain in service. Maintenance or replacement is needed, before returning to service.

- **Monitoring** means to measure one or more characteristic parameters. This usually refers to data acquired from sensors, but also include other sources such as the results from periodic tests, visual inspections, etc.

- **Online** means the transformer is energised and in operation.

- **Monitoring facilities** are diagnostic techniques and measurement methods performed on a transformer to analyse its condition. A diagnostic technique can be performed online or offline.

- **Operational data**, also referred to as SCADA data, is instantaneous values of power system analog and status points, such as volts, amps, MW, MVAr, circuit breaker status, and switch position. This data is used to monitor and control the power system, such as opening circuit breakers, changing tap settings, etc.
- **Condition data**, also called nonoperational data, contains information about the condition of a transformer. This data is acquired by diagnostic techniques sensors. Typical examples of data are temperatures, gas-content, moisture-content, partial discharge activity, etc. This data is not directly used for operational purposes of the power system, but for asset management purposes.
- **Surveillance centre** refers to the centre to which condition data are transferred from substations. It is similar to a control room for operational data.
- **Primary device** is a term used for all components that are in the grid conducting power, such as lines, cables, transformers, etc.
- **Secondary device** is a term used for all components that is a part of the substation automation system, and performs control, protection and monitoring functionalities.
- **Maintenance** is defined by [8] as ”the combination of all technical, administrative and managerial actions during the life cycle of an asset intended to retain it in, or restore it to, a state in which it can perform the required function”.
- **IED** is short for Intelligent Electronic Device and is a term used for microprocessor-based equipment. IEDs receive data from sensors and power equipment, and can issue control commands. Also, the terms remote terminal unit (RTU) and data acquisition unit (DAU) are used interchangeably with IED.

Chapter 3

Power Transformers

A *transformer* is in general terms a static electrical device, involving no continuously moving parts, used to transfer power between networks through the use of electromagnetic induction. The power grid consists of a large number of generation plants, distribution points and interconnections, and transformers are used at these points where a change in voltage level is required. The main function is to reduce transmitting losses and supply voltage levels suitable for user-applications. The term *power transformer* refers to transformers used between the generator and the distribution networks, and are typically rated at 500 kVA and above and can be either single-phase or three-phase [13].

Power transformers are rated based on the continuous power output capability at a specified rated voltage and frequency under ”normal” operating conditions, i.e. non-excessive load, without exceeding prescribed internal temperature limitations. The insulation deteriorate with increases in temperature, so the insulation chosen for use in power transformers is based on how long it can be expected to last by limiting the operating temperature.The maximum temperature the insulation is rated for essentially determines the output rating, called the kilovolt-ampere (kVA) rating. Standardisation has led to temperatures within a transformer being prescribed in terms of the rise above ambient temperature, since the temperature can vary under operating or test conditions. Power transformers are very efficient, typically 99.5% or better, meaning real power losses are less than 0.5% of the kVA rating at full load. Transformers are designed to limit the temperature based on the desired load, including the average temperature rise of a winding, the hottest-spot temperature rise of a winding, and the top liquid temperature rise. Absolute temperatures from these values are obtained by adding the ambient temperature. Table 3.1 lists standard temperature limits [13, 14].

Average winding temperature rise	65°C
Hot spot temperature rise	80°C
Top liquid temperature rise	65°C

Table 3.1: Standard limits for temperature rises above ambient [13].

Studies show that power transformers have the potential for long lifetimes, around 80 years, under ideal conditions with low load, proper cooling and low water penetration [15]. Despite this fact, manufacturers often define the expected lifetime of power transformers to be between 25 and 40 years [16]. According to experts in Statnett, they expect a minimum lifetime of 60 years during normal operation, and with maintenance performed on the transformer. Some subparts of the transformer, such as as the bushings, typically need to be replaced after about 30 years. The time for reinvestment is determined by condition monitoring and assessment.

Certain conditions such as overloading, through-faults, emergency rerouting of load or unusual service conditions may result in ”loss of life”. Unusual service conditions include, ambient temperature being above 40°C or below -20°C, altitudes above 1000 m above sea level, seismic conditions, and loads with total harmonic distortion above 0.05 per unit [13].

The main functions or rather abilities of a power transformer can be summarised as follows:

- The ability to *conduct current* without overheating.
- The ability to *isolate* parts at voltage potential from earth and from each other, often divided into a main isolation between windings and windings and ground, and sub-isolation between turns.
- The ability to *withstand* mechanical forces from electromagnetic forces during nominal operating conditions and at short circuit.

3.1 Subparts and Ageing Mechanisms

The power transformer consists of a collection of subparts. In this way it is possible to relate which subpart a fault or an ageing mechanism can be associated with. Figure 3.1 shows an illustration of a power transformer. It is common to divide the power transformer into:

- Core
- Windings
- Tank and oil
- Bushings
- Tap-changer
- Ancillary equipment such as coolers, fans and pumps

These subparts have various ageing and fault mechanisms. Ageing mechanisms refer to gradually occurring defects over long time, typically a few tens of years, while fault mechanisms refer to sudden, fast occurring defects. Ageing mechanisms can develop or be accelerated from initial defects, natural deterioration processes, or by operating conditions that exceed the capability of the transformer. When an ageing mechanism has deteriorated the transformer to such a degree that the transformer can no longer operate, faults occur. Deterioration processes may take many years to gestate before developing into a

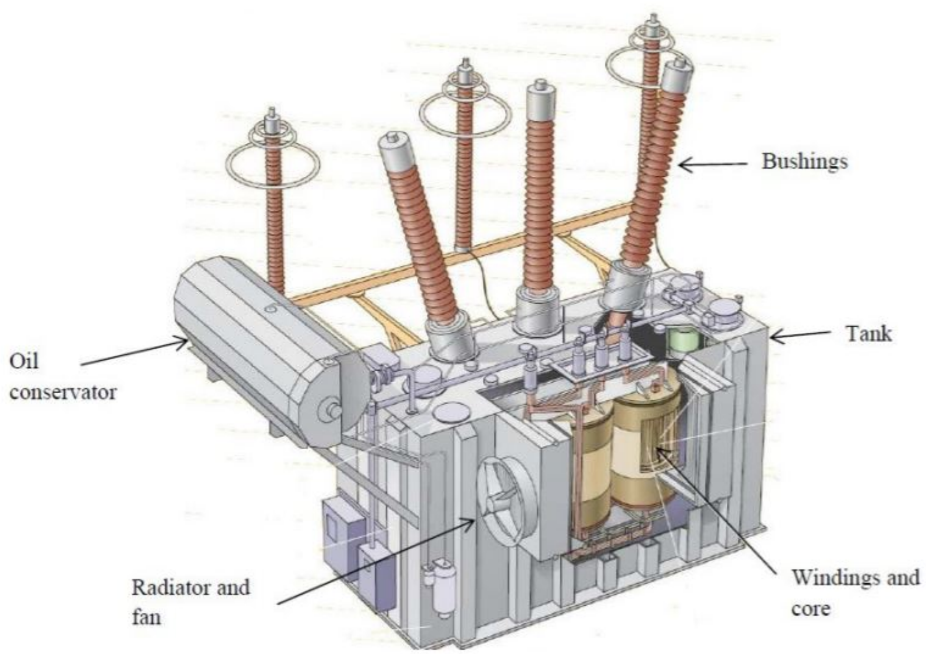

Figure 3.1: Illustration of a transformer [17].

fault. Common ageing mechanisms are presented and discussed in detail in the "Transformer Handbook" by the *Norwegian Group for Users of Power and Industrial Transformers* [18, 19, 20, 21, 22].

The stresses a transformer is exposed to can be categorised into:

- *Thermal stresses:* Usually over-temperatures. Cause accelerated degradation of insulation. The transformer is dimensioned for thermal stresses from magnetic losses, which are load independent and copper loss that are load dependent.
- *Electrical stresses:* Arise from the impact from high electrical fields on the insulation system and this can be a wide range of phenomena from partial discharges to full through-fault caused for instance by alternating voltage stresses or transient lightning surges.
- *Mechanical stresses:* Typically impact a transformer during transport, at greater transient currents like inrush and especially short-circuit. Stresses associated arising from changes of tap-changer position will cause contact wear and tear to contacts that will require maintenance.
- *Chemical stresses:* Is first and foremost the impact from oxygen and water that combined with high temperature give accelerated ageing of insulation.

Of critical importance to the ageing and life expectancy of the transformer is the condition of the insulation system. The insulation system is typically constructed of organic products, including mineral oil, cellulose paper, and cellulose pressboard. The organic products in the transformer degrade with time and eventually can no longer withstand the mechanical and dielectric stresses which often lead to transformer failure. It is not possible to eliminate the ageing process, but good maintenance practices which control the ageing factors can help prolong the service life of the transformer [19].

High temperatures result in decomposition and ageing of the insulating paper and oil in the transformer. Oil molecule bonds can break, and generate free particles. The interactions between these particles and external molecules form by-products. Common products are water, acids and dissolved gases formed due to contact with oxygen or copper and iron. This results in a reduction of the oil quality. The acids also trigger the decomposition of paper, which results in the production of water. This whole process is self-reinforcing as acids also cleave the oil molecules, and water in oil reduces the strength and further degenerates the oil. This leads to reduced service lifetime and reliability of the transformer. Actions including filtering or drying of the oil, or alternatively replacement, are done to improve the oil quality. On the other hand, the paper can not be repaired. A radical rehabilitation or replacement of the transformer is therefore necessary if the paper has poor quality. The paper is also subject to faster ageing than the oil. The strength of the paper is therefore considered to be the final limiting factor for the remaining lifetime of the transformer [21].

A list of ageing mechanisms of various components with associated measurable parameters are provided in Tables 8.3, 8.4, 8.5, 8.6, and 8.7 in appendix B.

3.1.1 Core

The transformer core's task is to conduct the magnetic field between the windings with least possible losses. It is therefore important with high permeability and low conductivity in the core material. High permeability is achieved through using iron added silicon ($\sim$3%) and mangansulfid or aluminium-nitrate. Low conductivity is achieved by removing carbon and addition of silicon. The core is constructed by thin steel laminations with a 0,2 to 0,3 mm thickness that are put together [20].

Ageing mechanisms are short-circuits between the laminations, resulting in circulating current called eddy-currents, that heat up the transformer. Usually some spots are being more heated than other spots in the core, and these spots are referred to as "hot-spots". Over time, this may speed up the degradation of the insulating materials. In addition, if the initial grounding of the core is gone, this may result in partial discharges.

3.1.2 Windings

There are usually two windings per phase that consist of the current-carrying conductors wound around the core. The windings are insulated from each other and the core by use of cellulose paper and pressboard. Windings are made of copper or aluminium conductors wounded in several layers of kraftpaper [19].

Ageing mechanisms are characterised by degradation of the winding insulation or the winding conductor which can result in electromechanical breakdown or partial discharge activity. Short-circuits or high losses can occur as a result from electromechanical forces, usually lightning, or from weakened insulation due to formation of cavities or water content in the paper insulation or gas bubbles within in the oil. Winding ageing mechanisms are considered to be the most critical as maintenance is often costly and takes a long time, and requires the transformer to be taken out of service.

3.1.3 Tank and Oil

A transformer tank is a metal container that is leakage proof that is filled with oil. The tank prevents moisture ingress into the oil. Usually mineral oil is used, as it has great insulating properties. Due to that the oil is a liquid, it can be circulated within the tank as a means of cooling the transformer, serving as an effective liquid to transport heat away from the active part[1] [20].

Ageing mechanisms are mainly related to the content of gasses and chemical compounds in the oil, as the higher the concentration of these, the lower the insulating quality.

3.1.4 Tap Changer

A tap changer is a component that is connected to the transformer to allow for variable turn ratios such that the voltage on the secondary side can be regulated to different levels. This is done by connecting to a number of access points known as taps along either the primary or secondary winding. Two types exists, one which can be operated under load, so-called on-load tap changer (OLTC[2]) and one which has to be off-line and de-energised to be operated (DETC[3]) [18].

Ageing mechanisms are characterised by contact coking of a tap or mechanical wear and tear of the switching mechanism.

3.1.5 Bushings

Bushings are insulated devices that allow the current from the external electrical grid to pass safely through a grounded conduction barrier such as the transformer tank to the active part. Bushings are typically made from porcelain [22].

Ageing mechanisms are air pollution of the bushings, oil leaks, bad connections within the bushings, loose field distributors and physical damage. Too severe ageing mechanisms can lead to short-circuits, high losses or outage.

[1] The term *active part* refers to the subparts that are in contact with the voltage and current and comprise core, windings, tap changer and bushings. The term may also refer only to core and windings.

[2] OLTC is called *lastkobler* in Norwegian.

[3] DETC is called *omkobler* in Norwegian.

3.1.6 Auxiliary Equipment

Auxiliary equipment is used to optimise operation and minimise risk of failure, and cooling is the main function. Cooling equipment typically comprise coolers (radiators), fans and pumps. In addition a gas relay called Buchholz relay is often mounted on top of the transformer to detect and trip the transformer in case of too high gas concentration. There are in addition many protection and monitoring facilities that can be mounted on the transformer, to be used for operational or condition monitoring purposes, such as protection relays and sensors.

Regarding cooling, there are different cooling methods available for a transformer. The most common ones are the ”oil natural air natural” (ONAN) and ”oil natural air forced” (ONAF) cooling systems. For ONAN, the oil and air is circulated without any forced measure, but for ONAN, the air is circulated through fans. Some transformers can switch between these two methods.

3.2 Failure Causes

An international survey conducted by Cigré presented in [23] analysed failure causes with respect to subparts of the transformer. The survey shows that winding, tap changer and bushing related failures were the major contributors, followed by lead exit related failures. The survey shows a difference in failure locations related to voltage level. Windings stood for 89% of the failures in transformers with voltages lower than 100 kV. Bushing related failures increased with increasing voltage. Tap changer related failures appeared to decrease with increasing voltage level. For transformers rated 100 kV and above, failures were predominantly caused by winding, 40% and tap changer, 27%. Figure 3.2 shows the failure locations for transformers rated at 100 kV and above, and is based on 675 major failures.

Winding and bushing failures correlate with aged insulation. The lifetime of a transformer is therefore highly dependent on its insulation condition. The ageing rate for oil and paper is strongly influenced by temperature. It is therefore important to keep the operating temperature as low as possible by ensuring that the cooling system is functioning properly.

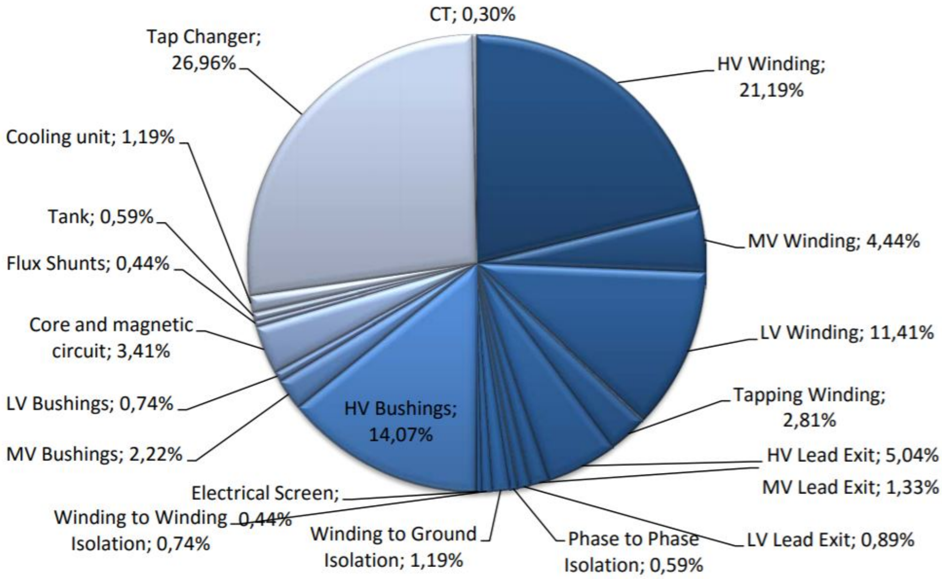

Figure 3.2: Failure causes of transformers [23].

3.3 Diagnostic Techniques

The primary objective of transformer diagnostic techniques is to monitor basic parameters which cause ageing and degradation. Various parameters of transformers using diagnostic techniques can be monitored with available sensor technologies. This section describes various methods to monitor power transformers.

3.3.1 Dissolved-Gas-in-Oil Analysis

Dissolved-gas-in-oil analysis (DGA) is a reliable diagnostic technique for the detection of incipient fault conditions. DGA has been widely used throughout the industry as the primary diagnostic tool for transformer monitoring. As a result, information relating certain fault conditions to various gases that can be detected and easily quantified by gas chromatography has been developed. Table 3.2 shows the gases that are generally monitored and their significance.

Existing technology can determine gas type, concentration, trending, and production rates of generated gases. Information of the rate of change of gases dissolved in oil is useful in determining the severity of a developing fault. The application of online DGA monitoring

Gas	Chemical Formula	Predominant Source
Nitrogen	N_2	Inert gas blanket, atmosphere
Oxygen	O_2	Atmosphere
Hydrogen	H_2	Partial discharge
Carbon dioxide	CO_2	Overheated cellulose, atmosphere
Carbon monoxide	CO	Overheated cellulose, air pollution
Methane	CH_4	Overheated oil (hot metal gas)
Ethane	C_2	Overheated oil
Ethylene	C_2H_2	Very overheated oil (may have trace of C_2H_2)
Acetylene	C_2H_2	Arcing in oil

Table 3.2: Gases typically found in aged transformer oil [13].

can considerably reduce the risk of a failure. For critical transformers, it can provide timely and continuous information in a manner that permits load adjustments to prevent excessive gassing. This may keep a transformer operating for many months while ensuring that safety limits are observed. An example is that maintenance or replacement of a transformer can be delayed to the summer when loads are usually lower, instead of during the winter when loads are usually higher.

DGA sensor technologies are [9]:

- *Fuel cell/catalytic technology* uses membranes to separate dissolved gases and generate voltage signals that correlates to types of gases and their concentrations.
- *Solid state sensor* uses membranes to separate gases or can be directly immersed in oil.
- *Thermal conductivity detection (TDC)*, uses membranes to separate gases.
- *Multi-gas* uses gas chromatography, Fourier transform infrared spectroscopy (FTIR) or photo-acoustic spectroscopy (PAS).

3.3.2 Moisture in Oil

Moisture in the cellulose/liquid insulation reduces the dielectric strength of the transformer. A sample of the oil is analysed and evaluated with the sample temperature and the winding temperature of the transformer. This combination of data can determine the relative saturation of moisture in the cellulose/liquid insulation. As the transformer warms up, moisture migrates from the solid insulation into the fluid. The rate of migration is dependent on the conductor temperature and the rate of change of the conductor temperature.

As the transformer cools, the moisture returns to the solid insulation at a slower rate. The time constants for these migrations depend on the design of the transformer and the solid and liquid components in use. The combination of moisture, heat, and oxygen are the key conditions that indicate accelerated degradation of the cellulose. Excessive amounts of moisture can accelerate the degradation process of the cellulose and prematurely age the transformer's insulation system [13].

Sensors monitors the relative humidity (RH), which is a more meaningful measure than parts per million (ppm). The conservator membrane in a transformer isolates the oil from the air as the oil expands and contracts. The integrity of the membrane can be monitored with sensor systems that detect air on the oil side or oil on the air side of the membrane [24].

3.3.3 Partial Discharge

A significant increase in the partial-discharge (PD) activity can provide an early indication that changes are evolving inside the transformer. Partial discharges will produce hydrogen gas dissolved in the oil. The PD sources most commonly encountered are moisture in the insulation, cavities in solid insulation, metallic particles, and gas bubbles generated due to some fault condition. PD sensors identify the apparent discharge magnitude and phase position of each pulse, number of pulses per cycle, and peak discharge magnitude. The interpretation of detected PD is not straightforward. No general rule exist that correlate the remaining life of a transformer to PD activity [13]. Two methods are used for PD detection, electrical and acoustic.

Using the electrical method, the electrical signals from PD are of the form of a unipolar pulse with a rise time that can be as short as nanoseconds. The signals exhibit a very wide frequency content. The detected signal frequency is dependent on both the original signal and the measurement method. A method to interpret PD signals is to study their occurrence and amplitude as a function of the power-phase position, called the phase-resolved PD analysis (PRPDA). Electric PD detection are generally hampered by electrical interference, and any monitoring method must minimise the influence.

Using the acoustic method, the sensitivity can be shown to be comparable with electric sensing. Acoustic signals are generated from bubble formation and collapse during the PD event, and these signals have frequencies of approximately 100 kHz. The high frequencies are generally attenuated during propagation and due to limited propagation velocity, acoustic signals are commonly used for location of PD sources. The main advantage of acoustic detection is that disturbing signals from the electric network do no interfere with the measurement. However, external influences in form of wind or rain, loose parts and cooling fan may interfere.

3.3.4 Temperatures

As mentioned, transformer failures can be caused by overheating. Monitoring of the top-oil, bottom-oil and ambient temperatures are vital factors in evaluating the condition. These temperatures in addition to load current, fan/pump operations, and direct readings of winding temperatures, if available, can be combined in algorithms to determine hottest-spot temperature and manage the overall temperature conditions of the transformer. Temperature sensor technologies include [9]:

- *Resistance thermometer detectors (RTD)* are temperature resistors. Pt100 is a commonly used RTD type, which has a resistance of 100Ω at °C, with a resistive slope of 0.385Ω /°C. The sensor can be 2, 3 or 4-wired, of which 4-wired provides the best accuracy.
- *Thermocouples sensors* are made of two conductors with different metals that with different temperatures will induce a voltage field, which is proportional to the temperature difference.
- *Fluorescence decay time sensors* use a pulse sent through optical fibre to a phosphor sensor that can based on the wavelength of the pulse measure the temperature.
- *Absorption shift of semiconductor crystals sensors* use a semiconductor crystal that shift its light transmission spectrum to increasing wavelengths at increasing temperatures.
- *Distributed temperature sensor (DTS)* measure the spatial temperature distribution along an optical fibre.
- *Thermal imaging* uses an infrared camera to monitor the temperatures across the whole transformer.

3.3.5 Winding Temperatures

There is a direct correlation between winding temperature and expected life of a transformer. The hottest-spot temperature of the winding is one of a number of limiting factors for the load capability of transformers. This can result in tearing and displacement of the paper and dielectric breakdown, resulting in premature failures. Conventional winding temperature measurements are not typically direct; the hot-spot is indirectly calculated from oil temperature and load current measurements [25].

Fibre-optic temperature sensors can be installed on the winding only when the transformer is manufactured or rebuilt. Two types of sensors are available: optical fibres that measure the temperature at single points and distributed optical fibres that measure the temperature along the length of the winding.

3.3.6 Load Current and Voltage

Maximum loading of transformers is limited by the temperature to which the transformer and its accessories can be exposed without excessive loss of life. Monitoring of current and voltage in combination with temperature measurements can provide a means to evaluate thermal performance. Load current and voltage monitoring can also automatically track the loading peaks of the transformer, increase the accuracy in distribution-system planning, and aid in dynamically loading the transformer.

The current and voltage are monitored by use of instrument transformers. These can be conventional (CIT) or non-conventional (NCIT). Typically, NCITs do not provide the standard analog 1 A/5 A or 110 V output as CITs, but require digital conversion. As such, the introduction of the merging unit together with the process bus simplifies the integration of NCITs into substations [26].

3.3.7 Insulation Power Factor

The dielectric loss in any insulation system is the power dissipated by the insulation when an ac voltage is applied. All electrical insulation has a measurable quantity of dielectric loss, regardless of condition. Good insulation usually has a very low loss. Ageing of an insulating material causes the dielectric loss to increase. Contamination of insulation by moisture or chemical substances can cause losses to be higher than normal. Physical damage from electrical stress or other outside forces also affects the level of losses.

When an ac voltage is applied to insulation, the leakage current flowing through the insulation has two components, one resistive and one capacitive. The power factor is a dimensionless ratio of the resistive current I_r to total current I_t flowing through the insulation, depicted in Figure 3.3, and is given by the cosine of the angle θ. The dissipation factor, also known as tanδ, is a dimensionless ratio of the resistive current to the reactive

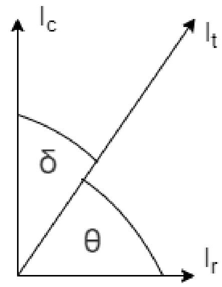

Figure 3.3: Power factor representation.

current flowing through the insulation and is the tangent of the angle δ.

3.3.8 Pump/Fan Operation

The most frequent failure mode of the cooling system is associated with failure of pumps and fans. Monitoring of pumps and fans shows if they are on when they are supposed to be on and are off when they are supposed to be off. This is accomplished by measuring the currents drawn by pumps and fans and correlating them with the measurement of the temperature that controls the cooling system. This can also be accomplished by measuring pump/fan current and top-oil temperature.

3.4 Monitoring Recommendations

There are a large number of available diagnostic techniques available for power transformer monitoring. The set-up can be customised to the size, age, condition, environment and criticality of the power transformer. [27] provides recommendations for monitoring which is presented in Table 3.3. The monitoring facilities are arranged into three levels, where level 1 is the minimum set of sensors required to provide basic monitoring of the transformer, level 2 provides a good level of monitoring, and level 3 provides a comprehensive level of monitoring.

	Sensor	Level 1	Level 2	Level 3
Active part	Top oil temperature	fit	fit	fit
	Bottom oil temperature		facility	fit
	Gas-in-oil content	facility	facility	fit
	Moisture in oil		facility	fit
	Oil level in conservator alarm		fit	fit
	Multiple gas monitor		facility	facility
	Partial discharge sensor		facility	facility
	DC neutral current			facility
Cooling unit	Cooling medium temperature		facility	fit
	Cooler operation		fit	fit
	Cooler inlet oil temperature			fit
	Cooler outlet oil temperature			fit
Bushing	voltage at bushing tap	facility	facility	fit
	Load current	fit	fit	fit
	Oil pressure			fit
OLTC	Tap-position	facility	fit	fit
	Active power consumption of motor drive		facility	fit
	Diverter switch compartment oil temperature		facility	fit
	Selector compartment oil temperature		facility	facility
	Main tank temperature near tap changer			fit
	Diverter oil level indication			fit
	Diverter oil level alarm		fit	fit

Table 3.3: Recommended condition monitoring facilities [27].

Chapter 4

Condition Monitoring Systems

The information, communication and sensing technologies are continuously developing and includes a variety of sensors, IEDs, servers and comprehensive monitoring systems with different levels of complexity and capability. Therefore many types of condition monitoring systems exists and there is, according to [1], no common practice among users on how condition monitoring systems are set up.

Systems range from relative simple stand-alone systems that monitors just a few parameters on just one or a few transformers, to complex systems that are integrated into the substation automation system that can monitor many parameters of a fleet of transformers.

Condition monitoring has in the past generally been performed on a stand-alone basis and just been associated with the transformer itself. As with protection and control (P&C), that were separated 20 to 30 years ago, they are now generally integrated. Similarly, condition monitoring is now evolving to become integrated into the P&C system. Such integrated condition monitoring would enable data collected from the P&C system, known as SCADA data or operational data to be harnessed for condition monitoring purposes. Therefore, monitoring should not be considered an individual system, but rather as an integrated that is a part of the overall substation automation system [28]. On the other hand however, when condition monitoring becomes integrated with the substation automation system and share channels with P&C channels, reliability and security are important considerations.

Despite the variety of condition monitoring system architectures a function-based generic view can be used to represent all functions of a condition monitoring system, and is shown in Figure 4.1.

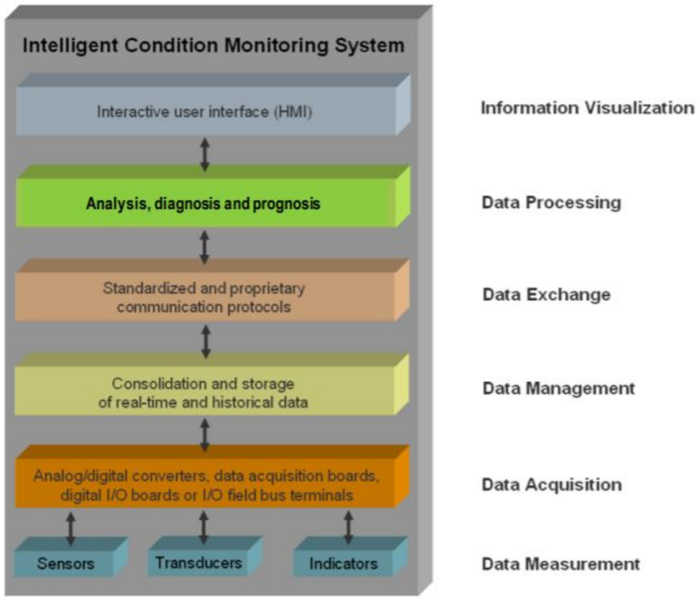

Figure 4.1: Function-based generic view of condition monitoring systems [2].

Components related to condition monitoring such as sensors, IEDs, servers, etc. should be able to communicate and share measured and analysed data by means of standardised interfaces, common input and output data and communication protocols. The aim is to achieve interoperability between components from different vendors.

4.1 Levels of Architecture

The architecture of a substation is divided into four levels that are shown in Figure 4.2. The process level, which is the closest level to the monitored equipment, i.e. the transformer, consists of primary devices, such as current and voltage transformers and sensors. They acquire condition data and operational data. This data is sent to a bay level device, typically an IED or RTU. These devices can be dummy or intelligent, depending on whether they perform some kind of processing on the input data or not. Data from bay level devices is forwarded to the station level, where the data can be stored in a database server, be processed and presented on a computer and/or sent onto a wide area network (WAN) via network devices. The data ends up in the surveillance centre where additional processing may be used for analysing the data. A human machine interface (HMI) presents the data to the asset manager which then may take appropriate actions based on the data. The set up of devices are arranged into different types of systems.

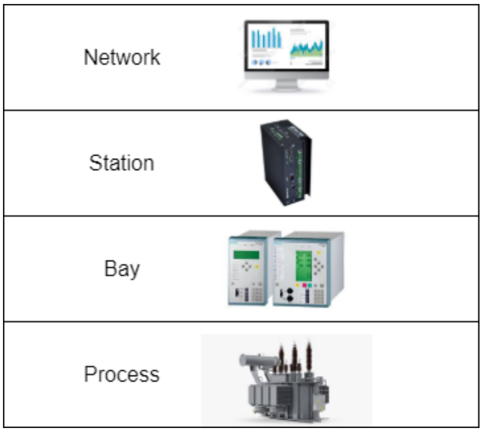

Figure 4.2: Communication levels.

4.2 Input and Output Data

The condition monitoring system's input and output data should be modeled in a standardised and modular way. An approach is to consider the output functionalities to be delivered and then what sensor and input data is required to fulfill the requirements. This chapter is presenting further details of this generic approach, such as details on output and input data, data sources which can be used for condition monitoring, including specific aspects related to data standardisation and IEC 61850.

4.2.1 Output Data

Output data of a condition monitoring system can be categorised into several categories which further may be characterised by a group of attributes as shown in Table 4.1 [2]. The output data should in general provide information that can be directly used to base decisions on. Data can consist of statuses or warning of any incipient faults and what subpart this is associated with and to what severity degree this is. Therefore it is also useful to identify who is the user, what reaction time is needed and follow-up actions to be considered. The table also includes some examples.

Output category	**Example**	**User**	**Main reason**	**Information content**	**Possible impact**	**Urgency**	**Follow-up actions**	**Comment**
Safety status								
	Increased level of acetylene	Maintenance personell	Avoid fault	Stop access to transformer	Extreme	Immediate	Judge unit turn off	Sparking, flashover are possible
Operation Capability								
	Top oil temperature too high	Operator, maintenance, personell	Operation of the transformer	Operate up to load value	Medium	Immediate	Control load to limits, check cooling	Operation limitations
Maintenance General Warning								
	Moisture or gas in oil	Maintenance personell	Maintenance team receives a general information	Warning, reminder, mail, SMS	Medium	Near term, Medium term	Diagnostics, oil treatment	Consider outage for oil treatment
Maintenance Specific Warning								
	Change in bushing health	Maintenance personell	Maintenance of a specific part of system	Warning, reminder, mail, SMS	High	Immediate, near term	Diagnostics replacement	Information is specific to part
Asset Management								
	High loading over time in service	Asset management	Asset managment planning	Reminder	Low	Long term	DP investigation, decision on future; maintenance or replacement	Ageing of unit

Table 4.1: Example of possible output categories [2].

4.2.2 Input Data

The data usable for condition monitoring depends on the sensing devices, existing systems, communication architecture, and strategy of the utility. The goal is to have input data which can be used in evaluation models in order to relate detectable deterioration to failure modes. As an example, Figure 4.3 shows a system where input come from sensors, the supervisory and data acquisition (SCADA) system, and history database. An important remark related to data quality is that any monitoring system is only as good as the input data.

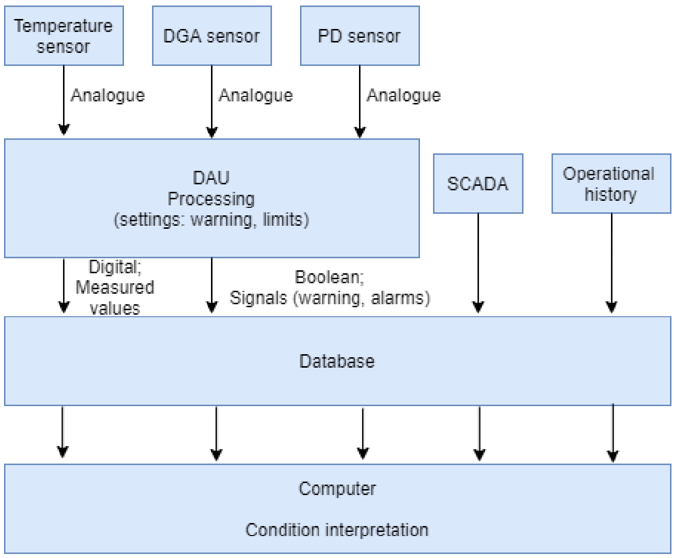

Figure 4.3: Example of data inputs [2].

4.2.3 Sources of Input Data

Sources of input data for a condition monitoring system depends on the sensing and monitoring devices and the data and communication architecture. Effort is made to acquire data which can be used in algorithms or models of a condition monitoring system, and should be closely related to detectable failure modes. The data can represent a single transformer or a fleet of transformers. In addition to sensor data, sources of input data may also comprise utility information systems, such as service history data or data collected during maintenance work on a transformer.

Data Acquired On The Transformer

The most important source of data comes from the power transformer by means of sensors. This data consists of measurable parameters that indicate the transformer's condition, and include oil temperatures, dissolved-gas-in-oil analysis, partial discharge activity, etc. The aim is to achieve a good representation of the condition by using the fewest possible sensors.

Operational data may also be included from the substation automation system, for instance the SCADA system, and serve as a complement to condition data acquired by sensors on the transformer. A good example is if the transformer is only equipped with a single gas sensor, then it may be useful to store measured loads, i.e. currents and voltages, coming from SCADA in the common monitoring database in order to interpret the gas concentration levels in context of the load.

Other data may come from protection relays and fault recorders. This data usually comes from unexpected events, for instance a phase-to-ground fault. This data can be used for monitoring of various events and situations on the transformer. An example might be the use of this data for analysing transformer trips triggered by protection relays or in case of electronic fault recorders to analyse switching processes. Continuous digital high resolution sinusoidal records might be used for phase angle tanδ measurement or bushing monitoring.

Investigation of an event, such as a transformer trip, can be eased by using data from distant devices located in adjacent parts of the network, for instance short circuits, transformers overloads caused by failures occurring in neighbouring substations. This data is usually not used for direct transformer monitoring, but may serve to clarify some unexpected events influencing the monitored transformer [2].

Data From The Utility Systems

Nameplate data is useful as computational models require a set of transformer nameplate data such as limits allowed, nominal load and voltage ratings, constants etc. In addition, service history data such as events, relocations and changes in service conditions are stored in a utility's system, and comprise all changes and events on the transformer, such as repairs, relocations, and service condition changes, provides a more knowledge of the in-service history and is important for any assessment of the technical condition of a transformer. Such data may also include average load, number of short circuits, past overloads, change of tap changer contacts, etc. All these sources provide an additive amount of information [2].

Data collected during maintenance or diagnostic works comes from regular maintenance activities. Maintenance can be preventative or corrective where the former provides data on the overall technical condition and the latter provides data on findings made during operational or maintenance checks. Such data may also contain works and changes done on a particular transformer as well as repairs, subpart replacements and relocations. A good practice is to store maintenance activities performed over time such as addition of oil, replacement of oil, filtering and/or degasification of oil.

Data from diagnosis and testing activities on the transformer and its components is valuable for evaluating the transformer evolution. Such data stem from tests before delivery, tests during commissioning or after on-site repair, or any off-line diagnostic testing method normally carried out such as: winding ratio tests, insulation resistance test, insulation power factor and capacitance tests on the windings, insulation power factor and capacitance tests on all bushings, winding resistance tests, or DGA analysis.

At last, data about a transformer's importance can also be included in a condition monitoring system. Such data can include the transformer's importance which is based on a N-1 criteria, what kind of customer is supplied, for instance industry or household, and possible consequences of failure which can be regarded in terms of cost of energy not supplied and cost of recovery.

4.3 Types of Condition Monitoring Systems

There are several ways of implementing a condition monitoring system. The systems differ in terms of complexity and degree of centralisation, meaning whether the system is local to the monitored transformer or integrated into a larger network, which can comprise several transformers from different substations and also collect operational data from the SCADA system. According to [27] systems can be categorised into stand-alone systems, systems using IEDs for data exchange to a centralised computer, and integrated systems that is a part of the overall substation automation system.

There is no right or wrong type of system as each of them are appropriate to their extent. For example data from a partial discharge sensor which requires a sophisticated local measurement and processing system may favour a stand-alone monitoring system whereas a system such as one for thermal monitoring requiring slowly changing inputs from many standard sensors may favour an integrated monitoring system. Besides technical selection criteria, other aspects may play a role in determining the monitoring architecture. For instance, in case of larger utilities operating many transformers, a comprehensive integrated system would be appropriate. However, for smaller utilities, a stand-alone solution with access for information visualization via a web-interface, might be more reasonable.

4.3.1 Stand-Alone Systems

Stand-alone systems are local to the transformer and this is technically the simplest type, and consists only of sensors and an IED that is directly mounted on the transformer tank, in the transformer cabinet or the tap changer. Sensor data is acquired by a central monitoring unit equipped with a microprocessor and communications link for external data access. The IED can monitor either a single parameter or many parameters and can be equipped with data storage, diverse analysis and diagnosis tools, data download and configuration features and a web-based visualisation software. The IED may be connectable to a network via standardised physical interfaces to support proprietary protocols or standardised communication such as IEC 60870-5-104 or IEC 61850.

4.3.2 Systems Using IEDs for Data Transfer

Sensors transmit data to a central monitoring unit, which further transmit data to an IED, and then further to a substation computer or via WAN to the surveillance centre. Only sensor data acquired on the transformer is collected. A system using IEDs for data exchange can integrate a single or a multitude of monitoring sensors for one or several transformers. The entire functionality and intelligence can either be implemented in one central monitoring unit per transformer or can be designed on a modular base and be allocated in various interconnected IEDs that cooperate. Furthermore the functionality can also be combined with a monitoring server installed at the station level. The acquisition of multiple parameters allows the analysis and assessment of the condition of the transformer to be more effective. Moreover, data acquired from a fleet of transformer can provide useful correlations of all relevant data of the transformer or even between several transformers.

4.3.3 Integrated Systems

Integrated systems form an integral part of the overall substation automation system. Sensors transmit data to a central monitoring unit which forwards the data to an IED, which further forwards the data to a substation computer and/or server and to the surveillance centre via WAN. Such systems integrate both condition data acquired on the transformer, operational data and data acquired from utility systems. Therefore, such systems would enable evaluation of transformer's condition in relation to operating condition, i.e. the load. Though there are restrictions concerning the use of operational data for other applications than control and protection, possibilities can be found to provide an isolated mirror image of operational data using read-only, for example by means of the process bus. Such a system can monitor one or several parameters for a single or a fleet of transformers. This issue is further presented in Section 5.4.1.

4.4 System Components

The substation architecture levels have specific components associated with them. The characteristics of them vary in terms of input and output signal types, internal processing and storage capabilities, electrical interfaces and communication link options.

4.4.1 Sensors

Sensors measure electrical, chemical, and physical signals of the transformers. Sensors are naturally located at the transformer collecting data about a measurable parameter or status. Standard sensor output signals are often analogue with 4 to 20 mA, 0 to 1 mA, and 0 to 10 volts levels. Another category of sensors communicates in serial format, typically by means of the electrical interfaces RS 232 and RS 485, or by standard protocols such as IEC 61580, Profibus, DNP 3, or by proprietary protocols. Communication media comprise copper, optical fibre, Ethernet and wireless. The sensors can be directly connected to the IED via point-to-point connections. Data transfer is triggered by a predefined event, such as a signal reaching a threshold, or the changing of a status. The transfer can also be initiated by a frequency, for instance once per hour. Sensors are typically placed in rough environments and must operate reliably to deliver good data for detection of ageing mechanisms and incipient faults. The sensor lifetimes are shorter than the primary equipment, and needs to be replaced several times before the transformer itself. It is also recommended to use an independent power supply circuit [9, 13].

4.4.2 Bay Level Devices

Bay level refers typically to IEDs or RTUs, but may also refer to data acquisition unit (DAU). They monitor and control devices which essentially acquire, process and store information from one or multiple sensors. They are generally microprocessor based and can be triggered to start to record an event, store the event and forward it to a computer. Typical functionalities are:

- Conversion (from current to voltage)
- Digitisation (from analog to digital)
- Scaling
- Routing
- Consistency check
- Detect measurement errors

Bay level devices may also have the functionality of processing data to produce condition information, triggers and alarms. This processing may include computational intelligence in the form of models and algorithms, that is configured into the device, that trends and evaluate the condition of monitored transformers. Data storage can also be facilitated, but due to typically small data memory, data should only be stored for a short time. The data can be useful in the event of a system failure, for instance caused by a lost connection. Similar to sensors, data transfer is triggered by a predefined event, such as a signal reaching a threshold, or the changing of a status, or be initiated on a time-based schedule, for instance once per hour. They can communicate on a ”horizontal”, peer-to-peer basis with other bay level devices. Typical communication standards and protocols supported include Modbus, DNP 3, IEC 60870-5-101, or IEC 61850, or proprietary protocols. Protocol converters or gateways can be used to convert data from one protocol to another. Bay level devices often support a range of communication standards and protocols. Multiple communication media are often supported such as Ethernet links, and serial links RS-232, RS-422 and/or RS-485 [29].

Bay level devices are also used for protection and control functions, as they can issue control commands, such as tripping of circuit breakers if they sense voltage, current, or frequency values exceeding a threshold, or raise/lower voltage levels by means of the tap changer. This is generally controlled by a setting file. Bay level devices can also have the capability to merge condition data and operational data.

4.4.3 Station Level Devices

Bay level devices typically send data to station level devices which are used for storage, processing, and presentation of the condition of the transformer. Typical devices include computers and servers. Computers are used for storage and processing, and servers may be added to provide extra storage and processing functionalities. Servers are typically used for comprehensive systems with many sources covering a fleet of transformers. The computer may be an integral part of the bay level device or can be located separately in the substation or at the surveillance centre. Communication supported can include Modbus, DNP 3, IEC 60870-5-101, or IEC 61850, or proprietary protocols. The computer is based on standard technology and manages the bay level devices and also acts as the data and communication server to the user-interface software.

4.4.4 Network Devices

Data can be transferred via a variety of communications networks such as LANs or WANs. Networks may be wired or wireless. There is a number of devices that can facilitate the data transfer and include [29]:

- Repeaters
- Routers
- Gateways
- Switches

Repeaters simply retransmits an incoming electrical signal. This means amplifying and retiming the signal received on one segment onto all other segments. All segments need to operate with the same media access mechanism and the repeater is unconcerned with the meaning of the individual bits in the data. Collisions, truncated packets or electrical noise on one segment are transmitted onto all other segments.

Routers are used to transfer data between two networks that have the same network layer protocols (e.g. TCP/IP), but not necessarily the same physical or data link protocols. The routers maintain tables of the networks to which they are attached and to which they can route messages. Routers use the network (IP) address to determine where the message should be sent, because the network address contains routing information. Routers maintain tables of the optimum path to reach particular network and redirect the message to the next router along the path [30].

Gateways are designed to connect dissimilar networks. A gateway may be required to decode and re-encode all seven OSI[1] layers of two dissimilar networks connected to either

[1]The OSI model is explained in the introduction of chapter 5.

side. Gateways thus have the highest overhead and the lowest performance of the internetworking devices. For example, a gateway translates from one protocol to the other and handles difference in physical signals, data format and speed.

Switches enable direct communications between multiple pairs of devices in full duplex mode. Full duplex mode means that two parties can communicate in both directions with each other simultaneously, i.e. transmit and receive data simultaneously. Thus it is not restricted by the limitations imposed by classical Ethernet architecture. Switches enable specific and discrete data transfers to be accomplished between any pair of devices on a network, in a dedicated fashion. The switch must be able to detect, from the packet header, the Ethernet destination address, and effect the required port connection in time for the remainder of the packet to be switched through.

4.5 Processing

To effectively monitor numerous assets it is essential to provide basic parameter monitoring combined with more complex condition monitoring algorithms. Some types of data can be used in the acquired form, while other types of data need to be processed further. For example, a transformer's top-oil temperature can be directly used, while a bushing's sum current waveform requires additional processing to calculate the fundamental frequency phasor. The data are then compared with various reference values such as limits, nameplate values, and other measurements, depending on the user's application. A warning, alarm or trip can be triggered when a parameter exceeds a threshold value. To limit the data exchanged, processed and stored, one common approach is to compare the measured parameter with the previous measurement. If the value has not changed significantly, then no data are recorded, saved or transmitted [31].

In situations where reference data are not available, a learning period may be used to generate a baseline for comparison. Data are accumulated during a specified period of time, and statistical evaluation is used to either accept or reject the data. In some applications, the rejected data are still saved, but they are not used in the calculation of the initial benchmark. In other applications, the initial benchmark is determined using only the accepted data.

Data must also be interpreted to detect abnormal behaviour, diagnose and identify what causes the abnormal behaviour and prognose how the condition will evolve in the future, using a wide range of techniques and approaches, that mainly can be categorised into two types [2]:

- *Knowledge-based techniques* aim to replicate expert knowledge and reasoning of an engineer. Examples include casual models, expert systems, and fuzzy logic.
- *Data-driven interpretation techniques* aim to replicate lower level pattern matching facets of intelligence, and undergo training be repeated exposure to examples before any interpretation can be performed. Examples of this type include neural networks, machine learning, multivariate analysis, rule indication and Bayesian networks.

Data interpretation is crucial for understanding the health of a transformer, but it is just as essential to convert this into useful information as a basis for taking maintenance and reinvestment decisions. Health index assessment is a good method of presenting data when considering the overall transformer life management process. When a whole population of transformers is considered, the health index assessment is made from condition data and operational data readily available. This assessment is combined with an impact index reflecting the strategic importance of this unit to the network including safety, impact of a failure on the network operation and ease of replacement. The resulting combined index allows ranking of the units to identify those that need further action [2].

Figure 4.4 shows an example of a risk plot showing the results of combined health for a population of transformers.

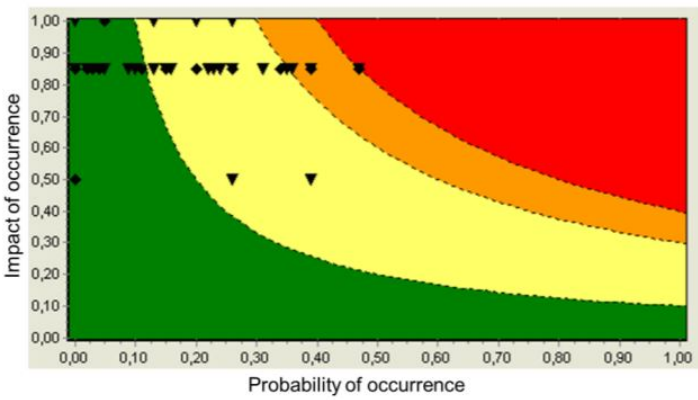

Figure 4.4: Example of health index methodology that combines the probability of occurrence and impact indexing for a fleet of transformers [2].

Chapter 5

Communication

From a technological viewpoint, communication can be described as the act of exchanging data from one device to another device. The means of how communication is exchanged is by communication media, and may consist of wire, radio, optical or other electromagnetic technologies. Communication operates on a number of protocols that define the rules for communication, in terms of syntax, semantics and synchronisation for data access and data exchange between substation devices. Protocols also define types of data, what commands are used to send and receive data, and how data transfers are confirmed. There exists many protocols that are either proprietary or open, meaning whether protocols belong to a protocol is kept secret by a vendor from industry, or openly accessible to any vendor. An open protocol or a set of open protocols, known as a standard, aims to achieve interoperability.

Protocols are defined in a layered manner and provide all or part of the services specified by a layer of the Open Systems Interconnection (OSI) model [32]. The OSI model consists of seven layers that can be seen in Figure 5.1.

Each layer handles the data in a way that is different from other layers. Some layers add layer-specific information to the data. This information added by the layers' protocols can be in the form of a header, a trailer, or both. The header information is added at the start, while the trailer information is added at the end of a data exchange. This header or trailer contains information that is useful in controlling the communication between two entities [33].

There is the issue that communication protocols have in the past to a great extent been proprietary and often kept secret from the industry. As a consequence, devices from different vendors have therefore not been interoperable and a drawback with this is that it makes it

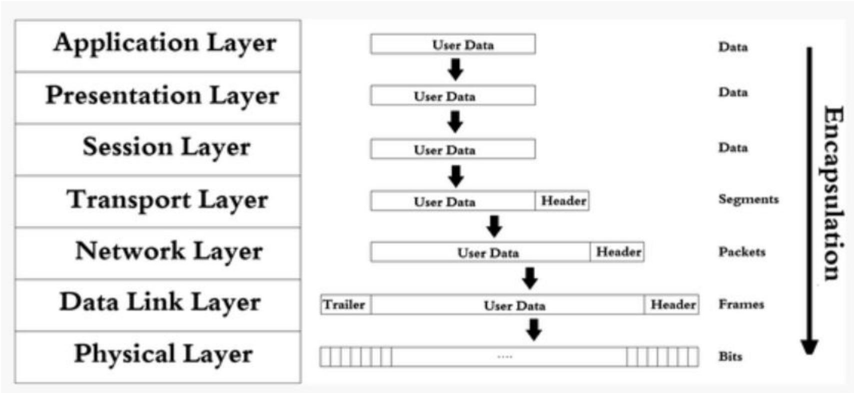

Figure 5.1: The OSI model [33].

more difficult for utilities to design substation automation systems using several vendors.

In despite of the proprietary past, there are efforts in IEC, in IEEE, and in Cigré to issue standards related to communication protocols to define guidelines or recommended practices. Two noteworthy standards are the IEC 60870-5, -101, 102, 103 and IEC 61850. The IEC 60870 family has been widely used in Norway and IEC 61850 is now emerging and will gradually replace IEC 60870. There are also other widely used protocols, however most dominantly used in North America and include DNP 3 and Modbus. One might implement several protocols for a condition monitoring system as an option is to use gateways or protocol converters to facilitate protocol conversion.

IEC 61850 is presented in detail in this chapter because this standard has the aim to cover the entire substation automation system from the process level to the network layer in addition to be compliant with future technologies.

5.1 IEC 61850

The IEC 61850 standard aims to facilitate a modern system for communication within a substation and between substations and surveillance centres. It is a part of the International Electrotechnical Commission's (IEC) Technical Committee 57 (TC57) architecture for electric power systems [34]. The aim is to establish means of communication and data access to cover all the architecture levels of a substation from process level to network level. The key objective has been to achieve interoperability between devices from different vendors. Other objectives of IEC 61850 include:

- High-speed IED to IED communication
- Networkable at all levels of architecture
- High availability
- Future-proof
- Support for voltage and current sampled data
- Support for file transfer
- Auto-configurable/configuration support

There are in particular two parts of the standard that is related to communication, protocols and message exchange. Part 4: *System and project management* defines abstract data models that can be mapped to a number of protocols. This is further discussed in Section 5.2.1. Part 90-3: *Using IEC 61850 for condition monitoring diagnosis and analysis* consists of defining logical nodes that contain information for condition monitoring, and is discussed in Section 5.1.1 [35, 36].

5.1.1 Data Model

The basic idea of the IEC 61850 data model is to make data addressing simple and to avoid the need of adapting the communication channels according to the protocol used. It is networkable and object-oriented, and this allows the possibility of ”pick-list” configuration rather than the labour-intensive and more error-prone points-list systems. Devices, in particular IEDs and sensors, are represented as data objects that are referred to as generic object models. A data interface to a device will provide information for logical devices, logical nodes, data and related data attributes. The syntax and semantics are based on the use of common data objects [37]. Figure 5.2 shows a graphic the IEC 61850 data model.

The IEC 61850 data model begins with a physical device which is the device that connects to the network and is typically defined by its network address. Within each physical device, there may be one or more logical devices. The IEC 61850 logical device model allows a single physical device to act as a proxy or gateway for multiple devices.

Each logical device contains one or more logical nodes. A logical node is a named grouping of data and associated services that is logically related to some power system function.

There are logical nodes for metering and measurement the names of which all begin with the letter “M”. Similarly, there are logical nodes for supervisory control (C), system logical nodes (L), protection (P), sensors (S), instrument transformers (T), power transformers (Y), and other Equipment (Z). Each logical node has an LN-Instance-ID as a suffix to the logical node name.

Each logical node contains one or more elements of data. Each element of data has a unique name. These data names are determined by the standard and are functionally related to the power system purpose. For instance, the transformer active part is modeled as an SPTR logical node.

Each element of data within the logical node conforms to the specification of a common data class (CDC). Each CDC describes the type and structure of the data within the logical node. For instance, there are CDCs for status information, measured information, controllable status information, controllable analog set point information, status settings, and analog settings. Each CDC has a defined name and a set of CDC attributes each with a defined name, defined type, and specific purpose. Each individual attribute of a CDC belongs to a set of functional constraints (FC) that groups the attributes into categories.

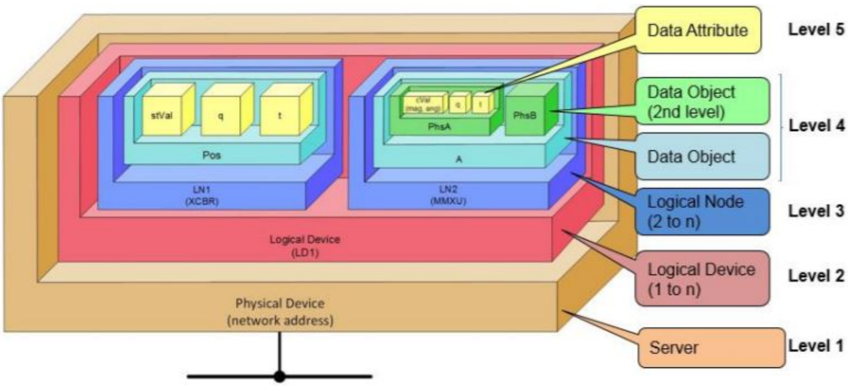

Figure 5.2: Data model hierarchy [2].

The IEC 61850 model of a device is a virtualized model that begins with an abstract view of the device and its objects. Then, this abstract model is mapped to a specific protocol stack in section IEC 61850-8-1 based on MMS, TCP/IP, and Ethernet. In the process of mapping the IEC 61850 objects to MMS, IEC 61850-8-1 specifies a method of transforming the model information into a named MMS variable object that results in a unique and unambiguous reference for each element of data in the model [37]. A simple example of nodes for monitoring are shown in Table 5.1.

Common data classes are defined in IEC 61850-7-3 and standardised logical nodes covering the most common applications of substation and feeder equipment are defined in IEC 61850-7-4 [38, 39]. One thing to bear in mind is that all logical devices shall contain at

Physical Device PHD	Measurement Data	Logical Node	Data Object	Common Data Class
Bushing	Voltage Leakage current	ZBSH	Vol LeakA	MV MV
Tap changer	Tap changer position	ATCC	TapChg	BSC
Accessories	Oil level Air moisture	SIML	Lev H2OAir	MV MV
Cooling Equipment	Inlet temperature	CCGR	OilTempin	MV
Active Part	Oil temperature	SPTR	TopTmp	MV

Table 5.1: Small partial list of Logical Nodes for condition monitoring according to IEC 61850 [2].

least two logical nodes: LPHD and LLN0. They are obligatory and are part of the system logical nodes group. The LPHD logical node is used to model common issues for physical devices and contains physical device information. The LLN0 logical node is used to address common issues for logical devices. Apart from those, there is the possibility for engineering work to be done with respect to what logical nodes that can be configured, as the engineer is free to choose which logical nodes to be used.

For condition monitoring data acquisition, power transformer temperatures and oil-related attributes can be modeled for example by using the logical nodes SPTR and SIML respectively. An example of this is shown in Figure 5.3.

5.2 Communication Methods

The data model define a standardised data access method for describing power system devices that enables them to present data using identical structures that are directly related to their power system function. The data model is abstract and separates services from coding. Therefore it is referred to as the Abstract Communication Service Interface (ACSI) [40]. Different communication methods are supported by ACSI services and is separated into two types:

- *Client - Server Services*
- *Real-time Services (Multicast)*

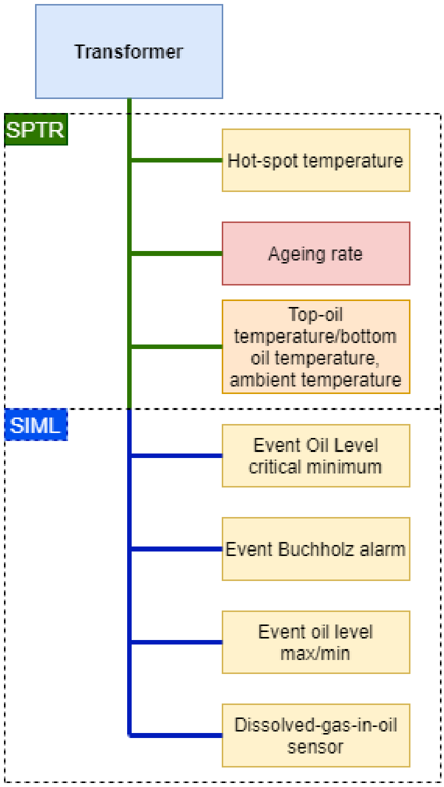

Figure 5.3: Example of condition monitoring logical nodes.

Client / Server

A server contains everything that is defined to be visible and accessible from the communication network. A client is any physical device that uses the ACSI services to exchange data with a server. Clients request services from a server and receive confirmations from the server with the data it asked for. It may also receive unsolicited reports from a server. This is different from master-slave communication, as the slave does not possess the ability to send unsolicited reports to the master. Client-server communication is non-time-critical, meaning data transfer is delayed. Figure 5.4 illustrates a client-server session.

Real-Time (Multicast)

For a multicast communication, two new roles are defined, the publisher and the subscriber. A multicast information exchange is provided between one publisher, and one or

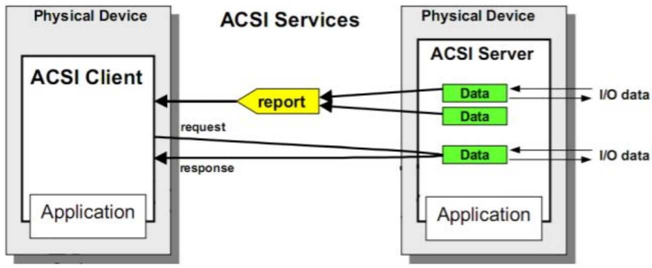

Figure 5.4: Client-server communication [41].

many subscribers, as illustrated in Figure 5.5. Multicast communication is used for real-time and time-critical applications, meaning data transfer delay is low compared to the client-server communication. It is also unconfirmed communication, as the publisher does not receive any response from the subscriber that the information was received.

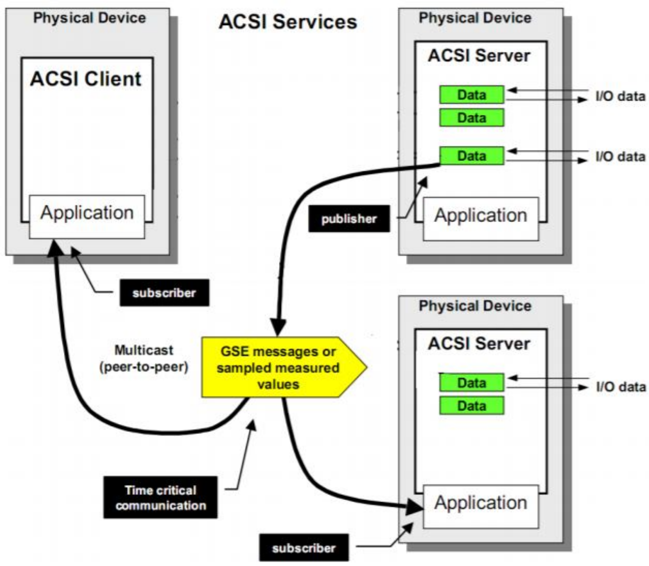

Figure 5.5: Multicast communication [41].

5.2.1 Mapping to Protocols

IEC 61850 defines a set of services and the responses to those services that enable all devices to behave identically from the network perspective. These services and responses are abstract and not related to any specific protocol. ACSI ensures that the standard can continuously be extended to new communication protocols and technologies, and therefore IEC 61850 is said to be future proof [37].

IEC 61850-8-1 maps the application layer services to the protocol Manufacturing Message Specification (MMS), of ISO 9506. The mapping is based on a service mapping where a specific MMS service/services are chosen as the means to implement the various services of ACSI. The object models of IEC 61850 are mapped to specific MMS objects, for instance logical device object is mapped to an MMS domain. Table 8.2 in the appendix C shows some ACSI services mapped to MMS [41].

In addition to the mapping to the application layer, part 8-1 defines communication methods, that are dependent on the services. There are three main communication methods included:

- Sampled Values (SV)
- Generic Object Oriented Substation Event (GOOSE)
- MMS Messages

SV and GOOSE are mapped directly into the Ethernet data frame thereby eliminating processing of any middle OSI layers. This makes them real-time and fast, avoiding the delays associated with processing of the header and trailer in a data transfer. A drawback is that they cannot be routed over network. MMS messages are mapped to the middle layers using TCP/IP, meaning they are routable over network. However, this makes MMS messages slower. Figure 5.6 shows the communication methods linked to the respective OSI layers.

GOOSE works on the publisher-subscriber mechanism on multicast or broadcast MAC addresses. It is designed for peer-to-peer communication. GOOSE uses VLAN and priority tagging to have separate virtual networks within the same physical network and sets appropriate message priority level. GOOSE also features enhanced retransmission mechanism. The same GOOSE message is retransmitted with varying and increasing re-transmission intervals. A new event occurring will result in the existing GOOSE retransmission message being stopped. A state number identifies whether a GOOSE message is a new message or a retransmitted message.The GOOSE has also been extended to communicate over network with the Routable GOOSE (R-GOOSE) [42].

SV data are streams of data acquired by the voltage and current transformers which are sent to a merging unit (MU). The MU samples the signals at an configured and synchronized rate. In this manner, any IED can input data from multiple MUs and automatically align and process the data. SV streams consist of 4 voltages and 4 currents which are sampled at 4 kHz, or 80 samples per cycle according to IEC 61850-9-2 LE. In addition to SV, the ability to acquire status information as well as set output controls is desirable, and therefore IEC 61850 has implemented Sampled Measured Values (SMV) services, defined in part 9-1 and 9-2 [37].

MMS messages works on the client-server mechanism using IP addresses. As mentioned, MMS defines a set of standard objects which must be implemented in devices to execute services such as read, write, set, get, etc. Virtual manufacturing device (VMD) is the main object and all other objects like variables, domains, journals, files etc. comes under VMD. An advantage with MMS messages is that they are routable over a network.

To summarise, Figure 5.6 shows the mapping of the types of messages to the OSI layers.

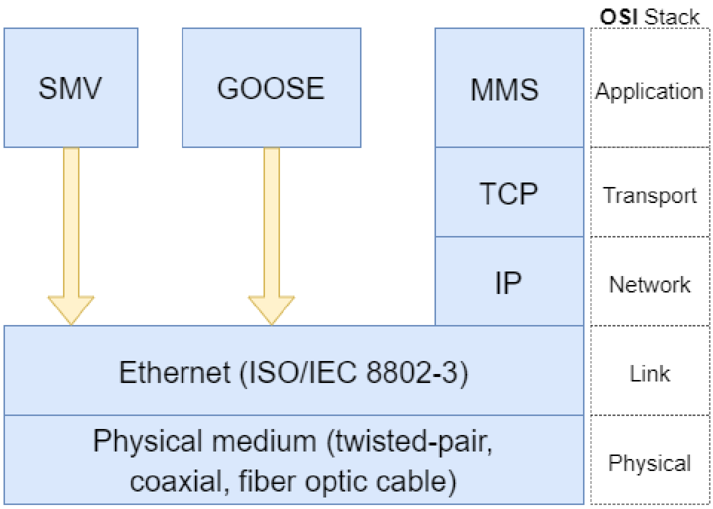

Figure 5.6: IEC 61850 communication mappings.

5.2.2 System Configuration

To configure a system based on IEC 61850, a ”language” called substation configuration language (SCL) has been created. It is based on the extensible markup language (XML), which is a *markup language* that defines a set of rules for encoding that is both human-readable and machine-readable. SCL specifies a hierarchy of configuration files that enable multiple levels of the system to be described in XML files. The various SCL files include System Specification Description (SSD), IED Capability Description (ICD), substation configuration description (SCD), and configured IED description (CID) files [40]. They are based on the same method and formats, but have different scopes:

- *The System Specification Description (SSD) file* describes the single line diagram of the substation, existing voltage levels, primary equipment and required logical nodes for implementing the substation functions. The standard defines as optional the import of this data in the system configurator[1].
- *The IED Capability Description (ICD) file* describes the functional capabilities of an IED type. Each IED type has its related ICD file. It contains the IED logical nodes, data and supported services.
- *The Substation configuration description (SCD) file* contains all configured IEDs, the communication configuration and the complete substation description. This file is generated by the system configurator during the engineering process and is an important part of the project documentation.
- *The Configured IED description (CID) file* is optional and vendor specific. It contains a subset of the SCD file with all information related to one specific IED. If used, one CID file has to be generated for each existing IED in the project for loading the configured data into the IED.

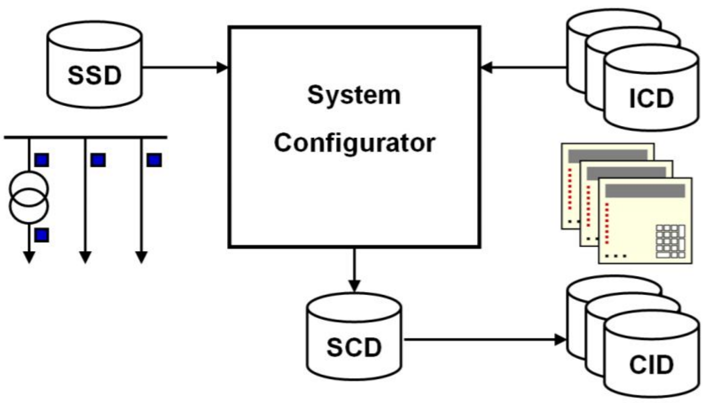

Figure 5.7: The IEC 61850 system files.

[1]The IEC 61850 system configurator is a software that runs on computers from which devices can be configured.

5.3 Process Bus and Station Bus

From the substation automation system viewpoint, IEC 61850 introduces the process bus which was mentioned in Section 2.2. Process bus communication is transferred by means of SV streams, multicast GOOSE messages and client-server MMS messages. Sampled current and voltage measurements from MUs and the associated MUs of NCITs are published to the process bus and sent to subscribing secondary devices as SMV streams. By the use of multicast messages, the same SMV streams can be sent to several bay level devices simultaneously. Status data and alarm information from the primary process are also transmitted to the bay level devices, typically by GOOSE messages. Trip signals and open/close commands are sent from the protection and control IEDs to station level devices as GOOSE messages. The buses are Ethernet networks that currently operates at 100 Mb/s that typically has a ring structure.

As mentioned, the station bus provides primary communications between the various bay level devices, which comprise the various station protection, control, monitoring, and logging functions. Communications will, similarly to the process bus, operate on either a client-server mechanism using MMS or a multicast mechanism using GOOSE. The process bus and station bus are typically separate, but can be combined in the same Ethernet network via common switches.

The process bus and the station bus are the according to §3.2.7 in *Kraftberedskapsforskriften*[2] legally obligated to implement redundancy to provide a certain level of communication safety, in case a fault should occur on the main bus:

> *"The facility shall have duplicated and physically independent routing of cables for control and communication, emergency and station power and high voltage, respectively, so that a single error or event cannot knock out vital functions."*[43] (Translated from Norwegian).

To fulfill this requirement, two buses can be put in parallel to provide a main bus and a backup bus to provide a [44]. Systems with a built-in redundancy can handle data permanently via two channels and any loss of a component or link will result in only an alarm without disturbance of the communication system and without loss of sampled value or other data. The switch-over time to change to the redundant bus is 10 to 50 ms or greater, depending on the structure and size of the communication network. The main bus and the backup bus can both be based on Ethernet wired network or wireless IEEE 802.11 network [45]. Time synchronisation of the devices should be carried out only through the

[2] *Kraftberedskapsforskriften* can be translated to "The Power System Readiness Regulation". It is further presented in section 5.4.

wired Ethernet. A time synchronization of all devices with a resolution of 1 ms is needed for proper time stamping of telegrams to organize the event and message queues properly. Figure 5.8 shows the topology.

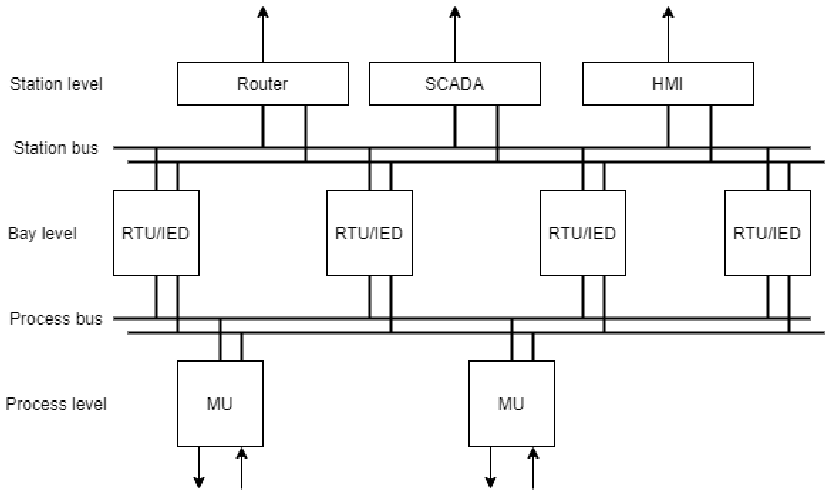

Figure 5.8: Redundant ring bus topology.

5.4 Substation Security

There are many threats to a substation condition monitoring system that can be either physical or cyber. A physical threat can be natural such as a storm, heavy rain, lightning, etc. or can be man made, such as vandalism or robbery. A cyber threat can be comprise worms, viruses and hacking that can interfere the substation system and enable intruders to acquire data and even control equipment, such as circuit breakers, and other switchgear.

Measures against physical threats are similar to those for conventional substations, such as fences, locked gates, security cameras, etc., and are therefore not further discussed in this thesis. However condition monitoring in digital substations introduces some cyber security issues which needs to be addressed. There are two main aspects of cyber security that are:

- *Data handling* relating merging of condition data and the transmission of data, explained in Section 5.4.1.
- *Data transmission* related to that data is sent over LANs and WANs that are potentially accessible to the general public, presented in Section 5.4.2.

Cyber security is especially important as a person or an organisation of any kind, or even a country with a motivation to steal data, can possibly operate protection and control devices or even destroy equipment may from places far away from the substation. Furthermore, and even more crucially, several substations may be attacked simultaneously with the potential for a huge blackout.

To protect substations, a security program can be designed using a systematic approach, that may include threat assessment, system analysis, risk management and implementation. The responsibility for security lies on the utility company operating the substation and the government institutions ”Direktoratet for samfunnssikkeret og beredskap” (DSB) og ”Norges vassdrags- og energidirektorat” (NVE). The utility must identify the person or department which will have the responsibility for security implementation and administration. Government institutions has the responsibility to legislate and mandate the auditing of the level of preparedness for incidents, monitoring of the system, etc. A significant legal act is the aforementioned Kraftberedskapsforskriften.

In general, measures to enhance cyber security include that communication should be authenticated and encrypted. The data messages exchanged between substations and the control room or surveillance centre is open to active intrusion as IEDs and other substation devices are often IP-enabled. In addition, much data goes over WAN, where intruders can record and interpret data exchanges and can insert their own messages to control devices. Further, legacy protocols have not properly addressed cyber security, however IEC 61850 has been extended to address security by IEEE C37.240 for WAN, IEEE 1711.2 for station level devices, IEC 62351 for station bus, and IEEE 1686 for process level devices.

In general, minimum measures to enhance cyber security include the following:

- Removing all default passwords on installed systems.
- Closing unneeded parts and disabling unneeded services.
- Installing security patches from software suppliers in a timely manner.
- Removing all sample scripts in browsers.
- Ensuring that all accounts have strong passwords.
- Implementing firewalls with appropriate rules to exclude all unneeded and/or unauthorised traffic.
- Log all activity.

5.4.1 Merging Operational and Condition Data

As mentioned, a main issue relating to condition monitoring systems is data handling. Condition data and operational data are sensitive and therefore access needs to be restricted §6.1 in Kraftberedskapsforskriften states who can have access, and who can provide access,

> *”All organisations involved in power supply shall after the energy law §9-3 first term identify what is sensitive information, where it is and who has access to it. The identification of what is sensitive information and where it is, shall also cover storage on paper, storage in electronic form or storage in any way. With proper users is meant physical and legal persons that has service needs within the domain and can decide if it is needed to share the sensitive information to any other external parts. The government organisation Beredskapsmyndigheten can in case of doubt decide who can have access.”* [43] (Translated from Norwegian).

As such, it is not straight forward how to merge operational data with condition data and further how data should be transmitted from the condition monitoring system to where it is stored. Ideally, condition and operational data should be located in one central database, which then can evaluate a whole fleet of transformers' condition in the context of operational circumstances. A typical example is if the transformer is equipped with a single gas monitor only. Then it may be good to store measured loads, currents, voltages, temperatures and other useful variables coming from SCADA to the central database in order to ease the analysis of an event. The goal is to depict load and temperatures together with increased gas level synchronously.

Merging of condition and operational data can be done in several of the substation levels. One way to merge data on the bay level is by using IEDs. As mentioned, condition monitoring IEDs do not need to posses control functions of circuit breakers and other equipment as they only need to acquire condition data. Therefore one could close the IEC 61850 MMS services ”write” and ”set” services within the IEDs. By using ”read” and ”get” services only, one can acquire condition data without providing control functions. Such an approach is called read-only [1].

Although the read-only approach can work, if IEDs and their communications link to the remote central database is not properly secured by standard methods, the condition monitoring system can be a ”backdoor” into the SCADA network [13].

5.4.2 Network Security

Despite that IEC 61850 digital substations can provide various advantages over traditional substations, there are several data security concerns. Attacks commonly performed on the internet can penetrate into substations because IEC 61850 employs the IEEE 802.3 Ethernet LAN for its network. Data security vulnerabilities include the lack of encryption used in the GOOSE messages, lack of intrusion detection system implementation, and no firewall implementation. By exploiting these vulnerabilities, there are some attacks that can be launched on IEC 61850 substation network [46]. These attacks can be categorized into two:

- Common network security attacks on IEC 61850 network. Types of attacks include denial of service (DoS) attacks, password cracking attacks, and packet sniffing attacks.
- Security attacks that exploit the IEC61850 multicast messages. Attacks include GOOSE and SV modification attacks, GOOSE and SV DoS attacks, and GOOSE and SV replay attacks.

The common network security attacks rely on IED that run FTP, HTTP and Telnet services. A way to reduce the attacks is therefore to close these services in the IEDs in the substation if they are not necessary. If the services need to be run, the access to the services must be restricted only to view access only so that the configuration is not tempered with. Data stealing also can be avoided by using HTTPS service instead of normal HTTP service, and SSH instead of Telnet and FTP [46].

IEC 62351 is a security enhancement to IEC 61850 and provides authentication of data transfers through digital signatures and encryption, and prevention from malicious activities. However, only DoS, password cracking attacks, and packet sniffing attacks are prevented with this enhancement. GOOSE-based and SV-based attacks are difficult to prevent, because of digital signatures and encryption require a lot of time to be generated and verified. Thus, it is not suitable for GOOSE and SV messages because the IEC 61850 standard specifies a 4 ms maximum latency for GOOSE and SV messages. In fact, there is a lack of security measures for GOOSE and SV messages [46].

Another vulnerability related to network security is transmission of data over WAN, which is typical when data is transmitted over long distances. WAN is potentially vulnerable to the aforementioned attacks, and thus measures to secure data transmission over WAN is an important consideration [47].

The ECoDiS meeting on 16th of April 2020 discussed among other topics, means of transmitting data from substation to surveillance centre. Statnett has gained some experience related to WAN, and has proposed a design where data is transmitted over several WANs, splitting up data depending on the needed level of security of the data, and by categorising types of data to be sent over different WANs [48]. The following paragraphs present some measures to acquire a more secure data transmission over WANs.

To start with, an example of a network architecture that does not provide proper security is shown in Figure 5.9. The security is weakened by that there are no measures to prohibit outside intruders to access the WAN [49].

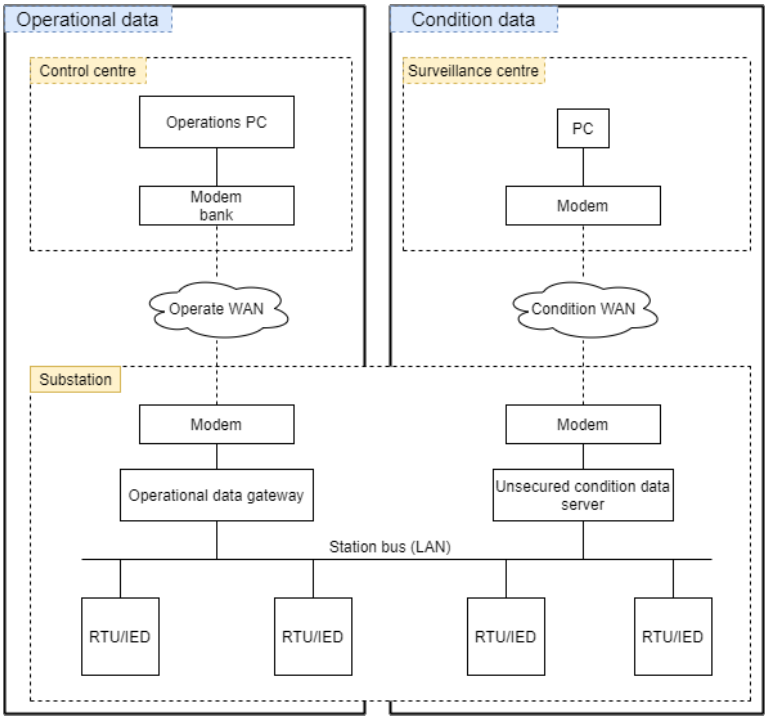

Figure 5.9: Unsecure network architecture [49].

The security can be improved in a number of ways. Figure 5.10 shows that WAN access can be secured by the use of individual accounts, two-factor authentication and user name and password challenge from the surveillance centre. Then by changing the unsecured condition data server to a condition data gateway, security access logs and gateway and IED access rights can be applied. Encryption can also be implemented, if the IED's processor provide sufficiently fast processing [49, 50].

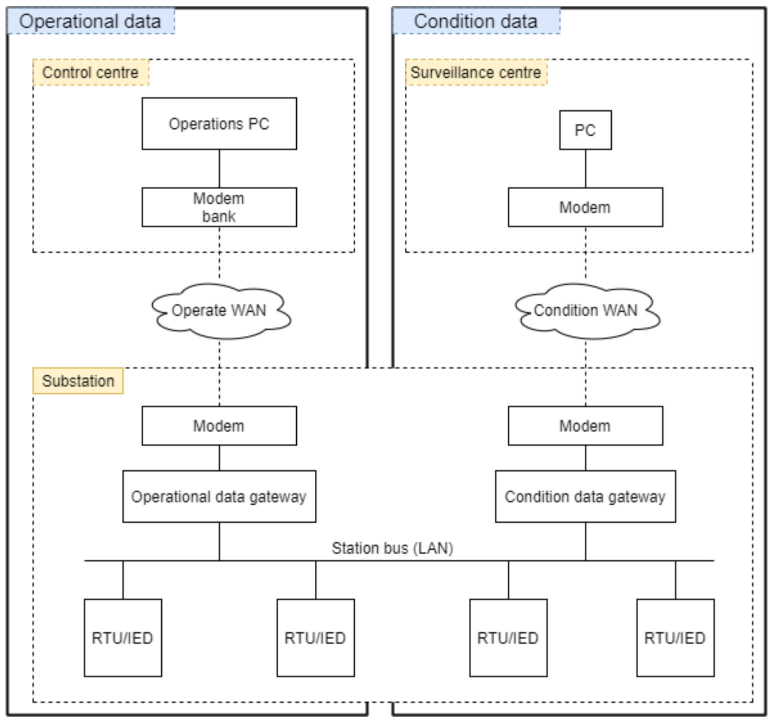

Figure 5.10: Separate operational and condition WAN with limited security measures [49].

Additional security can be achieved by adding a secure condition server in the surveillance centre with WAN connections. In this way the user access rights are stored on the condition server and sent to the gateway and only the condition server can access the gateway. Using this architecture, there is clearly defined "electronic perimeter" at the gateway server.

With the increasing trend and demand for interconnectivity between corporate and monitoring networks, the surveillance centre LAN may be connected via WAN with firewall protection to corporate offices, as illustrated in Figure 5.11.

Moreover instead of using multiple WANs, there is a possible solution to employ a shared operational and condition WAN [49]. By sharing the communications channel between the operations and condition data, the costs providing two connections is reduced. On the contrary, this can increase the security risks. and will also conflict the regulations. In spite, it may be an option in future with improved security measures.

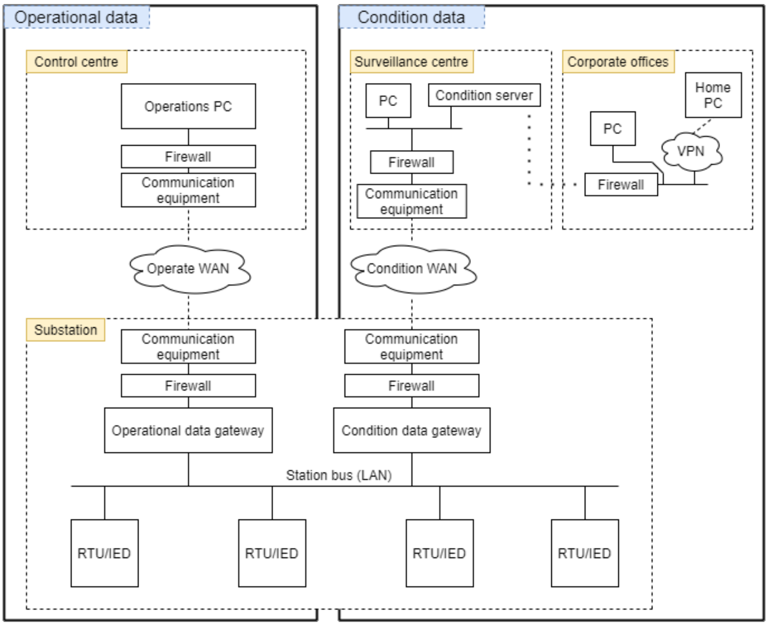

Figure 5.11: Separate operational and condition WAN with security measures [49].

5.5 iRTU Code

Co-supervisor and SINTEF Energy Research scientist Hans Kristian Hygen Meyer ordered a RTU from iGrid T&D. The RTU is called iRTU-B0C1 which has a central processing unit (CPU) that supports 8 digital inputs, 4 relays and 2 analogue inputs. Analogue input is 4 - 20 mA. An additional module can be connected to increase the number of analogue and digital inputs. Both GOOSE messages and MMS messages are supported. GOOSE messages are sent on a time-based schedule or when a report condition is triggered. The RTU was received without any configuration file included, but on request, the company provided a CID file. The complete file is shown in Listing 8.1 appendix C. The code is written in XML and is difficult to understand for someone that is not familiar with XML. The book [51] presents XML in detail. Irrespective of the competence with XML, the code shows from a practical viewpoint, the IEC 61850 coding and data model. Two noteworthy syntax rules, are that every new line of code must start with a ”<” and end with a ”\>”, and ”\par” is used at the end of a line to parse.

Listing 5.1 from the start of the code show that both MMS and GOOSE are configured into the RTU and further linked to an IP address and a MAC address respectively.

```
<Communication>\par7<SubNetwork name="W01" type="8-MMS">\par
<P type="IP">192.168.1.100</P>\par
<GSE ldInst="iRTU" cbName="GOOSE_Digital">\par
<P type="MAC-Address">01-0C-CD-01-00-01</P>\par
```

Listing 5.1: Configuration of MMS and GOOSE.

Listing 5.2 shows the declaration of the RTU, and contain a list of IEC 61850 services that are implemented in this specific RTU. There are many services that can be configured, and these are only a few of the many services available. A list of services of IEC 61850 services can be seen in Table 8.2 in appendix A. The services are commonly ”Get”, ”Set”, ”Read”, ”Write”, with variations to different objects, directories, etc.

```
<IED name="E1Q1SB1">\par
  <Services nameLength="32">\par
  <GetDirectory />\par
  <GetDataObjectDefinition />\par
  <GetDataSetValue />\par
  <DataSetDirectory />\par
  <ReadWrite />\par
  <FileHandling />\par
  <GetCBValues />\par
```

Listing 5.2: Declaring the IED and services.

Listing 5.3 shows the configuration of the inputs and configuration of logical node classes (lnClasses). Line 5 shows the implementation of the mandatory logical node class ”LLN0”. This node consists of a data set called ”General”, which includes information of the device in terms of behaviour, ”Beh” and satus ”stVal” [52]. Lines 12 to 25 shows the configuration of inputs. For instance line 12 declares the ”iRTU” instance, with prefix ”client”, which demonstrates that the client-server mechanism between the RTU and the sensor. The general input lnClass ”GGIO” is used for all inputs, however more specific lnClasses could have been used to differentiate inputs, such as ”TTMP” for temperature, ”TPRS” for pressure and ”THUM” for humidity.

```
1 <AccessPoint name="S1">
2       <Server>
3         <Authentication />
4         <LDevice desc="description" inst="iRTU">
5           <LN0 desc="description" lnType="iGrid_SINTEF_Sample_v1_LLN0"
    lnClass="LLN0" inst="">
```

```
        <DataSet name="General">
          <FCDA ldInst="iRTU" lnClass="LLN0" doName="Beh" daName="stVal" fc="ST" />
          <FCDA ldInst="iRTU" lnClass="LPHD" lnInst="1" doName="PhyHealth" daName="stVal" fc="ST" />
          <FCDA ldInst="iRTU" prefix="C1i" lnClass="GGIO" lnInst="1" doName="EEHealth" daName="stVal" fc="ST" />
        </DataSet>
        <DataSet name="Digital_MMS" desc="C1 module Digital Inputs (via MMS)">
          <FCDA ldInst="iRTU" prefix="C1i" lnClass="GGIO" lnInst="1" doName="Ind5" fc="ST" />
          <FCDA ldInst="iRTU" prefix="C1i" lnClass="GGIO" lnInst="1" doName="Ind6" fc="ST" />
          <FCDA ldInst="iRTU" prefix="C1i" lnClass="GGIO" lnInst="1" doName="Ind7" fc="ST" />
          <FCDA ldInst="iRTU" prefix="C1i" lnClass="GGIO" lnInst="1" doName="Ind8" fc="ST" />
        </DataSet>
        <DataSet name="Analog" desc="C1 module Analog Inputs">
          <FCDA ldInst="iRTU" prefix="C1i" lnClass="GGIO" lnInst="1" doName="AnIn1" fc="MX" />
          <FCDA ldInst="iRTU" prefix="C1i" lnClass="GGIO" lnInst="1" doName="AnIn2" fc="MX" />
        </DataSet>
        <DataSet name="Digital_GOOSE" desc="C1 module Digital Inputs (via GOOSE)">
          <FCDA ldInst="iRTU" prefix="C1i" lnClass="GGIO" lnInst="1" doName="Ind1" fc="ST" />
          <FCDA ldInst="iRTU" prefix="C1i" lnClass="GGIO" lnInst="1" doName="Ind2" fc="ST" />
          <FCDA ldInst="iRTU" prefix="C1i" lnClass="GGIO" lnInst="1" doName="Ind3" fc="ST" />
          <FCDA ldInst="iRTU" prefix="C1i" lnClass="GGIO" lnInst="1" doName="Ind4" fc="ST" />
```

Listing 5.3: Logical classes LLN0 and LPHD

Listing 8.1 in appendix C shows the entire code that was implemented into the iRTU.

Chapter 6

Vendor Products

In this chapter the attributes of some commercially available condition monitoring products are presented. In total eleven products were analysed, and are shown in Table 6.2. The information is based on the available technical documentation of the different products in addition to information obtained from contact with vendors.

Vendor	Product Name	IEC 61850 compliant
ABB	CoreTec	Yes
a-eberle	TraCoMo	Yes, IEC 61850 GOOSE
Altanova	EDS	Yes
Advanced Power Technologies	Total ECLIPSE	No, can be made compliant via a protocol converter
Siemens	SITRAM TDCM	Yes
Camlin	Totus	Yes
Dimrus	TDM-3F	Yes
Dynamic Ratings	E Series / C50-series	Yes
GE	MS 3000	Yes
Reinhausen	ETOS	Yes
Qualitrol	QTMS Qualitrol Transformer Monitoring System	Yes

Table 6.1: Some commercially available vendor products [9].

6.1 Product System Types

In general, all products are stand-alone type systems, as they consists of a range of sensors connected to a central monitoring unit that performs processing, provide storage, and establishes communication links for remote data access. However, they are also generally enabled to be integrated into the substation automation system. In this way, vendor products can use IEDs for data exchange and be configured to merge operational and condition data.

The systems are modular, and separate modules of the systems are often commercially available. An example is for instance that the vendors also offer transformer oil analysis sensors separately. Hence, by using IEC 61850 compliant devices, the utility can build its own customised system.

6.2 Monitoring Facilities

The vendor products integrate different monitoring facilities. Table 6.2 shows 11 commercially available vendor products and 6 of the most valuable monitoring facility categories. Then, it was checked if the vendor products implemented these. The term *standard* is used where the facility is implemented, but not much information about the facility was given. *Not standard* means the product does not contain this facility.

It was found that all the analysed products, except TDM-3F by Dimrus implemented DGA monitoring. Moreover, bushing monitoring was found to be facilitated by all except ABB. Total ECLIPSE by Advanced Power Technologies, Totus by Camlin, and TDM-3F were found not to implement temperature monitoring. MS 3000 was found to offer the most monitoring facilities of them all, further presented in [53]. The products have in general the options to be extended with more monitoring facilities. Several vendor, for instance GE, Camlin and Siemens, provides several standard configuration kits comprising different sets of facilities. Many of the vendors also provided voltage regulation, and cooling system control and monitoring in addition.

All monitoring systems generally supports several communication standards and protocols. In addition, the systems can be made compliant to non-supported standards and protocols with a gateway or protocol converter.

Regarding implemented interpretation methods, the vendors provided in general little information on this topic. Many describe their systems to have ”sophisticated modeling” or refer to some standard modeling techniques. However, some generally implemented functionalities comprise, hot-spot calculation, short-term overload capacity, thermal image, and residual life calculation.

Product	**DGA**	**Partial Discharge**	**Busing Monitoring**	**Moisture in Oil**	**Temperatures**	**Tap Changer**
CoreTec (ABB)	Hydrogen or multiple Two sensors available (HYDRAN, CoreSense)	Not standard	Not standard	Standard	Top oil Bottom oil Ambient	Position Moisture Temperature
TraCoMo (a-eberle)	Standard. Five sensors available, can measure up to 8 gases	Not standard, but available on request	Standard	Not standard	Winding	Not standard
EDS (Altanova)	Hydrogen is standard, but options for up to 8 gases	Not standard	Standard	Not standard	Top Oil Bottom Oil Ambient	Position Active power consumption
Total ECLIPSE (Advanced Power Technologies)	Standard	Not standard	Standard	Standard	Not standard	Not standard
Totus (Camlin)	Standard Up to 9 gases	Standard	Standard	Not standard	Not standard	Not standard
TDM-3F(Dimrus)	Not standard	Standard	Standard	Standard	Not standard	Standard
SITRAM TDCM Siemens	Standard, various sensors available (H2Guard, multisense 5, multisense 9)	Not standard	Standard	Standard	Standard	Standard
E-Series / C50-series Dynamic Ratings	Standard	Not standard	Standard	Not standard	Top oil Bottom oil Winding Ambient	Position Operation counters
MS 3000 (GE)	Standard (1 to 9 gases)	Standard	Standard	Standard	Top oil Bottom oil Ambient	Standard
ETOS (Reinhausen)	Standard (up to 9 gases)	Not standard	Standard	Not standard	Top oil Bottom oil Ambient	Standard
QTMS Qualitrol Transformer Monitoring System (Qualitrol)	Standard	Standard	Standard	Not standard	Top oil Winding	Standard

Table 6.2: Comprehensive monitoring systems commerically available.

6.3 Price

Condition monitoring systems are generally expensive, but the cost may vary significantly between different vendor products. Siemens estimated the price of their systems as follows, including installation and commissioning:

- SITRAM H2Guard: 70,000 kr
- SITRAM Multisense 5: 217,000 kr
- SITRAM Multisense 9: 345,000 kr
- SITRAM TDCM: 325,000kr - 433,000 kr

If purchasing multiple products simultaneously, a discount of about 10% is achievable. Prices for other vendors may vary, but these prices shows about in what range the price is expected to be in.

6.4 Expected Lifetime and Maintenance

The expected lifetime of the condition monitoring systems is considered to be approximately 15 years for the sensor electronics and 30 years or more for the sensors. The vendors specify that their systems require no maintenance or a low level of maintenance. If a part needs to be replaces, it is specified that only that part needs to be replaced, and no additional configuration is needed.

Chapter 7

Discussion

Power transformers have the potential for longer lifetimes. Long lifetimes can be safely achieved with condition monitoring. The introduction of the digital substation enables condition monitoring of power transformers to a greater extent than was previously possible. This will potentially lead to an improved estimation of condition and remaining lifetime, as well as enhanced decision-making processes for maintenance and reinvestment purposes.

It can be said that the long-range plan for electrical networks is the “smart grid”, which is a fully automated power system that can be achieved by integrating information technology, communication, control and intelligent equipment monitoring, to gain increased security of supply and better utilization of the power industry’s resources. As such, condition monitoring is a part of the transition towards the smart-grid.

This thesis did not include any case study or laboratory test, and thus this discussion is solely focused on the various aspects of condition monitoring. It summarised and highlights all the main points presented in this thesis.

7.1 Monitoring Facilities

Power transformers consist of many subparts that are core, windings, tank and oil, tap changer, bushings and auxiliary equipment. Each of these are associated with different ageing mechanisms. It was found from the Cigré survey [23] that major power transformer failures often originate from the windings. Therefore, condition monitoring of the insulation system is important to secure the reliability of transformers. Direct monitoring of winding temperature or indirect monitoring via DGA, top and bottom oil temperatures, ambient temperature and load condition can be used for this purpose.

There are a large number of available monitoring facilities and diagnostic techniques available for power transformer monitoring. The set-up can be customised to the size, age, condition, environment and criticality of the power transformer. From the Cigré technical brochure 343 [27], it was found that the most important parameters to monitor are the top oil temperature, dissolved-gas-in-oil content, voltage at busing tap, load current, and tap-position. If one where to evaluate which diagnostic technique is the most important, experts say that is it the dissolved-gas-in-oil content monitoring.

For more comprehensive monitoring, that may be suitable for more critical transformers, one can in addition to the mentioned monitoring facilities, extend the system to also measure bottom oil temperature, moisture in oil, oil level, multiple gases, partial discharge, cooling medium temperature, cooling operation, and active power consumption of tap changer. For a complete monitoring system, one can implement Level 3 facilities described in [27]. However, including all these sensors and facilities on a particular power transformer is unlikely to be economically justified.

Some parameters do not have to be measured and can instead be estimated based on other measured parameters. An example of this is that bottom oil temperature can be calculated based on the top oil temperature. Furthermore, the hot-spot temperature can be estimated based on top and bottom temperatures. Hot-spot temperatures are useful to estimate winding insulation degradation.

Senors are under continuous development, which results in greater monitoring capabilities. It is an advantage that underlying sensor technologies are understood. The lifetime of sensors are generally three to four times shorter than that of power transformers. As a consequence, the sensors should be, as far as possible, be easily retrofit-able and replaceable. Sensors may not need to be installed on transformers initially, but may be retrofitted at a later point. Suitable transformers can be those that have shown operational difficulties and are of importance for the reliability of the grid.

7.2 Condition Monitoring Systems

There is a variety of condition monitoring systems with different levels of complexity and system architectures. The simplest form of systems are stand-alone systems that consist of one or several sensors that monitors either a single parameter, for instance, dissolved-gases-in-oil content, or moisture-in-oil content, etc. or several parameters. The sensor transfer data to a central monitoring unit, that usually is attached to the transformer. It may also be an integral part of the sensor. This type of system is fairly limited because only one or only a few parameters are monitored and limited processing and storage functionalities.

More comprehensive systems uses IEDs or other types of bay level devices for data transfer. This type of system is similar to the simpler stand-alone systems, but have several advantages. The entire functionality of can either be implemented in one IED per transformer or can be designed on a modular base and be allocated in various interconnected IEDs, that cooperate, or the functionality of the IEDs is combined with a monitoring server installed, typically at the station level. Several transformers can also be connected to the same IED. Such approach will reduce the cost. With this type of architecture, various data from all subparts of the power transformer can be evaluated, and a useful correlation of all relevant data of the transformer or even between transformer can be provided more easily.

Systems can also be integrated into the overall substation automation system, to be integrated with protection and control devices. Protection and control systems collect much information and data, and often it is only a case of harnessing this data to use in condition monitoring systems. Thus, condition monitoring should no longer be considered a separate system. Integrated systems can in this way, have many sources of data that are acquired on the transformer and in the utility system. Condition evaluation and interpretation can then be based on a fleet of transformers. This data can also be used together with data about the substation's topology, transformer typology (based on the design and manufacturer), factory tests, periodic offline and periodic on-line diagnostics and inspections, and relevant information from protection systems. This will provide the full picture of the transformer condition.

Different utilities and different circumstances of use and different sizes and types of transformer means that there can be no one type of monitoring system to suit all transformers. The need for and type of monitoring required is likely to change during the lifetime of a power transformer. The thesis work found that systems varies greatly, and there is no standardisation of how condition monitoring systems should be designed. In addition, it is important to keep in mind that the quality of a condition monitoring system is only as good as good as the input data.

Due to that utilities generally have little or no experience with condition monitoring systems in digital substations, it can be assumed that technicians and engineers need some training. In addition, the connection of fibre optic cables requires special competence. In order to expand the competence of the workforce, resources have to be put down.

7.3 Communication

Regarding condition monitoring in digital substations one of the main aims is to achieve interoperability between devices from different vendors. There are several communication standards that are widely used in substations that can facilitate interoperability. IEC 61850 has the scope of to achieve multi-vendor interoperability, in addition to be networkable throughout the whole utility system, from the process level to the station and network levels.

IEC 61850 is object-oriented, and facilitates a data model for condition monitoring objects, services and data models. It defines standardised names instead of these being dictated by the device vendor or configured by the user. All names are provided in a power system context that enables the engineer to immediately identify the meaning of data. IEC also established the XML based language SCL, which enable the configuration of a device and its role in the power system to be precisely defined.

The standard does not code specific services to any protocols; ACSI ensures that the standard can continuously be upgraded and extended to include future technologies. The services are mapped to specific communication protocols, that are SV, GOOSE and MMS messages. Condition monitoring data is probably not advisable to be communicated over GOOSE or SV. GOOSE messages will send data to all devices that are configured to receive GOOSE messages, and therefore condition data may overload the communication channels. SV are sampled 80 times per cycle and this is a lot more samples than what is required for condition monitoring, which typically requires one sample per hour. Consequently, MMS messages is probably the best message type for exchanging condition monitoring data.

Condition monitoring systems also need to satisfy the regulatory requirements regarding duplicated and physically independent routing of cables and communication channels, which was mentioned in Section 5.3. With the application of a redundant process bus, these requirements may become easier to satisfy.

The main substation feature introduced by IEC 61850 and the digital substation layout is the process bus. However, as condition monitoring systems typically are made of sensors directly coupled to a central monitoring process device, which can be coupled further to a bay level device, condition monitoring data does not need to be transmitted over the process bus. This is also in accordance with the restrictions on merging condition data and operational data over the process bus. Despite the restrictions, a method to merge condition data and operational data is to configure the condition monitoring IED to read-only operational data from the process bus. As such, no write command can be issued to take control of substation devices.

Cyber security issues must be properly addressed. Condition monitoring networks may be a backdoor for hackers. It was found that IEC61850 standard has serious security problems that need to be dealt with. Security attacks commonly performed on the internet can hack into substation automation systems because IEC61850 employs a routable network using Ethernet technology. On top of that, the GOOSE and SV messages used in IEC61850 are found to be insecure due to the un-encrypted and un-authenticated nature of these messages.

The IEC 61850 delivers substation benefits that are not available using legacy standards. In terms of costs it lowers the installation, extension and integration costs. This standard also addresses issues regarding digitising substations, especially with regard to standardization of data names, creation of a comprehensive set of services, implementation over standard protocols and hardware, and definition of a process bus.

7.4 Vendor Products

A web search was carried out to look for commercially available products from different vendors. 11 comprehensive power transformer monitoring solutions have been briefly analysed. All systems except one was compliant with IEC 61850. This shows that the standard has really entered the market and become mainstream among vendors.

The monitoring facilities vary among the users, however DGA, bushing monitoring and temperature measurements are often implemented. Thus, most vendors follow the Cigré recommendations given in [27].

In terms of intelligent interpretation methods, it was difficult to find what methods the different vendor solutions use, as the vendors often state that their system applies several transformer's models and evaluation techniques, but rarely provides technical details about these. These are probably secret due to competition in the market to create the best models. However, systems are based on either knowledge based techniques that aim to replicate the expert knowledge of an expert while or data-driven techniques that aim to encode lower level pattern facets of intelligence. As methods should take into account nameplate values from the manufacturer, and other factory test data, it is an advantage to buy the condition monitoring system along with the transformer, so that the transformer and the system are provided in one set.

Based on information from the product survey which was conducted in this thesis, it can be estimated that the price of a comprehensive condition monitoring system is in the range of a few hundred thousand Norwegian kroner. However, the application of condition monitoring systems in digital substations can lead to several other cost savings, which should be taken into account when comparing it with conventional time-based monitoring. Prices for simpler systems is much lower, as one can buy stand-alone sensors with a central monitoring unit, that can measure one or a few parameters. A typical example is a dissolved-gas-in-oil content sensor. However, these as well range much in price. A single gas sensor measuring hydrogen costs around 70,000 Norwegian kroner, while multiple gas sensors costs about 340,000 Norwegian kroner. There is also probably great differences in prices between vendors. Cost was only collected from only one vendor. It is important to keep in mind that condition monitoring may not be the most cost efficient, as conventional or alternative practices may be more cost efficient.

Chapter 8

Conclusion and Further Work

In this thesis a literature review and a brief product survey on condition monitoring substations have been performed in order to evaluate means of how condition monitoring systems can be applied in digital substations in the transmission network. The analysis includes a discussion of the benefits and drawbacks of applying condition monitoring in digital substations compared to the use of time-based activities conventionally used.

This thesis started by describing the method of asset management involving the condition monitoring process. Then, typical ageing mechanisms and failure modes of power transformers were described, in addition to relevant measuring methods used to detect these. Various condition monitoring system architectures were presented, and ways to integrate the condition monitoring system into the substation automation system. Finally, some comprehensive system vendor solutions were analysed and presented to showcase what are commercially available on the market.

The purpose of this thesis was to investigate online continuous condition monitoring technologies and to provide a fairly broad insight into how these systems work. The aim has been to create a guide that can be of value to improve asset management decision-making in terms of maintenance and reinvestment. Monitoring facilities and ways of designing systems have been presented, and utilities can use this as a base to design their own systems ”in-house”.

It is certain that different utilities, different operational conditions and different power transformers will mean that there can be no one type of monitoring system to suit all transformers. The need for and type of monitoring required is likely to change during the lifetime of a transformer. The application of monitoring systems to transformers offers benefits particularly in detecting faults that can be fixed before causing irreparable damage. However, condition monitoring systems is a cost-adding alternative, and may not be the most cost efficient solution.

8.1 Recommendation for Further Work

Based on the discussion and conclusion, some considerations for further work and evaluation comprise the following:

- Application of condition monitoring on other components in the power system. Power transformers were used in this thesis because of its many parameters, subparts and corresponding monitoring facilities. It is also an expensive component that may be a good candidate for condition monitoring. Other components may include switchgear, power lines, power cables, generators, dry-type transformers, reactors, capacitor banks, and electrical machines.
- Test of GOOSE, SMV and MMS messages for condition data transfer, and compare them to see which is the best suited data transfer method.
- Although other protocols than IEC 61850 may not be very interesting as a standard for communication, other standards, such as DNP 3, MODBUS, etc., can be evaluated in terms of condition monitoring.
- Investigation of process bus redundancy, with a main bus and a backup bus. Main bus can be wired and the backup bus wireless. Experience will be used to establish verified process bus communication, and test synchronisation, time delays and cyber security aspects.
- Creation of a condition monitoring test facility for power transformers using digital substation architecture to test interoperability and cyber security measures.
- As pilot digital substations are implemented around in various utilities, both in Norway and abroad, it would be useful to conduct a survey on user experiences and challenges. Aspects to analyse could be monitoring facilities, communication architecture, cyber security, and cost evaluation.
- Test IEC 61850 compliance of devices and establish standard test procedures. This will make sure that the quality and interoperability of devices is achieved. As a result, network operators can implement IEC 61850 condition monitoring systems and devices with a plug and play approach.

- Investigation of which criteria that should be used for power transformer reinvestment. Reinvestments are economically challenging and should be based on several significant criteria. It can be a challenge to determine and specify good criteria.

- Cost-benefit analysis can be performed on a set of criteria that indicate what types of condition monitoring systems and monitoring facilities that are economical. With a comparison with conventional time-based monitoring, it is possible to evaluate what method is the most cost efficient for different situations. Such an evaluate should ideally see the economy of condition monitoring in the long run, preferably over the whole lifetime of a transformer, and should be based on many power transformers.

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Appendices

Appendix A

Table 8.1: IEC 61850 to MMS object mapping.

IEC 61850 Objects	MMS Objects
SERVER class	Virtual Manufacturing Device (VMD)
LOGICAL DEVICE class	Domain
LOGICAL NODE class	Named Variable
DATA class	Named Variable
DATA-SET class	Named Variable List
SETTING-GROUP-CONTROL-BLOCK class	Named Variable
REPORT-CONTROL-BLOCK class	Named Variable
LOG class	Journal
LOG-CONTROL-BLOCK class	Named Variable
GOOSE-CONTROL-BLOCK class	Named Variable
GSSE-CONTROL-BLOCK class	Named Variable
CONTROL class	Named Variable
Files	Files

Table 8.2: IEC 61850 service mapping (partial).

IEC 61850 Services	MMS Services
LogicalDeviceDirectory	GetNameList
GetAllDataValues	Read
GetDataValues	Read
SetDataValues	Write
GetDataDirectory	GetNameList
GetDataDefinition	GetVariableAccessAttributes
GetDataSetValues	Read
SetDataSetValues	Write
CreateDataSet	CreateNamedVariableList
DeleteDataSet	DeleteNamedVariableList
GetDataSetDirectory	GetNameList
Report (Buffered and Unbuffered)	InformationReport
GetBRCBValues/SetURCBValues	Read
SetBRCBValues/SetURCBValues	Write
GetLCBValues	Read
SetLCBValues	Write
QueryLogByTime	ReadJournal
QueryLofAfter	ReadJournal
GetLogStatusValues	GetJournalStatus
Select	Read/Write
SelectWithValue	Read/Write
Cancel	Write
Operate	Write
Command-Termination	Write
TimeActivated-Operate	Write
GetFile	FileOpen/FileRead/FileClose
SetFile	ObtainFile
DeleteFile	FileDelete
GetFileAttributeValues	FileDirectory

Appendix B

Table 8.3: Noncurrent-carrying metal components failure mechanisms, and measured signals [13].

<table>
<tr><th colspan="3">Noncurrent-carrying metal components</th></tr>
<tr><th>Specific</th><th>Phenomenon</th><th>Measured signals</th></tr>
<tr><td>Core</td><td>Overheating of laminations</td><td>Top and bottom temperatures
Ambient temperature
Line currents
Voltage
Hydrogen (minor overheating)
Multigas, particularly ethane, ethylene, and methane (moderate or severe overheating)</td></tr>
<tr><td>Frames
Clamping
Cleats
Shielding
Tank walls</td><td>Overheating due to circulating currents, leakage flux</td><td>Top and bottom temperatures
Ambient temperature
Line currents
Voltage
Multigas, particularly ethane, ethylene, and methane</td></tr>
<tr><td>Core ground
Magnetic shield</td><td>Floating core and shield grounds create discharge</td><td>Hydrogen or multigas
Acoustic and electric PD</td></tr>
</table>

Table 8.4: Winding insulation failure mechanisms, and measured signals [13].

Winding insulation		
Specific	Phenomenon	Measured signals
Cellulose: Paper, pressboard, wood products	Local and general overheating and excessive ageing	Top and bottom temperatures Ambient temperature Line currents RS moisture in oil Multigas, particularly carbon moxide, carbon dioxide and oxygen
	Severe hot-spot Overheating	Top and bottom temperatures Ambient temperature Line currents Moisture in oil Multigas, particularly carbon monoxide, carbon dioxide, ethane, hydrogen and oxygen
	Moisture contamination	Top and bottom temperatures Ambient temperature Relative saturation of moisture in oil
	Bubble generation	Top and bottom temperatures Ambient temperature Total percent dissolved gas-in-oil Line currents Relative saturation of moisture in oil Hydrogen Acoustic and electric PD
	Partial discharge	Hydrogen or mulitgas Acoustic and electric PD

Table 8.5: Winding insulation failure mechanisms, and measured signals [13].

Liquid insulation		
Specific	Phenomenon	Measured signals
Transformer oil	Moisture contamination	Top and bottom temperatures Ambient temperature Relative saturation of moisture in oil
	Partial discharge	Hydrogen Acoustic and electric PD
	Arcing	Hydrogen
	Local overheating	Ethylene, ethane, methane

Table 8.6: Cooling system failure mechanisms, and measured signals [13].

Cooling system		
Specific	Phenomenon	Measured signals
Fans, pumps, temperature-measurement devices	Electric failures of pumps and fans	Motor (fan, pump) currents Top-oil temperature Line currents
	Failure or inaccuracy of top liquid or winding temperature indicators or alarms	Ambient temperature Top and bottom temperatures Line currents
Internal cooling path	Defects or physical damage in the directed flow system	Top and bottom temperatures Ambient temperature Line currents
	Localised hot-spots	Carbon monoxide and carbon dioxide
Radiators and coolers	Internal or external blocking of radiators resulting in poorheat exchange	Top and bottom temperatures Ambient temperature Line currents

Table 8.7: Oil and winding temperature forecasting, failure mechanisms and measured signals [13].

Oil and winding temperature forecasting		
Specific	Phenomenon	Measured signals
Tranformer oil and windings	Overloading of transformer	Top and bottom tempeatures Ambient temperature Line currents Moisture in oil Multigas, particularly carbon monoxide, carbin dioxide and oxygen

Appendix C

```
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    <DO name="Ind5" type="iGrid_SINTEF_Sample_v1_SPS" />\par
    <DO name="Ind6" type="iGrid_SINTEF_Sample_v1_SPS" />\par
    <DO name="Ind7" type="iGrid_SINTEF_Sample_v1_SPS" />\par
    <DO name="Ind8" type="iGrid_SINTEF_Sample_v1_SPS" />\par
    <DO name="AnIn1" type="iGrid_SINTEF_Sample_v1_MV" />\par
    <DO name="AnIn2" type="iGrid_SINTEF_Sample_v1_MV" />\par
    <DO name="SPCSO1" type="iGrid_SINTEF_Sample_v1_SPC" />\par
    <DO name="SPCSO2" type="iGrid_SINTEF_Sample_v1_SPC" />\par
    <DO name="SPCSO3" type="iGrid_SINTEF_Sample_v1_SPC" />\par
    <DO name="SPCSO4" type="iGrid_SINTEF_Sample_v1_SPC" />\par
  </LNodeType>\par
  <DOType id="iGrid_SINTEF_Sample_v1_ENS" cdc="ENS">\par
    <DA name="stVal" fc="ST" bType="Enum" type="Beh" dchg="true" dupd="true" />\par
    <DA name="q" fc="ST" bType="Quality" qchg="true" />\par
    <DA name="t" fc="ST" bType="Timestamp" />\par
  </DOType>\par
  <DOType id="iGrid_SINTEF_Sample_v1_DPL" cdc="DPL">\par
    <DA name="vendor" fc="DC" bType="VisString255" />\par
  </DOType>\par
  <DOType id="iGrid_SINTEF_Sample_v1_ENS_Health" cdc="ENS">\par
    <DA name="stVal" fc="ST" bType="Enum" type="Health" dchg="true" dupd="true" />\par
    <DA name="q" fc="ST" bType="Quality" qchg="true" />\par
    <DA name="t" fc="ST" bType="Timestamp" />\par
  </DOType>\par
  <DOType id="iGrid_SINTEF_Sample_v1_SPS" cdc="SPS">\par
    <DA name="stVal" fc="ST" bType="BOOLEAN" dchg="true" />\par
    <DA name="q" fc="ST" bType="Quality" qchg="true" />\par
    <DA name="t" fc="ST" bType="Timestamp" />\par
  </DOType>\par
  <DOType id="iGrid_SINTEF_Sample_v1_MV" cdc="MV">\par
    <DA name="instMag" fc="MX" bType="Struct" type="iGrid_SINTEF_Sample_v1_AnalogueValue" />\par
    <DA name="mag" fc="MX" bType="Struct" type="iGrid_SINTEF_Sample_v1_AnalogueValue" dchg="true" />\par
    <DA name="q" fc="MX" bType="Quality" qchg="true" />\par
    <DA name="t" fc="MX" bType="Timestamp" />\par
    <DA name="db" fc="CF" bType="INT32U" />\par
    <DA name="rangeC" fc="CF" bType="Struct" type="iGrid_SINTEF_Sample_v1_RangeConfig" />\par
  </DOType>\par
  <DOType id="iGrid_SINTEF_Sample_v1_SPC" cdc="SPC">\par
```

```
  <DA name="SBOw" fc="CO" bType="Struct" type="iGrid_SINTEF_Sample_v1_SPCSelectWithValue" />\par
  <DA name="Oper" fc="CO" bType="Struct" type="iGrid_SINTEF_Sample_v1_SPCOperate" />\par
  <DA name="ctlModel" fc="CF" bType="Enum" type="ctlModelEnum" />\par
</DOType>\par
<DAType id="iGrid_SINTEF_Sample_v1_AnalogueValue">\par
  <BDA name="f" bType="FLOAT32" />\par
</DAType>\par
<DAType id="iGrid_SINTEF_Sample_v1_RangeConfig">\par
  <BDA name="hhLim" bType="Struct" type="iGrid_SINTEF_Sample_v1_AnalogueValue" />\par
  <BDA name="hLim" bType="Struct" type="iGrid_SINTEF_Sample_v1_AnalogueValue" />\par
  <BDA name="lLim" bType="Struct" type="iGrid_SINTEF_Sample_v1_AnalogueValue" />\par
  <BDA name="llLim" bType="Struct" type="iGrid_SINTEF_Sample_v1_AnalogueValue" />\par
  <BDA name="min" bType="Struct" type="iGrid_SINTEF_Sample_v1_AnalogueValue" />\par
  <BDA name="max" bType="Struct" type="iGrid_SINTEF_Sample_v1_AnalogueValue" />\par
</DAType>\par
<DAType id="iGrid_SINTEF_Sample_v1_Originator">\par
  <BDA name="orCat" bType="Enum" type="orCatEnum" />\par
  <BDA name="orIdent" bType="Octet64" />\par
</DAType>\par
<DAType id="iGrid_SINTEF_Sample_v1_SPCSelectWithValue">\par
  <BDA name="ctlVal" bType="BOOLEAN" />\par
  <BDA name="origin" bType="Struct" type="iGrid_SINTEF_Sample_v1_Originator" />\par
  <BDA name="ctlNum" bType="INT8U" />\par
</DAType>\par
<DAType id="iGrid_SINTEF_Sample_v1_SPCOperate">\par
  <BDA name="ctlVal" bType="BOOLEAN" />\par
  <BDA name="origin" bType="Struct" type="iGrid_SINTEF_Sample_v1_Originator" />\par
  <BDA name="ctlNum" bType="INT8U" />\par
</DAType>\par
<EnumType id="Beh">\par
  <EnumVal ord="1">on</EnumVal>\par
  <EnumVal ord="2">blocked</EnumVal>\par
  <EnumVal ord="3">test</EnumVal>\par
  <EnumVal ord="4">test/blocked</EnumVal>\par
  <EnumVal ord="5">off</EnumVal>\par
</EnumType>\par
<EnumType id="Health">\par
  <EnumVal ord="1">Ok</EnumVal>\par
  <EnumVal ord="2">Warning</EnumVal>\par
```

```
      <EnumVal ord="3">Alarm</EnumVal>\par
    </EnumType>\par
    <EnumType id="orCatEnum">\par
      <EnumVal ord="0">not-supported</EnumVal>\par
      <EnumVal ord="1">bay-control</EnumVal>\par
      <EnumVal ord="2">station-control</EnumVal>\par
      <EnumVal ord="3">remote-control</EnumVal>\par
      <EnumVal ord="4">automatic-bay</EnumVal>\par
      <EnumVal ord="5">automatic-station</EnumVal>\par
      <EnumVal ord="6">automatic-remote</EnumVal>\par
      <EnumVal ord="7">maintenance</EnumVal>\par
      <EnumVal ord="8">process</EnumVal>\par
    </EnumType>\par
    <EnumType id="ctlModelEnum">\par
      <EnumVal ord="0">status-only</EnumVal>\par
      <EnumVal ord="1">direct-with-normal-security</EnumVal>\par
      <EnumVal ord="2">sbo-with-normal-security</EnumVal>\par
      <EnumVal ord="3">direct-with-enhanced-security</EnumVal>\par
      <EnumVal ord="4">sbo-with-enhanced-security</EnumVal>\par
    </EnumType>\par
  </DataTypeTemplates>\par
</SCL>\par
}
```

Listing 8.1: The iRTU code that was implemented in the iRTU.

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