TAMPEREEN TEKNILLINEN YLIOPISTO

OSKARI VUORINEN

USING PROCESS DATA IN CONDITION BASED MAINTENANCE

Master of Science Thesis

Examiner: Professor Pekka Verho
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ABSTRACT

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Electricity plays a major role in today’s society and it is being taken for granted. For Electricity Network Company it is important that distribution of electricity is safe and disturbance free. Networks components faults will cause costs because compensation of disturbances is paid for the customers. For this reason it is important to minimize unplanned interruptions and optimize equipment performance. Network assets condition monitoring has an important role in the whole electricity network company’s operations so that investments timing and network assets lifetime can be optimize.

The objective in maintenance is to maintain electricity network performance as high as possible. Its purpose is maintaining reliability, guarantee safety, prevent disturbances and repair noticed failures as fast as possible with optimal costs.

Maintenance can be divided into preventative maintenance and corrective maintenance. In preventative maintenance the aim is to prevent failures and it can be performed either time based or condition based. Efficient maintenance is based on condition inspections when condition monitoring of components can be used to optimize its lifetime and maintenance costs. Networks components can be also overhauled in certain time intervals but then unnecessary investments are possible.

The objective of this thesis is to clarify how condition based maintenance can be implemented more efficiently by using available network information. Appropriate would be that the resources could be used to necessary overhauls and not to inspections. For this purpose failure development is explained. Also insights are given on how to improve maintenance. The primary substations transformer, circuit breakers and protection relays has presented manners how their condition could be estimated without visiting the substation. The basis has been conveying data from primary substation and modern numeric relay possibilities to operate as data collectors.

Today ICT-technology enables gathering of diverse data from the electricity networks. Telecommunications make it possible to transmit information however for this purpose it is necessary to develop a system which can analyse and restore this data. This thesis presents potential structures for system infrastructure and database which could be practical. Intention is that system would not only serve maintenance but would also make possible to implement future smart grid technologies.

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Sähkö on hyvin tärkeä osa nyky-yhteiskuntaa ja sen saanti otetaan itsestäänselvyytenä. Häiriötön ja turvallinen sähkönjakelu on sähköverkkoyhtiölle merkittävä asia. Verkoston komponenttien viat aiheuttavat kustannuksia ja häiriöistä maksetaan korvauksia asiakkaille. Tämän takia suunnittelemattomat keskeytykset halutaan minimoida ja laitteiden toimintakyky optimoida. Verkosto-omaisuuden kunnonvalvonnalla on tärkeä rooli sähköverkkoyhtiön koko toiminnassa, jotta investointiajankohdat ja verkosto-omaisuuden käyttöikä voidaan optimoida.

Kunnossapidon tavoitteena on pitää sähköverkko mahdollisimman toimintakykyisenä. Sen tarkoituksena on käyttövarmuuden ylläpito, turvallisuuden takaaminen, häiriöiden ehkäiseminen sekä ilmaantuneiden vikojen nopea korjaaminen optimaalisin kustannuksin.

Kunnossapito jaetaan ehkäisevään kunnossapitoon ja korjaavaan kunnossapitoon. Ehkäisevässä pyritään ehkäisemään vikaantuminen ja se voidaan suorittaa joko aikaperusteisena tai kuntotilaan perustuen. Tehokas kunnossapito perustuu kuntotarkastuksiin, jolloin komponenttien kunnonvalvonnalla voidaan optimoida käyttöikä ja kunnossapitokustannukset. Verkoston komponentteja voidaan myös huoltaa tietyin aikavälein, mutta tällöin saatetaan tehdä tarpeettomia investointeja.

Tässä työssä tavoitteena oli selvittää, miten kuntopohjaista kunnossapitoa voidaan implementoida tehokkaammin käyttämällä verkosta saatavaa informaatiota. Tarkoituksenmukaista olisi, että resurssit käytettäisiin tarpeellisiin huoltoihin eikä tarkastuksiin. Tätä varten on selvitetty vikojen kehittyminen sekä pohdittu miten kunnonvalvontaa voisi kehittää. Sähköaseman päämuuntajalle, katkaisijalle ja suojareleelle esitetään tavat, joilla niiden kuntoa voidaan arvioida ilman sähköasemalla käyntiä. Lähtökohtana on ollut tiedon välittäminen sähköasemalta ja nykyisten suojareleiden mahdollisuudet toimia tiedon kerääjinä.

ICT -teknologia mahdollistaa nykyisin hyvin monenlaisen tiedon keräämisen sähköverkosta. Tietoliikenneyhteydet mahdollistavat informaation välittämisen, mutta tätä varten pitää kehittää järjestelmä, joka pystyy analysoimaan ja varastoimaan tätä tietoa. Tässä työssä on esitetty mahdollisuuksia, millainen tietojärjestelmärakenne voisi olla toimiva. Tarkoituksena on esitellä järjestelmä, joka ei palvelisi vain kunnossapitoa, vaan mahdollistaisi myös tulevaisuuden älykkäiden sähköverkkojen ratkaisujen implementoimisen.

PREFACE

This work is a Master of Science Thesis for Tampere University of Technology. The work was made in LNI Verkko Oy in Tampere as a part of Smart Grids and Energy Markets (SGEM) research program project.

The supervisor from LNI Verkko Oy was M.Sc. Turo Ihonen who gave me ideas and advices for this work. I want to thank Turo for choosing me to do this master's thesis and giving me an opportunity to work at the premises of LNI Verkko Oy in Tampere. I also want to thank all of my other colleagues in LNI Verkko Oy for providing me information related to my work and other appealing conversations.

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Oskari Vuorinen
oskari.vuorinen@gmail.com

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ABBREVIATIONS AND NOTATION

I_0	Zero sequence current
I_1	The first phase current
I_2	The second phase current
I_3	The third phase current
I_{arc}	The arching current
I_{max}	Maximum current
k	Number of interruptions in certain current I
L	The absolute lifetime consumption
T	The operating time
t_1	The start time
t_2	The end time
U_o	Neutral point displacement voltage
V	Relative lifetime consumption
Θ_h	Hot spot temperature
φ	Phase-angle

ABB	Asea Brown Boveri
AMI	Advance metering infrastructure
AMR	Advance meter reading
ANN	Artificial neural network
ASP	Application service provider
C_2H_2	Acetylene
C_2H_4	Ethylene
C_2H_6	Ethane
CB	Circuit breaker
CBM	Condition based maintenance
CH_4	Methane
CIM	Common information model
CLEEN	Cluster for energy and environment
CO	Carbon monoxide
CO_2	Carbon dioxide
COMTRADE	Common format for transient data exchange
DER	Distributed energy resources
DG	Distributed generation
DGA	Dissolved gas analysis
DMS	Distribution management system
DSM	Demand side management
FRA	Frequency response analysis
H_2	Hydrogen
HMI	Human machine interface

ICT	Information and communications technology
IEC	The International Electrotechnical Commission
IED	Intelligent electric device
IT	Information technology
LCC	Life cycle cost
MDMS	Meter data management system
NIS	Network information system
OLTC	On load tap charge
PD	Partial discharge
P-F	Potential failure to failure
RBM	Risk based maintenance
RCM	Reality-centred maintenance
RMS	Root mean square
RTU	Remote terminal unit
SCADA	Supervisory Control and Data Acquisition
SF_6	Sulfur hexafluoride
SGEM	Smart Grids and Energy Markets
TBM	Time based maintenance

1. INTRODUCTION

Distribution of electricity is very important part of today's society and customers are monetarily compensated for outages in the electricity distribution. This is why unscheduled interruptions are wanted to minimize which are the most of the time result of faults. Maintenance of the electricity network plays an important role in this. Maintenance management in electricity networks consumes lots of resources and money. Nowadays maintenance for most of the components in the power grid are done periodically or when a fault is noticed. Time based maintenance (TBM) for certain components is unnecessary and it uses resources which could be directed on the objects for which maintenance provides maximum benefits. Unanticipated faults reduce also unwanted interruptions and could be prevented if the component's weak condition would be noticed early enough. Hereby it can be repaired and preventive operations could be implement which also could lengthen component's life time. Condition based maintenance could reduce redundant maintenance expenses and centralize resources to important repairs rather than inspections.

This research and analysis has been completed for primary substation and especially for protection relays, circuit breakers and transformers. The protection relay provides several possibilities to observe quantities which could be collected remotely. This makes protection relay an important component and gives an excellent aspect to study usability of process data. Information which is received from relays can be used to indicate circuit breakers condition. Past research has been done to evaluate how the transformer condition can be observed without interruption of electricity distribution.

Objectives of this thesis are to foresee circuit breakers and transformers faults from the information which is collected and can be received from the primary substations. The aim is also to explain how it is possible to lengthen the periodic testing intervals for protection relays. There are some ideas how maintenance management system could be implemented and integrated to current management systems and what could the condition based maintenance be in future. Ideas of how measured data could serve other purposes than only maintenance are also presented.

The thesis is organized so that the background of the theme is introduced in Chapters 2, 3 and 4. Electricity networks are and must be designed for long duration. In Chapter 2 information is presented about smart grids since decision, actions and long term plans for electricity network must be complete so that they support the future ideas. An explanation how this thesis is connected to on-going research programs in Finland is also provided.

Maintenance management definitions and concepts are briefly presented in Chapter 3. Differences between common strategies and how condition monitoring can be implemented will be presented. The last part of this chapter takes a small glance to how and why maintenance strategy is currently fulfilled in power grid companies. The focus is to summarize what maintenance is today.

This work concentrates to primary substations. Chosen components are very critical for substations safe and reliable operations. They are feeder terminal, circuit breaker and the primary transformer. Feeder terminal and circuit breaker forms electricity networks protection. Protection relay or feeder terminal as is spoken today of modern protection relays can be used more efficient than it is utilized today.

Chapter 4 represents protection relay and its most typical protections, short circuit and earth fault. The faults and the protections ways are explained briefly. The circuit breaker interrupts circuit and it operates with protection relay. There are many diverse circuit breakers but basic operating idea is same for all. Chapter 4 explains typical fault situation and condition monitoring techniques. Maintenance actions are also discussed shortly. It is crucial to know the condition of the transformer since it is the most expensive component of the substation. The end of Chapter 4 deals with the transformer. Failure reasons for transformers can be categorised. These are key factors to identify the correct targets which can be influenced by utilizing condition monitoring. There are various kinds of methods to examine the transformers condition. These methods and their objects are also presented. The last section presents auxiliary battery system which provides back up current for all the substations devices. It is presented here as its condition monitoring can be easily connected to the feeder terminal.

Today's maintenance strategies can be more efficient and can be enhanced. Chapter 5 will discuss this matter. Failure density for specific equipment is important to know or at least general trend when the maintenance actions are planned. In order to predict and detect failure, the basic principles how failures develop over time should be known. These matters are also discussed in Chapter 5. One incentive for electric network company to improve maintenance is the financial savings and for this purpose some calculations have been done in the last section of Chapter 5. Economical example is calculated for protection relays of how efficient condition monitoring would affect its maintenance expenses.

Condition based maintenance requires condition monitoring. Process data is available and possible to gather from electricity networks. The beginning of Chapter 6 concentrates on condition monitoring and process data. Protection's functionality is possible to evaluate from fault situation. This matter includes ensuring relays performance. Chapter 6 explains problems and method how over-current and directional feeder protection could be ensured. Ideas to estimate the circuit breakers condition are also presented. For primary transformers insulation monitoring and wearing is appraised in the last section.

In order to implement condition based maintenance advance and efficient system infrastructure is needed. Chapter 7 explains what requirements would enable to process data efficiently. System development needs to serve future purposes and that is why smart grid ideology is important to keep in mind. Adaptive system infrastructure can be very profitable option. A stand is taken for database concept and system infrastructure. The approach is done by explaining first today’s applications’ which are closely related.

Chapter 8 demonstrates what kind of pilots can be implemented by using subjects which are handled in this thesis. Example pilots are described so that the applications which are provided today would need as little as possible further development. Last chapter takes these concepts in the future and explains possibilities which are possible to implement. There are demonstrated feeder terminals possibilities and what the adaptive protection would require. Wider monitoring of the whole network infrastructure would set more requirements to the systems and connections. The last chapter also provides ideas what kind of monitoring and automation can be implemented to lower levels in electricity network hierarchy.

2. THE FUTURE OF ELECTRICITY NETWORKS

Many components in the existing network are old and are coming to the end of their lifetime. At the same time requirements for network and the risk for major disturbance are increasing. Also society's dependency to receive electricity is very high as last winter black outs in Finland prove. The penetration of renewable energy sources will continue due to environmental reasons. Especially now after Japan's Fukushima problems, discussions of nuclear power have accelerated society's awareness of distributed generators. These are just few reasons why it is very important to develop the current network to be more advanced in long and short term. 20/20/20- targets means that 20 % of Europe's energy consumption in the year 2020 must be covered by renewable energy sources and at the same time 20 % reduction in greenhouse gases and 20 % improvement in energy efficiency should be obtained. Europe's commissions view is that if the targets are to be achieved, especially in energy efficiently, it means development of smart grids. The following section presents basic ideas of futures smart grids in distribution network and how subject of this research is related to that development. [1; 2]

2.1. Smart grids in distribution power grid

The Current electricity network is a delivery network where power flows in one direction to the customer and grid is in distribution level radial. In the future when distributed generators, such as solar panels and wind turbines, are becoming more common the distribution network must be developed because the power flow in the grid can flow to both directions. This sets demands to the low voltage network. To use it more similar as the high voltage transmission network in which construction is build loop like is a possible alternative. Smart grid concept does not yet have a unique and exact definition. It usually depends on the person talking however smart grid concept always has same kind of features as shown in Figure 2.1.

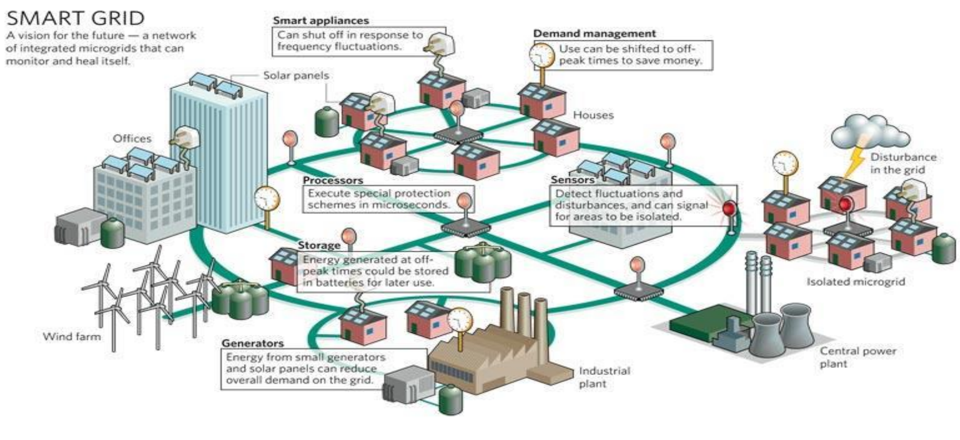

Figure 2.1 *One type of vision what could smart grid look alike* [3]

Now power supply is concentrated as shown in Figure 2.2 but in the smart grid concept the generators are distributed anywhere in the network. This and also the constant increase of electricity demand will require more efficient power network. In the future network should be active and flexible which comes from the use of available controlled resources. Today electricity production follows load but in the future it could be other way around for example electric vehicles are charged in the a night time when other electricity usage is lower. At the daytime synergy effects of supply from many energy resources will control load of the grid. This kind of synergy requirements and possibilities to connect distributed generators to the grid will make loop like design in low voltage network a good option as presented in the Figure 2.2. It would also decrease major disturbance probability if protection and usage plans can be made workable.

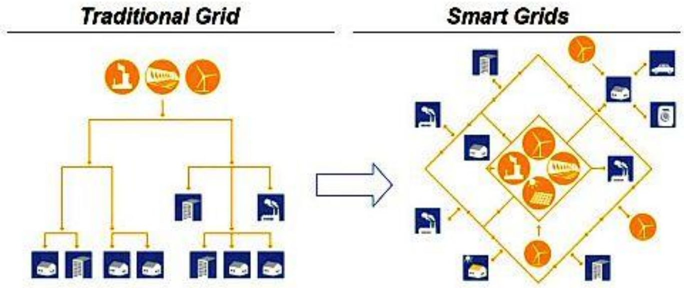

Figure 2.2 *The main characteristics of traditional and smart grid* [4]

It is certain that smart grid development demands more automation and intelligence to current grid. Within the scope of this thesis in distribution level of electricity network it would involve at least some common technologies which are presented next and in Figure 2.3.

- Distributed energy resources (DER)
  - Distributed generation (DG) integration → renewable energy sources
  - Demand side management (DSM) → balance of electricity supply and consumption
- Advance metering infrastructure (AMI)
  - Two-way flow of information → Automatic meter reading (AMR)
  - Meter data management system (MDMS)

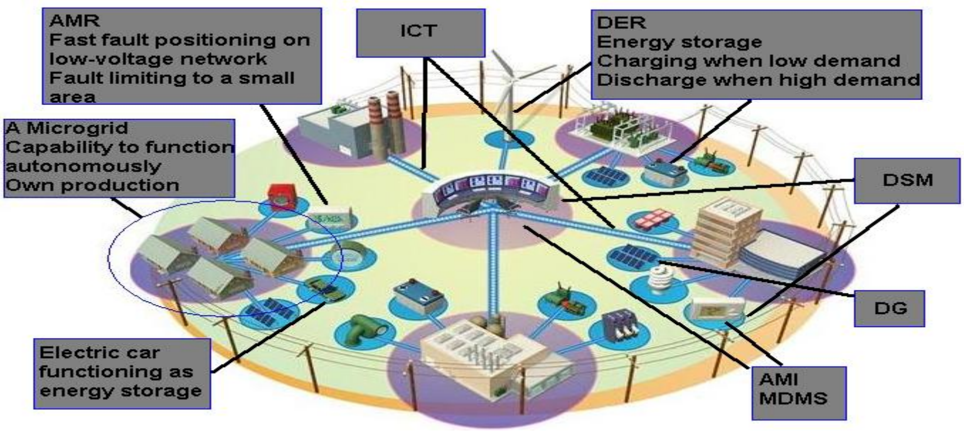

Figure 2.3 *Technologies which are connected to Smart Grids*

- Information and communications technology (ICT) integration
  - Two-way communication possibilities
  - Always available real-time information everywhere from network
- Wide-area monitoring and control systems
  - Real-time monitoring and display of power system components and performance over large geographic areas and across interconnections
  - Advance system operation tools

One demand for smart grids is that it would be self-healing. This function needs real-time information from power grid. Also it requires several automated controls to administer grid more efficiently for example to respond to system problems automatically. This is one point of view how this thesis subject is connected to smart grids. Another point is that if distributed generators are connected to the grid more information of loads and supply of electricity in distribution electricity network is needed. These matters and connections to smart grids are discussed more in Chapter 8. [1; 2; 5-8]

2.2. Smart grids and energy markets research program

Cluster for energy and environment (CLEEN) is energy and environment strategic centre for science, technology and innovation which have on-going research program called smart grids and energy markets (SGEM). This program is formed from seven work package like presented in Figure 2.4 and this thesis is part of the work package six. Vision is that parties which are working together in CLEEN generate significant innovations in an accelerating rate in the field of energy and environment. SGEM aims to develop international smart grid solutions which can be implemented in a real environment utilizing the Finnish infrastructure. One of these kinds of demonstrations is going to be in Helsinki Kalasatama.

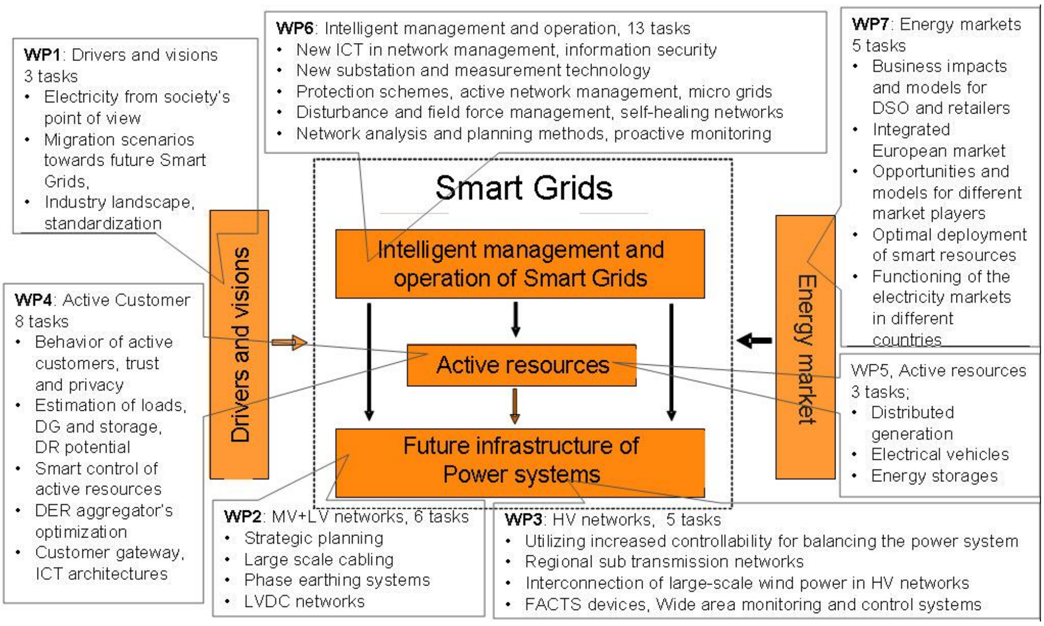

Figure 2.4 *SGEM work packages and connections to smart grids* [9]

Management and operation of smart grids is the theme of work package six. The three main categories are enabling technologies, applications and pilots. The different tasks are shown Figure 2.5. One task is proactive network monitoring in which the objective is to study of how the networks state can be predicted by monitoring. The research is done in network analysis and planning category.

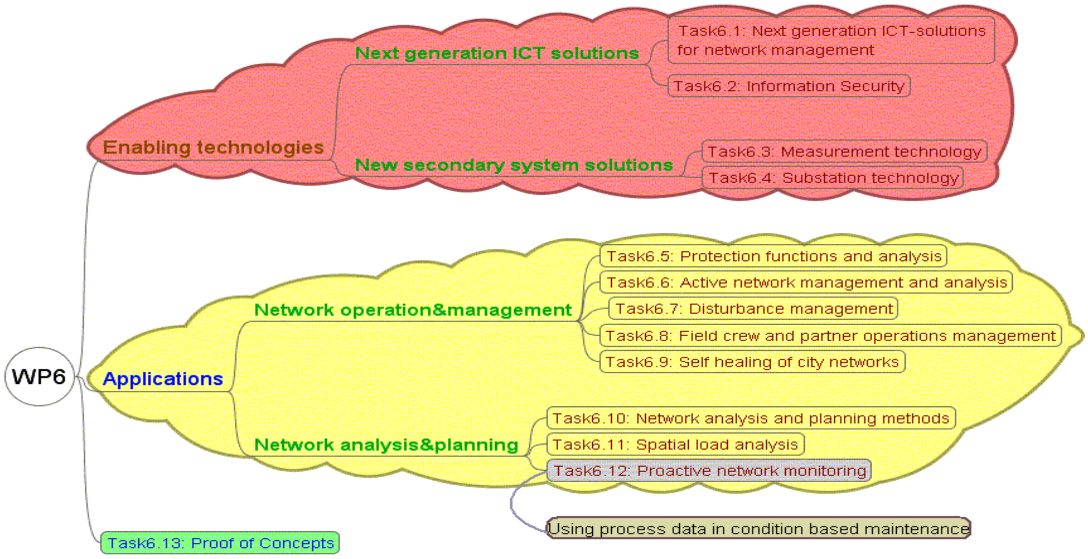

Figure 2.5 *SGEM work package 6 tasks and connections* [9]

The idea is to study how the current and needed technologies and processes can be implemented to proactive network monitoring like sensors, communication systems, smart substation automation etc. And is it possible to utilize current available technology more efficiently like information which can be received from protection relays. Focus is on maintenance and investments with intelligent decision making using process data and traditional network information. Connections of proactive network monitoring to the other network operations are shown in Figure 2.6. [9]

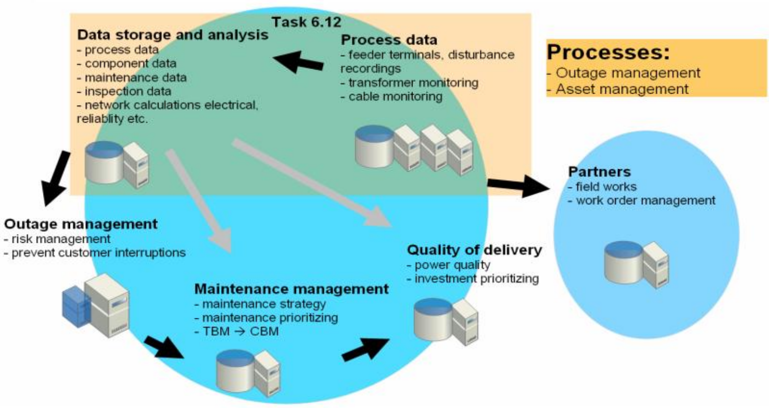

Figure 2.6 *Proactive network monitoring connections to the network operations*

As can be seen in the Figure 2.6 task's 6.12 idea is to utilize process and traditional data to serve various operations in the electric network business.

3. MAINTENANCE MANAGEMENT

Nowadays customers take for granted the availability and reliability of electricity. Power system reliability can be divided into adequacy and security. Adequacy means that power system is always capable of feeding enough power and energy to loads. Security on the contrary is concept that system can handle sudden failures. These factors are closely related to the condition of the equipment so that is why maintenance and maintenance management have important role in the electricity network companies. The idea of maintenance is to keep different components in power grid operational and optimize costs. Network companies are interested in improving their maintenance because it has always has had significant part in the utilities' financial plans. Maintenance is planned operations and the goals are to assure safety, maintain reliability, prevent disturbances and repair noticed faults as fast as possible with optimal costs. [2; 10; 11] This chapter explains background of maintenance in power grids.

Maintenance procedures are mainly preventative and corrective (remedial). Corrective maintenance is sudden and unplanned. Repairing is implemented when a failure is noticed. Preventative maintenance tries to prevent faults and it can be divided in to two groups, systematically done maintenance operations, time based or predetermined maintenance, and condition based maintenance operations. Preventative maintenance tries to minimize target's failure probability and keep the device operational. Maintenance strategies are presented in Figure 3.1. [11; 12]

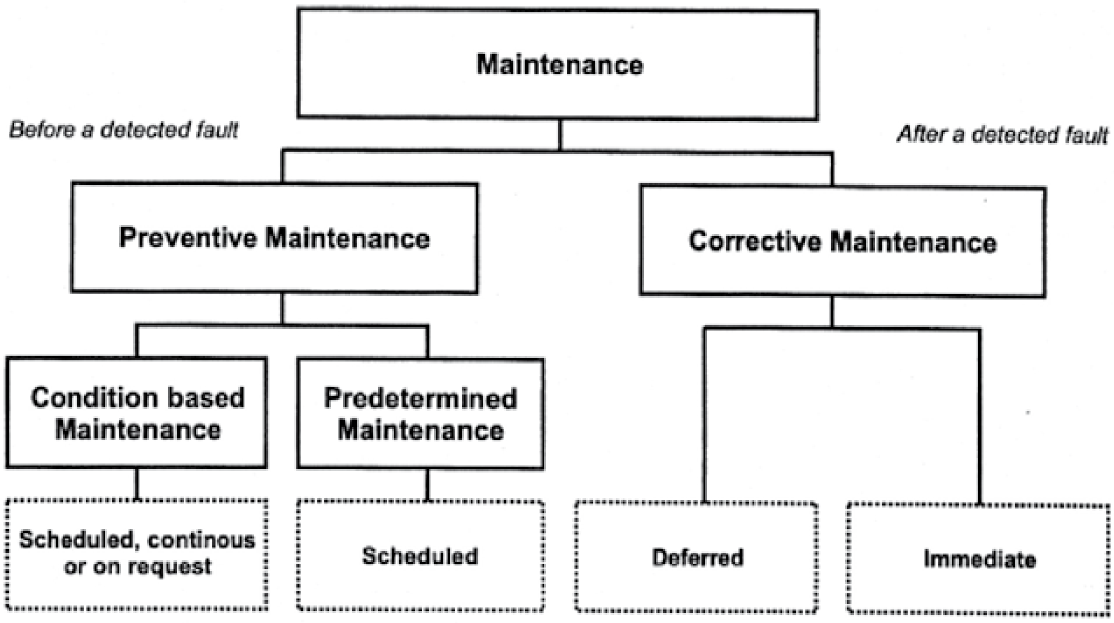

Figure 3.1 *Maintenance strategies and connections based on standard SFS-EN 13306:2001*

3.1. Corrective maintenance

If maintenance is only corrective, approach is reactive so that component is repaired only when a fault is noticed and electricity distribution is disturbed as a result. Remedial maintenance is only restoring component's condition to operational and it is the simplest maintenance strategy. There is no focus on any maintenance or repair operations of the device before the fault occurs. Strategy is cost-effective for components that are not critical for electricity distribution or just have low maintenance possibilities. Strategy is also applied to the components for which it is hard or expensive to get sensible condition information. Remedial maintenance will always be a part of maintenance management because it is not possible to predict all upcoming failures in power grid. That is why it is important for electricity network companies to have enough resources to operate effectively when the need occurs. [10; 11]

3.2. Preventive maintenance

The idea is to prevent components' unexpected faults. The economical boundaries are that if potential financial savings are bigger than expenses which are utilized to preventive maintenance, then its' use is valid. Preventative maintenance is based on predetermined and Condition Based Maintenance (CBM) actions, then components' weaknesses can be found and preventive maintenance can be performed. Anticipated actions have also important effect by increasing safety because preventive maintenance tries to decrease device's fault probability and retain its' performance.

Reliability-Centered Maintenance (RCM) or reliability based maintenance, name depends on the literature source, can be used as a tool to help to create preventive maintenance program. The idea for reliability-centered maintenance is that device's possible faults are individually taken to notice and the attempt is to optimize component's maintenance based on faults criticality and cost-consequence as can be seen from Figure 3.2.

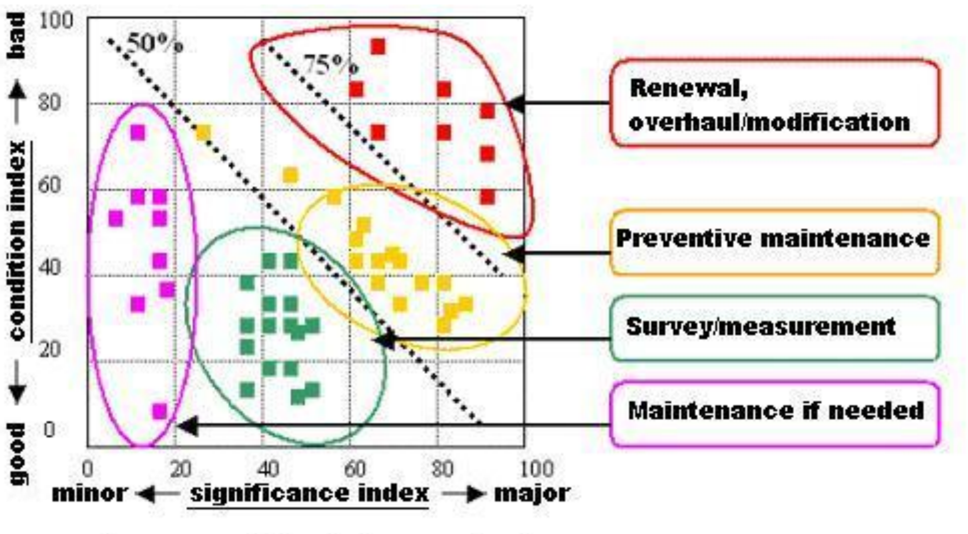

***Figure 3.2** Reliability-centered maintenance strategy* [11]

In this strategy each component is examined based on how crucial this component is and in what condition it really is. For example if component's effect to power grid's reliability is minor, then maintenance can be done only when it is needed. So basically in this example it is remedial maintenance. If component is crucial for power grid, inspections and measurements can be done in time intervals so that condition can be monitored. RCM is difficult to use and also expensive because it requires a fair amount of resources. Maintenance strategy, which is a combination of CBM and RCM, can be called Risk Based Maintenance (RBM) and connections are presented in Figure 3.3. There are also other usable methods however they are too expensive to apply maybe for other than high voltage components. [10; 11]

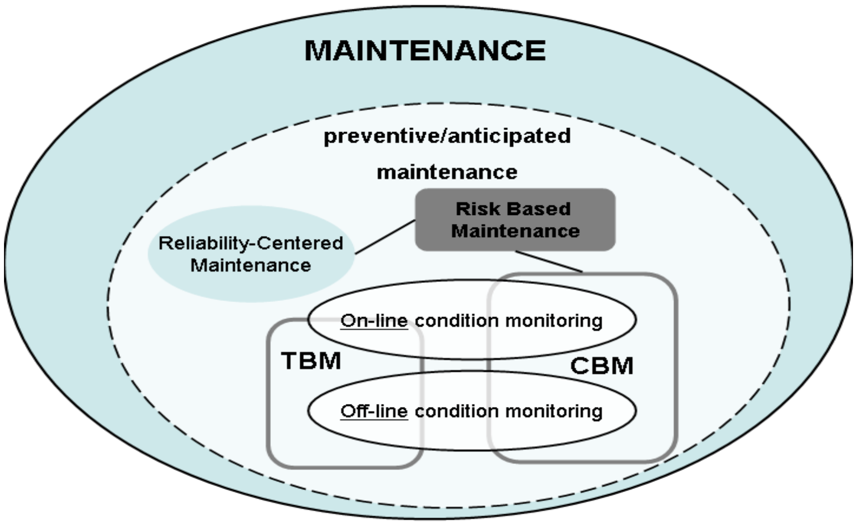

Figure 3.3 *Maintenance strategy connections in preventative maintenance*

Maintenance was started in time intervals, time based maintenance (TBM), when component's usage until it was broken was not enough as a strategy. Every device was maintained in certain period of time and at first the time interval was same for similar components. Mostly this service interval is defined by time but sometimes it is better to define it e.g. by usage time or by how many times component has operated. Chosen time interval is usually consistent with manufacturer's recommendation or within standards. Strategy is better especially for important components rather than just waiting for the component to break. But the problem is to specify best technical and economical time interval for different components since it is just a waste of money to maintain components that do not need maintenance. Many times it is sensible to maintain component soon after its condition has gone over certain critical limit. Time based maintenance has been in use for most parts of power grid. [10; 11]

It is not efficient to maintain each component in same time interval therefore a more developed strategy is condition based maintenance where maintenance is done based on each component's condition. Condition monitoring is very important part of this strategy. This thesis concentrates on how we can evaluate component's condition based on available process data and all other information available from that component. More about this strategy is presented in Chapter 6.

3.3. Condition monitoring

Condition monitoring has a major role in preventative maintenance because it is based on condition measurements, this can be used to decide when maintenance is needed or when the next inspections are reasonable to perform. Condition monitoring is the foundation for device's controlled lifetime extension. A few objectives of this thesis are to study how ongoing on-line condition monitoring can be improved and what kind of information can be discovered from available process data of distribution network.

Condition monitoring methods can be divided into subjective (visual) and objective (measured) inspections as can be seen from Figure 3.4.

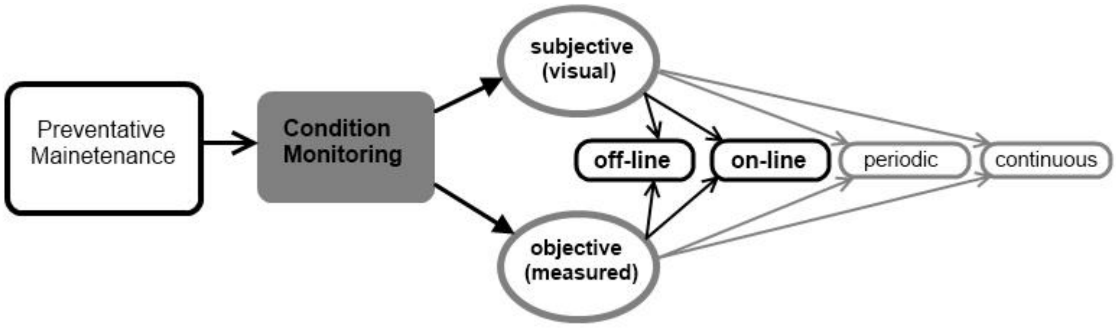

Figure 3.4 *Condition monitoring connections*

Measurement results received from condition monitoring are not always very unambiguous, especially visual inspections are usually based on maintenance personnel's earlier experience so results are not necessarily comparable. Both methods can be fulfilled either on-line or off-line and can be continuous or periodic but subjective rarely is continuous if it is not carried out by surveillance camera. On-line monitoring does not need interruption unlike off-line which requires always interruption to separate component from electricity network. Condition monitoring aims to prevent fault which is followed by some components weak condition and then maintenance operations can be focused to where they are needed. [11; 12]

3.4. Maintenance today

Electrical safety law defines that electric equipment must have a maintenance program. When maintenance is done according to the program it can be assumed that the electric equipment fulfils its safety requirements. There are no direct guidelines or standards from authority to make a maintenance program. Maintenance strategy depends on which electricity network the company has been examined and what kind of power grid they have. Every company can make a maintenance strategy and a program the way they want but it must be done in a way where safety regulations are followed. Maintenance policy most commonly used is the time based maintenance in distribution networks [13]. It is based on fixed time intervals for different components. The time interval is defined based on experience or/and recommendations from the industry guidelines.

Maintenance and maintenance management strategies have been developed and altered considerably during the last few decades [10]. Today electricity network companies do and have maintenance strategy and maintenance program which defines principles and practical actions of what, why and how maintenance is performed. It also defines how those actions will be documented which is important in order to have knowledge of what has been done. The work done by this the code of conduct is continuous and the plans comply with the laws. Correctly and well done maintenance strategy and program does not just serve authorities and safety, it also improves quality of electricity and reliability of electricity network and that way it has an economical impact as well.

Another objective of maintenance planning is to achieve as high reliability as possible for the electricity network. The optimal situation would be that in the long term the total costs of power network would be minimized and components would stay operational. Too much effort for maintenance and condition monitoring binds capital and increases operating costs however on the other hand too minor maintenance actions lead to increase some other expenses like corrective maintenance and interruption costs hence it is important to find balance. [10]

4. MAINTENANCE FOR PRIMARY SUBSTATIONS' COMPONENTS

The focus of this thesis is the primary substation and specially condition information of 110/20 kV transformer, circuit breaker and protection relays. The reason of this is because the transformer is the most expensive component of the network. Nowadays protection relay can provide more process information which is utilized and this information can provide information about the circuit breakers condition. Objective is also to explicate how relay protection testing intervals can be lengthened. Substations battery system is an auxiliary system which provides back up electricity for its devices and is briefly presented.

The next section explains how condition monitoring is performed to substation components and also general overview of their faults is explained. Focus is on protection relays, primary transformers and circuit breakers because they are crucial and the most important components of the primary substation. The reason why failure modes are presented is because they must be known and understood before maintenance can be improved.

4.1. Protection relays

Relay is similar as a measuring device which observes electrical quantities of electrical network. It can detect abnormal state of the network, variation from the set point values of protection relay are interpreted as abnormal state. When abnormal state is noticed relay gives control command usually for the circuit breaker to disconnect faulty section of the electrical network from the healthy one. Protection relays and controlled circuit breakers form protection areas. Protection must be always operational and monitor networks status in order to be functional as fast, reliably and selectively as possible. Relays' actions must be selective so that when fault is detected as small as possible section of electricity network is separated from the network and rest remains operational. This forms base for protection testing and condition monitoring. Protection should be comprehensive in order to cover the entire system, this is why protection areas are partly on top of each other and they have back-up protection for protection faults. [11; 14]

4.1.1. Short-circuit protection

Fault can happen when two or three-phase conductor lines have a conductive connection for example through an arc or other fault impedance. This is why a short-circuit fault can be two-phase or three-phase and it can also be connection between the earth and phase conductor line. It is typical that fault current is bigger than loading current. For the short circuit, protection is mainly carried out with over-current protection function which usually has two or three tripping steps. Different operation sequences are to ensure selectivity of protection and this is implemented with setting different time steps for tripping. Short-circuit protection detects increase of phase-currents and if pick-up is long enough tip command is given for the current breaker. Depending on how many, two or three, phase current has elevated, fault situation is two or three-phase short-circuit fault. The protection is tested as close as possible for real situation and that designed scheme behaves as it should with highest and lowest set values. [2; 11; 14]

4.1.2. Earth fault protection

Earth fault is a fault in the electricity network when a phase conductor line has a conductive connection directly or through fault impedance to earth. The Nordic distribution networks have no low-impedance route for fault current because network is usually isolated from earth or high impedance earthed. That is why fault current has only a passage through phase-to-earth capacitance of the conductors like in Figure 4.1. Fault current is very small in one single-phase earth-fault. Fault can also be two-phase when two phase conductor lines are connected to the earth without connection to each other, as in short-circuit if lines are connected to each other and also earth it is called two-phase short-circuit.

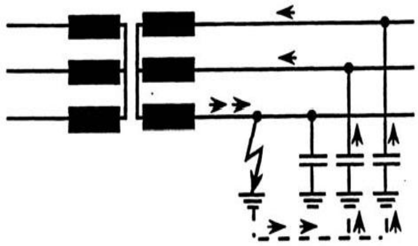

Figure 4.1 *A Single-phase earth-fault in an isolated network and current flow.* [15]

In network which is isolated from earth, fault current is so small that earth fault protection cannot be implemented as a short-circuit protection. Earth fault protection is executed by directional feeder protection which is based on phase-angle φ difference between zero sequence current I_0 and neutral point displacement voltage U_0 at the neutral point. Because the network is capacitive the current is approximately 90° ahead the voltage. The protection should be always selective so relay must operate only when fault occurs in its protection target area. Operating condition requirements for relay are that current and voltage exceeds settings values. A problem is that fault currents direction should be from the power station to the fault point and this third requirement can be solved with phase-angle difference between voltage and current which tells currents direction. The tripping is executed so that relay should awake after threshold values have been reached which usually includes specific time-delay. The testing is carried out as for short-circuit protection testing, everything works as they should and requirements are fulfilled and protection is solid in every possible fault situation. [2; 11; 14]

4.1.3. Protection relay testing

Electrical safety regulations and laws obligate to prove if asked that protection and protection devices work. Protection relays performance and condition are inspected when it is put in use and every now and then. Commissioning testing does not affect quality of electricity but periodic testing can influence as an interruption of electricity delivery if it is needed to unplug the device from the electricity network. For this reason it is important to plan interruptions so that necessary power can be fed through other substations. Also if relay protection testing intervals could be lengthened by condition monitoring, customers would experience fewer interruptions.

Today modern numerical relays, also called feeder terminals, contain multiple features and can contain comprehensive protection which is the minimum need for substations automation. All new numeric protection relays are based on a microprocessor technology which provides more features than are used.

The main object of protective relay testing is to maximize the reliability of protection and minimize the risk of malfunction or situations when tripping is not desired. So the reliability of protection means security and dependability of protection. In periodic protection testing, protection is tested in specific time intervals to make sure that system fulfills requirements which are set for it. Electric Network Company can decide testing intervals for relays but like explained earlier regulations and the law requires in many countries the inspection of protection devices in certain time intervals.

All the different protection functions in numeric relay needs to be tested separately and relay protection testing is usually done with a unit that can be used for testing all of them. The relay protection functions are tested with their lowest and highest setting values so that protection works. Also other components which are affiliated with protection are tested to verify that they work as they should. The test can be implemented in the primary circuit with a test unit which generates fault currents. Other method is to do testing in the secondary side to produce the fault currents and voltages directly to the protection relay's connectors. Either way relays actions, measured values and operation commands, are monitored so that it has worked as it should. The primary side testing is more comprehensive than secondary side in order to ensure that the entire protection for all measuring equipments and circuits works. [2; 11; 14]

4.2. Condition monitoring for the circuit breakers

Circuit breakers are devices which are used to open and close circuit. They can operate manually and automatically and usually automatic open situation is used because of the overvoltage of short-circuit or earth fault. When circuit breaker operates automatically it is protection relay, feeder terminal, which gives the open command and also closing can be automatic. This makes circuit breakers one of the most important components of protection with feeder terminal.

For all different types of circuit breakers it is common that they can open and close without any damage. For short-circuit where current is many times higher than normal current this operation wears circuit breakers mechanical tolerance. It is natural when breaking a circuit that current flow does not break immediately when circuit breaker opens but circuit stays closed due to the arc. This is also very important feature for circuit breakers that they can endure arc and extinguish it.

There are several methods for the circuit breaker to interrupt current and Table 4.1 shows the usual way to categorize them because of the diversity of design and application. Method and medium of current breaker in interruption situation can be air, oil, vacuum or SF6 gas. Table 4.1 describes also circuit breakers' development and most common known names. The development of circuit breakers has been influenced by the networks development. [2; 11; 16-19]

Table 4.1 *Circuit-breakers categories based on medium and interruption method* [2]

Name	**Prime manufacturing period**
Air circuit-breakers	
Bulk-oil circuit-breakers	1905-1950
Oil-minimum circuit-breakers	1930-1985
Air-blast circuit-breakers	1930-1970
SF6 puffer circuit-breakers	1975-
Vacuum circuit-breakers	1980-

Failure modes

Circuit breaker failure modes can be divided in many different ways and a majority of failures are contingent on operating mechanism but this can be consequence of some other fault. In the list below are the most typical failure modes.

- Fails to open or close on command
- Opens but fails to remain open, interrupt, maintain open contact insulation, conduct current
- Opens or closes without command
- Fails to conduct continuous or momentary current
- Fails to provide insulation, to ground, between phases, across the interrupter – external or internal
- Fails to contain insulating medium
- Fails to indicate condition or position

4.2.1. Monitoring techniques for the circuit-breakers

All different types of circuit breakers in Table 4.1 can still be found operational in networks and this affects maintenance because maintenance needs are diverse. Common indicator is operating mechanisms but there are several ways also to check how circuit breakers get its energy which it needs to interrupt circuit. Available condition monitoring techniques range from simple to very complex and measurement parameters must be carefully selected to provide the best possible information of the condition. Monitoring can be off-line or on-line, periodic or continuous and it is usually selected with cost benefits. In Table 4.2 is presented some circuit breakers condition monitoring targets and which elements of circuit breaker they are related to. There is no separation of different types of circuit breakers components in Table 4.2.

Table 4.2 *Circuit breakers monitoring components categories and subsystems*

Condition monitoring target	**Component**
Components dealing with service voltage	Main arcing contacts: auxiliary resistor and capacitor Main insulation to earth: bushings, oil, vacuum, air and SF6
Electrical control and auxiliary circuits	Command coils: auxiliary switches and relays, heaters, thermostats, and lockout devices
Operating mechanism	Mechanical transmission components: actuator and damping devices, compressors, motors, pumps, pipe work and fittings, and energy storage elements

Useful way to analyze components and subsystems is to know failure modes affect analysis to identify failure causes. And also how those failures develop over time can be used when selecting available monitoring operations. But it must be remembered that no single technique can reveal all failure reasons and extra information will enhance reliability of the circuit breakers condition. There are many options when choosing suitable monitoring technique like Dissolved Gas Analysis (DGA), tan delta method, temperature/pressure, operating energy, infrared scanning and some are easier to implement than others e.g. service voltage is easy to exam while circuit breaker is de-energized and requires less investments in short-term. But this kind of off-line testing can be non-effective to notice incoming failure condition. Like earlier was pointed out monitoring is decided usually by investments because online or continuous monitoring will raise cost. It is good to be aware that desired measurement signals are not always available from direct measurements. [2; 11; 16-19]

4.2.2. Maintenance for the circuit breakers

Circuit breakers maintenance in distribution network is traditionally implemented based on fixed time intervals. Today monitoring is often carried out by visual inspections and measured testing is done more rarely but still within a certain period of time. The internal isolation, operating mechanism and the command circuits are checked that their condition is as it should be so that circuit breakers are in operational condition and overhaul is done if needed. The maintenance is done according to the manufacturer guide and it is different for different types of circuit breakers. Crucial matters are connected to operating mechanism and the way circuit breaker interrupts circuit, like pressure of SF6 gas, oil level or control mechanism and control hydraulics. In Chapter 6 a explanation is provided about the use of possible available process data in the evaluation of circuit breakers condition.

4.3. Maintenance measures for the transformers

The transformer is one of the most important components of power-distribution network. When at substation transformers fault occurs, electricity delivery is interrupted and economical expenses are significant for electricity network company because customer can experience this interruption but if they do not, the repairs of the transformers fault is in every case an expensive operation. Properly operated and maintained transformer is assumed to provide reliable service for 20-30 years and with good maintenance even much longer. Condition management for transformer is very important in order to prevent its damages.

4.3.1. Transformers faults

Transformers faults can be a result of many factors. Combination of any electrical, mechanical, environmental and thermal factors can make serious damage to a transformer and cause it to breakdown. These stress factors can occur in normal use or can be consequence of an extraordinary event like lightning. Hereby it is not simple to say typical failure style for a transformer but it usually involves breakdown of insulation system. In any case environmental factors cause almost always electrical, mechanical or thermal stress or combination of these to the transformer. These factors are briefly presented in the next sections. [13; 18; 20]

Thermal factors

Insulation is usually a combination of oil and paper. Cellulose insulation system is expected to degrade over time due to normal heating generated by the loading. Physical strength of insulation is lost over time by the thermal degradation and it will weaken the paper to the point where it cannot any more withstand mechanical duty what was imposed for it. Thermal hot spots, hottest location inside the insulation structure, are connected to aging and deterioration rate because usually hot spots appear near the weakest point of insulation paper. This is the reason why hot spot temperature can be used to define transformers technical lifetime. The results of most usual thermal factors are summarized as following:

- Overloading of the transformer for too long of its design capability
- Failure of the cooling system
- Operating a transformer in an overexcited condition as over-voltage, under-frequency or under excessive ambient temperature

Hot spots maximum temperature 98 °C is defined in many literature sources. Therefore it is crucial to know the transformers thermal condition so that it would not be operated over its capability. Chapter 6.5 will concentrate on this subject in more detail to provide more information of its condition to foresee possible fault situations related to thermal stage.

Mechanical factors

The transformer's windings deformity is typical mechanical factor which is a reason for the cellulose insulation deterioration. If insulation has deteriorated enough, damage can cause the transformer to fail electrically. How long a transformer can operate and survive with this kind of damage is extremely hard to foresee and depends on criticality of the damage. Deformation of windings is usually an outcome of transport damage or electromechanical intensities.

The transformers should be build so it will internally withstand forces when it is moved but bracing may not be strong enough. Movement of the transformer can be too much in transportation when manufacturer's transporting instruction have not been followed or an accident might have happened. With old transformers winding materials were not as developed as today and the design was not to build as strong windings as today. When internal fault occurs windings may experience magnetic forces that it cannot endure. Sometimes damages as listed below may just be collateral damage due to a fault. Regardless of the case winding can have deformations. Next few of the most common mechanically induced factors are presented:

- The most inner winding inward radial buckling
- The tipping or telescoping of conductor
- Tightening of spiral
- End-ring crushing
- Failure of the coil clamping system
- Displacement of a transformer's incoming and outgoing leads

Electrical factors

Typically an electrically generated factor is corollary of fault in a transformer's insulation system. As illustrated almost everything in the end can be connected to insulation which is why it is important to size up all signs to create correct scenario of what might have happened. Electrically induced failure modes can be detected with one another or in combination with thermal or mechanical indicators.

Enduring or transient overvoltage usage can lead to overstressing of the insulation beyond its limits and overheating of the core which is depending on magnitude and duration of the overvoltage operation time. Lightning and switching surge are large magnitude impulses and the transformers are designed to tolerate some level without damage but they can cause serious damage to the mechanical and electrical integrity of the transformer. Partial discharge is usually a result of week insulation when strength of electric field exceeds the electricity strength of insulation [10]. It can be likened as a low intensity arcing and can lead to localized damage of the insulation and the conductors. [2; 10; 11; 13; 18; 20-22]

4.3.2. The transformers condition monitoring

The transformer condition monitoring can be broken down into five sections according to studies and the main techniques are represented in Table 4.3. Electricity Network Company can determine when maintenance and condition monitoring for the primary substations transformer is done.

Table 4.3 *Transformer condition monitoring techniques*

Technique	**Indicator**
Thermal analysis	Any inside incipient fault, insulation
Vibration analysis	The health of the core and windings, On Load Tap Changer
Dissolved gas analysis (DGA)	Insulation ageing
Partial discharge (PD) analysis	Insulation condition between conductors
Frequency response analysis (FRA)	Winding deformations

Many times incipient fault makes changes in thermal behaviour of the transformer. The transformer's lifetime is generally agreed to be related to hotspot and oil temperature. When the transformer function's higher temperature insulation suffers, the ageing process accelerates, and the transformers capacity to withstand transient overloading gets smaller. On-line temperature monitoring can be done with simple temperature and load measurements using artificial intelligence models or the thermal modelling techniques. In this research Chapter 6.5 discussing the transformers condition is trying to prognosticate an explanation of the thermal modelling method. [2; 10; 11; 13; 18; 20-22]

Vibration analysis is quite new condition monitoring technique and the research is in progress especially compared to the other transformer monitoring methods. The core and windings health can be evaluated using a vibration analysis. This is because the core and winding vibrations form vibrations of the tank when their generated vibrations propagate through the insulation oil to the walls of the transformer. On Load Tap

Changer (OLTC) condition estimation is done by using unique vibration signatures. Every OLTC has unique vibration signal and analysis is done based on collected data using different signal processing techniques. [18]

The transformers insulation condition can be monitored very effectively by dissolved gas analysis (DGA) of the transformers insulation oil. The oil includes various types of gases and the thermal decomposition changes their values and generates also other products into the insulation oil. In DGA it is important to do an analysis of the changes of the gases relations in different sample taking years. The problem and the major part of costs is that dissolved gas analysis requires special arrangement to survey dissolved gases.

Partial discharges (PD) occur when electric field strength goes over dielectric breakdown strength of certain area and creates partial discharge bridge through insulation between conductors, simply saying insulation's strength is not momentarily strong enough for electric forces. There are many measurable phenomena in partial discharge analysis like electromagnetic field, voltage drop, current impulse, acoustic shock-wave, light flash or chemical decomposition as presented in Figure 4.2. Different measures need different kind of equipment to measure examined phenomena but all phenomena are linked up with insulations condition. [10; 18]

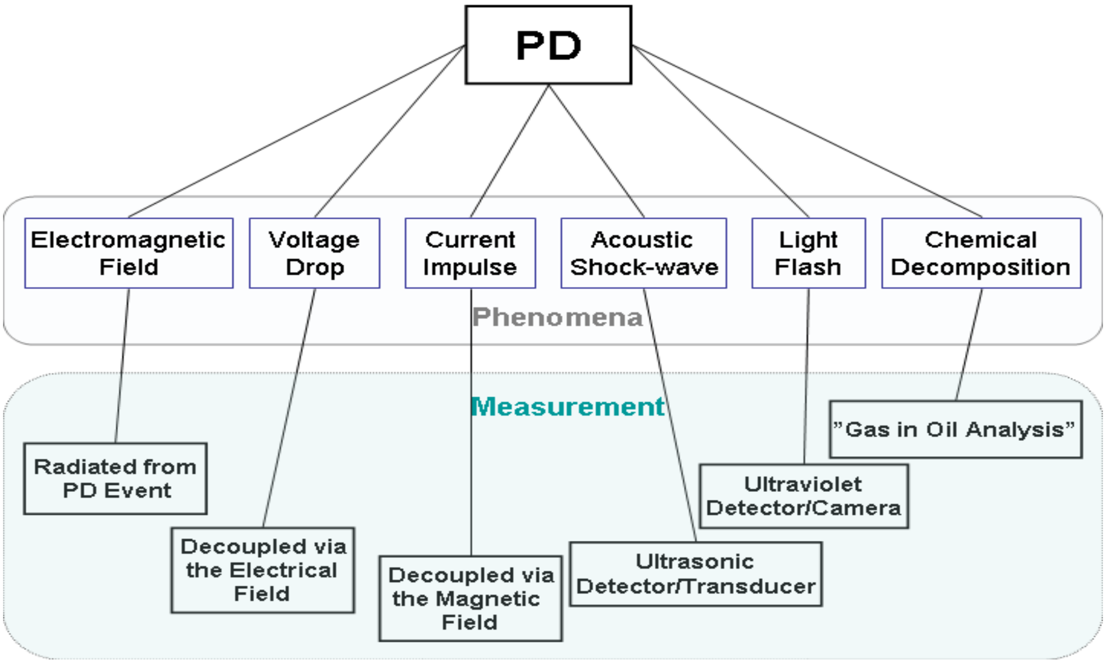

Figure 4.2 *Partial Discharge Phenomena and its measurable features*

The windings experience a lot of stress when the transformer is operating. This can cause windings movement and deformations. With frequency response analysis (FRA) method it is possible to determine what kind of healthy windings are. In this analysis winding unique response fingerprint is measured and compared to healthy one which can be used to define windings health and issue which is more important, the location of the damage. [18]

4.3.3. The transformers maintenance

Many literature sources consider the classical condition monitoring technique for transformers to be dissolved gas analysis (DGA) therefore it is well defined and understood [18]. Electric network company can decided the time interval when oil sample is taken for the dissolved gas analysis. The owner can decide the follow-up actions of the transformers to determine what kind of maintenance is needed. For distribution networks it is important that measurements are economically reasonable. Often load is not so much that the transformers condition would suffer from overload but it is a load and temperature is monitored frequently. Situation for the transmission transformers is totally different and their condition is monitored carefully with many different methods. This thesis concentrates on distribution networks but only to the substations primary transformers. The transformers in distribution networks expected lifetime, condition monitoring and maintenance costs are closely optimized. That is why in Chapter 6.5 cost-effective method is explained for the transformers condition monitoring and the focus is on obtaining sensible information of the oil temperature which reveals its thermal behavior. Also some ideas are presented for the transformers subsystems monitoring.

4.3.4. Defects in transformers auxiliary equipments

The transformers auxiliary equipment's fault can also often cause the transformer to disconnect from the electricity network. That is a reason why those equipments/components should also be monitored regularly. Oil pumps and air fans are responsible of transformers cooling. If their controls or motors do not work as they should temperature inside transformers tank can increase dangerously and cause serious damage to the insulation.

Load tap changer (LTC) has a few possible fault situations: one is related to its motors behaviour and another is basically its insulation. There are various motor problems but the most common are that motor will not work at all or it changes steps in the way it should not. Load tap changer is usually located in its own space where the oil insulation is. This can be a problem since dissolved gas analysis gives important information of transformers condition and in order to do so the load tap changer should be in such a working condition that it would not affect the transformers oil analysis. LTC overheating can cause serious damages and it can happen if insulation has failed. Load tap changer's insulation temperature is almost as important as transformer's tank's insulation.

Many contact failures or external components failure can be very critical for transformers proper operation. Fault on these peripheral components does not always cause them to disconnect transformer from usage however it can lead or make it vulnerable to other failures which can cause major damages.

4.4. The battery system

Battery system in primary substation is an auxiliary service. It is responsible for supplying current for all devices if there is a malfunction of supplying electricity. It is composed of a rectifier and a battery charger. Batteries are connected together so that there is a bank of batteries for each level of dc (direct current) voltage required.

The proper operation of auxiliary battery system is essential for substations controls and protection. If battery system is not charged and electricity is interrupted in substation, its controls and protection will not work because they need electricity.

Battery systems condition is checked in fixed time intervals. Condition monitoring includes checking voltage levels, checking chargers proper functionality and that battery water is in required condition. [23]

5. IMPROVE AND ENHANCE MAINTENANCE

This chapter presents ideas why maintenance activities require improvements and what things effect to those factors. Also explanation is provided on how equipments faults correlate with operating life and what kind of system could be developed for effective maintenance. In the last part some examples are provided to show the kind of savings can be done by utilizing condition based maintenance.

The quality of electricity has increased its meaning all the time. It can be divided as can see in Figure 5.1 roughly to continuity of supply which basically means interruptions, and voltage quality.

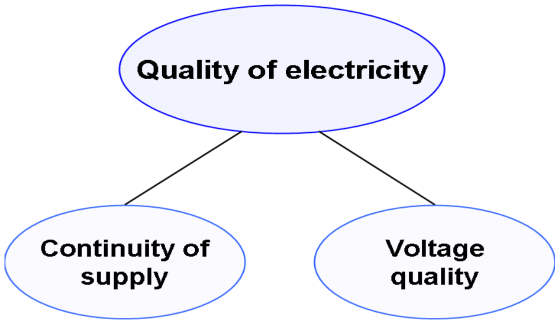

Figure 5.1 *Electricity quality and its areas* [2]

The voltage quality is a voltage level, harmonic over waves, flicker, voltage dips and voltage spikes. The most significant factors in electricity quality are interruptions, voltage level and voltage dips. The voltage dips and spikes are momentary sudden deviations in voltage level from nominal voltage. For human eye flicker is a disruptive change in the brightness of the lights. It is a consequence of fast changes in voltage which are usually smaller than changes which interferer electric equipments. [2; 11]

Integration of various levels of distribution automation features allow to use control management, asset management and electricity quality to be a developing part of automation. But in any case no matter how much there is automation in electricity network it will always need supervision. Smart grid concept will need smart maintenance like was pointed out in Chapter 2. It is crucial when more automation is merging in to the grid that existing systems are not compromised.

As mentioned earlier, today maintenance is mostly implemented as time based with certain time intervals to different components. With better condition monitoring the idea is to migrate support maintenance strategy from time based to condition based. With better condition monitoring it is possible to raise electricity networks usage because condition of networks components is better known so it is better to know how much load and usage network components can tolerate. But more important subject is that knowledge of the condition enables to plan maintenance actions before components fault escalate to unwanted interruption since maintenance is usually much easier and less costly to implement than having the condition progress to a major failure. With better knowledge of equipments health gives owners higher confidence to use equipment beyond its normal operating life. [24]

5.1. Electrical equipments failure rate and development

Electrical equipments failure rate is usually described by a curve as shown in Figure 5.2. For the first part density is high when the component is poorly chosen for the task or manufacturing defected components cause damages. But for the high voltage components as transformers and circuit breakers manufacturing defected equipment is eliminated already in commissioning testing. In the second area fault density lowers and stays usually long uniform but from time to time faults occur especially with insulation by sudden extraordinary event. When equipments' lifetime is near to its end density begins to rise again as area three in Figure 5.2 shows. Fault curves can be different for different components as can be noticed from three example figures below on the left side. Faults can be for example totally dependent on random factors when fault density is constant like shown by the Figure 5.2 top curve on left (a).

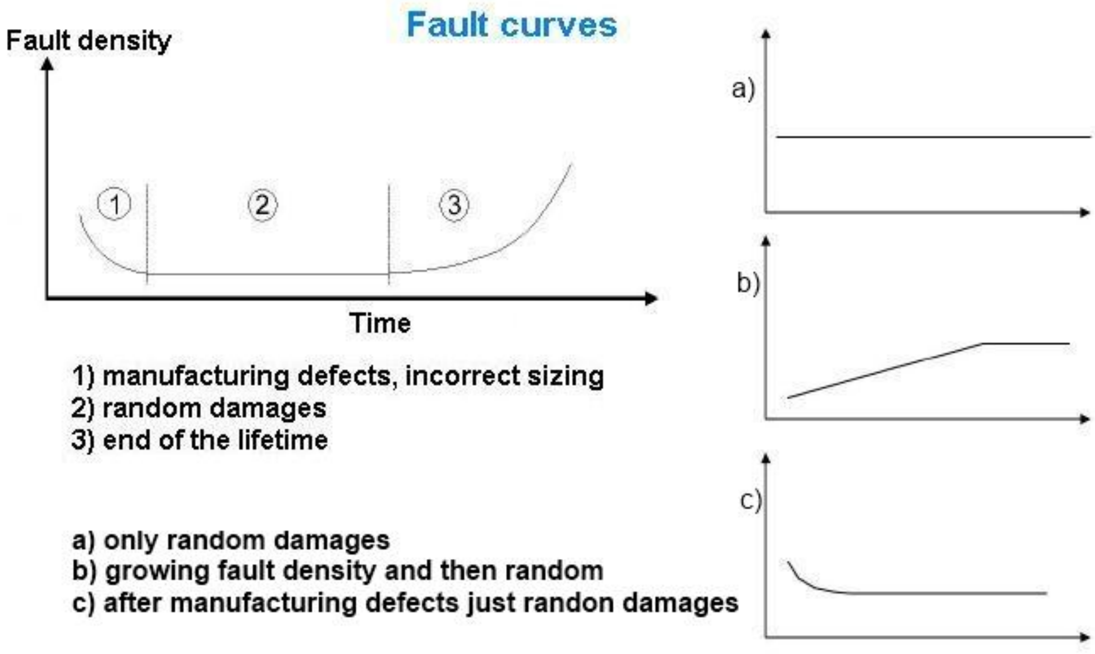

Figure 5.2 *Equipments lifetime fault curves* [25]

Like for the protection relay, it is hard to say a typical failure rate for particularly new a modern feeder because they contain self supervision which informs relay faults so mainly maintenance is about testing that whole protection works not just the protection relay.

Failures do not usually happen spontaneously, except due to weather, and this is a reason which enables to notice signals of potential failure. In Figure 5.3 is P-F (Potential Failure to Failure) diagram which can be used to describe how single potential failure develops to functional failure. When a failure starts it is not always possible to notice even with precise condition monitoring but in due time failure develops noticeably. After this point failures development, as can see from Figure 5.3, begins to accelerate. Equipments deterioration condition depends on many different factors and that is why it is important that potential failure is detected as soon as possible.

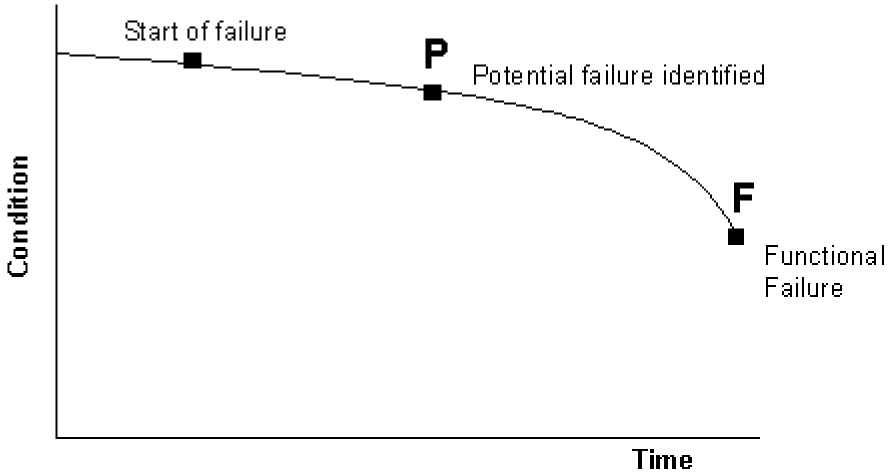

Figure 5.3 *Development of fault: P-F curve* [26]

If time between potential failure point (P) and functional failure (F) is long enough it might be possible to complete preventative maintenance actions. This time range is commonly called P-F interval. This interval can be measured in any unit related to exposure like days, cycles, or action times. Inspections interval must be obviously shorter than time between P and F points if potential failure is to be noticed before it develops into a fault. Therefore maintenance needs improvements because time based maintenance actions are not always carried out between this P-F interval and potential failure is not noticed on time.

5.2. Asset management integration

One approach to improve maintenance is asset management which combines all the major stages of maintenance actions. This can be divided to four categories like in Figure 5.4. These categories are data collection, integration and analysis, decision-making, and work execution. Some of these stages can merge or link on top of each other but first each one is presented and the types of actions they would include. Every stage would support the next one and these connections are shown with arrows. The process should be continuous so that actions would be as effectively as possible.

Figure 5.4 *Integrated asset management process*

The first starting point is data collection or defining maintenance targets, without data about the maintenance targets there is no point to do maintenance if the goal is to improve maintenance actions to condition base. This stage would also include centralized database which would have inspection and maintenance data, including results of testing and inspections, operator logs. This database should be easy to expand if additional information is to be added. This kind of database where all the necessary information would be in the same format could establish good decisions support. Important related action would be monitoring which should be as automated as possible. Later chapters will concentrate more on this issue.

Next stage would be system integration which is important and big issue for electric network companies, after all it would not be effective to have just a huge database with all information. That information must be put in use as effectively as possible. This database combined with another system which would notify when components condition is critical or would be critical in the near future can be very useful aid in making the right decisions and actions. A system or a program would make equipment condition assessment from the database which could simply be a notification for example in the transformers situation when insulation oil temperature is too hot or trend of temperature is rising. Reporting can be made very simply if needed like for protection relay, the relay did not operate as it should have. If more information is wanted then additional analysis can be done using the database information.

The decision-making step may be sort of on top of the earlier stage because notification is received and analysis is possibly done instantly or automatically when new on-line information is updated to database which should be continuous. But any way in this process available data and information from the first two steps is taken and best decision is made by evaluating various alternatives and scenarios. Connections to different asset are described in Figure 5.5.

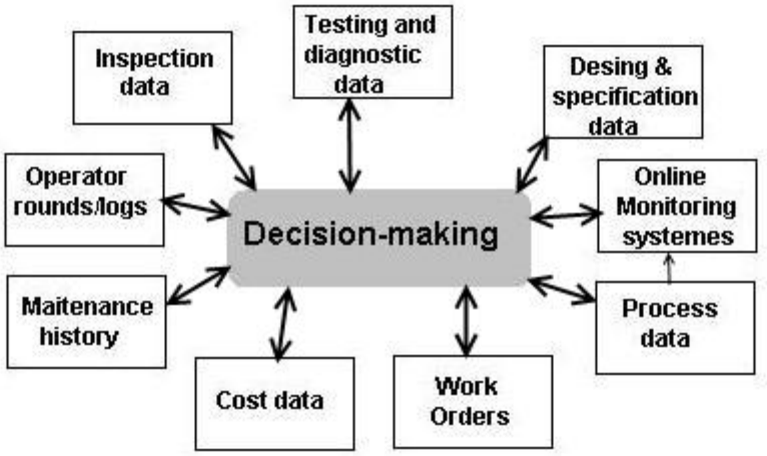

Figure 5.5 *Information to support decision-making*

An example could be a transformer which has escalating damage that has not yet become a critical fault. With available information future operations can be done while considering the capabilities of the current system. The reliability and performance of the network is possible to optimize when required data and information is available. This is how maximum system performance can be carried out while saving money at the same time because unnecessary maintenance operations would decrease. Like explained in Chapter 3 reliability-centered maintenance (RCM) and condition based maintenance (CBM) would be more cost- effective maintenance than most of the applied maintenances today.

The last step involves work execution and monitoring. Work execution is just doing the work; perform maintenance and everything that can be related to involve doing the work. Monitoring covers continuous monitoring of the performance of the whole network system and its assets. This is actually a part of data collection. [27]

Generally the aim of network operations is to minimize life cycle cost (LCC) without compromising the quality level of electricity. The LCC is harshly said costs which include everything from buying component/equipment to removing it from use [2]. But it must be kept in mind that companies has policies which guide their operations like LNI Verkko Oy idea to built weather proof power grid. This kind of policies can at first increase costs but in long term costs will be reduced significantly.

The ideal situation for electricity network company could be that components which are connected to the grid will notify when maintenance actions are necessary or condition can be predicted early enough so that maintenance can be conceived. So that economic resources could be focused on maintenance and not to traditional inspections. A problem is how to receive condition information of components without going to do inspections to the place where the component is. Chapter 6 presents ideas for the problems for primary substations protection relays, transformers and circuit breakers point of view.

5.3. Economical benefits due condition based maintenance

Like presented earlier efficient maintenance would be possible to achieve with a lot of automation in electricity network and a system which would support decision making process. But if rough calculations of the economical effects of using condition based maintenance are done, simple method would be to study the effects for component group. Select one group and calculate how much maintenance cost could be reduced by rescheduling overhaul or inspection work for the future. Of course this kind of examination would also need notice what the system costs would be. For this matter the easiest solution would be to choose a component group which already has connection possibilities to the current systems. This is because when the data from components is received, exploring that is not very expensive to perform. Only information technology system which would utilize the data should be developed.

Feeder terminals can provide these requirements and for them protection testing is completed now every three years so if it can be lengthen the economic impacts can be estimated. Hypothetical calculations are done based on 1800 feeder terminals and therefore 600 terminals are tested now every year. Costs for one test are approximately 300€. Another cost for method implementation could be the ICT systems cost, which would include system development, annual data transferring and storage. First system development cost are evaluated to be 60 000€ and annual costs for ICT system are 6000€. For every year single feeder terminal data cost are estimated to be 17€. It is expected that with analysis based on available data periodic protection testing interval could be moved into the future for 400 terminals. This means that only 200 feeder terminals are tested every year. So with all this information estimated calculations can be done and these are presented in Table 5.1.

Table 5.1 *Example of protection relays testing costs*

Year	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Periodic testing	180 000 €	180 000 €	180 000 €	180 000 €	180 000 €	180 000 €	180 000 €	180 000 €
ICT system	60 000 €	0	0	0	0	0	0	0
Annual ICT costs	0	6 000 €	6 000 €	6 000 €	6 000 €	6 000 €	6 000 €	6 000 €
Annual data costs	30 600 €	30 600 €	30 600 €	30 600 €	30 600 €	30 600 €	30 600 €	30 600 €
Periodic testing	60 000 €	60 000 €	60 000 €	60 000 €	60 000 €	60 000 €	60 000 €	60 000 €
Total costs	150 600 €	96 600 €	96 600 €	96 600 €	96 600 €	96 600 €	96 600 €	96 600 €
Annual difference	29 400 €	83 400 €	83 400 €	83 400 €	83 400 €	83 400 €	83 400 €	83 400 €
Accumulated total	**29 400 €**	**112 800 €**	**196 200 €**	**279 600 €**	**363 000 €**	**446 400 €**	**529 800 €**	**613 200 €**

As can be seen from Table 5.1 costs for normal periodic testing, annual data and ICT are the same for every year. Developing and installing ICT system effects only in the first year. Accumulated total is already profitable in first year this is because it was predicted that 400 periodic test could be postponed. This may be too optimistic approximation. That is why in Table 5.2 calculations are presented within different amount of relays for which testing could be postponed and relays which still need periodic testing. Basic idea of calculations is same and tables for each which present only the changed values can be found from Appendix 1. Table 5.2 presents only accumulated total for every year for each different calculation.

***Table 5.2** Accumulated cost within different sets of periodic tests and postponed tests*

Accumulated year total	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
450 periodic, 150 postponed	-45 600 €	-37 200 €	-28 800 €	-20 400 €	-12 000 €	-3 600 €	**4 800 €**	13 200 €
400 periodic, 200 postponed	-30 600 €	-7 200 €	**16 200 €**	39 600 €	63 000 €	86 400 €	109 800 €	133 200 €
350 periodic, 250 postponed	-15 600 €	**22 800 €**	61 200 €	99 600 €	138 000 €	176 400 €	214 800 €	253 200 €
300 periodic, 300 postponed	-600 €	**52 800 €**	106 200 €	159 600 €	213 000 €	266 400 €	319 800 €	373 200 €
250 periodic, 350 postponed	**14 400 €**	82 800 €	151 200 €	219 600 €	288 000 €	356 400 €	424 800 €	493 200 €
200 periodic, 400 postponed	**29 400 €**	112 800 €	196 200 €	279 600 €	363 000 €	446 400 €	529 800 €	613 200 €
150 periodic, 450 postponed	**44 400 €**	142 800 €	241 200 €	339 600 €	438 000 €	536 400 €	634 800 €	733 200 €
100 periodic, 500 postponed	**59 400 €**	172 800 €	286 200 €	399 600 €	513 000 €	626 400 €	739 800 €	853 200 €
50 periodic, 550 postponed	**74 400 €**	202 800 €	331 200 €	459 600 €	588 000 €	716 400 €	844 800 €	973 200 €

It can be noticed that even if only testing for 150 feeder terminals could be postponed then still the breakeven would be after 7 years. After this when more could be postponed breakeven would be sooner. Last row is for 50 feeder terminals periodic testing and this is because it would be almost impossible to postpone all periodic tests. Table 5.2 gives an example of what kind of economical benefits can be achieved by using process data in estimating performance of equipments and postponing periodic testing.

Here only calculations and presumption are made on what kind of saving can be achieved by postponing regular periodic testing. Another point of view is that how much unwanted operations can be eliminated by monitoring protection relays operations. It is hard to evaluate value of the costs which interruptions cause. Reason is that there are various interruption situations. Anyway if unnecessary interruptions are reduced because protection relays operations are monitored and new settings are made, then savings can be achieved by this way also. Let's make assumption that primary substation has eight outputs which feed power. One of these feeders protection relay does not work and the whole substation would be separated from electricity network because of back up protection. Situation would require station level checking and it would take one hour to reroute electricity feed through another substation or to execute inspection. Interruption would then last one hour and power fed through this substation would be estimated to be 20 MW.

Unwanted interruption cost can be estimated

$$K_{\cos t} = 20000kW * 1{,}15€ / kW + (20000kW * 1h) * 11{,}15€ / kWh = 254000€$$

As can be seen, costs would be more than estimated system development costs (60 000€) so unwanted interruption would have significant effects to economical calculations. Even if other implementations costs would be taken into account (150 600€) sum would be still lower.

6. USING AVAILABLE INFORMATION TO PROGNOSTICATE CONDITION

Earlier chapter presented one kind of asset management integration system which would support maintenance actions and help to optimize asset utilization. To develop a total efficient maintenance system much more automation would be needed to the electricity network but currently the most potential component to provide information from the primary substation is the feeder terminal. Communication possibilities to the primary substations are already in place.

This chapter explains how protection relays, circuit breakers and transformers condition can be evaluated by on-line methods. The feeder terminals disturbance records can be utilize to provide more efficient maintenance. The objective is to explain how determination can be made to lengthen actual relay protection testing from disturbance records. To estimate circuit breakers condition feeder terminals disturbance record can also be used. For primary substations transformer possibilities are presented to calculate isolations health by estimating hot-spot temperature. First condition based maintenance review is completed so that it is known what implementing CBM requires. Then discussion is provided about process data and explanation is given about what kind of information is examined and used for evaluating primary components condition. The lasts subchapters demonstrate how example equipments condition can be evaluated with available data. Relay protection can be ensured without actual relay protection testing, circuit breakers condition is estimated and transformers ageing prediction is explained.

6.1. Requirements for condition based maintenance

When maintenance is implemented as condition based it is crucial, as name condition based maintenance expresses, to find out condition information of the used equipment. The goal is to optimize reliability and availability. Diagnostic technologies offer nowadays possibilities to use easily available information to determine equipments condition but for every component it is not yet cost efficient. Transformation to use condition based maintenance cannot and would not be profitable to implement over night as the process should be continuous. Change could be sensible to initiate from components which can supply information readily and for which the condition is significant to know. Regular or monitoring in short time intervals the actual condition of equipment will ensure to minimize the cost and the number of unscheduled interruptions because condition is basically known at all the times. A typical preventive maintenance is done at specific dates as indicated in Figure 6.1. Mostly no effort is taken to evaluate the condition of the equipment and maintenance is done as scheduled work. In CBM findings of the condition assessment will define whether preventive maintenance is performed or is it rescheduled for a future date as can be noticed from Figure 6.1. This means that overhaul is only performed if there are indications that the work is needed or maximum time has gone since the last overhaul.

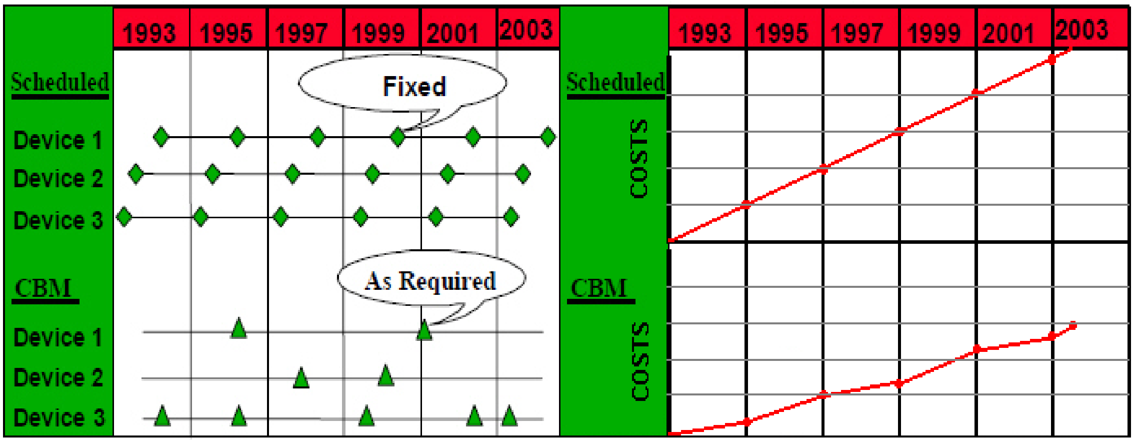

Figure 6.1 *The difference in overhaul times between traditional maintenance and CBM*

To plan condition based maintenance requires knowing typical faults of monitored equipment and which factors indicates them. Condition assessment can consist off-line and on-line monitoring. When CBM is implemented it should include new on-line process data but also traditional network monitoring information. From Figure 6.1 deductions can be made that maintenance costs can be decreased when overhaul work is rescheduled to the future because then overhaul times are optimized. If potential failure is detected on time before it has progressed to a major failure, overhaul costs are usually always much easier and less costly to perform. But for distribution network it is essential to calculate economical investments carefully in order to optimize maintenance. This is why condition monitoring methods must be simple but still capable to indicate equipments condition as reliably as possible. But at the beginning of implementing the condition based maintenance it will not completely eliminate regular inspections. No matter how reliable condition monitoring methods are. [24]

In practise condition based maintenance is nearly impossible to implement for every network section or equipment. This is because recourses are limited and maintenance always consumes economical capitals. That is why risk based maintenance (RBM) should be used when wanting to apply CBM. One example is cable street clearing because for a network company which has a lot of rural network huge investments are require to keep cable streets in good condition. For cable street clearing RBM can be used when condition information is available and other required factors are in place. Criticality of clearing area can be determined when RBM information is known e.g. quantity of customers, volume of reclosing, and the needs of small constructions of certain area can be used with condition information.

LNI Verkko Oy has some excellent examples how CBM is utilized. One is remote-controlled disconnectors engine wearing. On-line data is received from engine, e.g. current, and based on analysis of this information overhaul is implemented. Another stage still in development is the use of laser scanning data in need-based tree-clearing.

Right now LNI Verkko Oy photographs by helicopter the whole distribution network and manually checks where clearing is needed. It is very slow method but other things can be also examined at the same time. Intentions are to have this process completed automatically when system notifies when a tree or other things are too close to the wires. Then clearing can be ordered to the area which is critical and/or other demands are fulfilled. This will change traditional cable street clearing and gives possibilities to add other requirement to the process. In any case efficient maintenance is based on the database which offers possibilities to develop maintenance process in more efficient direction.

6.2. Process data

Basically all the information from power network can be considered as process data. It is a fact that process data can be collected from electricity network which is why it is crucial that first all the precious information must be defined. Important factors are what are measured, how and why as Figure 6.2 presents. When these three factors can be combined a potential target is achieved. Data can merely be e.g. motors current values and when those values have changed too much conclusion of the engine wear can be done.

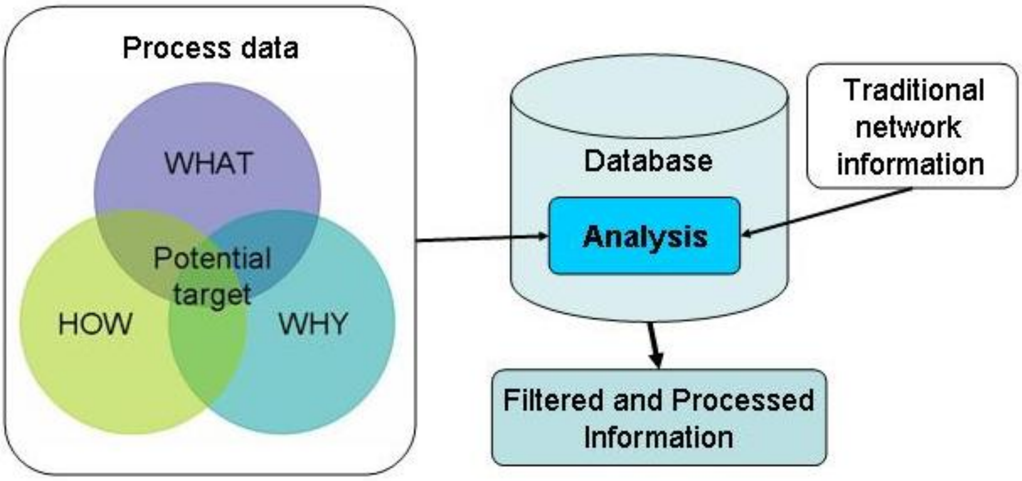

Figure 6.2 *Information flow chart*

It is important to remember that process data should be combined with traditional network information to obtain as wide of a picture as possible of the maintenance target. This would support development of the use of process data because when new kinds of methods are utilized it is not self-evident that it is done correctly or as efficiently as possible. This way at least old method would stay in the background and new methods would support them.

Distribution automation in networks, especially in primary substations, provides a lot of possibilities to transfer data by remote terminal unit (RTU). In principle any kind of measuring devices can be connected to RTU. Today also other parts of distribution network have a lot of possibilities to obtain process data via communication links. The one exact measurement equipment is AMR (Automatic meter reading) meters which are installed for example for all LNI Verkko Oy customers in Finland. Currently AMR meters provide information of customer's electricity usage and quality. There are more possibilities to utilize AMR meters but these are only briefly cited in later chapters. Right now very promising data is providing disturbance records which can be transferred through RTU because connection possibilities are already there. Disturbance records are very potential data however more automated analysis is needed to study so that output information can be considered reliable.

Another approach is to decide what type of information is needed and implementations are done based on this information. For primary substations transformers temperature knowledge or condition of its subsystems would support its maintenance. To collect more information from the transformer different sensors would need to be installed. But it would not matter if costs are not very high because to prevent even one major fault in the primary transformers expenses are usually covered.

The important objective of this thesis is what type of information can be exploited for predicting condition of specific devices. Information should be possible to connect directly to equipments condition. Great benefit would be that this information would not just support maintenance but this is not always possible, especially if on-line measurements are implemented only to aid maintenance of specific device.

One problem with transferring any kind of information from network is compatibility of applications and equipments. IEC 61850 standards is hoped to eliminate these problems [2]. More information about possibilities of different kind of process data and its utilization are discussed in later chapters.

6.2.1. Disturbance records

When protection acts the feeder terminal makes a record of that event which is called a disturbance record. Feeder terminal save a predetermined amount of wanted measurement values when one of the monitored values exceeds pick-up level. Recording time and basically everything can be set as wanted. If disturbance record is used to analyse the fault situation, sampling frequency and recording time before and after the fault, then recording should be enough information. It is possible that recording that is too short or too low sampling frequency does not show important information. Feeder terminal records instantaneous values and usually draws line between values by default. Disturbance records consist of these values which are called fault records as can be noticed from Figure 6.3. The purpose of IEEE standard COMTRADE is to help the cooperation of different information systems. [28]

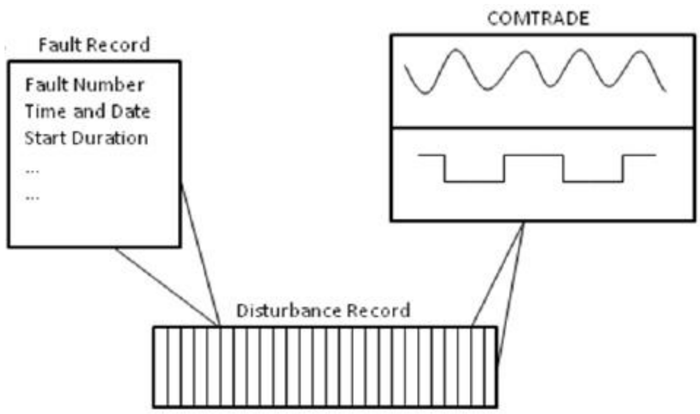

Figure 6.3 *Description of how disturbance record is formed*

Most of the time wave format reveals more of the fault situation than just numeric values. In Figure 6.4 is an example of disturbance record in a wave format. In the beginning of Chapter 5 an explanation was provided about how power quality has raised its interest among consumers. Recordings generated by protection feeder terminals can be used to measure many of these situations like flicker and voltage dips.

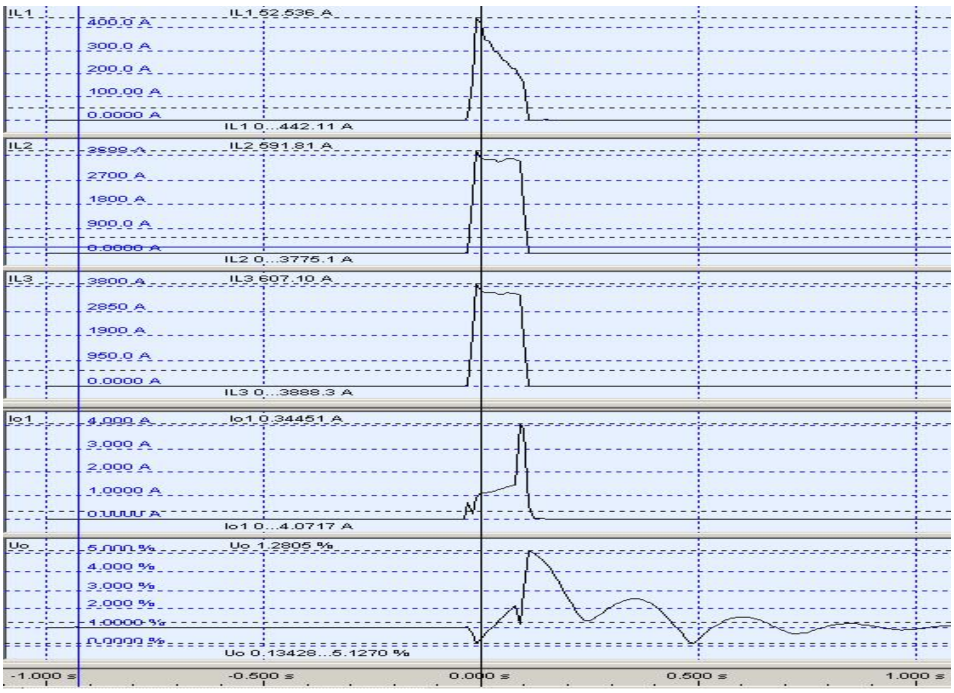

Figure 6.4 *Example of disturbance record's wave format*

There are curves of phase currents *IL1, IL2, IL3*, zero sequence voltage U_0 and zero sequence current I_{01}. Also RMS (root mean square) and maximum-minimum values of every curve appear in the Figure 6.4. Recording period of just a few seconds can be noticed from the timestamp on the bottom figure. These values, as can be seen in Figure 6.4, are potentially the most used values when analysing disturbance record. Short-circuit and earth fault situations can be detected from analysing these five curves. Appearance can be different depending of the manufacturer but the basic useful information is the same and can be displayed in COMTRADE format.

Disturbance records are not, at least by every distribution network company, collected from every fault situation but basically information and communication technology (ICT) today enables it. Automation in primary substations offers to transfer every single recording of fault situations using substation automation. More about automation and communication possibilities are discussed in Chapter 7.

6.2.2. Information from transformers' and circuit breakers

When evaluating transformers condition there is many different measurement possibilities. The most important values are load, currents and temperatures. Various temperature measurements would support transformers thermal modeling. Ambient temperature and at least one oil temperature with load and currents would already give chance to make thermal modeling as it is presented in reference [13]. These measurements can be implemented by various sensors which can be connected to the feeder terminal or other intelligent electric device (IED).

Peripheral devices' condition of the transformer such as load tap changer, oil pumps and fans can be monitored by estimating their motors condition. Current changes in motor can be recorded by feeder terminal. Load tap changer's insulation temperature would also be very useful information when its condition is wanted to estimate. Other measurements such as contacts resistance can be difficult to implement by on-line measurements but thermal imaging of the transformer can give valuable indicators of the transformers external components condition.

Circuit breakers operations are related to interrupting current therefore when currents break and operating times are the most valuable measurements. Circuit breaker does not have value if it is not able to operate that is why it is important that after every operation the interruption mechanism is in proper condition to act again. Many times operating mechanism requires motor which charges it and the motor's condition should be monitored. Disturbance record can give a direct indication of three phase circuit breakers operation. When it interrupts the circuit the phases should be broken almost simultaneously, time difference can be at the most 10 ms [2].

6.3. Ensure protection relays performance

The idea is that disturbance record acts as a test result for relay testing. When relay operates, all its actions which basically means all the setting values should be available to confirm. Most of these can be verified from disturbance record when protection has operated. This requires that there have been faults and relay has been operational. When values have been calculated from disturbance record they must be compared to the setting values. This means that relays would register other useful information. Conclusions can be done from these that relay's actions are what they should be. Therefore every trip command can be used as a test. This could even be a better test than actual relay protection testing because in this situation relay operates in real operating environment. For the authority proof must be shown that protection works if the protection testing is to be postponed into the future. The most important protections are short-circuited and earth fault protections. This sets demands what kind of information must be detected from disturbance record. Also it is crucial not to forget that protections are not only relays' proper operations but the whole protection system which includes for example the circuit breakers' performance. Circuit breakers' actions and condition monitoring are discussed in the subchapter after relays.

Next a demonstration is provided how over-current protection and directional feeder protection can be inferred from disturbance record that they work as they should. Events are presented in a wave format because it describes phenomenon better than raw numeric data. All indicators which are referenced in figures can be calculated from the numeric data and that is the way automated analyzing programs are implemented. It must be kept in mind that all needed values are not presented. To make automated analyzing program for disturbance records more careful studies would be needed. From disturbance record different fault situations can be detected automatically as is concluded in the reference [29].

To ensure protections performance first relays pick-up, time-delays and operating time values must be known. When relays measured value or values which pass the threshold value relays pick-ups, awakes. Time-delay is, as name tells, a time-delay so if relay is awake long enough relay sends a trip command to the circuit breaker. Operating time is the time from pick-up to trip command. Then values related to circuit breakers performance must be known to be sure so that the whole protection has worked properly. For circuit breakers important values are trip command time and operating time. These are explained in subchapter 6.4.2. Fault clearance time is the time frame from beginning of the fault to separate fault location in the network. All relays setting values can be attained from relays register but if its performance is to be confirmed then all these values should also be calculated.

Circuit breakers operating time and fault clearance time can change depending on the fault situation and wearing. Time-delay for relay is hard or even impossible to calculate if time stamp of its performance cannot be obtained. Time stamp for trip command would be very useful because it gives possibilities to calculate time-delay and circuit breakers operating time.

6.3.1. Over-current protection

For the over-current protection it is a simple process to detect whether an over-current event has occurred. If at least two of the phase currents I_1, I_2, I_3 has elevated over tripping level and tripping command acts as it should protection works. As can notice from Figure 6.5 phase-currents has increased. Three phase currents have elevated so the figure is three phases short circuit fault. Pick-up point when the relay awakes is the black vertical line in the figure.

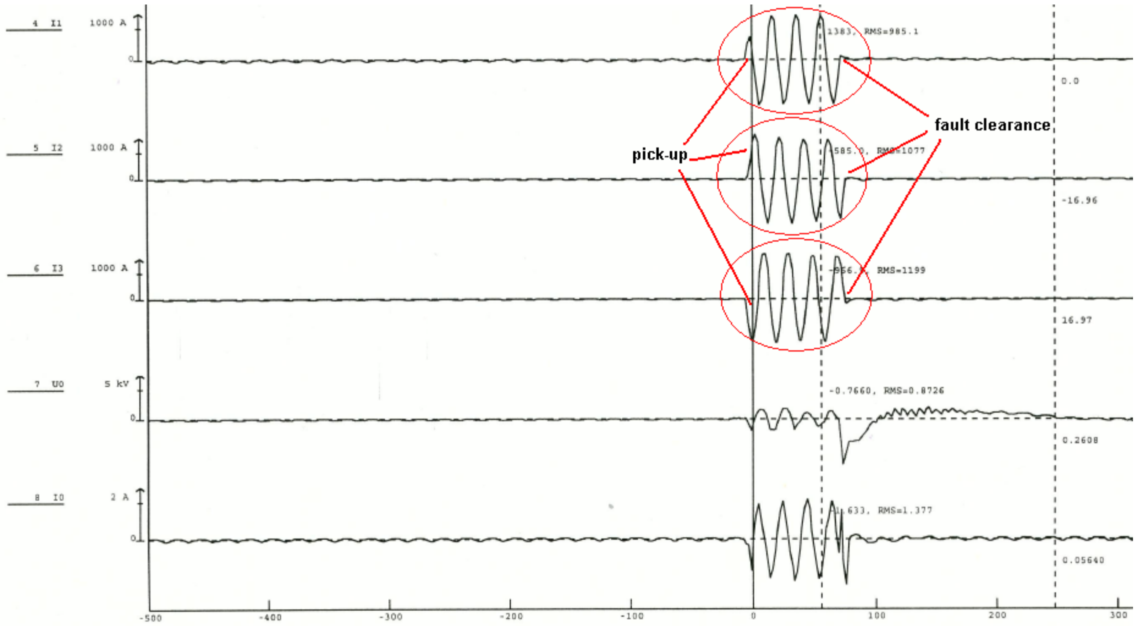

Figure 6.5 *Short-circuit disturbance record in wave format*

Then protection acts so that circuit breaker interrupts the circuit. To be sure that relay has worked as it should have setting values must be compared to the calculated values from the disturbance records numeric data. In Figure 6.5 some of these key points which should be calculated and compared to setting values are marked.

As mentioned earlier some values can be difficult to calculate from the disturbance record if additional settings are not used. Relays are tested with their maximum and minimum setting values and it is not clear whether the threshold value when the relay awakes is minimum or maximum. Also every tripping step should be calculated and this means that in a fault situation all the tripping steps should be used. Time related to the tripping steps would also need to be calculated like circuit breakers high speed automatic reclosing and delayed automatic reclosing times. Even so a bigger picture of the performance of the whole protection can be calculated and this already gives a good prediction of the performance of the protection system which is not only protection relays operations. When more fault situations are used to evaluate protections performance estimation of protection systems operations gets better.

6.3.2. Directional feeder protection

In the earth fault zero sequence voltage U_0 and current I_0 will raise when fault happens. When threshold values are achieved and phase-angle φ between them is over the setting value, tripping happens. The threshold value for zero sequence current should be set so it would not cause by itself the relay to function.

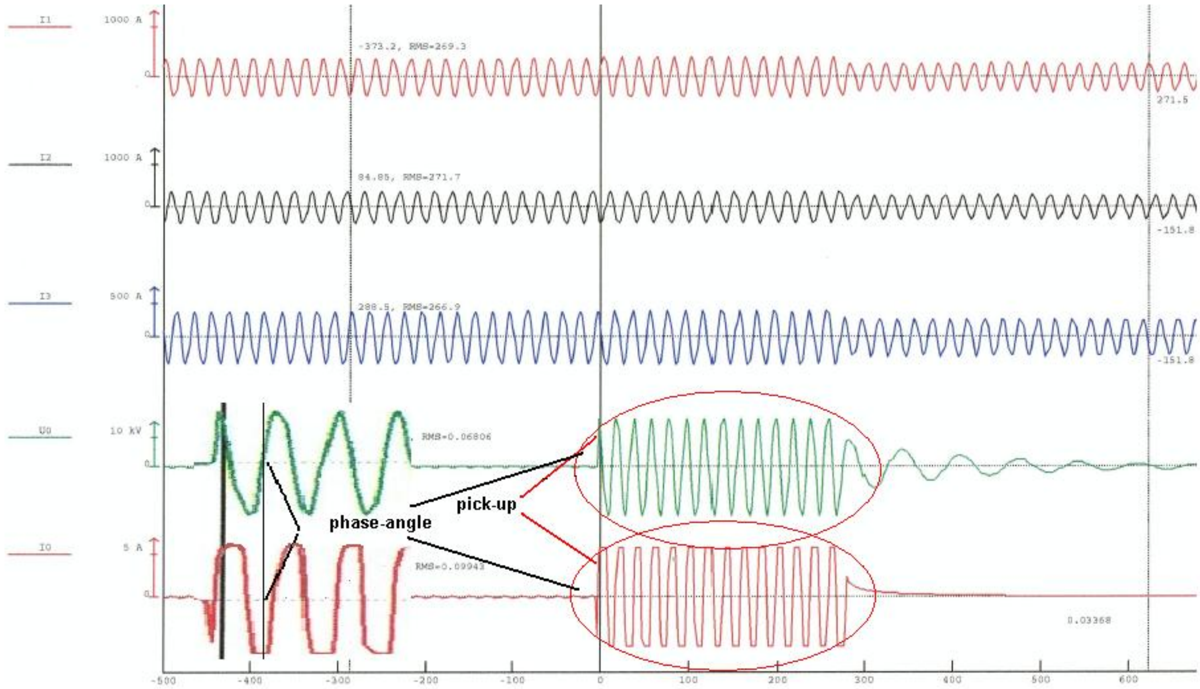

Figure 6.6 *Earth fault's disturbance record*

Phase-angle between zero sequence voltage and current can be calculated from the disturbance record and this is marked in a zoomed frame in Figure 6.6. Still the same problems remain which are pointed out in over-current protection chapter.

6.4. The evaluation of circuit breakers condition

As told in earlier chapter a good estimation of the whole protection system can be calculated. This could be made without detailed separated condition estimation calculations to the circuit breaker and protection relay. In any case circuit breakers condition is important factor when wanting to observe the protection system's condition. If circuit breaker does not work the whole protection system is useless because its function is to separate fault section from the electricity network.

Circuit breakers are tested in regular time intervals. This interval period is different for different types of circuit breakers. For oil-minimum circuit breakers testing period is often every three years and for example for vacuum or SF 6 gas circuit breakers it can be every six years or even longer. The reason is that when circuit breaker interrupts the current its medium is under stress. For oil-minimum circuit breaker this is a meaningful factor. But for other circuit breakers whose medium does not scuff so much when it breaks the circuit, a more significant factor can be wearing of the operating mechanism. This can be estimated from how many times the circuit breakers have interrupted the current in a specific set of conditions. Next four different ways how the condition of the circuit breakers can be evaluated is explained. More detailed methods are explained in the reference [30].

Some protection relays have condition monitoring functions for circuit breakers. These functions provide quite wide scale to monitor circuit breakers condition but these are not often efficiently utilized. One reason is that condition monitoring needs historical information and upgrading an IED (Intelligent electronic device) clears the history. Another reason is that a unit level disturbance recorder often includes very limited storage capacity. If recordings are not collected automatically and if memory would fill up, the older recordings would be overwritten.

Few of these monitoring functionalities such as operation counter, contact position indicator, accumulated energy, spring charge indication and gas pressure supervision are very useful tools [31]. If information which functionalities can provide could be utilized, a condition could be estimated and the other measuring devices would not be needed. An accumulated energy monitoring function uses the same duty rate approximation method which will be explained in Chapter 6.4.2.

6.4.1. Operating times and fault current

The most important condition information of circuit breaker is the number of interruptions it has done. Purely this gives direction of the circuit breakers wearing. But only the information of how many times circuit breaker has interrupt a circuit makes assumption that wearing has been same each time. Circuit breaker's wearing is proportional to the fault current which it breaks. The magnitude of the fault current is depends on where the fault is and the fault situation for example earth fault or short circuit. The fault current can be measured from few sequence RMS values before the current is broken. This value is easy to calculate automatically from disturbance record. If these two values, fault currents and cut-off times, are combined prediction can be enhanced. When these values are calculated they need to be compared to the values received from manufacturer and condition estimation can be done.

6.4.2. The values related to interrupt the circuit

Bluntly said the fault duration forms from three stages. When fault occurs and circuit needs to break, there is protection time, circuit breakers mechanism time, and arching time. In Figure 6.7 some of those times are presented from the disturbance record. Some values can be detected only from the circuit breakers status information. Other values can be calculated directly from the disturbance record. The challenge is that automated analyzing program would find those correct values. If some of those times change permanently between different interruptions it can be a sign of deteriorated condition of the circuit breaker. [32] Some values can change a little bit due to how great the current is which it is supposed to interrupt.

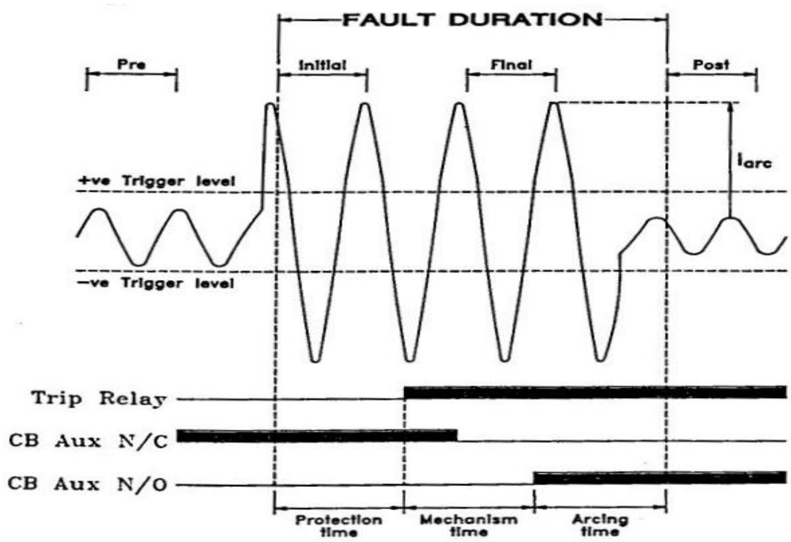

Figure 6.7 *Circuit breakers values in disturbance record* [32]

The protection time is the time between when fault has started until a trip signal is issued. It depends on relay and the fault situation how long it must be picked-up before trip signal is given. This time can be used to evaluate performance of protection. The time from circuit breaker to respond to the trip signal and open is called mechanism time or circuit breakers operating time. Arching time is the time which goes by when circuit breakers opens and fault current flow has stopped. Mechanism velocity is directly proportional to the time which takes for the circuit breaker to open, if this time changes a lot it means that circuit breakers mechanism does not work properly. In the Figure 6.7 this is the time between CB aux N/C and CB aux N/O. It can be pretty difficult to calculate these values from the disturbance record if additional information of circuit breaker operations is not measured.

The most wearing of circuit breaker happens when arc ignites due to interruption. The contacts in circuit breakers wear when it interrupts the current and this amount is directly related to I_{arc} and arching time. Arching time depends of circuit breakers structure, type and medium. Arc is always tried to extinguish as quickly as possible because of the wearing. Most of the time arc shuts off only when after interruption the next zero point of current is achieved which is in 50 Hz system 10ms or earlier [2]. If this time changes significantly it can be an indication of a developing fault of the circuit breaker. But this time can be hard to calculate from the disturbance record because it can be difficult to calculate when the arc has ignited. Prolonged arching time is a sign of circuit breakers weakened interrupting capability which can be due to changes in the medium or inordinate wearing of contacts.

Another very good indicator would be the mechanism time. Changes in the circuit breakers operating time could suggest that operating mechanism would not work as it should. The reason for this could be ageing, reduced energy in operating mechanism, components wearing or other related factors. Mechanism time can change when breaking different currents and in which point the currents wave interruption is performed. Also for some circuit breakers operating time can be slower when interrupting bigger currents. Any way correlations can be found and condition can be estimated. When mechanism time is measured there should be information of the time when tripping signal was given and when the arc ignited. If tripping signal of circuit breaker is not available it can be combined to protection time and make conclusions of how the whole protection works. [32]

6.4.3. Duty rating approximation

Manufacturer usually gives maximum circuit breaker ratings and continuous current ratings. The idea is that with two rating points for operations at certain current level, an approximation can be made regarding when the circuit breaker has eroded an estimation of the maximum wear. Assumptions in this approach are that arching times are constant and over the entire opening process, circuit breaker arc resistance from one operation to the next is the same. Then proportionate connections (1) can be made between the circuit breaker (CB) wear, energy dissipated in arching and summation of interrupted current.

$$\text{CB Wear} \propto \text{Energy}_{\text{arc-CB}} \propto \sum k * I^N \qquad (1)$$

From equation (1) calculations can be made to determine exponent N if two current points are known. Current I values in two points should be known and also how many operations circuit breaker can handle at a given current level. If energy is assumed to be same equation (2) can be made.

$$I_{\max}^N = k_1 I_1^N = k_2 I_2^N \qquad (2)$$

Where $I_{\max}^N$ is maximum sum of interruptions circuit breaker can withstand, k is the number of interruptions in certain current I. Now exponent N can be solved.

$$N = \frac{\ln\left(\frac{k_1}{k_2}\right)}{\ln\left(\frac{I_2}{I_1}\right)} \qquad (3)$$

Here an assumption is made that wearing obeys exponential curve which is not always true. The wearing can change substantially within different currents. However this means giving an estimation of circuit breaks wearing which can be compared to the manufacturer's values. Also duty maximum value can be calculated from equation (2).

$$I_{\max} = (I_{\text{interrupt}}^N * k)^{1/N} \qquad (4)$$

This method can be used to give an estimation of circuit breakers wearing when single interruptions I^N value is compared to the maximum I^N value. When wearing exponent is solved, it can be used to calculate maximum sum which the circuit breakers can handle. This can be done by using a rated continuous current and operations given by the manufacturer. Then calculated interruptions I^N value can be divided by the maximum sum and times by hundred when the estimation of circuit breakers wearing has been given in a percentage form. [33]

6.4.4. Operating mechanism

As explained, operating mechanism is an important issue when circuit breakers proper operations are explored. Operation mechanism can be monitored when its motor's currents are recorded when it operates. When there is too much variation in the currents it can indicate incipient malfunction on motor's behavior. Another useful measurement could be to measure energy which is restored to circuit breakers interruption mechanism. This can be difficult to implement because different circuit breakers have different kinds of interruption mechanisms.

Disturbance records show if phases are not broken simultaneously. Disturbance records in Appendix 2 have two fault situations. The first one is two-phase short circuit situation where the currents are not broken simultaneously. In the zero sequence current and voltage peaks can be notices which are results of time difference of the interruption in the third phase. The second situation is one phase earth fault where a time difference can also be noticed but now in the first phase. These are indications that circuit breaker does not operate correctly and delayed operation can lead to a worse fault e.g. to not interrupt current at all.

6.5. The condition of the transformers insulation

In Chapter 4 transformers faults and condition monitoring methods were talked about. Usually faults are related to insulation and that is why transformers medium can be used to indicate its condition. In Finland and for LNI Verkko Oy most of the transformers have oil paper medium. This kind of transformers hot spot temperature can be used to evaluate insulations ageing. It is usually accepted that maximum hotspot temperature is 98 C° as is defined in [34], over this the ageing rate increases significantly. Next a demonstrated is given on how hot spot temperature and condition can be estimated by on-line methods. Also on-line dissolve gas analysis and peripheral components are discussed.

6.5.1. The thermal model method

Calculated hot spot values should be used only as indicators of ageing because calculated temperature values can have high variation compared to the true values. This correlation can be improved by analyzing collected historical data. In any case high hot spot value should be considered to be a very important indicator because even short periods of high temperature can affect transformers condition permanently. In practice calculation errors can be taken into notice and lower alarm temperature of hot spot. [13]

Many literature sources offer different methods to estimate hot spot temperature by using external measurements and detailed information of the transformer. Easiest model does not require any information of the transformer itself. Only input parameters are needed and based on these output information is received. This is called Artificial Neural Network (ANN) modelling which is based on the output value which is gained from training data and is used to define correlation between output and input values. When enough data is collected, a model can be made. When model is done for one type of transformer it can be used to indicate condition of similar structure transformers. For ANN input values are ambient temperature, three phase currents and one previous output temperature value of a neural network. More about different thermal models are discussed in reference [13]. In practice the equations from IEC 60354 would give more accurate result than ANN if calculation is based on nameplate information. Transformers information is typically stored to NIS (network information system) and can be used with accurate measured ambient temperature and loading.

The reference value of hot spot temperature is defined to be 98 C° for normal ageing according to IEC 60354. In that temperature ageing is scaled with factor one. If hot spot Θ_h temperature rises 6 degrees and ageing is scaled by factor two so ageing is twice as fast in 104 C° temperature than in 98 C°. The maximum value for hot spot is approximated to be 140 C°, this is when permanent damages can already occur for the transformer. Values of relative lifetime consumption *V* are presented in Table 6.1. Ageing rates differs depending on which standard is interpreted but the basic idea is still same.

Table 6.1 *Relative lifetime consumption according to IEC 60354*[35]

Factor	Hot spot temperature (°C) /Relative lifetime consumption										
Θ_h	80	86	92	98	104	110	116	122	128	134	140
V	0,125	0,25	0,5	1	2	4	8	16	32	64	128

The absolute lifetime consumption *L* has very straight correlation between relative lifetime consumption *V*, hot spot temperature Θ_h and the operating time *T*.

$$L = V * T \Rightarrow L = \frac{1}{T}\int_{t_1}^{t_2} V * dt \qquad (1)$$

As can be noticed from equation (1) integration for real practice implementation time is needed since the surrounding temperature and the load level of the transformer changes all the time. The operating time $T = t_2 - t_1$ where t_2 is end time and t_1 is start time, the time length can be decided however shorter time gives more precise results. [35; 36]

6.5.2. On-line dissolved gas analysis (DGA)

Dissolved gas analysis (DGA) is usually the condition monitoring method which is completed for transformers when their condition is evaluated. This is because it is the most important tool to estimate transformers health. The first indicators of transformers faults can be noticed from oil sample. When oil sample is taken and examined, it requires interruption because transformer needs to be opened. That is why dissolved gas analysis is not done very often. Morgan Schaffer provides solutions for dissolved gas analysis. On-line dissolved gas monitor is connected to transformer like in Figure 6.8 and it does analysis automatically. It can be very powerful tool to estimate transformers lifetime.

Figure 6.8 *On-line dissolved gas monitor connected to a transformer*

Depending on which model is used different information is received and reported forward. The most expensive models do even diagnostic when it is required. Hydrogen (H_2) is mostly indicative gas that evolves to all types of faults. That is why simplest model monitors only hydrogen and moisture. Other faults related gases are carbon monoxide (CO), carbon dioxide (CO_2) methane (CH_4), ethane (C_2H_6), ethylene (C_2H_4) and acetylene (C_2H_2). The equipment does analysis and graph of the monitored value which is formed as in Figure 6.9.

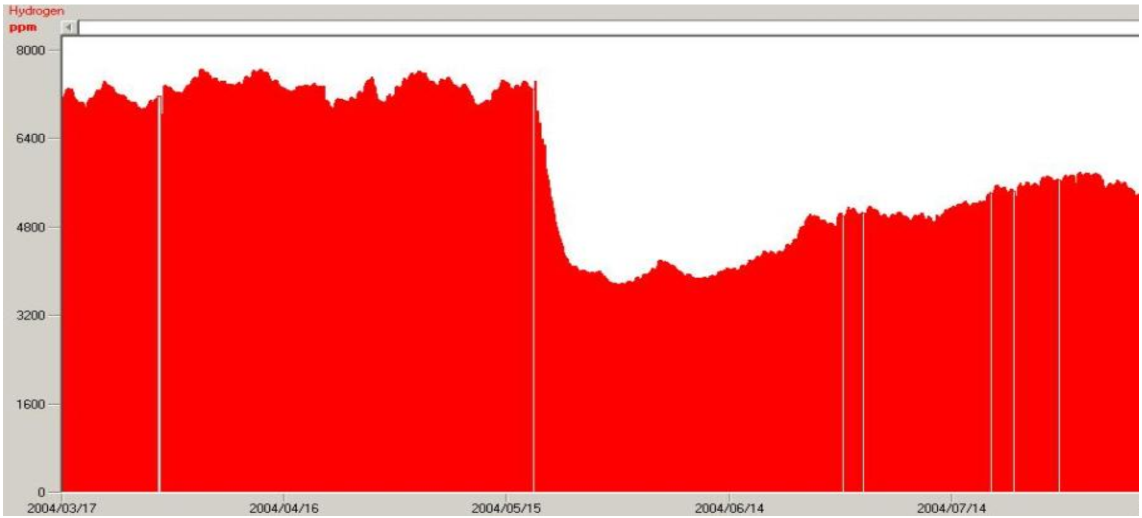

Figure 6.9 *Hydrogen evolution of the received data of on-line DGA*

This kind of information allows evaluations of transformer condition and need for overhaul can be made. If possible, the diagnosis should be based on recently formed gases. If there were reasonably stable concentrations of gases before initial state of the suspected fault, background concentrations can be subtracted out before precise analysis is performed. This way possible fault can be noticed easier but subtraction must be done with careful caution.

On-line monitors are tested carefully and they are easy to install. Their measured results have been promising and accurate. Manufacturer promises that monitors can be integrated with any data acquisition system using standard protocols. This enables to integrate monitoring system to any used systems.

6.5.3. Peripheral components condition estimation

Transformer’s pumps, fans and load tap changer have a motor or motors which control them. The changes of motor’s current would give possibility to estimate condition and it is possible to connect the measurement to the feeder terminal. As in circuit breaker’s motor’s situation too much variation in current can indicate initial problem. For load tap changer the situation is the same as for circuit breaker’s motor because their operations are momentary. When it operates its motor’s current could be recorded and values can be compared to the recorded historical values. For pumps and fans motors’ recording can be continuous and when defined threshold value is exceeded an alarm can be given.

Load tap changer’s insulation temperature would also give indication if a fault is going to develop. This could be implemented as transformers insulation temperature measurements. Another useful method would be thermal imaging. It would give indications of temperature changes. Thermal imaging could be used very widely in substations and it would provide information of external components temperature changes. Imaging should be implemented always similarly in order to make automated analysis from it. Good objects would be transformer’s tank, contacts and connections. It could also be used for load tap changer’s tank and circuit breaker.

6.6. Monitoring of the battery system

Many feeder terminals have a functionality to monitor battery system. The functions depend on feeder terminal but simplest would be to measure voltage level. This should be implemented in a way that battery systems charger would not interference the measurements. Feeder terminal could disconnect charger before measurement is implemented. Also leaking current could be possible to measure by feeder terminal and voltage difference between the negative and positive poles. If there is a difference it could indicate leaking current to ground or damage in the charger. Leaking current would also be possible to measure if battery system installation has central grounding and if there is leaking to the ground it would be possible to predict these problems in the battery systems cabling. [23]

7. MANAGEMENT SYSTEM INTEGRATION

Today many network companies want to integrate different systems to communicate together. In many cases this can lead to overwhelming amount of information. To exploit available information holistically, a separate system or systems would be required which would be able to deal with it. System would process and filter this information for needs of the current systems and users. This kind of method would also give possibilities to easily expand processing information. It would enable continuation to develop filters so that different user groups would receive only information which would meet their demands. But there should always be a possibility to view original data if closer research is desired to be implemented.

It would be very useful to have a database where all historic information would be stored. This provides possibilities to analyze and develop systems based on relevant data. It is a fact that in the beginning of implementing a new system and infrastructure everything does not work as efficiently as it could and all the potential is not being exploited. When network development is going towards smart grid ideology it is important that changes which are done now are easily customizable for future needs. For this reason development should be continuous. Next the most important systems in controlling and analyzing electricity network are explained.

SCADA (Supervisory Control And Data Acquisition) is a control system which has a function to provide real time monitoring of the electricity network. Its main characteristics are event data monitoring, controlling of switching status of electricity grid, remote control etc. So simply it allows the usage of the remote controls in electricity network like substation’s controls as circuit breakers and disconnectors. SCADA is a process computer/system which gives up to date information of electricity distribution process. Through it many critical operations can be implemented but traditionally it does not provide low voltage information and display in control centre is limited to a diagram form. Difference to distribution management system is that SCADA is a process computer system which efficiently controls, collects and conveys information. [11; 37]

NIS (Network Information system) includes technical information of networks components. It consists of database, database management system and application programs. Applications vary for users but the most important ones are updating, planning and calculation applications. [11; 37]

DMS (Distribution Management System) is a system which supports the operations of the distribution network such as controlling and planning. It contains information of the networks switching status, networks topology, disturbance management etc. This system is usually based on SCADA and network information system (NIS). It simply widens traditional SCADA. It has better visual graphic interface, contains information of the whole network and has analysis tools. DMS includes more features than traditional SCADA. [11; 37]

In the following subchapters, first brief explanation is provided about technical solutions whose combination would enable to develop an efficient management system for maintenance purposes. Two different approaches, applications, are surveyed which both have some the same qualities. There is also a short explanation of LNI Verkko FieldCom network structure. The first one is based on Power Q Oy services and second one is ABB's. Power Q has developed a comprehensive data management power system PQNet. ABB solution is COM 600 device which has a lot of features for substation level automation and also contains even some control functions. These two examples are explained because they both have features which would be efficient to combine and would serve the needs of LNI Verkko Oy. Then integration of the systems is demonstrated which would make possible to expand applications to the user groups.

7.1. Today's applications

PQNet is a data management system which helps to store all measurement data into a database. There it is possible to analyze all the data. This database concept makes PQNet's solution an interesting approach since the communication protocols are ignored here. Tools for automatic detection and analysis are provided such as fault and power quality analysis, network maintenance, and customer service. PQNet stores measurement data from different sources into a single database as can see from Figure 7.1. System is isolated ensemble from traditional the network systems such as SCADA and DMS. Power Q has shown that this kind of system works and all the tools to process Vamp's feeder terminals are already provided. This would enable to expand data collecting for many different measurement sources such as secondary substations which have been demonstrated and more information can be read from reference [38].

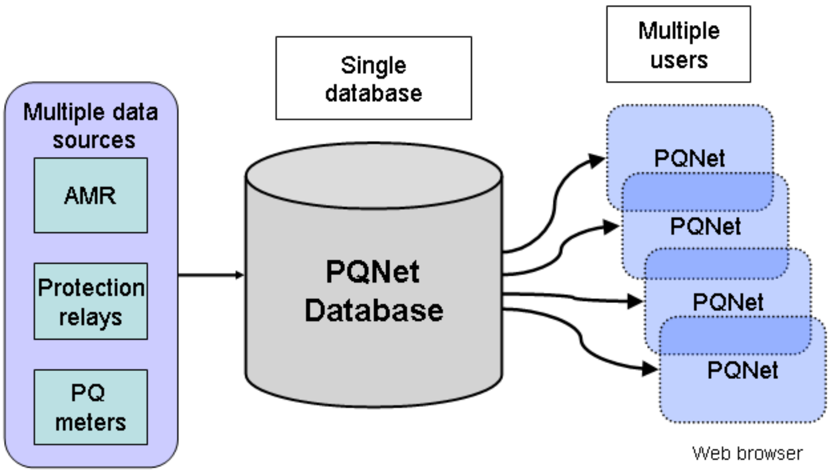

Figure 7.1 *PQNet data management system made by Power Q*

Information which can be stored to the database can include e.g. disturbance recording files, events and alarms, hourly energy data, voltage dips etc. Typical measurements in PQNet system can be substation (primary and secondary) relays especially disturbance records, consumer meters, PQ meters, AMR meters and quality modules. Automated notifications and analysis can be developed easily because PQNet operates in its own database and system. It is possible to customize this system is for customers needs and it can be connected to communicate with DMS or SCADA.

For post-analysis purposes only this kind of process flow can be very useful and can be made to work with many vendors equipments. This is because linking to other systems is implemented by Application Service Provisioning (ASP) by Power Q. Power Q and Vamp have demonstrated this in the secondary substation level as can be read from reference [38]. Especially if first is only concentrated to analyse and transfer data. Converting of the data into a format which can be analyzed can be implemented in the database where other calculations would be also done. Power Q can implement this process.

ABB provides COM 600 which is an all-in-one communication gateway, automation platform, and user interface solution. It connects substation IEDs and network-level control and management systems. It also offers human machine interface (HMI) solution in a web technology based functionalities providing access to substation devices. In Figure 7.2 COM 600 integration to substation level automation is shown.

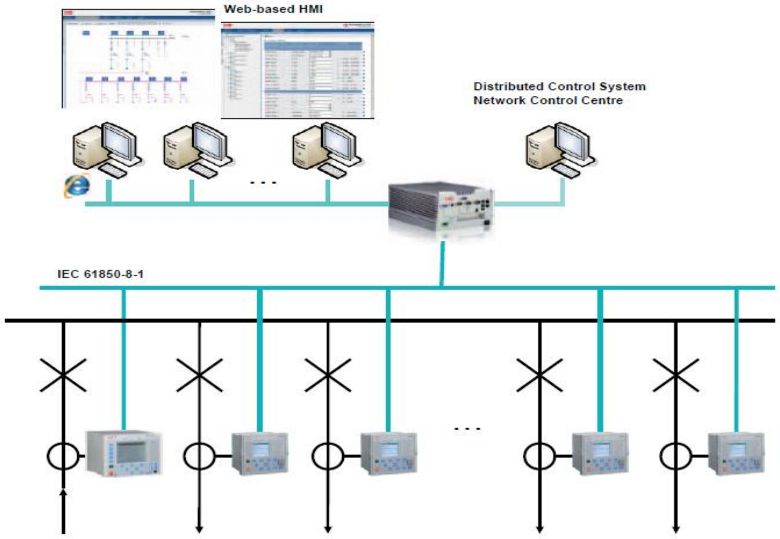

***Figure 7.2** General example of station level automation provided by ABB*

COM 600 adds more automation to the substation level. HMI is an excellent tool to view what is happening or has happened in the substations IEDs. Disturbance records are automatically downloaded from connected IEDs and saved in standard COMTRADE format. The data history is based on ABB’s software which provides a platform for process information management. The strength of ABB’s solution is that information is transmitted and filtered rapidly from station level to the control centre. The fault detection, fault isolation and load restoring (FDIR) is one of COM 600 control functions. [39]

LNI Verkko Field Communication Network (FieldCom) enables centralized and standardized outage management. Everything in the upper levels of network is centralized to one SCADA and one DMS as presented in Figure 7.3. This concept allows a wide integrated remote management and also the possibility to process a whole network structure faster and simpler.

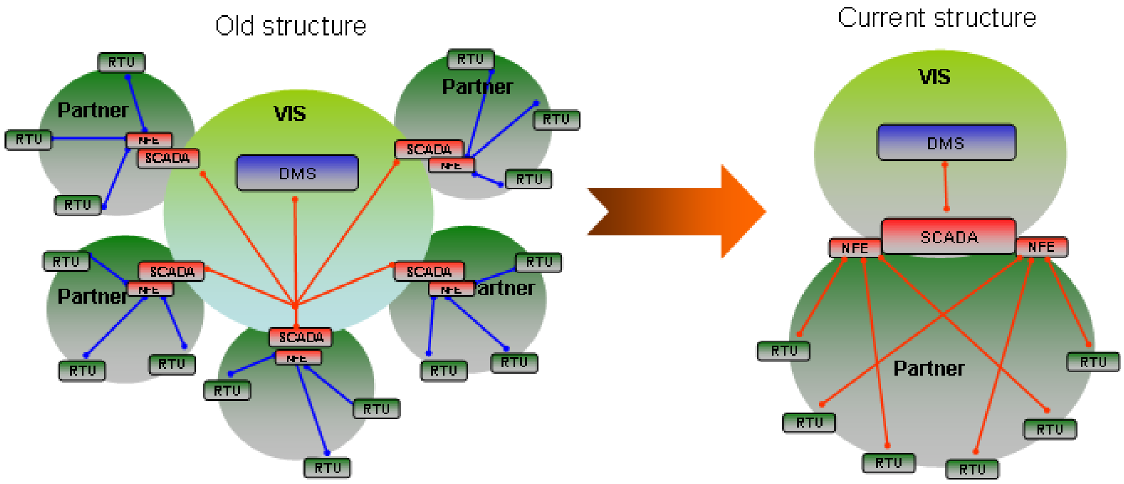

Figure 7.3 *Old and current network structure in LNI Verkko Oy*

FieldCom idea and structure enables to develop new applications efficiently to the whole network. Because substation automation is already implemented and it is the same for all, adding new features comprehensively to the whole network is a simple process. In a later chapter this structure is used for maintenance purpose and ideas are given what kind of development is required.

7.2. Communication links and IEC 61850 standard

Reliability and usability is amplified when remote usage is increasing. This has almost direct correlation to communication links between systems and equipments which are used remotely. Important factors are reliability and throughput. The amount of traffic a network can carry is measured as throughput [40]. Higher throughput enables to transfer all available data without compromising usability. Advance communication connections are meant to increase data's transfer rates. When telecommunications are duplicated, connections are not so easily compromised and reliability increases. No matter how communications are implemented if throughput is enough for design purposes and connections are guaranteed in high enough level, systems can operate properly, fast and reliably. In LNI Verkko Oy primary connection to primary substations is carried out by @450 broadband and back-up connections are fulfilled by a satellite connection.

The connection between RTU and the equipment which delivers data of measured quantity can be also executed in various ways. But importance of unambiguous method grows when the need is to apply the idea widely. IEC 61850 standards define complete communication architecture in electrical power systems. This kind of a unique standard is one of the key factors when the goal is to keep smart grid ideology in mind and development towards it is made. Interoperability between devices from multiple vendors is a problem because communications would almost always need some kind of converter to operate. It is hoped that IEC 61850 would solve these problems but it is not yet fully ready. This standard is not only for communication protocols but also for data models of electrical applications. Intelligent electrical devices (IED) could communicate more efficiently using a universal standard.

Compatibility is also a problem when there is a need to develop a new system. It cannot be assumed that the used equipment is only from a single provider. When multiple vendors are used there is most likely going to be compatibility problems. If data which is received from equipments is not unambiguous, processing and analyzing it would require additional modifications before it can be processed. When data is finally processed, output information needs to be as explicit as possible. But still for further development of systems and analysis afterward there should a possibility to study original data before the final processing step. That is why transmitted information from measuring instruments should be in the same format before any processing is done. This process is described in Figure 7.4.

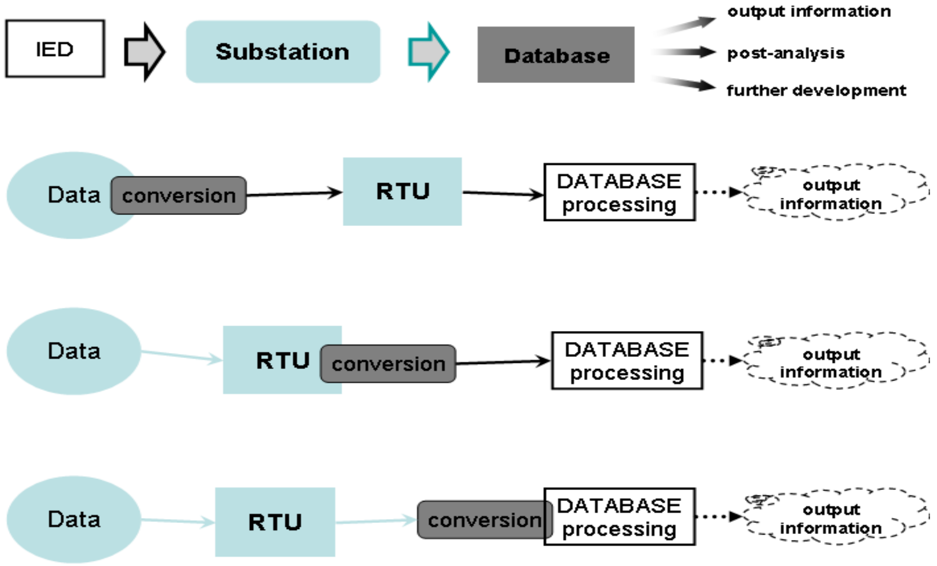

Figure 7.4 *Process flow possibilities*

The problem can be demonstrated with available data from protection feeders. Data here can be e.g. a single record of many different measurements. This record can be as measured values in circuit breakers operation when it interrupts a circuit. There are many suppliers for feeder terminals and output data record is not always in the same format. There are few possibilities to implement which enable data converting or dismantling. These venues are shown in Figure 7.4. The first is that immediately measured information is transformed to universal form before it is transmitted. This would require integrating converter to measuring unit or data is transformed to universal form when measurements are done. The second option is that the data is transformed in RTU and then transmitted for further process. One alternative is that all available data records are gathered to a database and needed conversions and all calculations are implemented there before output information is formulated. This method is maybe the most viable mode at first when this kind of process is going to put in practice. In any case the best option could be that all received data from same kind of equipment but from different vendors would be in the same format after it is measured but this requires universal standards. Maybe in the future this will be the situation.

7.3. Integrated system infrastructure

The applicability of a system is important factor for vendor who is developing it. When system can be integrated to customer's current systems it is much easier to sell it. But it is also must kept in mind that solution should be wise and efficient. System integration which is presented in this thesis condenses in Figure 7.5. Secondary information, process data is transferred to a database trough remote terminal unit (RTU) and it would support the traditional network information (NIS). First when implementing this scheme all the needed operations could be carried out in database such as disturbance record conversions, filtering, and needed calculations. So the most important feature in development would concern the database concept and its connection to the network information system data. This processed information connection to other systems is ignored here and described only as a management system because it depends on the company which kind of integration is wanted to implement. One possibility is to connect processed explicit information to DMS. Management systems connection to substation station computer (RTU) is illustrated as a two way arrow because e.g. remote access is crucial for further development and more about this matter is discussed in subchapter 7.3.1.

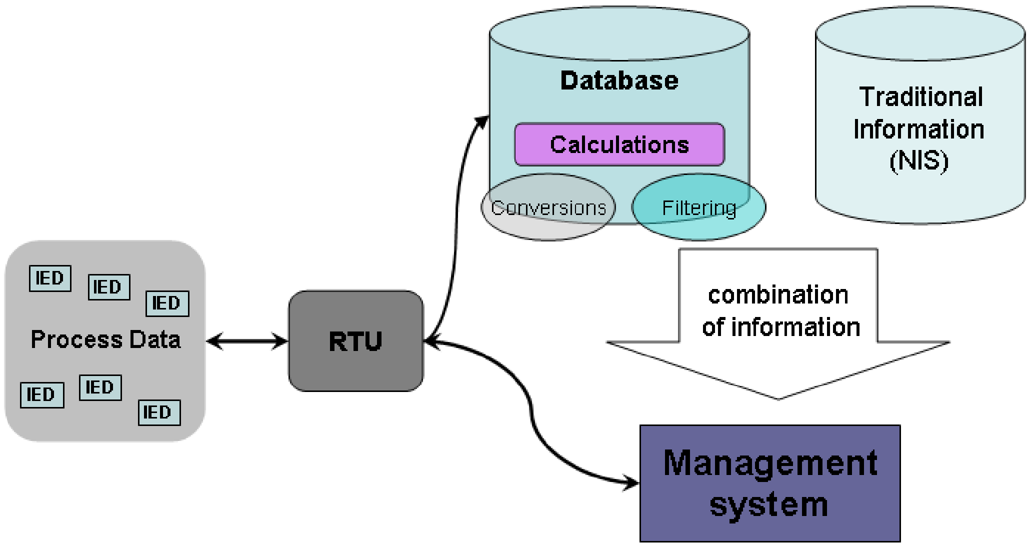

Figure 7.5 *System structure for utilizing process data*

LNI Verkko Oy's FieldCom structure supports the exploitation of single database method. As explained earlier, the idea is that the primary substation remote terminal unit (RTU) works as a collector of information and would pass the information on to the database or directly to the system. This is described in Figures 7.5 and 7.6. The database would be connected to a management system or earlier described system such as DMS which would deal with the available information. Probably a new management system is needed to be developed to handle available information or at least maintenance. It would be connected to SCADA, DMS or both where critical notifications could appear. SCADA has already a direct connection to substation and that is why it is described as dashed line in Figure 7.6.

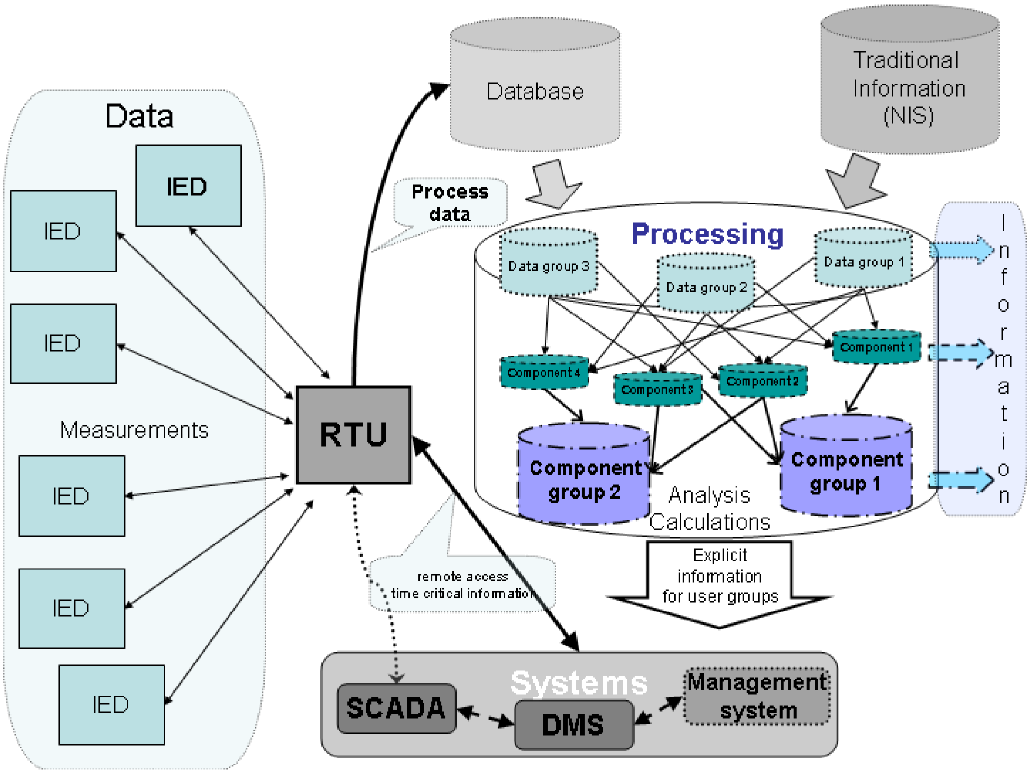

Figure 7.6 Communication connections in an integrated system infrastructure

Communication links should be as reliable as possible so that connections and information flows are secured. Calculation, analysis and reporting would be done from a database and traditional network information. Then necessary information is provided to the user groups. It is also possible that some calculations would be done already in RTU and data which is crucial to have quickly in the control room would be transferred instantly. This connection between RTU and systems is also presented in Figure 7.6. Protection feeder terminal is not just equipment which takes care of protection and which protection condition it tried to predict. It is also a device which can gather various data. That is why communication between relay and RTU is important as well. In general when automation is added to the network and information is transferred, significance of communication links is emphasized.

Critical information could be viewed in a control centre immediately and from notification could be a connection to a more detailed information or original data. This why direct connection from RTU to system is described in Figures 7.5 and 7.6. The simple example could be protection. When circuit breaker has operated a notification would display in the control centre which would show what kind of protection has operated and important values would be automatically calculated from protection relay's disturbance record. From the notification a connection could be to the original disturbance record so it would be easy to view the actual record. Information which is not so time critical can be processed from this disturbance record later on which would be in the database.

Systematic database is a foundation of efficient maintenance. Already today maintenance data should be restored systematically so it would be easy to analyze and update. Data can be from various sources like off-line inspections and IEDs. When databases are discussed here it must be remembered that it does not only cover condition information. Traditional and process data should be categorized wisely if the need is to use it for various purposes as is presented in Figure 7.6. Secondary data from networks which can be considered as process data is available today because of advanced communication.

Organizing a database has various possibilities and all of them have benefits and disadvantages. Easiest starting point is to divide traditional information and process data. Data can be categorized based on which type of data it is. Same matter concerns e.g. disturbance records but not for all data groups. Then the next step could be to filter data for different components and components could be categorized by substations or by type or area. Categorization of components depends on which user group uses this information. Components can be linked to many different groups as presented in Figure 7.6. Then filtering is easy to execute when user wants information of components in a certain category. It could be very useful if certain data groups, component, or component group's data could be viewed if wanted. Data group could be e.g. disturbance records and component group all of one substations components information. In any case e.g. condition information would be automatically calculated and notification would be linked to some other system.

Automation accentuates more when the amount of data rises. Data should be automatically filtered and categorized. When we include hand-fed traditional information which should be as easy as possible to do, demands are pretty high. Calculations should be made from all the data and simple explicit output information would be provided automatically which can be linked to the management system. These are factors which set boundary requirements for a database and its automation.

7.3.1. Remote access and development

When communications are no longer an issue and the database is created, upgrading it remotely and further development of its filters enables continuous progress. The remote controls of substations equipment provide enormous advantages for wide electric power grid management. Distribution automation enables good possibilities to develop holistic electricity distribution management. This means controlling the remote equipment and monitoring automated actions. A stand was taken and ideas were submitted in an earlier chapter how network data can be utilized and restored. It is not enough that devices just do automated actions and data is received. Passive solutions are not any more a sensible implementations because of the power networks requirements and the state of changes in the future. That is why equipment must adapt to new stages. Remote access of devices is one of the essential assets when future power network is developed. For adapting new requirements remote usage is efficient and the only option in the future because some changes must be done very quickly. Today remote access is mostly just about remote controlling and monitoring of measurements data. Like AMR meters which can be read remotely when wanted, the meaning of remote control increases when upgrades are wanted to implement for many IEDs or RTUs.

Remote upgrading is especially issue for feeder terminals. If protection could adapt to the changes of the electricity network, protection could be perform its purpose better. This matter is discussed more in later chapter. Any way at first a working solution must be made for how the traditional software upgrading could be handled remotely. Connection can be implemented through remote terminal unit (RTU) which can be seen in Figure 7.7. RTUs upgrading and controlling can also be done remotely and as notices from figure connections move both ways. Data can be received and transmitted.

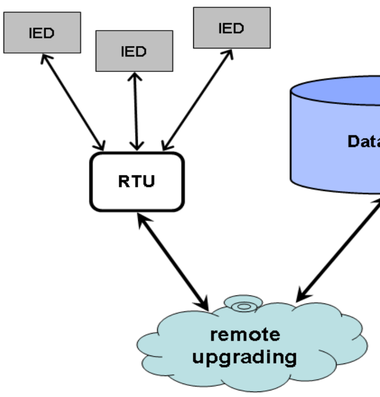

Figure 7.7 *Remote access items*

Database concept was presented earlier and it is taken here in examination also because its processing algorithms should be available to manipulate and upgrade when development has made significant progress. Databases information, unfiltered data or calculated information is meant to be able to view whenever needed. Stored data can be studied and new filter methods can be tested. Evaluations of new calculation methods can be done by comparing what kind of information new methods present to automatically filtered information from the database. This is how database processing can be developed.

When upgrading can be implemented remotely it is not wise that devices on the lowest level are upgraded. This means that some functionalities of IED in the bay level can be integrated in the upper level, substation level. Nowadays this matter concerns only protection and control. Protection relays features implementing can be done in a station computer and then IED acts only as a measurement device. Question is which features are smart to implement on the bay level and which on the station level. This kind of idea is also used when talking about partly centralized protection concept.

7.3.2. Maintenance process

As explained earlier notification from database would appear in control or management system. When maintenance is being develop to be easier and more efficient the whole process could be as explained in Chapter 5.2. Automated notifications of components which are in critical condition would appear and these could be processed to the next stage, decision making process. If it is decided that overhaul is needed, these targets could be easily moved to work execution and overhaul would be automatically booked. Targets can be defined by area, whole substation or however data groups are defined. When work would be done and contractor has documented what was done, a hand-fed documentation of what was done would be updated to traditional information and linked to components for which maintenance had been executed. This process has been described in Figure 7.8.

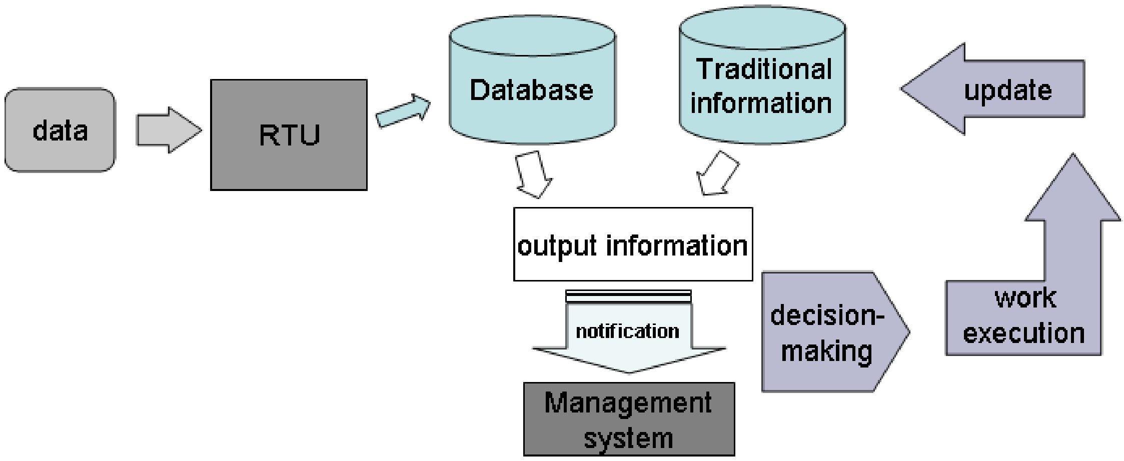

Figure 7.8 *Maintenance process flow*

For instance condition information of transformer could be notified when temperature has risen over the critical notification limit. First measurement value would be updated to the database. If the limit is exceeded a notification would appear in the system. Then its temperature curve can be viewed and conclusion of should maintenance actions can be determined.

8. RELATED PILOTS

The point of this study is to combine technological possibilities to have workable solutions with valuable implementations. The ideas and potential solutions which are presented in this thesis can provide pilot projects. These pilots will demonstrate that possible solutions will have a potential to become reality. Next three possible pilots are presented and what requirements they would have. All of these pilots have common that Information Technology (IT) system must be developed. Solutions are presented which would need further development but are already possible to realize. These solutions were presented earlier in this work.

First the gateway for information is needed. Connection between primary substations remote terminal unit (RTU) can be establish in many different ways. Things which matter are reliability and throughput of connections as was explained in Chapter 7. For the feeder terminal or some other intelligent electronic device (IED) communication to the RTU is important to have in a common format with others otherwise all data would need to be converted before it can be processed. Common information model (CIM) and IEC 61850 standards are hoped to provide solutions for communication and data format problems. A system which can handle data processing and combining information with traditional network information is crucial. To utilize the available information efficiently, automated processing should be used as was explained in Chapter 7.

8.1. Replacing relay protection testing with process information

For protection testing the principle is to use actual disturbance situations. Disturbance records and feeder terminals register would provide all the information which is needed to ensure that protection has worked as it should. These requirements and possibilities are described already in Chapter 6.3. Conclusion was made that it is possible to delay or replace protection testing with actual disturbance situation. In the cable network this can be an issue because fault situations are needed. Consequently cable wiring brings new challenges for fault situations like locating the fault point on the cable.

A database is needed where analysis of disturbance records and register information is implemented. This database concept and idea was already explained in an earlier chapter. In general database for maintenance is an important matter and relay protection testing is a great part of maintenance operations.

An important issue when is wanted to replace relay protection testing with actual protection event is that the disturbance situation would be as explicit as possible. This would enable to ensure performance of certain protection functions. Disturbances are still needed if testing is to be replaced. It would not be enough that single protection function has operated and its performance has been ensured from the disturbance record. In order to be sure that protection level is in a certain stage performance for some other protection functions should be also ensured. Question is which protection functions performances are enough to ensure that they work as they should. If remote control to the feeder terminal is available then the setting values can be tampered remotely and updated as was explained in Chapter 7.

There are possibilities to gather a bigger picture of the whole substations protection because other relays could also notice disturbance which have happened in a single output. If all the information is analyzed it could offer various information of other relay's which would not trip but they could notice deviation in the network and register the values. This is described in Figure 8.1. There interruption has happened in a single output but other relays would perhaps also register deviations.

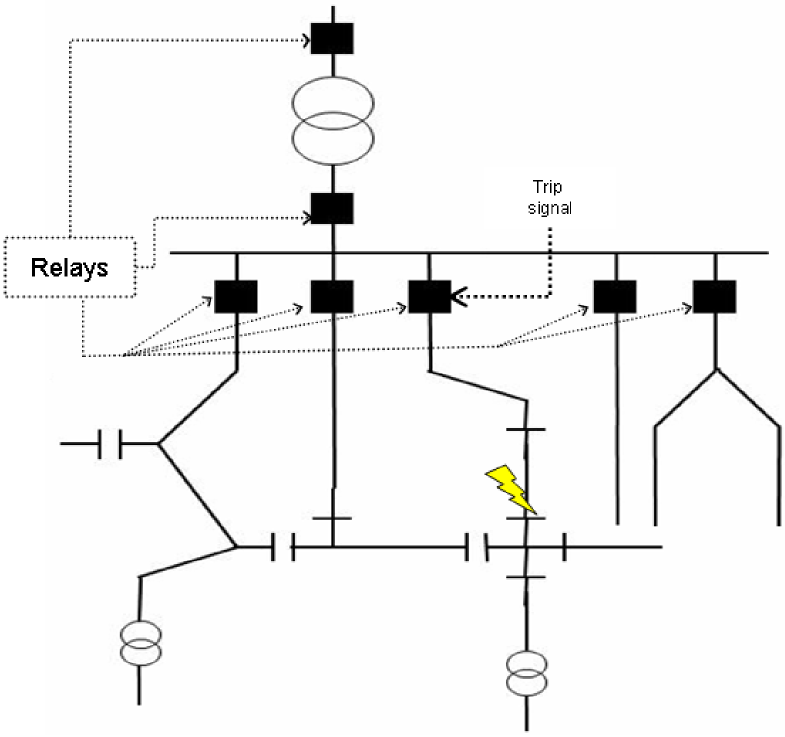

Figure 8.1 *Multiple relays can notice single output's interruption*

If these values could be analysed carefully protections performance could maybe ensured remotely. Even better would be that if remote connections to the relays are possible, a remote testing could be possible to implement. Other relays could just observe that testing is working as it is supposed to. But this kind of futuristic remote usage would need more studies. Anyway to form a bigger picture of the entire protection system better information gathering and analysis would be needed.

8.2. Primary equipment condition monitoring and condition based maintenance

Primary equipment in the substations is usually assumed to be a transformer and a circuit breaker. Condition monitoring of these equipment is highly important to ensure reliability and usability of the electricity network. If either of them is compromised the whole power system is unstable. To implement condition based maintenance on-line monitoring is required and executed for them and primary failure modes are identified. Chapter 6 explicate what kind of condition monitoring methods can be realized for both pieces of equipment.

If implementations of needed measurements, data, are not a problem then database for them is needed. All measurement devices can be connected to substations RTU or feeder terminal can act as a measuring device. But to have a better knowledge of equipment condition traditional network information could be combined with new measuring implementations as demonstrated in Figure 8.2.

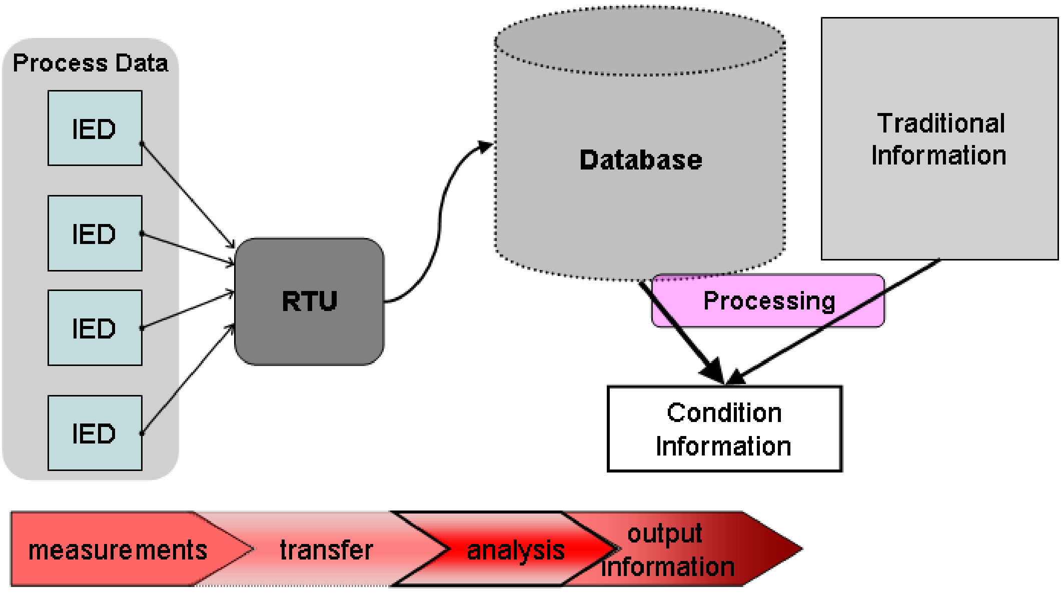

Figure 8.2 *Condition information and process flow for maintenance*

This way equipment which is under review for its condition can be estimated before new information is available and afterwards traditional information can supplement the condition estimation. Traditional measurements can be whatever is generally implemented such as DGA. An advantage of using process data for estimating condition of transformers and circuit breakers is that their condition is then better known all the time and traditional inspections can rarely be implemented.

Process flow for both, circuit breaker and transformer, is the same. This is described in Figure 8.2. First some of the measured values change which is a crucial indicator of a possible fault. Data is transferred to a database and combined with historical data and traditional information. Then notification appears for user which makes analysis of this deviation based on historical information or it would be done automatically. Finally decision can be made whether the event requires immediate actions or can overhaul just be ordered for some other time when other equipment needs overhaul also.

For a circuit breaker the simplest method is to analyze interrupted current and operating time’s information for condition estimation. Other easy measurements are related to its auxiliary devices condition. If those devices as interruption mechanisms’ motor indicate possible failure, it can lead to order maintenance for whole circuit breaker.

Primary transformers situation is more complex but insulation wearing gives possibilities to evaluate its condition. Artificial Neural Network (ANN) modelling uses five input measurements to model thermal behaviour of the transformer. These input values are ambient temperature, three phase currents, and one previous output temperature value of the neural network. More of this and other modelling methods is explained in reference [13] and was discussed in Chapter 6. With traditional information transformers nameplate values are known and IEC 60354 standards equations can be used for automated condition estimation. Other useful measurements can be obtained from peripheral components in which faults can also be crucial. More of condition estimation methods for both pieces of equipment were described in Chapter 6.

8.3. Automated disturbance and quality information

When more information of disturbances is needed it would require more automation. Electricity quality is related to disturbance because the most deviations of electricity quality are an outcome of disturbance or interruption of electricity flow. Idea is simple when disturbance or deviation of electricity happens it would be automatically noticed and presented in a control centre. In the first stage this would only concentrate to the information possibilities of primary substations but when development is evolved enough, secondary substation and customers AMR meters can be added to this information chain.

Information requirement is that when deviation of electricity has happened it can be noticed and information is delivered forward as can be seen in Figure 8.3. Protection relays observe already certain quantities and can be a maid to record also abnormal situations which would not cause interruption. Then these records, e.g. disturbance records, can be analyzed automatically and the necessary values can be presented in simplified format. More measurements can be added to the electricity network but today protection relays provide already a promising amount of information and that is why their possibilities should be observed more closely.

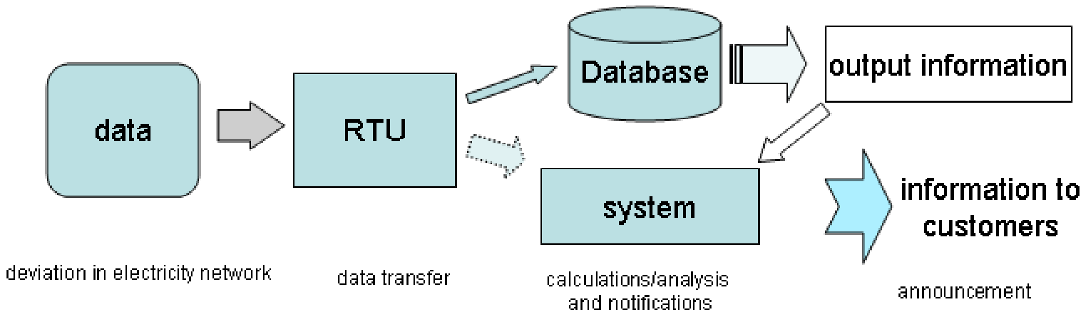

Figure 8.3 *Process flow from measured data to output information*

The important stage would be a database for collected data and reporting filtered information for further usage. In database the calculations and filtering would be done automatically. A problem is that most of the time disturbance information is needed as soon as possible in the control centre when interruption has happened. If data is transferred to the database and filtering is done before information is presented in the control centre, too much time has been wasted. Some filtering is needed to be done already in the primary substation if this process is to serve multiple purposes since it has the potential to serve. But if an idea is just to implement post-analysis processing which is not time critical, then all information can be collected to some sort of database where calculation and analysis is done before the results are presented in a simplified format. Complete process flow would be from measured data records to information to the customers and to electricity network company's personnel as is presented in Figure 8.3. The presented system in Figure 8.3 can be integrated to existing systems such as DMS. In any case automated information of electricity quality is made and announcement is formed. The process could be totally automated and notifications of electricity quality or disturbances would be delivered to the customers.

9. FUTURE ASPECTS AND POSSIBILITIES

Automation and ICT possibilities today enable the improvement of the whole asset management of electricity network companies. It is important when new applications are developed so that they correspond to the future needs because investments are usually valuable and installations are long-term. That is why especially systems must be easily adaptive for updated purposes.

When new is to develop there are few possible aspects to consider to find interesting subjects. Demand aspect is what is wanted to implement or needed but these are not always possible to realize at least not yet. The other aspect is supply which basically is just using today's technology to realize possible applications without much of new development. So actually everything needed exists already but execution to practise has not been done or thought how it could be implemented.

In the future, process data will be collected and it can be collected quite much. All that data is not needed in upper levels of network hierarchy. Filtering can be brought closer to the measurements sources and only processed information would be sent forward. Question is what kind of data can be filtered near the measurements and what data is precious to transmit forward in its original form.

Protection relays measure various ranges of quantities but all these features are rarely utilized. Also more can be integrate to them but first studies should be completed on how functionalities which are already provided can be used more efficiently. Next section gives some ideas how modern IEDs, feeder terminals, can give better information of the networks status. First assets which influence wider implementing of automation in the distribution network are explained.

9.1. Network hierarchy and secondary substation automation

If smart grid ideas are to be implemented in the distribution network more information of loads and productions are needed. One reason is because distributed generators are going to play a major role in the smart grids ideology. More specific information is needed from the node points from all the levels of distribution network. These kinds of places are going to be e.g. primary and secondary substations. Today measurements are mostly received from primary substations and from customers via AMR meters.

When "smartness" is implemented in the middle of the network hierarchy lots of new opportunities are possible to realize. Some information is needed for automation equipments in those key points and that is one reason why communication connections should be reliable and fast. This is because when calculations are done from measured data, information is needed in different levels of the network hierarchy and it could be implemented automatically. In Figure 9.1 possible example of those levels is described. Also the same system infrastructure is included which was explained in earlier chapter. System which handles management or remote access is skipped here but like speculated earlier it can be DMS or some other management system. In Figure 9.1 this ensemble is just described as a system. Condition monitoring information is rarely critical time but still some information flow can go through control centre systems where it is possible to execute automated analysis and control condition based on decisions on those points.

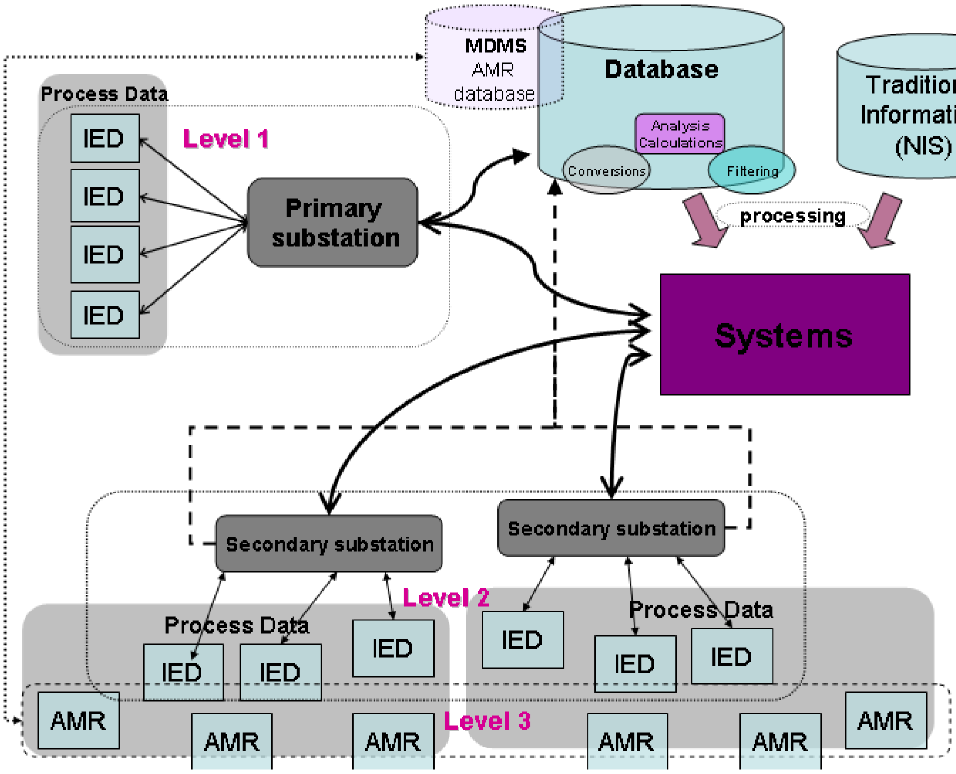

Figure 9.1 *Network hierarchy with different levels*

Network hierarchy could allow better and more efficient condition based maintenance for wider scale network because there would be more measuring point all over the network. This on the other hand can cause a problem of overwhelming amount of data. A solution can be that automated condition monitoring or at least storing of data can be implemented to the substations. Simply said database for information could be also decentralized to substation levels. Possibility could be that only filtered information would be restored to a single database and original data would be located at the substations.

It would be possible to make automated decisions on substation level e.g. if equipment is in critical condition and its usage needs to be decreased. Calculations for power flow and other important factors could be automatically done in primary and secondary substations and the power flow could be redirect so that equipment in critical condition would not cause interruption. This is only the case if low voltage network would be used closer to its limits and in current increase of electricity usage it can happen.

9.2. Obtainable information possibilities for relays

Protection relays can measure almost anything. That is why they can provide possibilities to monitor a wide range of components. Data is just needed to transfer station level RTU where it can be processed or transferred forward. Information which is not time critical can be stored to a database and analysis is implemented there. Some functionality needs immediate actions to serve its purpose such as some protection possibilities. This kind of data could be filtered already in the substation and information would be transferred directly to the control system.

Still like deviations which relays notice but would not cause circuit breaker to operate could be very useful to analyse in database. Another point is to analyse relays which are in different bay when fault happens as is presented in Figure 9.2. There a fault has happened in one output but data is collected from adjacent bays also. This can give important information of fault situation and quality of power. Better calculations of fault location can be made because of various measuring points. This idea requires that feeder terminals are sync together so that all measurements are done simultaneously. Another interesting perspective is that if all terminals are in different sync and differences between measurements are known then more information is possible to gather from one event. Different time sync measurements would need much more studies and is just presented here as a possibility.

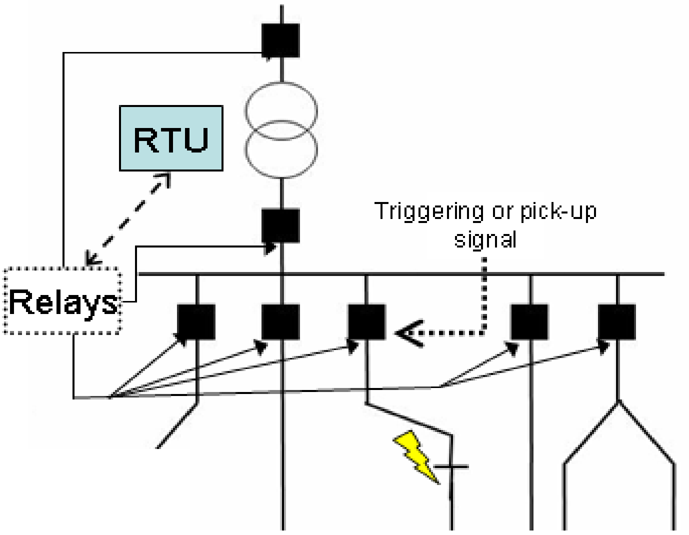

Figure 9.2 *Multiple relay connections*

The protection can be developed and made more selective if is better known to bigger picture of whole protection event. If all pick-ups would be also recorded condition estimation of protection could be more valid. There would be then more records which analysis can be done.

There is just economical issue if more functionality or better protection is wanted to implement. Because upgrading costs would then rise if all IEDs is needed to upgrade when some new functionality is developed or old one is improved. This can be prevent if those new functionality wouldn't be implement to all relays. If there would be station computer which could control those features and feeder terminals would act just collector of information for those features. All important protection functions would still be in relays but other less important for safety would be in RTU which wouldn't cost as much to upgrade. This idea is also known as partly centralized protection.

9.3. Adaptive protection

When connections to the feeder terminal are possible to implement, fast and reliable status can be monitored and controlled remotely. When protection has operated but operations have not been what they should, threshold values could be possibly changed on-line. When relay operates its values and measurements, they would be transmitted immediately to the control centre. There analysis could be done by automatic calculations or by a control personnel that have relays and circuit breakers operations been as they should. This process flow is described in Figure 9.3.

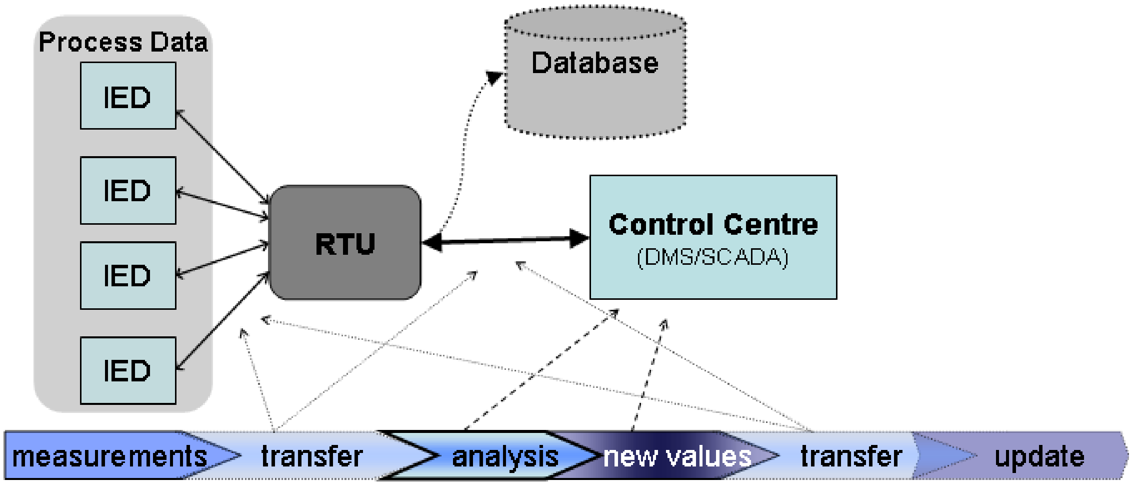

Figure 9.3 *Adaptive protection's connections and process flow*

After new values have been calculated upgrading them to relays would be done remotely. For calculating new values, real-time measurements are needed from the network in order to decide correct protection values. This would enable adaptive network protection. Protection would adapt and adjust when needed. Adaptive protection would make it possible to create more sensible, selective and flexible protection system which could respond to changes in the electricity network. This way also volume of unnecessary protection actions can be decreased and customers would experience less interference's.

10. CONCLUSION

Maintenance is an important subject for electricity network companies. This thesis first provides a small glance to smart grids because system development today should serve future needs and condition based maintenance is often considered as a part of smart grids objectives. Efficient and wise condition monitoring is the main factor which enables condition based maintenance. Monitoring should be aimed so that it would support maintenance and also other purposes. Therefore fault development must be known. The economical costs can be decreased if maintenance is implemented to targets which really must have an overhaul. To make condition based maintenance a reality, system development for maintenance is considered necessary. LNI Verkko Oy’s network infrastructure endorses a wide progress to update its systems toward smart grids. This enables continuous development and it should be remembered when the aim is to achieve progress.

The maintenance is mostly carried out today by fixed time intervals which is not efficient or necessary for every component. In Chapter 2 the focus was on the maintenance strategies. An explanation was provided for the differences between various strategies and how deliberate condition monitoring can improve maintenance operations from time based to condition based. Condition based maintenance is not always the best option for every component or device. Monitoring consumes resources and for some of the components in the network constant unnecessary supervision is unnecessary. Therefore reliability of the component should be considered when maintenance targets are chosen. As explained in Chapter 3 risk based maintenance (RBM) combines reliability and condition factors therefore this would possibly be the most competent maintenance strategy.

Careful consideration should be given to which targets can be achieved to provide efficient and reliable condition information to support maintenance operations. The easiest way is to begin from components which can already provide condition information. Chapter 5 explained the economical aspect for protection relays and demonstrated in hypothetical situation what kind of savings can be achieved. The reason is that protection relays can provide valuable information and it could be exploited quite easily. In Chapter 4 an explanation of the main protection situations, earth and short circuit faults, was provided. The proper operations of these are essential to know. As explained in Chapter 6 their protection functions accurate faultless operations can be hard to ensure but in any case information of the whole protection operations would be obtained. It should be kept in mind that data provided by the feeder terminals would not only serve to ensure protections correct operations. Data which the feeder terminals could collect would give condition indications of the other components also. That is why the most typical faults and their development should be studied first for those other components.

Economical aspects should be also included because on-line condition monitoring can be very expensive for some components. The on-line or often carried out monitoring can provide especially potential information to predict components condition. That is why condition monitoring measurement would be sensible to integrate together e.g. to feeder terminals because they already have communication and measurement possibilities. The economical costs for condition monitoring for the feeder terminals, as was demonstrated in Chapter 5, can reach breakeven quite quickly. The process can be even faster if the information possibilities of the feeder terminals would be utilized better.

When condition estimations are being completed, it must be remember that traditional network data should be combined with new sort of process data. Secondary data or to say process data can be easily utilize as the first support maintenance decision. Important feature would be to combine different condition information’s and to perform cross-references to obtain better vision of the components state. By cross comparison more reliable equipment status can be achieved because then there would be more information sources which would affect to those decisions. Also vulnerability of one information source provider would decrease. If that one source would be compromised and could not provide data there would be other information to support decision making.

At first targets should be essential components in primary substation like circuit breakers and primary transformers because they are very important devices for primary substations operations. Advance protection relays can convey information and at the same time useful information of relays operations could be obtained. It should be considered that components for which condition information is simple to gather would be also implemented like substations battery system.

Implementation of the condition based maintenance would need an effective system. Same system could serve also traditional maintenance actions and progress development toward smarter operations in electricity distribution business. It is clear that today’s broadband communications makes this kind of development possible. All kinds of information can be collected from network but in order for the system to handle this, it needs to be developed. As explained in Chapter 7 a database for process data is essential.

The system infrastructure for maintenance would enable to develop new applications to electricity distribution. Communications today provide transfers and control the whole network infrastructure. At first it is only needed to develop systems which can handle information possibilities. In future more real time information is required from various levels of network hierarchy if smart grid applications are to be implemented.

Condition based maintenance is an efficient approach to control networks components status but for all components it can be unnecessary and too expensive. If a lot of new sensors are needed to implement cost could rise too high. Reliability and importance of specific components should be considered when condition monitoring methods are implemented. When systems and communication for maintenance are in use to add more measurements afterwards executions is quite easy. Simple monitoring techniques can provide useful information and are easy to realize e.g. deviations in measurement values which should be same almost all the time. Advance protection relays have various features which are not in use and could provide very valuable information e.g. circuit breakers condition monitoring functions.

Further studies and the next object could be to define database for collected data and its connections to the other systems like NIS (network information system). Then valuable process data can be characterized and some sort of filtering is possible implement. The most potential device is feeder terminal because to it can be integrate many measurements. Amount of data can increase when it will be available to collect therefore some filtering and processing could be done already in the substation level. It would require more studies and analysis what kind of data can be processed in substation. Time critical information e.g. from fault situation could be first handled in the substation and only important values would be immediately after fault situation shown for the control personnel. All in all required system infrastructure for maintenance would give enormous possibilities to develop and exploit advance applications in electricity distribution business. In the future when primary substations components are monitored effectively, secondary substations can be added to this hierarchy also. Amount of data would rise in the future and decentralized databases are possible to locate in the substation level. Only crucial information would be transferred to the main centralized database. This would give possible to implement automated operations in substation level and control personnel would only monitor these actions.

The author’s opinion is that condition based maintenance (CBM) is workable solution and should be implemented to crucial components. At the same time CBM could be realized to other components for which condition monitoring is simple to carry out. Components which require more complex measurements or analysis reliability factor should be taken in consideration. All in all proactive operations can be implemented if more monitoring and analysis is executed. An effective maintenance system would improve operations and would make it possible to know networks assets better. As recent years storms have shown electricity network is vulnerable. A better knowledge of the networks status and its condition can help to prevent outages in electricity distribution. When more effort is put into knowing the status of networks through maintenance then operations can be focused on more critical and important targets.

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APPENDIX 1: PROTECTION RELAYS TESTING COSTS

Periodic testing for 450 relays and 150 postponed								
Year	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Periodic testing	135 000 €	135 000 €	135 000 €	135 000 €	135 000 €	135 000 €	135 000 €	135 000 €
Total costs	225 600 €	171 600 €	171 600 €	171 600 €	171 600 €	171 600 €	171 600 €	171 600 €
Annual difference	-45 600 €	8 400 €	8 400 €	8 400 €	8 400 €	8 400 €	8 400 €	8 400 €
Accumulated total	**-45 600 €**	**-37 200 €**	**-28 800 €**	**-20 400 €**	**-12 000 €**	**-3 600 €**	**4 800 €**	**13 200 €**

Periodic testing for 400 relays and 200 postponed								
Year	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Periodic testing	120 000 €	120 000 €	120 000 €	120 000 €	120 000 €	120 000 €	120 000 €	120 000 €
Total costs	210 600 €	156 600 €	156 600 €	156 600 €	156 600 €	156 600 €	156 600 €	156 600 €
Annual difference	-30 600 €	23 400 €	23 400 €	23 400 €	23 400 €	23 400 €	23 400 €	23 400 €
Accumulated total	**-30 600 €**	**-7 200 €**	**16 200 €**	**39 600 €**	**63 000 €**	**86 400 €**	**109 800 €**	**133 200 €**

Periodic testing for 350 relays and 250 postponed								
Year	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Periodic testing	105 000 €	105 000 €	105 000 €	105 000 €	105 000 €	105 000 €	105 000 €	105 000 €
Total costs	195 600 €	141 600 €	141 600 €	141 600 €	141 600 €	141 600 €	141 600 €	141 600 €
Annual difference	-15 600 €	38 400 €	38 400 €	38 400 €	38 400 €	38 400 €	38 400 €	38 400 €
Accumulated total	**-15 600 €**	**22 800 €**	**61 200 €**	**99 600 €**	**138 000 €**	**176 400 €**	**214 800 €**	**253 200 €**

Periodic testing for 300 relays and 300 postponed								
Year	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Periodic testing	90 000 €	90 000 €	90 000 €	90 000 €	90 000 €	90 000 €	90 000 €	90 000 €
Total costs	180 600 €	126 600 €	126 600 €	126 600 €	126 600 €	126 600 €	126 600 €	126 600 €
Annual difference	-600 €	53 400 €	53 400 €	53 400 €	53 400 €	53 400 €	53 400 €	53 400 €
Accumulated total	**-600 €**	**52 800 €**	**106 200 €**	**159 600 €**	**213 000 €**	**266 400 €**	**319 800 €**	**373 200 €**

Periodic testing for 250 relays and 350 postponed								
Year	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Periodic testing	75 000 €	75 000 €	75 000 €	75 000 €	75 000 €	75 000 €	75 000 €	75 000 €
Total costs	165 600 €	111 600 €	111 600 €	111 600 €	111 600 €	111 600 €	111 600 €	111 600 €
Annual difference	14 400 €	68 400 €	68 400 €	68 400 €	68 400 €	68 400 €	68 400 €	68 400 €
Accumulated total	**14 400 €**	**82 800 €**	**151 200 €**	**219 600 €**	**288 000 €**	**356 400 €**	**424 800 €**	**493 200 €**

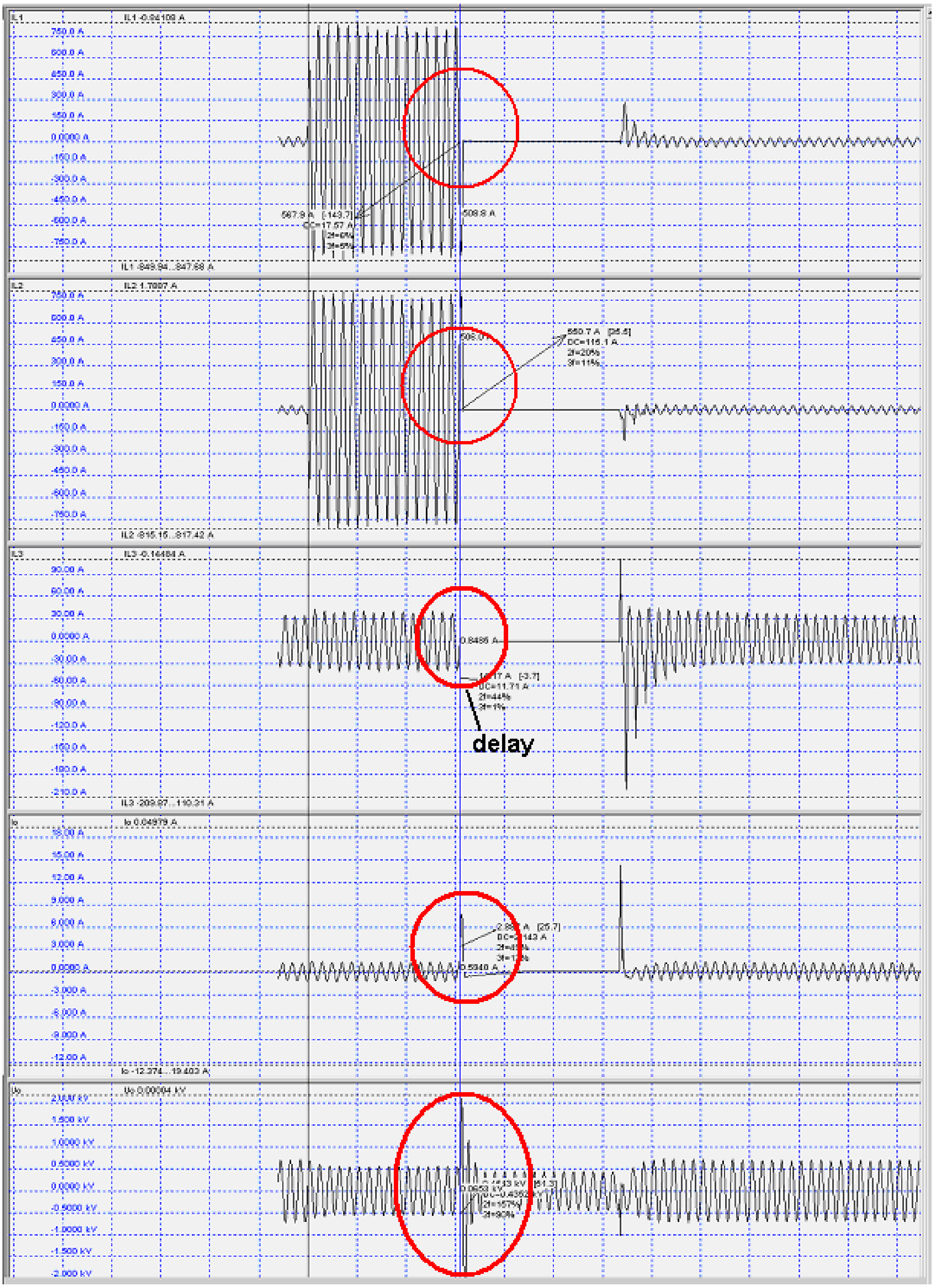
Periodic testing for 150 relays and 450 postponed								
Year	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Periodic testing	45 000 €	45 000 €	45 000 €	45 000 €	45 000 €	45 000 €	45 000 €	45 000 €
Total costs	135 600 €	81 600 €	81 600 €	81 600 €	81 600 €	81 600 €	81 600 €	81 600 €
Annual difference	44 400 €	98 400 €	98 400 €	98 400 €	98 400 €	98 400 €	98 400 €	98 400 €
Accumulated total	**44 400 €**	**142 800 €**	**241 200 €**	**339 600 €**	**438 000 €**	**536 400 €**	**634 800 €**	**733 200 €**

Periodic testing for 100 relays and 500 postponed								
Year	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Periodic testing	30 000 €	30 000 €	30 000 €	30 000 €	30 000 €	30 000 €	30 000 €	30 000 €
Total costs	120 600 €	66 600 €	66 600 €	66 600 €	66 600 €	66 600 €	66 600 €	66 600 €
Annual difference	59 400 €	113 400 €	113 400 €	113 400 €	113 400 €	113 400 €	113 400 €	113 400 €
Accumulated total	**59 400 €**	**172 800 €**	**286 200 €**	**399 600 €**	**513 000 €**	**626 400 €**	**739 800 €**	**853 200 €**

Periodic testing for 50 relays and 550 postponed								
Year	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Periodic testing	15 000 €	15 000 €	15 000 €	15 000 €	15 000 €	15 000 €	15 000 €	15 000 €
Total costs	105 600 €	51 600 €	51 600 €	51 600 €	51 600 €	51 600 €	51 600 €	51 600 €
Annual difference	74 400 €	128 400 €	128 400 €	128 400 €	128 400 €	128 400 €	128 400 €	128 400 €
Accumulated total	**74 400 €**	**202 800 €**	**331 200 €**	**459 600 €**	**588 000 €**	**716 400 €**	**844 800 €**	**973 200 €**

APPENDIX 2: SIMULTANEOUS OF CIRCUIT BREAKER OPERATION

<u>Two phase short circuit with time difference when interrupting phase currents</u>



One phase earth fault with time difference when interrupting phase currents