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DISTRIBUTION AUTOMATION OF MV/LV TRANSFORMER STATIONS AND LOW VOLTAGE GRIDS

Innovative Ideas for intelligent Distribution Grid

Licentiate thesis in Electrical Engineering

FOREWORD

For the trumpet will sound, and the dead will be raised imperishable, and we will be changed. For this perishable body must put on the imperishable, and this mortal body must put on immortality. Now when this perishable puts on the imperishable, and this mortal puts on immortality, then the saying that is written will happen, “*Death has been swallowed up in victory.*” “*Where, O death, is your victory? Where, O death, is your sting?*” The sting of death is sin, and the power of sin is the law. But **thanks be to God**, who gives us the victory **through our Lord Jesus Christ**! (Corinthians 15)

God of Abraham, Isaac and Jacob created the nervous system of human beings. The analogue to the network automation protection system is sometimes presented. The human nervous system includes the brain, spinal cord, the nervous system outside the spinal cord and the peripheral nervous system. A healthy human being does not feel pain. In the case of an injury in the outer parts the nervous system can also transfer information from the skin of fingers or of toes. If the capability of the human nervous system was compared with the distribution automation system, it could be said that DA can only detect the headache or heartache. In other words, the fault recognition in the substation can sense some faults in the medium voltage network. Thus, there is a lot improvement to be made in distribution automation on the way to fingers and toes. I sincerely hope you will enjoy reading this book.

Kuorevesi, Finland, Anno Domini MMXIII

Johan Nyberg

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Abbreviations

ABB	ASEA Brown Boveri & Cie joint corporation
AM/FM/	Automated Mapping/Facilities Management/
GIS	Geographic Information System
AMR	Automated meter reading
CAIDI	The Customer Average Interruption Duration Index
CT	Current transformer
DA	Distribution automation
DB	Database
DER	Distributed energy recourses
DMS	Distribution management system
DNO	Distribution Network Operator
ETH	Ethernet
GW	Gateway
HMI	Human-machine interface
HV	High voltage
ICT	Information and communication technology
IEC	The International Electrotechnical Commission
LV	Low voltage
LVA	Low voltage automation
M2M	Machine to machine
MV	Medium voltage
NC	Normally closed, contact marking
NIS/DMS	Network information system/Distribution management system application
NO	Normally open, contact marking
PDA	A personal digital assistant
PLC	Power line carrier, power network is used as communication media
PLC	Programmable logic controller
POC	Customer point of connection, also point of common coupling

PQ	Power quality
RCD	Recidual current detection
RTU	Remote terminal unit
SAIDI	The System Average Interruption Duration Index
SCADA	Supervisory control and data acquisition application
VPN	Virtual private network

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TIIVISTELMÄ

Tässä työssä tarkastelen sähkönverkon jakelumuuntamoiden ja pienjänniteverkon automaatiota. Työ liittyy verkostoautomaation ja verkoston hallinnan kehittämiseen. Käsittelen myös tutkimus- ja kehityshankkeiden määrittelyä koskevassa kartoituksessa havaittuja tulevaisuuden verkoille asetettuja tavoitteita. Suomen sähkönjakeluverkossa automaatiota on käytetty lähinnä sähköasemilla, keskijännitejohtolähtöjen kaukoerotinasemilla ja 2000-luvulla jälleen keskijännitejohtolähdöillä välikatkaisijoissa. Työn tavoite on sähkönjakeluverkon hallintaan käytettävän automaation laajentaminen muuntamoille ja pienjänniteverkkoon.

Työssä rakennan kuvaa tulevaisuuden sähköverkon toiminnoista esittämällä katsauksen viimeisimmistä kansainvälisistä tutkimustuloksista ja suomalaisissa jakeluverkkoyhtiöissä käydyistä keskusteluista erityisesti jakelumuuntamoiden ja pienjänniteverkon hallintaan käytettävän automaation osalta. Työssä käsittelen jakeluverkon hallinnan nykytilaa ja tulevaisuutta, erityisesti jakelumuuntamoiden ja pienjänniteverkon vikojenhallinnan osalta. Tuon esiin vaihtoehtoisia ratkaisuja ja parannuksia erilaisiin järjestelmätoimintoihin sekä esitän parannusten tuloksia visuaalisesti ja valvomokäytön kannalta esitettynä. Esitettyjen järjestelmätoimintojen, kuten kaukokäyttö, viantunnistus ja suojaus sekä kehittyneiden kommunikointitekniikoiden, avulla on mahdollistaa parantaa sähkönjakelun laatua, luotettavuutta ja turvallisuutta. Apujärjestelmät ja rakennusautomaatiojärjestelmät mahdollistavat jakelujärjestelmän ympäristön paremman seurannan ja toimenpiteiden kohdistamisen ja ajoittamisen. Uutena toimintona esitän käytöntukijärjestelmän valvontakerrosta, jota voidaan käyttää esimerkiksi luukkujen, muuntamon ovien valvontaan näin parantaen henkilöturvallisuutta ja verkkoon tehtyjen muutoksien jäljitettävyyttä.

IP-arkkitehtuuri on yleistymässä sähköverkkojen tiedonsiirrossa. Työssä olen kuvannut jakeluautomaation tietoliikennetekniikan ja tietotekniikan nykytilaa ja standardeja. Tarkastelen IP-pohjaisten protokollien, kuten IEC 61850 ja tiedonsiirtotekniikoiden kehityksen suuntaviivoja muuntamokäytön ja hallinnan kannalta. Standardeja noudattava, luotettava, joustava ja suorituskykyinen tietoliikennejärjestelmä mahdollistaa työssä esitetyt uudet järjestelmätoiminnot, hajautettua sähkötuotantoa tukevan informaatiojärjestelmän ja järjestelmien toimittajariippumattoman käytön.

Tutkimus onnistui hyvin tavoitteissaan tuoda esiin jakelumuuntamoiden ja pienjänniteverkon hallintaan käytettävän automaation mahdollisuuksia. Tutkimus tarjoaakin teollisuudelle ja sähköverkkoyhtiöille innovatiivisia ideoita järjestelmien kehittämiseen.

AVAINSANAT: jakeluautomaatio, keskijännite / pienjännite muuntamo, pienjänniteverkko, sähkönjakeluverkkojen tietoliikenne

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ABSTRACT

The distribution automation of distribution transformer stations and of low voltage grids are discussed in this licentiate thesis. The thesis aims at developing distribution automation and management. It also discusses the objectives set for future networks, found in a survey defining research and development projects. In Finland, distribution grid automation has been used mainly in substations, in medium voltage disconnector stations and in the 21st century again in intermediate switches. The objective of this thesis is to extend the automation used in distribution management to MV/LV transformer stations and to low-voltage grids.

I have presented a vision of the functions needed in the management of future MV/LV transformer stations and LV grids. The vision is based on the latest international research on distribution automation, and on discussions with the representatives of Finnish distribution network companies, focusing especially on automation used for the management of MV/LV transformer stations and LV grids. The present state and future of the management of the distribution grid is discussed, with the focus on the fault management of MV/LV transformer stations and LV grids. I will bring up alternative solutions and improvements on a variety of distribution automation functions and present the results visually from the perspective of the operation in the control centre. The distribution automation functions presented, such as remote control, fault detection and protection, and advanced communication techniques, make it possible to improve the power quality, reliability and safety of distribution of electricity. Auxiliary systems and building automation systems enable a better monitoring of the environment of the distribution system and the targeting and scheduling of management procedures. I suggest that a building automation monitoring layer be added to the NIS/DMS system as a new function. The layer can be used for the monitoring of hatches and doors of the transformer station, for example. This improves the safety of the personnel and civilians and the traceability of changes in the network.

The IP architecture is gaining ground in the communication of electrical networks. I have described the present state and standards of the information and communication technology of distribution automation. I have studied the development trends of both IP-based protocols, such as IEC 61850, and communication techniques from the perspective of the operation and management of transformer stations. A communication system that complies with the standards and is reliable, flexible and efficient enables the system functions, the information system that supports distributed generation, and the vendor-independent use of systems.

The study fulfilled its objectives of presenting new possibilities of distribution automation in the management of distribution transformer stations and low-voltage grids. The study offers innovative ideas for the development of the systems to industry and distribution network companies.

KEYWORDS: communication of electric networks, distribution automation, low-voltage grid, medium voltage / low voltage transformer station

1 INTRODUCTION

This thesis discusses the distribution automation (DA) including information and communication systems that utilize information concerning medium voltage / low voltage (MV/LV) transformer stations and LV grids. The term DA includes remote coordinate, real time and remote control requirements. Therefore, only local systems are excluded but information and communication systems are included. This thesis aims to introduce, analyse, enrich and process new ideas. The results are new distribution network operator (DNO) DA functions, which are crystallized visually in the form of schematic diagrams of management system programs, i.e. supervisory control and data acquisition application (SCADA) and network information system / distribution management system application (NIS/DMS). The study also contains a fresh Finnish DNO review, providing empirical facts and introducing changes taking place in the MV/LV transformer stations and LV grids management of the DA of Finnish DNOs. Although the Finnish system is focused on, the results from international studies, the ideas, functions and results presented are applicable to a large extent in the majority of European distribution grids, for example.

The topic of this thesis, an intelligent and flexible distribution automation system of the future and the part of this distribution system that is closer to MV and LV customers, can be understood by examining a simplified distribution system diagram presented in Figure 1. This distribution system consists of the electric energy distribution network and the distribution automation system, which includes also communication network. Control centre with its distribution management systems is presented on top of the figure. The control centre is the command post for remote distribution automation and field operations and the information processing centre. Therefore, the automation systems are connected to information systems of the control center via the communication network. In this thesis the role of IP-network is emphasized. The MV/LV transformer stations are supplied from HV/MV substation. The relays in the primary substation are important information sources about the status of the MV feeder at present. In future, distributed generation and energy storages supply part of the total energy via transformer stations or via LV grid or locally via the networks of customers. The distributed compensation of reactive power and filtering of harmonic frequencies can take place with the energy storages or separately. The topology of the MV network is usually meshed, but it is used as radial in Finland. Spare connections from neighboring transformer stations can be built also to the LV network. Fault recognition, fault isolation, feeder reconfiguration, reserve power supply and supply restoration involve remote and manual operations taking place in MV/LV transformer stations and in LV grids. The automation presented can enhance this. Also, by monitoring information about the status of the shown active network can be received.

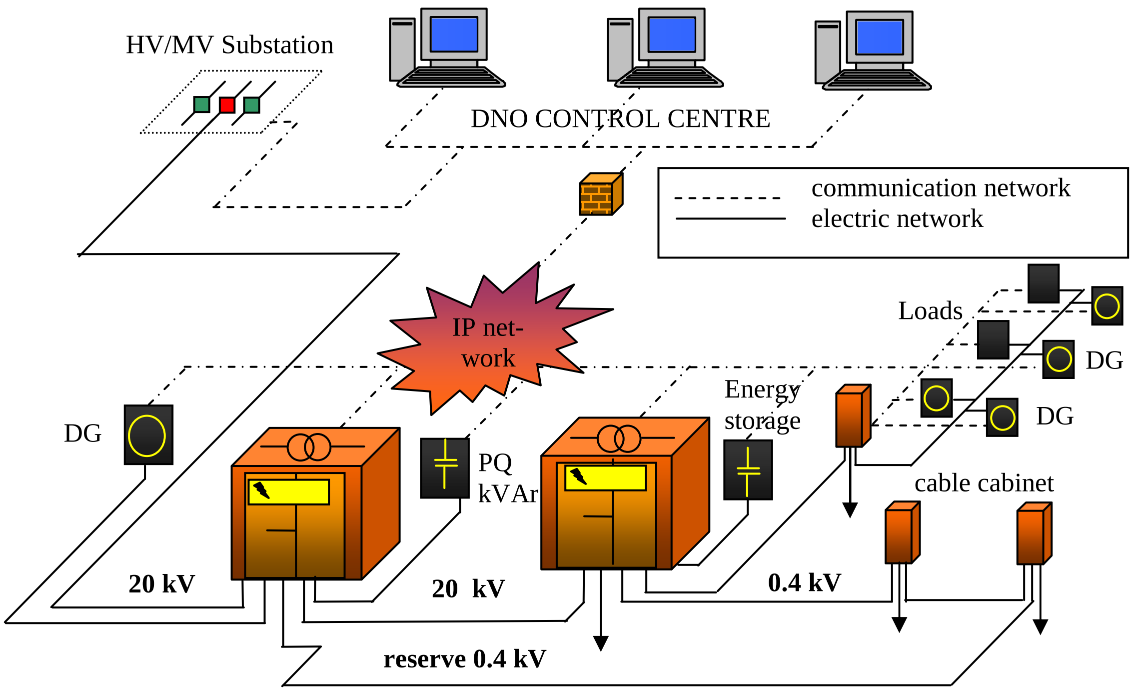


Figure 1. An intelligent and flexible distribution automation system that utilize information from MV/LV transformer stations and LV grid.

1.1 MV/LV transformer stations and low voltage grids

From the perspective of LV consumers transformer stations and LV grids are the nearest part of distribution network. The distribution network is in turn a part of the electric power system, which consists of power plants, the main grid, regional networks, distribution networks and connections of consumers of electricity. The main grid in Finland is part of the Scandinavian synchronous area, which includes Finland, Sweden, Norway and eastern Denmark. The distribution grid is connected either directly to the main grid or to a regional network and the connection takes place at the primary substation, i.e. high voltage / medium voltage (HV/MV) substation. (Fingrid Oy 2011)

The MV feeders are protected by protection relays in the primary substation. These modern computer-based protection relays have an important role in the distribution automation scheme as they enable many automation functions, which also give a basis for the classification presented later. The MV feeder relays are used primarily in protection, fault management, remote control and monitor functions. Tens of MVAs of electric power can flow through a single MV feeder to MV/LV transformer stations, which supply thousands of urban customers with electricity. Thus, the importance of MV/LV transformer station and low voltage automation and the research of this topic may raise some doubts. A single MV/LV transformer failure causes interruption usually only to tens or some hundred of customers, but a fault in a MV feeder can cause the feeder relay to trip and switch off the supply of the entire MV feeder. Therefore, MV/LV transformer station automation, low voltage grid automation and transformer station building automation applications, are now seen as additive. Although distribution automation at present is focused to MV grid management, in the future enhanced management is needed. This enhanced management should make it possible to better protect, monitor and control the MV/LV transformer station, low voltage grid and enable the safe connection, interaction and energy supply of distributed energy resources, which are connected to different voltage levels of the distribution grid.

In rural areas MV overhead lines and pole-mounted transformers, with ratings from 16 to 300 kVA, are still typically used in Finland. Low voltage feeders are connected to the pole-mounted MV/LV transformer station and these feeders are protected by fuses. LV feeders are used to supply electricity to customers within an approximately 500-meter radius from the transformer. A change in the structure of the rural network is taking place in Finland. Due to storms some DNOs now consider cabled MV lines worthwhile, despite the higher investment cost (Seppälä 2009). New miniature on-ground MV/LV transformers are used to transform the voltage level from the cabled MV feeders to the cabled LV grid. Still, the overhead distribution network, built between 1965 and 1985, form the typical rural grid in Finland (Nurmi 2011). The need to replace the aging network, storms and regulation incentives may motive DNOs to build cabled rural distribution networks. Still, because of the high investment costs, low density of customers, high capacity of overhead network, and in some areas too harsh ground conditions for cabling, the overhead MV network are considered optimal in some areas by some DNOs at present. However, because LV network cabling is cost-efficient and MV network structures vary, a mixture of pole-mounted and on-ground transformers and a mixture of cabled and overhead networks exist in Finnish rural areas in future. (Lakervi & Holmes 2003: 1–18)

In urban areas underground medium voltage cable feeders, usually with the voltage level of 10 kV or 20 kV, are connected to MV/LV transformer stations, rated usually from 200 to 1500 kVA. In city areas a MV/LV transformer station usually contains a ring main unit, which enables medium voltage switching operations. Therefore, it can also be called as a secondary substation. These urban transformer stations can be placed inside multi-storey buildings or they can be located in separate buildings near the supplied real-estates. In this thesis the transformer stations inside buildings are called building transformers and those on-ground transformer stations in separate buildings park transformers. The latter type I will classify into three different types: walk-in type, those without an entry and miniature rural on-ground park transformers. The cabled LV feeders of the MV/LV transformer station are connected directly to buildings or cable cabinets. From there they branch to other cable cabinets or to connections to the buildings. In cable cabinets and in MV/LV transformer station LV cabinets the cables are protected by fuse-switches. The transformer sizes are chosen based on consumption estimate and they will usually be overrated to withstand consumption peaks, harmonic load currents, due to the uncertainty of the consumption growth estimate and in some cases in order to supply the neighboring LV grid segments, e.g. in fault or replacement situations. (Lakervi & Holmes 2003: 1–18)

1.2 Distribution automation and communication of MV/LV transformer stations and LV grids in literature

The term Distribution automation (DA) was originally introduced as early as the 1970s, but was defined by the IEEE in (Basset, Clinard, Grainger, Purucker & Ward 1988) in 1998 as follows:

> "*A set of technologies that enable an electric utility to remote monitor, coordinate and operate distribution components in a real-time mode from remote locations*".

Northcote-Green and Wilson have analysed the IEEE DA term in (Northcote-Green & Wilson 2006). The distribution management system (DMS) is presented. In this thesis also the term NIS/DMS is used when a single a enhanced automated mapping / facilities management / geographic information system (AM/FM/GIS) application is discussed. This single application is not the same as the DA DMS system definition. DMS in (Northcote-Green et al 2006) refers to multiple systems and corresponds to the DA system definition. In addition to DMS, the term Distribution Automation system (DA system) term is also used. A further analysis of the DA definition contains the following:

- the term coordinate refers to automation,
- the term real-time refers to a 2-second response time, and
- the terms remote monitor, coordinate and operate refer to DA devices that are remotely controlled (Northcote-Green et al 2006).

The umbrella term DA does not define LV-automation. Feeder automation and home automation are both included in DA. Therefore, the term DA must be extended in order to include distribution automation used in MV/LV transformer stations and in LV grids. This can be done assuming that the DA definition applies from its previously introduced respects e.g. real-time and remote control and monitoring respects. The focus of this study remains the same in this classification: it is on local or remote functions that utilize information from MV/LV transformer stations and LV grids. MV/LV transformer stations and LV grids systems are vital parts of the distribution network and thus for a good reason to be included in DA. Also, communication, which enables information flow between the different locations of the DA distribution management system, is to be included in to the new extended definition.

Over the years the definition of DA has changed with changes in the information, automation and communication technology used by distribution facilities. Also, a new term *Advanced Distribution Automation* (ADA) has been introduced by the Intelligrid project and used in publications by EPRI, for example in (EPRI 2004). The introduction of the term ADA originally aimed to frame the research subjects of the project. However, it has also been widely adopted. The ADA used by the Intelligrid project deals with improvements e.g. in data preparation in near-real-time, optimal decision-making, and the control of distribution operations in coordination with transmission and generation system operations. The Intelligrid project has introduced many intelligent functions for future intelligent grids, which are needed to better manage e.g. demand response, distributed generation, demand side management and self-healing grid. Because these functions are targeted to manage customer systems, which in turn are connected to MV/LV transformer stations and LV grids, I assume that the functions introduced by the Intelligrid project will eventually increasingly utilize the information from MV/LV transformer stations and LV grids and increase MV/LVA automation. (EPRI 2004)

The functions performed by DMS can be classified as centralized or decentralized. Furthermore, in document (Northcote-Green et al 2006) the class remote operational is separately presented. Functionality is a set of functions that can be installed in the DMS (Areva-TD 2008: 422–441). In distribution automation the main automation functions can be classified as monitoring, control and protection functions. The main functions of monitoring are recording meter readings, system status and abnormal conditions events. The switching operation is central in control function. It can be found also in secondary substation e.g. in MV switchgear remote operation. (Basset et al 1988)

When the previously mentioned function classifications are applied to distribution management processes involving transformer stations, it can be stated that DA functionality could be implemented in the following ways:

- locally, e.g. a protection function in the protection relay,

- remotely, e.g. an operator-originated switch breaking command using the SCADA system, and
- in a centralized manner, e.g. SCADA system-originated switch breaking command (Northcote-Green et al 2006).

The distribution grid communication platform could be seen as a puzzle, which includes an MV/LV transformer station, long distance link, primary substation and control centre pieces. In addition to the previous pieces, the AMR PLC communication and other new LV grid communication, e.g. AMR GPRS communication, may be regarded as separate pieces. The AMR PLC communication can be included also in the MV/LV transformer station piece, which is the case with the AMR PLC concentrator. In general, communication can be categorized as the communication of two directly connected devices, of long distance networks or of local area networks (Stallings 2004). Communication can also be implemented wirelessly or using optical or copper wire. A mixture of these is used by DNOs in different applications and in different parts of distribution network automation. Also, communication protocols vary in different types of communication. Some protocols used are specific to electric networks communication, others are commonly used in ICT systems, but still in both cases the functional principle of a protocol is to determine architectural principles and mechanism to exchange data (Stallings 2004). Ethernet and IP protocols are increasingly used also in distribution network communication applications. Therefore, the architecture and working principles of these protocols define the communication in the distribution communication puzzle.

1.3 Distribution network companies, component manufacturers, customers and regulator

Electricity produced in power plants is distributed to the customers of DNOs through a property, which is also called the distribution grid. The term customer refers to an energy consumer connected to the distribution grid and paying DNO for energy transferring, called distribution tariffs. However, in the future the customers will not be only consumers of energy, but also either suppliers of energy, possessors of energy storages or manageable loads or both. They may control their generation based on control signals. In Finland the distribution companies are mainly owned by local energy companies, but they act as independent distributors for both the local owner energy seller, local energy producers and remote energy companies. DNOs provide services for these companies, such as energy measurement service. Distribution companies should act as a neutral party between consumers, energy sellers and producers and provide equal service for all concerned. (Helen 2010a)

Manufacturers make distribution automation components and distribution, consumption and generation components for their customers. These components are used by DNOs and their customers. A component can be of a single MV/LV transformer of transformer station or compact MV/LV transformer station, for example. Standards are used in order to ensure compatibility, operability, safety and quality. MV/LV transformer stations intended for European markets should conform the standards such as IEC 61330, IEC 60529 and in Finland also to the electrical safety regulations e.g. SFS-EN 6000, SFS-EN 6001 (2001) + A1 (2005). In addition, there are specific standards for power quality and for information and communication systems (ICT), which are introduced in Chapters three and four. Manufactures have to pay attention to customers´ requirements of less network construction, maintenance and operation efforts and costs and at the same time take into account new improved reliability and safety, and low environmental impact level demands. (Cormenier & Dides 2003; Tukes 2007))

The Finnish Energy Market Authority (EMV) supervises electricity transmission and distribution in Finland. Distribution network companies are responsible for the construction, maintenance and development of distribution networks in the area where a DNO possesses a license granted by EMV. In addition to that, DNOs have an obligation to connect consumers and supplier to the distribution grid and transmit energy to and between them. The Finnish Energy Market Authority is planning new guidelines for regulation for the years 2012–2015. Incentives are designed in order to speed up necessary replacements due to the ageing networks. The majority of networks in Finland were built between the years 1965 and 1985. The network replacement cycle of 40 years means that the components will have to be updated in near future. The age of LV components is monitored and reported to the authority. Therefore, also the age tracking methods and functions are relevant in ICT and automation methods. In Denmark a similar cycle was detected and automation used to manage and to slow down the replacement rate (Northcote-Green & Speiermann 2008; Vinter & Vinkelgaard 2005). New incentives are introduced by EMV. These are the innovation and quality incentives. (Matikainen 2010)

The quality incentive aims to increase distribution reliability and quality. The innovation incentive is intended to encourage DNOs to research and develop intelligent networks and grid technology and to implement and commission new technology. The replacement of AMR meters is included in the innovation incentive, thus encouraging the use of AMR-based NIS/DMS fault location and power quality (PQ) monitoring functions. Uninterrupted delivery and intelligent technology and market support the LV DA development, although the focus remains on the MV network, because an interrupt in the MV network has an effect on a considerable number of clients. However, most intelligent network technology, such as electrical vehicles (EVs) and electrical hybrid vehicles (EHVs), distributed small scale generation, microgrids and energy storages take place in the LV network and the protection, monitoring, control, isolation, backup power feeding of MV/LV transformer stations and LV grids should be supported in intelligent grids. These changes may be encouraged in the regulation period of 2016–2020. (Matikainen 2011; Nurmi 2011)

1.4 A short review of Finnish DNOs

A small scale distribution management review was conducted in discussions with private Finnish DNOs funding a VAHA study conducted in 2009–2011. The name of study, VAHA is a finnish abbreviation for Distribution management and ICT. As a result, a snapshot of the present distribution automation state of the DNOs involved was taken, the initial conditions for the study were revealed and empirical facts from the subject area were received (Laaksonen et al 2009; Heino et al 2009; Haapamäki et al 2009; Hyvärinen et al 2009a; Niskanen et al 2009; Seesvaara et al 2009). This review, the literature in the field (see e.g. Northcote-Green et al 2006) and currently available MV/LV transformer station brochures show that the automation of transformer stations and low voltage grids does not exist now, at least not on the same scale as it exists in primary substations. However, this review also revealed many indications about current development, e.g. Tekla XPower AMR-DMS technology or Helen secondary substation pilot (Haapamäki et al 2009; Hyvärinen et al 2009a). A need to map available technologies as a basis for discussion was clearly noticed. The results of the review are presented in Chapters two and three. Some empirical facts from Helsinki, Turku, Vaasa and Lahti are presented next.

In the urban Helsinki-based DNO Helen Electricity Network different navigation signs can be seen on the distribution automation development path. One of these is the MV cable condition management objective. There are significant cable investments expected in the future. Different types of MV online and offline technologies for cable condition measurement have been developed, which could be used to manage these investments better. Another objective is to increase the remote control and monitoring of the MV network. These systems have become more cost-effective. The essential advantage of applying control and monitoring to MV/LV stations is to decrease interrupt duration. With a small extra investment and some extensions to remote monitor and control automation, the MV/LV components and buildings can be monitored and managed. The operation of the distribution grid is based on manual connections. During a fault situation the field personnel is dispatched, but reaching the target may be and may become more difficult in Helsinki. Heavy traffic during rush hours, traffic accidents, sometimes bad weather conditions or the location of transformer stations form a challenge. The transformer station may be located in the middle of a multi-storey building or underground. New applications of automation are expected. Cable cabinets will be placed under the street or built in the walls of buildings. Another application expected is a cable T-joint without a cable cabinet. (Hyvärinen et al 2009a; Siirto, Hyvärinen & Hämäläinen 2009)

In the urban DNO Turku Energy Electricity Network LV network, automation will be increased significantly. More than 10% of all the transformer stations contain an intelligent measurement device. In automated meter management the function provided by Landis + Gyr Enermet EPS32 switching device is considered. The switching device is installed after the AMR in power supply direction. The relay output of the AMR meter, controlled remotely, is connected to the switching device control input. However, because the main manual disconnector is located before the AMR meter in the supply direction, communication to the meter is lost if a manual disconnector is used. Control and monitoring can be achieved by the use of an extra cabinet disconnector before the AMR meter and a main manual disconnector after the AMR meter. There is a risk involved if electricity is switched on remotely after it has been disconnected for some period of time. An electrical kitchen or sauna stove may be left on and some electrical machines may also be on in industrial premises. The grease in the ventilation system above the kitchen stove may fall on the heated plate and cause a fire. Therefore, after connecting the electricity after disconnection the consumption should be checked. If usage is detected, the power is disconnected and the customer contacted. (Laaksonen et al 2009)

In the urban and rural DNO Vaasa Electricity Network, the use of NIS/DMS system has increased in many processes. The operation, the fault service and maintenance use the advanced functions of the Tekla Xpower NIS/DMS system. The NIS/DMS system is used to access and store grid information from MV/LV transformers and LV grids. The connection information of the LV network is based on SCADA MV acquisition and manually entered secondary substation and LV cable cabinet information. The installation of AMR PLC concentrators in MV/LV substations led to an extensive LV grid data update and revealed that the AMR concentrator had no automatic registration function. The fault service records faults by filling in a fault event entry form. The information from this form is later used by the repair crew and by the customer service. The compensation to the client is determined on the basis of the time elapsed from the fault record entry to the repairs finishing entry time. Approximately 100 such cases per annum are entered in the report system. The personnel of the company use maintenance plans that are loaded onto the NIS. This tool helps to maintain MV/LV transformer stations, LV grids and cable cabinets by providing a graphical distribution grid map and an NIS/DMS user interface. The components are classified as checked and clear or in need of reparation on an urgency scale of 1 to 5. (Heino et al 2009)

The DNO LE Electrical Network (based in Lahti) is preparing for energy consumption changes, demand control, LV grid infrastructure changes, due to EVs and EHVs and the climate change. By the end of the year 2014 the AMR meters are scheduled to be installed for every LE customer. These meters could enable e.g. demand control, determined in the electric energy sales contract, and automatic connection after the contract has been signed. The state information of the distribution grid could be supplemented with transformer station and AMR measurements. In this way the loading profiles become more accurate and they could be used in NIS/DMS network state calculation and in design and planning functions e.g. when designing a new MV/LV station. Electric vehicles are expected to increase the demand by 10–20 %, depending on the proportion of EVs share of all vehicles. The EV charging time and charging ways are expected to vary, which brings some uncertainty to LV grid planning and to the preparation for the future distribution. A two-level model of fast, half an hour charging and slow, 4–8 -hour charging are considered at present. EVs need a charging infrastructure and this means that long term planning is needed e.g. MV feeders have to be used to supply large charging stations. Also, a small customer energy trade system is expected. The lightning radar information enables the monitoring of lightning activity. This information helps the repair crew. The wind speed alarm level is set at 13 m/s in Net alontrol SCADA. (Seesvaara et al 2009)

1.5 Research objectives

Cabled LV network and MV/LV transformer stations are seen as a considerable part of the distribution network and of the entire distribution network investment. Therefore, DNOs and the electric device and service industry are interested to find out if there could be found new applicable and cost-effective automation solutions especially to network management, component lifetime and to maintenance management purposes. In the Finnish urban grid of 2011, automation and automation functions took place mainly in the primary substations and the control centre. Remote control and monitoring, including fault detection is expanding to secondary substations. The next logical step towards a comprehensive network management is to extend automation further. In industrial applications the automation of electric networks has been used for years. The responsibility of DNOs stops at the energy meter. The customer system and home automation begin after the meter. In Finnish distribution network of today AMR meters are reaching the majority of customers.

The objective of this study is to examine the distribution network side, focusing on the systems and functions needed to manage future MV/LV transformer stations and in LV grids. Operation and maintenance management, for instance, utilize these systems and functions in DNOs. Functions enabled by AMR are not excluded entirely, but they are considered from the perspective of network management. One objective and research question which this study aims to answer is *how to extend the process monitoring path between substation and feeder automation to reach the customers system*.

Many DNO functional processes such as electric distribution, fault management, client relations, network management and connection management utilize information from MV/LV transformer stations, LV cable cabinets or LV grids. This information can be gathered e.g. during field operations or received during client interaction and stored in the database. Information can also be extracted from databases existing already or retrieved using automation. Nevertheless, up to date network data improves decisions based on this information and reduces needed resources. Information is used by client, personnel or subcontractor, in work management of grid construction, operation or maintenance. Future technologies could be used to make the grid more intelligent, i.e. more reliable and flexible, e.g. for distributed generation, demand management and advanced electricity trade. A second challenging objective therefore is: *which kind of new DA and ICT technologies could be used to manage MV/LV transformer stations and LV grids better?*

During a MV feeder fault or a major fault it can be seen that the transformer station or the LV grid seldom work as an island. The MV feeder fault can be detected based on the automatically acquired information from primary substation relays or from fault indicators and the fault can be isolated using switching operations in secondary substations. However, today transformer station or LV grid fault information is not automatically retrievable. In order to achieve more precise and faster information to form a good basis for decision making and to enable automatic functions the following research question needs an answer: *How the transformer and LV feeder fault detection could be improved?*

Operators use distribution management system functions to manage the entire grid, NIS/DMS and SCADA, for instance. In case of normal operation and fault situation the network status information is acquired partly automatically and partly over the phone. As to the MV/LV distribution transformer stations, the automatic information originates the MV grid. For example, the LV feeder energized or de-energized state information is usually read from HV/MV or MV/MV substation relays. This leads to yet another research question: *which kind of systems could be used to aid the MV/LV transformer and LV network fault situation operation*?

Power quality and fault detection are cousins. In DNO power quality is not usually a problem. It becomes a problem if customers complain. They complain if their devices do not work properly or break down, or if the malfunction is thought to be caused by low power quality. Also, faulty distribution network components e.g. MV/LV transformers and LV cables may cause distortion. Sometimes tracking faulty equipment may be time-consuming. LV cables are considered a significant asset. High current on a low voltage level, through a bad joint, for example, may cause sparking and even component burning. Also, because the power electronic consumer loads have increased and are estimated to increase even more, harmonic currents and reactive power are expected to rise. Although, in cities the grids are strong, the accumulated harmonic content may rise. Therefore, the research questions are the following: *how could the power quality of MV/LV transformer stations and LV grids be monitored and managed better and how their distribution component fault detection and analysis could be implemented*?

Novel information and communication technology makes it possible to satisfy different user needs. An efficient ICT infrastructure and accurate, real-time information are key components when responding fast to different fault situations. This can reduce risks caused by service failures or component failures. Thus, the following research question: *Which kind of ICT systems and protocols are presently used to enable automation sys-*

tems and services that use information from MV/LV transformer stations or LV grids, and which kind of future systems could improve automation and services?

The IEC 61850 protocol is widely used in primary substation communication. The implementation of this standard utilizes Ethernet and IP protocols. The standard enables new, reliable, efficient and spontaneous communication and a bunch of new services. Secondary substation relays and other automation equipment are rare at present. However, for primary substation usage an extensive variety of IEC 61850 compliant devices are available and being developed. Also, in process automation Ethernet communication and communication cabling enable IP networks and wireless IP-based communication techniques, which are increasing and developing. Thus, the following research question arises: *could this protocol be used in secondary substation applications*?

Auxiliary systems are needed in order to ensure the fault situation operation of the automation system. Building automation is needed e.g. to ensure safe, secure and a proper distribution environment and working conditions. The questions: *Which kind of auxiliary and building automation systems could be possible in MV/LV transformer station applications and could auxiliary systems and ICT provide extra value for the MV/LV transformer station and low voltage grid management?*

1.6 Thesis outline

In Chapter two advanced and piloted systems that show how the management is expanded to distribution transformer station and LV grid are introduced. Also the results from the latest international studies are presented. They provide an overview about potential applications in the field of MV/LV transformer station and LV grids distribution automation. Also, MV/LV distribution automation functions are presented. These DA functions enable e.g. process monitoring between MV feeder automation and home automation, LV fault detection, transformer and LV network monitoring and transformer and LV network fault situation operation. Visual schematic diagrams are used to illustrate new ideas.

In Chapter three power quality (PQ) and fault detection are discussed. An overview of power quality measurement systems is given. PQ information from different locations is needed for many reasons. The share of power electronic loads in grids is increasing, which will increase harmonic currents and reactive power, if not filtered properly. Therefore, harmonics and filtering solutions are discussed. The propagation of harmonic voltages on a low voltage level is presented to form a basis for the discussion about optimal usage and location of PQ devices, i.e. PQ measurements and filters and fault detection devices. The relation of power quality to fault detection and fault location is discussed. Potential PQ management solutions including LV automation solutions, e.g. passive and active filters systems are presented. The distribution automation management system also comprises the monitoring, analysis, and control of filters. New ideas from the latest international studies are presented. These ideas could be used e.g. in PQ analysis functions of distribution management applications. The advantages of PQ monitoring and control functions are illustrated using SCADA schematic diagrams and architectural diagrams.

Chapter four discusses information and communication technologies that can be used in the management of MV/LV transformer stations and LV grids. DA communication enables remote procedures. Nowadays serial communication is commonly used in the communication of two directly connected devices. The protocols presented are specific to electric distribution applications. The advantages of using standards are addressed. The lifespan of primary distribution components is relatively long, some 40 years. However, the fast development of ICT systems shortens their lifespan. Therefore, also new ICT platforms, systems, protocols and interfaces are introduced. The IEC 61850 protocol is widely utilized in primary substation DA. The implementation of this standard utilizes IP/Ethernet network. The IP/Ethernet network has many advantages in fast communication in primary substation LAN. It is worthwhile to try to find out if IP/Ethernet and IEC 61850 could be used for the intra- or intercommunication of MV/LV transformer stations. Also, many potential applications are presented.

In the Chapter five auxiliary and building automation systems are discussed. Some auxiliary systems are needed to support automation after fault in the non-energized state, and others can be used to increase reliability and power quality, which is the case e.g. in LV over voltage protection. Building automation can be regarded as an auxiliary system, because it is used to monitor and control the MV/LV transformer station building environment in order to ensure safe and reliable distribution system operation. Possibilities to monitor multiple-building environment are explored including moisture and humidity monitoring, splash and flood water detection, SF_6 gas leak detection, temperature monitoring in an MV/LV station, air ventilation monitoring, hatch open detection, motion detection and entrance detection using a door switch. Weather conditions are changing also in Finland due to the climate change. The distribution operation, as long as possible, will give extra time for safe evacuation under extreme weather conditions and in certain risky areas e.g. on river banks. This chapter introduces some potential techniques helpful in precautionary measures. The idea of building automation monitoring layer in distribution management system is presented.

Chapter six evaluates the answers to the research questions and conclusions are drawn from the results.

2 MV/LV MANAGEMENT FUNCTIONS

Chapter two deals with functions that are used primarily in network management, fault management and safety management processes. Most of them utilize information from MV/LV transformer stations and LV grids. The literature review provides the reader with an exceptional view on future DA systems by presenting advanced and piloted systems and results from the latest international research. An overview of applications used by Finnish DNOs which operate in Vaasa, Turku and Helsinki city area extends this view by opening a door to the present DA and ICT systems. Novel MV/LV distribution automation functions are presented, which can be used to extend the process monitoring path between MV feeder automation and home automation. These functions can improve MV/LV fault detection and indication, transformer and LV network monitoring and transformer and LV network normal operation and fault situation management. An extensive set of visual schematic diagrams and a technology portfolio aim to crystallize and concretize the ideas.

The very special functions, where automation is needed, are protection, control and isolation. In MV/LV transformer stations and in LV grids the protection of distribution components, persons, animals and equipment is supplied by a system in case of a fault such as short circuit or earth fault. The latter can be a consequence of a insulation failure. The control of the distribution grid is also needed for the modification of the load-carrying network e.g. when optimizing the LV network or switching on and off distributed energy resources (DER). Isolation is needed for switching off a part of the network for fault management or maintenance work when a transformer is changed, for example. Sometimes it is required to switch off the network for other reasons than maintenance e.g. under grid construction or in order to control demand when a power shortage occurs. (Schneider 2010)

2.1 Advanced and piloted MV/LV transformer station DA systems in Europe

In document (Dota & Giansante 2009) Enel low voltage protection system using local and remote functions is presented. In the Enel MV/LV transformer station the MV/LV transformer supplies an LV switchboard with four LV lines, each protected by an LV circuit breaker. There is a trip position in the circuit breaker, which indicates that a fault has occurred. The trip can be a result of the local protection operation. In the system of Enel special attention has been paid to personnel and public safety issues in the remote management processes. The circuit breaker is equipped with a three-position manual selector: “remote controlled”, “manual” and “locked”. In the Enel network operating centre the staff can remotely control the circuit breaker by selecting its graphic symbol. It is not possible to execute remote operations with the selector in the “manual” and “locked” positions. (Dota & Giansante 2009)

In Denmark PowerSense A/S has developed the remote supervision and remote control system of MV/LV transformer stations, installed in distribution grid of Dong Ltd. Dong has classified configuration as three different types: A, B and C. They are meant to be used in different locations of the MV feeder. Type A configuration, which includes the remote monitoring of both MV and LV and the remote control of an MV ring unit, is typically located on the first T-joint of the MV feeder. Type B configuration, which includes the remote monitoring of both MV and LV networks is located on the second T-joint. Type C includes the remote supervision of LV feeders only and is located on the tail of the MV feeder. Type A configuration presented in Figure 2 shows the modularity of the system and technology used well. The configuration consists of e.g. current, voltage and power measurements of both the MV ring unit and the transformer. Medium voltage cables are equipped with optical current measurements. The switchgear is equipped with a remote control system. The control system module with optical current measurement input connects MV and LV sensors and controls, the RMU master is used for communication and the implementation of the functions. The analog I/O unit is for LV voltage measurements. The communication is a separate module connected via the serial bus. As it can be seen, the condition of the fuses (red) and the loading condition and voltage level of the transformer can be monitored. Type A has the following functions:

- Measurement of the daily peak load of the transformer,
- Measurement of the pressure of oil filled MV cables,
- Transformer temperature measurement,
- SF_6 gas pressure measurements,
- Air temperature and humidity measurements,
- MV circuit breaker open-and-close control,
- MV breaker position monitoring,
- MV short circuit indication, directional,
- MV fault location indication, distance to fault in ohms,
- MV earth fault indication,
- MV and LV fuse open phase and fuse blown indication,
- High temperature alarm,
- System faulty alarm, and
- Station door open alarm

(Northcote-Green & Speiermann 2008; Vinter & Vinkelgaard 2005).

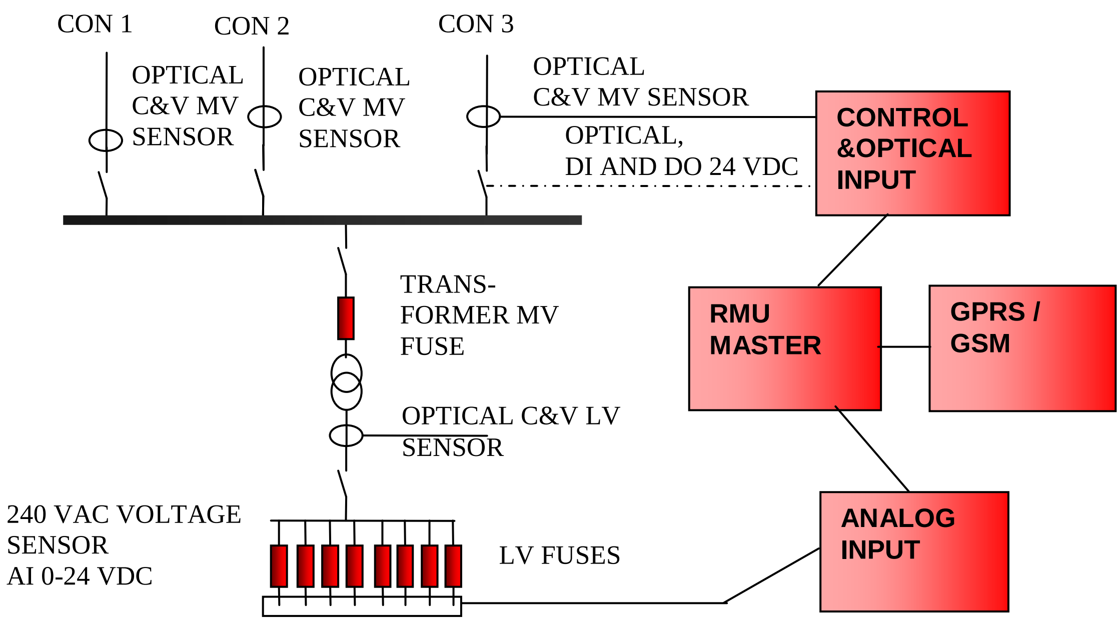


Figure 2. Dong (PowerSense) type A system configuration used in the supervision and control of MV/LV secondary substations.

In the Netherlands a consortium was formed and a future MV/LV transformer station system developed in a project called IntDs. The functions include the remote control and monitoring of MV/LV, energy storage, demand control, LV voltage control and power quality monitoring. The capacity of the energy storage system is only 30 kWh, but the test report shows a 30 % reduction in the peak load of the transformer. The MV switchgear is Eaton Xiria, which can also be used to enable automatic transfer function. The transformer used in the pilot system is SmartTrafo by Imtech Vonk, which can be used to enable voltage control, when there is a very high penetration of small-scale distributed generation in the LV grid. The power scheduling system of the transformer station, PowerMatcher, is connected to Eaton Xanura home automation system. The balance between both energy storage supply, small-scale production supply and demand is matched. According to the algorithm used the customers are supplied electricity from the energy storage of the MV/LV substation during peak demand and the energy storage is charged after the peak demand. (Kester, Heskes, Kaandorp, Cobben, Schoonenberg, Malyna, De Jong, Wargers & Dalmeijer 2009)

2.2 Fault management of MV/LV transformer stations and LV grids in Vaasa Electricity Networks

A typical fault management process in LV underground networks starts from a customer indication of the fault. The indication is received by a DNO operator in case there is no common fault in the grid, i.e. if the feeding MV grid is energized. If the MV grid is de-energized, e.g. during major disturbances, phone calls are received by an automatic responder. Assuming there is no such fault (MV energized), the fault location is revealed by the location of the callers. If there is just a single indication, the customer is asked to check the main fuses and switch of the facility. If these fuses are not blown, the field personnel can be dispatched. In many cases the fault is located visually (excavator in place) or by checking where the blown fuses are. In some cases there is a detected distribution transformer failure or cable joint or cable failure. (Heino et al 2009)

In Finland the protection of low voltage network feeders in cable cabinets and MV/LV transformers are implemented with fuses. In urban areas the low voltage network is implemented with underground cables. In rural areas there are still thousands of kilometres of pole-mounted networks, but the proportion of underground cables is rising steadily. In cities underground cables have already been used for a long time. Therefore, there is a variety of cables. Their properties, condition and expected lifespan vary. In these cables there may occur different types of faults, i.e. permanent short circuit or earth faults, but also different types of transient faults.

The control centre keeps a record of faults in MV/LV stations and the record can be located in the NIS/DMS system or e.g. on an Excel worksheet. Scheduled interruptions in the MV network are recorded in the system. The implementer id and timestamp are recorded too. The lack of EMV regulation, automation and a large quantity of LV components in the grid results in lesser surveillance of recorded LV events. The communication of the AMR PLC (power line carrier) requires topology information about LV network, which must be updated and precisely recorded manually in order for the meter to be registered into the concentrators. Once this is done, the need for manual work is reduced. The Vaasa LV network lacks automation. However, the automated recording of network topology changes would shorten the time used both for AMR installation and other operations. (Heino et al 2009)

2.3 MV/LV transformer station DA development of Helen and Turku Energy Network

The intelligent grid is not just AMR meters or intelligent primary substation automation functions, although they play an important role and have been the primary target of LV automation investment in the past few years, especially in Finland. Fault anticipation and the automatic isolation of the faulty network part is estimated to improve network management significantly. The low voltage network is a considerable part of the distribution grid needing a lot of components and investments. Steps towards the intelligent grid must be taken gradually, but with determination and careful planning in order to avoid extra investments. A Finnish DNO Helen Electricity Network has recorded about 200 LV network faults in a year. Helen supplies electricity for 340 000 LV customers in Helsinki. The operation of the distribution network requires field operations. On the average one of the circa 1 900 transformers malfunction and 90 transformers are replaced in the period of two years. (Hyvärinen et al 2009a)

The Finnish DNO Helen has introduced new functions that include e.g. the fault indication, location and isolation of the MV feeder based on measurements in MV/LV transformer stations (Hyvärinen et al 2009a; Kumpulainen et al 2010; Siirto et al 2009). Because fuses are mainly used for protection and there have not been any intelligent electronic devices (IEDs) in MV/LV transformer stations or LV grids, thus no automation functions have been available. In the urban area MV/LV transformer stations are mainly ones with MV ring units, called secondary substations. At present remote control and monitor systems are being increasingly added to secondary substations in Finland (Laaksonen et al 2009, Hyvärinen et al 2009a). These stations are carefully selected from among hundreds of substations using multiple criteria. The main functions used in fault management for these are the following:

- fault and outage location,
- fault isolation,
- feeder reconfiguration,
- fault repair,
- service restoration, and
- distribution system monitoring. (Laaksonen et al 2009, Hyvärinen et al 2009b)

In document (Hyvärinen et al 2009b) the DNO Helen pilot system and some of these functions are presented. In the Helen MV/LV transformer stations fault indication, location and separation functions of the monitoring system work in a semi-centralized manner. The input to these functions is received by a monitoring device from sensors placed on the MV and LV sides of the transformer. The measurement and control device used and the measurements are presented in Figure 3. As can be seen in Figure 3, voltage and current measurement are placed in transformer LV terminals. These measurements can also be read remotely, which enable the values from the measurements to be used as an input to both local and centralized functions. Fault path indicators, i.e. 3I> symbol in the figure, are connected to the digital input of the monitoring device and the earth fault current measurement, I_0, to the analogue current input. Voltage is measured from phases of LV bus and also from N bus. CTs are used to measure LV L1, L2 and L3 phase currents. Transformer temperature is also measured. PT100 resistive temperature sensor is used to measure and remotely monitor the transformer temperature. MV earth fault current is measured with an I_0 sensor. (Vamp Ltd 2008)

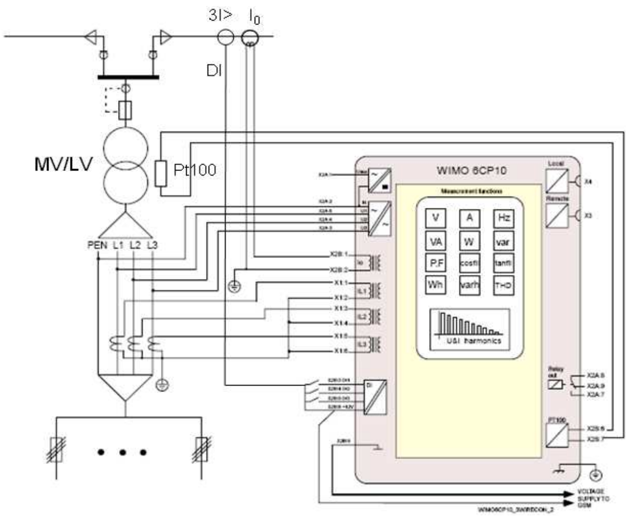
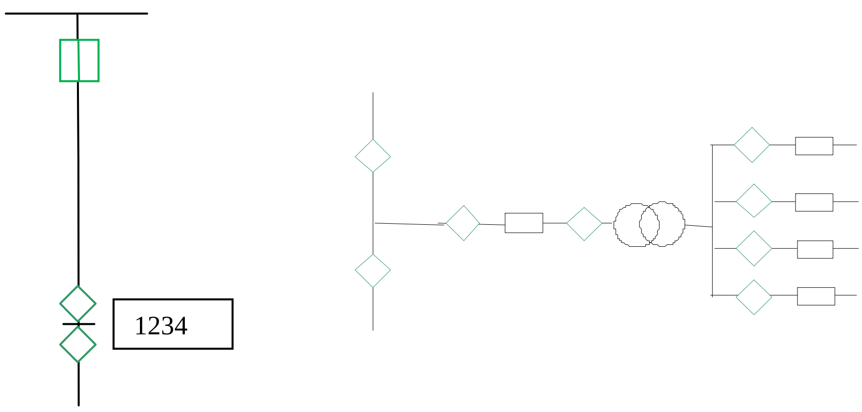


Figure 3. Connection diagram of the measurement and control device used in the DNO Helen secondary substation monitoring pilot system. (Vamp Ltd 2008)

The SCADA system, i.e. supervisory control and data acquisition application, can monitor faults that primary substation relays or relays used in feeder automation have detected. Based on SCADA information the NIS/DMS, i.e. distribution management system, which is an extended AM/FM/GIS system, can be used to calculate and display fault location on the distribution grid map. This fault detection and location function works on the MV network. In short circuit faults the location accuracy can be high enough to pin-point the fault near the MV/LV secondary substation. In an earth fault the detection and location accuracy is normally far less. The objective of distributed MV fault path indicators and earth fault current measurement is to increase accuracy. The MV fault detection function and MV remote control are two key functions to an extensive transformer automation system.

The development of the remote control and monitoring of MV/LV transformer stations can be visualized with SCADA schematic diagrams. These diagrams present well the functionality available for the operation process. A typical monitoring view of a MV feeder is presented in Figure 4a. Only the MV feeder manual disconnectors are presented by green unfilled diamond. The operator registers the on-off and grounded positions of the disconnector based on the action report by the field personnel. The station number 1234 is displayed. The control diagram of the entire MV/LV transformer station is presented in Figure 4b. The diagram is a visionary diagram and it is not very common in the present SCADA systems. It can be seen that the control diagram is extended to the low voltage side. The station, however, is the same as in Figure 4a. This substation includes no automation, but it could be used to register manual operations. The diagram contains both manual MV ring and transformer feeder disconnectors, but no MV feeder protection. The manual disconnectors are presented with green unfilled diamond symbol. The diagram also contains MV fuse protection for transformer and fuse-switch protection for LV feeders. The fuse-switches are presented with the disconnector and fuse symbols.



(a) (b)

Figure 4. A detail of a typical SCADA diagram of MV feeder with MV/LV transformer station and without remote control or monitoring (**a**). Extended visionary SCADA monitoring diagram of the MV/LV transformer station including MV disconnectors and LV fuse-switches. (**b**).

In Helsinki as well as in Turku the traffic is steadily getting heavier. Traffic jams occur during the rush hour or in accident situations or during bad weather. All this can slow down repair crews and have an effect on the break durations. In addition, reaching the location of the transformer inside a building can cause difficulties: contrary to DNO requirements, the personnel do not sometimes have the right keys to the locked premises or a separate entrance is not provided. There is also a growing need for faster fault management and for additional flexibility concerning distributed resources and demand control. Therefore, the level of automation in MV/LV substations is expected to rise.

The next step of automation, which partly exists in Helen already, is the increase of control and monitoring on the MV side and the monitoring on the LV side (Laaksonen et al 2009; Hyvärinen et al 2009a; Siirto et al 2009). A control and monitoring diagram of the remote operational MV feeder is presented in Figure 5a. Compared with the manual system presented in Figure 4a, the diagram in Figure 5a contains remotely controlled MV feeder disconnectors, which are shown with green coloured diamonds. In a fault situation the operator can issue commands, i.e. open or close the remote controlled disconnector. The control and monitoring of MV feeder disconnectors usually shortens the interrupt duration of many customers. However, it is not the main objective of this study to discuss the effects and benefits of a more extensive use MV feeder automation. This information can be obtained e.g. from (Northcote-Green et al 2006). The real-time operational status of the transformer can be determined from the LV measurements presented in Figure 5b. These measurements can be acquired by using a device presented in Figure 3, for example. The indications could include e.g. remote controlled disconnector failure, MV switchgear gas pressure alarm, transformer temperature alarm and battery voltage alarm. The visionary control diagram of the entire MV/LV transformer stations is presented in the Figure 5c. Using this extended diagram of the MV/LV operations and distribution state tracking could be possible. The information about the state of manual disconnectors of the transformer feeder still comes from the action reports by the personnel, though remote controlled disconnectors of MV feeder are used. The measurements show well the state of the transformer but they do not contain information about changes in the switching state.

An intermediate switch is used in the middle of a MV feeder e.g. in places where a semi-long cable feeder is extended with a long overhead line (Heino et al 2009). Sometimes, and increasingly in the future, this intermediate switch is located inside an MV/LV secondary substation because of the increased use of cabling. If a short circuit fault occurs on the feeder behind the switch, for instance, the part of the grid before the switch remains connected. If the impact on SAIDI and CAIDI values is clear and positive, it will be taken into consideration in the network planning and DA investment planning. This kind of MV/LV transformer station is usually equipped with communication equipment making the SCADA connection possible. Also, in this case the extended supervising presented in Figure 5 is possible at a small additional cost.

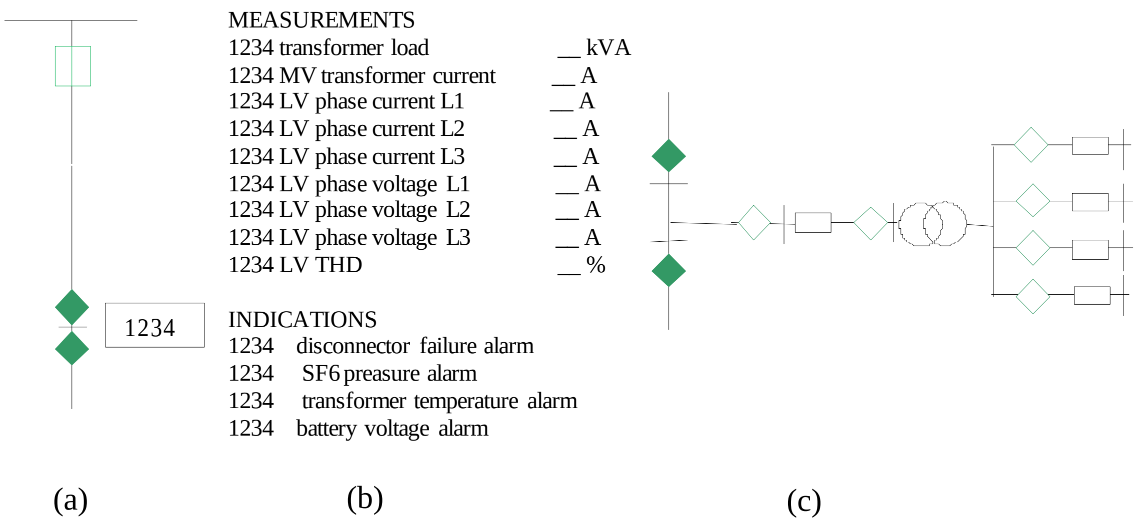


Figure 5. A detail of a typical SCADA diagram of remote controllable MV feeder (**a**). Measurement and indication information from MV/LV transformer station (**b**). Extended visionary supervisory diagram of the transformer station including the remote controlled MV ring unit disconnectors, manual transformer disconnectors and manual LV fuse-switches (**c**).

2.4 Fuse blown detection and indication

The protection function works in the case of an overload, short circuit or earth fault. The fuse is melted if the current is high enough and the circuit is open and de-energized. This often requires correcting the failed component and changing the fuse. In a cabled network the reported fuse blows are not frequent. Fuse-switches are commonly used in Finland and at present they are considered optimal for the protection and isolation of LV feeders in MV/LV substations and cable cabinets. The word switch actually refers to a manual disconnector, which is located before the fuse in normal power supply direction and is manually operated by the DNO personnel. The switch has usually no fault current breaking capability, but it has a limited fault current making capability in order to be able to perform a make to the faulted circuit.

The fuse blow in a faulty phase does not usually have an effect on the fuses of other, healthy, phases. Depending on the type of the fault this results in a situation where one or two phases may be missing. In absence of automation, the indication is received from the customer. The break time therefore depends on the response time of the customer, on that of the network operator to the complaint by the customer, on the mutual fault check time, and if the fault is found to be located in the distribution grid, on the fault management time of the network operator. The fuse blown detection function may reduce this fault management time by providing exact and real-time information about the location and the details of the failed component, i.e. the coordinates of the location, the phase and related information.

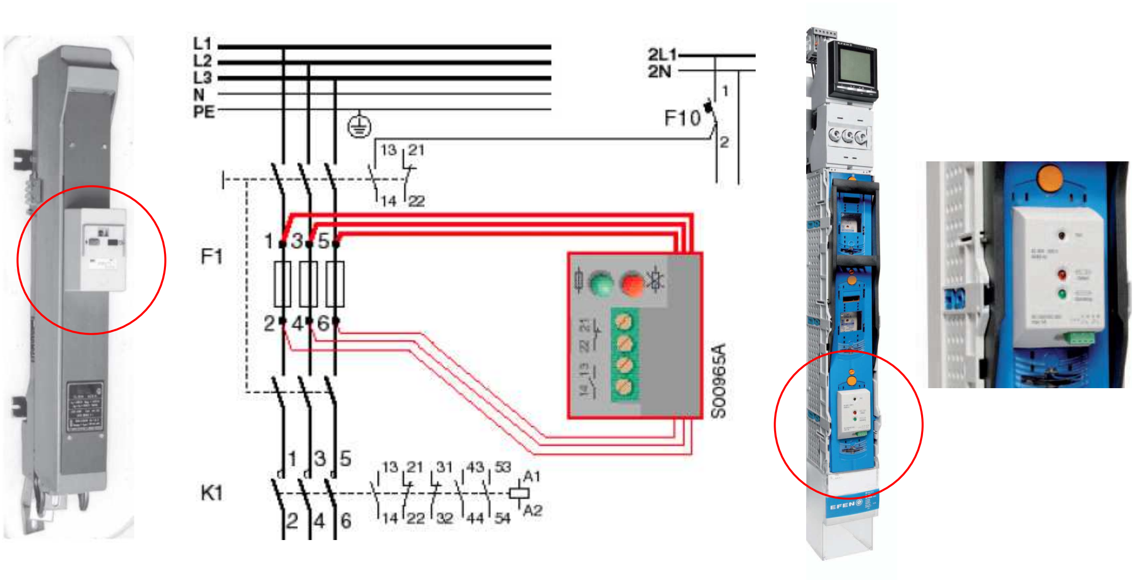
2.4.1 Fuse blown detection systems in radial networks

Radial LV feeder fuse blown detection can be implemented as follows:

- NIS/DMS (network management system / distribution management system) functions and alarms received from AMR meters,
- fuse blown detection units installed in the context of the fuse-switches,
- voltage measurements from LV feeders after the fuse-switch, and
- current measurement from CTs installed in the context of fuse-switch or the LV feeder.

Technologies that utilize AMR-based information on network status have become available. This information from AMR meters is linked with new functions of NIS/DMS, i.e. Network information system distribution management system and distribution management system. The primary function of AMR meters is to measure energy consumption and generation, but also power quality and LV network status information can be collected (Tekla 2011; Keränen 2009; Tryg, Mäkinen, Verho, Järventausta & Rinta-Opas 2008; Järventausta, Mäkinen, Kivikko, Verho, Kärenlampi, Chrons, Vehviläinen, Trygg & Rinta-Opas 2007). However, it must be noticed that the communication also enables these functions in a fault situation. In order the network status to be available from AMR meters, the communication network has to work properly. The fuse blown information is deduced by NIS/DMS system from AMR alarms or non-responding meters.

Fuse blow indicators have become common auxiliary equipment of fuse switches, which could indicate that fuse blown monitoring is a required function in an increasing number of applications. Also, mounting has been taken into consideration in the design of the product. This is presented in Figure 6, which shows a collection of three fuse blown indicators from two manufactures. The mounting of the detector unit on an ABB SLBM cover is presented in Figure 6a. The contact diagram of the ABB OFM indicator is presented Figure 6b, which indicates the operating principle of the detector unit. The detector is compatible with OS fuses and it is connected to the three phases and to both the sides of the fuse. There is one output for the indication of three phases, but both NC and NO modes are supported. The operating principle is not documented in (The ABB Group 1998), but to indicate fuse blown it is most likely the indicator detects that voltage is missing from the other side of the fuse. This principle is suitable for radial networks. The mounting of the detector on EFEN E3NH fuse-switch is presented in Figure 6c and a closer look at the indicator is given in Figure 6d. The LEDs indicate that the fuse has blown. The fuse blown information can be connected to remote terminal unit using signal output. The indicator reveals that one or more of the fuses of a three-phase system is blown, but not which of them. Hence, the fuse blown indication function is LV feeder selective, but not phase selective.



(a) (b) (c) (d)

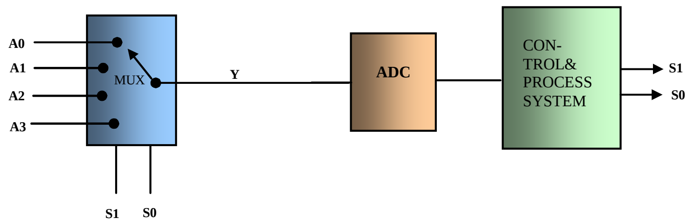
Figure 6. ABB SLBM fuse-switch with fuse blown indicator installed (**a**) (The ABB Group 1999a). A connection diagram of the ABB OFM fuse blown indicator (**b**) (The ABB Group 1998). EFEN E3NH fuse-switch with fuse blown indicator (**c**) (Efen GmbH 2011). A closer look at EFEN E3NH fuse-switch indicator shows two indication LEDs and one detection output (**d**) (Efen GmbH 2011).

The second implementation technique of a fuse blow detection system is based on voltage measurement and is presented e.g. in (Northcote-Green et al 2008; Vinter et al 2005). The voltage after the LV feeder fuses is converted and the voltage signal is connected to the analogue-to-digital unit of IED, e.g. see Figure 2. In the application in (Northcote-Green et al 2008; Vinter et al 2005) the phase voltage is converted to a 0–24 V DC voltage signal, which is then converted to a digital mode using an analogue-to-digital converter. The technology of this converter is not presented in detail. However, from the figures in these documents it can concluded that at some stage a true RMS value is calculated and the nominal value is selected from a range of 0–24 V. This obviously requires converter adjustments. The implementation of analogue-to-digital conversion is possible to do using a voltage message converter. The display frequency of the voltage values is four voltage values in two hours in distribution management applications (Northcote-Green et al 2008; Vinter et al 2005). High-density measurement of voltage from a LV busbar could enable also power quality monitoring. However, fuse blown detection may require a function which compares LV feeder voltage with LV bus voltage. This is needed to detect and filter MV feeder distribution disturbances or distribution interruption.

The idea and algorithm of a fuse blown detection function based on current measurement has been introduced in protection relays as overcurrent protection function. The idea has not been widely adopted concerning fuse blown detection units. Based on the complexity of implementation, two new system ideas, approximate or exact, is next presented. However, notice that these ideas should be thoroughly tested and simulated before applying them.

In the *approximate fuse blown detection system* the overcurrent protection function of the LV busbar relay or the overcurrent detection function of the measurement and monitoring device is used for fuse blown detection. The function is based on the fact that in normal power flow direction the short circuit current, which melts the fuse, normally goes through a LV busbar and thus the busbar LV relay or the monitoring device could detect it. In the first type of approximate detection, the inverse time overcurrent function, i.e. I>, is used and configured. The overcurrent limit can be determined based on the dimensioning overcurrent of the smallest LV feeder fuse size that is used and on time setting according to the characteristics of this fuse. This function could send an alarm. In a more sensitive type of approximate fuse blown detection the base load current is taken into account. In the detection function the smallest LV feeder fuse dimensioning overcurrent is added to the base load current setting. In addition a time window, which dimensioned according to the fuse, is used to trigger this extra overcurrent, I>, detection function. Because overccurrent makes the fuse melt in a range of a second, at the maximum, a base load current value of three seconds before the peak would probably be sufficient. The I> function could be used to give an indication of LV feeder fuse blows, and I>> and I>>>, could be used in the overcurrent protection of the busbar, for example. Therefore, the configuration of the I> function would be same if a relay was used instead of the smallest LV fuse. The information of a possible fuse blown in a specific MV/LV transformer station can be received at the control centre, where this information starts fault management operations.

In the *exact type of fuse blown detection* the current of each fuse and each phase is measured. If a neutral feeder fuse is used, also the current of this fuse can be measured. Conventional current transformers (CT), electronic measurements based on Rogowsky coils or optical sensors could be used for measurement. Mountable current transformers are available for some fuse-switches, see (Efen GmbH 2011). However, it must be noticed that measurement coil current transformer may be saturated in case of short-circuit current. Therefore, the indication level should be set according to the characteristics of measurement coil saturation, or a non-saturable Rogowsky coil or a non-saturable optical sensor should be used instead of the conventional CT. The measurement of each phase and the neutral feeder of many LV feeders require a multi-channel measurement device. Therefore, a multiplexer circuit (MUX) could be used to reduce costs. Figure 7 shows the block diagram and truth table of a multiplexer in an analogue measurement application (Storey 1998: 612–614). In this fuse blown detection application the current measurements of each phase are connected via MUX to the analogue-to-digital converter (ADC). The MUX and the ADC are controlled by a control and processing system and digital output channels are processed in a real-time operation system (RTOS). In the RTOS software detection loops can be used for each current measurement. In the detection loop an inverse overcurrent algorithm I> could be used to detect fuse-melting current. Thus, an exact fuse blown indication could be achieved.



(a)

S0	S1	Y
0	0	**A0**
0	1	**A1**
1	0	**A2**
1	1	**A3**

(b)

Figure 7. A connection principle of an analogue multiplexer (MUX) circuitry suitable for fuse blown detection of multiple fuses. The analogue MUX is shown in (**a**). The MUX input channels A0..A3 are switched to the MUX output Y according to the control signals presented in truth table (**b**). The control and process system controls the multiplexing and the analogue-to-digital conversion (ADC) and processes the digital data.

2.4.2 Fuse blown detection system in meshed networks

The fuse blown detection system of the meshed network could also use current measurements. The following idea is of the exact type according to the previous classification. An overcurrent protection function, similar to the system explained earlier, could be applied. If short circuit current flows through the feeder and the fuse, the protection function, I> awakes, and if the fault is permanent, the fuse is blown and an indication is sent by IED. Also, the direction of the current can be determined if the voltage measurement of the LV bus is used. Like the radial system, the meshed network fuse blown detection could also be of the approximate type.

2.4.3 Fuse blown indication in distribution management applications

The monitoring of LV fuses can provide real-time and phase-selective information from the LV grids, which is supplied from the MV/LV transformer station. The reliability and cost of such investments depend on installed or planned distribution automation. The cost is determined by the choice of the monitoring technique, maintenance, vendor pricing and coverage of the system, i.e. the number of installed units. The additional cost of the fuse blown indication system can be kept reasonable by careful preplanning, i.e. by reserving enough resources for the fuse blown detection extension when planning the DA system. The coverage of the system affects the need to configure SCADA. Only small changes to the SCADA system may be possible using the DNO recourses e.g. the detection information of 10 LV feeders would be possible without an extension to the SCADA license. The addition of the fuse detection system may become an important solution, when discussing the overall reliability requirements by sensitive customers, e.g. hospitals.

New NIS/DMS functions are available that include LV network fault indication and location. This functionality is based on information from the AMR system. This information acquisition can be classified from DMS perspective either as spontaneous or forced. In spontaneous or event-based communication data is available and readable from the automated meter management system (AMM) without requesting it. AMR alarms such as missing phase or voltage imbalance are sent by meters spontaneously to the AMM database and read from there by DMS. In forced acquisition the operator makes a request from DMS to AMM, which makes a further request to the selected AMR meters. The accuracy of NIS/DMS fault location algorithm is such that the faulted protection zone of the LV network can be detected. Once this functionality for the LV network exists in NIS/DMS, it could be assumed that changes needed for fuse blown indication function implementation, based on real-time information and the SCADA system, are reasonable. Figure 8 visualizes the implementation of the fuse blown indication of MV/LV transformer stations in the SCADA and NIS/DMS systems. The SCADA schematic diagram of MV/LV transformer station is shown in Figure 8a. It includes remote controlled MV ring unit disconnectors, a transformer relay and manual LV fuse-switches with fuse blown detection. The fuse-switch with a blown fuse is shown red and the fault indication is presented below. A NIS/DMS view of transformer station and LV grid is shown in Figure 8b. The red triangle and the fault indication message pinpoint the source of the fault message in the distribution map. The fuse blown indication and faulty feeder is shown in red. (Haapamäki et al 2009)

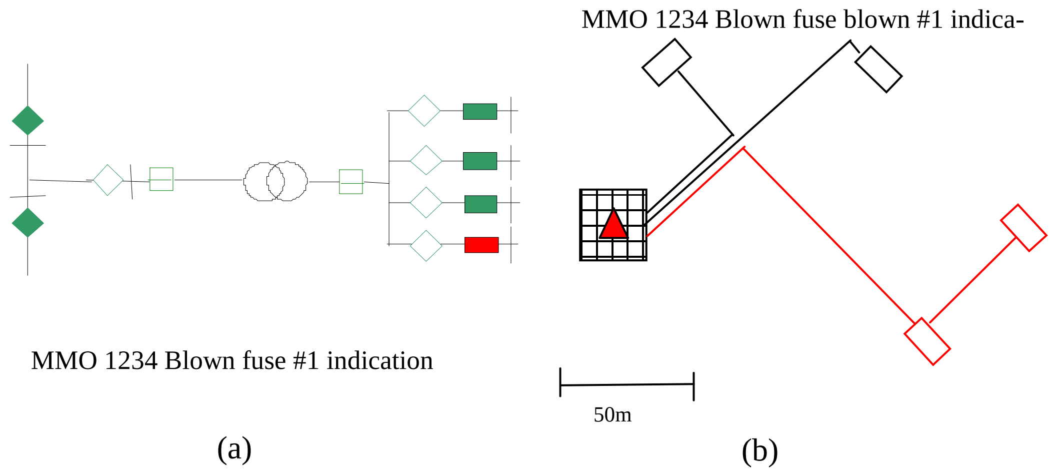


Figure 8. The monitoring of the fuse blown indication in SCADA (**a**). The fuse blown indication in NIS/DMS system (**b**).

2.5 Relay protection in MV/LV transformers stations

Small distribution transformers can be protected satisfactorily, both technically and economically, by the use of fuses or overcurrent relays. This results in time-delayed protection due to downstream co-ordination requirements (Areva-TD 2008: 254–279). The first statement assumes, of course, that there is no reverse power, which is the case in the majority of cases at present. However, distributed energy recourses (DER) applied to LV grids can change the direction of the power and can cause protection blinding. In addition to what is said above about DER protection, relay protection could be needed because of the enhanced protection they enable and other DA functions such as monitoring and control. Overcurrent relay protection can be applied both to the transformer protection on the MV side, to LV bus protection and to LV bus secondary feeders, but the transformer can be protected from both supply directions using differential protection.

There are several different types of transformer faults, in which transformer protection can fulfill the safety requirements and prohibit further property damage. They are:

- winding and terminal faults,
- core faults,
- tank and transformer accessory faults,
- on-load tap changer faults,
- abnormal operating conditions, and
- sustained or uncleared external faults.

Circa 60 % of faults in a study were winding and terminal faults. (Areva-TD 2008: 254–279)

The fault current in urban MV networks is rather high. Document (Northcote-Green et al 2006) lists devices capable of fault current breaking and making. These devices are: a circuit breaker, a fuse-switch and a recloser. Ring main unit coding and available technologies for transformer protection are also introduced. The ring main unit is a medium voltage switchgear used in MV/LV transformer stations or secondary substations from which the feeder can be reconfigured e.g. in the case of a fault. In the case of coding CCF and CCV, C refers to the cable switch, F to the fuse used in transformer protection and V for vacuum circuit breaker used in transformer protection. A common circuit breaker rating used for transformer protection is 200 Amps and for medium voltage feeder protection 630 Amps. (Northcote-Green et al 2006)

The switch is a relatively expensive component and therefore its potential insertion in the middle of the MV feeder requires careful planning using SAIDI and CAIDI values to evaluate the benefits. The switch used in feeder protection can be used in overhead and underground cable networks. In the urban cable network the number of customers after the primary substation switch is high. Thus the number of unsupplied customers during a fault can be reduced by adding a switch in the middle of the MV feeder. In the rural overhead network the feeder length after the switch is high, thus the effect of adding a switch would reduce break time even more.

2.5.1 MV/LV transformer protection in the protection chain, a simulation case study

Distribution network relay protection should be co-ordinated in a way that each component is protected. The protection zones should form an unbreakable, selective protection chain from the primary substation to the LV network and even continue in the networks of the customers. An individual link in this chain is a single protection function of a single protection device. The protection zone is the part of the distribution network protected by the protection function of the protection device. These zones may overlap, i.e. for one protected component there is a primary protection device and a backup protection. Backup protection operates and opens the circuit if the primary protection fails, e.g. the protection of the MV/LV transformer operates, if the protection of the LV busbar fails. A simulation case study of the selective protection of the distribution grid is presented in Appendix 1. In this study the overcurrent protection design is simulated using Digsilent® software. The protection zones from primary substation to the busbar of the LV customer and further are presented in Figure A1.

A time-overcurrent plot can be used to determine the relay settings in order to establish the gapless protection chain. The correct protection settings needed for adequate component protection and the adjustment of the grading margin, which is needed for selectivity, can be determined using either a bottom-up or top-down method, i.e. starting from the LV network of LV customers or from the HV/LV substation. Normally the top-down method is applied, because the latter could require very hard calculation, but in a simplified network the bottom-up method is also possible. The planning method of the protection chain, using an time-overcurrent plot, is presented in Figure A2 of Appendix 1. Figure A2 presents the overcurrent protection operation in the simulated network, see Figure A1. From the perspective of the electrical safety management of MV/LV transformer stations it can be concluded that transformer protection is selective in both directions and primary and backup protection will operate correctly. This can be deduced by comparing the transformer damage curve with the transformer protection operation curve of the plot. Also, the backup protection will operate before the transformer is damaged.

2.5.2 Differential transformer protection

In case of in several faults, differential relay protection can prevent the distribution transformer from causing further damage. Documents (The ABB Group 2008) and (Areva-TD 2008: 254–279) discuss the application of differential protection of MV/LV transformer. In addition, they address the earth fault of transformer secondary winding and selectivity between the protection relay of the transformer and LV relays. For example, in a DY transformer the following faults can be detected by using differential protection:

- earth fault in secondary windings in resistance-earthed transformer,
- earth fault in secondary windings in solidly earthed transformer,
- interturn fault in primary side,
- interturn fault in secondary side,
- primary winding phase-phase fault,
- primary winding phase-earth fault,
- secondary winding phase-phase fault,
- secondary winding phase-earth fault, and

- core fault (Areva-TD 2008: 254–279; The ABB Group 2008).

Differential protection provides a very comprehensive protection for the MV/LV transformer, but requires many current transformers as can be seen in Figure 9. It also gives ideal transformer protection when distributed generation or backup generation are connected, while it works if the power direction changes. Differential protection works with current measurements only, thus voltage measurements in the medium voltage side is not neccessarily used, but they could be used to indicate the direction of the current. An application of differential protection and a protection case of the secondary side earth fault is presented in Figure 9 (The ABB Group 2008). This secondary side earth fault protection can be used in solid or resistance-earthed systems. The implementation of Id> function of differential protection contains phase loops, which are used to measure the difference in phase currents. Each of these independent application threads, i.e. objects in parallel processes, is used to monitor the difference in current measured from the primary and secondary side of the same phase. In addition to the three phase loops, a secondary side earth fault protection loop is added. Id,g> function is used to detect the difference in secondary side zero sequence component and current in the neutral feeder, which reveals the secondary side earth fault, presented with red lightning symbol. It can be seen that one CT is used to measure current of the neutral conductor. The current measurement of this CT is then compared with zero sequence component from the secondary side phase current measurements. The difference in these measurements reveals earth fault.

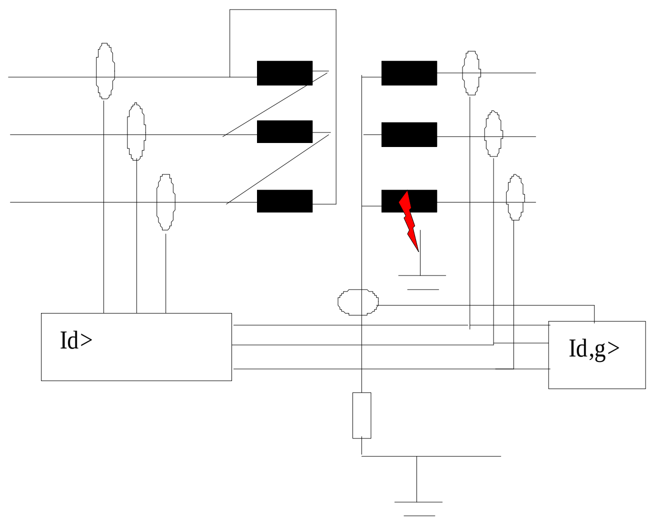


Figure 9. An application of differential protection of the MV/LV transformer with an extra function detecting the secondary side earth fault.

2.5.3 Relay controlled fuse for economic distribution transformer protection

New solutions to MV high fault current breaking have not been widely presented. However, an automatic Sectionalizer has been developed for rural networks and for economic Sectionalizing. The Sectionalizer has an integrated protection unit, which detects the fault current and the de-energized state and breaks the connection during the de-energized state, if fault current has passed the Sectionalizer. Therefore, it can be said that the device has no breaking or making function. These devices are used primarily in MV overhead network T-joints (Northcote-Green et al 2006). A controlled fuse might be a cost-effective protection device. One idea for a cost-effective protection of transformer is presented in Figure 10. As with automatic Sectionalizers, it has no making function, but in MV/LV transformer protection the fault current making function is not as important as the breaking function because faults are not frequent. The question therefore is, could there be a more economic solution to high current breaking than a switch, which could enable relay control and monitoring, at the same time. The basis for the protection idea is the controlled MV fuse to be used with the switchgear. A relay detects the transformer fault (see list of detectable faults in Section 2.5.2) and sends a break signal to the fuse control. The fuses are special, equipped with explosive charge. In a transformer fault the remote monitorable differential protection relay sends a trip signal to the fuse control unit using IEC 61850. The fuse control sends a break signal to the three fuses. The encapsulation of the fuse prevents any breaking parts of the fuse from causing trouble. The protection function of the controlled fuse is partly implemented in the relay, differently compared with the automatic Sectionalizer. For the normal switching operation and for remote control circuit “open” call, a spring-powered circuit breaker with manual re-close, available e.g. in ABB Safering and ABB Safeplus, ring main units could be used (Vinter et al 2005). This function could be implemented e.g. in the remote control unit instead of the relay. However, in a transformer fault the three phase separation of transformer must be done. In practise this would mean breaking all the three fuses. The relay should also detect, if one fuse is blown from some other cause than overcurrent. This could trigger unsymmetry alarm, for instance.

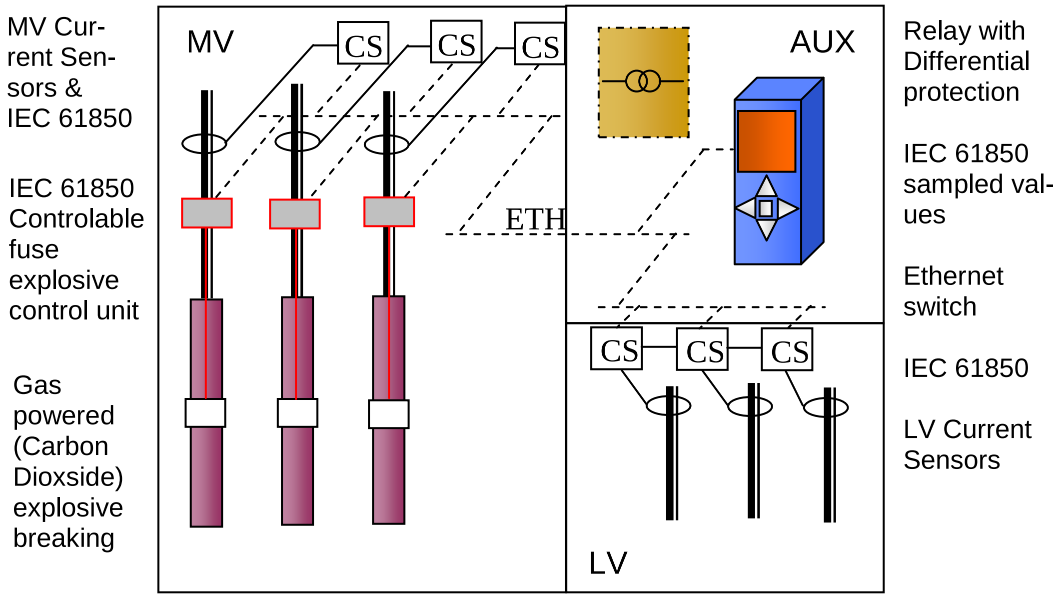


Figure 10. An idea of MV/LV transformer protection configuration using controlled fuses, differential transformer relay protection, IEC 61850 in communication with the fuse control and IEC 61850 sampled values in communication with current sensors.

The transformer failure indication is received by the control centre in real time. A SCADA schematic diagram of a MV/LV transformer station with controlled MV fuses and a spring-powered circuit breaker is presented in Figure 11. The diagram shows e.g. MV remote disconnectors with green diamonds and transformer controlled fuse which is blown with red rectangle. Also, an indication message from the relay is shown.

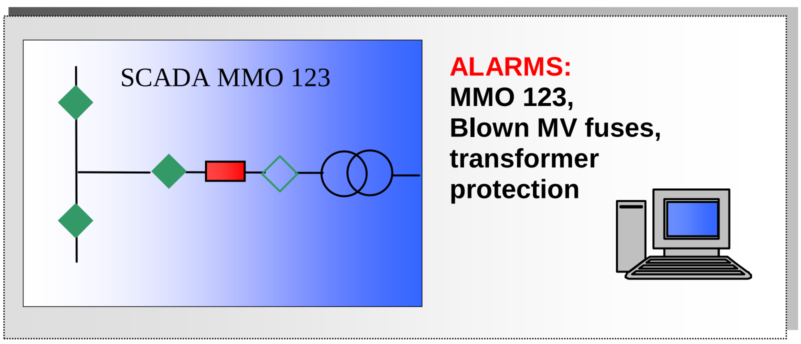


Figure 11. A SCADA schematic diagram of a MV/LV transformer station with controlled fuses, differential protection and remote controlled disconnector.

2.5.4 An application of reserve power generated in the LV grid

If a MV/LV transformer failure occurs, reserve power can be connected by using a mobile generation unit, the connection from the neighbouring transformer station or the backup generation unit of the DNO customer. In this application the switching of the own backup generation unit of the customer is examined. Switches are usually operated manually and thus the interrupt duration is partly unknown. At present new transformer components are easily available and the tools and the skills of personnel needed for replacement are good. Also, when the reserve power connection is well planned in advance, the manual operation can be straightforward and the interrupt time tolerable in many cases. However, if the interrupt risk is considered to be too high, automation could be used to minimize this risk. Many of the faults causing interruption are not transformer faults, but those of the MV feeder. The fault can also be elsewhere in the network. Automation could allow the vital operations continue to stay in operation such as the operation of water pumping stations and waste water plants. It could reduce the interrupt time especially if fixed generation is applied.

When reserve power is fed, a part of the grid is made into an isolated subgrid. The new relay protection settings depend on the generation connection point with respect to protection devices and the generation size. Why use a relay? If the power delivery route changes, new settings may be needed, which also take the smaller short-circuit power into account, but still preserves selectivity. Why not use a fuse? The major differences in overcurrent protection between a LV fuse and LV relay protection can be seen in the shape of the operation curve. Better sensitivity, monitoring and automated switching functions are achieved by using relay protection. Selectivity can be achieved by using either fuses or relays, but the configurability of the relays makes protection changes more flexible if the underlying grid topology changes e.g. in reserve power situations or after the addition of DER resources. The selectivity of LV and MV protection can be determined by using e.g. a time-overcurrent plot, similar to the one already presented in Figure A2 in Appendix 1. The effects of reserve generation on LV relay settings are discussed in (Heinonen 2006). Often in overcurrent protection it is only the grading margin that needs to be adjusted when the subgrid is supplied with reserve power. The normal and reserve power protection settings can be saved as two setting groups in the relays. This makes it easier to change the setting when the grid topology changes. The reserve power group settings could be then automatically taken into use and the normal setting group restored when mains is available again.

Let us examine the SCADA schematic diagram shown in Figure 12, which presents the monitoring and control possibilities enabled by the relay protection. The network consists of an MV/LV transformer, a dividable LV busbar, a reserve power generator connected to the LV busbar, and LV feeders. The intelligent LV busbar relay (1) can detect supply interruption. The relay trips and sends “open” to the LV busbar disconnector (2) and “change new setting group” to relays (3) . Also, “trip” is sent to the generator protection relay (4) and “start” to generator (5). Once the generator is at nominal speed, it sends “clear” to the generator relay (4) and the generator is connected to the LV subgrid. A part of the LV grid is supplied with reserve power from the generator. Once the main connection is available and detected by relay 1, after the delay, a reverse command sequence is started, which restores the original relay settings and grid topology. However, some delay is needed to make sure the mains connection is steady.

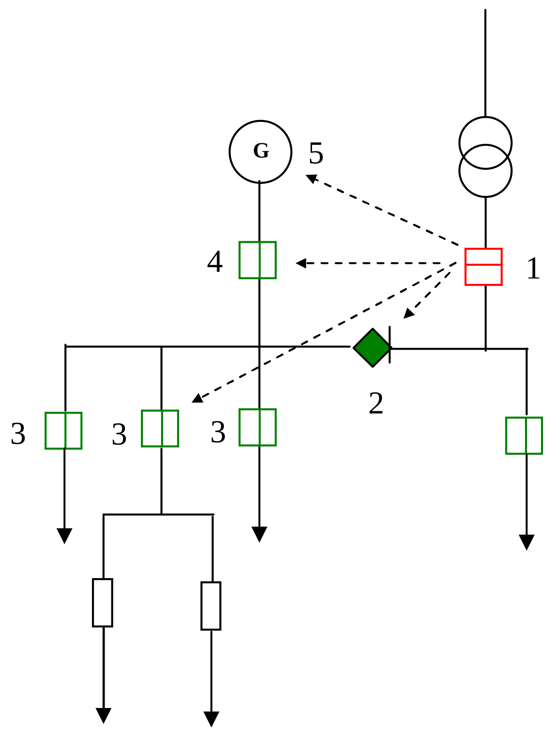


Figure 12. Reserve power supply of LV grid using a generator. LV relay protection, local control and a command sequence are used.

LV relays are primarily used only in industrial grids in Finland at present. This is probably the reason why communication protocols available for compact switches and LV relays are those used in industrial applications. For applications, such as presented in Figure 12, hard wiring can, of course, be used instead of a communication bus. IEC protocols, such as IEC 61850, is recommendable for remote operation also in LV distribution grids and for interlock and remote trip functions. Therefore, distribution grid protocols could be seen on the LV product development list in the near future.

2.5.5 An application of reserve power supplied from MV/LV transformer station

In a MV/LV transformer station fault situation a reserve power supply from the neighbouring transformer station is a commonly used solution, if the neighbouring transformer has leftover capacity available. The needed switching operations in this situation are typically manual. However, automatic functions can decrease the interrupt time significantly and thus the effects of the power loss are minimized. Therefore, local and remote changeover functions are efficient in the reserve power supply from the neighbouring transformer station. A local changeover function can be triggered e.g. by a MV/LV transformer protection relay trip or a fuse blown indication signal. The remote changeover function can be triggered similarly, but the operator in the control centre accepts the reserve power command sequence, suggested by SCADA. The automatic switching of the LV network increases the risk of personal injury due to the automatic electrification of the repaired part of the network. Therefore, safety procedures must be strictly obeyed and it is highly recommendable that the part of the network being repaired should be both disconnected using the manual disconnectors and grounded.

Figure 13 presents an example of the application of the MV/LV reserve power from the neighbouring transformer station. It presents the remote changeover function, in which the command sequence, approved by the operator using SCADA, is sent to LV relays and remote controlled disconnectors. A transformer protection relay e.g. Vamp 52 (1) and an LV bus protection relay e.g. ABB SACE PR123 (2) are used. A normally open motorized switch-disconnector, e.g. ABB OTM 250 (3), is used in the middle of a divided LV busbar of the cable cabinet, which is located on the boarder of the neighbouring LV grid. An indication of the transformer failure is received by SCADA from the

MV relay (1). The relay (1) sends a trip command to the LV busbar relay (2), remotely and automatically. The operator sees the available capacity of the network (B) and the consumption estimate of the network (A). These could be formed by forming load profiles based on the current measurements of the transformer protection relay or using normalized load profiles. The operator accepts the capacity check and accepts the reserve power supply scheme from network (B). SCADA sends a "change protection settings group" command to the protection relay of the LV busbar of the transformer station (B) and a "close" command to the motorized switch. Once the transformer is changed the supply can be restored by accepting the normal supply scheme from SCADA.

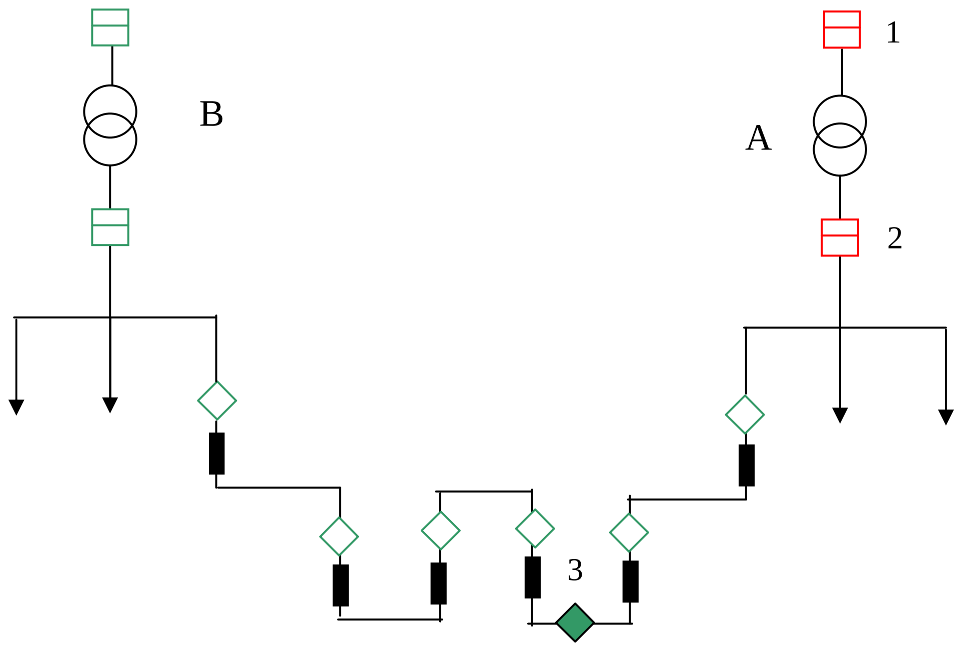


Figure 13. SCADA schematic diagram of reserve power supply from the neighboring transformer station using the LV core connection cable network and the remote changeover function.

The Helen LV network topology is discussed in (Vartiainen 2007) and this topology was used as an initial parameters for the presented reserve power changeover function. In the Helen LV network a core connection cable network is used, in which MV/LV transformer stations and cable cabinets are connected with a thick core cable. Near the transformer station a pair of 185 mm^2 is used and further away a single 185 mm^2 core cable connects the cable cabinets. Cable cabinets can be supplied with electricity from multiple transformer stations, but normally the topology is radial. (Vartiainen 2007)

2.6 MV/LV transformer overload detection and the calculation of aging

The normal load of the transformer can be concluded from the distribution transformer rating directly in terms of kVA. The nominal load is defined as the current output at the nominal voltage at the rated power of the transformer. The transformer is overloaded if this nominal load current is exceeded. The overload current overheats the winding insulation, which accelerates the aging of the transformer. Hence, the expected lifespan depends on the loading conditions of the transformer. Aging is not restricted to the fundamental frequency, but also the harmonic currents affect the hot spot temperature. An overload increases aging significantly and is dependent on the amount of the overload. Extreme overloading can burn the insulation of the winding and the oil of the transformers if protection does not work. However, the transformer can safely and temporarily be overloaded, when the ambient temperature has a cooling effect.

The overload can be detected by measuring the phase currents of the transformer. The algorithm can simply follow the true RMS values of phase currents. The transformer is in overload if the RMS phase current exceeds the nominal phase current for a time period. Once the overload is detected, an indication can be given. The overload setting can be defined by using sizing recommendations (Anjala 2008; Simonen 2006), for example. Some useful methods of monitoring the load, aging and hot spot calculations are discussed e.g. in (Pylvänäinen, Nousiainen & Verho 2007). In addition to the transformer MV or LV phase current measurements, the following methods to deduce the load current information are presented:

- protection relay measurements,
- measurements using transformer metering unit,
- load calculations using summed customer energy information, read hourly,
- load calculations from summed load information, and

- load calculations from load estimates, which exploit customer group load profiles and the number of customers in these groups (Pylvänäinen et al 2007).

Figure 14 presents potential NIS/DMS tools suitable for the monitoring of the load of the distribution transformer, which can be used for operation and maintenance purposes. With a web server and advanced web technology this MV/LV transformer station information can be transmitted to the DNO personnel and subcontractors. An NIS/DMS navigational view of a MV/LV transformer station is presented in Figure 14 a. The view contains an active overload warning and its symbol the red triangle. The graphical view of NIS/DMS system is useful, because the switching status of the LV grid and the coordinates of the transformer can be seen. If this graphical view is presented in web form, it can easily be used in mobile devices e.g. when a DNO team or a subcontractor is dispatched to the site. The peak load measurement of the transformer, in Figure 14b, is one of the most checked measurements of the transformer station. This virtual peak load gauge view shows the peak load in respect to the nominal load in an easily readable form. The main differences compared to the traditional peak load gauge are that the digital measurement can also provide both a time stamp and the peak load value. The peak load could be checked anywhere using a mobile device, e.g. a laptop, PDA, tablet or mobile phone. The bar graph, in Figure 14c, could be used to present the loading of the three phases compared to the nominal load. The colours of the bars could be used to indicate the load condition of the phases, i.e. green for below nominal, yellow for near nominal and red for nominal or an overload. The load diagram, in Figure 14d, can provide information about a chosen period of interest e.g. a month, week or day. From this graph the network operator or designer can find out the time of the overload and compare the profile with the calculated load profiles to see whether e.g. a LV network reconfiguration or the redimensioning of the transformer could be the solution needed. If the peak load is temporary, no action is necessarily needed. Also, when reserve power is needed, using the capacity of the neighbouring transformer, overload detection is useful in monitoring the condition of this transformer.

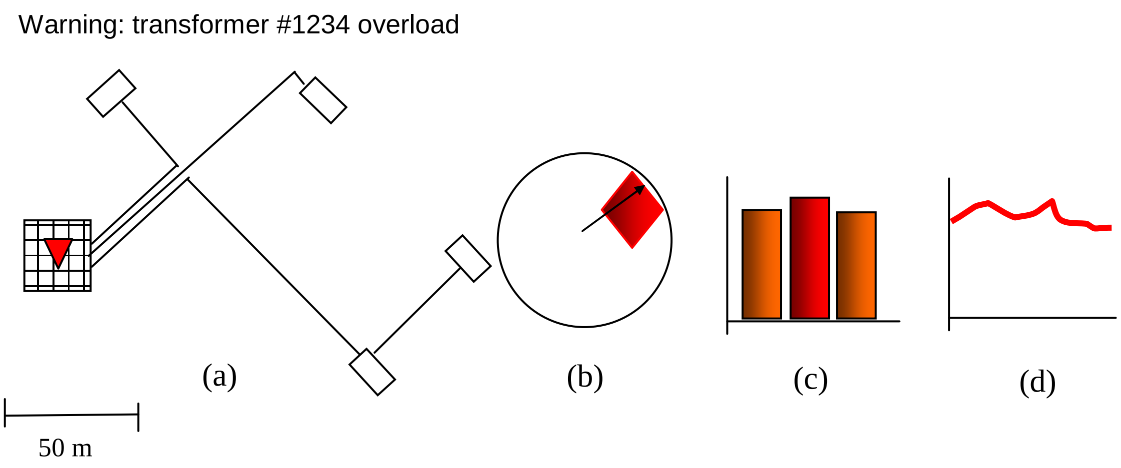


Figure 14. Graphical tools for the load monitoring of the MV/LV transformer station. The navigation of LV grid in the NIS/DMS system and the transformer overload warning are shown in (**a**). The virtual transformer peak load gauge is shown in (**b**). The transformer phase current bar graph is shown in (**c**). The loading compared to the nominal load is expressed in different colours. The historic view of the load profile of the transformer is shown in (**d**).

It should be possible and easy to access the phase current measurements of the transformer during the different activities of the distribution operator also from the field. One idea for easy distribution grid component navigation is to exploit the NIS/DMS graphical information system. Also, web servers and advanced dynamic web pages with a graphical information system (GIS) e.g. Google maps could be used to make the data easily available and accessible. It is assumed, of course, that security issues should be taken into consideration. However, international service providers, e.g. Google, store information from searches. Some of the information of the electric grid and some DNO customers could be considered confidential information and therefore should not be publicly distributed.

In Finland electrical heating reaches the highest values during the cold winter months and therefore also the highest loading peaks occur when the ambient temperature is freezing cold in many park or pole-top transformers. However, the ambient temperature does not have a cooling effect if the transformer is in a heated space or in a wellinsulated house. Heat pumps are replacing direct electric heating. Hence the load decreases when the ambient temperature is above 0 °C, but remains the same below -10 °C degrees. Some heat pumps can be used for cooling during the summer time, which can already be seen as a change in the load profiles (Niskanen et al 2009). Overloading also increases transformer load losses e.g. 1.2 times nominal load may mean 1.4 times nominal load losses (Prašnikar 2007). These losses could be avoided if the overload is detected, the loads are managed and the transformer size is properly selected. In Finland there are public recommendations for transformer sizing and overloading, documented e.g. in (Anjala 2008). Also, DNO-specific instructions are used in planning and network construction, documented e.g. in (Simonen 2006). The concern is that upgrading or changing worn-out transformers too frequently and using overrated design recommendations could cause unnecessary costs. A goal of monitoring of the load of the transformer is to optimize the size of transformers. This should be taken into account in planning networks. An overload detection system could provide the maintenance and operation processes with exact information. Also, a temporary reduction of the load of the transformer could be done in time by changing the network topology. A better management using automation of temporary overloads could lengthen the age of transformers. However, secondary components, including automation, can never be used to extend the life of worn-out primary components. They can only provide good company for the healthy ones.

2.7 Real-time state monitoring of the LV network

In the previous chapter real-time transformer load measurement was introduced. The transformer current and power measurement could be utilized in DNO processes. The voltage of the point of connection (POC) of the customers must be calculated. To do this, based on transformer measurements, the peak load and the maximum voltage drop of each LV grid are calculated. Real-time transformer measurements enable the real-time calculation of the POC voltage of the customers and hence also graphical indications about exceeding POC voltage limits using the NIS/DMS system.

Let us consider MV/LV transformer terminal and customer voltages. The POC of the customer voltage *U*, has the following relation to the load current, *I*, and no-load transformer voltage *E*:

$$U = E - IZ , \tag{1}$$

where *Z* is the impedance of the transformer and LV conductors.

However, because complex power is delivered to the customer and because the impedance of the LV network is complex, the voltage drop can be presented using active power, *P*, and reactive power, *X*, and an approximated equation in the following way:

$$\Delta U = \frac{RP + XQ}{U} , \tag{2}$$

where

R is transformer and LV network resistance,

X is transformer and LV network reactance and

U is voltage of the POC of customer.

This can be further expressed using load current, *I*, as follows:

$$\Delta U = RI \cos \vartheta + XI \sin \vartheta , \tag{3}$$

where

θ is the angle between voltage and current.

It is known that the impedance of the LV network is almost resistive and the equations can be further approximated, if necessary, by ignoring the influence of reactive power *Q* and the influence of the reactance *X* of the LV network in equations (2) and (3). Hence, the voltage drop is directly proportional to active power and the real component of current. (Bollen & Gu 2006: 55–56)

The previous equations could be used to evaluate the POC voltage in the case of a single customer per transformer, where the entire load current of the transformer is drawn by this customer. In reality, there are multiple LV feeders, T- joints and multiple customer connections per LV feeder. Therefore, multiple methods exist for the estimation of the transformer load current division to the LV feeders of the transformer station and further division in cable cabinets to connection cables. One method for the estimation of measured transformer current division is based on the customers' yearly total energy consumption figures. This information is available in the NIS/DMS system. A more sophisticated method could be found using customers' consumption data, measured hourly. This data can be used to form consumption profiles. In the absence of measured profiles also normalised profiles could be used to calculate current division in the LV grid. Hence, the POC voltage of customers could be calculated in real-time using transformer load measurement and consumption profiles. Also, AMR techniques have been developed to monitor the EN 50160 voltage level. The data provided by AMR meters for state estimation have been studied and reported e.g. in (Mutanen 2008).

2.8 Unbalanced load detection function

The imbalance of three-phase systems causes extra loading of the neutral conductor and stress to the transformer. At unbalanced loads also harmonic currents increase the loading of the neutral conductor. For example, the third multiple harmonic current waveforms of the three phases do not compensate each other. The residential LV system is designed in such a way that the loads are distributed equally to the three phases in electric power centres of customers. However, also during normal operation the load currents are somewhat unbalanced, because single-phase loads draw currents from different phases at different times. These single-phase loads from different sources are summed up in the distribution network and the summed currents are distributed more and more evenly to three phases on the way upstream. Therefore, the light imbalance of MV/LV transformer load is normal. In a faulty network the imbalance of the transformer may increase and may even cause the transformer to be damaged. The LV busbars L1, L2 and L3 of the transformer are in Finland usually protected by MV fuses or LV fuses. LV feeders are usually protected by fuse-switches. Therefore, the unbalanced load may result from the operation of the phase fuse. Also, a transformer failure, broken cable or failed cable joint can cause imbalance. The neutral busbar and the neutral conductors of LV feeders are not usually protected by fuses.

The unbalanced load detection function is possible to implement using max and min algorithmic functions. The current imbalance, in percentage, $I_{imbalance}$ can be calculated by 100 % · (max{I_{L1}, I_{L2}, I_{L3}}- min{I_{L1}, I_{L2}, I_{L3}}) / max{I_{L1}, I_{L2}, I_{L3}}. Inverse time characteristics can be used in addition to the percentage setting to adjust the system. On the smallest possible detection level the function wakes and the imbalance alarm could be given or a trip could be executed after configured operation time. (The ABB Group 2000)

The unbalanced load detection DA function is possible to implement in a LV network where three-phase current measurement, suitable IED (intelligent electronic device) and communication devices are available. The natural load imbalance is the greatest near at the customer point of connection. Therefore, the MV/LV transformer station provides a good place to monitor the imbalance of the LV distribution network and the transformer. The function could be implemented in the transformer protection (differential transformer protection) or power quality monitoring device. The NIS/DMS graphical network map could be used to present an overall analysis of the loading state of MV/LV transformers, where the current imbalance, transformer capacity and warnings could be presented using graphical symbols.

2.9 Monitoring LV network switching actions

In the medium voltage distribution network the switching actions are recorded. Usually also name of the responsible operative is recorded. The information on the primary substation relay action or on the state change of the remote controlled disconnectors can be automatically recorded. The manual switching actions are recorded by the operator using NIS/DMS or SCADA switching events record forms. In the LV network a similar recording system of switching actions does not exist. The switching event could be recorded by the operator if the customer has left a LV fail message, a switching action or a fuse replacement is needed, for example. New technology has become available, which enables to record LV network switching actions. One of the advantages of such a system is enhanced security and automatically updated topology information. The fuse-switch state, either open or close, can be detected by using a micro-switch and a fuse blown with a fuse blown indicator (Efen GmbH 2011). This state information can be enriched with timestamp and component location information, recorded in the fault log and forwarded to customer systems. The functionality of an outage communication system based on AMR alarms is introduced e.g. in (Kuru, Haikonen & Myllymäki 2009). The outage communication system could use real-time information coming from the micro-switch of the fuse-switch or from the fuse blown indicator event.

In a radial network the LV voltage measurements of the MV/LV transformer station could also be used to monitor the switching of LV fuse-switches by the utility or subcontractor personnel. The indication could be formed by comparing the LV busbar voltage with the voltage after the fuse-switch. If the voltage measurement value at the same instant is the same, zero or nominal, for instance, the fuse is intact and the fuse-switch is closed. If the voltage of the same phase differs, e.g. the bus voltage is nominal and the fuse-switch voltage zero, the fuse is blown. If all the phase voltages of the three fuse-switches at the same instant differ from the phase voltages of the LV busbar, switching using a fuse-switch has occurred or all the three fuses have been blown. However, the probability that all the three fuses of the fuse-switch blow simultaneously is less than switching activity. Therefore, the switching activity could be indicated, recorded and the field crew dispatched.

In addition, the switching state recording system introduced could also contain work monitoring, the detection of unauthorized use and real-time customer messaging functions. The event information coming from fuse blown or micro-switch could be received by LV SCADA or by OPC database, for example. The latter is a system introduced in the context of the AMR DMS integration systems. The sequence starts when the NIS/DMS system receives an event from the fuse-switch. A database query can be done. In this query the matching could be done e.g. by comparing the co-ordinates in the work management database of the transformer station or cable cabinet with those of the NIS database. The co-ordinates of the two systems can already be linked, when the work order is entered. Also, the name of the DNO person responsible for electric work and information of the subcontractor can be read by the NIS/DMS from the work management database, if a match is found. The operator should be asked by the system to verify the switching action. If no match is found, the data could be entered manually by the operator, but if unauthorized use is suspected, the field crew with a watchdog should be dispatched. The number of outage clients and the outage duration could be recorded automatically based on the LV network information of NIS and the present switching state information of DMS. The outage information is recorded the fault and outage databases. Based on the non-electrified LV network information stored in DMS and electronic contact information of the customer stored in the customer information system (CIS), the customer can be informed about the outage automatically.

3 POWER QUALITY AND DISTORTION LOCATION FUNCTIONS

In Chapter three power quality (PQ), and the distortion location, i.e. fault location, are discussed. Power quality measurements can, in some circumstances, be used to track the origin of the fault. Also, the same IEDs may be used to produce both fault records and power quality measurements. Therefore, these two could be called cousins and both are discussed in this chapter not only to focus on MV/LV transformer station and LV grid systems and functions, but also to give the reader a chance to evaluate system requirements suitable for different PQ and fault location functions. The PQ and fault recording data are used by many processes. A single interruption may have an economic impact on DNO business, on the business of the electricity vendor and on customer business, for example. In addition to financial considerations, power quality and fault recording information are used in the processes of electrical safety and network management, for instance. Equipment damage may occur, if power quality is weak. Using PQ measurements and fault recordings it may be possible to monitor the condition and health of the components. Therefore, also fault and asset management processes may benefit from the measurements.

In this chapter functions that utilize PQ and fault recording information from MV/LV transformer stations and LV grids are introduced. The definition of the power quality is first presented. A brief review of the results from international studies is then presented. It shows the development status of the PQ monitoring of MV/LV transformer stations and LV grids. The PQ measurement system of E.ON Kainuu Electrical Network is presented, because it represents well a systematic utilization of PQ data. Of all PQ quantities harmonics are focused on. The power electronic loads are increasing, which will increase harmonic currents and reactive power, if not filtered properly. Hence DNOs could in future expand services or be encouraged by the regulator to use power quality shaping functions in LV distribution grids in future. At present, however, filtering systems are used primarily in customer networks, but e.g. an active power electronic grid interface and energy storage applications could enable PQ shaping solutions also in distribution systems at a small additional cost. The discussion of the quality of voltage contains some theory of propagation of harmonic voltages at the LV level. It may help

DNOs to evaluate suitable locations for monitoring and filtering applications in MV/LV transformer stations and LV grids. Processing PQ and fault recordings should not consume the scarce recourses of DNOs. Therefore, PQ and fault detection systems should be taken into use gradually, using standard protocols and efficient ICT.

3.1 Power quality and standardization

Power quality has an impact on the efficiency, security and reliability of the distribution network, but the term power quality is normally used to express the quality of voltage and current. A PQ definition is given in (Fuchs & Masoum 2008) and this definition can be adjusted to form a new definition needed for the discussion of PQ in MV/LV transformer stations and LV grids as follows:

> *“ Power quality is the measure, analysis, management and shaping of the quality of distribution system voltage and current and the frequency of these two. One of the objectives of PQ management and shaping functions is to maintain the sinusoidal waveform at the rated voltage and frequency.”*

In addition to the previous definition, power quality is defined in the measurement standard IEEE 1159 and in the term dictionary IEEE 100 as *powering and earthing concept.* (Fuchs & Masoum 2008)

In Europe the EN 50160 standard, published by the European standardization organization Cenelec, is considered perhaps the most referred standard by DNOs concerning power quality. The EN 50160:2010 is the latest version of this standard and it defines voltage quality quantities for frequency, amplitude, waveform, and symmetry of voltage in distribution in a normal steady state and transitory state, each distribution voltage level, LV, MV and HV, being discussed in separate chapters of the standard. The steady-state requirements or recommendations include definitions for voltage peak, flicker, asymmetry and harmonic wave. The transitory-state requirements or recommendations include the definitions of transient overvoltage and voltage sag. The EN 50160 standard defines distribution voltage properties also at the point of connection of customer (POC). It is referenced in the terms of network service VPE 2010, which is used in connection contracts to define service terms by most DNOs in Finland (Energiateollisuus 2010). (Cenelec 2010)

The VPE 2010 also defines that devices of the customer should meet with the requirements of the applicable electromagnetic compatibility (EMC) standard, if defined for each individual device. In practice this refers to the EN 61000 standard and it defines e.g. the electromagnetic compatibility levels of devices and their immunity. It can be applied when PQ problems in the customer grid have occurred and must be solved by negotiating with customers. Also, the limits of the harmonic currents of devices of customers are specified in EN 61000, but DNOs are usually more concerned about the total load and therefore the standard can be applied by DNOs in negotiations with customers, if necessary. Power quality is measured using various devices. One of the most discussed recently is the PQ measurements using AMR meters. The IEC 61000 standard includes definitions of the requirements and classification of measurement devices. If multiple measurement devices all meet with the class A requirements of the IEC 61000-4-30 standard, the measurement results should be the same and accurate. The IEC 61000-4-7 standard specifies requirements for harmonic and inter-harmonic measurement methods and the IEC 61000-4-15 for flicker measurements. The standard EN 50160:2010 refers to the IEC 61000-4-30 standard in voltage sag measurements, for instance (Sirviö 2011: 14-15). (IEC 61000-4-30 2003a; IEC 61000-4-7 2002; IEC 61000-4-15 2003b)

The term power quality can be used as an umbrella term to include also reliability and availability. It could also contain the idea of service quality. After the winter storms of December 2011 and January 2012 in Finland many rural DNO customers, if they had been asked to define power quality, they would have given the following answer: “*What is power quality without power distribution service*?” However, automation can be used also to help reporting reliability and availability. The most significant factors defining reliability are perhaps the duration of permanent faults and the frequency of short interruptions (Partanen, Verho, Lassila, Järventausta, Honkapuro, Strandén, Kaipia & Mäkinen 2010). In the statistics permanent faults and short interruptions are presented using the system average interruption duration index, SAIDI, and the system average interruption frequency index, SAIFI. These indexes must be reported to the regulator by DNOs. Availability is well described using the momentary average interruption frequency, MAIFI, which is used to express the number of three-minute breaks or less per client per year. These service quality indexes were originally defined in the IEEE 1366-1998 standard, which was revised in 2004 (IEEE 1366-2003 2004).

Power quality disturbances cannot be examined just by using the EN 50160 standard in the distribution grid. One possible approach is to examine the disturbances of the electric system caused by electric devices, failed distribution components or lightning, for example. Another approach is to examine the exposure of the personnel and civilians to the disturbances caused by the system. In both cases the disturbance can be classified based on the way it is conveyed. Hence disturbances can be galvanic or electromagnetic depending on whether they are conducted or radiated. Device-to-system galvanic disturbances are e.g. over-currents and voltages, current and voltage transients, voltage fluctuation, i.e. flicker, swells and sags, interruptions, voltage asymmetry and earthing faults. (The ABB Group 2007: 1–2).

The MV/LV transformer and conductors may cause exceeded radiated electromagnetic disturbance due normal or fault operation. The radiation due normal operation is normal if a certain threshold level is not exceeded. Because the voltage level in the LV network is low, depending on the load, the current level can be high, and once it is directly proportional to the magnetic field, the field can cause device malfunction and excessive exposure to human beings. Therefore, in addition to the PQ of the distribution voltage and the EMC requirements of the devices, also recommendations concerning human exposure to the electromagnetic field, specified e.g. in the European union Directive 2004/40/EU and Finnish social and healthy ministry Act STM 294/2002, should be taken into account. (Valkealahti 2008)

3.2 PQ measurements and presentation applications in literature

The Council of European Energy Regulators (CEER) recommends that programmes monitoring voltage quality should be launched in European countries. Therefore, The Union of the European Electricity Industry, Eurelectric, a sector association representing electricity industry including electricity distribution network operators (DNOs), made a survey to map the present PQ situation within its member organizations. The results showed that permanent power quality measurements produce important data, which can be used for the following tasks:

- to plan and implement appropriate mitigation measures in order to provide the sensitive customers with better power quality,
- to allow trends of power quality parameters to be monitored,
- to monitor voltage quality and adherence of standards, and
- in cross references to customers complaints.

Voltage quality at the point of connection of the customers of the majority of European DNOs should meet with the EN 50160 requirements. In the survey the majority of DNOs answered that they measure the following voltage quality parameters: 10-minute average voltage, rapid voltage changes, long-term flicker severity, voltage imbalance, total harmonic distortion (THD), individual harmonics, dips and swells. 82 % of the DNOs reported that they use permanent power quality measurement devices in MV busbars and 50 % of DNOs reported that they have also PQ measurements at other voltage levels than MV. 81 % of DSOs report that they have a system, which enables collecting and storing PQ data. (Eurelectric 2009)

EDF has been studying power quality and especially harmonic levels and their changes in French LV networks since 2000. In (Berthet, Eyrolles, Gauthier & Sabeg 2007) were reported PQ measurements using 20 measurement nodes. This number of nodes is low with respect to the fact that EDF has 28 million customers, but although there are only 20 measurement nodes, EDF PQ measurements represent continuous measurements and an analysis of harmonic levels in LV networks from a long time period, which is only possible using fixed PQ measurement nodes. The measured values of 5 residential district nodes, 4 light industry nodes, 7 office and commercial zone nodes and 4 LV networks nodes, which were installed at the end of LV networks, were compared with the voltage quality standard EN 50160. The results indicated for instance the following:

- The share of fifth harmonic was found to be high. On the average 5th harmonic frequency was 4 % in 95 % of all measurements. The maximum value in EN 50160 is 6 %.
- The harmonic levels was found to increase and the multiplications of non-linear loads was mentioned as main reason for that. (Berthet et al 2007)

In South-Korea, the Korean Electric Power Corporation is designing a new function to be implemented in the distribution automation system. The monitoring point possibilities are presented in the feeder model of Figure 15. This DA power quality monitoring system contains the following monitoring points: primary substation, distribution substation, switching station, automated switches, medium voltage and low voltage customers, and distribution transformers. The PQ function is designed to be used in remote terminal units and the system is designed to send spontaneous indications about exceeding threshold values. The values are configured according to the PQ standard IEEE 1159. Having received the indications, the operator can download the PQ recordings and analyse them in an analysis program. (Ha, Park, Shin, Kwon & Park 2007)

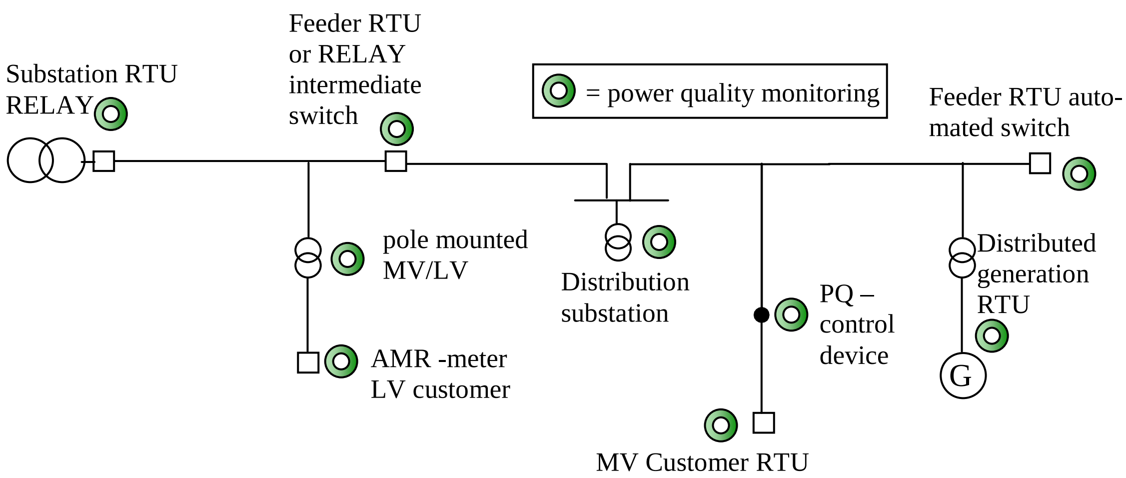
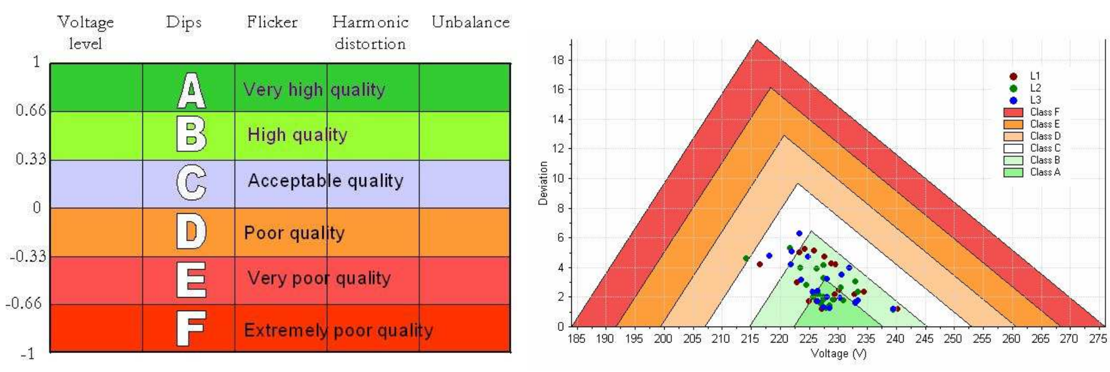


Figure 15. Possible power quality monitoring points presented in (Ha etc 2007).

New illustrative ways representing power quality in systems of control centre are presented in (Cobben 2007). These include power quality monitoring and classification methods. In the classification method indices of power quality are formed, which represent the situation with respect to national regulator limits e.g. EN 50160. The PQ indices are formed by calculating the average value and standard deviation of the PQ measurements. The method includes graphical representation as well, where colours are used to represent the classified indices. The principle of this classifying method is presented in Figure 16a. The standard deviation and the average value are used to give an overview of PQ measurements in different locations. The accepted compatibility level corresponds to the zero normalized level. The normalized values are divided into classes, which are presented using colours. An example of voltage measurements in MV/LV transformer stations is presented in Figure 16b. The standard deviation on the vertical axis is used to indicate how much the measured values typically differ from the average value. A large standard deviation corresponds to large fluctuation in measured values. The average value of the voltage level is presented as a dot on the horizontal axis. The position of the dot on the vertical axis indicates the deviation. The coloured area expresses the class the index (dot) belongs to**.** This method filters the weakest power-quality measurements both in time and in place, but is very illustrative and gives a PQ overview at a glance. However, the method presented in (Cobben 2007) could possibly be used as an element in the analysis function utilized in the graphical map of the NIS/DMS system. Hence, the method enables a PQ analysis using classification, symbols and colours. (Cobben 2007)



(a) (b)

Figure 16. PQ classification method using colouring is shown in (**a**). The vertical axis shows normalized power quality level. The horizontal axis shows an example of possible PQ aspects. An example of a presentation using standard deviation, average value method is shown in (**b**). Measured voltage in transforming substations (LV side) is presented. (Cobben 2007)

Siemens has presented a PQ system using AMR measurements in (Abart, Lugmair & Schenk 2009). This PQ monitoring system is a good example of a PQ analysis system, which utilizes PQ information from AMR meters, the location information of the distribution components displayed in the NIS/DMS system and a graphical representation of PQ quantities. The system includes a classification, histogram and graphical map presentation of PQ measured by AMR meters. The classification of e.g. PQ voltage measurements is implemented using 11 classes in total for normal, under and overvoltage. Also, average, minimum and maximum voltages are calculated. An overview of the PQ state of LV grids can be displayed using symbols and a distribution map. AMR meters reduce the amount of transmitted information. They calculate 15-minute values, which do not correspond well to the EN 50160 requirements of 10-minute values, but the AMR system allows to measure the PQ of the distribution grid, comprehensively. It also enables a measurement analysis using the NIS/DMS system. The system could be used also e.g. to evaluate the need and location of temporary or fixed PQ measurements. The system has been piloted in Austria. (Abart et al 2009)

3.3 The PQ measurement system of E.ON Kainuu Electrical Network

Power quality is not considered problematic by DNOs unless customers complain of insufficient power quality, which they think may have caused a failure or bad function in their equipment. In many cases the complaints initiate PQ examination procedures. These are often done using temporary measurements in Finland. In the MV distribution network also fixed PQ measurements are used to give PQ information covering a long period of time and to see how power quality corresponds to EN 50160, which is used by DNOs e.g. in their terms of delivery with customers (Niskanen et al 2009).

E.ON Kainuu Electrical Network is a DNO, which utilizes a systematic power quality measurement and analysis system. In 2008 the E.ON Kainuu network comprised 12 700 km of mostly overhead MV network, 5 200 MV/LV transformers and 5 200 km of LV network, out of which 72 % was overhead network. The E.ON system includes PQ measurements in MV/LV transformer stations and in LV grids. A power quality management and development mapping was done in 2007 (Niskanen, Oikarinen, Hartikainen, Alasalmi, Rusanen & Pennanen 2007). The map was used to present compactly the distribution grid, PQ components, distribution management systems, work tasks and users of PQ data. These PQ users consist of customers, customer service, technical customer service, network construction, maintenance, measurement service, subcontractors, control centre personnel, grid planning, automation and protection planning, business management and public authorities. The centre of the system is the PowerQ PQNet system, which is used to manage fixed and temporary PQ measurement data. In addition to the PQ data, also weather data is saved in PQNet. There are selected specific nodes from the distribution network for monitoring power quality as follows. One fixed node is located in the substation, one in the middle of the feeder in the context of a remote controlled disconnector and one temporary measurement can be located in some the system of the customer. A part of the mapped plan are also MV/LV transformer station measurements using MxElectrix EQL modules, and an option of fixed LV customer measurements. The PQ mapping project was found useful by the DNO E.ON Kainuu and can be used in PQ planning and developing tasks. (Niskanen et al 2009; Niskanen et al 2007)

3.4 Harmonic wave propagation and distortion location

Power quality is often regarded as voltage quality and the results of the measurements are compared against the EN 50160 standard. However, if customers complain that voltage quality is not sufficient, for example, the cause of distortion source must be located and filtered or otherwise eliminated or the network reinforced. In locating the disturbancies harmonic current measurements could be found useful. From the perspective of distortion location the harmonic current measurements could be divided into steady state and transitory state measurements. The three-phase and neutral current measurements at the POC of customer can reveal each customer contribution to the total harmonic load current in the MV/LV transformer station. The harmonic load currents of each customer flow through the upstream series impedance causing a harmonic voltage drop. The harmonic load currents sum up and can be measured in MV/LV stations. The influences of the harmonic load current on the harmonic voltage are examined later using a propagation theory, but let us first study the current measurements presented in

Figure 17. Four measurement locations are presented: one in MV feeder relay and three in LV terminals of downstream MV/LV stations. The THD measurement may show that the current of each measurement node can be distorted quite a lot. However, by examining the current spectrum from B, C and D MV/LV transformer stations, the share of each harmonic frequency of the total load current, measured by the primary station MV feeder relay A, could be found. Hence, the share of the harmonic current contribution of each MV/LV station of harmonic voltage could be evaluated and further studied if necessary.

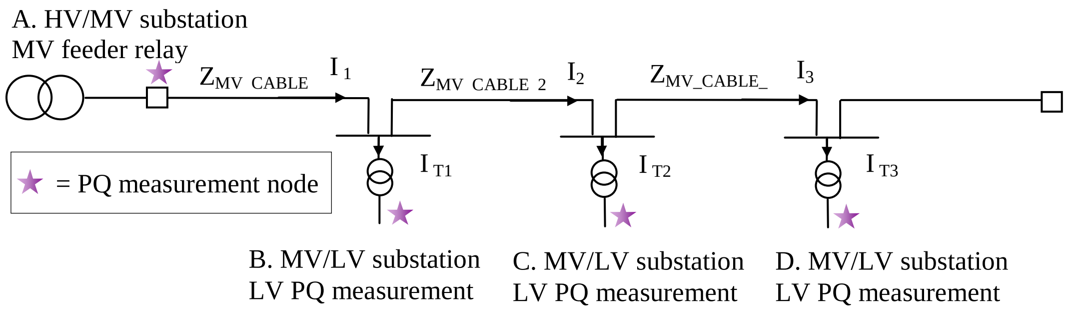


Figure 17. Harmonic frequency current measurement used in evaluating the contribution of MV/LV transformer stations B, C and D to the total harmonic current in the MV feeder A of the primary substation and to the harmonic voltage level specified in EN 50160.

The transitory state analysis assumes that the current peak can be captured. Let us assume that a current peak is captured from station B. The magnitude of the current peak affects the magnitude of the voltage distortion at location B. The voltage distortion can be transmitted to locations C and D. The current peak measurement, located in MV/LV station, could in theory be used to trace the distortion source to one of the measured MV/LV transformer stations and to their LV networks. The distortion is stored in the fault records. New memory techniques enable storing gigabytes of information locally. Hence, memory should not become an obstacle, but the current distortion capturing criteria and automatic analysis methods can be found to be very challenging.

The harmonic wave propagation theory could be used to estimate and evaluate the effects of voltage distortion in different parts of LV grids. The power quality of the LV network has been studied and the results have been published in dissertation (Cobben 2007). The propagation of harmonic voltages on a low voltage level depends on the location of the observation point, the short-circuit power of the source and the location of the disturbance. There has been defined a transfer coefficient, which is the ratio of harmonic voltage at the same moment at these two points as follows:

$$T_{Uh,AB} = \frac{U_{h,A}}{U_{h,B}} \quad , \tag{4}$$

where h is the order of the harmonic frequency,

T_U is transfer coefficient of the voltage signal,

U_A is momentary voltage at location A, and

U_B is momentary voltage at location B.

An example of the transfer coefficient usage and propagation characteristics is presented in (Cobben 2007). This example is also shown in Figure 18. The voltage transfer coefficient is nearly one from the LV busbar of the MV/LV transformer station, A to location B at a 500-meter distance. This means that the voltage distortion at point A is 100 % propagated downstream to the customer connected to location B. This distortion at A can originate from the MV network or the source can be connected to a location near point A in the LV network. The voltage transfer coefficient is nearly 0.1 from the customer at location B to the transformer station at location A. This means that only 10 % of the voltage distortion at location B is propagated to location A. The voltage distortion at location B may result from load current with harmonic content. Although, 10 % of the voltage distortion originating from location B is transmitted to location A and out of it nearly 100 % is propagated to all the LV feeders connected to location A. In reality there is not just one customer with harmonic loads connected to LV feeder from A to B, but multiple customers and harmonic currents sum up thus affecting the overall harmonic voltage. (Cobben 2007)

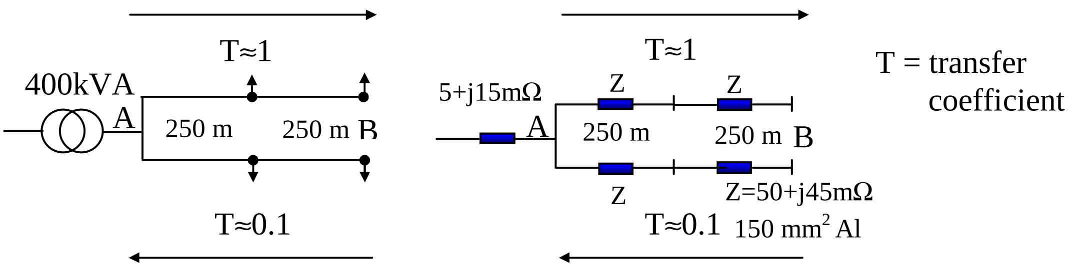


Figure 18. Circuit diagram and its equivalent circuit of harmonic voltage propagation between MV/LV transformer station A and customer connected to the LV feeder at a distance of 500 m B. From location A harmonic voltages are almost entirely transmitted to location B. From B only 10 % is propagated to location A.

3.5 Distortion location function requirements

Faults, e.g. a cable connection fault or a cable insulation fault, can cause transient harmonic voltage. Depending on their characteristics, faults can be classified as transitory, intermittent or permanent. In (Livie, Gale & Wang 2007) LV transitory faults are classified as short non-fuse blowing faults, which may change from intermittent, repetitive fuse blowing faults into permanent faults. The tracking of the source of the intermittent fault, for example, requires a high sampling frequency and trigged power quality records. An intermittent earth fault detection system used in MV networks is presented in (Sauna-aho 2008). It uses the sample frequency of 32 samples per cycle. This sampling frequency is the same as used in the measurement and monitoring device used in MV/LV transformer station, documented in (Hyvärinen et al 2009b; Vamp Ltd 2008). Thus an intermittent fault detection function could use the same hardware. However, a much higher sampling rate and a pulse injection period of 500 µs are used in an LV fault location technique called Time Domain Reflectometer (TDR) (Livie et al 2007; Siew, Soraghan, Stewart, Fisher, Fraser & Asif 2007). In order to catch the distortion and produce fault records, especially of the non-fuse blowing faults, measurements using a high sampling frequency will be needed.

Also, adequate time synchronisation is needed whenever two or more signals are compared or when the cause is investigated. The fault location application determines the needed synchronization accuracy. For instance, the fault location techniques using travelling waves need more accurate synchronisation, but less accuracy is needed in an analysis system in which the MV/LV transformer station measurement can be compared against the MV feeder measurement at the HV/LV substation to see which distortions of MV/LV captured fault records originate from upstream network.

One synchronisation technique is based on global positioning system (GPS). It is documented in (Livie et al 2007) that many available GPS devices can provide 1 μs accuracy, which enables the accuracy of 150 metres, if location techniques based on travelling wave (TW) theory are used. Synchronization is also possible to implement using communication. A broad band wireless network could probably be used to enable synchronisation in the range of a couple of ms. The functionality of GPS synchronization has also been introduced in mobile phones. For example, FreeTimeBox application for Nokia mobile phone is available for time synchronization. Further study could be needed to see if the GPS technology of mobile phones could be used to enhance time synchronization accuracy in MV/LV transformer stations, e.g. in fault location and PQ recordings applications. An extremely accurate time synchronisation could enable transient recording analysis. There are also GPS devices with pulse per second (PPS) output e.g. Garmin GPS 18x LVC, which already offers high accuracy.

Let us consider measurements in the MV/LV transformer station. Distortion can originate from an upstream MV network, MV/LV transformer station, downstream LV network or from a customer network. The switching actions and faults of the MV network are well monitored. Therefore, using an analysis system, MV-related faults could be recognized and eliminated from the list of all possible faults. This would help to recognize LV cable and transformer faults. In (Paszkier, Santander & Gauthier 2007) a solution has been presented to determine the cause of the fault, deduced from PQ recordings and real-time network data. In this system a PQ event is formed from a fault record or from a triggered PQ recording. The PQ event is associated with network components e.g. a substation, feeder or transformer. Correlations are then calculated between the event and the state changes of the quick breaker. These correlations are needed for the following reasons:

- The timestamp of the PQ event does not exactly match with the state change.

- There is a gap between compared timestamps, which also differ.

Therefore, users of the analysis system are asked to select the cause from the list of probable causes. Each cause is weighed by the system on the list of potential causes. After the selection the cause can be associated with the PQ record and can be used in PQ reports for clients, for example. (Paszkier et al 2007)

3.6 Power quality management using filters

The objective of distribution companies is to provide equal distribution service for all the customers. Therefore, installing expensive PQ shaping equipment in the distribution grid is not the primary way for DNOs to manage power quality. However, by using monitoring the low power quality or the distortion source could be localized. After the localization the management includes the selection of a proper PQ improvement method. The following power quality improvement methods can be used to resolve the problem:

- decreasing the disruptive load or by adding extra filters to these loads,
- negotiating with customers about the replacement of the disruptive equipment,
- contracts with customers and the connection requirements of the contract, which comply with PQ standardization,
- passive and active filters, in customer and DNO grids,
- transferring the disruptive customer to another LV grid with less sensitive customers or to a stronger grid, and
- strengthening the grid (Cobben 2007; Mäkinen 2006).

In order to improve power quality with expensive methods such as filters placed in the MV/LV transformer station, financial discussions would probably be needed with the sensitive and disruptive customer (Niskanen et al 2009). However, if the problem occurs and when it is the domestic loads such as energy saving lamps and personal computers that make the harmonic levels rise, the DNO could be obligated or encouraged by the regulator to manage harmonics and reactive power in the future. The installation costs of PQ filters are compensated to some extent by the energy savings achieved using reactive power compensation.

There are plans to equip distribution networks with energy storages e.g. in the Kalasatama project of Helen Electricity Network and its associates in Finland (Hyvärinen 2010). The energy storages are equipped with power electronics. The storages may include a separate AC-DC converter, i.e. rectifier for charging and an DC-AC converter, i.e. inverter for supply or a single converter for both tasks. However, in future applications a single transformer station could be equipped with a combination of an energy storage, active filter and dynamic voltage restorer. In Finland the voltage sags are more common in those primary substation MV feeders which have overhead MV feeders. In urban areas uninterrupted power supply (UPS) devices are standard equipment in the power supply of ICT and healthcare devices. To produce the UPS function the grid-side converter of energy storage should be dimensioned properly in order for the supply and protection to work properly. Therefore, studying and experimenting with shaping power quality should be discussed among Finnish distribution companies in the context of future intelligent grids. The location of the energy storage in the LV network defines whether the control and monitoring system is called secondary substation automation, low voltage automation or something else.

In the LV grid the propagation and properties of harmonics can be taken into account when deciding on actions to shape PQ. The harmonics can be grouped into zero sequence, positive sequence and negative sequence harmonics. This grouping is based on a behavioural analysis of a different harmonic order compared with the fundamental frequency. In Europe this fundamental frequency is 50 Hz. The order of the instant values of the positive sequence harmonics in phases L1, L2 and L3 is the same as that of the fundamental frequency. This group of harmonics includes frequencies 4,7,10,13…In the negative sequence, which includes frequencies 2,5,8,11,…, the order is opposite that of the fundamental frequency. With the triplen harmonic group, which includes harmonics dividable by 3, i.e. 3,6,9,12…, the phase is common to all the three L1, L2 and L3. The triplen harmonic currents cause an increased risk of neutral conductor overloading and voltage distortion, because the impedance of the zero sequence network is bigger than those of positive and negative sequence networks (Ghijselen, Ryckaert & Melkebeek 2004: 181–190). Also, a phase angle difference of 120 degrees between the phases L1, L2 and L3 causes the triplen harmonics to be in the same phase angle in all phases at the same time, which causes the triplen harmonics to sum up in the neutral feeder (Bingham).

The connection diagram of a commonly used DY distribution transformer and the behaviour of some common harmonics is presented Figure 19a. The magnetizing current triplen harmonics are cancelled in the primary winding. Third harmonics are zero sequence harmonics. The zero sequence network does not continue from secondary to primary side. Therefore, third harmonics cannot be measured from the MV side, i.e. they are not propagated through the transformer. The third harmonics are typically emitted from the chopper power sources, i.e. switched mode power supply used in consumer electronics and computers. On the LV side the triplen harmonics cause an increased risk of an overloaded neutral conductor and lower power quality, which may cause malfunction of devices.

Third harmonics can be filtered in the LV network using a third harmonic filter. A typical application for a third harmonic filter is in the distribution transformers of computer centres, where the power sources of the computers produce harmonics. The third harmonic filter design and installation is presented in Figure 19b. The filter is installed in series with the PEN and the grounding point and the star point of the secondary side of the transformer (The ABB Group 1999b). The series connection of the filter increases the risk of a neutral conductor fault, which may cause dangerous situations in the TN-C-S system used in Finland. Therefore, monitoring the neutral conductor is highly recommendable, when a third harmonic filter is used. One potential solution to the breakage detection of the neutral conductor in the transformer station in the TN-C system is to use the voltage imbalance function of MV/LV transformer relay protection. Another possibility in the TN-C system is to add a sensitive overvoltage detection function connected between the neutral terminal and earth of the transformer. The connection points of this measurement are illustrated in Figure 19b. This function should be used to trip the transformer protection relay when voltage, U_g, exceeds the threshold level over. The filter operation, not the neutral conductor breakage, could be monitored with power quality measurements, i.e. by setting threshold levels for power quality events or indications. For example, a spontaneous warning message could be sent, if third harmonics levels exceed the recommended level of EN 50160.

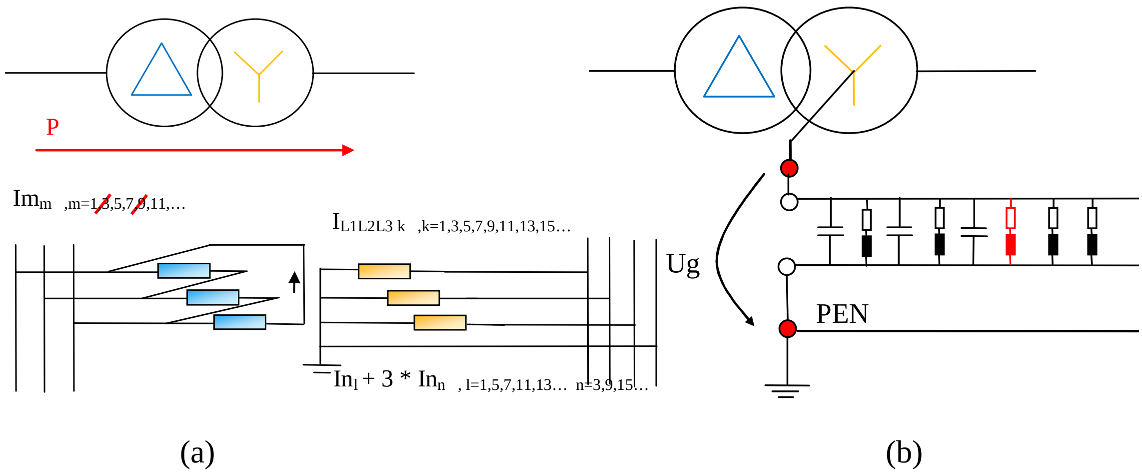
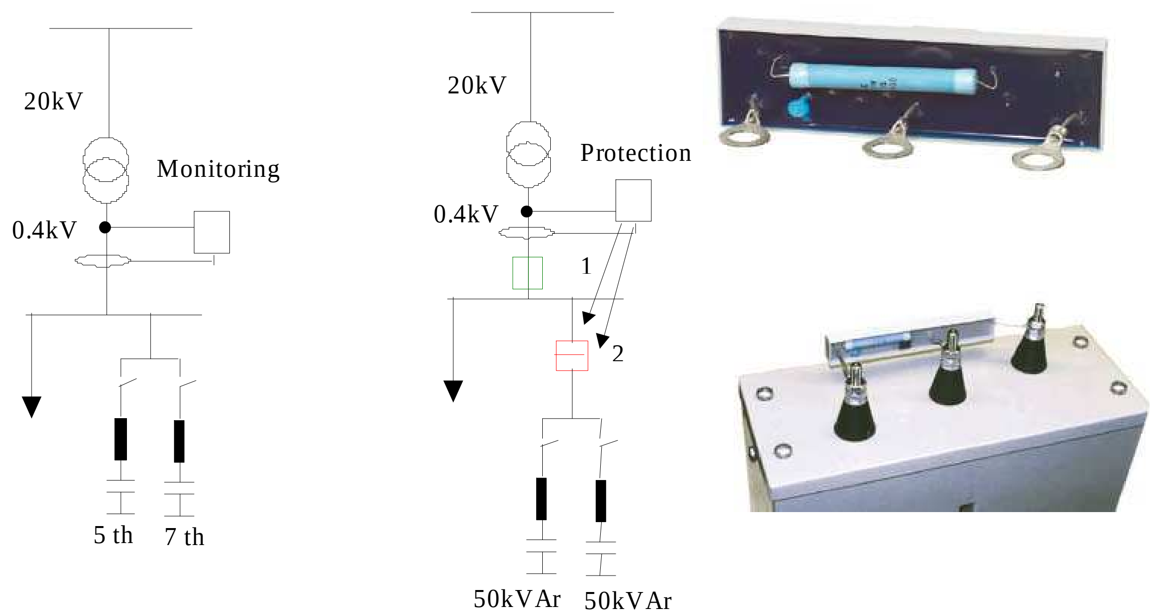


Figure 19. A diagram of DY distribution transformer and the propagation of some common harmonic frequency currents is shown in (**a**). Third harmonic filter design and installation position diagram is shown in (**b**). Overvoltage measurement for neutral breakage detection is shown.

Passive and active filters are used in managing harmonic frequency distortion. Automation management also includes remote control and monitoring applications. These could be included in distribution automation, if the MV/LV transformer station could be found to be an optimal location for filtering. In Finland DNOs rarely use filters, but some customer transformer stations are already equipped with them. The following passive capacitor banks are commonly used: automatic capacitor banks for reactive power compensation, detuned capacitor banks and harmonic filter capacitor banks (Nokian Capacitors 2007). The passive harmonic filter can be designed to filter a certain frequency or to filter frequencies above a certain frequency (De La Rosa 2006: 70–72). However, without blocking reactors passive filters may produce dangerous resonance especially when there are harmonics in the network and the resonance frequency and the frequency of some harmonic is the same. The resonance is a consequence of the equal but opposite reactance of the capacitor and the network (De La Rosa 2006). Therefore, the harmonic level of the network should be known prior to the addition of the filter, and blocking reactors connected in series with capacitors are recommended. The harmonic level of the network can be monitored and analysed, prior to and afterwards the installation of the passive filter with the help of harmonic current measurements. In detuned filters the resonance frequency caused by the network and the capacitor is tuned below the lowest harmonic in the system by adding the blocking reactor in series with the capacitor (Nokian Capacitors 2007).

New functions for MV/LV transformer stations with capacitor banks are shown in Figure 20. A connection diagram of the monitoring device used for the measurement of harmonic current in MV/LV transformer stations with passive filters is presented in Figure 20a. The harmonic level is monitored from the LV busbar. In filter malfunction the harmonic level increases tremendously. The remote monitoring of the operation of the filter, which is connected to the LV busbar of the transformer station, may prevent process interruptions and filter and device damage, because it enables early actions (Tuomainen 2004). On the basis of an alarm of a high level of harmonic current, the operator could remote control the circuit breaker of the feeder of the capacitor bank, dispatch a team or start negotiations with the client. In addition to the monitoring function of the harmonic current, also voltage imbalance, voltage level and voltage harmonic level measurements are useful in MV/LV transformer stations with filters. The voltage imbalance or overvoltage causes stress to the passive filter and may cause damage to the filter and customers devices. The voltage imbalance may be a consequence of a fuse burn. Therefore, the fuse monitoring function is also useful in passive filter applications. (De La Rosa 2006)

In the distribution break or during even a small interruption the charge can be trapped in the passive filters. Normally the electric field of the capacitors of the filter follows the polarity of sinusoidal voltage, but if the supply voltage is interrupted, the capacitors remain charged in the state of the polarity they were immediately before a break. Therefore, recurring short breaks due to recloser action, for instance, increase the risk of high transients, which will follow if capacitors have opposite charged polarities when being connected. This is called capacitance switching. In order to avoid switching to an opposite polarity the capacitor can be discharged before reconnection. For this purpose new electronic discharge devices and a trapped voltage protection with a function sequence shown in Figure 20b could be used. An electronic discharge device connected to the filter terminals is presented in Figure 20c (Nokian Capacitors 2007). Discharging takes time, which depends on the charge in the capacitor bank and on the resistor size of the discharge equipment. Hence a reconnection delay should be used. To achieve this, one possible solution is to use both the information from a busbar protection relay and an intelligent switching of the relay in the feeder of the filter. The LV busbar relay detects the loss of mains. Under voltage protection of the protection relay of the LV busbar, abbreviated U<<< , for instance, could be used to remote trip (1) the circuit breaker of the feeder of the capacitor bank and remote connect (2) when the discharging is done and voltage is restored. In addition to the trapped charge protection the shown relay protection enables the remote disconnection of the LV and filter circuitry.



(a) (b) (c)

Figure 20. New functions for MV/LV transformer stations with capacitor banks. Harmonic monitoring and resonance detection system is shown in (a). Trapped voltage protection with a function sequence (b). An electronic capacitor discharge device (c) (Nokian Capacitors 2007).

3.7 Advanced power quality management systems and communication of MV/LV transformer stations

Unlike passive filters, active filters do not produce connection overvoltages, because the charge will not be trapped in capacitors similarly. The typical structure of active filters contains an inductor, i.e. filter coil and power electronic converter, i.e. switches and capacitor energy storage. The active filter converter is typically controlled in such a way that opposite phase harmonic waveforms are produced and harmonic propagation is reduced or eliminated. In addition to harmonic filtering, the power factor can be corrected by using active filters. In future active filter functions, harmonic filtering and power factor correction could be implemented in the grid side control of the energy storage. Therefore, the management of an active filter by using SCADA and NIS/DMS could be used as a guideline on the management of energy storage applications. Distributed energy storages have been studied e.g. in the ENVADE and PAREE projects under the Finnish DENSY program. Another example of an active filter and energy storage used in MV/LV stations is reported in (Kester et al 2009).

Managements systems and the communication architecture of a MV/LV transformer stations with energy storage are shown on the Figure 21. The communication architecture of this vision is based on the public internet and it consists of Ethernet and IP protocols, transformer centre gateways (GW) and the local IP network in the MV/LV transformer station and the control centre. The IP network enables multiple protocols to be used, which can be used e.g. by energy trade, storage management configuration, remote control, power quality and web-based services. An encrypted virtual private network (VPN) could be used, when the traffic is tunnelled through the public network. Standard IEC protocols are used to control distributed resources and filters. The intelligent logical device of the energy storage could be modelled using the object-oriented structure and architecture defined in IEC 61850 and in its later IEC additions. Advanced management applications of energy storages, including battery management, could be web-based and accessible also from the NIS/DMS system. The communication of the energy storage consists also of that of the configuration of the storage and that of energy trade applications. The power quality measurement of the energy storage could be used in a power quality database, in the NIS/DMS system and in SCADA.

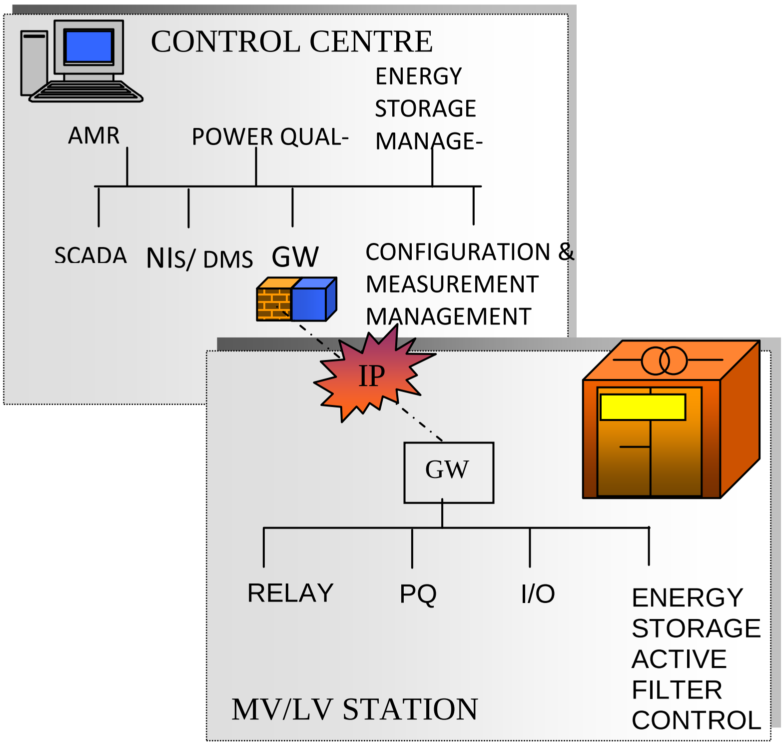


Figure 21. A vision of MV/LV transformer stations with energy storage, management systems and IP -communication architecture.

The SCADA schematic diagram in Figure 22 shows an MV/LV transformer station with an active filter. It consists of the symbols of the disconnectors of the ring unit, the disconnectors of the transformer, the transformer, the relay of the LV busbar, the fuse-switches of the LV feeders, and the relay of the feeder of the active filter. In addition, the active filter (red) and possible measurements and indications are presented.

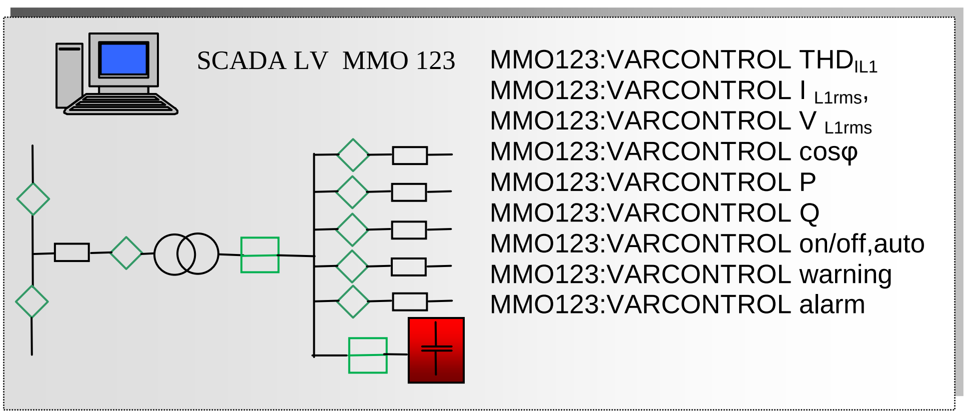


Figure 22. The SCADA schematic diagram of a MV/LV transformer station with an active filter. Examples of possible variables, alarms and warnings of an active filter on the right.

Extensive monitoring of LV processes and of PQ indices with SCADA contain a high number of points for both measured and calculated values. The pricing of SCADA products depends on the number of the points needed. This has provided until now a reasonable way for small and large distribution companies to afford SCADA updates. In order to allow large-scale, multi-value LV monitoring, new SCADA and NIS/DMS pricing ways would be needed. A new pricing that is not based on the number of points could eliminate the unnecessary virtual grouping, structures and condensing of LV information. A relational database, for instance, is capable of handling very large databases and the processing and memory capacity of the information system has increased exponentially. Also, high-speed networks have become available and are developing fast. The actual bottleneck could therefore be the pricing of the SCADA product. Also, DNO work resources are needed for the configuration of the LV network monitor points to be programmed into SCADA. This is expected to be an extensive task (Laaksonen et al 2009).

3.8 Broken neutral conductor detection and broken phase conductor insulation detection

The TN-C system is used to connect the MV/LV DY distribution transformer and the network of the metering cabinets of LV customers. The network of LV customers is TN-S. Therefore, the overall system is called TN-C-S system and it is used in new LV networks in Finland at present. The TN-C abbreviation refers to the coding of the grounding arrangement. In this code, letter T refers to the DY connection of the transformer and to the neutral point of the low voltage side, which is directly earthed. Letter N refers to the exposed conductive parts, which are connected to the neutral conductor. Letter C refers to the combined neutral (N) and protective (PE) conductor. Letter S in TN-S refers to separate N and PE conductors. Usually the translation from TN-C into TN-S is implemented by grounding the PE conductor and linking PE and N busbars in the metering cabinets of the customers. TN-C-S with a broken neutral conductor is presented in Figure 23. The system has combined the N and PE conductor from the transformer to the customer point of connection (POC). In POC the PE is grounded and N and PE separated. The exposed conductive parts of loads and electric equipment are grounded using the PE conductor. The AMR is usually located in the POC of LV customers before the separation of N and PE. (Schneider Electric :75–185)

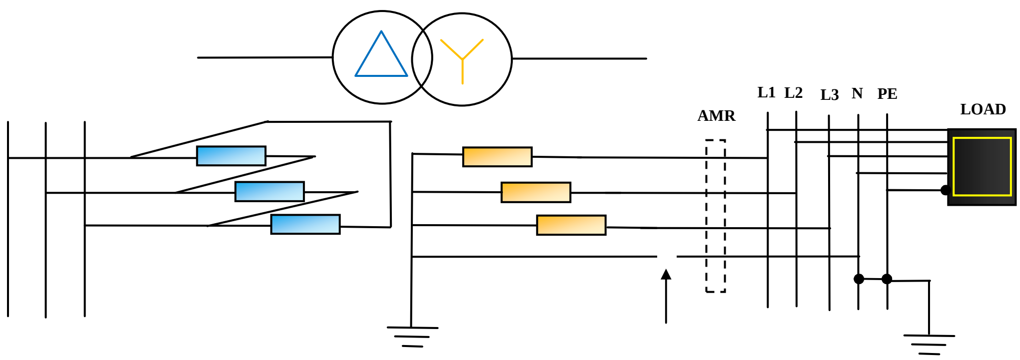


Figure 23. TN-C-S low voltage distribution system used in Finland. An arrow indicates the location of the broken neutral cable.

The direct return path of the single-phase loads to the source is missing, if the neutral cable is broken or missing. When a single single-phase load is switched on, the current drawn by the load may search an alternate route through the ground to the source, but because of the higher resistance, the potential of N busbar changes near the phase potential that the load is connected to. Through the connected load, e.g. an electric stove or a washing machine in the bathroom, the neutral busbar potential changes with the phase conductor potential and through the N and PE busbar joint, also this potential may exist in conductive parts, which are grounded by PE conductors. The impedance of the local earthing rod influences the PE conductor potential and the resistance of earth. Usually also the loads of the customers are distributed into the three phases and a mixture of the loads are connected during the neutral conductor break. Hence, the position of the neutral point can be constantly shifting depending also on the mixture of connected loads e.g. the plates in the electric stove, and the hazardous combination may be found through a terrible misfortune. (Cohen)

Cohen presents the situation and available detection solutions used in Southern African countries, where TN-C-S is used and also the conductivity of the ground is poor because of dry weather in (Cohen). When the neutral conductor connection is missing, three-phase systems that include single-phase loads may experience voltage shifts between the star point and the three phases, depending on the balance of single-phase loads across the three phases. Therefore, overvoltage protection is suggested in addition to the standard earth leakage circuit breakers for customer level protection. Also, an option of monitoring the neutral to earth voltage at the position of N to PE joint is introduced. (Cohen)

AMR-based methods have been presented for missing neutral conductor detection in Finland (Tekla 2011; Keränen 2009; Tryg et al 2008; Järventausta et al 2007). In document (Keränen 2009) two operating principles of AMR-based neutral conductor breakage detection and some detected weaknesses are presented. In the NIS/DMS system there has been developed a function that can determine the fault based on the number and location of the AMR meters which have sent alarms. In overhead networks simultaneous faults may occur due to a stormy weather, for instance. One simultaneous fault is an MV phase fault and LV neutral cable broken fault. An MV phase fault and a broken LV neutral conductor can both cause LV voltage imbalance. Distinguishing the different faults using the unbalanced voltage indication from the AMR meter may be challenging. An algorithm of distinguishing an MV phase fault from a broken LV neutral conductor fault is also introduced in (Keränen 2009). Simultaneous undervoltage and overvoltage or just undervoltage is used for MV fault detection and just overvoltage for the loss of neutral detection. The adjustment of sensitive threshold detection levels can be challenging. Detection based on AMR alarms is also difficult during a major fault, because meters are powered from the grid. If the mains connection is lost, the meter loses both power and connection to control centre. Nevertheless, once the MV missing phase fault is cleared, it improves the probability of detecting neutral cable broken fault.

In a radial network the probability of AMR-based neutral conductor missing detection could be improved by comparing the AMR voltage measurements with the voltage measurements from the LV terminals of the MV/LV transformer. Voltage imbalance, due to an MV fault, can be detected both in the LV terminals of the supplying MV/LV transformer and in the measurements of AMR meters. In neutral cable breakage the voltage imbalance can be seen from AMR phase to neutral voltages measurements only after the breakage point. The phase to phase voltages remain the same also when the neutral cable is absent.

Residual current is a vector sum of the instantaneous values of the current in all the conductors of a circuit at a given point in an electrical installation. Residual current can be measured e.g. by using a toroid coil presented in Figure 24. If the vector sum of the instantaneous values of the current in all the conductors is not zero, a magnetic flux will form in the toroid and a current is induced, which is measured by the RCD circuit. The indication level is adjusted in the RCD circuit. Also, zero sequence current sensor measurements using e.g. Rogowsky coil could improve the accuracy, because the DC saturation of the iron core does not cause problems for RCD sensitivity. Residual current detection (RCD) is one of the techniques that could be used to detect neutral conductor absence, but in the TN-C system the multiple earthing points of the PEN conductor can cause the neutral current to seek new routes through earth resistance and hence make detection difficult. Also, the leakage currents through capacitance between conductors and earth, and the leakage currents of the loads make the RCD level settings difficult. Therefore, RCDs are not recommended for the TN-C system in (Merlin Gerin 2005). The RCD technique is and could be applicable in many parts of the TN-C-S network. The most applicable place for RCD is probably at the separation point of the customer TN-C-S, and if applied, it could be attached to the communication of AMR meters or even integrated to the AMR meter. The usage of the TN-S LV grounding system instead of TN-C would enable RCD usage in multiple-function protection applications, also in MV/LV transformer stations and thus increase safety. At present the RCDs are used primarily in the LV socket installations of transformer stations in Finland, because SFS-EN 6000 states that outdoor LV power socket installations, including those used in park MV/LV transformer stations should be protected with a residual current protection device.

RCD detection usage in TN-C system and in MV/LV transformer stations could be further studied. A separate grounding current measurement could improve the usage of RCD also in the TN-C system. The detection principle is that RCD would detect the changes in recidual current of the main LV feeder of transformer and the extra earth current measurement would detect, if the return route of the leakage current goes through the transformer grounding wire. This enhanced RCD might be used to detect the insulation fault of the phase conductor or the breakage of the neutral cable occurance near the transformer. The placement of such measurement is indicated in Figure 24.

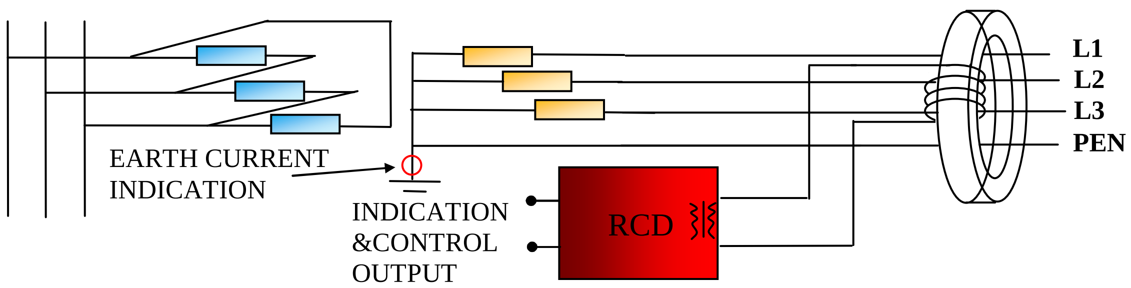


Figure 24. RCD detection using a toroid and the position of an extra earth current measurement. TN-C system.

The appearance of current transformer, attached to both the neutral conductor of the MV/LV transformer and to the phase conductors of the transformer, is presented in Section 2.5.2 and in Figure 9, for example. The presented differential protection enables the detection of LV earth fault currents in the MV/LV transformer, but new functions, let us name them RCD and PEN-N, could also be used to detect insulation faults and neutral cable breakage faults near the transformer. In addition to measurements of the differential protection presented in Figure 9, these new functions require a new PEN conductor current measurement. In normal operation the load imbalance and zero sequence harmonics are seen as zero sequence current. In the TN-C system this zero sequence current uses the PEN conductor as a return path. PEN is used as far as the grounding point of the N-busbar and after that the N conductor is used up to the N-terminal of the transformer. In the phase conductor cable insulation fault the return path of the phase current may be found through the ground or through the ground shield of the cable. Thus, the zero sequence measurements from phase conductors and PEN shows a difference, but this difference differs from measurements of the N conductor and phase conductor zero sequence, because some of the zero sequence current is routed through the ground or the ground shield of the phase conductor. In a neutral cable breakage fault, the PEN and N conductor current difference indicates leakage current that uses transformer grounding as the return path. Thus a PEN cable breakage near the transformer could be detected. The PEN cable detection function is also called neutral cable breakage detection in literature, also because different grounding systems are used worldwide. Further study, simulations and practical tests in different grounding environments are needed to distinguish the correct levels of RCD and PEN-N function settings in order to evaluate its usefulness in detecting phase conductor insulation faults and breakage of neutral conductor near the MV/LV transformer station.

In underground networks fuse-switches are used. An idea of selective cable insulation fault detection and PEN cable breakage fault detection of the faults near the transformer, could possibly be implemented using new optional CTs of fuse-switches. The near transformer fault can be understood as the fault somewhere between the transformer station and the next grounding location of the LV feeder. The RCD function in a TN-C network would require four conductors, L1, L2, L3 and PEN fuse-switch current measurements and the cable grounding before these measurements. The three-phase fuse-switch current transformers are presented in Section 3.10 and in Figure 26 (b). The adding of the fourth neutral fuse could, however, expose the system to the loss of neutral fault, if the fuse of the neutral is blown and that is not detected. At present the fuse-switches used are typically three-phase fuse models and CT is also used in each of the three phases. However, if a four-conductor fuse-switches with optional CTs are used to enable RCD, a short-circuit blade could alternatively be considered instead of the fuse. Instead of a CT in a fuse-switch, an external CT of the neutral conductor could be used to enable RCD or all these four CTs could also be replaced with a zero-sequence current sensor. This RCD function idea for LV feeder fault detection in the TN-C distribution system would require further study and tests. If the function proved to be efficient, the detection system could later be included in the remote control system. Remote control system functions could include the remote disconnection and grounding of the faulted phase conductors using e.g. a motorized switch or a remote spring-powered trip of the fuse-switch. At present also LV relays with residual current protection, such as ABB SACE PR 123, are available. They could possibly be used in order to set up a detection and protection system. It is possible, however, that only-spring powered semi- automatic remote fuse-switch disconnection systems may turn out to be cost-efficient enough for LV distribution networks.

3.9 An application of messaging system intended to increase the safety of the personnel in earth faults

The distributed location techniques of a MV earth fault are being developed in parallel with one- and two-end location methods. A good place for the distributed sensors in a cable network can be found in the MV/LV secondary substation (Kumpulainen et al 2010). In document (Hyvärinen et al 2009b) a zero sequence earth fault current sensor connected to the automation system of the MV/LV transformer station is presented. The earth fault current can produce dangerous step and touch voltages. The earth fault might be the result of broken insulation near the secondary substation. The voltage is the highest at the point where the current enters the ground. Therefore, the personnel are exposed to a risk due the dangerous voltage of the grounded parts caused by the MV earth fault. The risk is high in the MV/LV secondary substation because in the TN-C-S system groundings are connected through LV network groundings also to distant points and because there are grounded metal enclosures near MV grid components with possible faults in insulation of components. The groundings in the MV/LV substation are designed in such a way that the voltage rise should not exceed the limits. However, if the detected earth fault could be automatically informed about, the fault could be isolated and cleared faster and extra safety procedures could be used by the personnel.

Earth fault location techniques are developing constantly. Several techniques are studied and introduced, e.g. earth fault location methods that use zero-sequence impedance calculation and variable transient analysis methods. Once the earth fault can be located accurately, also a warning system can be introduced. The system locates the operative near the earth fault and sends a warning and information to the field the mobile device of the operative. The following idea of a warning system is suitable for many dispersed techniques and it utilizes MV/LV automation and multiple databases. The idea and architecture of a warning system is presented in Figure 25. The measurement of the MV earth fault is in this case based on zero-sequence current and voltage measurements located in the MV/LV transformer station. The measuring device sends an earth fault indication spontaneously to the SCADA system and is transferred to the NIS/DMS system, in which a fault location function can be triggered. The fault records can be downloaded and analysed. The location of the earth fault is calculated on the basis of fault record and network component information. The work management database contains information about scheduled work and it can be expanded to contain information about the location of the personnel. NIS/DMS could use this information in the work management system and send a warning of dangerous step and touch voltages to the personnel. This warning could contain a graphical map of fault location and warning messages. In addition to the personnel, the warning could also be sent to subcontractors. The IP communication architecture enables the operation of the system.

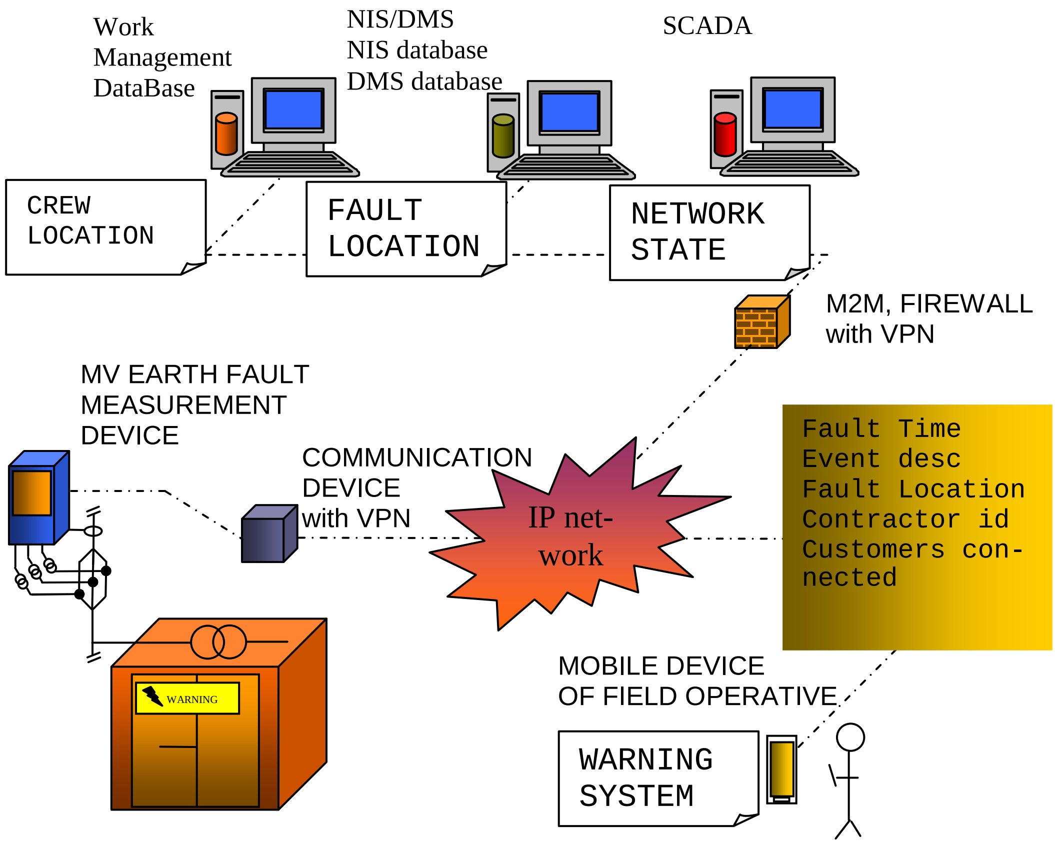


Figure 25. An illustration of step and touch voltage warning and information system based on distributed MV earth fault measurements in the MV/LV transformer stations.

3.10 Personnel and civil safety management, magnetic field exposure limitation applications

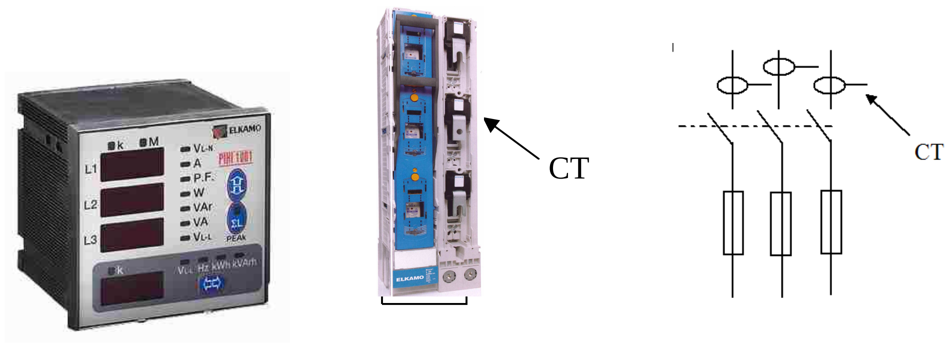
Civilians, DNO personnel and sensitive equipment may be exposed to too high magnetic field of MV/LV building transformers. Instructions for measuring magnetic fields in buildings are presented in document (Jokela 2003). In the recommendations of the Finnish Ministry of Social Affairs and Health there are two values for the maximum density of the magnetic field given: the root means square value, 100 μT and the peak value 140 μT. Recommendations concerning human exposure to the electromagnetic field are specified in e.g. the European Union directive 2004/40/EU and the Finnish Ministry of Social Affairs and Health Act STM 294/2002. The harmonic content of load current affects the peak value, which is determined by high pass filtering the magnetic field measurement and then evaluating the amplitude of the peak. The exposure of the personnel of electric utilities to the magnetic field is studied in a Finnish MS-Safety project and the results are reported in document (Valkealahti 2008). The results show that the exposure is high in work procedures such as measuring the transformer load current from the LV terminals or from LV feeders, changing the LV fuses or resetting the transformer temperature peak load meter. The risk of excessive magnetic field exposure could be reduced as follows:

- using automation, fixed measuring and monitoring equipment instead of manual measurement and checks in high-risk areas,
- using magnetic exposure shields in cable cabinets (Elkamo 2009),
- installing CTs or current sensors to MV/LV installations and using wiring or wireless systems for measuring and checking from a safe distance or remotely, open CT secondary circuits should be avoided (Northcote-Green et al 2006), and
- using field mitigation techniques in design (Hearn, Luternauer & Schiesser 2007). (Valkealahti 2008; Jokela 2003)

The need to go near the high magnetic fields decreases, if automation, fixed measuring and monitoring equipment is used. In many DNO operations only portable devices are used for load measurements. In addition to these, fixed measurement devices are used especially in MV/LV park and building MV/LV transformer stations, installed during the previous two decades. However, these devices are not usually connected to the control centre and therefore the devices do not comply with the distribution automation criteria. An example of this kind of device, quite commonly used in LV measurements in Finland, is presented in Figure 26a. The current, power and voltage measurements are possible with this device. Although remote operation is not commonly used, the risk of exposure to high magnetic fields becomes less, because manual measurements are avoided using a fixed metering device. However, e.g. the power quality and fault diagnostic measurements are not possible using the device shown in Figure 26a. Therefore doing these manual measurements still causes exposure to the magnetic field. The remote measurement could also be used to evaluate the risk of exposure to the personnel, because the risk increases when the transformer loading current increases. Based on the loading profile information of the transformers, the obligatory manual measurements could be scheduled to a non-peak load period.

The risk of magnetic field exposure can be avoided also by using temporary portable measurement devices, if the measurements are made from the auxiliary compartment instead of transformer terminals or LV feeder cables. This is possible, if CTs or current sensors are installed in MV/LV transformer stations before commissioning and they are wired as far as the cross connection in the auxiliary cabinet. If also measurement devices with communication are added, remote procedures become possible. This can save time and provide accurate real-time information for decision making. A fuse-switch -unit with compliant integrated optional current transformers are presented in Figure 26b. These CTs enable, if they are installed and wired prior to powering the LV grid, automatic or manual LV current measurements from a safe distance of the magnetic source. Hence measurements are possible without high magnetic field exposure e.g. from an auxiliary compartment of MV/LV station. A diagram of a fuse-switch with current measurements is presented in Figure 26c. The reader may notice that the CTs are installed before the switch in the normal supply direction and therefore can be used also by e.g. fuse blow detection and load control functions.

A detailed construction drawing of the transformer station could be attached to NIS/DMS network information with the information from magnetic field measurements. Magnetic fields produced by the distribution system follow Ampere´s law. Therefore, the information in the drawings and the monitoring of the peak loading and harmonic content of the transformer during these peaks makes it possible for the user of the NIS/DMS system to analyze even the worst risks of exposure. In the analysis function graphical symbols could be used to present the risk points on the map and in the construction drawing. This analysis could reveal risk points, in which mitigation techniques could be used to reduce the risk. Also, scheduling work can be used to do the high- risk tasks in a non-peak period.



(a) (b) (c)

Figure 26. Avoiding exposure to magnetic fields by using fixed measurement devices. One current, voltage and power measurement device, commonly used in Finnish MV/LV transformer stations **(a)** (Elkamo). Integrated optional CTs in a LV fuse-switch (Efen) (**b**). The location of the current measurements in the diagram of the fuse-switch (**c**).

3.11 Overvoltage monitoring system using information from a lightning radar system, weather station, NIS/DMS and PQ devices

Lightning is formed when particles in the clouds having opposite polarity interact. There are cloud lightning and earth lightning. Cloud lightning occurs more frequently than earth lightning. The operation of lightning radars is based on sensors that are used to triangulate the location of the lightning, based on the signal delay. The precision of the system depends on the density of the sensors in the sensor grid and the intensity of the lightning. The present location precision is about 500 meters. The lightning locator has a delay of approximately 10 seconds and the typical lightning density is approximately 60 cases of lightning per 100 km^2 per year. The climate change will affect the occurrence of lightning due the warming climate (Martikainen 2006). The most common effect caused by lightning is overvoltage that is transmitted to the network by conduction from a stroke into a tree or high structure nearby. According to a study about the network of E.ON Kainuu, out of all the faults cleared by speed reclosing 27 % is estimated to be caused by lightning and with the help of the MO surge arrester the number of speed recloses can reduced in the overhead network (Parviainen 2008). In the MV overhead network the voltages induced by a nearby lightning stroke are more common than in the cable network. However, antennas used for telecommunication and the high structures of distributed generation expose the distribution systems to the effects of lightning. (Mäkelä 2009)

DNOs use weather services, which may include the co-ordinate data of lightning radars. It can be used by DNOs to evaluate the lightning activity in the distribution grid area. The radar system provides some possibilities to monitor the occurrence of lightning. The lightning stroke co-ordinates from the radar system and the grid co-ordinates from the NIS/DMS system could be compared to evaluate the probability of a lightning stroke near the network. This co-ordinate information, PQ information and the relay action information could be used to dispatch the field crew and to evaluate the severity of the impact needed for customer and fault reports. In addition, in the document (Kagan, Matsuo, Duarte, Itocazo, Ferrari, Vasconcelos, Domingues, Rodrigues & Monteiro 2007) procedures are presented to determine whether lightning strokes can damage the equipment of low voltage customers. The distance between the striking point and the given customer, as well as the withstand capability level of a given piece of equipment are needed for evaluation of damages due lightning. The history of lightning co-ordinates could be also used when protection against lightning overvoltages is planned or when recommendations are given.

Figure 27 presents an idea of a monitoring system, which could be used for the monitoring of lightning effects. The system consists of control centre and distributed systems. In the control centre, the power quality database, SCADA and NIS/DMS systems are used. SCADA receives the action data of the relay of the MV feeder. The local weather station provides e.g. wind, pressure, humidity and temperature data. The lightning radar service provides earth lightning co-ordinates. The power quality system in the MV/LV transformer station provides overvoltage information. The operator is sent automatically a power quality or interruption report, which could be used in reporting to complaining customers.

The basis of this PQ event managing system is presented in document (Paszkier et al 2007). In comparison with (Paszkier et al 2007) the idea presented in Figure 27 is enriched with PQ system data presented in (Niskanen et al 2007) and lightning radar information data presented in (Mäkelä 2009).

The overvoltages in the LV grid can be monitored with PQ monitoring units, e.g. devices presented in Table 1in Section 4.3. There are three major causes for temporary overvoltages in the LV grid: lightning, switching and capacitive switching. Based on the PQ analysis system presented in document (Paszkier et al 2007) a solution has been offered to determine the cause of the fault from PQ recordings and real-time network data. In the system of Figure 27 the PQ measurement system sends a PQ event. The PQ event is associated with a network component, a substation, feeder or transformer in the NIS/DMS system, for instance. Correlations can then be calculated between the event and the state changes of the quick breaker. In the MV/LV transformer station a PQ device measures voltage quality. In lightning nearby the voltage is induced into the network, and after the threshold value is exceeded, a power quality event is sent spontaneously. Based on this PQ event a power quality record can be downloaded by the PQ database system. SCADA receives information from the MV feeder relay if the induced overvoltage causes relay action in the primary substation or in the intermediate relay. The information of a PQ event and SCADA relay action are compared with each other in the NIS/DMS system. Weather data is collected from the lightning radar and from the local weather station. Based on this weather data, e.g. a thunder storm and lightning near the distribution grid are detected. In a thunder storm the speed of wind can fluctuate and increase heavily. The weather data, especially the lightning stroke co-ordinates provided by the lightning radar can be then associated with the action of the quick recloser and with the measured overvoltage event. Similarly, other PQ events could be associated with network or weather events. The functionality of NIS/DMS could be used to estimate which components may have been damaged. Something may have been damaged, when the lightning strikes a tree or a thunder storm fells trees close to the distribution grid. A power quality report could be sent automatically to the operator and further to complaining customers or those customers that have ordered the PQ reporting service of DNO. For the majority of customers the interruption statistics, i.e. the start and end time of the interruption may be sufficient.

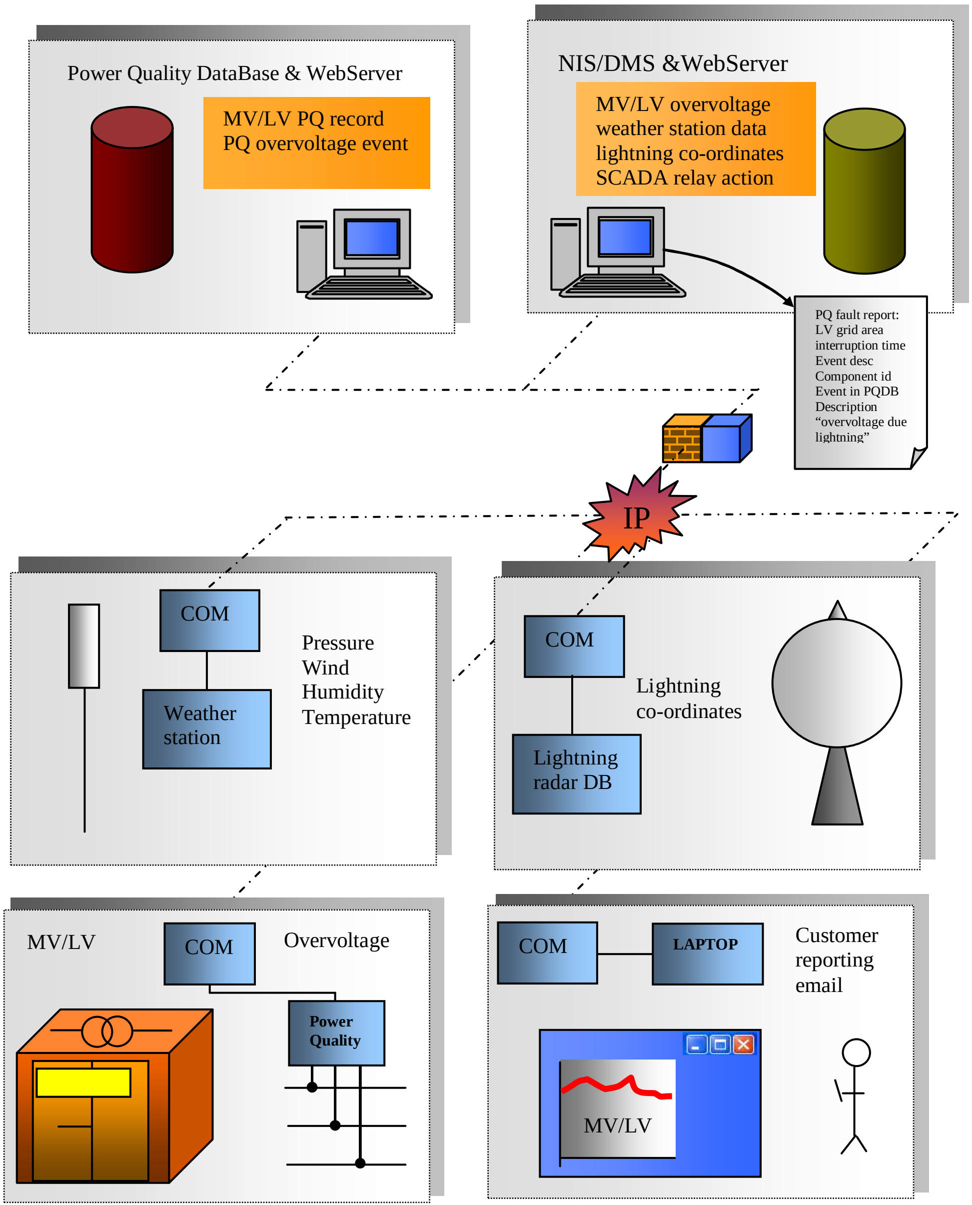


Figure 27. A monitoring system for estimating the effects of weather and lightning on power quality of customers.

4 INFORMATION AND COMMUNICATION TECHNOLOGY

In this chapter four information and communication technologies that utilize information from the MV/LV transformer stations and the LV grids are discussed, including hardware and software. Because the MV/LV transformer station and the LV grid can be seen as a link between the MV distribution network and the LV customers, also the substation, feeder and home automation are discussed mainly from the perspectives of protocol integration and synergy. Communication enables the remote procedures of distribution automation and hence it also enables a variety of DNO processes, which are referred to in other chapters. Control centre systems are essential on the ICT platform of DNOs. The ICT platform consists of local and remote systems, protocols and interfaces, also used to manage information from MV/LV stations and LV grids. At present serial communication is commonly used in the communication of two directly connected devices in MV/LV transformer stations. The IP and IEC 61850 protocols are, however, utilized in the majority of the communication platforms of new primary substations. Therefore, the chapter deals with the utilization of presently used serial and future IP communication in the intra- or intercommunication of MV/LV transformer stations and LV grids.

In Chapter one the term DA, published in (Basset et al 1988), was introduced. It includes the requirements of the communication system in words “remote monitor, coordinate and operate”. Although many MV/LV transformer stations have been equipped e.g. with a monitor and measurement device in Finland, the lack of communication has not enabled DA so far. In Chapters two and three functions for “remote monitoring, coordination and operation” were introduced. In this chapter the focus is on the word “remote”, i.e. ICT systems enabling remote control, monitoring and protection-related functions which utilize ICT. Let us consider a visionary SCADA schematic diagram of the MV/LV transformer station presented in Figure 28. The control consists of the remote controlled MV disconnectors of the ring unit (1), a transformer protection relay (2), an LV busbar relay (3), the status information of fuse-switches (4) and different measurements and indications, for instance the transformer temperature measurement (5). The ICT architecture of Figure 21 enables the remote functions needed for the monitoring and control of the system presented in Figure 28. The architecture consists of control centre level systems, the communication system of the long- distance link and MV/LV transformer station level systems. These levels can be seen also in the DA systems of the present and piloted MV/LV transformer stations introduced in Chapters one, two and three. In addition to the systems in the control centre and transformer stations, the ICT architecture also contains communication protocols, some of which are specific for electric distribution applications.

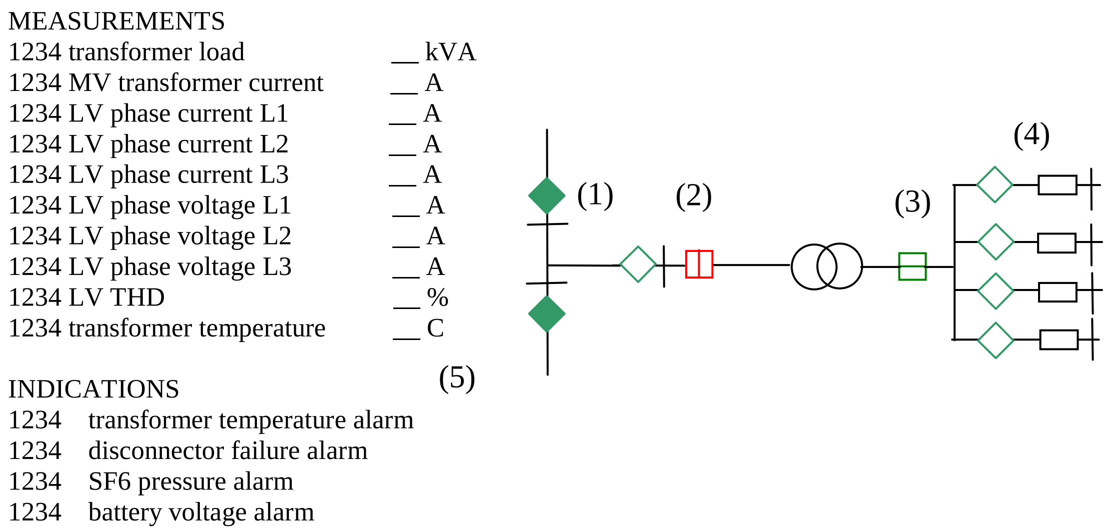


Figure 28. An example of remote control and monitoring of the MV/LV transformer station. ICT is needed to enable the shown functionality.

4.1 Horizontal and vertical communication of the MV/LV transformer station automation

In the communication of distribution automation there can be seen both horizontal and vertical communication. Vertical communication can consist of the traffic from the control centre system, e.g. SCADA, up to the substation computer or the intelligent electronic device (IED) through the local area network of the control centre, the long-distance link gateway, e.g. M2M server, the internet or the private network and the long-distance gateway of the MV/LV transformer station. Horizontal communication is information exchange between control centre systems, for instance, commonly using Ethernet-based local area network (LAN) and IP protocols. The control centre systems introduced in Chapters one, two and three consist of SCADA, NIS/DMS, power quality database and vendor- related management systems. (Laaksonen et al 2009, Hyvärinen et al 2009a)

Let us examine communication of the DA system, which is used to manage the MV/LV transformer station and the LV grid presented in Figure 21. When systems in the control centre communicate using information originally received from the distribution transformer station or they exchange information about components of the transformer station, this is can be said to form control centre level intra information exchange and also called horizontal communication. Vertical communication, from the bottom up, starts from the MV/LV transformer station. Actually, vertical communication starts from different sensors e.g. the current transformer, but the intelligence of the communication is in devices that are traditionally called remote terminal units (RTU). At present there are also devices capable of local communication, called remote monitoring and control units (RMCU) e.g. ABB REC 523 and measuring and monitoring units (MMU), e.g. VAMP WIMOTEC 6CP10. Long-distance link communication is typically implemented using an integrated or external communication device. If a public IP network is used, this device can be called a gateway, because it can be used to provide a connection to a remote location. Figure 21 showed also the position of the communication device of the long-distance link and, by using it, the intelligent electronic devices can be connected to the control centre LAN and to the distribution management systems. (The ABB Group 2008; Vamp Ltd 2008)

4.2 Protocol theory, OSI and IP protocol stacks

A protocol is needed to interchange data between two systems. In order for communication to succeed, not only the electrical characteristic of the physical media, but also the format of the transmitted data blocks, control of transmission, error handling, speed matching and transmission sequencing must be agreed on by the two systems. This is done using the rules of conventions, i.e. a protocol, which must be the same at both the ends. The term protocol architecture is introduced when different functions needed for communication are implemented in the subtasks of layered modules. These modules form a vertical stack, in which the modules provide services for the module of the next layer. The best-known models of protocol stack are the OSI, i.e. ISO 7498 and IP protocol stack models. The OSI reference model and the function of the layers are referred to, when the protocol structure of protocols used in distribution automation communication is discussed. The physical interface introduced in Section 4.3 corresponds to OSI model layer 1. The IP model is referred to when new distribution automation protocols e.g. IEC 61850 are discussed. Therefore, also the theory of the protocol reference model and the IP model are briefly dealt with.

Layer 1 defines the electrical functional and procedural characteristics of the physical medium and also the connector types. Layer 2, a data link layer, is used to define reliable communication. The communication is framed, i.e. split into data blocks with a header and trailer added to them. The information in the header and trailer are used for synchronization, error control and flow control functions. Layer 3 is a network layer, which is used to establish a connection path between two systems. Also, the packet routing of packet-switched networks is implemented using layer 3. Layer 4 is a transport layer. It is used to control transmission e.g. to provide error recovery and flow control. Layer 4, similar to the previous layers, uses functions provided by the lower layer and provides an application interface for the upper layer. Layer 5 is a session layer, which is used to establish, manage and terminate the connections of applications. The next upper layer 6 is the presentation layer, which is used to manipulate the data structure and representation syntax of communication applications. Finally, on top of stack, is layer 7, the application layer, which is used to access the protocol stack by the applications and to provide management functions. (Stallings 2004)

In layer 7 a header is added to the data before the message containing the data is passed on downwards to layer 6. When the message is received and processed at the other end by a similar protocol stack and the information in the header is used as parameters of the functions of the protocol, the header is removed. All the headers and trailers added by different layers produce overhead to the data, which is passed on to the protocol stack by the applications. The header and trailer information is essential for the operation of functions of different layers, but the added overhead causes delay in narrow communication channels. The distribution automation applications need a timestamp of the occurrence of the event. Therefore, the clocks used in different locations need to be synchronized and they can be synchronized by using the communication channel. In the design of distribution protocols the need for a timestamp, accurate synchronization and other mechanisms needed for real-time control and monitoring have been taken into account. These can be seen when the design and implementation of distribution automation communication protocols are examined and compared against the OSI model. However, the optimizations done in the design of the distribution protocols are not discussed in detail here, but this chapter aims to give an overview of DA communication. Communication technology is rapidly developing and a larger bandwidth has become available also for distribution automation applications. Also, the use of IP protocols and packet-switched networks has increased also in distribution automation. Therefore, the IP protocol architecture will be discussed briefly.

The TCP/IP protocol architecture, published in RFC1122, consists of a protocol suite and functionality description. The protocol suite has developed over the years and so is the underlying technology. The protocols of TCP/IP are in five layers, but their functionality corresponds to the seven layers of the OSI model. The physical layer, layer 1 of TCP/IP stack, specifies the characteristics of the physical medium. The next two-plus-half layer is used for network access, addressing and switching the packets, also called protocol data units (PDU), in the network based on the address attached to the header of the PDU by the sender. The protocols used in this layer two-plus-half depend on the type of network used. In the Ethernet/IP architecture the Ethernet protocol is used in layer 2. The Ethernet/IP architecture is quite commonly used in distribution automation and it can contain the same upper layer protocols as the TCP/IP architecture. Layer 3 is an internet layer and the protocol used is internet protocol (IP), defined in RFC 791. The IP protocol adds, among other parameters, the source and destination addresses. Based on the destination address, the PDUs, i.e. IP packets, are routed from the sender to the receiver in a multi-network system also called the intranet or the internet. The layer four-plus-half is referred to as a transport layer and the most commonly used protocol is transmission control protocol TCP. TCP is used to provide a reliable connection between the source and destination applications. Another protocol in layer 4 is user datagram protocol UDP, which does not guarantee a reliable connection. Both these protocols provide sockets, i.e. ports, for each connection and applications. Finally, at the top of the TCP/IP stack is an application layer, which provides different mechanisms for different applications. (Stallings 2004)

4.3 Serial communication interfaces used in MV/LV transformer station automation

The intra-communication of the MV/LV transformer station serial communication is widely used at present. An RTU, RMCU, MMU, I/O unit or a relay must be accompanied by an integrated or external communication device, which enables connections to the control centre systems. Also, the distribution protocols used may need to be changed before the data is sent; hence a protocol conversion device may be included in the communication device. At present ABB REC 523 or WIMOTEC 6CP10 devices make use of an external communication device, which is connected via a standardized serial interface e.g. RS-232 or RS 485 to the devices above. A standardized interface enables the usage of different communication media, such as power line carrier (PLC), also called digital line carrier (DLC), of a mobile network, radio modems and so on.

The ANSI/EIA standard serial interface RS-232 (EIA RS-232-C 1969) was originally developed for communication between a computer and a modem. In addition to the limitation of only these two devices per bus, it has a limitation of maximum cable length of approximately 15 meters and that of noise immunity. Despite these disadvantages, the RS-232 interface is widely used and has in many cases provided a sufficient, standard and commonly known interface, which has enabled the connection of a variety of devices. The ANSI/EIA standard serial interface RS-485 (EIA RS-485 1983) defines the electrical characteristics of the serial bus. It does not define the syntax needed for communication and thus it needs an accompanying protocol before the communication can be established. In comparison with RS-232, RS-485 makes it possible to connect multiple devices to a single bus. Also, the noise immunity is better and the bus length bigger. Engineers usually need an RS232/RS485 converter in order to configure devices that have only a single RS485 port.

4.4 Serial communication protocols used in MV/LV transformer station automation

A variety of protocols are used in MV/LV transformer station communication applications. An overview of these is given in Table 1, where protocols used in four monitoring devices are briefly reviewed. The Modbus protocol appears to be the default in the four devices. The IEC 60870-5 protocols 101 or 103 are implemented in all these devices, except for Janitza. Janitza is probably intended for industrial applications, but it has a variety of ETH/IP protocols and internet functions, which the others do not have.

Table 1. A review of serial protocols used in four monitoring devices. (The ABB Group 2008; Vamp Ltd 2008; Siemens 2008: 13/3-13/18; Janitza 2009)

			
ABB REC 523	VAMP WIMO 6CP10	SIEMENS P600	JANITZA UMG 605
RS-232 / 1 port RS-485 / 1 port	RS-232 / 1 port	RS-485 / 1 port	RS-485 / 2 port RS-232 / 1 port
Modbus (RTU / ASCII) SPA bus LON	Modbus, RTU Spa Bus	Modbus RTU/ASCII	Modbus RTU
IEC 60870-5-101 DNP 3.0	IEC 60870-5-101 IEC 60870-5-103 DNP 3.0	IEC 60870-5-103	
		PROFIBUS DP	PROFIBUS DP

IEC 60870-5 standard is product of working group 3 (WG3) of IEC technical committee 57 (TC57) and the first parts were published in 1994. In parts 5-1 to 5-5 the layers 1, 2 and 7 in the Open Systems Interconnection Reference Model (OSI) are defined. The functionality of layers 3, 4, 5 and 6 are left to be implemented in layer 7. The protocol is founded on the serial communication of two devices and, among other things, it defines the functionality of the optional error check calculation and that of the time stamp. In addition to standards 60870-5-1 through 60870-5-5, the IEC Technical Committee 57 also generated the following 60870-5 companion standards:

- IEC 60870-5-101 Transmission Protocols, companion standards especially for basic telecontrol tasks,

- IEC 60870-5-102 Companion standard for the transmission of integrated totals in electric power systems,
- IEC 60870-5-103 Transmission protocols, Companion standard for the informative interface of protection equipment, and
- IEC 60870-5-104 Transmission Protocols, Network access for IEC 60870-5-101 using standard transport profiles (IEC 60870-5-Ser 1994).

Protocols IEC 60870-5-101 and -103 are actually profiles that use structures defined in parts 5-1, 5-2, 5-3, 5-4 and 5-5. These are also implemented in the devices of Table 1. Protocols 5-101 and 5-103 are both designed to be efficient in binary information transfer and in transfer that includes time stamps and both indication and control messages. In addition to this communication, IEC 60870-5-103 supports disturbance file transfer, too. IEC 60870-5-101 can be used in two modes. In the unbalanced mode the SCADA system is the master and RTUs are slaves. Acquisition is implemented by polling the slaves. Because of the limitation of only two devices in RS-232 connection, multiple clients could only be connected to a single master using RS-485. In the balanced mode one acquisition device is connected to multiple RTUs using multiple physical connections, i.e. ports in the acquisition device. Both of the devices in the same physical connection can initiate the information transfer. IEC 60870-5-103 protocol was designed for the arrangement used in primary substation including relays and RTU. RTU actually refers to a device consisting of the substation computer and the protocol gateway device. In this protocol RTU is the master requesting data by polling the relay slaves. Multiple relays are connected using the RS-485 bus or an optical link. (Vähämäki 2009)

The distance from the MV/LV transformer station to the SCADA system is usually far more than 15 meters, which is the limitation of RS-232. The distance is actually even more than the cable length limitation of RS-485. Therefore, when IEC 101 or 103 are used, the protocol is either tunnelled to the long-distance link or converted to e.g. IEC 60870-5-104 before being transferred. The link to the control centre can be implemented using e.g. a power network, i.e. power line carrier (PLC), mobile network, radio network or a fibre optic cable. The variety of media usually means that an external communication device is used, which is selected on basis of the chosen physical media.

One example of an external communication device suitable for the tunnelling of serial protocols is radio modem Satel Satelline (Satel 2010). (Vähämäki 2009)

4.5 New communication interfaces

A common serial interface in PCs and other devices is the universal serial bus, USB. It is a standard of the USB-Implementers-Forum. In many embedded platforms the USB interface has been used to program and configure the device. The architecture is that of master/slave. A new addition to the standard USB OTG (On-to-go) makes it possible for a single device to act both as a master and a slave. This could make it possible e.g. in future RTU applications to use the same USB port first for device configuration using a laptop and then for the connection to a communication device. USB enables also wireless communication using 3G WAN or devices such as USB memory or extended I/O. (USB-IF 2011)

Ethernet has almost replaced serial interfaces in industrial applications. It is frame-based and packet-switched communication for local area networks and is defined in the IEEE 802.3 standard (IEEE 802.3 2008). Devices e.g. PLCs, i.e. programmable logic controllers and motor drives use Ethernet. The physical media can use a twisted pair or fibre-optic cable. Due to the high magnetic field of the transformer and LV feeders, noise may be induced to the communication channel. Therefore, twisted pair, shielded twisted pair and optical cables are better in the harsh environment of the transformer station. IP protocols and especially IEC 61850 are extensively used in substation communication applications. Multiple devices such as RTUs, relays and in the future also sensors (e.g. current transformers) can be connected to the ETH bus. One example of an external communication device suitable for Ethernet and IP protocol tunnelling for a long-distance link is a radio modem called Satel IP-Link (Satel 2010).

USB and ETH enable a broad range of possibilities for applications communication using the IP protocol. Although the need for high-speed and small-delay communication in secondary substations is not as essential as in primary substations, these interfaces enable future applications and the use of standard IP protocols. A variety of standard serial protocols have been used in the communication with the intelligent electronic devices used in the transformer station. These devices include e.g. a monitor and control, a remote I/O and a communication device. The usage of IEC and DNP serial protocols has provided both economical and efficient enough solutions to the SCADA connection at present. However, there can be seen significant changes that signal a need for interface improvements also in devices used in secondary substation applications. These are e.g. the following:

- widespread and developing use of an object-oriented architecture, e.g. IEC 61850,
- high sampling rate and the larger size of failure records, dispersed fault detection and protection algorithms,
- need for improved communication due to demand control and energy storage applications,
- rapid development of wireless high-speed networks e.g. 3G and 4G,
- expiry and extinction of the RS-232 interface from personal computers, programmable logic controllers and embedded printable circuit broads, and
- implementation of USB, Ethernet and wireless interfaces used in industrial and personal IT equipment.

A device with Ethernet interface and a flash memory card is presented in Figure 29.

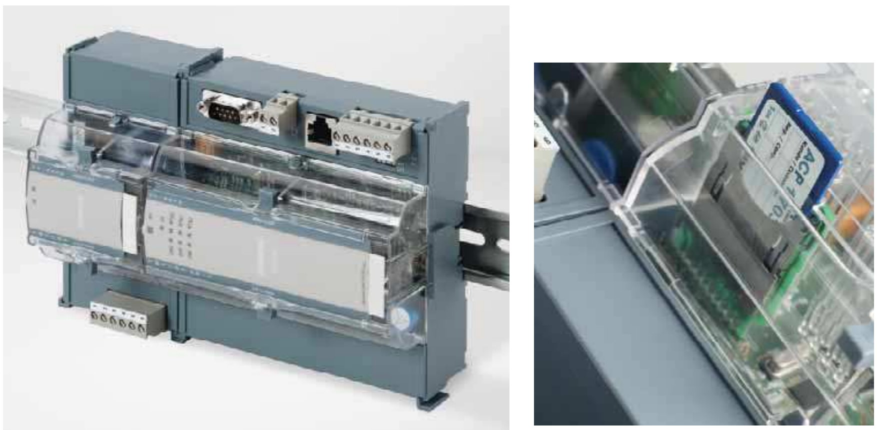


Figure 29. Siemens Sicam Terminal Module 1703 Emic provides both serial and Ethernet interfaces. The device supports IEC 60870-5-104 and DNPi over Ethernet TCP/IP. The flash memory card enables e.g. a servicing function. (Siemens 2009)

4.6 Object oriented architecture of IEC 61850

The IEC 61850 standard, Communication networks and systems in substations, was made by the same IEC committee 57 as IEC 60870-5, but it was later published. The parts and their descriptions are shown in Table A2 of Appendix 2. The implementation of this standard is based on a specified data model and communication mappings with Ethernet and IP based protocols. This standard includes the exchange of real-time data indications, control operations, and report notification. The physical media and devices of the primary substation applications are an Ethernet switch or router, station computer, relays and twisted pair cables or optical fibre cables. The use of IEC 61850 is spreading into applications outside the primary substation, such as distributed generation applications and it is even been proposed for home automation applications (Rintamäki & Kauhaniemi 2009; Nestle, Bendel & Ringelstein 2007).

The usage of IEC 61850 allows DNOs to manage the automation functions needed in substation automation in an inter-operative and multi-vendor way. The automation functions specified in IEC 61850 can be grouped into system support functions, operational and control functions, process automation functions and maintenance and system configuration functions. The standard uses the object model, the objectives of which are to increase the transparency of automation functions, improve the usage of modular construction methods and utilize the object-oriented data structures, algorithms and architectures. The specified data structure is presented in Figure 30. In the figure the structures specified by IEC 61850 are visualized in a protection relay form, although the standard can be used in other automation equipment as well. The relay is a physical device, connected to the network and having an IP address. A physical device, also called an intelligent electronic device (IED), can be regarded as a container, which contains multiple virtual devices. The IEC 61850 data model architecture, i.e. the structure contained by IED is hierarchical. It includes one more servers, which are not shown in Figure 30. The functionality is split into virtual devices, called logical devices that perform a certain functionality of IED, e.g. protection or control. Logical devices have multiple logical nodes, which are the virtual structures that are used to exchange data. One example of a logical node of the protection relay is the PTOC overcurrent protection logical node. In the data structure hierarchy the logical node contains multiple data objects, which e.g. in the case of PTOC specify the aspects of information used by the overcurrent protection function. Finally, the data objects contain data attributes. (Ekanayake, Jenkins, Liyanage, Wu & Yokoyama 2012: 65-67)

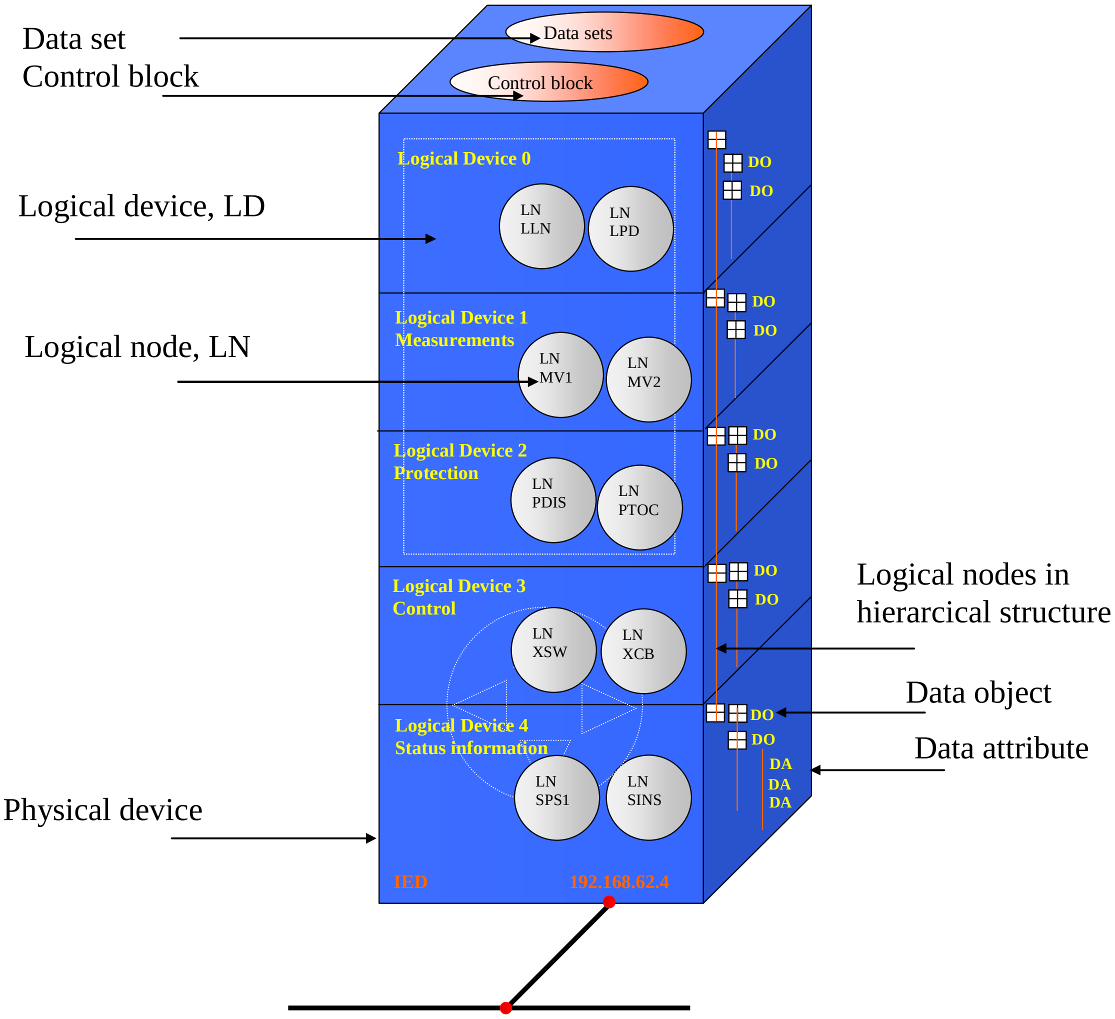


Figure 30. IEC 61850 data structure.

In addition to the data model, IEC 61850 also specifies an information exchange model, which includes e.g. an ASCI interface and object model structures such as data sets and control blocks. The abstract communication interface (ACSI) is specified in part 61850-7-2 and it is used in the implementation of the service interfaces, one for the client server and the other for application to application communication. The data set is a container object, which is used to contain the references of data objects and data attributes that are needed in information exchange. An example of the information exchange is an event e.g. an overcurrent protection trip. The sending of e.g. the PTOC trip event is controlled by an object model structure called control block and in this information exchange the data set objects are used to convey information. (Hammer & Sivertsen 2008)

4.7 Communication architecture of IEC 61850

Part 61850-8-1 of the standard specifies a method of exchanging time-critical and non-time-critical data through local-area networks by mapping ACSI to MMS and ISO/IEC 8802-3 frames (IEC 61850-8-1 2011a). The Manufacturing Message Specification (MMS) is an international standard (ISO 9506) dealing with a messaging system for transferring real-time process data and supervisory control information between networked devices and/or computer applications. It is the OSI layer seven protocol, which is specified in ISO standards 9506-1 and 9506-2. The MMS is more commonly used above the TCP, IP, Ethernet and physical layers of the TCP/IP stack. However, apart from the typical TCP/IP stack, which has only one application layer, the MMS view of network also includes OSI layer 5, session layer and OSI layer 6, presentation layer. (Sisco 1995: 2–4)

The MMS is not the only mapping specified in part IEC 61850-8-1. Sampled values, GOOSE and generic substation state event (GSSE) messages are mapped to Ethernet layer, ISO 8802-3 protocol. GOOSE is an abbreviation of generic object oriented substation events and it is used to execute fast messaging, e.g. by the protection functions interlock and the remote trip, which require fast communication between the protection relay and the station computer and other relays. GOOSE also supports virtual local area network (VLAN) technology and priority tagging. Through the use of VLAN the broadcast zone of a switched network can be limited. Priority tagging enables the prioritising of packets, if congestion occurs in the switch. The VLAN and Ethernet packet priority through tagging are both properties of the Ethernet switch. Gigabit Ethernet support was added to 61850-8-1 in 2011. Since 2001 some Gigabit routers have been capable of routing and switching the traffic in wire-speed, i.e. without packet loss (Nyberg 2001). Hence the optimising of mapping to ISO 8802-3 instead of the MMS is done also to support slower Ethernet networks and routing based on hardware or software. In MV/LV transformer station communication the IEC 61850 Ethernet communication could be used in a similar way as in primary substations e.g. to interconnect remote the I/O and the remote terminal unit (RTU) or to interconnect relays or to connect relays to the substation computer. Further study is needed to examine the possibilities. (IEC 61850 2011b)

Different protocols can be used in the long-distance link between the control centre and the MV/LV transformer station. The discussion here will be limited to IEC protocols, which are widely used in Europe. Figure 31 presents IEC protocols used in remote control and monitoring between SCADA and RTUs or substation computers (West 2005). IEC 60870-5-104 is an IP protocol used in the conversions of the serial protocol IEC 60870-5-101 before the transmission over the long-distance link. IEC 60870-6 is a control centre protocol and can used when a part of SCADA functions is implemented in the substation already. IEC 61334 defines power line carrier communication. (West 2005)

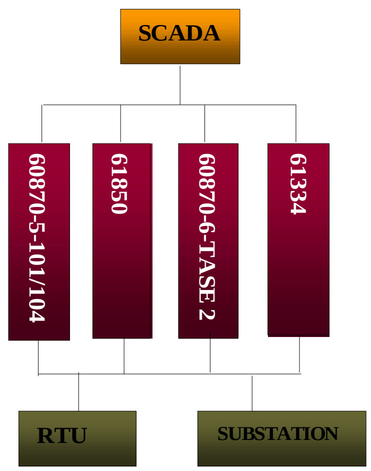


Figure 31. IEC protocols used to connect RTUs or substation computer to SCADA in the control centre

IEC 61850 is communication networks and systems for power utility automation, earlier called communication and systems in substations. It is primarily used in intra primary substation communication, but its use is expanding outside the primary substation

(Brunner 2008). At present IEC 61850 is usually converted before the transmission over the long-distance link. This conversion is specified in 61850-80-1. However, as presented in (Hammer et al 2008) and (Brunner 2008), the implementation in communication between SCADA and substation RTU is possible. The IEC 61850-90-2 report discusses how to use the protocol between the control centre and the substation (Brunner 2008). The idea is that the substation network could be connected to the control centre and SCADA in a similar manner as local human to machine interface (HMI) in the primary substation. Also, a new standard will be added to form the part IEC 61850-8-2, called mapping to web services. It could possibly be used in the communication between the MV/LV transformer station and the control centre, thus enabling the use of object-oriented architecture in ICT systems. Web services are based on XML. XML is a hierarchical, ASCII-based and structural information presentation format, which can be used on different platforms. XML can be used to save information in files by applications, which are programmed using different languages. The communication of web services is based on the SOAP (Simple Object Access Protocol) protocol, which is conveyed by HTTP and TCP/IP protocols. Web services are also used by the AMR middleware application introduced in Section 4.14.2 (Forsström 2007). Further study is needed to examine the possibilities of IEC 61850-8-2 in MV/LV transformer station applications. (Brunner 2008; W3schools)

4.8 An application of IEC 61850 in Distributed generation and MV/LV transformer station communication

In Germany the share of wind power and other renewable energy generation is already significant. Distributed power generation (DG) e.g. wind power plants is expected to increase in Finland as well. Grid protection is considered to be very challenging, when DGs are connected to the network. The grid protection of distributed generation units and the protection changes which are needed in the protection of the MV feeder of the primary substation are discussed in (Nyberg 2008). The document introduces protection planning principles to support the connection of wind power plants to the network and to aid the development of wind power plant protection and of protection relays. Also, concrete design practices and solutions to the grid protection problems of distributed generation are discussed. In addition to the phase-to-phase fault and phase-to-earth fault solutions, the use of communication techniques in grid protection is discussed. A good grid protection can be achieved with the help of communication techniques. For example, the earth-fault detection of the MV feeder relay in the primary substation could send a trip signal to the protection relay of the wind turbine. The MV/LV transformer station could also be considered the connection place of DGs, the location of the intermediate relay and a communication node for DGs in the LV grid. It is estimated that distributed generation will be increasingly connected also to MV and LV networks. Therefore, one example of grid protection and the related communication solution is discussed briefly. (Nyberg 2008)

It is possible and probable that distributed generation will be increasingly connected also to different points of the medium voltage feeder. In the middle of the MV feeder there may be an intermediate switch controlled by a relay. The switch can be placed in the MV switchgear or be an external unit in overhead networks. Figure 32 presents an example of a fault situation where two-phase short circuit fault occurs at the end of the MV feeder. There is an intermediate switch located in the secondary substation and there is a significant amount of MV and LV distributed generation connected to the feeder. The relay at the beginning of the MV feeder cannot see the entire fault current, because large generators at the beginning of the MV feeder feed a part of the fault current. However, the intermediate relay can see more. Therefore, loss of mains (LOM) protection can be arranged in such a way that the feeder relay or the intermediate relay, located in the MV/LV secondary substation, sends a trip signal to DGs downstream, which are connected to MV and LV grids. The intermediate relay in the secondary substation trips and the end of the feeder is disconnected. The large DGs at the beginning remain connected as do the loads before the intermediate switch. This relay could be used to send a trip signal to all DG relays and LV relays in the MV/LV transformer stations. In the communication network the trip signal is conveyed in MMS or GOOSE packets, which are routed or switched on subnets that are next introduced.

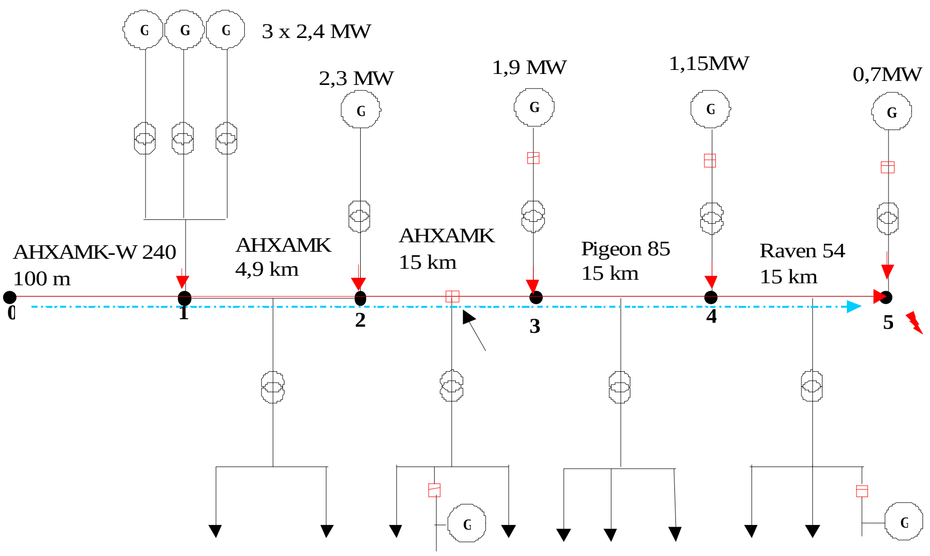


Figure 32. Grid protection in a short-circuit fault at the end of the MV feeder. DGs are connected along the feeder**.** The intermediate switch in the secondary substation operates. Loss of mains protection using IEC 61850 protocol is implemented and DGs are disconnected.

A communication application to be used in the LOM protection of DGs in the network of Figure 32 is presented in Figure 33. Two alternative IEC 61850 solutions are presented. One uses VLANs and IEC Goose messaging, the other uses IP subnets and IEC 61850-8-2 Web services mapping. In the second alternative it is assumed that a fast IP router capable of wire speed routing is used in the secondary substation. The network architecture of the VLAN/GOOSE solution is presented in Figure 33. The communication architecture consists of the LAN network of the HV/MV and MV/LV substations, IP link devices, the Ethernet switch in the MV/LV station and the protection relays of the DGs and those of the HV/MV and MV/LV substations. Wireless IP link devices are used to connect the intermediate protection relay in the MV/LV transformer station, the MV feeder relay in the primary substation, DGs and the MV/LV transformer station, where MV or LV distributed generation are connected. The VLAN is specified in 61850-8-1. In this application the architecture consists of three VLANs, as follows:

- Network A is used for communication between the MV feeder relay of the primary substation and intermediate relay.

- Network B is used for communication between the intermediate relay and DGs, located at the end part of the feeder.
- Network C is used for communication between the MV feeder relay of the primary substation and DGs, located both at the beginning and end parts of the feeder.

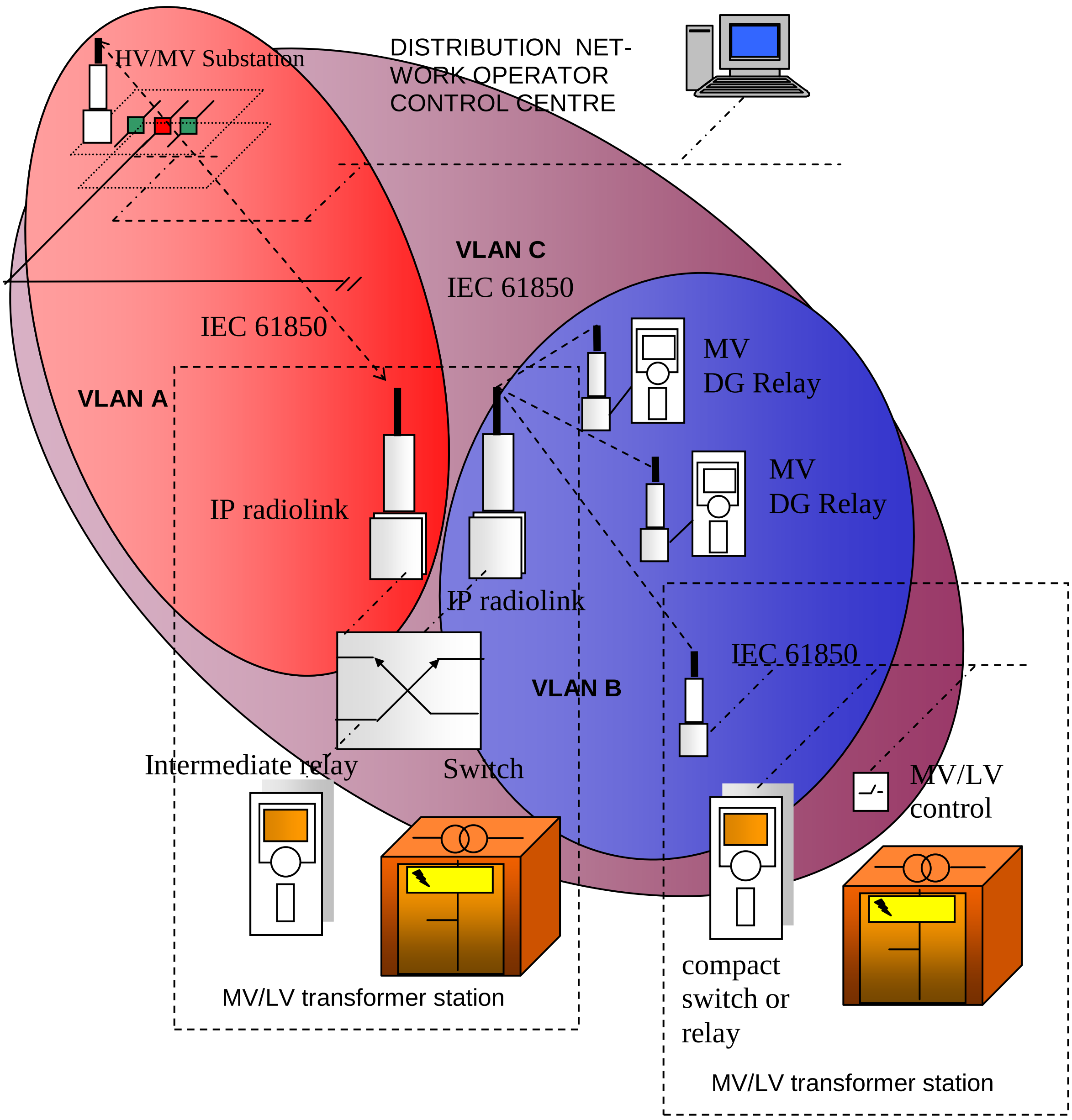


Figure 33. A communication architecture needed for distributed generation loss of mains protection using IEC61850 GOOSE messaging and VLANs.

LOM protection can be used in short circuit and earth faults of the MV feeder and the idea is simply that once the feeder relay or intermediate relay has detected the fault and operated, the DGs can be remotely tripped, i.e. disconnected from the grid. The organizing of communication networks into three VLANs ensures selective operation of the protection as follows: In the fault between the primary substation and the intermediate switch all the DGs are tripped and the communication uses GOOSE messaging in VLAN C. In the fault after the intermediate switch only the DGs at the end part of the feeder are remotely disconnected, but the others stay connected. VLAN B can be used for communication between the intermediate switch and the DGs at the end part of the feeder. VLAN A can be used for communication between relays. For example, the intermediate relay interlocks the MV feeder relay of the primary substation, after it has detected the fault at the end part of the feeder. GOOSE also enables control signals needed for the island operation of the microgrid that starts from the MV/LV transformer station.

In the IP subnets/Web services architecture, the IP subnets cover the same area as presented in Figure 33, but a fast router is used instead of the Ethernet switch. In the communication of the protection functions a small delay is essential. The GOOSE communication using layer 2 was developed to reduce the delay of communication. In the application presented the delay consists of the sum of the delays in the following components in VLAN B, for example: intermediate protection relay, ETH switch or IP relay, IP link and DG switch and protection relay. The IP link speed, or more precisely bandwidth, has an essential influence on the delay of the communication. The IP relay can prioritise network traffic. Prioritising also shortens the delay of communication of the protection, especially when a narrow link is used by multiple applications. Simulation and tests should be arranged to verify what has been the presented in this chapter. DG protection, specified by the interconnection requirements, should not be replaced by communication-based LOM protection, but be enhanced by LOM.

Distributed small-scale generation can influence the LV grid power quality if the penetration is high enough. In (Cobben 2007) also a PQ study of a holiday village is presented. The houses were equipped with solar panels and the measurements indicated e.g. a negative influence on voltage level, i.e. the voltage level increases during high distributed small-scale production. Therefore, voltage measurements in LV grid, which contains high penetration distributed energy recourses are useful in order to verify that the distribution voltage quality complies with the standard EN 50160. Ethernet, IP and wireless communication techniques can be used to enable advanced automation functions in MV/LV transformer station and in LV grid. (Cobben 2007)

4.9 Requirements of future DA for the ICT of MV/LV stations

In future transient earth fault location methods used in MV networks can take advantage of distributed measurements in secondary stations. These locators operate with a high sampling frequency and the resulting failure records are compared to the other failure records of the secondary substation in the control centre. The time synchronisation must be accurate. Networks that have a high speed, low delay and low jitter become thus necessary. In LV networks online cable fault location devices (Livie et al 2007) and temporary measurements (Siew et al 2007) are already used. In temporary measurements the devices are usually equipped with memory cards, which are used to save the waveform and the related data of the fault event. These records can also be downloaded remotely. Fixed online systems are needed for tracking the source of intermittent faults. These faults are non-fuse blowing, and multiple detection devices may be needed for the capture of the distortion signal.

Data exchange formats IEEE PQDIF 1159.3 and COMTRADE C37.111 can be used to record failure data in an interchangeable way (Mueller & Grebe 2007). These files can, of course, be transferred using either serial protocols or IP protocols e.g. IEC 61850, but the IP network enables a wider selection of communication protocols, for instance. In addition to IEC 61850, a widely used secure file transfer protocol could be used, such as SSH (secure file transfer protocol). This could be an advantage in a system like a power quality database. The use of SSH requires the implementation of an SSH client in the power quality database and an SSH server in IED in the MV/LV transformer station. Using SSH the device file structure must be known. IEC 61850 data structuring could help to locate the files and to notify the user of recent file additions and changes. A change into ETH/IP communication also enables different vendor-related IP protocols. IEC standard protocols can use the same bus as the non-standard protocols.

In primary substations the utilization of the IEC 61850 protocol is developing towards including also an Ethernet sensor network. The IEC 61850 protocol is designed for the transmission of sampled values. These sampled values (SMV) can be used when current sensor values are transmitted to protection relays using LAN, for instance. This SMV application can be used to enable IEC 61850 in differential protection (Apostolov 2011). Although the MV/LV transformer substations have at present a lower automation level, because of the smaller influence on interruption indexes, MV/LV automation may still increase, when reliability, safety and flexibility requirements are tightened. Also, the cost of technology utilizing IEC 61850 sensor networks may decrease. Therefore, a high-speed network could be a cost-efficient solution to the horizontal communication of the MV/LV transformer station in future. Also, mobile networks in cities have wide coverage and are developing towards broadband bandwidth. Therefore, network technologies may provide efficient communication media also for DNO applications, which utilize vertical communication and an MV/LV long-distance link.

The secondary substation and MV/LV transformer station can operate also as a communication node. When e.g. PLC communication is used, AMR meters transmit and receive information using the power network as communication media. AMR concentrators are installed in MV/LV transformer stations. Monitoring, measurement and control systems are more and more used in secondary substations (Laaksonen et al 2009; Hyvärinen et al 2009a; Hyvärinen et al 2009b). AMR-based information can be enriched and individual components monitored and controlled by the use of MV and LV automation systems.

4.10 Wireless networks

On the 4th of December, 2008 The Finnish Government made a decision to implement a broadband internet infrastructure development project, where the availability of the broadband connection will be enhanced. The goal is to connect every primary house-hold and corporation head quarters to a 1-Mbit/s connection by the end 2010 and to a 100-Mbit/s connection by the end of 2015 (Pursiainen 2008). The first target has been partly achieved, if data communication using the frequency band of 455 MHz is considered. This frequency was used by the NMT, i.e. Nordisk Mobiltelefon system and it had in 2010 99.8 % coverage in Finland. The data communication system of 455 MHz band uses FLASH ODFM. i.e. Fast Low-latency Access with Seamless Handoff Orthogonal Frequency Division Multiplexing technique, and it is constructed and administered by Digita Ltd company. (Rantala 2010)

In addition to radiolink technology referred in the context of Figure 33, also mobile networks have gained foothold in Finland. GPRS, i.e. general packet radio service is used extensively by the AMR system and in the remote control and monitoring of distribution network applications (Laaksonen et al 2009; Heino et al 2009; Hyvärinen et al 2009a; Niskanen et al 2009; Seesvaara et al 2009). However, the GPRS communication technique has occasionally choked e.g. at exhibitions, because of a high amount of simultaneous voice and data traffic (Nyberg et al 2010). Also, during MV faults the electric supply of mobile phone base stations are interrupted and in a couple of hours also the mobile communication connections will be interrupted. In rural areas lightning causes the malfunction of base stations. Therefore, wireless connections may be left without good signal strength for weeks in Finland, before they are repaired. At present the available techniques are both 2G and 3G. Number 3 and letter G of 3G refer to standards International Mobile Telecommunications-2000 by the ITU-T, i.e. International Telecommunication Union. 2G refers to 900 MHz and 1800 MHz GSM, including GPRS, 2.5G and EDGE, 2.75G. Universal Mobile Telecommunications System UMTS, 3G and HSPA, 3.5G are presently available techniques. They are designed for data transfer, and the geographical coverage in Finland is good especially in urban areas. 3G operates at the frequency bands of 900 and 2100 MHz. New technologies, which are expected to gain foothold, are HSPA+ and LTE, i.e. long term evolution, which is a standard from the 3GPP group. In Finland, all these different 2G and 3G techniques are and will be operated and maintained in parallel, which increases the operating costs of mobile communication. The amount of transported data in mobile networks is increasing steadily. In mobile 2G networks voice data is decreasing, in 3G voice traffic is increasing and other data traffic increasing. Because the revenues do not increase at the same rate as the traffic does, it is vital to reduce network costs so that the business remains profitable. Also, other new wireless standards and technologies have been presented for video and multimedia usage, one of these is mobile wimax. (Niemelä 2010; Tella 2010; ITU 2009)

4.11 IP traffic routing in MV/LV transformer station communication

Let us assume that the MV/LV transformer station is equipped with an Ethernet LAN network. Ethernet provides a compatible network for a variety of distribution automation protocols and a chance to change the communication technology used in long-distance link, if necessary. The suitability of Ethernet for MV/LV transformer station applications is evaluated in (Gerbec, Curk & KoŠnjek 2007). The usability of UMTS and WLAN for the long-distance link of the MV/LV transformer station is also evaluated. A single long-distance link increases the risk of a control operation failure due to the failure in media. Therefore, the idea of the paper (Gerbec et al 2007) can be enriched by using an IP router and multiple long-distance links in MV/LV transformer station communication. Two or more communication links enable the usage of multiple ISPs, i.e. internet service provider, for example.

A router is a device which connects two or more computer networks and routes the IP packets to the correct network based on the routing table and the IP address in each packet. The public IP network is not just two connected networks, but multiple constituent interconnected networks. The connections of these networks are implemented with routers. Also, more than one possible route for a single packet can be found in this interconnected network. Therefore, routing protocols, e.g. OSPF, are needed to find out the best possible path for the packet to travel through the interconnected networks. The routes found and their routing metrics are stored in a routing table. Based on the routes and the metrics, the best possible route is distinguished, e.g. the route with the smallest delay. For DNOs this routing operation of the interconnected networks is normally not as relevant as the host to host connection available. However, if multiple ISPs and networks are used, the need for DNOs to use routing techniques increases. (Stallings 2004)

Let us consider the usage of a single communication link and wireless gateway. Such a system was presented e.g. in Figure 21**.** From the perspective of DNOs the objective is to connect two LAN networks; the control centre network and the MV/LV transformer station network. For that purpose, the internet service provider assigns a static or a dynamic IP address to both the access points of LANs. These addresses are then used by the terminal routers to access the ISP subnet and interconnected networks. Hence, IP traffic is routed from LAN to the internet and then again to LAN. The IP address includes a host and network parts, which are separated using the subnet mask. Therefore, actually routers in the control centre and the transformer station are meant to route the traffic between two subnets: the ISP subnet and the local LAN subnet. An integrated router and wireless gateway device is typically used, if only a single ISP is used. This router has an IP address for the interface connected to the ISP network and another for the interface connected to the LAN subnet. The LAN interface can be connected to a switch, which enables the protection relay to send packets via the switch, for example. The IP of the LAN port of the router and wireless gateway device is assigned as the default gateway.

Let us consider the usage two or more communication links and routers, which will add redundancy to the communication compared with previous presented single communication link technique. An idea of control centre and MV/LV transformer station connection using three long-distance links is presented in Figure 34. The network architecture consists of the control centre IP subnet, control centre router, subnets B, C, and D for MV/LV connection, primary substation subnet A, primary substation router, MV/LV station router, MV/LV station subnet, IP wireless link and two tunnelled public internet links, which are implemented e.g. using 2.5G, 3G or 4G from two internet service providers. The three links demonstrate routing possibilities and provide redundancy, if the service availability of one ISP is not good enough. The primary substation and MV/LV transformer station connection also provides a possibility for DG function discussed in Section 4.8. The subnet e.g. subnet B, is configured in such a way that the same subnet is also available in the MV/LV transformer station. The subnet is tunnelled over the public internet using VPN. In the absence of a single link the other two will provide the connection. However, in order to avoid multiple parallel links and harmful loops routing protocols must be used. One possibility is to use an internal routing protocol such as

OSPF, i.e. open shortest path first, which routes the IP packets to the best route out of the alternatives that are listed in the routing table. Once the long-distance link is tunnelled, a second protocol GRP, i.e. general routing encapsulation must be used to enable the OSPF messages. A single IP packet is routed e.g. from the MV/LV subnet by the transformer station router, tunnelled and routed by the gateway, received from the tunnel and routed by the control centre (CC) gateway and once again routed by the CC router. The IP network enables the usage of multiple IP protocols such as IEC 61850, IEC 60870-5-104, internet protocols, commonly used, and e.g. vendor- related IP protocols used for device configuration. Policy-based routing could also be applied, if needed. This idea of network architecture should be further examined and tested before implementation. (Cisco 2008)

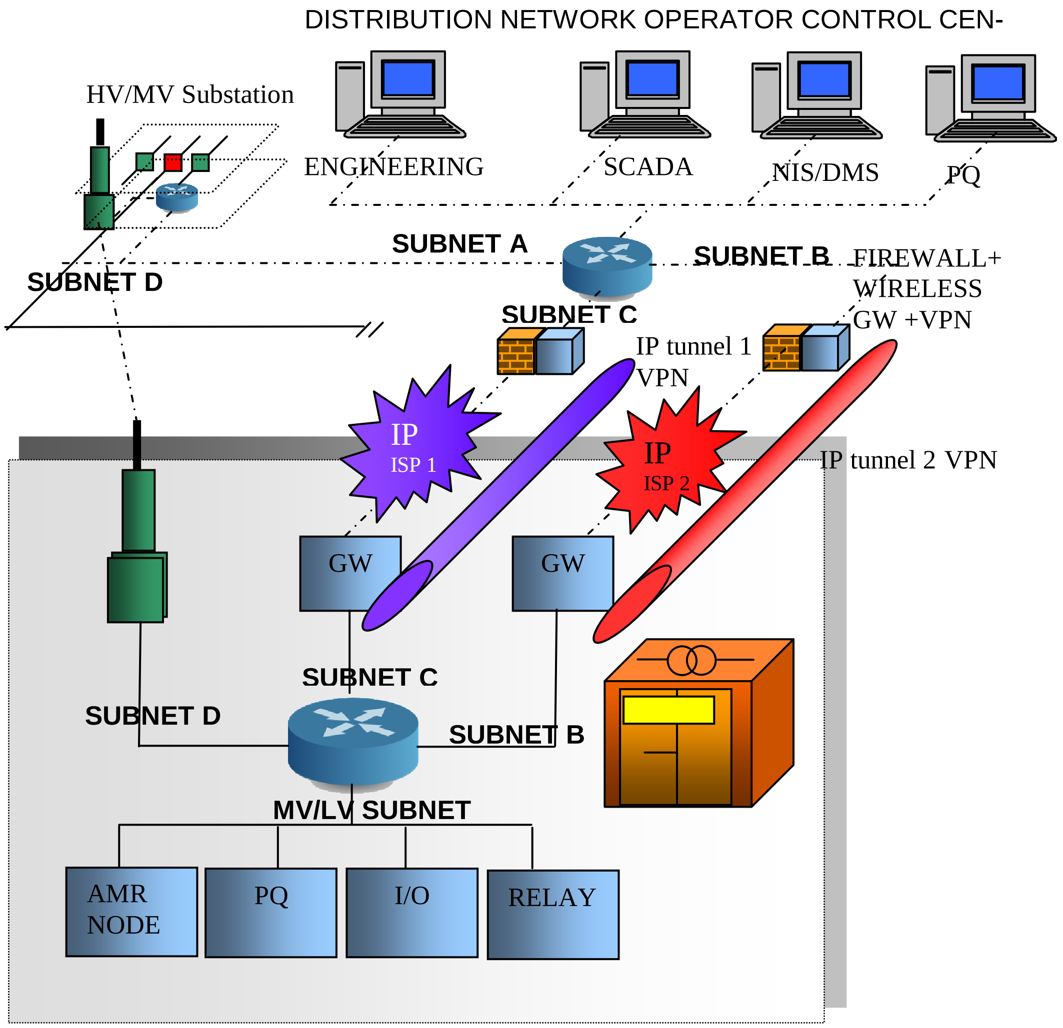


Figure 34. Routing of traffic of multiple communication links in MV/LV transformer station and control centre IP communication application.

The risk of a control operation failure, when a single mobile network long-distance link is used, can be examined by studying experiences from AMR communication operation. The communication is commonly implemented using a GPRS modem in rural areas in Finland. In urban areas also PLC is used in Finland. The communication of a wireless GPRS modem is based on the connection with the base station nearby. The system has two major disadvantages. Firstly, the base station towers are occasionally hit by lightning during heavy thunder storms and are sometimes damaged and are left out of service for an undetermined period of time. During this period the GPRS modems in this area try to establish a connection to the next cell with weak signal strength or are left without any connection. In order to improve the reliability of AMR-based fault location, also the fault detection and information system of the mobile network base station should be developed. Secondly, during an MV fault the MV/LV substation supplying the base station is left unsupplied, which makes the backup batteries run out of energy in 2–3 hours. Therefore, in order to provide more communication time during electricity network faults, new microgrid solutions could be applied to base stations. Further study about microgrid applications in GSM base stations and an automatic fault information system of the base stations is needed. The introduced routing system provides a chance to add redundancy using multiple communication systems.

4.12 Requirements for cable cabinet communication

There was no utilization of distribution automation or cable cabinet communication in the five Finnish distribution companies reviewed (Laaksonen et al 2009; Heino et al 2009; Hyvärinen et al 2009a; Niskanen et al 2009; Seesvaara et al 2009). Also, public discussion in journals or seminary papers is rare. Therefore, the discussion of cable cabinet communication is welcome. Some automation applications for LV grids have been presented in Chapters two and three. Also, some functions that utilize cable cabinet communication will be presented in Chapter five. The communication ideas presented here are based on available techniques from other industrial automation applications.

The cost-benefit ratio limits the usage of an extensive communication system of cable cabinets. Therefore, power line carrier (PLC) and wireless operator-free communication media could be suitable for communication link techniques from cable cabinets to the MV/LV transformer station. This communication link between cable cabinet and transformer station can be a part of the communication architecture where the device in the transformer station operates as a communication concentrator node (gateway) and devices in the cable cabinets as measurement nodes (nodes). Also, synergy could be achieved, if other than electricity network components could be monitored using the same communication infrastructure. For example, measurement nodes could possibly be connected to water and heat network components. Street lightning uses automation and communication equipment, which are near distribution cable cabinets and MV/LV transformer stations, but these are usually considered as separate systems. A combined multi-application system reduces costs per system, but could make administrative tasks and responsibilities more complex.

The LV network has a high number of potential components for monitoring objects, e.g. fuse-switches and cabinet doors. The cabinets also endure harsh environmental conditions: cold, heat, moisture and to some extent traffic vibration. If an extensive and covering monitor system is used in cable cabinets and maintenance cannot be increased, then bullet-proof, maintenance-free, energy-efficient, low-cost and long-lived technology is required from automation and communication systems used in cable cabinets. Also, the system should improve to the processes of distribution companies and bring benefits even to customers.

4.13 Ideas for cost-efficient cable cabinet communication

A piloted water consumption monitoring system is presented in (Piispanen 2009). This custom-made, licence-free, 433 MHz radio communication system is intended to be used for collecting data from water consumption meters. The antenna location and design becomes important in order to achieve adequate signal strength for the communication system to operate, because the low power allowed for transmitters. New application would be to use a licence-free radio system also in LV cable cabinet communication.

For example, the system could be used in the monitor applications of LV grid electricity processes and components where control is not needed. Also, industrially manufactured license-free radio communication systems are widely available. (Piispanen 2009)

One quite new radio communication technology is IEEE 802.15.4, also called Zigbee. The Zigbee modules, e.g. XBee (Digi International 2008), can be installed to a variety of integrated circuit (IC) boards of embedded systems. Such an IC board could be the communication module of the DA device. The Zigbee wireless radio communication system operates at the frequency of 2.4 GHz. The transmitter power is restricted in Europe to 10 mW, which gives a wireless range of less than 100 meters. Let us consider the example of the urban LV network is presented in Figure 35a. From the 100-meter-diameter circle in Figure 35a it can be concluded that the wireless range does not reach all the cable cabinets from the MV/LV transformer station. The range can somewhat be extended by moving the antenna up, e.g. on top of a long pole, which is shown in the illustration of Figure 35b. Another method to extend the range without using more transmission power is to use the multipoint wireless network, which is supported by IEEE 802.15.4. The architecture of the Zigbee network with modules and a gateway is presented in Figure 35c. (Digi International 2008)

An electric distribution network can be used as communication media. In LV networks the AMR system can already use PLC, i.e. power line carrier. However, PLC communication used by AMR is not necessarily an open architecture. One type of standard PLC communication is IEC 61334, which is intended for SCADA communication. Although it is slow, it could be used to convey status information from fuses, for instance. Instead of a separate PLC system, it is also possible to use a system compatible with or the same as the AMR system. For example, in the MV/LV transformer station a device similar to the AMR concentrator could be used to connect the cable cabinets to the transformer station. Hence, the communication could use the same long-distance link with the transformer station. A wireless concentrator is shown in Figure 35c.

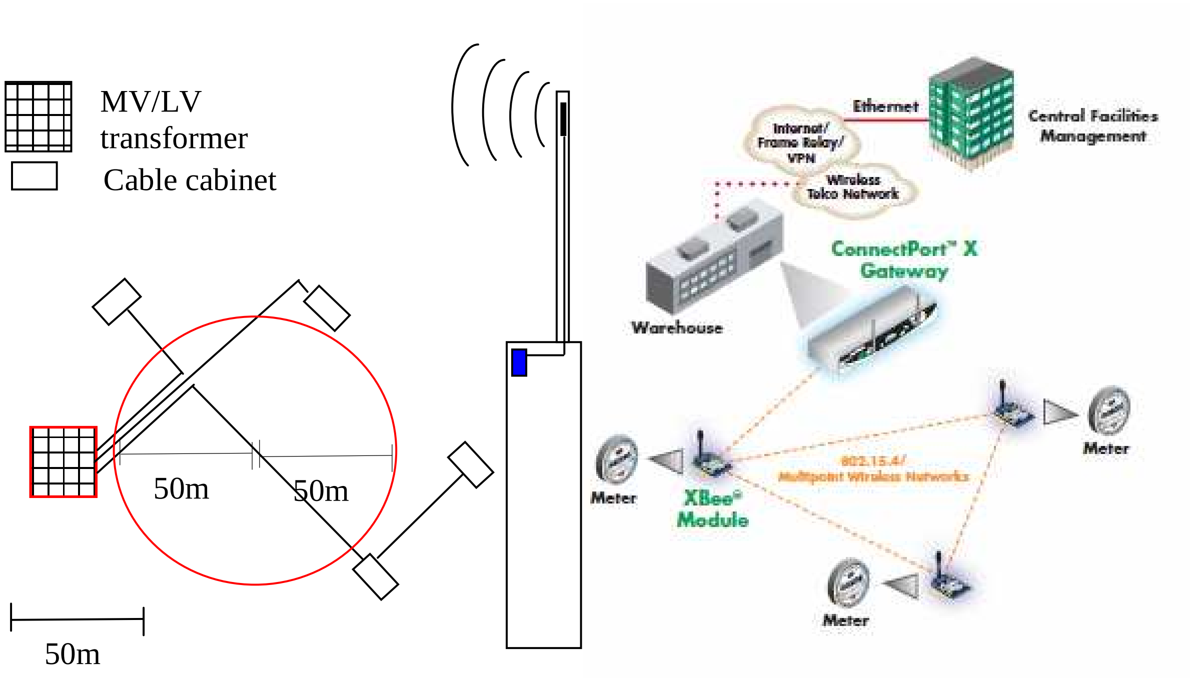


Figure 35. Using IEEE 802.15.4 wireless communication usage in monitoring application of LV distribution network. The LV network map and Zigbee range of 100 meters are shown in (**a**). The range does not reach all the cable cabinets. The range can be somewhat extended by placing an antenna on top of a high pole, as shown in (**b**). IEEE 802.15.4 supports multipoint network architecture, which also extends the range, presented in (**c**) (Digi International 2008).

When power cables are renewed, the additional cost of added signal wiring is at its lowest. Also, combined power and communication cables have been developed. For example, HVDC cables, which contain both optical fibre and power conductors, are used in wind park installations. Similarly, it would also be possible to manufacture low-voltage cables which contain an optical fibre. Also, it would be possible to place an optical fibre cable inside the same or extra cover pipe. Hence, after the installation the communication media used for cable cabinet communication does not cause additional costs. One alternative to lower the costs is to sell one fibre of the two fibres installed for the internet use of housing companies or telephone operators and reserve the other for the communication of distribution automation and power market use. In Finland telephone companies are usually responsible for residential communication cables. A rented cable or bought service will increase operating costs, but reduce investment costs. Also, the use of a mobile network, e.g. GPRS, is possible, but the cost-benefit ratio will most likely be low, especially if multiple LV monitoring locations are used.

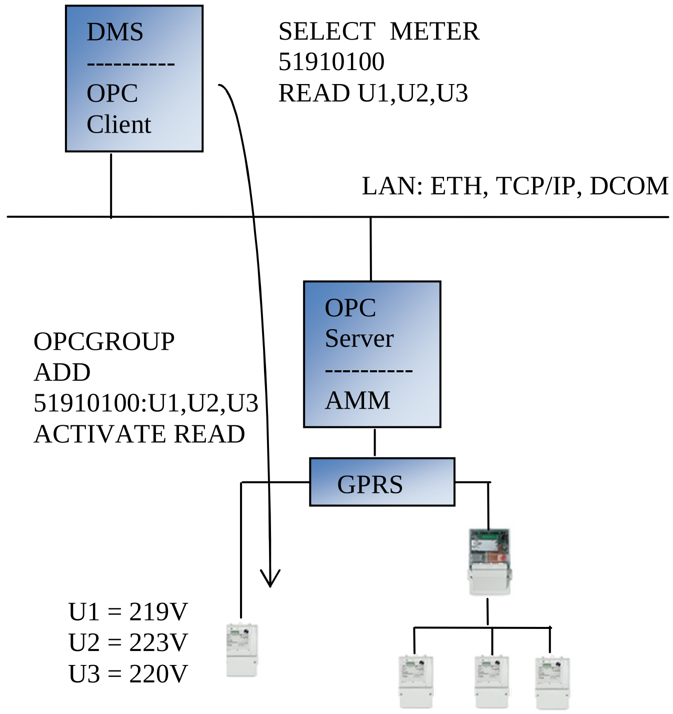
4.14 AMR/AMM NIS/DMS integration system

This study does not focus on the utilization of information provided by AMR. The main purpose here is to provide an ICT architectural view, useful in planning MV/LV transformer station and low voltage grid management systems because the ICT of the AMR/AMM NIS/DMS integration system could be used for this purpose. In March 2009 the Finnish Government gave an act, one of the objectives of which is that the energy consumption of 80 % of all customers should automatically be read by the end 2013 (TEM 2009). This act, general measurement development and the other benefits brought by automatic meter reading have led to the present situation where in LV grid there is an overlying and extensive energy distribution process monitoring grid available. However, AMR information can be used in LV grid management and fault location. At present AMR-DMS integration systems are available and these systems enable e.g. LV feeder fault location determination based on centralized automatic or operator initialized enquiry from DMS to AMR system (Haapamäki et al 2009). In the fault location function the NIS information of fuse link location, DMS information of switching state and the information from DMS and AMR alarm are used. These information together enable the function of DMS fault location algorithm and the fault location indication using the the graphical map of the NIS/DMS system. (Haapamäki et al 2009)

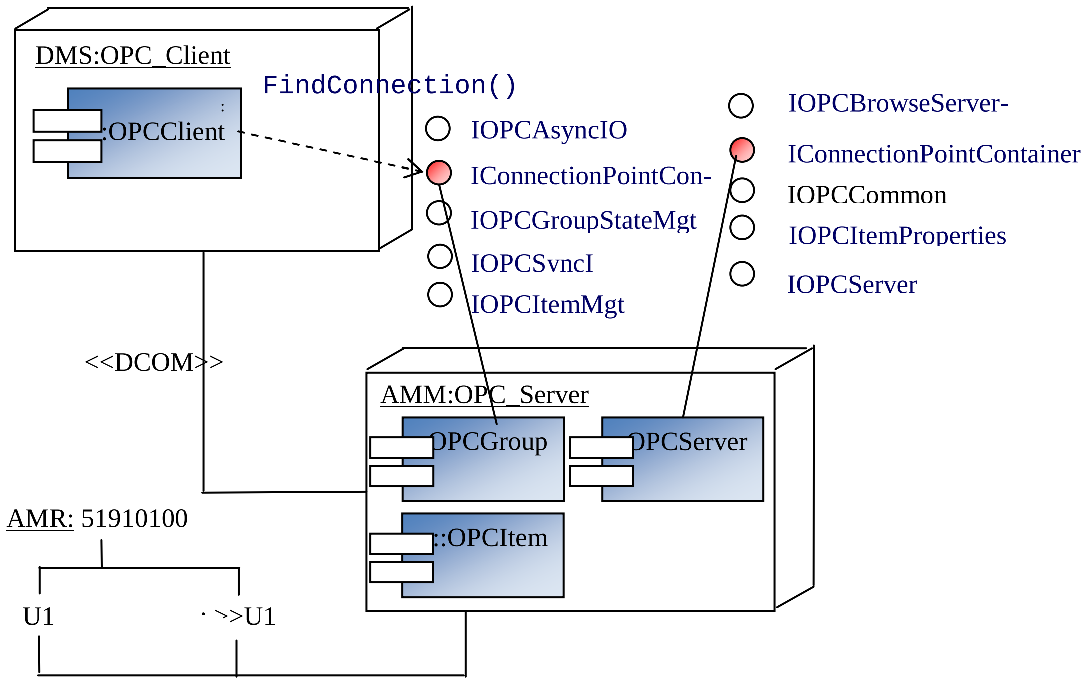
4.14.1 ABB Microscada Pro DMS 600 AMR/AMM integration

A LV network management function is provided by ABB DMS 600 system. In this function AMR based alarms and deduced alarms are presented in NIS/DMS system graphical distribution map with symbols and colouring of wires. The integration is implemented using Ole for process control (OPC) server. The vendor of automated meter management system is expected to provide the OPC server component. In the DMS system OPC client component is used for data acquisition. The OPC was originally designed on the Microsoft windows operating system platform. Hence it uses COM/DCOM, i.e. distributed component object model interface. OPC Data Access definition interface describes following objects: server, group and item. OPCserver is used for state information interchange and as a container for group objects. Group objects have methods for classification of data. This classification is done using Item objects to group. Item object properties are measured value, quality flag and timestamp. (Opc foundation 1998; The ABB Group)

There are two data acquisition types in AMR/AMM NIS/DMS: *Active alarms* are based on alarms received from meters and alarms are readable from OPC according to system settings and *latest measurements*, in which the acquisition is conducted from meters once information is requested from OPC. *The latest measurement acquisition* is presented in Figure 36a. In NIS/DMS system the meters and quantities are selected using distribution map and network information e.g. phase voltages UL1, UL2 and UL3. OPC client of the NIS/DMS system connects to the OPC server of the AMR/AMM system. The queried meter and quantity is added to OPCgroup. The query is activated and AMM performs the query from meters. As a result the phase voltages are received from meters. An UML architectural illustration from previous AMM/AMR NIS/DMS integration implementation using OPC Data Access interface is presented in Figure 36b. NIS/DMS system and OPC client component are executed in Microsoft server, which is connected to control centre LAN. OPC connectivity is implemented using distributed COM (DCOM), which enables software components that may be located in different control centre servers interaction. Automated meter management (AMM) server and OPC server application components are executed in meter management server. OPC server application component contains OPCserver, OPCgroup and OPCItem objects. Meter voltage information acquisition begins by establishing connection between OPC client and OPC server using IOConnectionpoint interface. This is followed by OPC clients sending pointer of its callback function. This callback is later used by OPC group object, when passing the requested voltage information to client. OPCItems are attached to OPC group container. Item objects are bind to exact addresses of AMR meters, which enables to inquiry using AMM. (Opc foundation 1998; The ABB Group)



(a)



(b)

Figure 36. Measurement acquisition in ABB Microscada Pro DMS 600 AMR/AMM integration system and used OPC architecture **(a)**. An architectural illustration of OPC Data Access using UML notification **(b)**. OPC uses DCOM. OPC client is used to connect OPC server. In OPC server OPCgroup container is used to implement the acquisition.

4.14.2 Tekla XPower NIS/DMS 7.x and AMR/AMM integration

Tekla NIS/DMS 7.x utilizes OBDC (open database connectivity) interface in NIS/DMS (network management system) network information communication with Oracle database server. NIS server and ODBC client component are executed in NIS server. ODBC Client is used to connect to ODBC driver on the same server. The driver is then used to connect with database management server (DBMS) component running on Oracle database server. The switching state information of the distribution grid can be viewed in DMS system. This DMS functionality is based on the network information of the NIS system and switching state information of the SCADA system. A commonly used SCADA interface is Elcom. The information read by NIS/DMS using Elcom interface from SCADA is assumable stored to the DMS database running on Oracle server to be used by DMS functions. In NIS/DMS AMR/AMM integration suite the presented database architecture is extended by the dynamic part acquisition from AMR/AMM system. Several interfaces are available for interaction. One possible information exchange format between DMS and AMM is web services (Haapamäki et al 2009). Another possibility to connect multiple systems to AMM is to use middleware software, e.g. Tietoenator ComC (see Forsström 2007). Middleware system reduces the number of interfaces, the configuration work and enables multiple system interaction and connection e.g. customer information system, measurement information system, meter management system and distribution management system can be connected using middleware. Webservices communication was introduced in context of Section 4.7. and IEC 61850-8-2 standard. (Haapamäki et al 2009; Forsström 2007; Microsoft 2007)

4.15 An application of ICT used in the information management of MV/LV transformer stations

In Section 1.2 the DA term was introduced. In this context it was mentioned that communication is used to enable local, remote and central functions. In Section 2.6 functions for MV/LV transformer load monitoring and overload detection that utilize the communication were presented. Let us now specify the functionality little further in order to design a suitable communication and ICT platform suitable for load monitoring application of Section 2.6. The loading monitoring and overload detection requires an intelligent electronic device (IED), which has a true RMS current measurement functionality. The IED is to be equipped with flash memory card, which was introduced in Section 4.5. The idea of using memory card is from industrial PLCs (programmable logic device), where the flash memory card has been used for long time to save additional data. Memory card enables recording of current fundamental and harmonic frequencies information from long time. Also, a web server interface is applied to provide possibility for remote field operation usage. The idea of using a web server in IED is from industrial power quality monitoring devices, e.g. (Janitza 2009), where web server has been introduced a long time ago. By using web server the overload and PQ information can be remotely read e.g. the traditional peak load meter will be utilized in new virtual way. In Section 3.2 a classification method and a power quality system was introduced (see Cobben 2007). Therefore, in this application 10 min average values are to be used to form the indices data, but for fault recordings also instant values are stored and transmitted, if they are enquired by the operator.

The MV/LV transformer station IED is a PQ device and connected to a long distance link communication device via Ethernet switch. Communication uses IP protocol and the physical media is twisted pair or fibre optic cable. In addition to the standard http and secured https protocol used to transmit web pages, the IP communication network enables variety of communication protocols to be used e.g. web services, JAVA RMI and IEC 61850 protocol. The IEC 61850 enables variety of remote and central services and functions. In the overload detection application the IED could send an overload indication spontaneously, i.e. after threshold value the IED generates and sends the event to SCADA. The connection to SCADA is to be done without a station computer and protocol conversion. The long distance link to control centre can be arranged in multiple ways. In this application the long distance link uses public internet service through internet -network of the service provider. For the public IP network a variety of techniques are available from the fibre optic cable to the wireless e.g. GPRS, 2.75G to 4G, Wimax and Flash-OFDM. The communication is tunnelled using virtual private network (VPN) technique. In the VPN technique the communication through public internet uses standard uncrypted IP protocol packets, but the payload of these IP packets consist of crypted IP packets from private intra network. The payloads of the IP packets of the intra network consist of above layer packets, i.e. usually TCP or UDP. The crypting is usually done in tunnel entry points. The points, MV/LV station communication device, control centre wireless communication device and PDA device are presented in Figure 37. Typically, a firewall router is equipped with the VPN function. In this application the router is extended with wireless communication device or module. Hence, it is the firewall router, which identifies the communication using VPN and decrypts the communication. Also, the communication device in the MV/LV transformer station is actually a router with VPN function, since it operates on a layer 3 of OSI model.

In this application three control centre systems are presented, i.e. SCADA system, NIS/DMS system and PQ database system. These can be seen in top of the Figure 37. NIS/DMS graphical interface could be used to easily access the MV/LV transformer station monitoring device. In the transformer overload situation the indication is displayed in NIS/DMS events window and warning symbol is displayed in the detail level map view. The operator could publish the page where the network of interest is displayed using dynamic web pages and send a link to the field operatives or subcontractors. The operator could also send the transformer station the IP address of the web server, if the IED in the MV/LV transformer station provides a web server service. Alternative solution is to use mobile versions of NIS/DMS with replica databases or remote connection using the VPN communication link. In the later case the link, that the operator sends to field operatives, could contain a macro program, which loads the MV/LV transformer station map view, the related indication and updates the replica database with MV/LV transformer station and LV grid information. The information exchange should use the policies that are designed for the mobile station usage. It is therefore assumed that no data loss should happen and data is accessible by authorized users only. This application example aims to present a communication and ICT architecture for secure but easy access to the transformer station information services. The SCADA can be used to monitor measurement and indication data from the transformer station.

The transformer station measurement can be saved also centrally using e.g. power quality database. The PQ database is designed to store PQ measurement data gathered from a long period. Multiple architectures can be used to easily access PQ measurements. One possibility is to NIS/DMS system graphical map, which was previously explained.

The relational database architecture enables to link database information from different databases. The network information system (NIS) contains a unique identifier for each transformer station. PQ information database includes a unique identifier for each measurement point. In IP communication the PQ data is acquired from transformer station using transformer station the IP address of the IED. In the relational database these identifiers can be tied together. Once the unique identifiers are tied the measurements from a transformer station can be retrieved using database queries with identifiers. One possibility to link the correct PQ measurement node data to NIS/DMS is to link to pages provided by the power quality database web server service. The correct pages could be retrieved with identifier data in a script. Also, file transmission can be used in the data exchange. Hence IEEE PQDIF 1159.3 and COMTRADE C37.111 can be used. Once the PQ database is linked to NIS/DMS transformer station information, a link to web pages containing correct measurement from a particular transformer station can be sent to the field operatives. A variety of mobile devices are available for field operatives. The field operative can be located in bottom right of the Figure 37. The IP network and mobile internet access are used in this application example to connect to transformer station and control centre. The VPN tunnelling provides a secure connection.

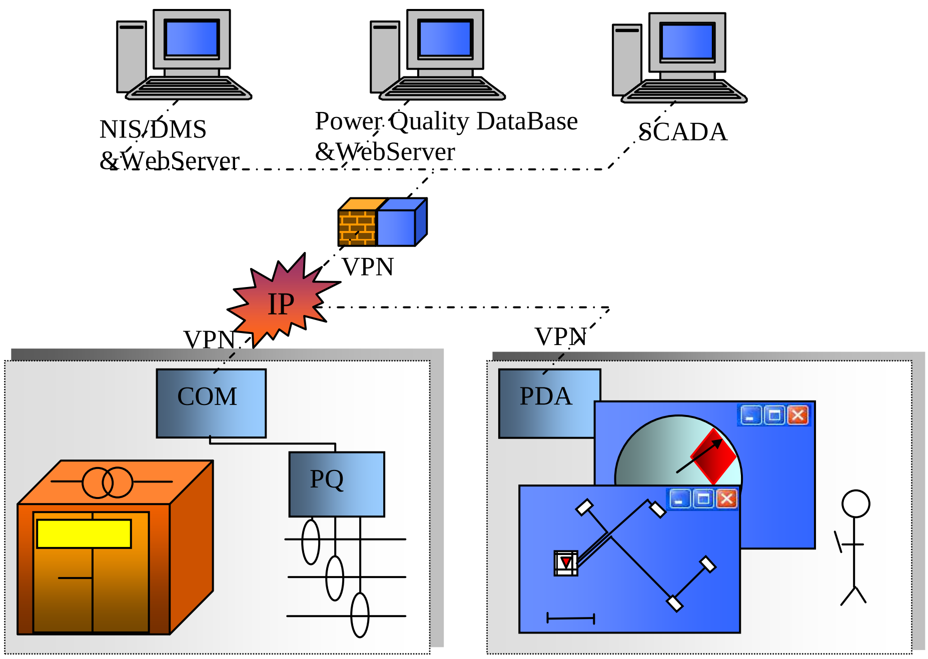


Figure 37. MV/LV transformer station communication and ICT platform for transformer overload monitoring application.. Overload indication and related grid data can be obtained using mobile technology.

5 AUXILIARY SYSTEMS AND BUILDING AUTOMATION

Auxiliary systems and building automation systems are discussed in this chapter. Auxiliary systems, e.g. batteries, are needed to aid the operation of the main systems of the distribution automation. Therefore, auxiliary systems have an impact on many DNO processes, such as electrical safety and fault management. These processes utilize functions, such as relay protection and monitoring, and they need auxiliary systems. Building automation is used to monitor and control the building environment of the MV/LV transformer station in order to ensure a safe and reliable operation of the distribution system. Some of the systems to be discussed are also applicable to monitoring cable cabinets. The building automation systems introduced in this chapter can be used in several DNO processes in the safety management of the personnel and civilians and in asset management, for example.

Also, in Finland the weather conditions are changing due to the climate change. The longer power distribution operates safely, the more time can be used to evacuate people in extreme weather conditions such as floods. This chapter introduces possible systems and ideas suitable for normal daily operation and for precautionary measures taken in order to ensure the operation of the distribution system in extreme conditions. An idea of an optional monitoring layer of the building automation is presented on top of the graphical interface of the NIS/DMS system. It could benefit the operation and maintenance processes in particular. These systems may even help to avoid human injuries and material loss, help managing network assets and help monitoring the ambient environment of the distribution process by providing more exact information about the distribution environment.

The discussion of auxiliary systems focuses on overvoltage protection and battery management. Batteries provide backup power during distribution interruptions, but they need maintenance. Therefore, maintenance systems and functions are presented. This chapter discusses possibilities to monitor multiple building environments and enclosures. The following building automation functions are dealt with: moisture and humidity monitoring, splash and flood water detection, SF_6 gas leak detection, temperature monitoring in the MV/LV station, air ventilation monitoring, hatch open detection, motion detection and entrance detection using a door switch. The main purpose of this chapter is to stimulate discussion and development. The ideas in this chapter are not all tested in the actual building environment of the distribution network.

5.1 Overvoltage protection with surge arresters

Surge arresters are used for the protection of both the primary and secondary components of the MV/LV transformer station. The transformer and MV switchgear are the most common of the valuable primary components protected. The secondary components, which include distribution automation, may also need protection. Overvoltage protection with surge arresters can be used to protect automation systems nearby, the control systems of street lighting, for example. In addition to the protection of the automation systems of the transformer station, new protection objectives include sensitive distributed generation, e.g. a biogas plant in areas where lightning or switching overvoltages occur. Overvoltages caused by lightning were dealt with in Section 3.11. In addition to lightning overvoltages, also switching actions and MV earth faults cause overvoltages. Protection against an MV earth fault in the LV system is specified in standard SFS 6001.

The overvoltage protection specified in SFS 6001 also includes earthing practices of the DY connected transformer used in the TN-C system. In the Finnish LV standard SFS 6000 it is stated that distribution companies define necessary overvoltage protection (SFS 6000-8-801.443 2008). In overhead networks MV surge arresters, such as Metal oxide (MO) arresters, are commonly used to provide general transformer overvoltage protection (Niskanen et al 2009). However, LV surge protectors can be used for more fine-grained protection of LV devices including distribution automation devices in the risk areas. One of the criteria used in defining a risk area is the number of lightning days a year. Over 25 lightning days is presented in IEC 60364-443, but the risk area should be evaluated also by other criteria. The most important criteria for the evaluation of the usage of LV surge protectors is human safety, but also the material loss of the components of the distribution system and that of the components of the system, which is supplied with electricity can be evaluated. Also, voltage quality should meet with the SFS-EN 50160 requirements. There are both recommendations and requirements for temporary operating frequency overvoltages and transient overvoltages in the standard. LV surge protectors are available for different protection rating and usage. For the LV distribution system such overvoltage protection products as DIN rail application ABB OVR T1 4L and cable cabinet NH fuse application Dehn + Söhne 2V NH are available (Arnold-Larsen 2009; Dehn+Söhne 2007).

5.2 Battery management systems

Batteries are needed in remote control applications to provide backup power. The disadvantage is that they need maintenance. For example, checking the condition of batteries with the help of portable devices and replacing faulty or old batteries are done manually. The battery management functions of MV/LV substation automation include battery charging, battery condition monitoring and battery discharging monitoring during a fault. In MV/LV station automation devices, e.g. ABB Rec 523, the status of the condition check can be read remotely from the memory registry of the device (The ABB Group 2008). Based on the status measurements replacement of batteries could be planned and scheduled. Compatible batteries with ABB Rec 523 are of a sealed lead acid type, for example. The lead acid batteries have voltage charge dependency, i.e. the charge can be deduced from the voltage with respect to the nominal. Lead acid batteries have been found to be suitable for temperatures below 0°C, although the operation time is reduced in cold temperatures. Therefore, the heating of auxiliary compartment also increases the operation time during an interruption. (The ABB Group 2008)

The ABB Rec 523 device, for instance, uses a low-rate discharge test for battery condition monitoring. The battery will be loaded by auxiliary systems when the charging voltage has been low for a period of time. Simultaneously the voltage is measured. After a period the voltage is checked, a large voltage drop indicates weak condition. Another method used for battery condition testing is a conductivity test. The battery is exposed to a small current signal, which is used to measure conductance, the real part of admittance. According to document (Feder & Hlavac 1994) the test data shows that at low frequencies the (dynamic) conductance of a battery indicates the health of the battery. The conductance test is fast and does not discharge the battery and is suitable for several sealed battery types. The battery condition manager function can be integrated into the automation system of the transformer station. In such a case, it provides a cost-efficient way to manage batteries remotely. Hand-held battery test devices can be used as well, but usually in connection with other maintenance checks. There are also remote control systems for managing large battery banks, such as those of HV/MV substation backup power or LV energy storage. A new automation function could include the temperature measurement of the auxiliary compartment, because the temperature of the compartment holding batteries is needed for precise measurements of the battery condition and the influence on the operation characteristics of batteries. (The ABB Group 2008; Feder & Hlavac 1994; Champlin 1989)

Capacitor power storage units of 240 As are available for less critical, energy-efficient loads. Compared to the capacity of batteries the capacity of the capacitor power storage units is significantly less, because even one Ah is 3600 As, but the capacitor requires less maintenance. The charge is held in the capacitor battery for over 48 hours, if the battery is not loaded or charged. Multiple capacitor battery units provide more capacity. The primary application is probably the distribution automation that does not include motor actuators. However, if motor actuators are used, a charge monitoring system can be found useful. For example, if the charge is too low, the function of the motor actuator could be prohibited, which would leave enough power for the intelligent electronic devices and communication units. The charge left in the capacitor bank could be estimated without any power measurement by calculating the energy used from the elapsed time of the unenergized state and parameterised consumption information. (Kries Electroteknik)

5.3 Moisture and humidity monitoring

Extreme weather conditions are becoming usual due the climate change. Rainy days and repeated temperature changes around 0 °C increase the moisture load of surfaces. Moisture condenses if the surface is colder than the ambient temperature. The condensing is most critical inside automation equipment compartments. The climate change may also cause floods, wind, heavy rain and storms and increasing precipitation, increasing soil moisture, changes in ground water level, erosion, increasing landslides and a change in freezing conditions. Therefore, precautions could be taken by DNOs. Moisture makes iron parts rust and may cause ruptures, which can result in an oil leakage, for example. In transformer stations located in heated buildings the excess moisture could cause mould, which is harmful to human health. Moisture in the soil and its changes can cause changes in the basement structures of historical transformer buildings, for instance. Increasing moisture does not usually cause the malfunctioning of transformers. However, sometimes malfunctioning occurs as in Metsä Tissue Mänttä Mill in Finland, where a short circuit was reported, because hot steam penetrated into some electric facilities. A similar situation is possible when central heating pipes are damaged near the MV/LV transformer station. A short circuit may also cause harmful gas emissions inside the MV/LV transformer station or electric facilities. Therefore, a building automation system which can be used to monitor moisture and humidity changes is introduced. Humidity change information could be used to inform the personnel of the need to be prepared for extra ventilation or water damages. (Martikainen 2006)

Humidity changes in the air inside the transformer station can be measured using building automation systems. In certain building transformer stations in the middle of a high building or in a metro tunnel, for instance, the detection of excess moisture could be used to indicate water leakage. In residential and office buildings this moisture can increase the risk of property damage and lead to mould damage. This damage has had time to develop, because the transformer rooms are entered rarely. Therefore, in these specific places a humidity sensor could be used to indicate and alarm about the excessive level. The alarm could be conveyed both to the building automation system and the distribution management system, where e.g. NIS/DMS could be used to indicate the warning on the map. A Thermokon LC-FA54 V is an example of a humidity sensor, suitable for most transformer station automation systems (Thermokon a). In order to connect moisture sensor with an automation system of the transformer station an extra analogue input and the programmability of the system are needed.

Humidity changes in the air outside the transformer station can be monitored using local measurements at selected MV/LV transformer stations or using a central measurement at a primary substation, for example. Central humidity and temperature measurements are a part of weather information, which can be obtained from weather stations. Together with air pressure information, the occurrence of rain can be deduced. In storms the wind speed also increases. The weather station at the HW/MW substation could be used for a good estimate of local weather changes (Niskanen et al 2009).

5.4 Splash and flood water detection

Storms and heavy rain can make the water flow into a transformer station or a cable cabinet through the ventilation holes in the walls. On the waterfront this may happen due to high waves or flooding. Some park transformer stations are designed to cope with an oil leak. For that an oil pool is used, which can, however, be filled with water leaving no space for the oil leakage. At its worst the water level exceeds the electrical connection point causing a ‘water fault’, a special case of the earth fault or a short circuit. In specific risk areas water leakage detectors could be used to inform the personnel in advance. This gives time to disconnect the supply or change its route. In transformer stations which are located in the basements of buildings a flooding river, pipe damage or sewer flooding can cause water damage. Countermeasures can be initiated after the indication is received from the building automation system. Up to a certain point the water level can be managed by pumping and by blocking paths. An early indication gives time for precautionary measures and thus the functioning electricity system can even save lives. However, a flooded transformer station exposes the personnel to the risk of an electrical shock. One example of a flooding sensor which can be connected to the monitoring system of the transformer station is Thermokon LS02 (Thermokon b). Such a sensor is useful in underground cable cabinets, too.

5.5 SF_6 gas leak detection

Sulphur hexafluoride, SF_6, is a colourless and non-smelling gas, which is used inside the medium voltage switchgear for insulation and for arc extinction purposes. Electric accidents are rare because of the switchgear enclosure. A gas leak can cause two risks. In closed spaces the heavy gas can replace oxygen, which may cause suffocation. If an arc burns inside the SF_6 switchgear, it will produce toxic compounds that can expose the personnel to poisoning if the enclosure is broken. The best practise is to organize the ventilation of the space, if contamination is expected. In the standard SFS 6001 there are requirements for SF_6 switchgear usage. (Helen)

A pressure sensor and a gauge are mostly used to indicate the operation condition of a gas-insulated switchgear. In addition to this gauge, a pressure sensor transmitter could be used, being connected to the transformer station automation system. Based on the indication limits an alarm could be sent to the control centre system and displayed e.g. in the NIS/DMS system in the form of symbols on a graphical map. An oxygen level of less than 19.5 % is dangerous to humans. Therefore, in addition to ventilation, a portable oxygen meter could be used to detect the risk.

5.6 Temperature and ventilation monitoring

Transformer temperature monitoring was mentioned, when transformer overloading detection and the calculation of aging were discussed in Section 2.6. The transformer ambient temperature was used in the calculations (Pylvänäinen et al 2007) and measuring the top temperature of the transformer was also used to manage the risk of fire due overloading (Hyvärinen et al 2009b). As for pole-top transformers, the centralized temperature measurement e.g. HV/MV substation weather station could possibly be used to estimate the ambient temperature. In park transformers cooling could be enhanced with fans. In distribution transformers this option has not been commonly used. The majority of park transformers in many urban network companies are oversized. Based on the temperature measurement the fan control could be also possible. There are two following loading cases, for instance, in which cooling with fans could extend the age of the transformer, if normal-rated transformers are used:

- the warm season cooling load peak, and
- the cold season heating load peak.

The ventilation of building transformers could be equipped with local control (Monni 2003). This local system could also be extended with remote monitoring and indication and perhaps also with remote control. The temperature information history of the transformer could be used to guide transformer replacement and other planning tasks.

Room temperature information may be needed if transformers are located on different storeys or basements of the buildings. Excess heat from the transformer or some other source may make a fire break out. According to (Monni 2003), the room temperature measurement can be used to control the temperature of MV/LV building transformer station. The measurement could also be used to indicate external heat sources. In the cold season the temperature of residential buildings is usually above 0 °C. Unnecessary cooling can produce the loss of energy in heating the building, if the cool air from the transformer room is admitted to the other parts of the building. Energy could be saved if the transformer load and other losses which produce heat could be used for heating during cold seasons. This could complicate the building infrastructure and increase maintenance costs. However, in the context of the heat capture system of the computer server hall, the capturing of the extra heat of the transformer could be cost-efficient (HS 2009). The ventilation system should be in such a location that it can be maintained without disconnect the transformer from the grid (Helen 2009). The same requirement could be applied to other heat exchange systems, if implemented.

Temperature control is used in local auxiliary and DC cabinets i.e. a thermostat controls the heating element. The information and communication devices need to be maintained at temperatures above zero. Also, the operation time of backup power batteries is dependent on the temperature. Therefore, the inner temperature of auxiliary and DC cabinets could be monitored in order to detect the failure of the warming elements. Future battery technology can require heating and cooling. Therefore, optional temperature measurements, monitoring and I/O for the control of heating and cooling could be reserved for future use in the MV/LV automation system. Multiplexing makes it possible to use one analogue to digital conversion port for several measurements.

The room temperature of the transformer station rises if the ventilation is stopped or blocked. Differential pressure switches can be used to monitor the forced ventilation system. The natural ventilation system could be monitored by using e.g. transformer temperature measurements. The ventilation of the MV/LV transformer station can be dependent on or independent of the ventilation of the building in which the transformer is located. Therefore, pressure sensors can also be used to detect if fans malfunction or filters or valves block the air flow. A pressure switch is a pressure sensor which can be connected with the transformer station automation system by using its contact output. In addition, it could also be connected with the DA system using Modbus communication. Modbus enables multiple clients on the same sensor bus. (HK instruments)

5.7 Hatch open detection

Hatches and compartment doors could be monitored by micro switches, also called door switches in some applications. So far that hasn't been done unlike on the doors of building transformers and MV/LV park transformers which can be entered. The door switch is introduced more in detail in Section 5.9. In compact transformer stations the compartment doors are actually hatches. The micro switch can be connected to the digital signal input of the distribution automation device and the device could be programmed to send an event to SCADA or to e.g. the NIS/DMS system via the AMR/AMM integration suite introduced in Chapter 4. A building automation monitoring layer could be added to the NIS/DMS system. Hence, it could be used in a different NIS/DMS client from that used for distribution monitoring. This could prevent confusion with other warnings and symbols and provide easy usability. A draft of a building automation monitoring layer is presented in Figure 38. The NIS/DMS system is used to display the hatch-open warning symbol on a graphical map. This could then be expanded to the graphical alarm presentation shown also in Figure 38, for example. The illustrative graphical information could make use of CAD, i.e. computer aided design, drawings, which the indicating symbols could be attached to. The event information, the transformer station data sheet, manufacturing information, alarm information and scheduled maintenance information could be presented as visualized in Figure 38. The scheduled maintenance information could be used to detect unauthorized access, too.

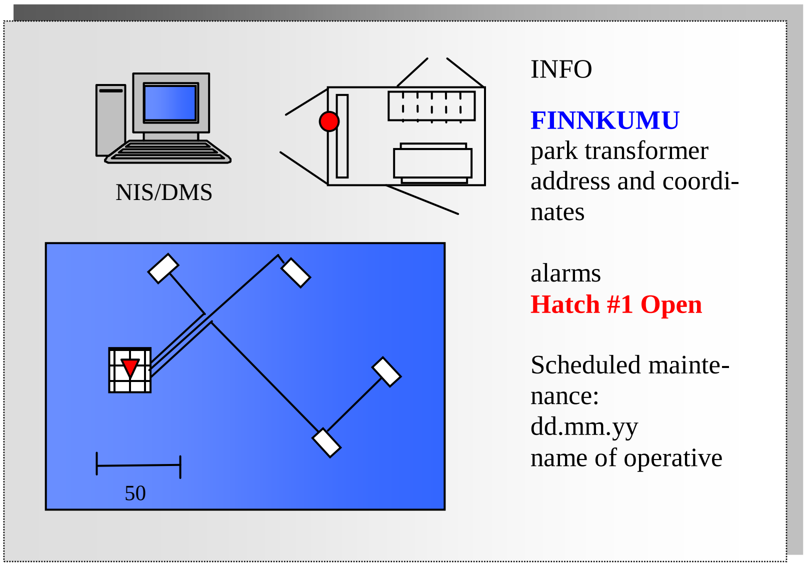


Figure 38. The building automation monitoring layer of the NIS/DMS system, where building automation events e.g. the hatch-open event can be displayed on a graphical map and on a 2D transformer layout drawing. The transformer station information, event description information and scheduled maintenance information is also presented.

5.8 Motion detection

Motion detection could be used at least in two applications: to detect unauthorized access to an MV/LV transformer station and to detect graffiti painters outside the station. The first application needs a sensor inside the station. The sensor could be connected to the automation system of the transformer station. However, timer settings could be needed to eliminate multiple indications from the same entrance. In the anti-graffiti application the multiple motion sensors are located outside the station. The sensors could be connected in parallel and to a single digital input of the automation system. The area which the motion sensor is used can be too large in cities. Therefore, multiple proximity sensors could be used to detect hands spraying on the station walls. Motion detection could also be used to trigger following systems: a camera system, flash light, warning light, a remote indication function and audio warning message system e.g. " Danger, move away from transformer" or just a loud siren sound. The anti graffiti system could be remotely switched off to allow the personnel to approach the transformer without any alarm.

5.9 Entrance detection using door switch

In the Helen Medium voltage transformer station requirements (Helen 2009) it is stated that the lighting of the MV/LV transformer station must adequate, and in addition to general lighting, a door switch which turns on a separate light source should be installed. This door switch could also be used for entrance detection. The idea of entrance detection using a door switch has appeared in the description of the remote supervision system of Dong (Northcote-Green et al 2008) and also at meetings with Helen (Hyvärinen et al 2009a). The door switch can be e.g. a mechanical limit switch. A simple spring mechanism pushes a lever arm out when the door is opened, simultaneously opening or closing the contacts. Also, magnetic door switches have been presented in distribution applications (Kries Electroteknik). The digital input of the automation system of the transformer station often requires logic 24 V dc voltage. The output signal of a mechanical sensor may fluctuate and also the door may be opened several times during maintenance. Therefore, multiple repeated door-open signals should not cause multiple entrance detection indications in the control centre. They must be filtered. The objective is to produce a single-entry detection indication from a single entry.

One filter application could be a timer relay which has an adjustable off delay. The off delay could also be used to control the hold time of the light. The operation diagram of the timer relay is presented in Figure 39. Let us first assume that the light connected to the door switch does not use backup power, but is supplied using 230 V ac voltage. The phase voltage from the LV fuse of the electric centre is connected to U connector of the relay. U is the power input of the timer relay. The door switch return conductor could then connected to the signal input, S, of the relay. The relay operates when the rising edge is received from S. The output, O, and hence the light should immediately be turned on. The output is turned off based on the configured off delay time. The 24 V dc relay, controlled by the 230 V ac voltage, could be used to transform the AC signal into the DC signal, which is used in the automation system of the transformer station. If the door entrance light is combined with an emergency light which uses a 24V backup battery, no such transformation is needed. The rising edge of this 24 V signal could be used to produce an entry indication in the automation system of the transformer station. The off delay could be adjusted on the basis of previous experiences. Off delay could be a couple of hours, for instance. The entry detection indication from the MV/LV transformer station could be stored e.g. in the database of the NIS/DMS system. The time stamp and location information could then used to search the work management database for matches. Also, the scheduled maintenance activities in the management database could be searched for. The objective is to match the entry with the task and the personnel. The functionality could enable the backtracking of events and sequences, personnel safety management and unauthorized access detection.

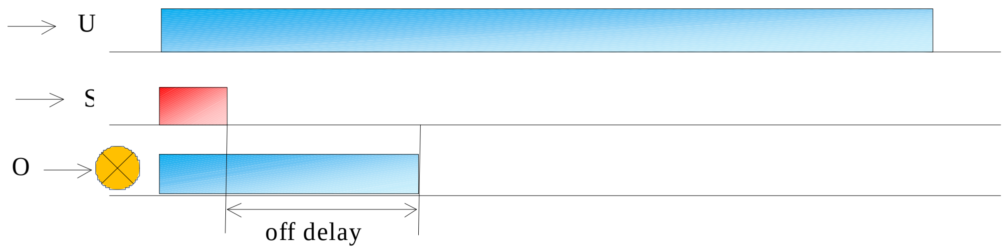


Figure 39. Operation diagram of timer relay, used for door switch signal filtering in MV/LV transformer station entry detection application; U= 230 V ac supply, S= control signal from door switch, O= output to light 230 V ac.

6 CONCLUSIONS

In this chapter conclusions are drawn. The research questions introduced in Section 1.5 are discussed. They were set to outline and focus on MV/LV transformer station and LV grid automation. They were the following:

- the extension of process monitoring path,
- new technologies for intelligent MV/LV and LV management, improved fault detection of MV/LV,
- enhanced PQ management and distortion location functions,
- ICT used in MV/LV management,
- the enhanced usage of IEC 61850 in MV/LV automation, and
- the extra value of auxiliary and building automation systems.

The discussion of the new functions is meant to benefit many DNO processes. These are safety management, network management, asset management, business management, fault management and client relations. The discussion is crystallized by comparing the traditional system with the new intelligent system, which is based on the ideas presented in this thesis. Finally all presented are gathered in a summary.

6.1 The extension of process monitoring path

Monitoring the distribution process consists of power division and short circuit calculations, and the evaluation of the technical conditions of the process, which include e.g. distribution and load estimates, minimum voltage calculations, and protection validation checks. As mentioned earlier, the process is monitored from primary substations at present. In Chapter 2 many improvements to MV/LV transformer station monitoring were introduced. Some of the international improvements were the following: Enel has decided to use LV circuit breakers, Dong has applied an automation system to MV/LV stations, which adds many monitoring as well as control functions and IntDs project applied energy storage and LV voltage control to the LV grid. The SCADA system is used to monitor the primary substation and the distribution process. The state of the relays and remote-controlled disconnectors can be seen in SCADA in real time. The gradual extension of distribution automation to MV/LV transformer stations in Finland was presented in Section 2.3. This included the remote control of MV voltage disconnectors, MV fault detection and MV/LV measurements. The LV circuit breakers used by Enel extend the state monitoring to LV networks. SCADA is used to pass the network switching state information also on to NIS/DMS systems. Thus, the monitoring of the relays of the LV feeders of MV/LV transformer stations could allow the extension of the monitoring done with the SCADA and NIS/DMS systems to LV networks. However, at present the LV circuit breakers are not considered cost-efficient and suitable for harsh distribution conditions which occur in park transformers in Finland. Therefore, also other functions for the switching state monitoring and protection were introduced. Some of these were the following: fuse blown indication could be used to monitor the protection of the LV grid and voltage and current measurements could be used to monitor the state of the LV grid. The idea of monitoring LV switching actions is discussed in details in Section 2.9. New technology enables this extension of monitoring. However, the monitoring of LV grids will increase the number of points and configuration work tremendously. The current SCADA pricing system does not favour the addition of monitoring points, but other ICT systems are already more suitable for the addition of these MV/LV monitoring points. If SCADA is used to connect LV measurements, also the SCADA to NIS/DMS link need to be reconfigured. One possibility to add monitoring points is to use AMR/AMM system interfaces, which were introduced in Section 4.14. The effect of the addition of the fuse blown indication to the SCADA and NIS/DMS systems was presented in Section 2.4.3. The advantage is a more sensitive monitoring system, which would enable a precise and faster response in the case of faults and unauthorized usage, for instance.

The relay protection of MV/LV transformers not only extends the process monitoring path, but also increases safety and flexibility since e.g. the differential protection presented in Section 2.5.2 works in both possible supply directions. Hence, it is also a suitable transformer protection, if distributed generation is added to the LV network, and when its energy is distributed via the MV distribution network. The safety of LV networks could be increased easily by using more copper and the TN-S system with RCD protection. Phase and neutral breakage faults could be monitored better by using Separate N and PE conductors and simple residual current detection (RCD) protection. The disadvantage of the TN-C system is the risk of PEN conductor breakage. However, the usage of the RCD function in the TN-C system was discussed in Section 3.8. The multiple grounding points of the PEN conductor in the TN-C system increases the safety of the TN-C system, but makes fault detection more difficult. The cost of cable installation work in relation to the cost of an additional PE conductor has changed tremendously since TN-C was adopted in Finland. Therefore, the TN-S system and the RCD function monitored remotely could be a solution to extend the process monitoring path to the LV network and to increase safety.

6.2 New DA technologies for intelligent MV/LV and LV management

Communication was discussed in Chapter 4. The umbrella term distribution automation (DA) includes communication specified by the words “remote monitor, coordinate and operate” (Northcote-Green et al 2006). Therefore information and communication technology (ICT) is enabling the DA. The ICT is used e.g. in protection relays. One of the new ICT technologies used in relays is the IEC 61850 protocol. According to the terminology of the IEC 61850 protocol, the relay is called an intelligent electronic device IED. Using this intelligent electronic relay device with IEC 61850 the adjustment of protection settings can be done remotely when the network topology changes. Network topology changes in reserve power applications were introduced in Section 2.5. The selectivity in a static network can be achieved also by using fuses, but if the grid topology changes e.g. as a result of feeder reconfiguration, the protection configuration may need to be changed. In addition to the remote configuration changes, the intelligent electronic relay device enables also many automatic local functions, fault location functions and indications of network events to the control centre. The relay could be used in reserve power applications introduced in Sections 2.5.4 and 2.5.5. The reserve power enables the customers to continue their activities, e.g. to continue business in department stores. The switching interruptions, even as short as 0.4 s, may cause interruption to customers with sensitive processes, but the reserve supply may still enable a controlled shutdown and the use of ventilation and pumps, which may be needed for safe idle operation. Hence, these distribution automation enhancements are justified.

The development of embedded systems, programmable logic controllers and relay technology has produced a number of measuring and monitoring devices capable of communication. The devices can be used to monitor MV/LV transformer stations and LV grids. Some of these devices were introduced in Section 4.4. Also, AMR meters are capable of communication and can be used to provide information from the LV grid. AMR integration to the NIS/DMS system was introduced in Section 4.14. New AMR-NIS/DMS DA functions include e.g. the fault location of LV network and PQ monitoring introduced in Section 3.2. One of the advantages of the AMR NIS/DMS integration system is that it enables the usage of a comprehensive PQ measurement grid and a measurement analysis using the NIS/DMS system.

Transformer overload detection and the calculation of aging is one of the new functions presented in Chapter two, which can utilize information from multiple sources e.g. monitoring and measuring devices and AMRs. The calculation of aging is a part of the enhanced management of MV/LV and LV components. In Section 1.3 it was stated that monitoring the ageing of network components is a part of the regulator activities. Although one of the purposes of the regulator is to speed up necessary replacements, calculating the ageing could be used to avoid unnecessary replacements. The overload detection may extend the operation age of the transformer by providing information for fast decision making, enabling actions to decrease the load. One of these actions may be the load separation to the neighbouring grids. Transformers are typically heavily oversized, i.e. the typical load may be e.g. 50 % of transformer capacity. By providing accurate information from the loading of the transformers, unnecessary over sizing could be avoided and thus extra costs could be avoided. Another new function is real-time network state monitoring, which can be implemented using monitoring and measuring devices. Real-time transformer measurement enables the calculation of real-time customer point of connection (POC) voltage and hence also graphical indications about exceeding POC voltage limits using the NIS/DMS system. Transformer current measurement enables also unbalanced load detection discussed in Section 2.8. The imbalance of three-phase systems increases the load of the neutral conductor and causes stress to the transformer. Therefore, this function could be especially useful for fault management and anticipated maintenance.

6.3 Improved fault detection of MV/LV station and LV grid

In Chapters two and three two types of fault detection were presented: fault detection related to protection functions, and distortion detection and location related to power quality monitoring and fault records. Although the protection device related to fault detection, e.g. the short circuit protection of a relay or fuse blown detection, may more often indicate a permanent fault, the cause of these two may still be the same: a failed distribution network component. However, distortion location may also indicate customer equipment faults. Customer equipment faults may cause distortion to other customers near the location of the disruptive equipment. Both fault detection and distortion detection may even utilize the same current and voltage measurements from the MV/LV and LV grid, assuming that non-saturating measuring components are used. One of the new ideas is a fuse blown detection function based on over current detection, I>. The applications were introduced in Sections 2.4.1 and 2.4.2. One possible implementation could e.g. be a monitoring and measuring device equipped with MUX circuitry to enable multiple measurements (see Figure 7). A harmonic frequency analysis of the MV feeder relay and three in downstream in the LV terminals of MV/LV stations was presented in Section 3.4 as a solution to locate distortion and to evaluate the contribution of each LV grid to voltage quality. The distortion phenomenon can be steady-state or transitory. In Section 3.5 the requirements for transitory voltage measurements for e.g. cable connection or cable insulation fault detection were discussed. In order to catch the distortion and to produce fault records, especially those of non-fuse blowing faults, high sampling frequency, adequate time synchronisation and an enhanced analysis system of the measurements and protection indications will be needed.

An MV feeder fault can be detected automatically from the information acquired from the primary substation or from distributed fault indicators and the fault can be isolated using switching operations in secondary substations. In Section 2.3 it was stated that in Finland remote control systems and MV fault indicators are being increasingly added to secondary substations (Laaksonen et al 2009; Hyvärinen et al 2009a). These stations are carefully selected from among hundreds of substations using different feeder automation selection criteria. The SCADA (supervisory control and data acquisition application) system can monitor faults that primary substation relays, relays used in feeder automation or fault indicators have detected. This SCADA information is available for NIS/DMS (the distribution management system) also and it can be used to calculate and display fault location on the distribution grid map. Earth fault location and step-and-touch voltage warning functions, which use dispersed MV earth fault measurements placed in MV/LV transformer stations, were discussed in Section 3.9. The accurate earth fault location would enable fast fault management actions needed for fault and outage location, fault isolation, feeder reconfiguration and fault repair. The safety of the personnel who is implementing the manual management actions could also be improved by using the step-and-touch voltage warning system. A typical fault management process in LV underground networks starts from the customer indication of the fault. The location of customers that have called the control centre can be used in the NIS/DMS system. In the United States of America, for example, this is used in the location of LV faults. The monitoring of LV fuses could be used to provide real-time and phase-selective information about LV grid faults. AMR-based fault location functions have been developed in the NIS/DMS system. In Section 2.4.3 the fault indication functionality of the SCADA and NIS/DMS systems that use the information from DA of the MV/LV stations and LV grids was presented. A system with both AMR and DA would improve fault detection significantly. A fuse blown detection application, shown in Figure 8, provides a good overview of the advantages of SCADA and NIS/DMS LV monitoring.

The fault management functionality in SCADA and NIS/DMS would be, of course, possible using the information from MV/LV transformer and LV relays. These relays could be used to convey the information which caused the trip, and to capture the distortion waveform. This could allow the use of some distribution management system functions, which are used in the fault management of the MV grid, also in the fault management of MV/LV stations and LV grids. Transformer faults were discussed in Sections 2.5 and 2.5.2. Winding and terminal faults are the major reason for transformer faults. The transformer differential protection is one of the most efficient forms of protection, which can be used to detect, protect and isolate the transformer in these faults. In the short circuit faults of the LV grid, the LV grid could be used to provide the same fault current information needed for NIS/DMS fault locations as seen in the MV network fault location function. An LV earth fault in the TN-C system may cause high fault current, which causes the operation of over current protection. It can also be a cable insulation fault, which is more challenging to discover. The challenges of neutral conductor detection and broken phase conductor insulation detection in TN-C system were discussed in Section 3.8 and also analysed in Section 6.1.

6.4 Power quality monitoring

The PQ system of E.ON Kainuu, a rural Finnish distribution operator, was presented in Section 3.3. At present fixed PQ measurements are commonly located in primary substations and along MV feeders (Niskanen et al 2009; Eurelectric 2009; Niskanen et al 2007). These measurements are then supplemented with temporary measurements. Also, customer complaints are investigated using temporary measurements. The literature review of Section 3.2 contains the results of the extensive PQ monitoring system plans of the KEPCO company. New PQ monitoring technologies would enable the PQ monitoring chain to be easily extended. At the customer POC AMR meters and optional AMR PQ modules can be used to measure power quality. Temporary PQ measurements and the optional PQ measurement device of the fuse-switch can be used in cable cabinets, e.g. see Figure 6c (Efen GmbH 2011). In MV/LV transformer stations monitoring and measuring devices provide many PQ functions, and portable temporary devices can also be used. The main benefits of a PQ system which uses permanent monitoring devices were listed in the CEER study (Eurelectric 2009) and presented in Section 3.2. The disadvantage of too extensive a system is the high cost. Therefore, permanent measurement locations should be planned to monitor the overall situation well and can be used to provide reports for as many customers as possible.

Power quality classes and indices, which were presented in (Cobben 2007) and (Abart et al 2009) and introduced in Section 3.2, could form a basis for graphical presentation, which could provide a good overview of the PQ situation. Many times an overview can provide enough data for the personnel to decide on further procedures. One of these procedures can be investigations using temporary measurements. Accurate power quality and fault recordings are still needed. The distortion phenomenon can be transitory. The result may be a permanently broken device or an interrupted sensitive process. The distortions cannot be captured and localized using PQ devices, which reduce the data by forming indices, e.g. using 10-minute values specified by EN 50160:2010. Also, in order to produce reliable reports to the customer complaints, the measurement device should meet with the requirements of the class A of IEC 61000-4-30. Therefore, power quality measuring devices which can be triggered to store distortion waveforms are needed. New integrated flash memory is presented in Figure 29 in Section 4.5. Using external memory detailed power quality records can be stored from a long period of time. Using data exchange formats IEEE PQDIF 1159.3 and COMTRADE C37.111 the distortion record data could be saved in flash memory in an interchangeable way (Mueller et al 2007). Using new fast wireless communication media introduced in Section 4.10 and an IP network the power quality records could be downloaded and analysed.

The harmonic voltage wave propagation theory was examined in Section 3.4. It was concluded that harmonic voltage distortion is almost fully propagated from the MV/LV transformer station to the customers at the end of a 500-metre LV feeder, but only 10 % is propagated from the customer location to the transformer station (Cobben 2007). This is a guideline when measures against harmonic voltages are considered. A strong grid attenuates the effects of harmonic currents. DNOs recommend that filters are used in customer grids which harmonic currents originate from. LV customers' harmonic currents cause a part of the harmonic voltages in the MV/LV transformer station. Another part of the total harmonic voltage propagates from the MV network and a minor part originates from the transformer. However, a filter placed in the MV/LV transformer station can be used to remove the harmonic voltage that originates from the MV/LV transformer station and hence does not propagate to the locations of the customers. A filter positioned near the customer disruptive load prohibits harmonic currents and hence also harmonic voltage from being propagated from the location of the customer to the transformer station. If all customers should use filters, the harmonic currents do not flow to and sum up in the transformer station. Harmonic currents exist and harmonic voltages exist in LV grids. PQ monitoring enables harmonic trend evaluation and targeting managing measures, if EN 50160 levels are exceeded. Domestic power electronic loads, such as energy saving lamps, home electronic and computers, are increasing. Although many of the new devices need less energy than older devices, they produce both harmonic currents and reactive power. Solutions to prohibit the propagation of harmonic currents include consumer devices with better filters, the usage of filters also in residential buildings, strengthening the grid and the usage of filters also in the distribution grid. The last option will increase distribution tariffs almost certainly, but improve the power quality and allow DNOs to monitor and manage filters in collaboration with other distribution automation. Some new protection functions to be used with filters and the relay protection of the MV/LV transformer station were introduced in Section 3.6. These improve safety and power quality.

6.5 Intelligent management using ICT

The functional processes of Distribution Network Companies (DNO), such as the electric distribution, fault management, client relations, network management and connection management, utilize the information from MV/LV transformer stations, LV cable cabinets or LV grids. Information and communication technology is needed on many levels to provide, to communicate and to process this information. At present a lot of the information used by processes is manually gathered and entered in the distribution management system. The switching state information of LV grid used by connection management and network management processes and the component condition information used by condition management process are examples of the information gathered manually. The ICT architecture also includes SCADA and other distribution management systems, which are used in remote operations. The SCADA schematic diagram, e.g. see Figure 28, shows some possibilities of future functions enabled by ICT. The control and monitoring functions of SCADA could consist of remote-controlled MV disconnectors, a transformer protection relay, transformer temperature measurements, a LV busbar relay, the status information of fuse-switches, different measurements and indications, for instance. These ICT systems were discussed in Chapter 4. The main focus was on MV/LV transformer stations, but also system functions were discussed. ICT can be seen as enabling technology for automatic information acquisition and for local, remote and central functions that utilize this information.

The communication in future is communication using the IP protocol, which is used in local area networks, mobile networks, industrial networks, telephone networks and electric distribution automation networks. The increased usage of the IEC 61850 protocol in primary substations is one of the applications of utilizing the IP protocol in electric distribution automation networks. The application examples of the IEC 61850 protocol have been shown in Chapters two, three, four and five. More thoroughly the protocol was introduced in Sections 4.6 and 4.7. But why IP and IEC 61850 in MV/LV transformer station communication? The information and functions of the MV/LV transformer station is far less than those of the primary substation. The communication network of the MV/LV transformer station may at present consist of a single serial link between the measuring and monitoring device and the communication device. The serial IEC standard 60870-5 was introduced in Section 4.3. At present and in Europe this protocol provides the standard and efficient way to organize both the local and long-distance link communication of the MV/LV transformer station. In America the DNP protocol is used instead of IEC 60870-5. IP networks are used in industrial automation. The process networks are changing from serial communication to Ethernet and IP communication. This change has appeared in distribution automation communication network applications, too. The IEC 61850 usage in the primary substation and the process network applications introduced in (Apostolov 2011) is one concrete example of this change. IP networks are used in wireless and wired communication. They also enable multi-protocol usage. In the physical wiring of MV/LV transformer station equipment the change merely means the changing of wiring to twisted pair or optical.

The usage of electrical network is expected to change gradually. The change can include energy storages, self-healing networks, dispersed energy recourses in MV and LV networks, new protection, demand control and micro grids. Also, energy measurement is automated. The energy meters of MV and LV customers typically communicate using a GPRS or PLC communication network. Therefore, the changes will affect the ICT of the MV/LV transformer station and the LV because it is the part of the distribution grid nearest the customers. The MV/LV transformer station may be used as a connection location for MV distributed generation. It is already a connection place for LV industrial reserve supply, i.e. backup generators. In future it may be a place for energy storage and intelligent transformers introduced in (Kester et al 2009) and discussed in Section 2.1. Therefore, IP is a step towards intelligent grids, but it enables standard automation functions as well, some of which are introduced in this thesis. Moreover, the usage of the

IEC 61850 protocol is superior also in ICT transformer stations and in the communication of the transformer station, because it makes use of object-oriented structures, which enable efficient processing, communication and functionality.

The communication of future DA utilizes multiple communication media. It is a puzzle, which has smaller and bigger parts. A part of the puzzle e.g. the long-distance link of the MV/LV transformer station may need to be changed due the development of communication networks and available services. Therefore, the usage of standard protocols may also aid adapting to the new communication technology, i.e. fitting a new part to the communication puzzle. The communication arrangements may include also bought services from operators or from some other service providers. One of the advantages using these services is that it hides the underlying communication technology and enables DNOs to focus on the distribution management. One of the disadvantages may be a little higher cost, challenging contract management and in possible failure cases also the difficulties in the interpretation of the terms of service.

6.6 Extra value of auxiliary and building automation systems

Protection against overvoltages in MV/LV transformer stations is recommended when the transformer is connected to an overhead MV network. Surge arresters, located as near the transformer as possible on the MV side, are used to protect the MV/LV transformer against overvoltages. This protection provides also some level of protection for the supplied LV grid. The cabled MV grid is not as exposed as the overhead network to lightning overvoltages. New technology, such as communication antennas used by distribution automation, communication antennas of water pumping stations, distributed energy rooftop structures and other nearby metal structures e.g. street lighting or high voltage lines may expose MV/LV transformer station components and the LV grid to lightning overvoltages. The weather conditions also in Finland are changing due to the climate change. Power distribution, as long and as safe as possible, will give extra time for emergency procedures e.g. evacuation under extreme weather conditions. Overvoltage protection located in the LV compartment of the transformer stations or in cable cabinets could be used to protect distribution automation equipment, distributed generation, energy storage equipment and even at some level the equipment of customers. LV overvoltage protection is especially recommended in areas where lightning days are frequent, if there are higher structures than in the surrounding area, if the protected equipment is connected to services which have an increased risk of a lightning strike or if human safety needs to be increased e.g. in hospitals or on biogas manufacturing sites. The usage of surge arrestors was discussed in Section 5.2. The effects of lightning and an overvoltage monitoring system were introduced in Section 3.11. In addition to surge protectors, overvoltage relay protection is used to protect passive filters. The application of filters including overvoltage protection was introduced in Section 3.6. This new technology allows DNOs to organize efficient monitoring and protection against overvoltages.

The protection, control and monitoring systems need batteries for uninterrupted operation. In a cabled urban MV network intermediate switches, remote-controlled disconnectors and fault indicators, for example, are more often located in the MV/LV transformer station, see Section 2.3. Hence, these stations are more often equipped with batteries. These batteries require some automation functions, but also manual checkups are needed. The automation functions include charging and discharging control and monitoring, condition checks and power supply detection. These were introduced in Section 5.2. The manual checkups include battery condition checks with portable test devices and the replacement of batteries. The manual tasks could be scheduled to coincide with other checkups. The automation functions enable a single remote check or checking the condition of the batteries of all remote controlled MV/LV transformer stations systematically using NIS/DMS functionality, for instance. Standard protocols, such as IEC 61850 and the management function of IED could be a solution to integrate the check of the condition of batteries to DA systems and thus the condition management could be done partly automatically and perhaps more systematically.

Building automation allows DNOs to monitor the MV/LV transformer station building environment, ambient conditions, i.e. weather, and to control access to these dangerous facilities. In the control centre the building automation management function could be implemented and integrated to the existing distribution management systems e.g. to the NIS/DMS system. However, in order to avoid confusion with other warnings and symbols and in order to provide easy usability, an optional building automation monitoring layer could be selected and used separately from operational functions. An example and illustration of this kind of monitoring functionality was presented in Section 5.7. Hatch-open monitoring, presented in Figure 38, could provide DNOs with a chance to detect unauthorized access and ensure the safety of the distribution system. In addition to these, automatic records of access with the name of the responsible worker could be kept. This kind of functionality would provide a chance to track possible connection changes.

6.7 Traditional system and new intelligent system

The traditional MV/LV distribution system is designed mainly for energy distribution in one direction, from medium voltage to low voltage. Also, the protection operation is based on the assumption that the direction of the power flow does not alter. The system consists of very few remote monitoring or control functions. The MV fault detection is based primarily on the functionality of protection relays in primary substations. The real-time status information of the MV switchgear, MV/LV transformer and LV grid is missing. The network switching state and status information of MV/LV transformer stations and of the LV network is based on the actions and reporting of the field personnel. Fault indications from customers are typically received by phone.

The new system is either a hybrid, i.e. a mixture of the conventional and the new or a full micro grid system. New system functions could also be taken into use gradually based on the new distribution requirements. They can be built from modules e.g. intelligent MV/LV transformer station components or intelligent LV distribution cable cabinet components. The advanced and piloted systems, introduced in Section 2.1, already gave an overview about the possible functionality of the new system. Also, the Finnish DNO review in Section 2.3 extended this overview. In the Helen (Hyvärinen et al 2009a; Siirto et al 2009) and Dong (Northcote-Green et al 2008; Vinter et al 2005) solutions the MV functions based on MV/LV transformer station information form an essential part of the new system. These functions include e.g. MV circuit breaker open and close control, MV breaker position monitoring, MV directional short circuit indication, MV nondirectional short circuit indication, MV fault location indication, distance to fault in ohms and MV earth fault indication. The functions based on LV information can, therefore, be classified as supplementary (Laaksonen et al 2009; Hyvärinen et al 2009a). The IntDs –project system (Kester et al 2009) also includes a self-healing MV network feature enabled by providing the switchgear with the function of automatic transfer to another MV feeder, but the MV/LV and LV functions are essential. These functions include e.g. energy storage, LV voltage level regulation, monitoring and shaping power quality and matching the demand and supply of power.

The SCADA and NIS/DMS monitoring views present well the potential monitor and control functions of the new MV/LV transformer station system. The first step, the SCADA monitoring extension to LV grids, was presented in Figure 4. The old system view consists of the primary substation MV feeder relay and the symbols of manual MV feeder disconnectors located in the MV/LV transformer station. The new system view also presents the manual transformer MV disconnectors and LV switchfuses. Hence, the monitoring is extended to the MV/LV transformer station, although the information about switching event is received by phone from the field personnel. The second step, the MV and LV side measurements and indications of the transformer station is presented in Figure 5. These measurements could include transformer loading, LV voltages and currents and total harmonic distortion (THD) value (Laaksonen et al 2009, Hyvärinen et al 2009a). The indications could include e.g. MV disconnector position monitoring, MV switchgear gas pressure alarm, transformer temperature alarm and battery voltage alarm. The third step, the addition fuse blown detection to the SCADA and NIS/DMS systems is presented in Figure 8. The SCADA schematic diagram of the MV/LV transformer station with the fuse blown detection of fuse-switches consists of a fault indication and a red blown fuse symbol. The NIS/DMS fault indication consists of the red triangle symbol on the distribution map and a fault indication message. The monitoring of LV fuses could provide real-time feeder and phase-selective fault information about the LV grid.

The MV feeder protection of the old system contains an MV feeder relay in the primary substation. The feeder relay controls the feeder switch and in MV feeder faults the entire feeder is disconnected. In the new system, in addition to the MV feeder relay, also intermediate relays could be located in 1–3 locations along the MV feeder. In a cabled network the location of the intermediate relay is the MV/LV transformer station, which is also called a secondary substation. The number of these stations may be 3–4 % of all secondary substations. In the new system distributed generation (DG) can be connected along the MV feeder. Therefore, the transformer stations which have an intermediate MV relay may have unique requirements for protection coordination and communication. The relay protection of distributed generation connected to MV feeders is discussed in (Nyberg 2008). An application example of MV/LV transformer station communication requirements was presented in Section 4.9. An idea of loss of mains protection of DGs and of suitable communication architecture was presented in Figure 33. The idea consists of an IP network, the usage of the IEC 61850 protocol, GOOSE messaging and VLANs. This example shows how the new system with intermediate MV-relays, distributed generation and LoM protection requirements may have an impact on the vertical communication of the MV/LV transformer station.

The old MV/LV transformer component protection consists of MV fuses. The MV fuses are used to protect the transformer from the faults of high fault current. In the new system relay protection can be used for better transformer protection. The advantages and disadvantages, additional costs and technical grid protection requirements could be considered case by case. The advantages of relay protection were discussed in Section 2.5. In addition to the better protection of the transformer component, one of the essential advantages is also the remote monitoring and control. The fault information about the MV/LV transformer station can be received at the control centre in real time. If the exact fault is known, the field team can be equipped with correct spare parts and a diesel generator, for instance, before the team is dispatched. Another advantage of relay protection is the possibility to adjust and change the protection settings. In future the protection chain could be checked using the simulation features of the NIS/DMS system and then these correct settings uploaded to the transformer protection relay. The time-overcurrent plot design method, used for protection planning, was presented in Section 2.5.1 and in Appendix 1. The correct protection settings and protection grading margin needed for selective protection can be determined using this method. In the old system it is also assumed that the direction of the power flow is from the MV network to the LV network and there is no high penetration of distributed energy resources connected to the LV network. If the power flow direction can be changed, new transformer protection e.g. differential protection, presented in Section 2.5.2, is needed. The differential protection of the MV/LV transformer improves the safety of the MV/LV transformer station by providing better protection, but it may be exposed to auxiliary system failures e.g. battery supply failures and configuration mistakes.

Automatic switching functions are not utilized in the old system. In the new system relay intelligence could be used to detect power interruptions and to initialize automatic reserve power connection sequences. Two reserve power applications which utilize automatic switching functions were discussed in Sections 2.5.4 and 2.5.5. In Figure 12a SCADA schematic diagram the first automatic switching function was presented. In this function the intelligence of the LV busbar relay was used to detect supply interruption and then to initialize an automatic sequence, in which the LV bus is separated, new configuration settings are commanded to be used in relays, the generator protection relay is commanded to wait until the generator is ready and to then close. Another SCADA schematic diagram including an automatic switching function was presented in Figure 13. In this function the intelligence of the MV/LV transformer protection relay and SCADA are used. The SCADA schematic diagram was used to present a reserve power supply situation from the neighbouring transformer station using the LV core connection cable network and the remote changeover function. As a result of the function, the interrupted LV grid was powered from the neighbouring transformer station using automatic and remote control procedures. Similar reserve power applications that were presented in Sections 2.5.4 and 2.5.5 could already be found in some industrial distribution grids, in paper mills or chemical factories, for example. This kind of enhancement reserve power automation could therefore be used to provide a similar service to the LV customers DNOs.

In the new system the measuring and monitoring functions of MV/LV transformer stations IEDs provide useful process monitoring and power quality information from the MV/LV transformer station and the LV grid. In distribution management systems, i.e. SCADA and NIS/DMS, this information can be further used by many functions. The measurement and indication view in SCADA presented in Figure 5 shows a typical use. The deduced functions presented in this thesis consist of e.g. MV/LV transformer overload detection and the calculation of aging introduced in Section 2.6, real-time LV network state monitoring introduced in Section 2.7, unbalanced load detection function introduced in Section 2.8 and power quality database and NIS/DMS power quality analysis functions referred to in Sections 3.2 and 3.3. The Council of European Energy Regulators (CEER) recommends that voltage quality monitoring programmes be put in place in European countries. PQ monitoring functions enable the PQ monitoring chain to be extended to MV/LV transformer stations. The temporary measurements and AMRs allow the monitoring chain to be extended even further. However, in order to produce reliable and standard measurements and reports, the measurement device should meet with the requirements of the IEC 61000-4-30 standard class A. At present this is achieved only by using temporary measurement devices. Also, exchange formats IEEE PQDIF 1159.3 and COMTRADE C37.111 could be used to produce interchangeable power quality records data.

The new system utilizes new ICT technology. ICT enables the SCADA control and monitoring of the MV/LV transformer station, see Figure 21. ICT also enables the interaction of multiple systems. For example, an overvoltage monitoring and lightning reporting system was presented in Figure 27. In both these applications the interaction and functions of the power quality database system, SCADA and NIS/DMS are essential.

A communication protocol theory, IEC serial communication protocols and a review of the use of serial protocols in measuring and monitoring devices were presented in Chapter four, as well as new information and communication technology for distribution automation usage. These were e.g. the IEC 61850 communication architecture presented in Section 4.7 and IP routing architecture in Section 4.11. Future communication will use the IP protocol. It is used in local area networks, mobile networks, industrial networks, telephone networks and electric distribution automation networks. The increased usage of the IEC 61850 protocol in primary substations is one example of IP protocol utilization and a driver to the other applications of electric distribution automation. The MV/LV application examples of IEC 61850 protocol usage have been presented in

Chapters two, three, four and five. More thoroughly the protocol was introduced in Section 4.6 and Section 4.7 and discussed in Section 6.5. The routing of IP traffic enables the usage of multiple communication links between the MV/LV transformer station and the control centre or the primary substation. The routing of traffic could be used to enable e.g. multiple IP long-distance links from two ISPs and a wireless IP link connection via the primary substation. Routing increases the reliability of the communication system e.g. during 2G or 3G base station service breaks, which may be caused by an interruption in the electric distribution system.

The new system also consists of auxiliary and building automation systems presented in Chapter five. The integration of building automation monitoring to the existing distribution management systems was discussed in Sections 5.7 and 6.6. An example and illustration of building automation monitoring was presented in Section 5.7 and Figure 38. The monitoring could be realized in an optional building automation monitoring layer, used separately. This could prevent the confusion with other warnings and symbols and to provide easy usability. The systems presented in Chapter five included e.g. overvoltage protection using surge arresters, the management of power backup batteries, and a variety of building automation functions e.g. moisture and humidity monitoring, splash and flood water detection, SF_6 gas leak detection, temperature monitoring in the MV/LV station, air ventilation monitoring, hatch-open detection, motion detection and entrance detection using door switch functions. The new systems provide DNOs with valuable information about auxiliary systems, the building environment or about the cabinet entry, for example.

At the beginning of each chapter a process map of DNO key processes were presented. The functions could provide information for e.g. network management, fault management, safety management, asset management processes. However, practical tests to discover the benefits of these functions were not conducted in this study. The objective was to introduce ideas and create discussion among distribution network companies, component manufacturers, customers, the regulator and the research community. Unfortunately, the results of this discussion cannot be estimated beforehand. Only a few of all the MV/LV transformer stations in Finland are equipped with DA. Therefore the examination of benefits of the MV/LV distribution automation is difficult.

6.8 Summary

Distribution automation and DA functions needed for the management of MV/LV stations and LV grids were presented in this thesis. These new presented management functions provide a process monitoring path from the primary substation through feeder automation to the automation of the LV grid. These functions also enable MV/LV fault detection, transformer and LV network monitoring and efficient operation in fault situations, for instance. They were presented in Chapters two and three. The extension of power quality monitoring to MV/LV transformer stations and LV grids was discussed in Chapter three. Information and communication technology that is used to enable distribution automation was introduced in Chapter four. The MV/LV automation system can also be extended with auxiliary and building automation systems. These were presented in Chapter five. Finally, the discussion of the research questions was presented in Chapter six.

The majority of distribution automation systems exist in primary substations and in control centre at present. On a minor scale DA exist at specific locations along MV feeders. MV/LV transformer stations and LV grids are managed based on calculations, consumption profiles, manual measurements and checks and customer indications received by phone. This has been both cost-efficient for DNOs and adequate service for the majority of customers. However, network investments are long-term investments and more and more intelligence is expected in the future. Investments in future intelligence are especially problematic at MV/LV transformer stations and LV grids because many of the possibilities are unknown and because this part of the distribution grid forms such a great share of the entire distribution network asset. The objective of DNOs to provide equal service to all clients is better justified using SAIFI and CAIDI et al. in accordance with MV network improvements. At the beginning of gradual and long-term MV/LV and LV grid automation improvements the customers will be placed in an unequal position. At present some technologies, such as passive and active filters, are efficient and most cost-efficient nearer customers and at the LV voltage level. The urban network MV feeder management already includes MV/LV remote control and monitoring functions. In these MV/LV transformer stations further investments in MV/LV and LV grid automation can be seen as a small additional cost. In addition to the improved management of the DNO processes and constantly tightening requirements for reliability, MV/LV and LV automation may also offer solutions to the new flexibility requirements of energy storage, demand management and distributed generation applications, for example. However, the discussion, outlined by the research questions, concentrated on better overall management and improved reliability and safety.

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Appendix 1. A simulation case study of overcurrent protection

This simulation case study presents a time-overcurrent plot design method used for the overcurrent protection planning of the distribution network. The simulation is done using Digsilent and the simulated network model is presented in Figure A1 (Kauhaniemi 2010). The model includes, from top to down: an external grid connection, a primary substation with two busbars, a modelled MV feeder, a MV/LV transformer station, a modelled LV feeder and a LV busbar of the customer with a motor lo.ad. The busbar short circuit current levels are shown inside the boxes. The arrows indicate the position of the protection devices and the coloured rectangles show the protection zones, which these devices are configured to protect. The primary substation MV1 busbar relay (1) is used to protect the red zone, the primary substation MV2 busbar and short circuit level reducer relay (2) is used to protect the green zone , MV feeder relay (3) the blue zone and MV/LV transformer relay (4) the yellow zone.

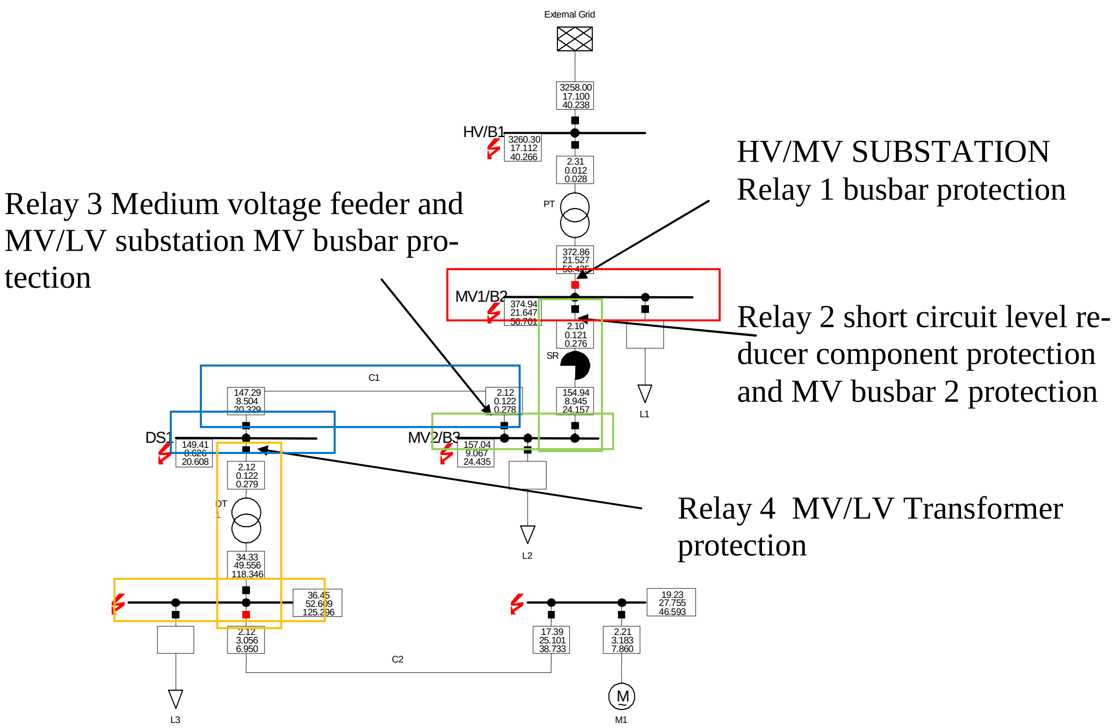

Figure A1. A Digsilent model of the simulation case study of distribution grid overcurrent protection. The protection zones from feeding substation to MV/LV transformer are presented with colored rectangles and the configured relays are indicated with arrows.

Figure A2 shows the time-overcurrent plot method used in protection chain planning. This plot presents the overcurrent protection operation in the simulated network, see Figure A1. The vertical axis shows the overcurrent and the horizontal axis operation time needed for the protection to operate. The following can be deduced by exploring the plot. The curves 1-12 and the relays 1-4 mentioned below refer to figures A2 and A1, respectively.

- MV/LV transformer protection operation curve (7),

  → relay 4 operates before the damage curve of transformer, i.e. curve (6),

- the MV feeder protection curve (8),

  →the operation time of relay 3 is slower and the current is higher than those of relay 4 protection the transformer

  → in a transformer fault or in a LV busbar fault both relays 3 and 4 should detect the overcurrent, but only relay 4 should operate before relay 3, and

  → curve (2), in a fault in the LV grid, the LV feeder fuse operates before the relay operates.

Figure A2. Simulation case study: Digsilent time-overcurrent plot of the overcurrent protection operation of the simulated network. This plot can used to determine selective relay settings in the distribution grid. **1**. load current of the fuse-protected LV feeder of MV/LV transformer station, **2**. fuse melt curve, LV feeder **3**. load current of the MV feeder serving the MV/LV transformer, **4**. load current of MV busbar 2 (in HV/MV substation), **5**. load current of the substation busbar, **6**. damage curve of the MV/LV transformer, **7**. operating curve of MV/LV transformer protection relay 4, **8**. operating curve of MV feeder relay 3, **9**. operating curve of MV busbar 2 relay 2 (in HV/MV substation), **10**. operating curve of MV busbar 1 relay 1, **11**. LV feeder damage curve, **12**. MV feeder damage curve.

Appendix 2. Parts of the standard IEC 61850

Table A2. Parts of the IEC 61850 standard and descriptions of the parts (IEC 2011).

STANDARD	DESCRIPTION
IEC 61850-1	Communication networks and systems in substations - Part 1: Introduction and overview
IEC 61850-2	Communication networks and systems in substations - Part 2: Glossary
IEC 61850-3	Communication networks and systems in substations - Part 3: General requirements
IEC 61850-4	Communication networks and systems in substations - Part 4: System and project management
IEC 61850-5	Communication networks and systems in substations - Part 5: Communication requirements for functions and device models
IEC 61850-6	Communication networks and systems for power utility automation - Part 6: Configuration description language for communication in electrical substations related to IEDs
IEC 61850-7	Communication networks and systems in substations - Basic communication structure for substation and feeder equipment
	IEC 61850-7-1: Principles and models
	IEC 61850-7-2: Abstract communication service interface (ACSI)
	IEC 61850-7-3: Common Data Classes
	IEC 61850-7-4: Compatible logical node classes and data classes
IEC 61850-8	Communication networks and systems in substations - Specific Communication Service Mapping (SCSM)
	IEC 61850-8-1: Specific Communication Service Mapping (SCSM) - Mappings to MMS (ISO 9506-1 and ISO 9506-2) and to ISO/IEC 8802-3
	IEC 61850-8-2: Specific communication service mapping (SCSM) - Mappings to web-services
IEC 61850-9	Communication networks and systems in substations - Specific Communication Service Mapping (SCSM)
	IEC 61850-9-1: Sampled values over serial unidirectional multidrop point to point link
	IEC 61850-9-2: Sampled values over ISO/IEC 8802-3
IEC 61850-10	Communication networks and systems in substations - Part 10: Conformance testing