TAMPEREEN TEKNILLINEN YLIOPISTO
TAMPERE UNIVERSITY OF TECHNOLOGY

LAURI LÄHTEENMÄKI

# SMART DISTRIBUTION NETWORK FUNCTIONALITIES - INFORMATION AND COMMUNICATION TECHNOLOGY REQUIREMENTS FROM A STRATEGIC PLANNING PERSPECTIVE

Master's thesis

Examiner: Professor Sami Repo

Examiner and topic approved by the Faculty Council of the Faculty of Computing and Electrical Engineering on 5 May 2014

# ABSTRACT

**LÄHTEENMÄKI, LAURI**: Smart distribution network functionalities - Information and Communication Technology requirements from a strategic planning perspective
Tampere University of Technology
Master of Science Thesis, 87 pages, 12 Appendix pages
May 2015
Master's Degree Programme in Electrical Engineering
Major: Power systems and market
Examiner: Professor Sami Repo

Keywords: Distribution network, strategic planning, communications, protection, automated fault location, isolation and restoration, smart grid

Advanced automation functionalities present a viable alternative for improving the reliability level experienced by the customers in a electricity distribution network in addition to other methods. The requirements imposed on information and communication systems vary according to the chosen implementation of the automation features. The purpose of this study is to examine two functionalities and their requirements. Main objective is to clarify the main differences between alternative implementation options and to support the decision making process of the distribution system operator by a financial evaluation of the functionalities.

The thesis consists of two parts. The chosen automation solutions, multi-level protection of medium voltage feeders and automated fault location, isolation and restoration, are introduced and examined in the first part. The basis for economic viability studies are also identified and discussed. In the second part, the financial aspect is explored through case analysis and with reference to current regulatory framework.

Three fundamental operation alternatives are found for both automation functionalities. The requirements set for field equipment, communication network and control center IT systems range from similar to those of present ones to a demand of highly intelligent integrated system. Especially the scenarios with independent field agents utilizing distributed decision making provide challenges to system design.

The effect on reliability of the network is assessed in typical rural and urban environment. Both of the features presented show a potential for improvement. The resulting customer outage cost benefits are notably greater in rural area, but some advantage is also gained in urban environment. However, the needed investments in urban network surpass the economic benefits. In rural network the implementation is profitable, provided that the current IT and communication systems are adequate or only part of the system require renewal.

# TIIVISTELMÄ

**LÄHTEENMÄKI, LAURI**: Tiedonsiirto osana strategista verkon suunnittelua ja kehittämistä
Tampereen teknillinen yliopisto
Diplomityö, 87 sivua, 12 liitesivua
Toukokuu 2015
Sähkötekniikan koulutusohjelma
Pääaine: Sähköverkot ja -markkinat
Tarkastaja: professori Sami Repo

Avainsanat: Jakeluverkko, strateginen suunnittelu, tiedonsiirto, suojaus, automaattinen vian etsintä ja rajaus, smart grid

Kehittyneen verkostoautomaation hyödyntäminen on varteenotettava vaihtoehto jakeluverkon luotettavuuden parantamiseksi muiden toimien lisäksi. Tietojärjestelmille ja tietoliikenneverkolle aiheutuvat vaatimukset riippuvat pitkälti valituttujen toiminnallisuuksien toteutustavasta. Tämän työn tarkoitus on tutkia kahta edistynyttä automaatiotoiminnallisuutta ja niiden asettamia vaatimuksia. Päätavoite on selvenetää tärkeimpiä eroavaisuuksia eri toteutusvaihtoehtojen välillä ja tukea jakeluverkkohaltijan päätöksentekoprosessia toiminnallisuuksien taloudellisella arvioinnilla.

Työ koostuu kahdesta osasta. Moniportainen lähtöjen suojaus ja automaattinen vian etsintä, rajaus ja palautus esitellään ja niitä tarkastellaan ensimmäisessä osassa. Taloudellisen tarkastelun perusteteet tunnistetaan ja niiden vaikutusmekanismia pohditaan. Toisessa osassa taloudellista kannattavuutta tutkitaan case-tapausten analyysillä ja regulaattorin valvontamallin avulla.

Kolme päätoimintamallia tunnistetaan molemmille automaatiosoveluksille. Vaatimukset verkon toimilaitteille, tietoliikenneverkolle ja käytön tietojärjestelmille vaihtelevat nykyisen kaltaisista älykkään integroidun järjestelmän tarpeeseen. Erityisesti mallit, joissa hyödynnetään itsenäisiä toimilaitteita hajautettuun päätöksentekoon aiheuttavat haasteita järjestelmäsuunnittelussa.

Automaation luotettavuusvaikutuksia arvioidaan sekä tyypillisessä kaupunkialueen jakeluverkossa että maaseutuympäristössä. Molemmila esitellyillä toiminnallisuuksilla voidaan saavuttaa luotettavuusparannuksia. Parannus keskeytyksestä aiheutuviin haittakustannuksiin on huomattavasti suurempi maaseutuverkossa, mutta pienempiä hyötyjä on mahdollista saavuttaa myös kaupunkiympäristössä. Tarvittavat investoinnit ovat kuitenkin kaupunkialueella niin suuret, ettei automaation lisääminen ole taloudellisesti kannattavaa. Maaseutuverkossa toiminnallisuuksien käyttöönotto on kannattavaa, jos nykyisiä tietojärjestelmiä ja viestiverkkoa voidaan hyödyntää tai ne joudutaan uusimaan vain osittain.

# PREFACE

This study has been done as part of Smart Grids and Energy Markets research program of CLEEN Ltd. Established in 2008, CLEEN Ltd. is a Finnish research cluster in the field of energy and environment. CLEEN Ltd has 45 shareholders consisting of major international companies and national research institutes.

I would like to express my gratitude to Professor Repo for examining my thesis and for the valuable input during our conversations. I wish to also thank my supervisor Jarmo Saarinen (MSc, Tech.) for the guidance and practical advices during the project.

This has been a long journey. Finally, I wish to thank my wife Minna for the patience and understanding.

March 3rd, 2015

Lauri Lähteenmäki

# CONTENTS

## TERMS AND DEFINITIONS

| | |
|---|---|
| CAIDI | Customer average interruption duration index |
| CPI | Consumer price index |
| COC | Customer outage cost |
| DAR | Delayed automatic reclosing |
| DG | Distributed generation |
| DMS | Distribution management system |
| DSO | Distribution system operator |
| FLIR | Automated fault location, isolation and restoration |
| HSAR | High-speed automatic reclosing |
| IED | Intelligent electronic device |
| ISO | International Standards Organization |
| IRR | Internal rate of return |
| OSI | Open system interconnection |
| PV | Present value |
| RMU | Ring main unit |
| RNA | Reliability-based network analysis |
| RTU | Remote terminal unit |
| RV | Replacement value |
| SAIDI | System average interruption duration index |
| SAIFI | System average interruption frequency index |
| SCADA | Supervisory control and data acquisition |
| WACC | Weighted average cost of capital |

# 1. INTRODUCTION

At the same time as society's reliance on electricity has increased rapidly, it has become clear that the electricity distribution in its current state does not meet the stricter requirements for quality and reliability of supply. Major winter storms of 2011 and 2013 caused outages in broad areas leaving customers without electricity for days or even weeks (Pörssitiedote 5.1.2012; Häiriötiedote 13.12.2013).

Distribution utilities have been obliged to improve the overall reliability of their networks with a recent additions in Electricity Market Act. After a 15 year transition period, customer's storm or snow related outage cannot last for more than 6 or 36 hours, depending on whether they live in area covered by a town plan or not. (L 1.9.2013/588)

Renewal of old distribution network, mainly consisting of overhead lines, with a structurally more weather resistant technique will surely be the primary method to meet the strict legislative requirements. Depending on the operational environment of the utility, the overhead lines could be replaced with underground cables or covered conductors in conjunction with moving the line alongside a road. Effective fault repair organization is also crucial as technically fully fault free network is neither possible to achieve in real world nor financially viable scenario.

Advanced network automation could be utilized to improve the reliability level during the transition period and to assist in the fault clearance process  especially in the event of major disturbances. The effect of fault could be limited efficiently to the smallest possible area with automated fault location and isolation system. Repair crews could be dispatched efficiently to the faulted location and power restored automatically to customers outside the faulted section.

Another possible method would be addition of protection zones on a feeder. This would also limit the impact of a fault to a certain segment of the feeder. The fault location, isolation and restoration sequences could then be applied to further reduce the number of customer affected.

Both of these solutions have multiple alternative implementations options. Depending on the chosen method, the requirements for field devices and secondary systems vary. Keys to successful implementation are integrated information systems and effective communication system between the subsystems.

The purpose of this thesis is to explore the different technical solutions for described automation solutions and to identify the set requirement level for mainly communication but also other IT systems. This enables the comparison of found solutions and further, more specific studies.

Another objective is to analyze the advanced automation scenarios from the asset management viewpoint. Main question is the viability of such investments against the regulatory framework currently in place. The effects of automation will be simulated with the help of available tools in network information system using real distribution network data.

The subject of network automation could be easily broadened to include other automation functionalities or deepened within the chosen applications. Interesting related topics include the handling of distributed generation with multiple consecutive protection zones, utilization of current and voltage sensor data required for protection to other applications and adaptive relay setting values. However, the main focus of this thesis is on the two chosen functionalities and their evaluation and additional features are excluded from the thesis.

# 2. COMPARISON BETWEEN TRADITIONAL DISTRIBUTION NETWORK AND SMART GRID

A distribution network forms the final part of the electric power delivery system between the generation and transmission of electricity and the end-user. On account of the principles which the different subsystems are constructed and operated, the distribution system determines the quality of the supply to a great extent. As discussed above, the requirements for uninterrupted, high quality supply of electricity have increased. Therefore a thorough examination of traditional distribution network is needed in order to detect the potential course of actions to improve reliability.

Reliability has been one of the central focus areas in various ongoing research programs, that intent to develop solutions to existing challenges and rising needs in the future (Smart Grid R&D Multi-Year Program; Visions and Strategy for European Electricity Networks of the Future). Widely used term for a vision of such future network described in these programs is smart grid. Although details may vary, a smart grid is generally seen as flexible and intelligent grid, that enables energy distribution in an energy- and cost-efficient way. In this chapter certain key aspects of smart grids are introduced and compared with a traditional grid with emphasis on network automation.

## 2.1 Traditional distribution network

A distribution system consists of high voltage (HV) regional networks, high to medium voltage transforming substations or primary substations supplying medium voltage (MV) networks and further medium to low voltage secondary substations and low voltage (LV) networks. The HV networks are supplied by inter-regional transmission network. Most customers are connected to LV network, but large customers connect directly to the MV or HV networks. The basic structure of the distribution system is presented in Figure 2.1 with an arrow indicating the direction of power flow. (Lakervi & Holmes 2003)

Differences in network design practices between distribution system operators (DSOs) have given rise to regional variance in system arrangements and technical solutions. However, the elemental features remain similar. The network is operated radially practically without exception due to simpler protection arrangements and better controllability. (Lakervi & Holmes 2003)

In rural areas the distribution network usually has a partially looped construction. Backup connections to MV feeders from the same or adjacent substation exist, but still long branches may remain prone to lengthy outages in the remote areas. MV lines are typically overhead lines with bare or insulated conductors and secondary substations pole-mounted. LV distribution is arranged with aerial bunched cables or underground cables. (Lakervi & Holmes, 2003)

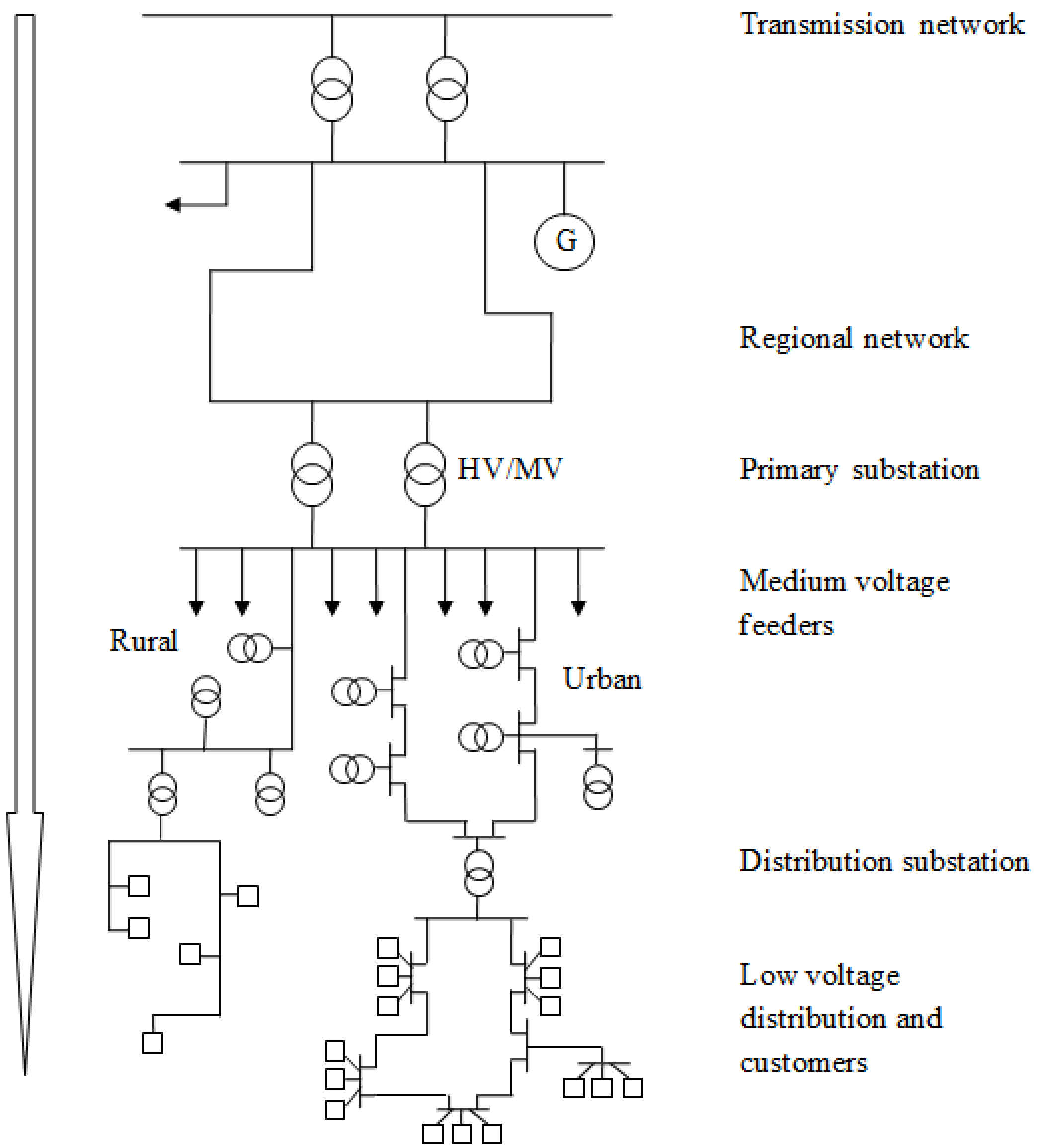


***Figure 2.1.*** *A simplified structure of distribution system. The arrow indicates the direction of power flow.*

In urban areas the network is constructed in a more tightly looped arrangement with two or more alternative supply routes to almost every distribution substation. Underground cable is primary choice for both MV and LV lines and secondary substations are pad-mounted with steel or concrete enclosures or placed in the basement of buildings. (Lakervi & Holmes 2003)

Other primary components relevant to this work are different sort of switchgear, such as circuit breakers and disconnectors. Switchgear is used to disconnect faulted equipment to prevent further damages, to allow maintenance or other work to be done on isolated part or to group circuits into a specific configuration for operational purposes. A circuit breaker is capable of breaking both load and fault current, whereas typical disconnector can only open or close a circuit with very limited current. Specific load-breaking disconnectors are available with higher current breaking capacity. (Lakervi & Holmes 2003)In Finland MV feeders are typically protected with one circuit breaker placed at the beginning of the feeder at a substations feeder cubicles. Secondary circuit breakers along the feeders are rare. (Lakervi & Partanen 2008)

In addition to primary components a distribution system comprises of various secondary components and systems. These include protective relays and auxiliary low voltage systems in primary substations, remote control and monitoring system, distribution management system and communications system for network operation and other extensive information systems, such as network information system and customer information system. (Lakervi & Partanen 2008)

## 2.2 Smart grid

Smart Grid (SG) is a general term describing a smarter future energy system and electricity grid. Different visions of SG exist, such as SmartGrids of European Technology Platform (ETP), Smart Grid Research & Development Program of U.S. Department of Energy (DOE) and Smart Grids and Energy Markets (SGEM), which is a Finnish research program coordinated by CLEEN Ltd . All see that the aging network doesn’t fulfill future requirements and demands for energy supply (Smart Grid R&D Multi-Year Program; Visions and Strategy for European Electricity Networks of the Future; Cluster for energy and enviroment). As the current grid approaches the end of its lifetime in the near future, it would be a logical opportunity to upgrade it to meet the modern standards.

The key features associated with Smart Grid are flexibility to respond to changes and challenges, accessibility in terms of all network connection and especially distributed generation, improved reliability and finally cost efficiency through innovation, efficiency and competition. These high level objectives are thought to be achieved through a combined effect of several new or improved techniques and approaches. Among other things this means increasing penetration of distributed generation (DG), smart metering and demand response (DR), microgrids and increased level of automation. (Visions and Strategy for European Electricity Networks of the Future)

From the perspective of distribution networks a smarter grid means convergence with the transmission networks characteristics. Distributed generation connected to low or medium voltage distribution networks will introduce two way power flow to the system. Depending on the form of production the momentary power produced by the DG can fluctuate significantly causing the direction of the power flow to also change accordingly. The distribution system has to be able to adapt to these rapid changes constantly. In addition, compliance with the safety and voltage quality requirements has to be ensured at all times. Thus more active management of the network and increased level of information of the state of the grid are required along with advanced automation functionalities and developed information and communication systems to fulfill these requirements. (Strategic Research Agenda for Europe's Electricity Networks of the Future)

## 2.3 Primary substation automation

A primary substation is the linking part between the HV network and the MV network. It consists of a HV switchgear, one or several main transformers, a MV switchgear and an auxiliary low voltage system along with protection, control and communications systems. HV and MV switchgear can be either air- or gas-insulated and their busbar arrangements vary according to requirements for reliability, maintenance and operational reasons. (Lakervi & Partanen 2008)

A substation is considered to be the single most important component of the distribution system. Its properties like location and size define the shape of the MV network, maximum length of the feeders, conductor dimensioning and the backup connections to other substations. As a substation is a central and common point to the part of the distribution network it supplies, most of the protection and automation equipment has been gathered there. For example, the voltage level of the supplied area is regulated with the on-load tap changer located at the high voltage winding of the transformer. (Lakervi & Partanen 2008)

Traditionally distribution automation has been seen as a system capable of remote monitoring, coordination and operation of network components. At substations this has meant remote control of circuit breakers and acquisition of measurement values, various alarms and status indications. The control of the system has been centralized to the network control center (NCC) and network operators with limited local functions such as protection of feeders, busbars and transformers. (Northcote-Green & Wilson 2007)

A conventional substation control system utilizes dedicated hardware devices for each function with excessive wiring between process level sensors and actuators, bay level control and protection relays, and station level functions. A remote terminal unit (RTU) collects necessary data and conveys it to the control center as well as connects the operators commands to a particular device at the substation. In other words, the RTU acts as a gateway between the NCC and the substation. (Brand et al. 2003)

The introduction of static and later numerical relays have led to the development of multi-functional intelligent electronic devices (IED). The integration of multiple functions into one device decreases the number of fault-prone equipment and the need for wiring thus improving reliability and reducing costs. In addition, the increasing processing power and memory capacity enables more intelligent functions. On the other hand, a more complex system requires careful system design and configuration. Additionally, the IED will become a more critical component and its reliable operation will have a significant effect on the performance of whole automation system. (Brand et al. 2003)

Besides the development of IEDs, advancements in communication technology have also affected substation automation. Available bandwidths have risen from the few bits or kilobits per second of the past to a range of 10 Mbit/s to several Gigabit/s due to optical fibers, transport protocols such as PDH and SDH/SONET and Ethernet technologies. Together with new TCP/IP based communication protocols introduced in standards like IEC 60870-5-104 and IEC 61850, advances in communications have enabled utilities to fully exploit all the functions of IEDs and new applications, such as remote monitoring and maintenance through a specific service bus. (Brand et al. 2003)

Upcoming changes in distribution networks most likely lead to smarter substation automation systems. In (Heckel 2009; Valtari & Verho 2011) several aspects were identified as new requirements for a smart substation. These aspects include automatic fault location, isolation and restoration of supply to the healthy parts of the grid. Another key feature is the condition monitoring of the primary components and use of this information for Condition Based Maintenance (CBM). To enable data collection, processing and delivery forwards from the substation, open and standardized interfaces, such as IEC 61850, are needed in both process and utility level. All this has to be implemented within strict requirements for security and cost efficiency. (Heckel 2009; Valtari & Verho 2011) In addition, automatic adaptation of protection and monitoring functions according to changes in network topology or in response to changes in DG. A more advanced and accurate protection functions are also needed to meet the growing public requirements for reliably supply of electricity. (Valtari & Verho 2011)

## 2.4 Secondary substation automation

Automation in distribution networks has typically been concentrated in primary substations. The level of automation along the MV feeders varies depending on country and utility (Heckel 2009). In Finland feeder level automation has been comprised mostly of remote controlled disconnectors (Lakervi & Partanen 2008). Remote controlled disconnectors are located in key nodes as pole-mounted disconnector stations or integrated in ring main unit (RMU) of pad-mounted secondary substation.

The level of secondary substation monitoring automation has been modest. Only some local measurements, such as peak current measurement, have been available. More versatile systems have not been economically feasible until recent technological development. Today several manufacturers provide automation systems especially designed for secondary substations. (Löf 2009)

Implementation of automation system depends on DSOs choice of strategy, characteristics of the feeders and the substations, availability of communication, and desirable functions and performance of the automation system itself. According to (Heckel 2009) four different levels of automation could be identified. The most simple system consists only of automation devices without communication to the NCC. It performs predefined tasks, such as fault restoration sequences or voltage regulation, on its own. Second level system is capable of monitoring and transmitting measured values to a primary substation or the NCC. The communication is one way only and cannot receive any information or commands sent from the NCC. Third option combines control with above mentioned automation and monitoring. Two way communications enable comprehensive utilization of advanced functionalities. The highest level system adds protection functions to the third level automation system. (Heckel 2009)

## 2.5 Advanced metering infrastructure

One of the key features of future distribution networks in different Smart Grid visions has been the implementation and development of smart metering or AMI (Advanced Metering Infrastructure). AMI comprises of AMR meters (Automated Meter Reading), communication system and data collection and processing system (Keränen 2009). Usually AMI is seen as a measuring system of the consumption points. However, in a broader definition AMI encompasses measurements everywhere in the distribution network. This may be considered one of the first steps in bringing automation also to the low voltage network. In the past automation in LV network has not been economically justifiable compared to benefits gained by it. (Löf 2009)

The integration of AMI and network operation system enables the introduction of various low voltage network management functions. For example, the possibility to use AMR meters to indicate faults in LV network is a significant improvement over the traditional situation, where indication is based on customer calls. Alarms of the existence and type of fault are provided to control center. When the status information of all the meters under certain secondary substation is linked to the topological network model the exact location of the fault can be found. (Järventausta et al. 2007) Meters may also include remotely controllable main switch and additional relay outputs for load management. These features enable direct load control by customer service or control center and additionally customer tariff or power based load management. (Löf 2009)

In addition, the AMR meters provide means to extensive power quality monitoring of customer service points. Reliable and comprehensive measurements collected over several years could be utilized in customer services, asset management and network operation. The newest generation of meters can measure and log a wide range of quantities related to power quality in addition to basic electrical quantities. This information could be used to deepen the knowledge of the state of the distribution network and thus improve the efficiency of the DSOs and the quality of service experienced by the customers. (Järventausta et al. 2007)

## 2.6 Information and communication technology in electricity distribution

Different information and communication systems have a great role in DSO's daily operations. Network operation relies highly on automation of network components and information systems built to monitor and control them. Asset management, network design and customer services all have their own systems with interfaces interlinking them. Data communication forms the backbone for other applications both in the office network and in the field communications.

Role of ICT is growing in electricity distribution. New automation applications, integration of active resources, such as distributed generation and electric vehicles, and low voltage level management set new requirements for ICT solutions (Järventausta et al. 2010). Carefully executed system integration and efficient communication networks both in system and field level form the basis for this development.

### 2.6.1 Utility data communications

Utility data communications forms the backbone of network automation and control systems. It enables the monitoring and controlling of distribution network remotely from a centralized control room including network protection and measurement arrangements. In this concept the data communication usually refer to digital data being transferred over digital and analogical links. (Strauss 2003) In this chapter the basic characteristics of data communication are introduced with focus mainly on communication between automated network components in substations or elsewhere in the distribution network and control center.

Open system interconnection model (OSI) defined by the International Standards Organization (ISO) and presented in Figure 2.2 specifies the architecture of data communication network. It consists of seven sub-processes with specific services and functions provided through protocols. Each sub-process or layer provides services to the higher layers. The sender AP1 gives the data to be transmitted to receiver AP2 to highest layer called application layer, which adds its own application header AH to the beginning of the data. Header contains necessary control information and information exchange destined to its peer entity at the same level in the AP2. The message is then transferred to the next lower level for further processing and another header is attached. Finally, the physical layer transmits the message over a communication media to the physical layer of the receiver. At the destination, the message is processed in reversed order starting from the physical level up to the application level and finally to the receiver AP2. (Hura & Singhal 2001)

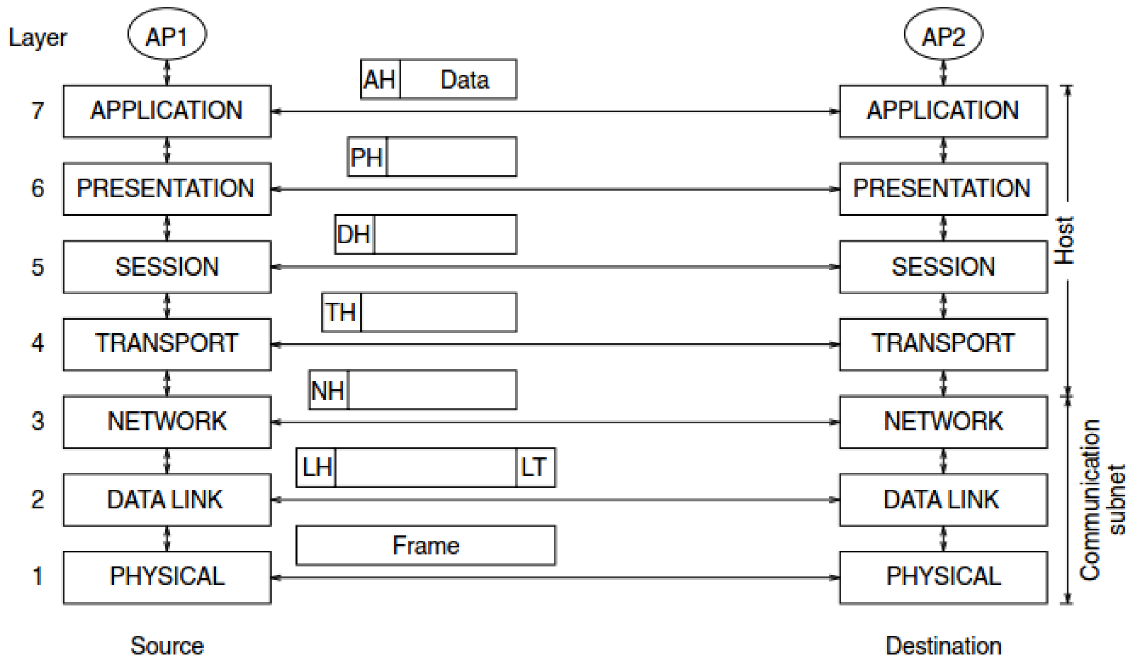


***Figure 2.2.*** *OSI model. (Hura & Singhal 2001)*

Different types of physical links can be roughly divided into wireless and wire communication. Wireless formats include radio modems and links, different cellular techniques and satellite connections. Wire connections include optical fibers, copper lines, coaxial cables or power lines (power line carrier, PLC). (Northcote-Green & Wilson 2007) Physical link can be owned by the utility or leased from specific supplier. It can be dedicated only to utilities use or even exploit public network.

Physical link impacts several critical characteristics of the communication system. As its main task physical layer provides a physical connection between transmitting and receiving nodes, and transmission of data units in serial or parallel mode. Transmission media, transmitter and receiver define the transmission speed, efficiency and capacity of the channel. They also affect other aspects of the quality of service, such as error rate, signal distortion and noise. (Hura & Singhal 2001)

Communication network topology has three physical and logical alternatives, namely star, ring and bus. In a star topology all of the remote stations are connected to a single master and communicate through it. Therefore star is vulnerable to failure of the master node. On the other hand, maintenance, fault location and repair, and adding or removing remote stations is easy. (Strauss 2003)

In ring topology all of the nodes are connected to two adjacent nodes to form a ring. Messages travel along the ring through each node until a receiving node is found. Nodes can also communicate directly with each other and a master node is not necessarily needed. On the downside, failure of a single node disrupts the operation of the whole ring, fault isolation is harder as well as adding and removing nodes. (Strauss 2003)

In bus topology nodes are connected to a communication channel known as a bus. Each node monitors messages travelling in the bus and accepts those sent to it. Bus is the most flexible topology in terms of configuration, reliability and scalability. On the other hand, troubleshooting is difficult as any part of the bus may fail, heavy traffic may disrupt communications and messages may be lost or caught by a wrong node. (Strauss 2003)

Above the physical layer data link layer is responsible for the integrity of the data transferred providing for example protocols for error recovery. Data link layer is divided into two sub-layers called media access control (MAC) and logical link control (LLC). (Hura & Singhal 2001) MAC is responsible for method of media access and has thereby essential part in the communications. Four different main methods are applied to media access control.

First alternative is polling, where a slave station may send data only when requested by a master station in a certain order. In a more refined version of polling only exceptions or changes are transferred. Both version share the advantages of reliability and predictability rising from the systems simplicity. Main disadvantage is the inefficient use of available connection and slow response rates. (Strauss 2003)

Second alternative is called time-division-multiplex media access (TDM), in which each node has been given a timeslot for sending and receiving data. TDM has similar advantages and disadvantages as polling, but in addition the configuration of the network is more complex. (Strauss 2003)

Third possible method is token pass media access, where a token is circulated in ring or bus type network. Any node may take the passing token to use the communication network. Token is released to circulation again, when the transmission is completed. This configuration results in a more efficient use of network, faster peer-to-peer communication and more flexible modification of data transfer requirements. A central controller is still needed, configuration is complex and exact response times cannot be predicted anymore. (Strauss 2003)

Fourth type of media access control is called carrier sense multiple access with collision detection (CSMA/CD). In principle, a node listens to communication bus and sends its messages, once the bus is idle. If another node happens to send a message at the same time and a collision happens, both of the nodes stop transmitting and try again after some random time interval. CSMA/CD is a very efficient and fast choice for access control, but demands special attention on data collision detection and network configuration. (Strauss 2003)

Media access control and other rules for communication are compiled into communication protocols. A communication protocol addresses the format of messages and methods for transmitting and receiving them. Some common protocols include IEC 60870-5, Modbus, DNP 3.0 and new IEC 61850, which aims to become a universal communication standard for power system automation (Strauss 2003).

Current communication network in Caruna represents a typical traditional field communication solution. It has been designed solely for remote control of substations and disconnector stations. Network has been composed of several communication networks of acquired regional distribution companies. A fiber optics core network connects regional access points to control center. Regional trunk connections consists mostly of digital or analog radio links between substations with layered star topology, but copper cables and fibers can also be found in some regions. Last-mile connections from substations to disconnector station have been mainly executed with radio modems. Communications take place by serial communication with polling using several protocols. (Koli, Petteri; Vähälä Antti 2012)

In such a network transmission bit rates remain at a quite low levels and response times can be long due to the technique used and polling nature of the network. Long response times cause especially problems in major disturbance situations when the network is in high load and needed the most. Network is also vulnerable to faults as no reserve connections exists. In worst case a single fault may cause whole area to lose connection to control center and fault is only noticed, when the connection is needed. In addition, the fact that some of the links are leased from external contractors and the wide variety of different techniques and equipment used further complicate fault repairs and maintenance.

Clearly the current communication network doesn't meet future needs. Rising reliability requirements denote also increase in network automation and set new demands for data communications. In normal situation the two most important requirements are bandwidth of the channel and latency (Laverty et al. 2010; Sauter & Lobashov 2011). Other main concerns of interest are reliability and availability of the system, communication security, scalability and Quality of Service management (Sauter & Lobashov 2011).

Reliability, availability and capacity of the system have a larger role in a major disturbance situation, when the communication network is stressed and needed the most. For instance, public communication network utilized as part of DSO's field communications may suffer from large electricity distribution outages. If base stations are not equipped with backup batteries or the batteries drain before electricity is restored, communication network coverage may suffer or even be completely lost as demonstrated in (Horsmanheimo). This leads to longer repair times as network automation cannot be utilized and field crew communication is disrupted. Remaining base stations are likely to be congested by increased number of emergency calls and inquiries. Thus the simulation results are somewhat optimistic compared to real-life situation. (Horsmanheimo) This should be considered in planning of utility communications network and coordinated with communication network operator.

### 2.6.2 Remote terminal unit

Remote terminal unit (RTU) enables communication between a central system and field instruments at the local process level. The earliest RTUs only converted the information from the field instruments to language supported by the central system and transmitted it to the master system. RTUs also received messages from the master and converted them to the field instruments. Over time RTUs have become more intelligent and have adopted some of the control functionalities of the central system to the local level. (Strauss 2003)

In addition to the basic features of the first RTUs, a modern version can also store, filter and process the acquired data. These aspects distinguish a basic RTU, that only acts as a gateway between process and system level, from the more advanced ones and enable more sophisticated functionalities to be performed. Local processing capacity contribute for its own part to extended control of the whole distribution network, as it increases the performance of the system by decreasing the dependence on the central system. (Northcote-Green & Wilson 2007)

As a substation RTU required extensive wiring to connect it to all individual field equipment, thus increasing the cost of a substation, a small RTU was developed. This small RTU could be installed closer to the switchgear and the field equipment to save wiring costs. At first small RTUs communicated with the substations master RTU, but after the next step of development they were able to communicate directly with the central system. Small RTU has been since renamed as a bay controller after its main purpose. (Strauss 2003)

### 2.6.3 Intelligent electronic device

Intelligent electronic device (IED) is a term that could be used to describe any electronic device capable of local intelligence. In this thesis a more relevant definition is adopted. According to (Strauss 2003), IED is "a device that has versatile protection functions, advanced local control intelligence, monitoring abilities and the capability of extensive communications directly to a SCADA system."

Development of IEDs began shortly after the introduction of intelligent microprocessor-based relays. Communication capabilities were added first to enable remote programming of the relays. Later the benefits of data retrieval were understood and communications developed further. In the next step the advanced control functions of bay controller and the protections functions of intelligent relay were incorporated into same physical device named as IED. (Strauss 2003)

Current IEDs master versatile protection, control, monitoring, metering and communications functions. A typical IED offers directional and non-directional overcurrent and earth fault protection, phase discontinuity protection, and over- and under-voltage protections as basic feeder protection. Control functions include local and remote control of several switching components, fully programmable control sequences and bay level interlocking to prevent unnecessary tripping. Monitoring functions enable supervision of the IED itself and its trip circuit, condition monitoring for the circuit breaker, event recording and other monitoring functions, such as temperature monitoring. IEDs can also measure three-phase currents and voltages, neutral current, frequency, active and reactive power, energy and harmonics. In addition, IEDs offer transient disturbance recorders. (Strauss 2003)

### 2.6.4 SCADA

SCADA stands for supervisory control and data acquisition. It is the central system used by network control center to acquire information of the state of the distribution network, transfer the data to the SCADA master, and process, store and display it according to utilities demands. As the other main task SCADA is used to centrally control the remotely controllable components of the grid. (Strauss 2003)

SCADA was originally used as a central control system for industrial plants. Today it is used widely to control infrastructure and facility processes, such as electrical transmission and distribution, water treatment or air conditioning systems. (Strauss 2003)

SCADA system consists of master station and RTUs or other devices capable of advanced communications, such as modern IEDs. SCADA master station includes the hardware and software needed to display real-time data acquired from the network, store this received data, activate alarms and display reports of events and to provide an interface for an operator controlling the network. In addition, communications capability and connections between the master station and the other connected devices are needed. (Strauss 2003)

### 2.6.5 Distribution management system

Distribution management system (DMS) is a support system for network operations. DMS combines the geographical and structural information of the network with status and measurement information from SCADA. It displays the current switching state and can be used to plan and simulate upcoming switching sequences or analyze the effects of certain faults and status of the network at given time. (Northcote-Green & Wilson 2007)

Other main task of DMS is outage management and reporting. Outage management encompasses fault notification, location and repair as well as switching operations to isolate fault and restore supply to customers. In order to enable outage reporting for DSO's own needs and to authorities, statistics of the fault reason, location, length and affected customers has to be reported as part of the outage management process. (Northcote-Green & Wilson 2007)

### 2.6.6 Network information system

Network information system (NIS) contains all of the technical and location information of the network components. Its main functions include data and documentation management of the current and planned networks. In addition, various specific functions for network design, asset management and maintenance purposes are part of NIS. (Lakervi & Partanen 2008)

NIS is a central system for a DSO. Interfaces to customer information system, DMS, SCADA, project management system and other systems ensure the efficient use of available data and enable basic functionalities of NIS, such as load flow calculation and short circuit or earth fault calculations. (Lakervi & Partanen 2008)

# 3. FINNISH REGULATORY MODEL

Electricity distribution in Finland is regulated by Energy Authority (EA, formerly Energy Market Authority, EMA). Because of the capital-intensive nature of distribution business, DSO's typically operate a natural local monopoly. In absence of the normal market forces generated by rivalling companies, economic regulation has to be established to ensure the effectiveness of the industry. This is the case in most of the European countries, USA, Canada, Japan, Australia, India and some Latin American countries (Jamasb & Pollit 2001).

Finnish regulation model is based on retrospective rate-of-return (ROR) regulation with several incentives in place (Sähkön jakeluverkkotoiminnan). Regulatory period is four years and the current 2012-2015 period is the third one. The principles and key methods are presented in Figure 3.1.

On the left-hand side of the Figure 3.1 the balance sheet is adjusted to determine the reasonable return. The calculation is started with determination of the replacement value of network (RV) based on the number of network components and unit price list provided by the regulator. Present value (PV) is then calculated with the help of component specific expected lifetime and average age data from the RV. The DSO may choose the lifetime from a predefined range provided by the EA. Other adjusted capital invested in the network is calculated and added to PV to gain the adjusted invested capital. The reasonable return is calculated by multiplying this by real reasonable rate of return, which is based on weighted average cost of capital (WACC) calculated using fixed capital structure of 30/70 (interest-bearing debt/equity) and interest of Finnish 10-year bond as the greatest influencing factor. (Sähkön jakeluverkkotoiminnan)

The calculation of actual adjusted profit is presented on the right hand side of Figure 3.1. Calculation starts from the actual operating profit, upon which the change in refundable and transferable connection charges, paid network rents and depreciations on goodwill are added. Then the outcomes of investment, quality, efficiency, innovation and security of supply incentives are deducted as well as other adjustments. The result of this is the actual adjusted profit, which is compared with the reasonable return calculated earlier to determine the deficit or surplus of the DSO. (Sähkön jakeluverkkotoiminnan)

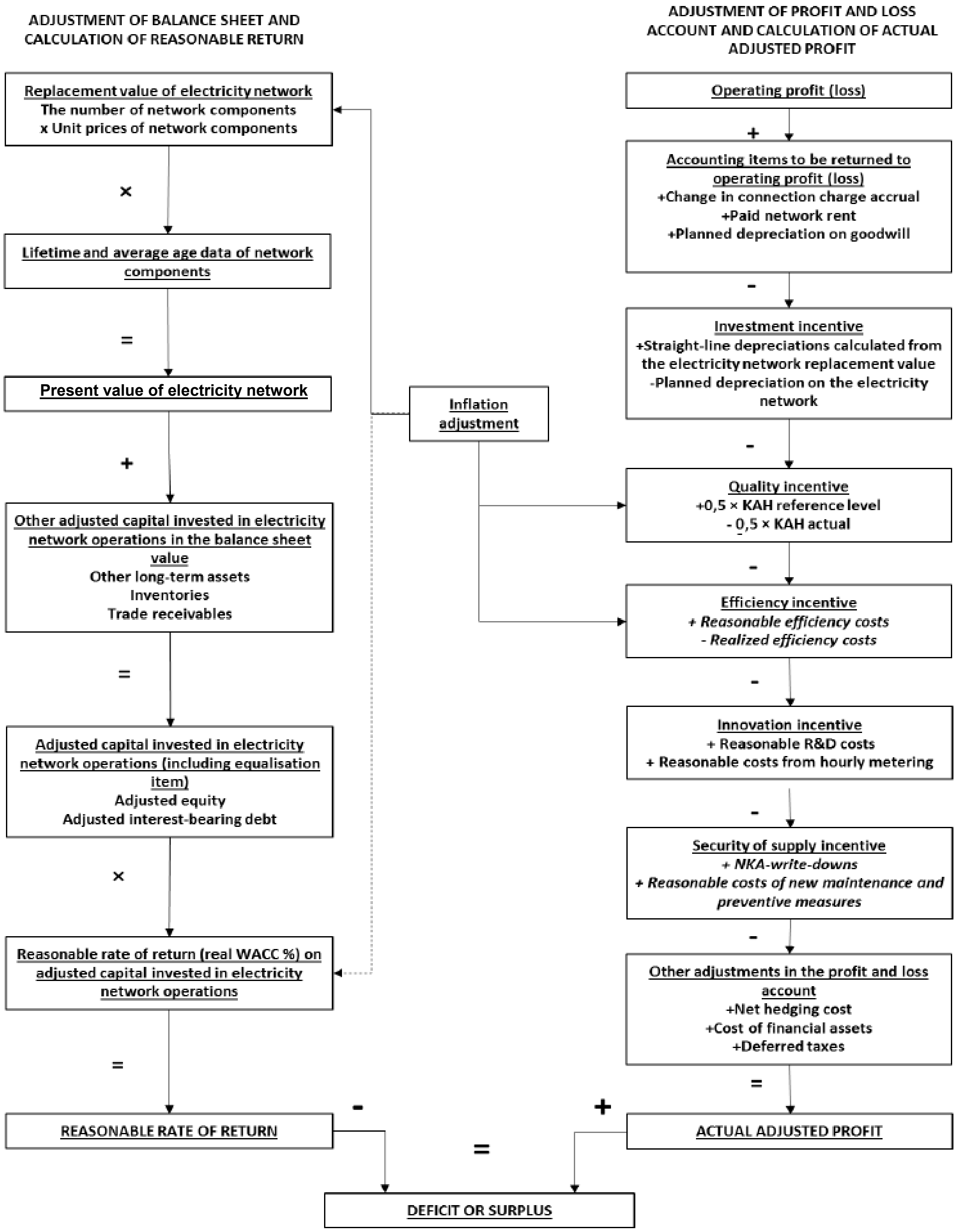


***Figure 3.1.*** *The principle of calculating reasonable return and key methods of regulation. Adopted from (Sähkön jakeluverkkotoiminnan)*

## 3.1 Quality incentive

The purpose of quality incentive is to encourage the DSO's to maintain and develop their networks in a reliable manner. Incentive is based on annual customer outage costs (COC) derived from collected outage statistics and unit costs. The outage statistics comprise of number and duration of both unexpected and planned sustained interruptions as well as number of high-speed automatic reclosings (HSAR) and time-delayed automatic reclosings (DAR) of momentary interruptions. The unit costs are based on a study conducted in 2004-2005 (Silvast et al. 2005). The unit costs in the 2005 monetary value are presented in Table 3.1. (Sähkön jakeluverkkotoiminnan)

***Table 3.1.*** *The unit prices for customer outage cost calculation in the 2005 monetary value. (Sähkön jakeluverkkotoiminnan)*

| Unexpected outage | | Planned outage | | Time-delayed autorecloser | High-speed autorecloser |
|---|---|---|---|---|---|
| $c_{e,u}$ | $c_{w,u}$ | $h_{e,p}$ | $h_{w,p}$ | $c_{dar}$ | $c_{hsar}$ |
| €/kWh | €/kW | €/kWh | €/kW | €/kW | €/kW |
| 11,0 | 1,1 | 6,8 | 0,5 | 1,1 | 0,55 |

The COC in year *t* in the value of money in year *k* is calculated as

$$COC_{k,t} = \big(OT_{u,t} \times c_{e,u} + ON_{u,t} \times c_{w,u} + OT_{p,t} \times c_{w,p} + ON_{p,t} \times c_{w,p} + DAR_t \times c_{dar} + HSAR_t \times c_{hsar}\big) \times \left(\frac{W_t}{T_t}\right) \times \left(\frac{CPI_{k-1}}{CPI_{2004}}\right) \tag{3.1}$$

where

$COC_{k,t}$ = customer outage cost in year *t* in the value of year *k*

$OT_{u,t}$ = customer's average annual outage time weighted by annual energies, caused by unexpected outages in the 1-70 kV network in the year *t*, hours

$c_{e,u}$ = unit cost for unexpected outage duration [€/kWh]

$ON_{u,t}$ = customer's average annual number of outages weighted by annual energies, caused by unexpected outages in the 1–70 kV network in year *t*, numbers

$c_{e,u}$ = unit cost for unexpected outages [€/kW]

$OT_{p,t}$ = customer's average annual outage time weighted by annual energies, caused by planned outages in the 1–70 kV network in year *t*, hours

$c_{e,p}$ = unit cost for planned outage duration [€/kWh]

$ON_{p,t}$ = customer's average annual number of outages weighted by annual energies, caused by planned outages in the 1–70 kV network in year *t*, numbers

$c_{w,p}$ = unit cost for planned outage [€/kW]

$DAR_t$ = customer's average annual outage number weighted by annual energies, caused by time-delayed autoreclosers in the 1–70 kV network in year *t*, numbers

$c_{dar}$ = unit cost for time delayed autoreclosings [€/kW]

$HSAR_t$ = customer's average annual outage number weighted by annual energies, caused by high-speed autoreclosers in the 1–70 kV network in year *t*, numbers

$c_{hsar}$ = unit cost for high-speed autoreclosings [€/kW]

$W_t$ = annual distributed energy of the DSO [kWh]

$T_t$ = number of hours in year *t*

$CPI_{k-1}$ = consumer price index in year *k-1*

$CPI_{2004}$ = consumer price index in year 2004

The calculated actual COC is then compared with a reference level gained from the historical performance of the DSO. The reference COC is calculated as

$$COC_{ref,k} = \frac{\sum_{t=2005}^{2010}\left(COC_{t,k} \times \left(\frac{W_k}{W_t}\right)\right)}{6} \qquad \textbf{(3.2)}$$

where

$COC_{ref,k}$ = reference customer outage cost for year *k*

$COC_{t,k}$ = actual customer outage cost in year *t* in value of year *k*

$W_k$ = annual supplied energy in year *k* [kWh/a]

$W_t$ = annual supplied energy in year *t* [kWh/a]

The actual quality incentive is then calculated as difference between $COC_{ref}$ and COC

$$Quality\ incentive = 0{,}5 \times \left(COC_{ref} - COC\right) \qquad \textbf{(3.3)}$$

Only half of the difference is taken into account. In addition, the incentive is limited to a maximum of 20 % of the reasonable return on capital. As the incentive is symmetrical, end result may be either positive or negative. (Sähkön jakeluverkkotoiminnan)

## 3.2 Investment incentive

The purpose of investment incentive is to encourage the DSO's to invest adequately to their networks in order to at least maintain the condition level of the network. The method used to secure a sufficient income level to enable this considers straight-line depreciations calculated from the replacement values and the lifetimes of components. Straight-line depreciation for network component *i* is calculated as

$$Depreciation_{t,i} = \frac{RV_{t,i}}{Lifetime_i} \qquad \textbf{(3.4)}$$

where

$Depreciation_{t,i}$ = straight-line depreciation of the network component *i* in year *t*

$RV_{t,I}$ I = repurchase value of network component *i* in the year *t*

$Lifetime_i$ = techno-economic lifetime of network component *i*

The component-specific depreciations constitute the straight-line depreciation for the entire distribution network. In the calculation of the incentive, the book value of planned depreciations are deducted from the straight-line depreciation for the whole network. The incentive is taken into account in the adjustment of profit and loss. (Sähkön jakeluverkkotoiminnan)

The investment incentive has also another purpose. The EA uses it to monitor the proportion of straight-line depreciation to actual replacement investments in the network. The logic is that as the depreciations are meant to cover the cost of component replacement at the end of its lifetime, DSO should make as much replacement investments as the calculated depreciations are. If less investments are made, a replacement investment deficit arises. (Sähkön jakeluverkkotoiminnan)

## 3.3 Efficiency incentive

Efficiency benchmarking has an important role in the regulation model. It prompts DSO's to improve their performance in absence of normal market forces of rivaling companies. Efficiency incentive has similar structure as quality incentive. DSO's actual efficiency is compared with established DSO-specific target level. The target efficiency includes both general and enterprise-specific efficiency targets. General targets describes the improvement potential of the entire sector, whereas enterprise-specific targets compares the DSO with the most efficient companies. (Sähkön jakeluverkkotoiminnan)

The efficiency incentive for year *t* is calculated as

$$Efficiency\ incentive_t = STOTEX_t - TOTEX_t \tag{3.5}$$

where

$STOTEX_t$ = reference level for efficiency costs in year $t$

$TOTEX_t$ = actual efficiency costs in year $t$

The actual total efficiency cost is calculated as

$$TOTEX_t = OPEX_t + 0{,}5 \times COC_t \tag{3.6}$$

where

$OPEX_t$ = actual operational costs in year $t$

$COC_t$ = actual customer outage costs in year $t$

The reference for efficiency costs is determined by StoNED method (Stochastic Non-smooth Envelopment of Data). The main inputs consist of the DSO-specific efficiency requirement, the general efficiency requirement, estimated efficiency costs and medium voltage network cabling rate. The general efficiency requirement common for all DSOs is 2,06 % per year. The reference level is calculated as

$$STOTEX_t = \left(\frac{CPI_{t-1}}{CPI_{2009}}\right) \times (1 - X)^{t-2009} \times \hat{C}(y_t, z_t) \tag{3.7}$$

where

$STOTEX_t$ = reference level in year $t$

$CPI_{t-1}$ = consumer price index in year $t-1$

$CPI_{2009}$ = consumer price index in year 2009

$X$ = DSO-specific efficiency target

$\hat{C}(y_t, z_t)$ = cost frontier of DSOs in 2019, in the 2009 price level

$t$ = calculation year

$y_t$ = vector of output variables in year $t$

$z_t$ = degree of cabling in the medium voltage network (1-70 kV) in year $t$

Output variables used for calculation of cost frontier $\hat{C}$ are the volume of supplied energy, the total length of network and the number of customers. The different operation environment of DSO is taken into account in environment variable $z_t$. $\hat{C}$ is calculated as

$$\hat{C}(y_t, z_t) = \hat{C}(y_t) \times \exp(\delta z_t) \tag{3.8}$$

where

$y_t$ = vector of output variables in year *t*

$z_t$ = degree of cabling in the medium voltage network (1-70 kV) in year *t*

$\delta$ = slope of degree of cabling in the medium voltage network (1-70 kV) = 0,585239980789296

DSO-specific efficiency target $X_i$ is calculated as

$$X = 1 - \sqrt[8]{TL} \times (1 - 2{,}06\ \%) \tag{3.9}$$

where

$X$ = DSO-specific efficiency target

$TL$ = DSO-specific efficiency coefficient, estimated with the StoNED method

*(1-2,06 %)* = the need to improve the efficiency of costs in accordance with the general efficiency target

The DSO-specific efficiency coefficient TL is calculated as

$$TL = \frac{\overline{TOTEX}}{TOTEX_{2005-2010}} \tag{3.10}$$

where

$\overline{TOTEX}$ = the reference for average efficiency cost in 2005-2010

$TOTEX_{2005-2010}$= the average efficiency cost in 2005-2010, in the 2010 price level

The $\overline{\mathrm{TOTEX}}$ reference level is calculated as

$$\overline{TOTEX} = C(\overline{y}) \times exp(\delta\overline{z} + \varepsilon) = C(\overline{y}) \times \exp(\delta\overline{z} + u + v) \qquad \textbf{\textit{(3.11)}}$$

where

| | | |
|---|---|---|
| $\overline{TOTEX}$ | = | the reference for average efficiency cost in 2005-2010 |
| $C$ | = | estimated cost function, the frontier of DSOs' reasonable efficiency costs |
| $\overline{y}$ | = | average vector of output variables in 2005-2010 |
| $\delta$ | = | parameter describing the average cost impact of the MV cabling degree |
| $\overline{z}$ | = | average MV cabling degree in 2005-2010 |
| $\varepsilon$ | = | combined error term |
| $u$ | = | average inefficiency term in 2005-2010 |
| $v$ | = | random error term |

The average actual $TOTEX_{2005\text{-}2010}$ is calculated as

$$TOTEX_{2005-2010} = \frac{\sum_{t=2005}^{2010}\left((OPEX_t + 0{,}5 \times COC_t) \times \frac{CPI_{2010}}{CPI_t}\right)}{6} \qquad \textbf{\textit{(3.12)}}$$

where

| | | |
|---|---|---|
| $TOTEX_{2005\text{-}2010}$ | = | the average efficiency cost in 2005-2010, in the 2010 price level |
| $OPEX_t$ | = | actual operational costs in year *t* |
| $COC_t$ | = | customer outage costs in year *t* |
| $CPI_{2010}$ | = | consumer price index in year 2010 |
| $CPI_t$ | = | consumer price index in year *t* |

## 3.4 Other incentives

Other incentives in the regulation model include innovation and security of supply incentives. The innovation incentive incorporates research and development costs and costs of remote meter reading for under 63 A connections. The reason for including costs for remote meters lies in the change in legislation and is compensated only once. Research and development costs accepted in the incentive have a maximum of half a per cent of the DSO's turnover. As of extra costs caused by remote meter reading, regulator accepts five euros per AMM meter in hourly metering. (Sähkön jakeluverkkotoiminnan)

The security of supply incentive is a new incentive added in the middle of the third regulation period. It applies only to the years 2014 and 2015. As the new Electricity Market Act came into act, the incentive was added to compensate for costs of renewing network prior to the end of its planned lifetime. The incentive includes the remaining NPV of medium and low voltage aerial lines, pole mounted substations and overhead line disconnectors and disconnector stations replaced for improving reliability. In addition, maintenance costs related to forest management near medium voltage lines and development and maintenance costs of systems used to communicate with customers or the authorities fall within the scope of the security of supply incentive. (Sähkön jakeluverkkotoiminnan)

# 4. MULTI-LEVEL FEEDER PROTECTION

The protection of radially operated medium voltage networks is typically arranged with single protection relay with both overcurrent and earth-fault protection functions at the beginning of each feeder. In this kind of simple protection scheme the whole feeder forms one protected zone. A fault occurring anywhere in this zone leads to temporary interruption for all the customers within that zone. As primary substations are generally situated close to major customer concentrations, most of the customers are situated at the beginning of feeders and suffer from faults at the end of the feeders. Current trend of emphasizing reliability and quality of supply gives cause to seek for more advanced protection arrangements.

A straightforward way to improve customer experienced reliability is to introduce new protection zones or decrease the size of the current ones. The first option implies large changes to the network topology and could require major investments either at the substations or into the MV network. In the other option additional relays and circuit breakers would be installed on a same feeder in order to divide the existing protection zone into several smaller zones. In this thesis, a term multi-level protection is adopted for a protection scheme where two or more cascading relays are used for protection of a single feeder.

Basic principles of reliability, operation speed, selectivity and cost efficiency of protection arrangement have to be considered when new elements are added to the current system. This means that the smallest possible section of feeder is always disconnected as fast as possible to minimize risk of equipment damage or injuries and unnecessary actions are avoided. (Gers & Holmes 2004)

## 4.1 Operation principles

In order to gain a reliability improvement from multiple relays on a feeder the selectivity of protection has to be ensured. For example, if the first relay operates in a case of two consecutive protection zones and a fault that occurs in the second zone, no benefit has been achieved compared with a case of only one zone. With sufficient discrimination margin between the relays the protection operates correctly.

Depending on the type of the relay, discrimination for overcurrent protection can be achieved by time, current or both. Other more sophisticated means include interlocking of relays or use of differential or distance protection. (Teknillisiä tietoja ja taulukoita -käsikirja 2000)

Discrimination by time is based on a time delay given for each relay. Relays closer to the beginning of the feeder have longer delays than those further along the feeder to ensure that the relay closest to the fault operates first. (Northcote-Green & Wilson 2007) Typically a delay of 0,2 to 0,3 seconds is sufficient between relays. This limits the number of consecutive relays as thermal capacity of components together with maximum overcurrent level defines the maximum time delay.

Discrimination by current is based on fault current level. Current level varies according to the location of the fault because of impedance of the line. With enough distance between two relays, they can be set in such way, that only the nearest relay operates when fault occurs. (Northcote-Green & Wilson 2007)

Combination of time and current based discrimination is achieved with inverse-time type relay. As the name suggests, relays operation time is inversely proportional to the fault current and hence it is a function of time and current. Different characteristics curves are available, but settings have to be calculated carefully for multiple relay systems to ensure functionality and reliability of the system. (green, Wilson)

Differential protection is based on measuring and comparing incoming and outgoing currents of protection zone. It is commonly used in transformer, machine and busbar protection and could be applied to feeder protection. (Teknillisiä tietoja ja taulukoita -käsikirja 2000) However, as current measurements are required from both ends of the protection zone, implementation of differential protection would be expensive because of the needed current transformers and communications.

Distance relay measures impedance seen by the relay and therefore is unaffected by changes in short circuit current deviations. Distance protection is usually applied to protection of transmission lines, ring operated networks and electrically weak branch networks. Although distance relays perform solidly, they rely on time discrimination or communications to secure selective protection. (Teknillisiä tietoja ja taulukoita -käsikirja 2000)

Interlocking is a technique used to accelerate the operation speed of protection system. With two consecutive relays both detecting same fault, the primary relay sends an interlocking signal to the backup relay preventing its operation. This enables the utilization of shorter time delays between protection levels. A typical delay with interlocking enabled is approximately 100 ms depending on the relays used and communications between them. (Teknillisiä tietoja ja taulukoita -käsikirja 2000)

In addition, modern relays have directional protection capabilities, which can be utilized in particular situations besides other means of discrimination. These situations include meshed network operation, parallel feeders and parallel transformers. (Bayliss & Hardy 2007)Directional protection requires voltage measurement in addition to current measurement to be able to calculate the direction of the current flow. At substations voltage transformers are already available, but elsewhere in the distribution network measurements are rare and have to be specifically arranged if directional protection is required.

In earth fault situation the protection arrangements are somewhat more problematic. Most of the Finnish distribution networks are either isolated neutral or resonant earthed systems. In isolated neutral system the fault currents flows through fault impedance, line to ground capacitance and line impedances through main transformers windings to the faulty phase. Resonant earthed systems differ from isolated in that the line capacitance is almost totally compensated with inductive coil connected to main transformers neutral point thus lowering the fault current. This leads to small fault currents of only few amperes making earth faults more difficult to detect than short circuit faults (Lakervi & Partanen 2008). Flow of the current in isolated neutral system and resonant earthed system is presented in Figure 4.1 and Figure 4.2, respectively.

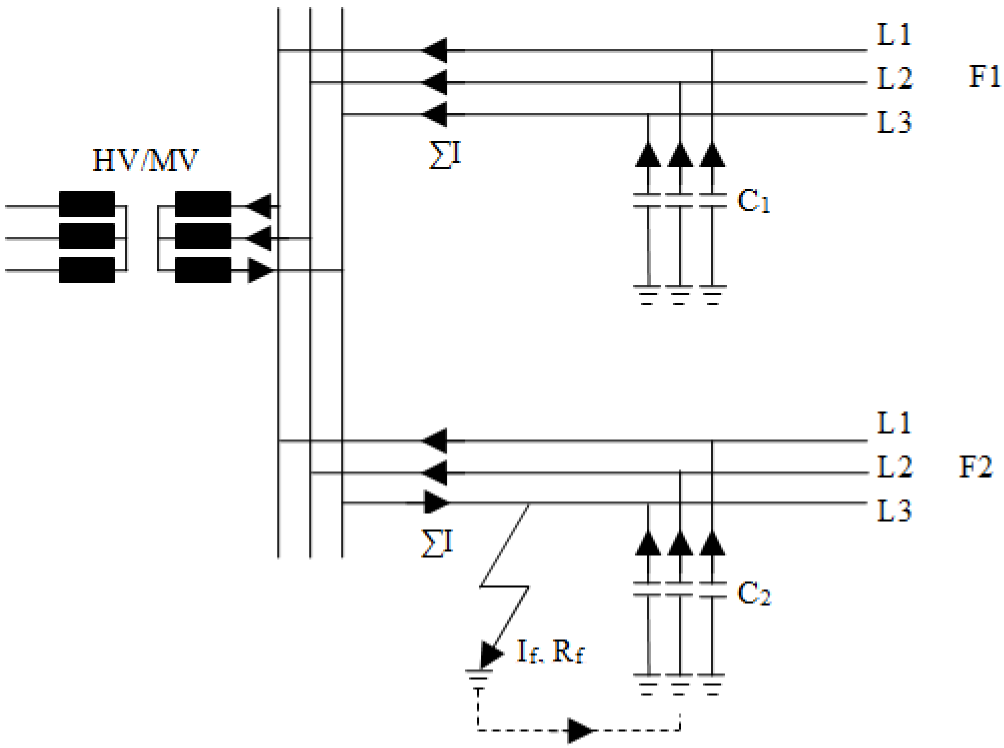


***Figure 4.1.*** *Earth fault in isolated neutral system. Adopted from (Lakervi & Partanen 2008)*

Earth faults can be detected with several different methods. For example, measured variable could be neutral point displacement voltage, phase voltage, zero current or current and voltage harmonics. Commonly used directional earth fault relays measures both magnitude and phase angle of fault current and compares it with neutral point displacement voltage to determine the direction of fault current. Additionally the magnitudes of both current and voltage have to exceed a preset value for the relay to operate. (Lakervi & Partanen 2008)

The directional earth fault relay works selectively in isolated neutral network with one relay at the beginning of each relay in the sense that only the faulted feeder is disconnected. Relay operates correctively also in resonant earthed network, if the earth fault current is not entirely compensated. Relays directional properties could also be utilized with consecutive relays on a same feeder as illustrated in Figure 4.3.

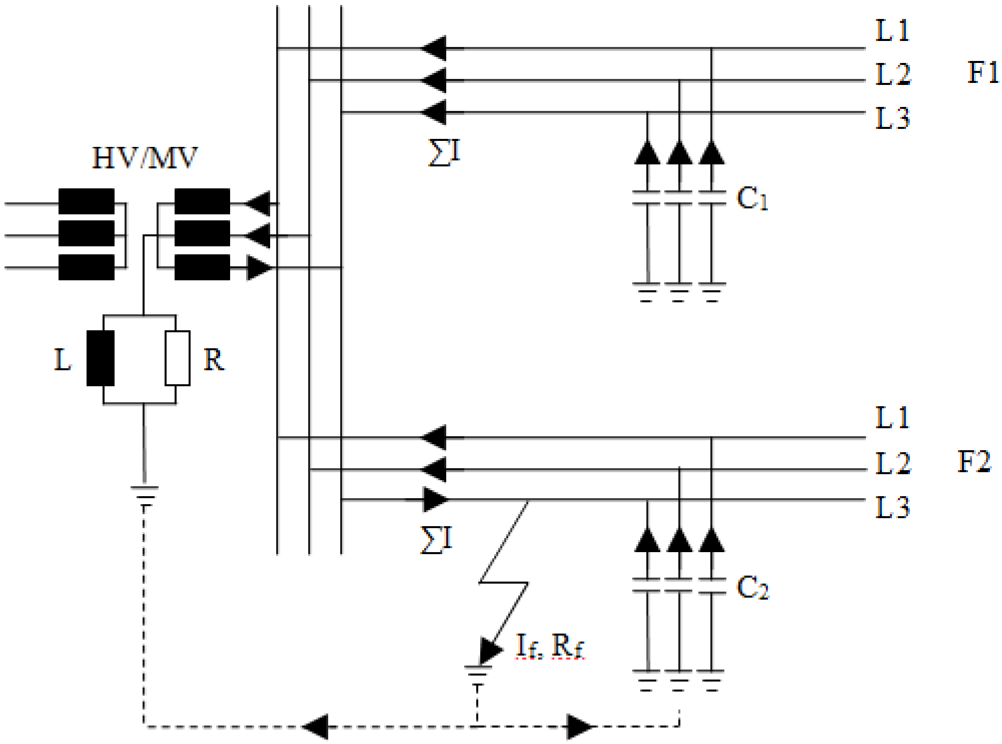


***Figure 4.2.*** *Earth fault in resonant earthed system. Adopted from (Lakervi & Partanen 2008)*

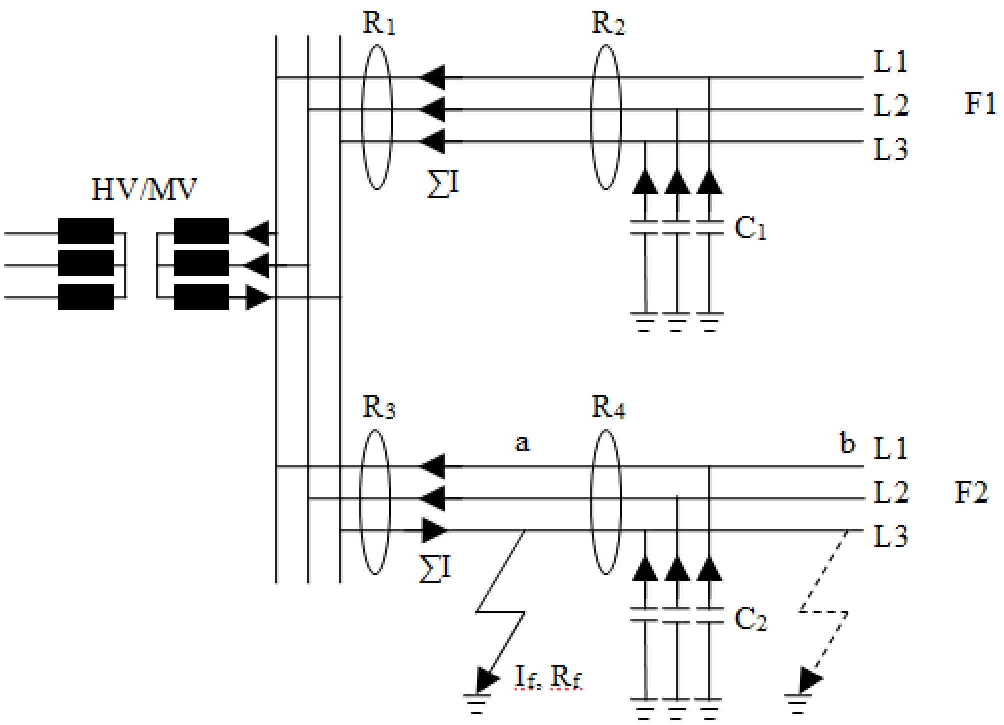


***Figure 4.3.*** *Directional earth fault relays R1…R4. Adopted from (Lakervi & Partanen 2008)*

In Figure 4.3 feeders F1 and F2 have two relays each. One is located at the beginning and the other in the middle of the feeder. In the event of earth fault at location a, fault current flows through relays $R_1 \ldots R_4$ as shown in the figure. Relays $R_1$, $R_2$ and $R_4$ see the current flowing towards busbar and hence do not operate, whereas relay $R_3$ detects flow of current towards feeder F2 in phase L3 and operates correctly. If the fault would occur at location b, relays R3 and R4 would both see almost the same fault current. Therefore a time delay is required between R3 and R4 to ensure discrimination.

## 4.2 Benefits and challenges

Major benefits emerging from functional and extensive multi-level protection system are related to reliability and quality of supply improvements. Increasing the number of protection zones in an existing distribution network self-evidently leads to smaller zones. Total amount of faults does not decrease, but as each smaller zone contains less network components and customers, faults per protection zone decline and number of customers suffering from a single fault drops.

With cascading protection zones faults occurring in the first zone cause outages also for the customers in the second zone. Provided that adequate back up connections exist, the circuit breaker of the second protection zone brings no added benefits over a remote controlled disconnector as the time required to restore the supply via back up connection is the same for both. On the other hand, the reliability improvement seen by the customers in the first zone when a fault occurs in the second protection zone is significant as in ideal situation all outages could be limited to the second zone only.

According to (Keskeytystilasto 2012 2013), 90 % of customers interruption hours were caused by MV overhead line faults and 61 % of faults were weather related. As primary substations are usually located near the focus point of consumption, a large share of customers are connected to the beginning of MV feeders. If that part is built with a weather proof technique and another protection zone is composed of the rest of the feeder, the supply of most of the customers could be secured in normal operational situation and during major disturbances without having to renew the whole feeder.

In many cases single feeder can be divided into more than two zones with careful selection of switching station placement, as illustrated in Figure 4.5. The switching station would be equipped with circuit breakers as illustrated in Figure 4.4. The incoming line could also be equipped with circuit breaker in order to prepare for changes in network topology where the direction of feeder is reversed but would be used as disconnector under normal situation. This is beneficial in several ways. Fault location is faster in smaller geographical areas and number of test switchings is reduced. Reclosings caused by transient faults in protection zones further along the feeder are seen as voltage dips in other zones instead of temporary outages.

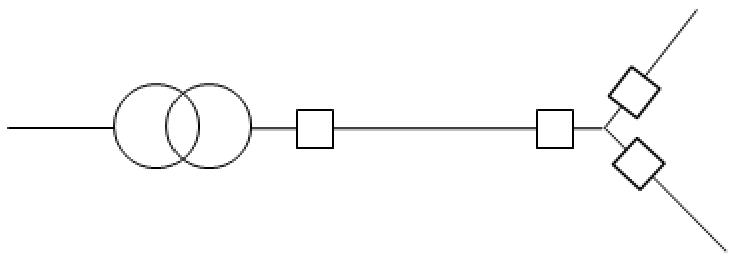

***Figure 4.4.*** *A schematic representation of switching station used in Figure 4.5.*

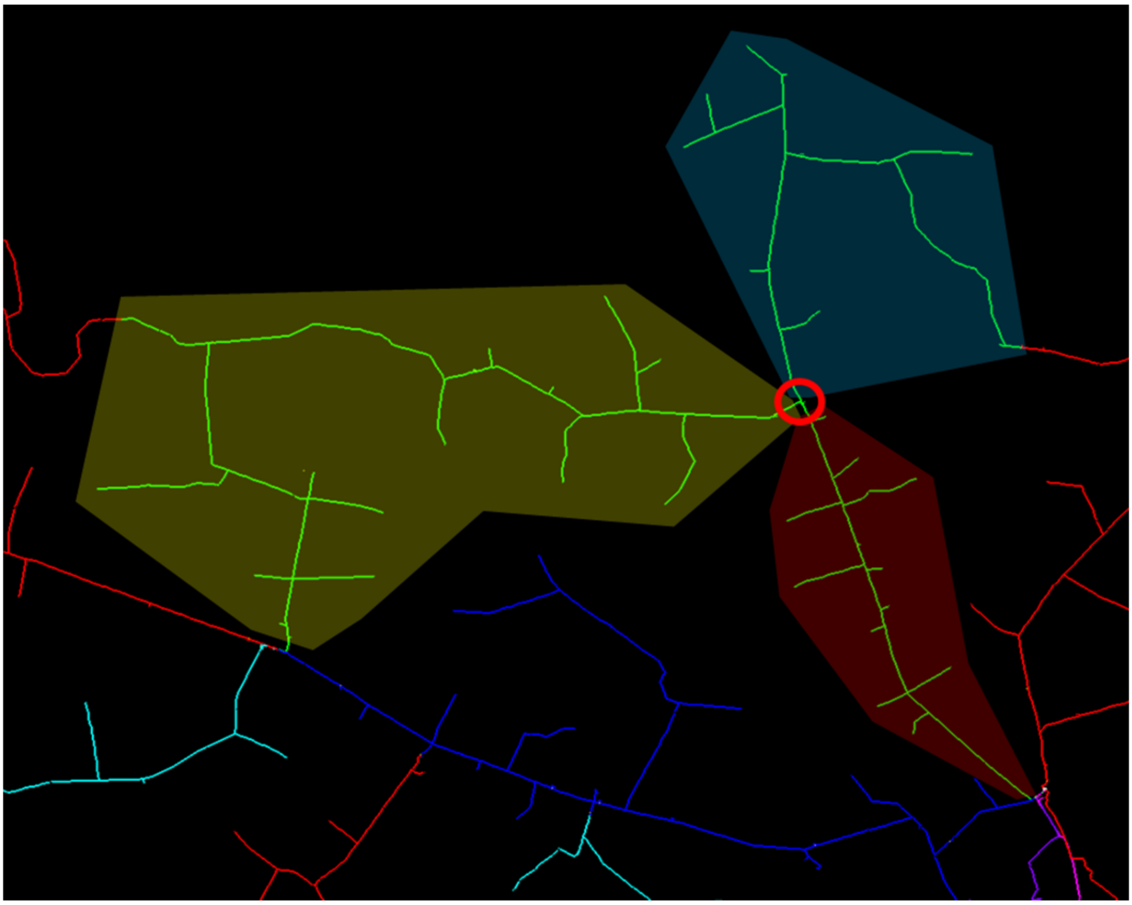

***Figure 4.5*** *Example of feeder, which could be divided into three different protection zones with two circuit breakers. Switching station is marked with red circle and protection zones are highlighted.*

As a downside, a more complex protection system may also increase the risk malfunctions caused by configuration errors or device breakdown. Malfunctions can mean a lack of correct operation when required or an incorrect operation when not required. Older relay types used at the primary substations may cause compatibility issues or limitations to functionality, if not renewed at the same time. Altogether, the price of the system may rise due to various challenges to a level where the benefits no longer outweigh the investment costs.

## 4.3 Requirements

Three alternative, practical implementation models for multi-level short circuit and earth fault protection can be identified. Common requirements for all three include necessary network components relay, circuit breaker, current and voltage transformers or sensors, and communication equipment. Depending on the method of implementation, requirements set for relay or level of communication connection vary.

In the most sophisticated case, advanced communications is utilized and intelligent relays discuss with each other to ensure correct coordination between relays.

Interlocking has been used mainly between feeder and busbar or main transformer protection in the primary substation on distribution level. In literature, IEC 61850 and its GOOSE messages has gained attention for the possibilities it offers in substation protection and control (Hou & Dolezilek 2008; Mackiewicz 2006). Real world examples of substation automation systems implemented with IEC 61850 can be found in (Matsuda et al. 2011; Kimuraet al. 2008).

GOOSE messages are peer-to-peer messages capable of conveying multiple data types to other IEDs. Several message types with performance requirements have been specified according to application. Maximum transmission times for protection and fast control use are 10 or 3 ms, which includes the communication processing in both sending and receiving device as well as the actual transit time between the devices. (Hou & Dolezilek 2008)

Currently GOOSE messages cannot be routed, which complicates message transformation between substations. A solution to this problem has been presented in (Skendzic & Moore 2006), where Virtual LAN (VLAN) has been used for intersubstation communication. With IEC 61850 compatible relays and substation communication, same principle could be applied to messaging between substation and remote circuit breaker. In this case, the communication network has to meet strict performance requirements, thus limiting the choices for communication media in practice to fiber optics.

The second approach is based on active relays, that operates independently without communications according to a predefined algorithm in the event of fault. Such an arrangement is examined in (Jecu et al. 2011). In the proposed protection scheme relays measure impedance and roughly locates fault. Tripping time is then determined according to the faulted protection zone. Relay nearest to the fault sets its tripping time to minimum value. Next relay upstream adds a delay to its tripping time according to a predefined logic. First relay at the substation acts as backup with twice the delay and other relays in between do not trip at all.

Compared to the first alternative, a simpler and slower field communications suffices. Relays operate independently and only status information is send to control center. Relay itself has to be capable of calculating the fault location without compromising its primary task of tripping the circuit breaker. As a downside, relay has to know the network it feeds at all times. This means that relay has to be readjusted every time the feeder configuration is changed. In addition, earth fault location in compensated network is challenging. All things considered, the second alternative could be considered in a situation, where several consecutive protection zones are needed on a single feeder but communication based discrimination cannot be achieved.

Third alternative relies on time discrimination only. Number of consecutive relays is thus limited by the minimum operation time of the last relay on the feeder and maximum allowed operation time of the first relay at the substation. Maximum time is limited by the operation time of busbar protection, which is typically set to approximately one second. With 0,3 s time delay between relays the number of consecutive zones is hence three, when the minimum operation time is assumed to be 0,2 s, which consists of operation times of relay and circuit breaker.

This approach shares communication requirements with previous case, but could be implemented using ordinary relays. Relay settings are fixed and have to be determined and adjusted carefully according to the specific feeder. In some parts of the network selective protection might be impossible to achieve at all or several different sets of relay settings are needed to cover all possible operational situations. Compared to the other alternatives, the third one loses in versatility and about 0,1 s in operation speed.

***Table 4.1*** *Summary of alternative implementation models.*

| Discrimination method | Communication between relays | Local fault location and predetermined logic | Time delay |
|---|---|---|---|
| Pros | • Enables versatile protection arrangements<br>• No limit to consecutive protection zones | • Operates independently of communications<br>• No limit to consecutive protection zones | • Simple implementation |
| Cons | • Depends heavily on communications<br>• Complex system to configure and maintain<br>• | • Depends on fault location accuracy<br>• Settings have to be changed when feeder configuration is altered | • Limited number of consecutive protection zones<br>• Practical relay settings do not always exist<br>• Settings may have to be changed when feeder configuration is altered |
| Relay requirements | High | High | Low |
| Communications requirements | High | Low | Low |

Key aspects of presented cases are summarized in Table 4.1. High relay requirements means that the relay has to be capable of logical decision making based on predetermined rules and real-time measurements in addition to normal protection functions. High level communication requirements are similar to those usually associated with differential protection or HV network protection. This denotes response times of few milliseconds and no tolerance for errors or wait times (Strauss 2003).

## 4.4 Basis for business case

As discussed earlier, the major benefit of multi-level protection is improved reliability. Finnish regulator, Energy Authority (EA), has included a quality incentive in the regulation. The objective of this incentive is to encourage DSOs to improve the reliability by decreasing number and length of unexpected outages, planned outages and automatic reclosings. The incentive is deducted from the operating profit in the calculation of realized adjusted profit and therefore affects the allowed income of DSO.

The calculation of the quality incentive takes into account half of the difference of reference outage costs from the years 2005-2010 and actual outage costs of the year in question (Sähkön jakeluverkkotoiminnan). In this context the actual outage denote disadvantage to customers caused by interruptions in the supply of electricity and is calculated for a certain year as presented in Chapter 3.1.

As can be seen in Equation (3.1), the calculation of disadvantage to customers includes long unexpected or planned outages and short outages in a form of number of reclosings. Cost for long outages consists of two elements: interruption duration and amount both weighted with annual customer energy. Planned outages include outages related to maintenance, network alteration or building that customers have been notified of in advance. Similarly to fault interruptions, planned outage lengths and amounts are weighted with annual customer energy in calculation of disadvantage. Number of reclosings is also weighted with customer energies.

In evaluation of financial viability of introducing multi-level protection to a part of distribution network calculation of customer interruption costs has a vital role. Investment costs of additional circuit breaker, relay and required communication equipment and attained improvements in interruption costs form the two key inputs to financial calculations.

Interruption cost savings arise from the decreased number of customers affected by unexpected outages and reclosings. For the business case evaluation changes in interruption costs have to be estimated.

# 5. AUTOMATIC FAULT LOCATION, ISOLATION AND RESTORATION

One of the most often referred feature of Smart Grid visions is the idea of self-healing network. As a matter a fact, this denotes a network capable of automatic fault location, isolation and service restoration (FLIR) to as many customers as possible. This kind of built-in ability of the distribution network to react to real-time events and to reconfigure itself leads to higher level of reliability and shorter customer experienced outage times.

Normally when fault occurs, control center operator routinely start with trial switchings to identify the faulted section of the feeder. At first only the remote controlled switchgear is used but often manual operations are also needed by the field crew. After the fault has been located within a certain isolation area, situation is assessed and power is restored to those customers outside the faulted section for whom it can be done in a reasonable time. Usually manual restoration is used only if the fault repair is expected to last very long. After that the fault is repaired and swithcings are made to restore the pre fault situation.

With FLIR enabled, the fault location could be based on other methods besides trial switching, such as measurements, fault passage indicators or probabilistic calculations. Besides faster fault location, FLIR enables faster isolation and restoration switchings with remote controlled switches. Optimal switching sequences are calculated automatically with boundary conditions considered. Manual switches have to be still operated by field crews. In most cases the field crew could concentrate on the actual fault repair, if the number of remote controlled devices is sufficiently high and the fault can be fixed in reasonable time so that the manual restoration can be omitted.

## 5.1 Alternative methods

The implementation of FLIR functionality could follow several different operational principles and methods. First and foremost, the level where the decisions are made can be chosen between control room level, substation level and field equipment level. This choice limits the range of technologies needed and sets requirements for communications and computing power of the equipment. Another choice greatly affecting the whole system is the method of fault location used. A variety of alternative approaches exist and two or more of these could be combined to create even more options.

A FLIR system controlled in the system level at the control room resembles the traditional system without FLIR. The only real difference is that the operator's reasoning and actions to open and close switching devices are replaced with algorithms run in DMS and SCADA. In the most basic configuration, FLIR only composes the switching program and control center operator approves and executes each step manually. This approach could be also used to gain knowledge of the real-life functionality of the FLIR in the first stage of implementation. Later when the performance has been confirmed configuration is changed to automatic operation mode, as has been the case in one Finnish DSO (Kuru et al. 2013).

With the system level FLIR the calculation power of DMS can be fully utilized. Probabilistic reliability calculation is used to complement fault location based on measurements in the substation (Kuru et al. 2013). The most suitable backup connection for power restoration can be selected with the help of power flow calculation considering the reserve capacity of the lines. In addition, safety and suitability of the protection settings can be confirmed with a fault analysis.

Some argue that the central decision making makes the system vulnerable (Azevedo et al. 2000). Data has to be gathered and transferred to the control center for processing and commands are sent back to field devices. Depending on the architecture of the communication system., a failure in communication equipment or connection may disrupt or halt the operation of the FLIR. On the other hand, the communications and DMS are vital to the normal activities in the control center and should be secured with backups.

Local level or distributed FLIR represents the completely opposite ideology. Intelligent field devices share information with each other and make the necessary decisions independent of higher level systems. The decentralization means that the system is adaptive and less susceptible to failure of a single device, but at the same time quite complex from the perspective of the system configuration and dependent on communication network.

A simple example presented in (Higgins et al. 2011) and Figure 5.1demonstrates one plausible solution. In the case, a MV feeder with two backup connections to two other substations is considered. Each of the feeders have two sectionalizing switches.

In the event of a permanent fault between CB1 and ROS1, switches ROS3 and ROS4 realize the situation as the feeder is no longer energized and initiate the isolation and restoration sequence. For this to work, each of the switches has to be conscious of the network topology. They call out for CB2 and CB3, respectively, and get back the response with information about available excess capacity. This is compared with prefault loads of the Feeder 1 to come up with a switching plan. ROS1 and ROS2 are opened and ROS3 and ROS4 closed to isolate the faulted section and to transfer the remaining sections to both Feeder 2 and 3. (Higgins et al. 2011)

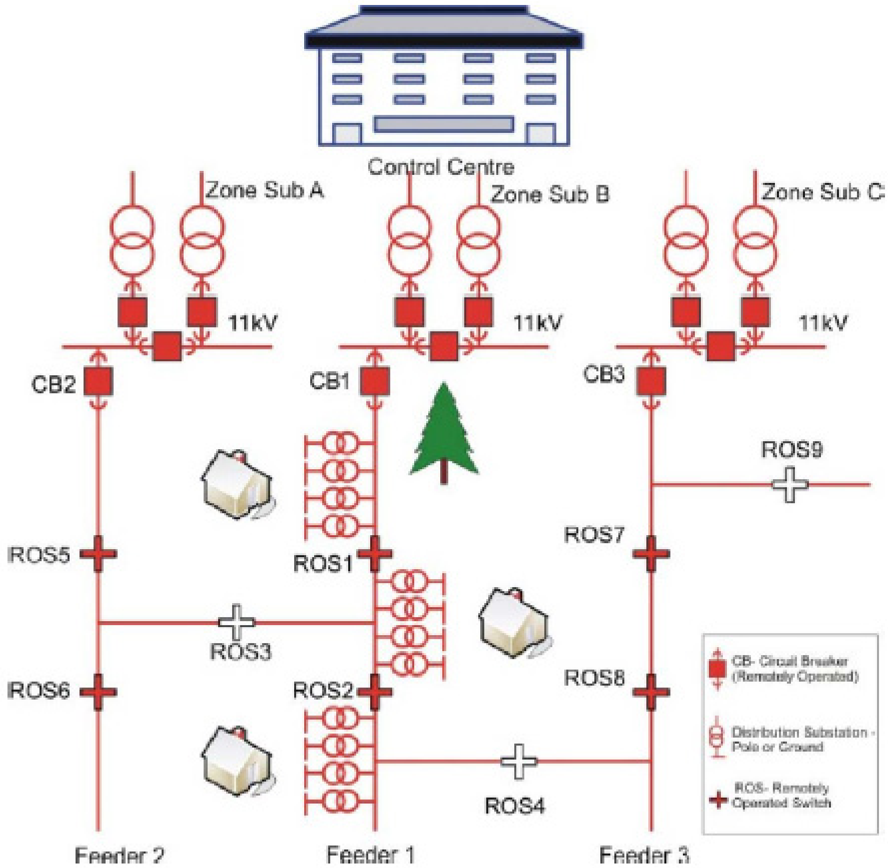


***Figure 5.1.*** *A sample network with local FLIR functionality. (Higgins et al. 2011)*

The third option for FLIR implementation is a compromise between the two others. In this pattern, the FLIR functionality is handled by a dedicated computer unit at the substation. This station computer compiles all the information from the IEDs at the substation and in the supplied distribution network. Besides FLIR, the station computer could coordinate relay interlockings, employ novel fault location algorithms that require measurement data from the whole substations or support station-wide condition management of the equipment. (Valtari & Verho 2011)

The advantages of station computer based FLIR over the other two options stem from practical reasons. Adding a component to complement the existing equipment at the substation rather than having to exchange all of the bay IEDs or to invest extensively on secondary substation automation makes the adaptation of new functionality a straightforward process. Primary substations have more likely already sufficient communications compared to that required in the local FLIR. In addition, from the system configuration and maintenance viewpoint the station computer simplifies both initial and daily tasks. However, communication between control center and station computed is required.

## 5.2 Comparison

Both the centralized decision making based system represented by the control room and the substation level FLIR implementations and the distributed system of individual intelligent field devices have their own advances and disadvantages. A DSO has to consider these when deciding the operational principles of the FLIR.

The centralized system structure embodies a simple and convenient system. Field devices send their data to control center and wait for the commands. Thus the system relies on the control center and a single fault in control center equipment paralyzes the whole system. In addition to the robustness, lack of openness and flexibility may be considered as systems disadvantage. (Ghorbani et al. 2013)

Decentralized approach of the distributed system is more robust and flexible than the centralized solution. However, the communication is not optimal in all situations if the field agents discuss only with their neighbors. (Ghorbani et al. 2013)The more complex implementation requires powerful maintenance tools for surveillance and updating the field equipment.

## 5.3 Requirements

A FLIR system sets requirements mainly for two components of the distribution network. First is the field equipment needed to execute the switching actions either on its own or according to commands made elsewhere. The second major element is the communication system needed to convey the messages reliably and sufficiently fast between other subsystems. These requirements vary according to the chosen implementation model and the objectives set for the FLIR.

With centralized decision making ordinary remote controlled disconnectors suffices in the field. From the viewpoint of the disconnector this approach does not differ from a normal control center initiated operation. More requirements are placed on field equipment in the decentralized implementation, as decision making is expected of the field devices. Modern IED's are capable of this sort of functions and IEC 61850 presents one solution for peer to peer communication.

The performance level of the FLIR system is largely determined by the quality and characteristics of the communications system. Reliable and fast messaging is a fundamental requirement for a high performance FLIR implementation with well synchronized and controlled actions (Ghorbani et al. 2013)

Various communication technologies can be utilized. Based on the communication media, they can be divided to either wired or wireless communication. Whereas wireless links are cheaper and easier to implement, they are inherently unreliable and prone to interference. However, reliability can be improved with higher layer protocols and retransmission, at the cost of latency. Wired media is immune to interference, but also more expensive and remains susceptible to physical risks. (Ghorbani et al. 2013)

In an ideal situation, the faulted section of the feeder would be isolated instantaneously after the fault has become a permanent one or even during the dead time of the delayed automatic reclosing sequence. Therefore, the latency of communications should be consistently low.

The latencies of wired and wireless communication media was simulated and analyzed in (Ghorbani et al. 2013). Simulation was run with centralized, hierarchical and distributed architectures in a small system of 16 field agents. The hierarchical architecture corresponds to the station computer scenario presented in chapter 5.1. The results show that centralized and distributed systems with wired communications have the lowest total system latency in both best and worst case. The wireless communication media competes almost with wired solutions, if the reception probability is high. However, the deviation of best and worst case latency rises rapidly with wireless, if the reception probability declines. (Ghorbani et al. 2013)

## 5.4 Viability

The benefits of FLIR arise from the improved reliability including improved reliability indices, reduced customer outage costs and savings in fault repair costs. The origin of these improvements is illustrated in Figure 5.2.

The course of actions triggered by a fault without FLIR in operation is outlined at the lower part of the figure. After the fault has been detected and confirmed to be permanent, it is reported in the DMS and a fault repair crew is alerted. The crew then drives to the assumed area of the fault. Some rough location could be gained via experimental switchings before the repair crew arrives if remote controlled disconnectors exist or recorded fault current is available to DMS for attempt of fault location calculation. After the crew arrives, fault is patrolled and investigated. When the exact location is found, the decision to manually restore power to the healthy sections of the feeder is made based on the presumed repair time. Finally, the fault is repaired and the feeder is restored to its original state. (Aguero 2012)

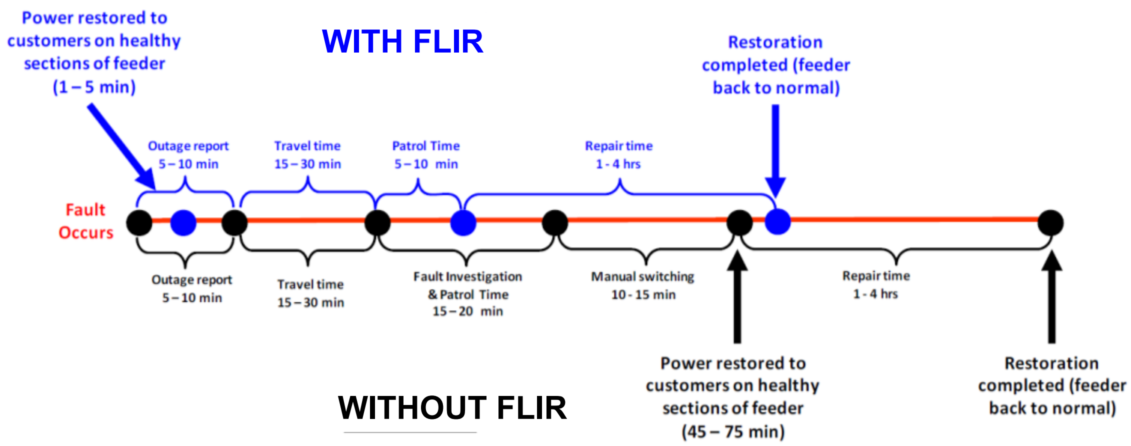


***Figure 5.2.*** *Reliability improvement due to implementation of FLIR. Adopted from (Aguero 2012)*

With FLIR enabled, the most significant difference is that power is restored to the healthy parts of the feeder during the first few minutes. Naturally, only remote controlled switches can be used and fault location has to be successful. The patrol time is decreased as the repair crew can be guided closer to the precise fault location based on initial location and hence the actual repairs are started earlier than without FLIR. If remote controlled switches are sparse, manual restoration is still executed if repair work is tedious.

In total, FLIR saves 45-75 minutes of outage time for those customers outside the faulted section and 10-25 minutes for those inside the faulted section, according to (Aguero 2012). In this example only manual disconnectors are available without FLIR. The actual times may vary and are certainly more or less DSO specific as fault management practices and level of network automation impacts the figures. Nevertheless, even a few minutes saved per customer could result in substantial COC savings over a period of a year if the number of outages, customers experiencing outages or level of automation increases.

In addition to decreased COC, FLIR also improves related reliability indices, such as SAIDI and SAIFI, and reduces energy not supplied to customers due to outages. Accurate fault location reduces fault repair costs in total as less time is spent on patrolling.

# 6. DEFINING THE CASE STUDIES

In order to be able to evaluate the financial meaningfulness of multi-level protection or FLIR, some estimate of the potential savings has to be made. Easiest way is to calculate interruption cost decreases and further the effects on DSO's allowed income through the quality incentive of the regulatory model. Six cases with different amount and placement of remote controlled disconnectors and circuit breakers were determined. Calculations were carried out in two parts of the distribution network.

## 6.1 Reliability based network analysis -tool

Reliability effects of multi-level protection and FLIR were calculated with Trimble NIS. Trimble NIS is a network information system, which incorporates versatile tools for network analyzes, calculations and planning. Reliability calculation is possible with Reliability-based Network Analysis -tool (RNA) based on work done in LuoVa project.

LuoVa project was a research project aimed to develop a model and a prototype tool for distribution network reliability calculation and analyzing purposes. Project was carried out in 2002-2005 in collaboration with several DSOs, IT system suppliers and research groups. As a result, a versatile component level fault model was created and demonstrated in a prototype program developed on top of ABB's existing NIS. Further development work was left to companies involved in project. (Verho et al. 2005)

Network model in RNA-tool consist of overhead lines, covered overhead lines, underground cables, secondary substations and disconnectors. Components that have smaller impact on fault frequency are modelled as combined other component. Each component has certain identified failure modes, for which fault frequencies are defined. For instance, wind/snow and other are the two failure modes of overhead line. In addition, weight factors are used to adjust fault frequencies depending on the environment, condition or other reasons. Overall RNA-tool has over hundred different weight factors in use. Based on the fault frequencies and weight factors a total fault frequency is determined for each component and total fault interruptions caused by individual components are calculated. Similar model is used to calculate work interruptions and reclosings. (Verho et al. 2005; Administrator's Guide 2012)

Interruption duration is calculated for each zone of the feeder, which is separable by switching device. Algorithm imitates a typical fault clearance procedure, which is illustrated in Figures Figure 6.1 and Figure 6.2. (Verho et al. 2005)

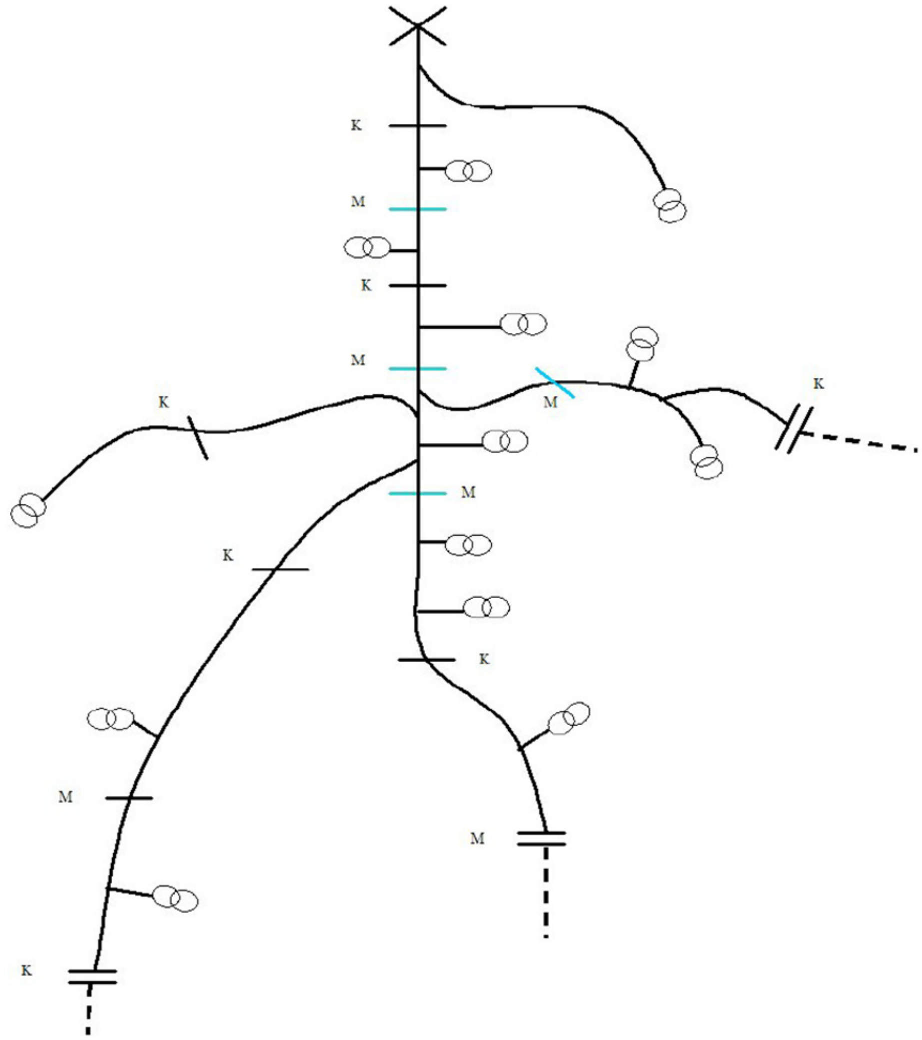


***Figure 6.1*** *Example feeder. (Verho et al. 2005)*

Figure 6.1 represents the example feeder in normal situation. Cross at the top denotes circuit breaker and feeding point of the network. Single lines are closed disconnectors and double lines open disconnectors. Letters describe the control mode of the switching devices (M = manual, K = remote controlled). Back-up connections to other feeders are illustrated with dashed lines. Distribution substations are represented by double circles at the end of each branch. (Verho et al. 2005)

The fault clearance process is depicted in Figure 6.2. Faulted part is denoted by lightning symbol in the middle of the feeder and the affected area is outlined by grey dashed line. First the algorithm locates zones, that are remotely disconnectable and restorable (yellow zones). Areas, that can be remotely disconnected but remote restoration is not possible (blue zones), are also noted in this stage. The possibility of manual reconnection is checked later for these areas. (Verho et al. 2005)

Next the remotely disconnected fault area is defined as the area outlined in red in Figure 6.2. Zones inside the area are examined to identify manually disconnectable zones (green zones). At the same time those remotely disconnectable zones with no remote controlled back-up connections are re-examined for the existence of manual back-up connections. In the example network the lower blue area can be restored with manual disconnector. However, it is also included in a larger zone, which could be disconnected and restored manually (orange zone). The final fault area is illustrated as the red area. The blue area in the left experiences also the interruption as no back-up connection exists. (Verho et al. 2005)

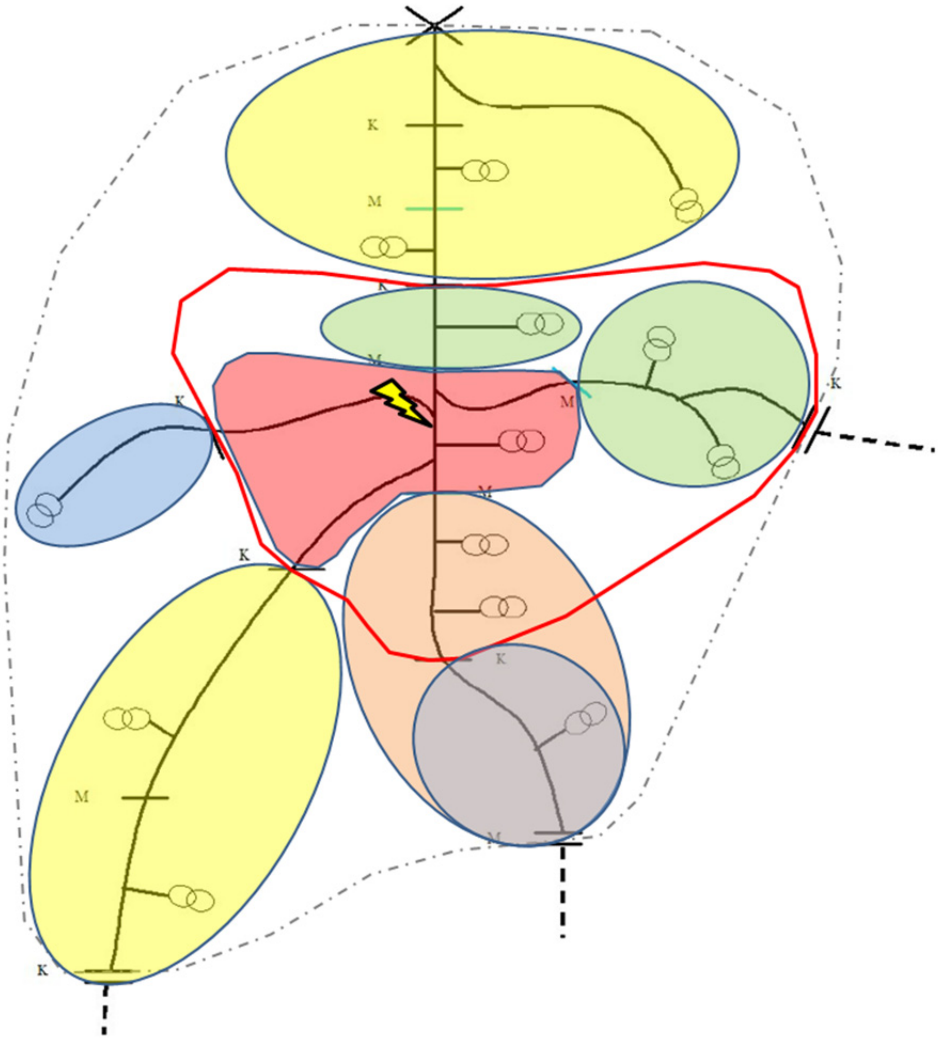

***Figure 6.2*** *Zone model used for simulating fault clearance in RNA-tool. Adopted from (Verho et al. 2005; Koponen 2013)*

Interruption times in different zones results from the operation mode of the disconnectors and the availability of reserve connections. Manual and remote disconnections are always done as well as remote restorations, but the execution of manual restoration depends on fault repair time. If the fault can be repaired in a reasonable time, manual restoration is omitted. Interruption times in different zones and the parameters affecting them are presented in Table 6.1. (Verho et al. 2005)

***Table 6.1*** *Experienced interruption times in different areas with default parameters.*

| | | |
|---|---|---|
| | Disconnection and restoration with remote control<br>RnaTimeIsolRemote | 5 min |
| | Disconnection with remote control, restoration with manual disconnector (if possible)<br>RnaTimeRestManualMV | 60 min |
| | Disconnection with manual disconnector, restoration with remote control<br>RnaTimeIsolManual | 45 min |
| | Disconnection and restoration with manual disconnectors<br>RnaTimeRestManualMV | 60 min |
| | Final fault zone (repair time)<br>RnaFaultRepairTimeMV<br>RnaTimeFixTrafo<br>RnaTimeFixCableMV | <br>120 min<br>150 min<br>240 min |

## 6.2 Calculation parameters

Calculation parameters for RNA-tool were originally determined in 2012 based on actual reported fault statistics from 2005 to 2011 as part of a Master's thesis. Initial parameter values were defined individually for five operational areas used in outage reporting. (Koponen 2013) Since then the environmental information for overhead lines has been improved with the utilization of results from MV network helicopter inspections. All of the MV overhead lines were photographed and scanned with laser. The number of trees capable of falling over a certain line part was interpreted from the laser data and environment of the line was determined on Trimble's four level scale, where 1 denotes open areas and 4 fault prone forest. At the same time the area division of the parameters was refined to cover 9 geographical asset areas and the parameters were adjusted to match the calculated outage costs and amounts to actual average regional values.

For the purposes of this thesis some parameters had to be revised. The values for parameters affecting manual and remote disconnection times were readjusted based on fault statistics from the year 2013. Longer sample period could not be obtained, as the disconnection times for manual and remote switching have not been reported before for individual faults. Results for urban and rural area presented in Table 6.2.

***Table 6.2*** *Disconnection times.*

| Parameter | Urban | Rural |
|---|---|---|
| RnaTimeIsoRemote | 9 min | 12 min |
| RnaTimeIsoManual | 51 min | 71 min |

RNA-tool has a separate parameters for fault location function in short-circuit and earth faults. Fault location reduces the time of manual disconnection and fault repair by default with 20 minutes. As no better information was available and the value seemed reasonable considering the manual switching times, default parameter was used in FLIR simulation. Calculations were also carried out with the parameter set to 30 minutes to gain understanding of the impact the parameter has. In addition, remote disconnection time was set to 1 minute. Assumption was that no notable delay would be caused by effective field communications.

## 6.3 Area for analysis

The focus of reliability analysis is to estimate the achievable reliability benefits of multi-level protection and FLIR in comparison to the current reliability level. For practical reasons the analysis was conducted for a MV distribution network fed by a single substation instead of the whole distribution network. To gain a better understanding of the impact the network structure has on the results, two different substations were selected. The selected substations represent typical urban or city area and rural area.

### 6.3.1 Urban area

The urban area selected for analysis is presented in Figure 6.3. Located in southern Espoo, Niittykumpu substation feeds the surrounding residential areas of Haukilahti, Olari and parts of Matinkylä, as well as industrial area in Niittykumpu and city-like area center of Tapiola. Residential areas consist mostly of densely built row houses and detached houses in between and apartment buildings at the center of each area. Highway 51 running through the area in east-west direction is lined with offices and various stores. Commercial life is centered in Tapiola at the edge of the distribution area of Niittykumpu substation.

The substation has two 40 MVA primary transformers and a total of fifteen medium voltage feeders. It supplies just over 20000 customers with annual energy of 250 GWh. Total MV network length adds up to 96,5 kilometers.

MV network is almost entirely underground cable with a few exception of aerial cables used. Secondary substations are either pad mounted or indoor substations. Most of the substations are equipped with line disconnectors and cables are usually disconnectable from both ends. However, all of the disconnectors operate manually as remote control has been considered unnecessary in cable network.

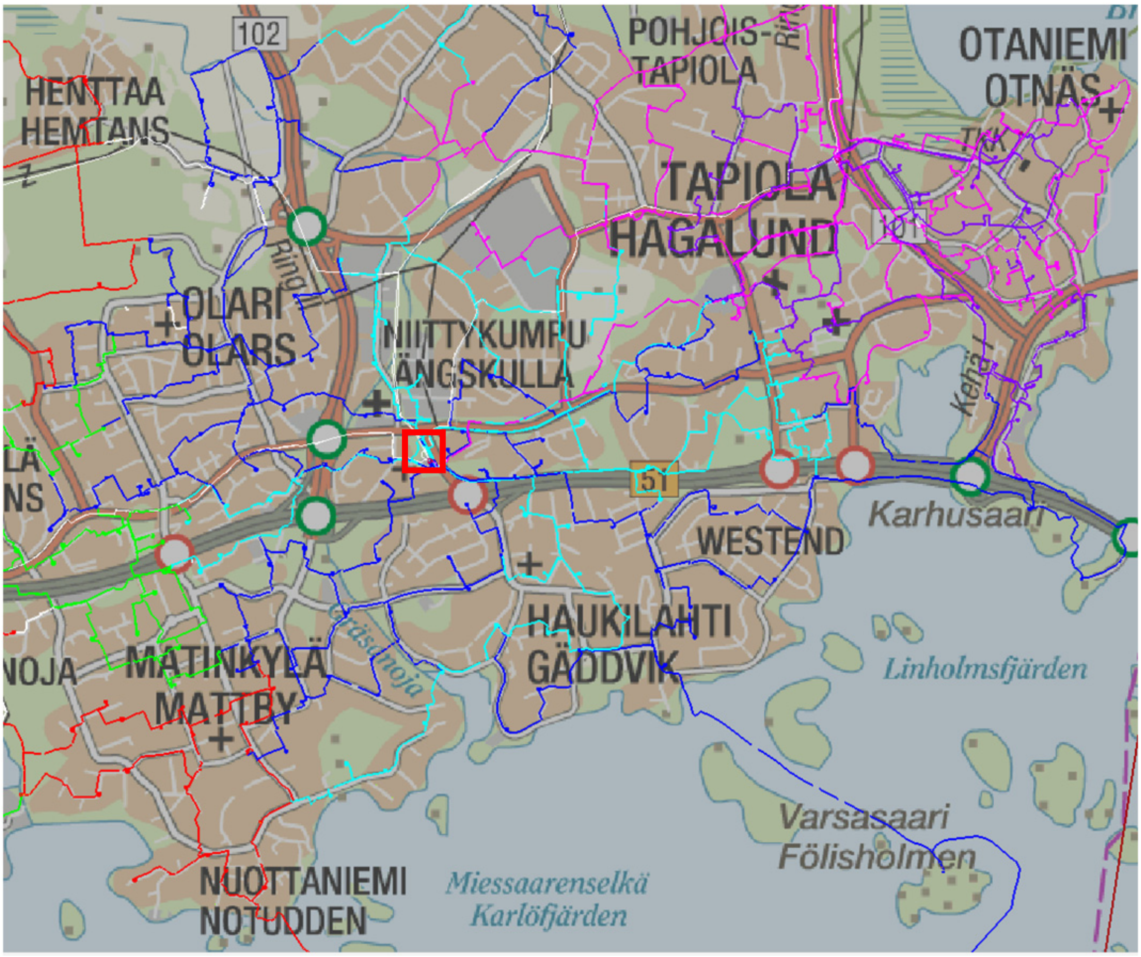


***Figure 6.3*** *Niittykumpu substation area. Substation is highlighted with red square. Network fed by the two main transformers is highlighted with light and dark blue.*

***Table 6.3.*** *The feeders of Niittykumpu substation.*

| Feeder | Customers | Distribution substations | Length/km | Pmax/MW |
|---|---|---|---|---|
| B04 Orion | 180 | 1 | 2,4 | 0,61 |
| B05 Hakalehto | 1220 | 17 | 6,3 | 3,54 |
| B06 Olari | 2604 | 21 | 10,7 | 4,85 |
| B09 Mankkaa | 31 | 6 | 2,2 | 1,73 |
| B10 Ahertajantie | 6 | 1 | 2,5 | 0,68 |
| B11 Länsimetro | 2318 | 14 | 5,9 | 3,04 |
| B12 Länsiväylä | 2445 | 29 | 20,7 | 7,58 |
| B16 M21521 | 0 | 1 | 1,4 | 0,00 |
| B17 Itätuulentie | 449 | 10 | 4,6 | 3,17 |
| B18 Toppelund | 2262 | 14 | 6,9 | 4,29 |
| B19 Haukilahti | 2413 | 17 | 7,6 | 4,70 |
| B22 Piispankallio | 904 | 6 | 3,9 | 1,17 |
| B23 Matinkylä | 1275 | 8 | 3,9 | 2,25 |
| B24 Suomenoja | 2468 | 21 | 10,7 | 5,25 |
| B25 Lukupuro | 615 | 12 | 6,8 | 3,32 |
| **Sum** | **19190** | **178** | **96,5** | **46,18** |

Table 6.3 shows the basic information about the feeders in the study. As typical to urban feeders, the length of the feeders remain quite low, but the customer amount per feeder can still climb high. Remote controlled disconnectors could be easily positioned at the points where the feeder branches out or connects with adjacent feeder. Usually a pad mounted secondary substation with three or four disconnectors is already present at these points.

For the purposes of this study, the existing secondary substations were used and disconnectors converted to remote controlled. Locations were chosen to maximize the number of remote controlled sections and remote controlled back-up connections while keeping the sections reasonable and equally spaced.

### 6.3.2 Rural area

Rural substation area is presented in Figure 6.4. It covers the municipalities of Koski Tl and Marttila in Southwest Finland fed by Selkä substation. The substation is located approximately 4 kilometers from the main population center of Koski Tl and 15 kilometers from the center of Marttila.

The Selkä substation has a single 25 MVA primary transformer and 6 MV feeders. The substation is situated along a HV line and can be fed by two circuits. However, this study focuses on the medium voltage network reliability and both HV and primary transformer or busbar faults are neglected. In total 3500 customers with annual energy consumption of 63 GWh are supplied via 300 km of medium voltage lines.

***Table 6.4.*** *The feeders of Selkä substation.*

| Feeder | Customers | Distribution substations | Length/km | Pmax/MW |
|---|---|---|---|---|
| SLKJ05 | 102 | 15 | 17,3 | 0,71 |
| SLKJ06 | 784 | 63 | 64,1 | 1,63 |
| SLKJ07 | 876 | 40 | 29,2 | 2,07 |
| SLKJ08 | 279 | 35 | 36,6 | 0,59 |
| SLKJ09 | 1111 | 89 | 95,1 | 2,78 |
| SLKJ10 | 387 | 52 | 55,2 | 1,00 |
| **Sum** | **3539** | **294** | **297,6** | **8,78** |

Most of MV network is old overhead line. Newer parts have been built with covered conductors or cables. The current cabling rate is just over 5 percent and 90 percent of all the secondary substations are pole mounted. In contrast to urban network, a total of eight remote controlled disconnector stations are located at the junctions of adjacent feeders, two of which are older pole mounted versions and the other newer pad mounted ones. In addition, one pad mounted substations is equipped with circuit breaker in the center of Koski Tl, which is fed by the purple feeder in Figure 6.4. The purpose of the circuit breaker is to isolate the faults of the downstream rural part of the feeder. However, the circuit was not taken into account in the reliability calculations.

The basic information about the feeders of rural area are gathered in Table 6.4. While the feeders are significantly longer than in urban area both the number of customers and maximum power are obviously lower. Additionally, less back-up connections with other feeders or internal loops are available. In contrast to the entirely cabled network design, the aerial network makes the placement of the remote controlled disconnectors more challenging. In this study the existing line disconnectors were converted from manual to remote operation in order to be able to analyze just the reliability influence of the increased automation. Although in some feeders this approach exaggerates the number of disconnector substations but as this is a matter of feeder topology compromises have to be made also in real life.

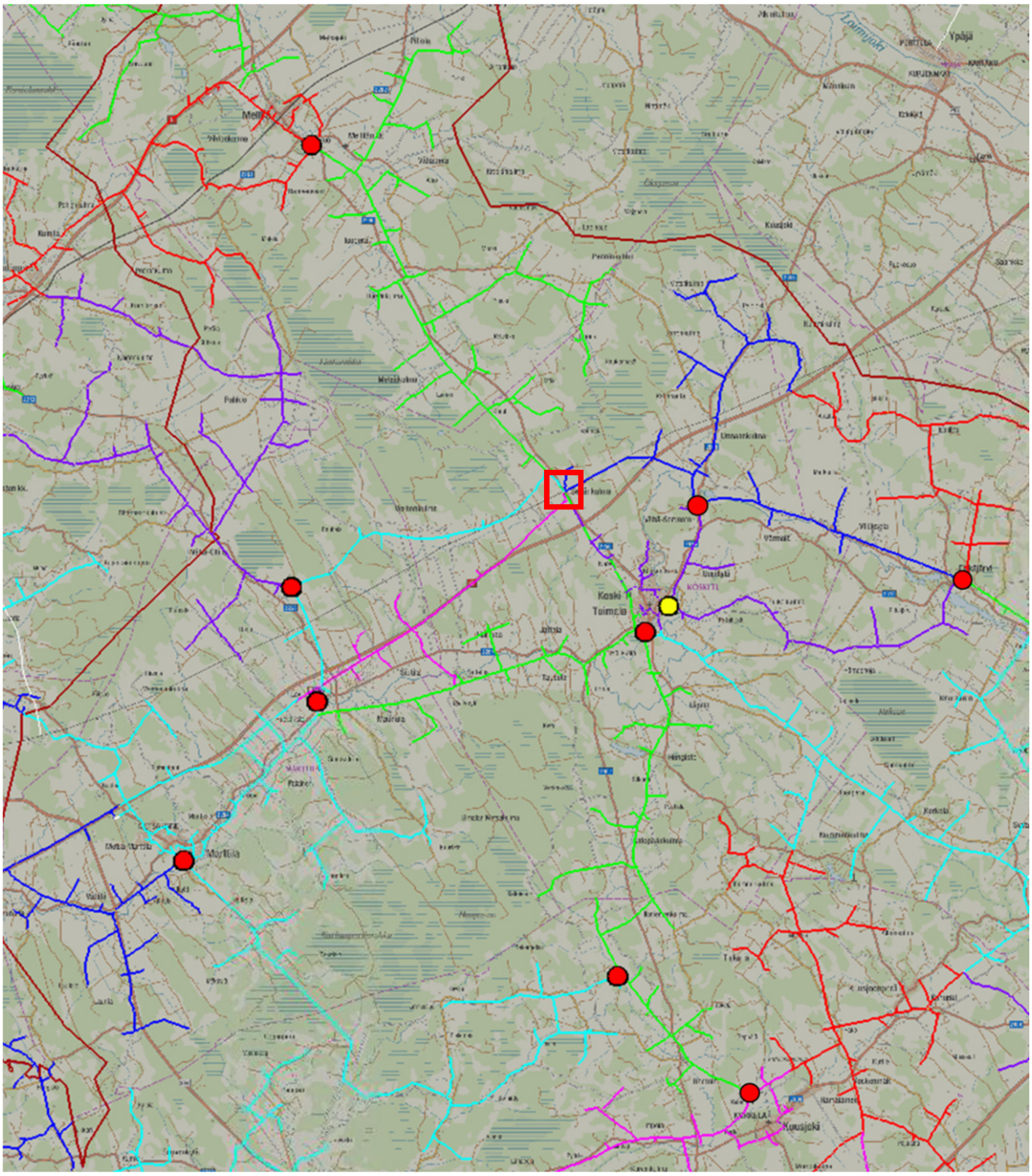

***Figure 6.4*** *Selkä substation area. Substation is highlighted with red square. Red dots represent remote controlled disconnector stations and yellow dot secondary substation with a circuit breaker.*

## 6.4 Cases

In total 15 different cases were defined for reliability calculations, six of which are common for both urban and rural networks. The effect of FLIR was studied in cases 1 to 4 and multi-level protection in cases 5 and 6. The objective was to attain the benefits of added automation functionalities, but as the current amount of remote controlled switchgear greatly influences the gained results, especially with FLIR, the number and placement of remote controlled disconnectors was varied throughout the cases.

A situation with no remote controlled switchgear except for the circuit breakers at the substation was chosen for a reference level. This was also the current situation in the urban network and therefore a natural choice for case 1. In case 2, remote controlled disconnectors were added to the open points between adjacent feeders. For the next case, a remote controlled disconnector station was added in a suitable position at approximately half way down the feeder. A place where the feeder split into two or more branches was favored to maximize the number of remote controlled sections. For rural network the current existing disconnector stations complemented with the backup disconnectors served as case 3. Case 4 was similar to previous case, but the feeder was further divided into smaller sections. In urban network, a second disconnector station could be added at another junction point. Due to sparser network structure, a slightly different approach was adopted in rural network, where single pole mounted disconnectors were used for longer branches.

Multi-level protection was simulated in cases 5 and 6. First in case 5 a switching station equipped with one or two circuit breakers was placed at the same location as the disconnector station in case 3. No additional automation was present. In case 6 remote controlled backup disconnectors were added. All the cases are presented in Table 6.5.

***Table 6.5*** *Common cases for urban and rural networks.*

| | |
|---|---|
| Case 1 | No remote controlled switchgear |
| Case 2 | Remote controlled backup connections |
| Case 3 | Remote controlled backup connections, feeders remotely divisible at half way |
| Case 4 | Remote controlled backup connections, feeders remotely divisible at several points |
| Case 5 | Circuit breaker |
| Case 6 | Circuit breaker and remote controlled backup connections |

Rest of the cases 7 through 15 presented in Table 6.6 concern only rural network. Recent changes in Electricity Market Act lead inevitably towards a more weatherproof network. Anticipated changes in network technology presumably focus more on rural areas than already cabled urban centers. Purpose of these cases is to determine whether an increase in weather resistance and therefore improved basic reliability level renders automation functionalities purposeless.

Weatherproofing rate was increased from the default 59 % of the Selkä substation area at the time of the study gradually to 87 % with MV cabling. First the trunk of the feeder was cabled to the disconnector/switching station. In the next phase the branches at the beginning of the feeder were changed to cables. Lastly, cabling was extended to cover the trunk line all the way to the end of the feeder. Weatherproof network was in this instance defined as underground cables or overhead lines with either plain or covered conductors in the treeless areas. The locations of cabled sections were roughly optimized with respect to the customer and energy consumption density. The fault frequency of individual lines could be also considered, but the chosen method was deemed adequate for estimation of impact of weatherproofing on FLIR.

Calculations were carried out first without any automation to gain understanding of the reliability improvement caused by chances in the network structure. Then the existing remote controlled disconnectors were added for cases 10-12 and finally the same circuit breaker locations used in case 5.

***Table 6.6*** *Cases for rural network with increased MV cabling.*

| | |
|---|---|
| Case 7 | No remote controlled switchgear, weatherproofing rate 67 % |
| Case 8 | No remote controlled switchgear, weatherproofing rate 73 % |
| Case 9 | No remote controlled switchgear, weatherproofing rate 87 % |
| Case 10 | Existing remote controlled disconnectors, weatherproofing rate 67 % |
| Case 11 | Existing remote controlled disconnectors, weatherproofing rate 73 % |
| Case 12 | Existing remote controlled disconnectors, weatherproofing rate 87 % |
| Case 13 | Circuit breaker and existing remote controlled disconnectors, weatherproofing rate 67 % |
| Case 14 | Circuit breaker and existing remote controlled disconnectors, weatherproofing rate 73 % |
| Case 15 | Circuit breaker and existing remote controlled disconnectors, weatherproofing rate 87 % |

# 7. CALCULATION RESULTS

The calculations were conducted in Trimble NIS with actual distribution network. As Trimble was not the primary network information system and the network model was only updated at a certain interval, both substation areas were first examined to verify the calculation situation. To begin with, the feeders were aligned with the normal situation as shown in DMS.

Then the customer amount per feeder was checked against the DMS. While the rural substation was in line with the DMS, the urban are lacked nearly 2000 customers. This was mostly caused by shortages in the documentation of ongoing projects at the time of previous network update and problems with certain types of customer connections. However, after manual repairs the number of customers still missing from Trimble was decreased to just under 1000 customers. As this was common to all of the cases and the maximum power in load flow calculation matched the measured power no further measures were taken to improve the situation.

Lastly, the annual total energy supplied to the network was compared with actual measurement from the substations. On both substations the calculated value was found out to be well in line considering the calculation parameters.

Before the calculations were carried out both parameter sets for RNA-tool were adjusted to match the reported fault amounts and customer outage costs of each substation to gain more accurate results. Average statistics from the years 2009 to 2012 were used as older statistics was considered insufficient in terms of data quality. The statistics are presented in Appendix 2.

A separate plan was then prepared in Trimble NIS for both network areas and for each case. Required chances to existing network were made and reliability calculations were carried out with three different parameter sets. Results from first calculations without FLIR were used as reference. The second and third parameter sets simulated FLIR with 20 and 30 minute improvement to the fault location and repair process.

## 7.1 Urban

The first six cases were studied in the urban network. In this chapter the location of added automation is presented case by case and reliability calculation results are analyzed.

### *Case 1*

Case 1 is used as reference for other cases. As no remote controlled disconnectors have been installed in the particular area, the actual network was used. **Error! Reference source not found.** shows the basic information about the feeders in the study. As typical to urban feeders, the length of the feeders remain quite low, but the customer amount can still climb high.

### *Case 2*

For case 2 remote controlled back-up disconnectors were added to every open point between adjacent feeders. The placement of these disconnectors is illustrated in Figure 7.1. In total 40 disconnectors were converted from manual to remote control with an average of 2,7 per feeder.

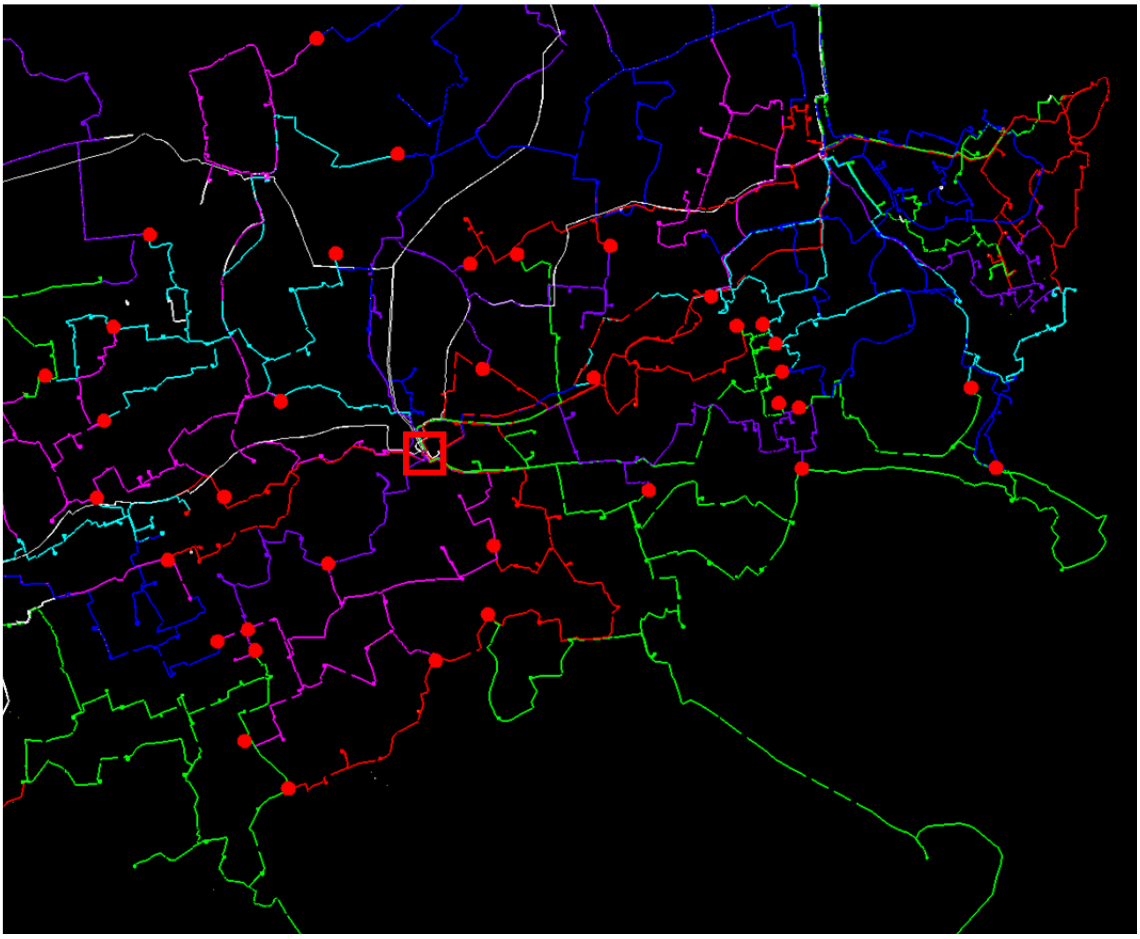

***Figure 7.1.*** *Case 2 for urban area. Remote controlled disconnectors are highlighted with red dots and primary substation with red square.*

### *Case 3*

Compared with case 2, more remote controlled disconnectors were added. The objective was to add disconnectors roughly in the middle of the feeder. If possible, a substation with two or more disconnectors was chosen to divide the feeder into several sections.

Some of the locations presented in Figure 7.2 were the same as those in case 1. In addition to the previous, 29 new remote controlled disconnectors were added to 13 secondary substations resulting in an average of 2,2 remote controlled sections per feeder.

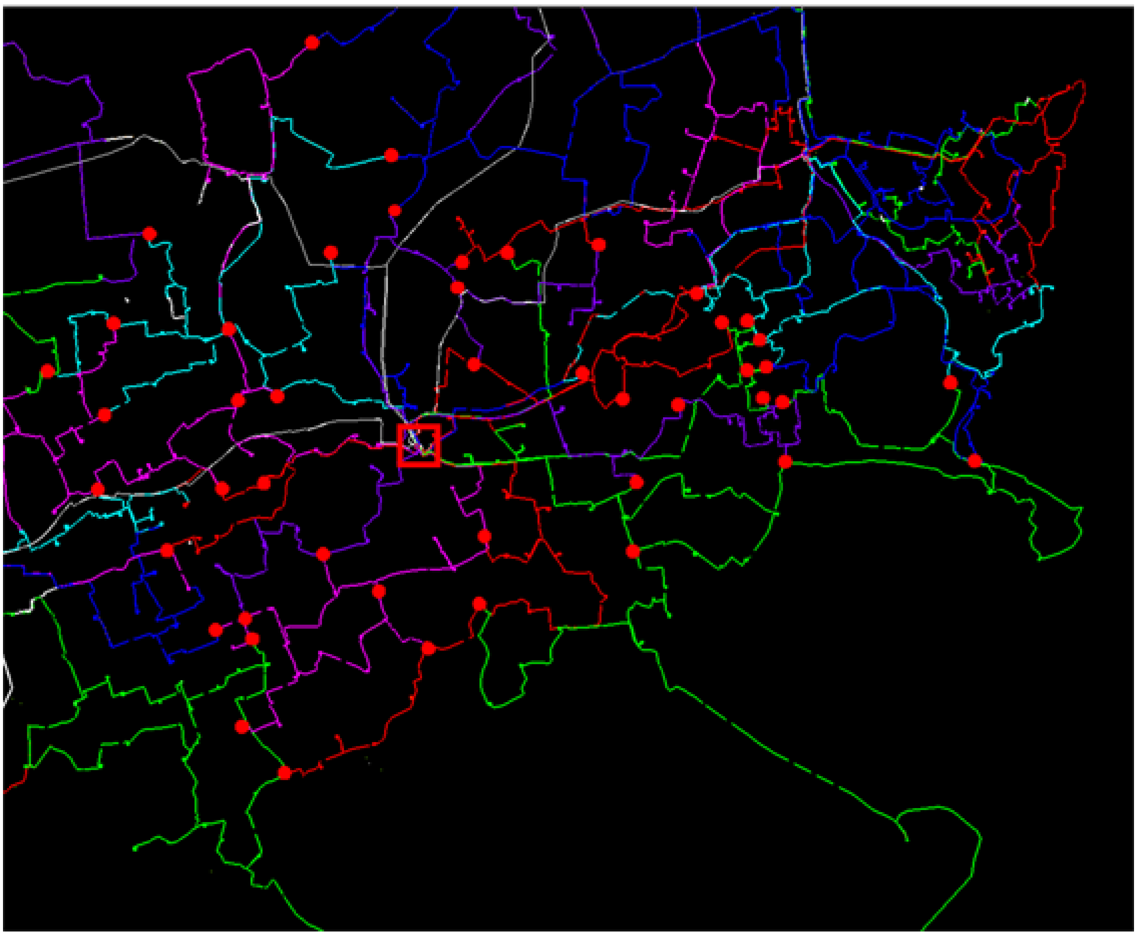

***Figure 7.2.*** *Case 3 for urban area. Remote controlled disconnectors are highlighted with red dots and primary substation with red square.*

### *Case 4*

For case 4 the feeders were further divided into smaller section. Remote controlled disconnectors were placed in three points along the feeder in addition to the back-up disconnectors. At the end the number of disconnectors on the feeders increased to 59 in 23 different secondary substations. The average number of remote controlled sections per feeder was 3,5. Placement of the substations is illustrated in Figure 7.3

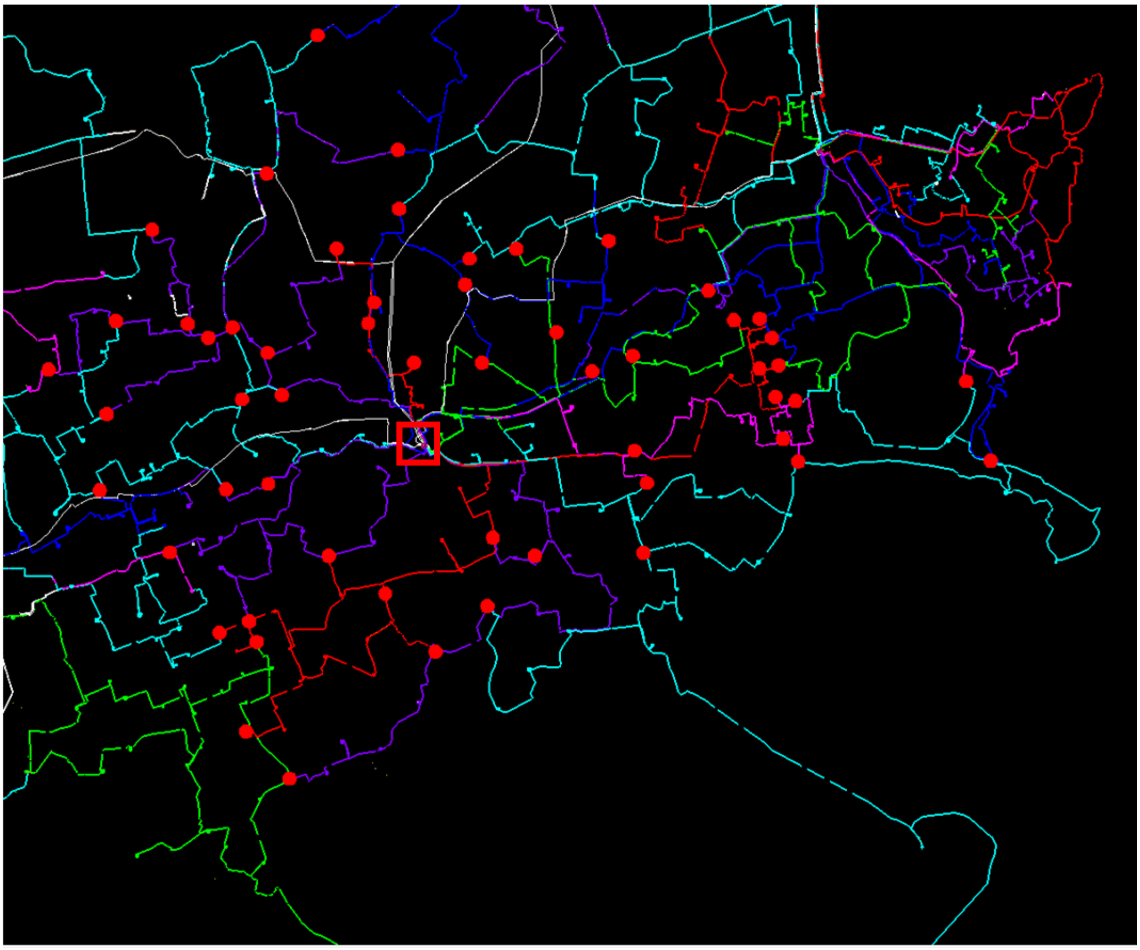

***Figure 7.3.*** *Case 5 for urban area. Remote controlled disconnectors are highlighted with red dots and primary substation with red square.*

### *Cases 5 & 6*

In cases 5 and 6 the impact of added protection zones was studied. Case 5 included only added circuit breakers and in case 6 the same remote controlled back-up disconnectors were introduced from case 2 to add the possibility of remote restoration on the farthest protection zones. The circuit breakers were located at the existing secondary substations replacing the manual disconnectors. The locations are presented in Figure 7.4. In total 19 circuit breakers were added to 11 secondary substations. Thus creating 19 new protection zones to bring the average number of protection zones to 2,3 per feeder.

***Figure 7.4.*** *The locations of substations with circuit breakers in cases 5 and 6.*

### *Calculation results*

The reference level of results for each case is shown in Table 7.1. As the switches do not have a fault frequency defined in the RNA-calculation parameters, the number of faults stays constant in all of the cases. In reality the difference between manual and remote controlled disconnectors is negligible as the actual disconnectors are identical and the added control mechanism and communications do not cause outage if it malfunctions. On the other hand, circuit breakers are expected to have different fault frequency compared with a disconnector but still the effect on the fault frequency of the whole network is minimal.

*Table 7.1. Results for urban area without FLIR.*

| | Faults [pcs/a] | Sum of fault interruption hours of customers [h/a] | SAIDI | SAIFI | CAIDI | COC [€/a] |
|---|---|---|---|---|---|---|
| Case 1 | 3,30 | 4 730 | 0,314 | 0,301 | 1,045 | 95 631 |
| Case 2 | 3,30 | 4 188 | 0,277 | 0,301 | 0,923 | 87 367 |
| Case 3 | 3,30 | 2 284 | 0,178 | 0,301 | 0,593 | 56 073 |
| Case 4 | 3,30 | 1 784 | 0,152 | 0,301 | 0,506 | 48 638 |
| Case 5 | 3,30 | 3 111 | 0,221 | 0,202 | 1,098 | 64 355 |
| Case 6 | 3,30 | 2 052 | 0,166 | 0,202 | 0,825 | 49 128 |

With cases 1 to 4 the SAIFI is unchanged as the interruption frequency does not change with the addition of remote controlled disconnectors. The effect of remote controlled on the fault isolation can yet be seen in the other figures which show a steady decrease. This is caused by the reduction of fault isolation times with remote control over manual operation. For example, the customer outage costs decrease by approximately 50 % in both case 4 and 6 compared with the case 1. On the other hand, the circuit breakers in cases 5 and 6 impact all of the reliability indices. Compared with cases 1 and 2 a significant decrease in COC is notable.

*Table 7.2. Results for urban area with FLIR improving fault location by 20 min.*

| | Faults [pcs/a] | Fault interruption hours of customers [h/a] | SAIDI | SAIFI | CAIDI | COC [€/a] |
|---|---|---|---|---|---|---|
| Case 1 | 3,30 | 4 657 | 0,310 | 0,301 | 1,032 | 94 311 |
| Case 2 | 3,30 | 4 077 | 0,272 | 0,301 | 0,904 | 85 359 |
| Case 3 | 3,30 | 1 894 | 0,158 | 0,301 | 0,525 | 49 748 |
| Case 4 | 3,30 | 1 344 | 0,129 | 0,301 | 0,430 | 41 649 |
| Case 5 | 3,30 | 3 037 | 0,217 | 0,202 | 1,079 | 63 124 |
| Case 6 | 3,30 | 1 869 | 0,157 | 0,202 | 0,777 | 46 350 |

*Table 7.3. Results for urban area with FLIR improving fault location by 30 min.*

| | Faults [pcs/a] | Fault interruption hours of customers [h/a] | SAIDI | SAIFI | CAIDI | COC [€/a] |
|---|---|---|---|---|---|---|
| Case 1 | 3,30 | 4 621 | 0,308 | 0,301 | 1,026 | 93 651 |
| Case 2 | 3,30 | 4 022 | 0,269 | 0,301 | 0,894 | 84 355 |
| Case 3 | 3,30 | 1 872 | 0,157 | 0,301 | 0,522 | 49 384 |
| Case 4 | 3,30 | 1 302 | 0,127 | 0,301 | 0,423 | 40 957 |
| Case 5 | 3,30 | 2 999 | 0,216 | 0,202 | 1,069 | 62 509 |
| Case 6 | 3,30 | 1 831 | 0,155 | 0,202 | 0,767 | 45 735 |

The results with FLIR enabled are presented in Tables Table 7.2 and Table 7.3. The benefit of FLIR over the reference is calculated in Tables Table 7.4 and Table 7.5. From

Table 7.4 it can be seen that FLIR functionality improves the calculation results slightly even with no added automation available. In cases 3 and 4 a significant improvement is noted especially with COC and customer fault interruption hours. However, the ten minute decrease in fault location and repair times in Table 7.5 shows only minor effect on the results. With the additional protection zones in cases 5 and 6, the implementation of FLIR brings even larger improvement over the base cases. It should be noted, that without the remote controlled back-up disconnectors the circuit breakers have little benefit to FLIR.

***Table 7.4.*** *The benefit of FLIR with 20 min improvement in fault location.*

| | Faults [%] | Fault interruption hours of customers [%] | SAIDI [%] | SAIFI [%] | CAIDI [%] | COC [%] |
|---|---|---|---|---|---|---|
| Case 1 | 0,0 | 1,5 | 1,2 | 0,0 | 1,2 | 1,4 |
| Case 2 | 0,0 | 2,6 | 2,1 | 0,0 | 2,1 | 2,3 |
| Case 3 | 0,0 | 17,1 | 11,4 | 0,0 | 11,4 | 11,3 |
| Case 4 | 0,0 | 24,6 | 15,1 | 0,0 | 15,1 | 14,4 |
| Case 5 | 0,0 | 2,4 | 1,8 | 0,0 | 1,8 | 1,9 |
| Case 6 | 0,0 | 8,9 | 5,8 | 0,0 | 5,8 | 5,7 |

***Table 7.5.*** *The benefit of FLIR with 30 min improvement in fault location.*

| | Faults [%] | Fault interruption hours of customers [%] | SAIDI [%] | SAIFI [%] | CAIDI [%] | COC [%] |
|---|---|---|---|---|---|---|
| Case 1 | 0,0 | 2,3 | 1,8 | 0,0 | 1,8 | 2,1 |
| Case 2 | 0,0 | 4,0 | 3,1 | 0,0 | 3,1 | 3,4 |
| Case 3 | 0,0 | 18,0 | 12,0 | 0,0 | 12,0 | 11,9 |
| Case 4 | 0,0 | 27,0 | 16,5 | 0,0 | 16,5 | 15,8 |
| Case 5 | 0,0 | 3,6 | 2,6 | 0,0 | 2,6 | 2,9 |
| Case 6 | 0,0 | 10,8 | 6,9 | 0,0 | 6,9 | 6,9 |

The benefit gained from adding the circuit breakers is presented in Table 7.6. Increased number of protection zones decreases the COC and customer fault interruption hours by approximately 33 %. Combined with the remote controlled back-up connections for faster restoration of healthy sections the numbers are decreased by 44 % and 51 %, respectively. System level interruption indices SAIDI and SAIFI show also significant improvements but in the case of interruption hours experienced by a single customer the effect is smaller. In fact, CAIDI actually increases in case 5.

*Table 7.6. The benefit of circuit breakers without the effect of FLIR.*

| | Faults [%] | Fault interruption hours of customers [%] | SAIDI [%] | SAIFI [%] | CAIDI [%] | COC [%] |
|---|---|---|---|---|---|---|
| Case 5 | 0,0 | 34,2 | 29,5 | 33,0 | -5,1 | 32,7 |
| Case 6 | 0,0 | 51,0 | 40,1 | 33,0 | 10,7 | 43,8 |

## 7.2 Rural

In the rural network all of the cases were studied. In this chapter the location of added automation is presented case by case and reliability calculation results are analyzed.

### *Case 1*

Being the reference case for all other cases, the existing remote controlled disconnectors were converted to manual disconnectors and circuit breakers were removed.

### *Case 2*

For case 2 remote controlled back-up disconnectors were added to every open point between adjacent feeders. The placement of these disconnectors is illustrated in Figure 7.5. In total 21disconnectors were converted from manual to remote control with an average of 3,5 per feeder.

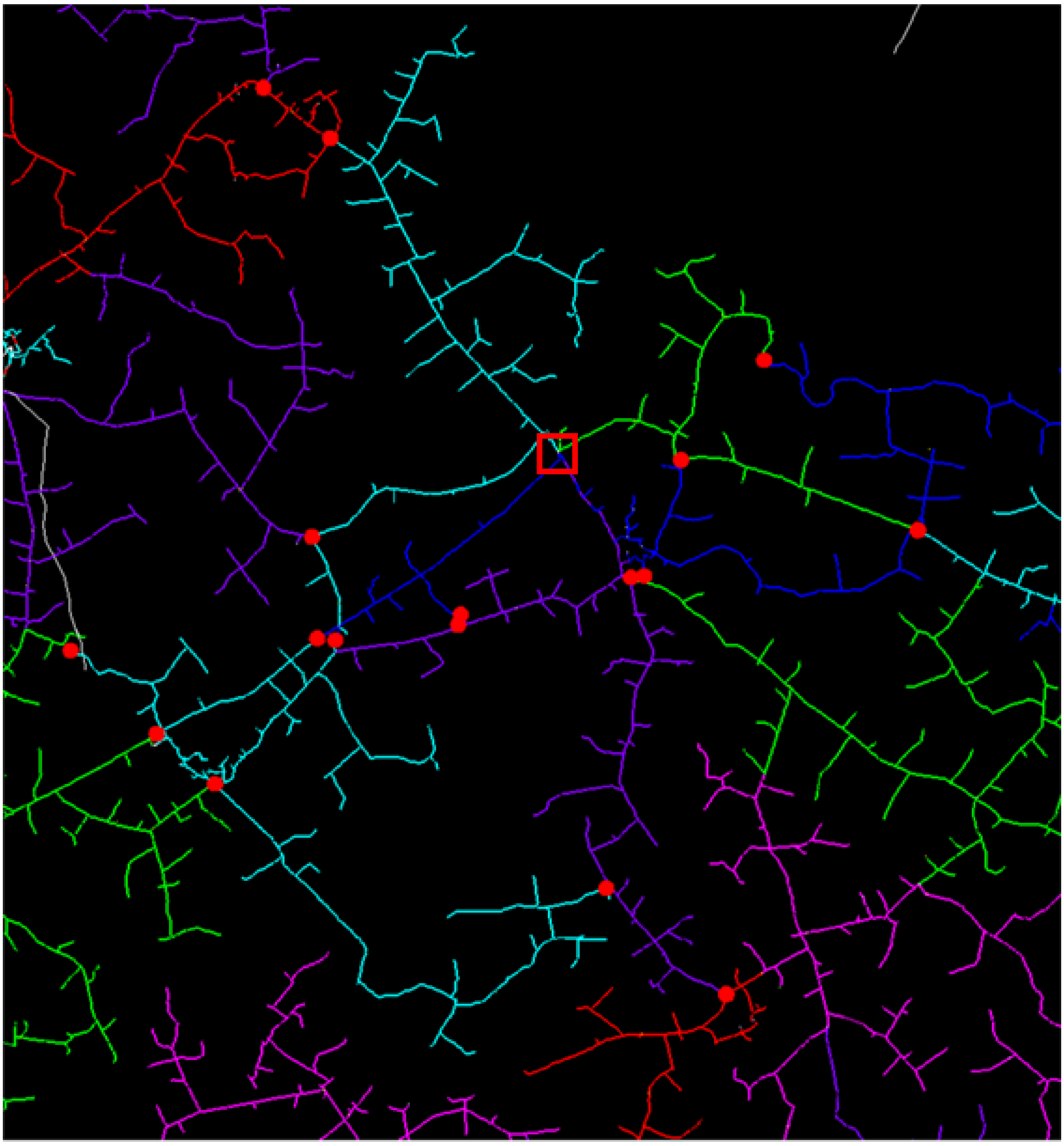

***Figure 7.5.*** *Case 2 for rural area. Remote controlled disconnectors are highlighted with red dots and primary substation with red square.*

### *Case 3*

As with case 3, the objective was to add disconnectors roughly in the middle of the feeder in addition to the disconnectors from case 2. Since almost every feeder already had a disconnector substation the existing 5 stations with 11 remote controlled disconnectors resulting in an average of 2,5 remote controlled section per feeder were used. Most of these disconnectors illustrated in Figure 7.6 are in the same substations as back-up disconnectors.

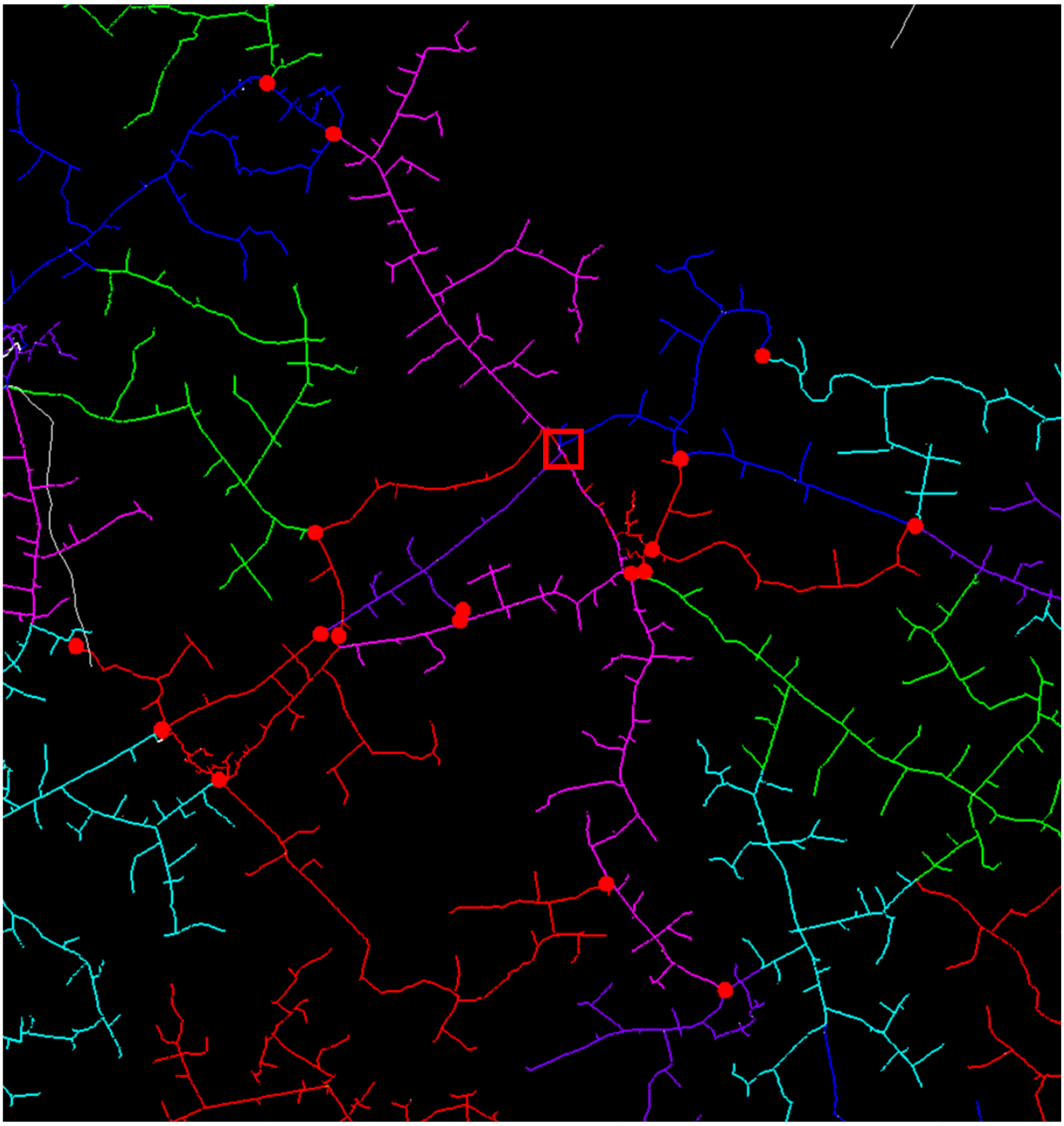

***Figure 7.6.*** *Case 3 for rural area. Remote controlled disconnectors are highlighted with red dots and primary substation with red square.*

### *Case 4*

In case 4 the number of remote controlled section increased to an average of 5,5 per feeder as a result of 14 new remote controlled disconnectors. As illustrated in Figure 7.7, the disconnectors are placed individually either at the beginning of longer branches or in the middle of the feeder thus denoting also 14 new locations.

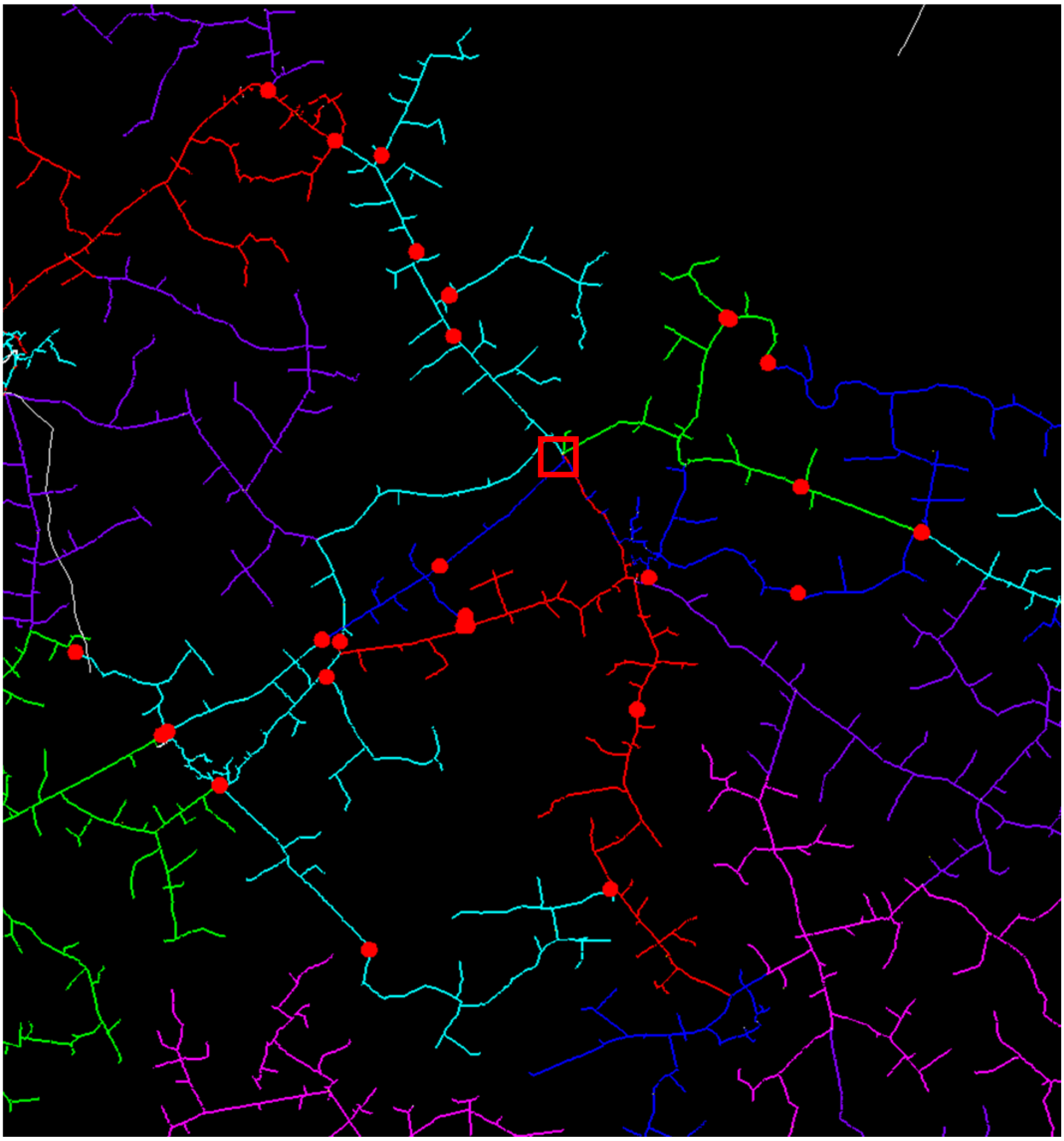

***Figure 7.7.*** *Case 4 for rural area. Remote controlled disconnectors are highlighted with red dots and primary substation with red square.*

### *Cases 5 & 6*

The locations of added circuit breakers in cases 5 and 6 are presented in Figure 7.8. Case 5 included only added circuit breakers and in case 6 the same remote controlled back-up disconnectors were introduced from case 2 to add the possibility of remote restoration on the farthest protection zones. The circuit breakers were located at the existing secondary substations replacing the manual disconnectors. In total 9 circuit breakers were added to 5 secondary substations. 9 new protection zones were added in the process to increase the average number of protection zones to 2,3 per feeder.

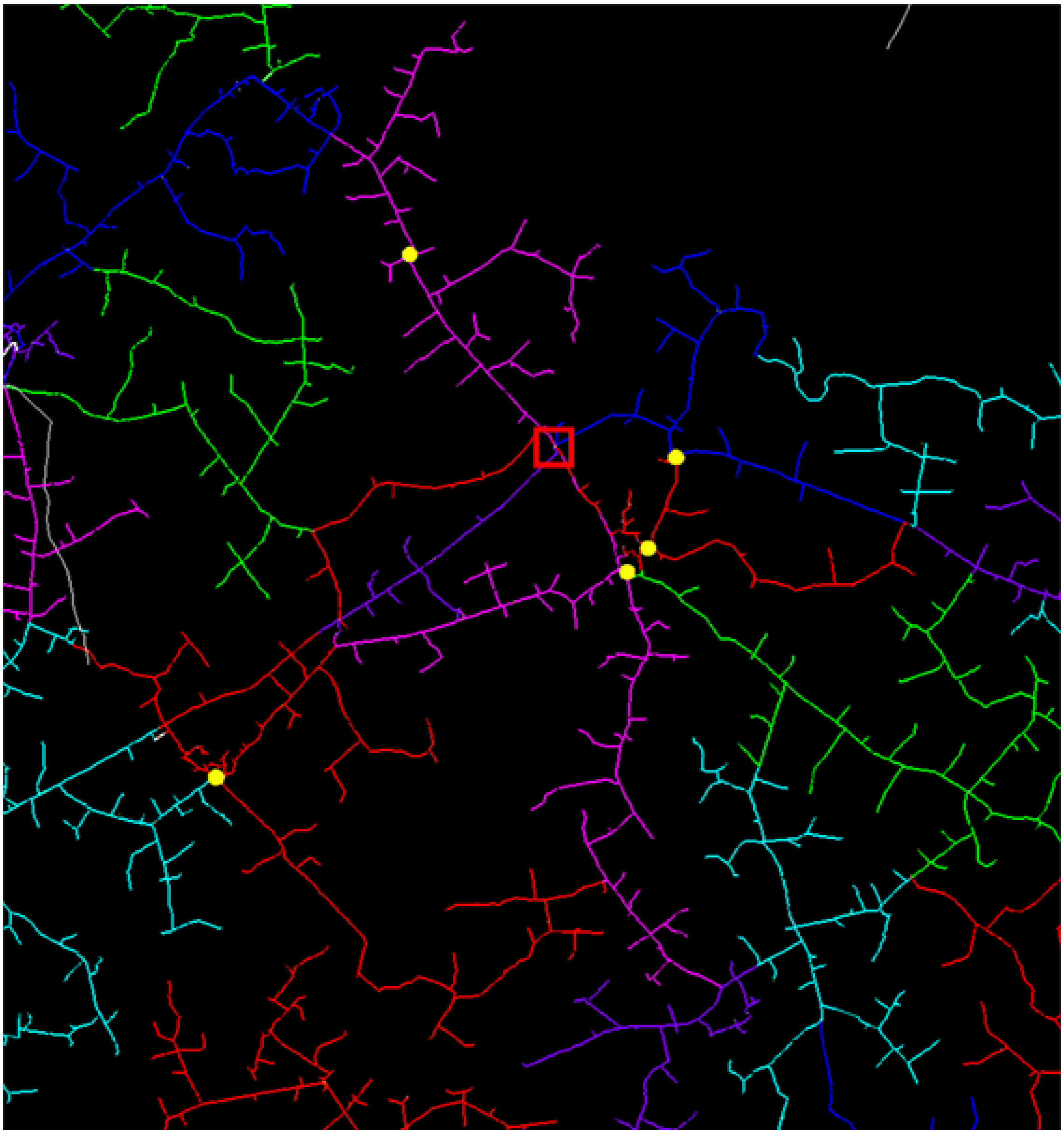

***Figure 7.8.*** *The locations of substations with circuit breakers in cases 5 and 6.*

### *Cases 7-15*

Cases 7-15 were specific for rural network. Figures Figure 7.9 through Figure 7.11 present the network structures common to all the cases. Underground cables are denoted with yellow lines whereas pink represents covered conductors and blue plain overhead lines. The current network structure used in cases 1-6 has a weatherproofing rate of approximately 59 % including underground cables and overhead lines with either plain or covered conductors in treeless areas. The source of the environmental information was Corine Land Cover data available in Trimble NIS. From there the weatherproofing rate was increased by the means of replacing the overhead lines with underground cables. This was done in the same place as the original lines were to negate the effect the changes in line length to the RNA calculation.

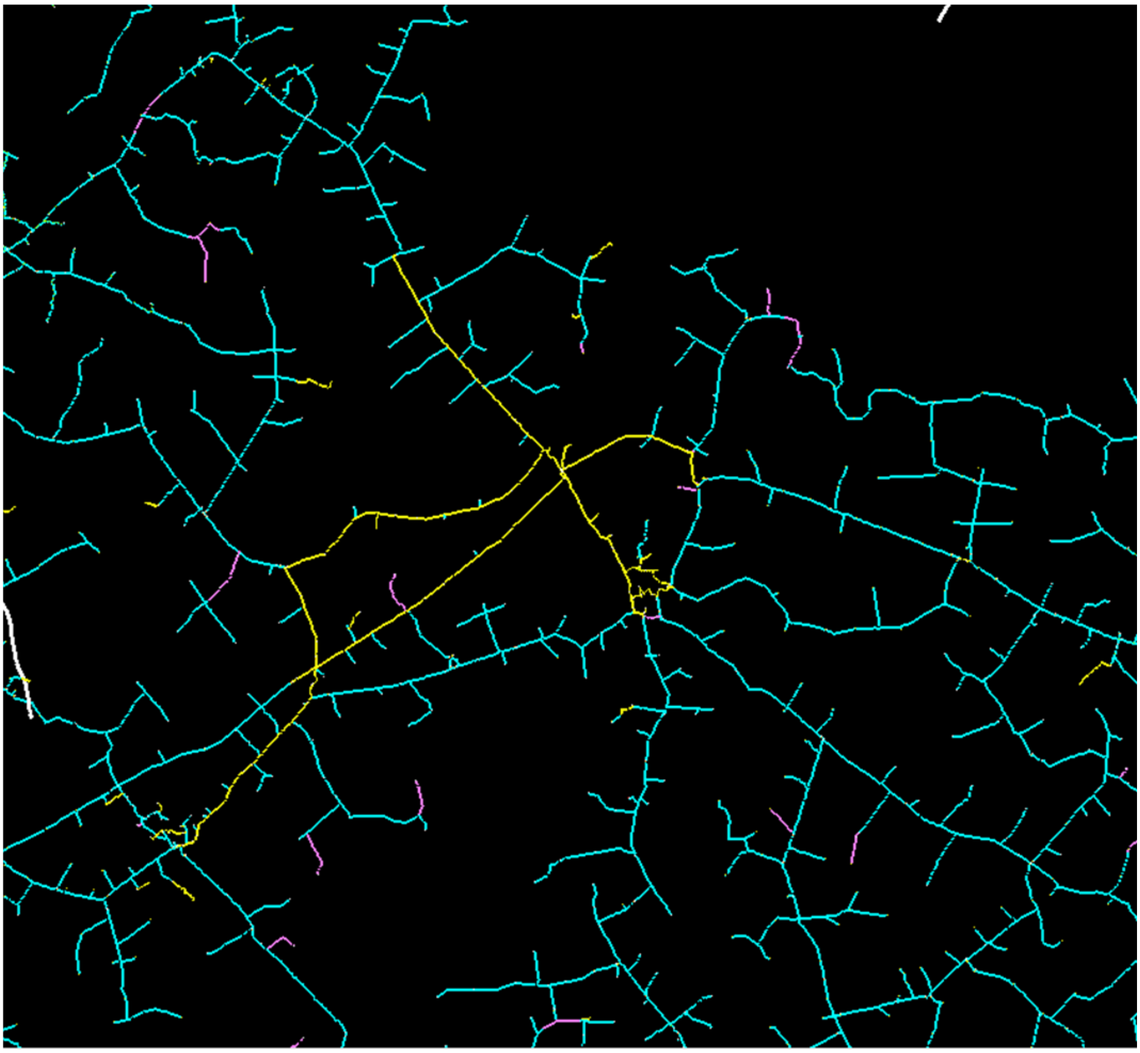

***Figure 7.9.*** *Rural area with 67 % weatherproofing rate. Cabled lines are in yellow.*

Table 7.7 summarizes the cabling rate and the share of residual overhead lines that remain susceptible to falling trees corresponding to different weatherproofing rates. Notably the initial weatherproofing rate is relatively high compared to the cabling rate. From the nearly constant forest rate of the remaining overhead lines it can be concluded that the forest patches are somewhat uniformly distributed in the area and thus the overall fault frequency of the overhead lines is approximately constant along the feeder.

In this study, the overhead line replacement was not optimized according to the surrounding environment in order to minimize the cable length. This is evident from both the rapidly rising cabling rate as well as the constant forest rate. With optimization the required cabling rate would be somewhat lower. However, the simulated cases represents decently a real life situation, where also other boundary conditions, such as land lease contracts and fault frequency of cable terminals have to be considered and likely the resulting cabling rate is above the optimal rate.

***Table 7.7.*** *The network structure in cases 7-15.*

| Weatherprooging rate [%] | Cabling degree [%] | Share of remaining overhead lines susceptible to falling trees [%] |
|---|---|---|
| 59,3 | 5,1 | 42,9 |
| 67,2 | 23,6 | 42,9 |
| 72,5 | 38,6 | 44,7 |
| 87,1 | 70,5 | 43,7 |

The calculations were conducted on the case networks first without any network automation to gain the base reliability level for later comparisons. Then the existing remote controlled disconnectors were added and calculations repeated. Finally the third round included also the added circuit breakers. Same locations were used as in cases 5 and 6. In addition, all of the network configurations were calculated without FLIR and with FLIR. With all these results individual effects of remote controlled disconnectors, circuit breakers and FLIR were identifiable.

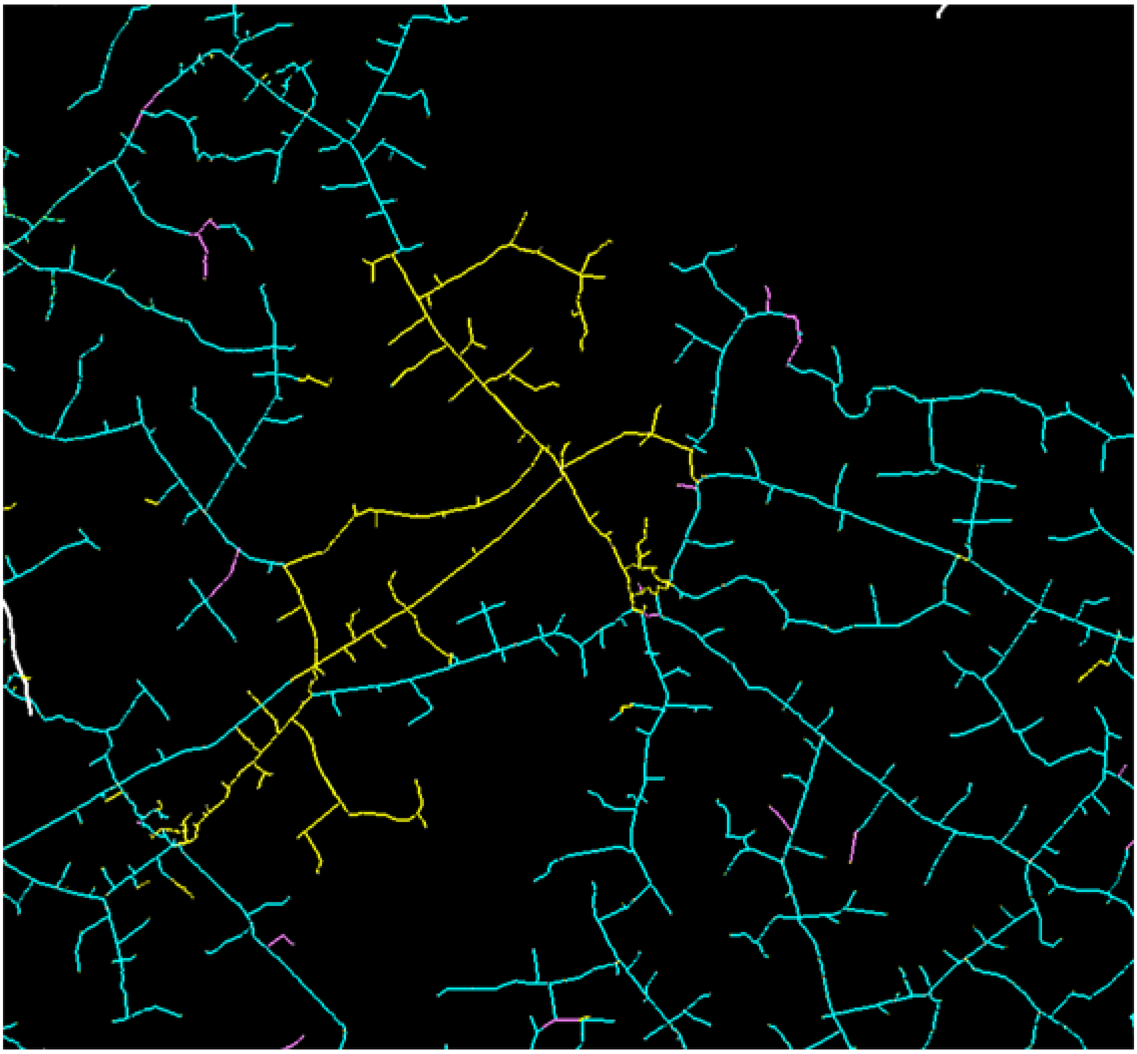

***Figure 7.10.*** *Rural area with 73 weatherproofing rate. Cabled lines are in yellow.*

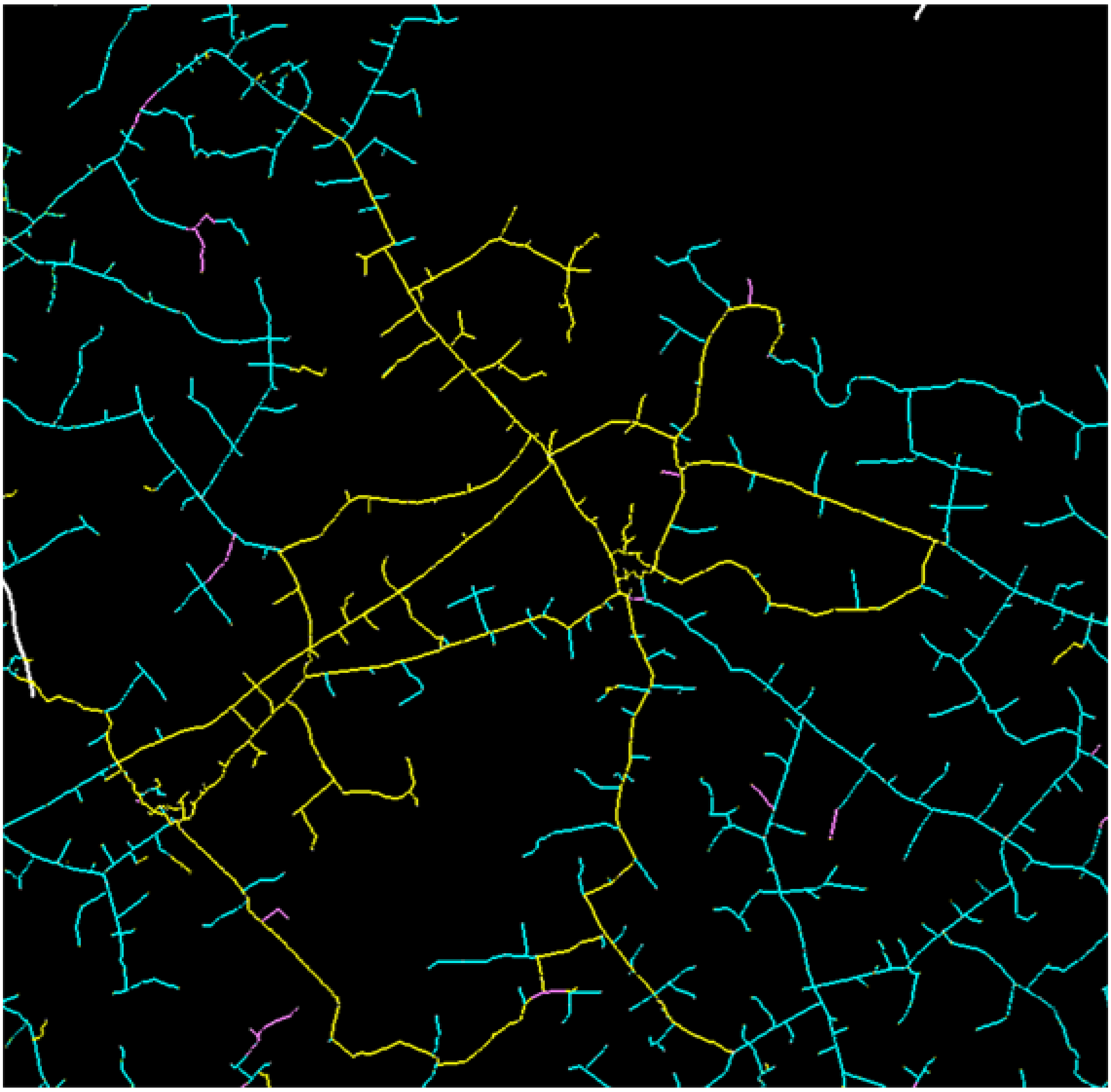

***Figure 7.11.*** *Rural area with 87 weatherproofing rate. Cabled lines are in yellow.*

### *Calculation results*

The reference results for other cases are presented in Table 7.8. Compared with the urban results, all of the numbers are significantly higher even though the number of customer, affecting especially the COC, is by far lower. This simply denotes that the more frequent faults take longer to repair and as the back-up connections are sparse or nonexistent and distances between manual disconnectors are lengthy, the customers suffer longer outages. While the relative improvement gained from the addition of remote control is only slightly larger than in the urban scenario the absolute savings in COC is much greater.

The added circuit breakers seem to have less impact on the rural network. While they certainly lower the COC, the effect on reliability indices is smaller than in urban network results. This is explained by the network topology with fewer possibilities to restore power behind the faulted section and long branches without any backup connections. The high fault interruption hours with lower COC suggests that large part of the load is located in the first protection zone. On the other hand, these protection zones are quite large and in general the load can be quite evenly distributed in rural networks in the absence of larger towns or industrial clients.

***Table 7.8.*** *Results for rural area without FLIR.*

| | Faults [pcs/a] | Fault interruption hours of customers [h/a] | SAIDI | SAIFI | CAIDI | COC [€/a] |
|---|---|---|---|---|---|---|
| Case 1 | 16,67 | 22 227 | 6,494 | 3,837 | 1,692 | 497 793 |
| Case 2 | 16,67 | 21 954 | 6,416 | 3,837 | 1,672 | 469 692 |
| Case 3 | 16,67 | 9 230 | 2,828 | 3,837 | 0,737 | 273 350 |
| Case 4 | 16,67 | 5 835 | 1,871 | 3,837 | 0,488 | 214 107 |
| Case 5 | 16,67 | 13 500 | 4,030 | 2,127 | 1,894 | 296 668 |
| Case 6 | 16,67 | 8 753 | 2,693 | 2,129 | 1,265 | 238 706 |

As with the urban area, the introduction of FLIR further improves the results from the reliability point of view, as can be seen in Tables Table 7.9 and Table 7.10. Even with the quite high total faults the customer experienced outage times denoted by CAIDI are on the same level as in the urban cases. The addition of remote controlled disconnectors in parallel with FLIR reduces the fault interruption hours of customers and thus lowers the customer outage.

***Table 7.9.*** *Results for rural area with FLIR improving fault location by 20 min.*

| | Faults [pcs/a] | Fault interruption hours of customers [h/a] | SAIDI | SAIFI | CAIDI | COC [€/a] |
|---|---|---|---|---|---|---|
| Case 1 | 16,67 | 18 897 | 5,555 | 3,837 | 1,448 | 439 960 |
| Case 2 | 16,67 | 18 631 | 5,479 | 3,837 | 1,428 | 413 459 |
| Case 3 | 16,67 | 6 676 | 2,108 | 3,837 | 0,549 | 228 943 |
| Case 4 | 16,67 | 3 493 | 1,211 | 3,837 | 0,316 | 173 392 |
| Case 5 | 16,67 | 10 437 | 3,166 | 2,127 | 1,488 | 263 548 |
| Case 6 | 16,67 | 7 175 | 2,248 | 2,129 | 1,056 | 208 381 |

***Table 7.10.*** *Results for rural area with FLIR improving fault location by 30 min.*

| | Faults [pcs/a] | Fault interruption hours of customers [h/a] | SAIDI | SAIFI | CAIDI | COC [€/a] |
|---|---|---|---|---|---|---|
| Case 1 | 16,67 | 17 292 | 5,103 | 3,837 | 1,330 | 412 182 |
| Case 2 | 16,67 | 17 043 | 5,031 | 3,837 | 1,311 | 387 932 |
| Case 3 | 16,67 | 6 117 | 1,951 | 3,837 | 0,508 | 219 284 |
| Case 4 | 16,67 | 3 215 | 1,132 | 3,837 | 0,295 | 168 640 |
| Case 5 | 16,67 | 9 556 | 2,918 | 2,127 | 1,372 | 246 909 |
| Case 6 | 16,67 | 6 567 | 2,077 | 2,129 | 0,975 | 195 950 |

The benefits of FLIR are summarized in Tables Table 7.11 and Table 7.12. The major difference between rural and urban cases is that in rural area the FLIR has clear impact even with lower number of remote controlled switches in cases 1 and 2. Same trend is seen with the cases 5 and 6. Overall the improvements are greater in rural network with 10 to 20 decrease in COC and 15 to 35 percentage decrease in interruption duration related indices.

In addition, the difference between 20 and 30 minute fault location time improvement is notable in cases with fewer remote controlled switches. When the controllable feeder section are larger the faster fault location time affects more customers and thus has as system level effect. As the number of remote controlled sections rise and correspondingly their size decreases, the time delay of remote disconnection and restoration clearly becomes more important than the time saved in fault location.

***Table 7.11.*** *The benefit of FLIR with 20 min improvement in fault location.*

| | Faults [%] | Fault interruption hours of customers [%] | SAIDI [%] | SAIFI [%] | CAIDI [%] | COC [%] |
|---|---|---|---|---|---|---|
| Case 1 | 0,00 | 14,98 | 14,46 | 0,00 | 14,46 | 11,62 |
| Case 2 | 0,00 | 15,14 | 14,60 | 0,00 | 14,60 | 11,97 |
| Case 3 | 0,00 | 27,67 | 25,46 | 0,00 | 25,46 | 16,25 |
| Case 4 | 0,00 | 40,13 | 35,28 | 0,00 | 35,28 | 19,02 |
| Case 5 | 0,00 | 22,69 | 21,43 | 0,00 | 21,43 | 11,16 |
| Case 6 | 0,00 | 18,02 | 16,52 | 0,00 | 16,52 | 12,70 |

***Table 7.12.*** *The benefit of FLIR with 30 min improvement in fault location.*

| | Faults [%] | Fault interruption hours of customers [%] | SAIDI [%] | SAIFI [%] | CAIDI [%] | COC [%] |
|---|---|---|---|---|---|---|
| Case 1 | 0,00 | 22,20 | 21,43 | 0,00 | 21,43 | 17,20 |
| Case 2 | 0,00 | 22,37 | 21,58 | 0,00 | 21,58 | 17,41 |
| Case 3 | 0,00 | 33,72 | 31,03 | 0,00 | 31,03 | 19,78 |
| Case 4 | 0,00 | 44,89 | 39,47 | 0,00 | 39,47 | 21,24 |
| Case 5 | 0,00 | 29,22 | 27,59 | 0,00 | 27,59 | 16,77 |
| Case 6 | 0,00 | 24,98 | 22,89 | 0,00 | 22,89 | 17,91 |

The reliability effect of the additional protection zones is summarized in Table 7.13. The values have been gained by comparing cases 1 and 5 as well as cases 2 and 6 without FLIR in use. The results are in line with the results from urban network. The COC improvement is approximately 8 percentage higher than in urban area and a similar improvement can be seen in other results.

***Table 7.13.*** *The benefit of circuit breakers without the effect of FLIR.*

| | Faults [%] | Fault interruption hours of customers [%] | SAIDI [%] | SAIFI [%] | CAIDI [%] | COC [%] |
|---|---|---|---|---|---|---|
| Case 5 | 0,0 | 39,3 | 37,9 | 44,6 | -11,9 | 40,4 |
| Case 6 | 0,0 | 60,1 | 58,0 | 44,5 | 24,4 | 49,2 |

The purpose of the cases 7-15 was to examine the effect of increased weatherproofing rate on the reliability improvements gained from network automation. At the center of the attention was the customer outage costs, as it affect the viability of the automation solution. The results are presented in Figure 7.12. with the effect of remote controlled disconnectors and circuit breakers illustrated separately in addition to the total effect.

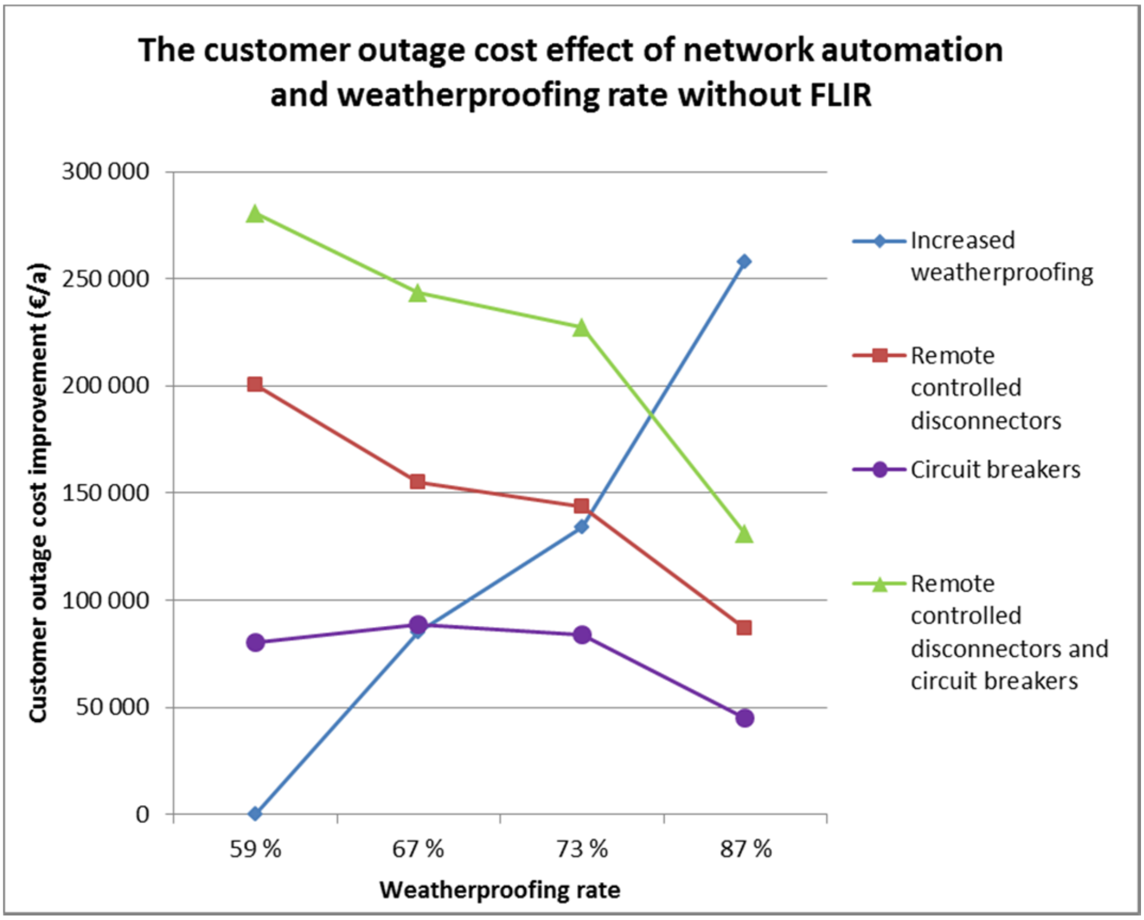


***Figure 7.12.****The total customer outage cost results with increased weatherproofing rate.*

The COC savings arising from the network structure increase almost linearly from zero to 260 k€. as the weatherproofing rate is improved. At the same time the savings gained with the automation decreases as expected. With the current network structure the initial COC decrease potential of remote controlled disconnectors and circuit breakers is actually slightly higher than the final achieved value with the structural changes. The

COC improvement declines at first evenly from 280 k€ to 230 k€ and then falls to 130 k€ as the weatherproofing rate is boosted from 73 % to 87 %.

When the effect of disconnectors and circuit breakers are viewed individually, it can be seen that the circuit breakers actually perform better with higher weatherproofing rates of 67 % and 73 % where the graph of circuit breakers stays almost constant at 80 k€ and the graph of remote controlled disconnectors declines steadily. This is likely due to the fact that the cabling was started in the first protection zone and thus the majority of customers experienced a major improvement in reliability. When the cabling was extended further, the impact of added protection zones decreased as the total fault amounts declined.

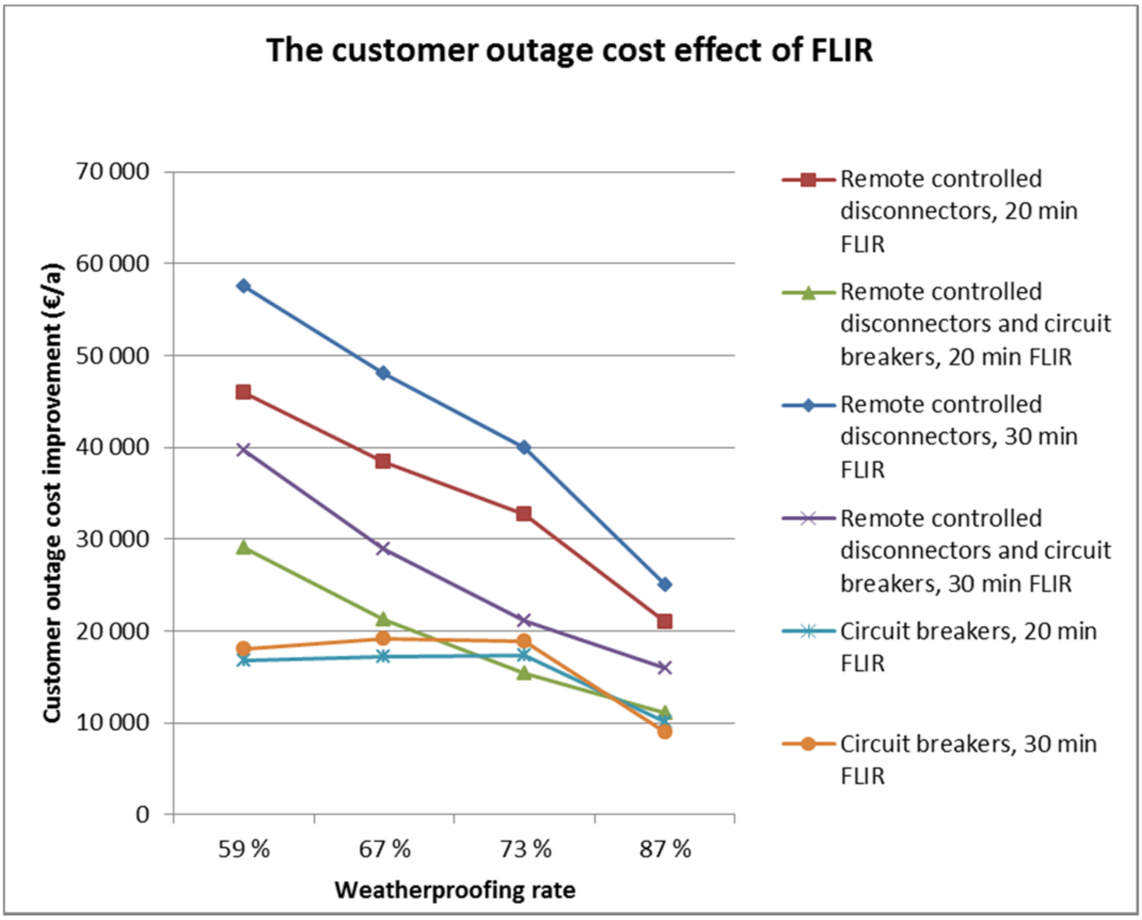


***Figure 7.13.*** *The added COC effect of FLIR as a function of weatherproofing rate.*

The results for the additional reliability effect of FLIR implementation are presented in Figure 7.13. Both 20 and 30 min settings for fault location were calculated for cases with only remote controlled disconnectors and cases with both remote controlled disconnectors and circuit breakers. The initial COC improvement due to FLIR range from 58 k€ to 19 k€. From there all of the curves fall nearly linearly to a range of 25 k€ to 10 k€. As illustrated, the benefit gained by implementing FLIR is highest with only remote controlled disconnectors in place. With circuit breakers the absolute COC level is lower but only minor additional benefit is available with implementation of FLIR.

The outage is already limited to a smaller area by circuit breaker in the case of fault in the farther protection zone and thus less customers are affected by FLIR. The nearly constant diagram for circuit breakers at lower weatherproofing rates is explained by the choice of cabled sections, where the beginning of feeder is cabled first and only in the last scenario the second half of the feeder is cabled.

In general the cases with 30 min FLIR settings show better results than the corresponding cases with 20 min settings. However, the difference is reduced as the weatherproofing rate is improved. FLIR seems to have smaller absolute impact in network with added circuit breakers. Nevertheless, as seen in previous case results, the relative impact is equivalent or slightly better.

## 7.3 Investment costs

The investment costs for all of the cases were calculated to set the reliability effects into perspective and to enable further economic studies. The RNA-calculations had manual disconnectors as a reference but an assumption that they cannot be retrofitted for remote control was made. This is a valid assumption as in the case of pad mounted substations available space limits the addition of extra components and in the case of pole mounted disconnectors it is often practical to change the whole device because of mechanical condition or age of the disconnector.

The costs of RTU and the communication equipment for the substation are included in the calculations but the cost of communication network is excluded.

The unit prices used in the analysis were extracted from Energy Authority's price list for 2014. The price list represents the average investment cost level of the whole industry. It is based on a survey commissioned by Finnish Energy Industries and adjusted by Energy Authority. The 2014 price list is presented in Appendix 1.

The applied unit prices are presented in Table 7.14. As the EA's price list has only price for single pole mounted, remote controlled circuit breaker, a price for a switching station with two circuit breakers had to be conveyed from other units. This was calculated as

$$\mathrm{P}_{\text{Remote controlled switching station,2 circuit breaker}} = 2 \times P_{\text{Remote controlled disconnector station,1 disconnector}} \tag{8.1}$$

***Table 7.14.*** *Unit prices for cases 1-6.*

| Unit | Original EA price [€] | Unit price [€] |
|---|---|---|
| Remote controlled disconnector station, 1 disconnector | 14020 | 14020 |
| Remote controlled disconnector station, 2 disconnectors | 26100 | 26100 |
| Remote controlled disconnector station, 3-4 disconnectors | 37050 | 37050 |
| Remote controlled switching station, 1 circuit breaker including relay | 17170 | 17170 |
| Remote controlled switching station, 2 circuit breakers including relay | - | 34340 |

The total amount of automated substations and their types were collected individually for the first six cases and the investment costs were calculated with the unit prices. The summarized results are presented in Tables Table 7.15 and Table 7.16.

***Table 7.15.*** *The investment costs for urban network.*

| | Remote controlled substations | Switching stations | Total |
|---|---|---|---|
| Case 1 | 0 | 0 | 0 |
| Case 2 | 560 800 | 0 | 560 800 |
| Case 3 | 895 380 | 0 | 895 380 |
| Case 4 | 1 282 970 | 0 | 1 282 970 |
| Case 5 | 0 | 326 230 | 326 230 |
| Case 6 | 560 800 | 326 230 | 887 030 |

***Table 7.16.*** *The investment costs for rural network.*

| | Remote controlled substations | Switching stations | Total |
|---|---|---|---|
| Case 1 | 0 | 0 | 0 |
| Case 2 | 288 600 | 0 | 288 600 |
| Case 3 | 411 830 | 0 | 411 830 |
| Case 4 | 608 110 | 0 | 608 110 |
| Case 5 | 0 | 154 530 | 154 530 |
| Case 6 | 288 600 | 154 530 | 443 130 |

In the urban area the additional investment cost over manual disconnectors required to install remote controlled disconnectors range from 560 k€ to almost 1283 k€. This is caused by the complex topology of already cabled network in a densely populated area. The amount of disconnectors rises quickly thus increasing the cost level. However, several disconnectors could usually be situated in the same secondary substation to lower the share of communication equipment costs.

The equivalent costs in the rural area are approximately half of those in the urban cases. The total number of required disconnectors explains the difference. The rural network was much sparsely interconnected and fewer suitable locations for substations are available.

Similar figures can be seen with the circuit breaker cases. The investment costs for the urban area are twice the costs of the rural area. As the ratio of circuit breakers per switching station is almost the same in both areas, the investment costs are in line with the amount of circuit breakers.

# 8. ECONOMICAL STUDY OF CASES

The economic feasibility of the different cases were studied against the Finnish regulatory model described in chapter 3. The aim of these studies was to determine whether the investment into increased automation level would be financially justified and how the increased communication costs would affect the viability. A reasonable case for the analysis was chosen for both environments using a marginal utility approach.

The actual cost of automation system depends on the operational environment, scale and geographical characteristics of the distribution network, features and exploitability of the existing communications network and network automation in addition to properties of SCADA and DMS systems. Depending on the current situation of the DSO, the required investment could vary from purchasing of software updates to custom interface development to total reconstruction of the communications network. Therefore, the objective of this study was to find a break-even point for the communication and IT system costs in addition to the actual investment costs for the field equipment.

## 8.1 Marginal utility of customer outage cost improvement

To enable the comparison of cases a marginal utility approach was chosen. The efficiency of different solutions was benchmarked with the ratio of the customer outage cost improvement to the investment costs of the network components. The communication equipment cost for the substations was included but costs at the system level, namely the IT system and communication network cost, excluded at this point. The marginal utility was calculated separately for both environments with and without FLIR.

The results are presented in Figures Figure 8.1 and Figure 8.2 for urban and rural network area. As expected, the gain in COC savings without FLIR is ten to fifteen times greater in rural than urban area due to the base reliability levels. In the urban area each invested euro results in a 0,1 € COC saving at best whereas the ratio is 1 to 1,5 in rural network. However, this cannot be interpreted as a straight indication of investment profitability as the quality incentive constitutes only part of the whole regulation model. On the other hand, the differences in current real life situations has to be considered. Whereas no remote controlled switchgear has been installed in urban area, the state of the rural network corresponds to the case 3. Most of the remote controlled disconnecor stations have been built in the 1990s and complemented in the 2000s.

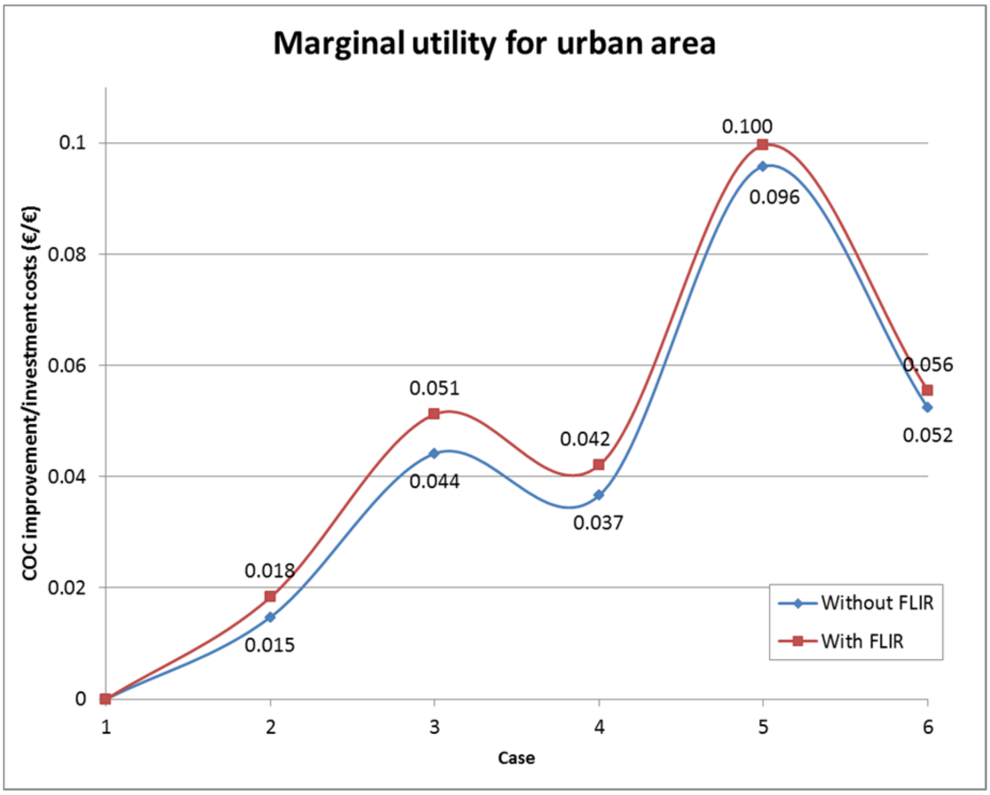


***Figure 8.1.*** *The marginal utility of customer outage costs for urban area.*

Otherwise the shape of the figures are similar in both areas. The marginal utility rises at first in cases 1 to 3 suggesting that the addition of remote controlled disconnectors has a positive effect on reliability. For case 4 the marginal utility decreases compared to case 3. This signifies that the additional increase of disconnectors is less beneficial and the peak of cost-efficiency has been reached between cases 3 and 4.

Cases 5 and 6 show a similar pattern. The addition of circuit breakers in case 5 has the highest marginal utility but for case 6 it drops to approximately the same level as in case 3. For the rural environment the marginal gain in case 5 is somewhat ambiguous. As the case includes only circuit breakers and in reality the automation level is already high the implementation of case 5 would be closer to case 6.

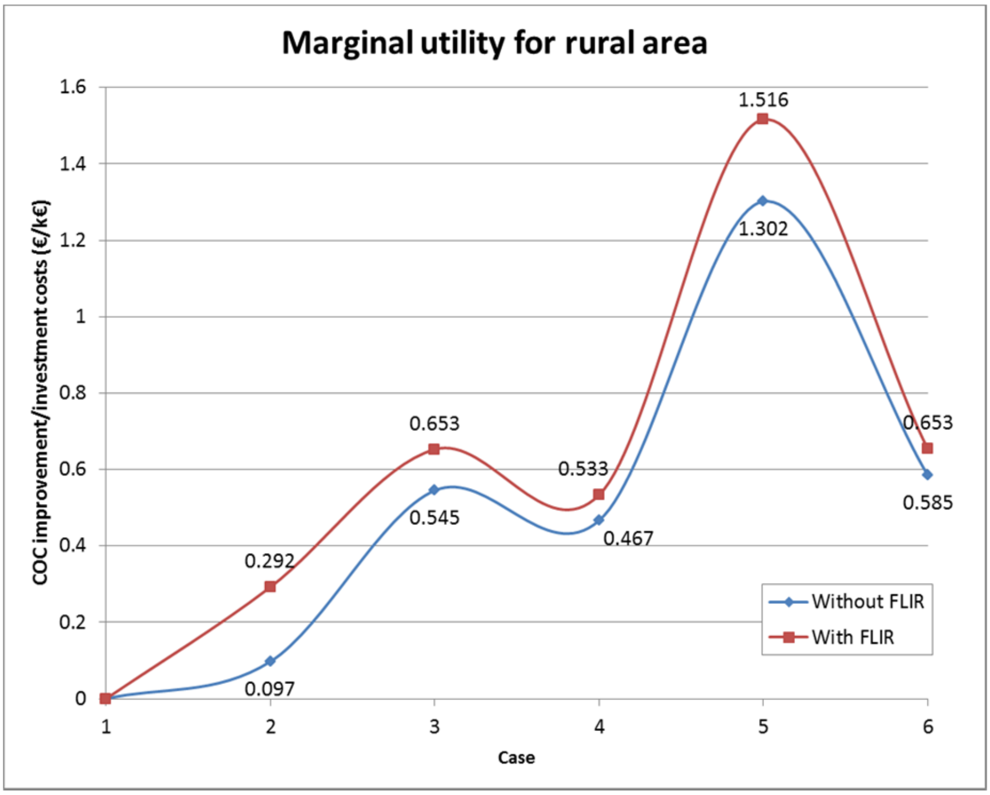


***Figure 8.2.*** *The marginal utility of customer outage costs for rural area.*

The addition of FLIR provides further benefits in both areas. In the urban area the curve of marginal utility with FLIR follows closely the curve without FLIR. It appears that the benefit of FLIR is greatest in case 3. In the rural network the FLIR has the greatest effect in cases 2 and 5. This implies that the fault location in rural areas benefits from FLIR also with less protection or disconnector zones. In reality, this would be also technically more feasible solution, as high short-circuit currents might cause problems with relay settings and selectivity on short feeders or short-circuit capacity of the cables might set constrains in some areas. It should be noted also, that part of the costs related to FLIR are not included in this analysis.

## 8.2 Break-even point for communication and IT system costs

The case 6 was chosen for further economic studies as it represents a feasible method for reliability improvement especially in rural area but also in urban area considering the marginal utility of customer outage costs. To assess the rationality of the calculations, the break-even point for communication and IT system costs in scenario with FLIR.

Calculations were performed using the Finnish regulatory model for the years 2012-2015. The regulatory WACC for 2014 was chosen for the calculations as it is at historically low level. This sets the lower limit for the break-even costs. Additionally, inflation was neglected and an internal WACC of 6,5 % was used to discount the future incomes.

The calculation model accommodates all the primary incentives described in chapter 3. The most significant one in this context is the quality incentive. Half of the customer outage cost improvement is taken into account through quality incentive and half through efficiency incentive. The calculation model assumes four year regulatory periods and adjusts the reference level for COC in the first year of each period. Therefore the quality incentive has major impact on the results in the first few years of calculation. The use of StoNED for efficiency benchmarking is assumed to continue for the next regulatory period. The presumed regulatory lifetime of investments was 40 years including the IT, communication network and field communication equipment.

The investment was made completely in 2014. The investment costs include project costs for installing the network automation equipment as well as communication equipment for each substation. The costs were calculated using the current real life situation as reference point. An annual rise in operational expenditures was estimated to be 400 € per substations which consists of monthly communication costs and maintenance visits.

***Table 8.1.*** *The results for break-even point with investment in network components included.*

| | Investment costs (k€) | Communication network and IT costs (k€) | Total costs (k€) | COC saving, FLIR included (k€) |
|---|---|---|---|---|
| Urban | 887,0 | -365,6 | 521,5 | 49,3 |
| Rural | 154,5 | 214,1 | 368,7 | 65,0 |

The break-even point for communication and IT systems was defined as the point where the investment and other costs are barely covered without generating any profit. The regulated asset value of communication network includes a base network component as well as an additional value for secondary substations. In this case only the substation component was included as the number of base networks does not increase. The results are presented in Table 8.1.

For the urban network the allowed value is negative, which implies that the scenario is unfeasible. While the COC savings are lower than in rural area, the number of substations and thus the required investment costs are several times higher.

In the rural area the COC improvement is relatively higher compared to the investment costs. The allowed cost of communication and IT system in the break-even point is 214 k€. In the worst scenario of outdated communication and operational system, where both DMS and SCADA would need to be replaced in addition whole communication system, this would have cover all the costs for a single primary substation.

Another possible viewpoint into this matter is presented in Table 8.2. If only the additional benefit gained from FLIR is considered and the investment in regulated network components is neglected the results are different. The case of urban area is still unfeasible. In the rural area the FLIR alone supports ICT costs up to 113 k€.

***Table 8.2.*** *The results for break-even point with only the effect of FLIR considered*

| | Investment costs (k€) | Communication network and IT costs (k€) | Total costs (k€) | COC saving, FLIR only (k€) |
|---|---|---|---|---|
| Urban | 0,0 | -249,8 | -249,8 | 2,8 |
| Rural | 0,0 | 112,9 | 112,9 | 30,3 |

Assuming that the rural substation chosen for this study represents an average rural area and those areas with medium sized population centers lie somewhere between the urban and rural cases both in network structure and thus potential COC savings, the results can be generalized. In a situation with 100 substations, of which 10 % are urban type, 40 % rural and 50 % in between with no effect on the feasibility, the limit for communication and IT renewal costs would be approximately 2 M€ or 20 k€ per substation.

Whether this would be adequate depends entirely on the DSO and the current systems available. For a large DSO with 100 primary substations and return requirement above zero the estimated limit would suffice for either communication network renewal and minor IT development or IT system renewal. For example, the average price of SCADA system including 100 primary substation RTU's is 1,27 M€ and corresponding communication system 630 k€ (Appendix 1).

## 8.3 Profitability and sensitivity analysis

The profitability of the case 6 was assessed using the estimated break-even costs per primary substation and the same parameters as in previous chapter. Additionally, the sensitivity of these results were calculated with respect to key variables. To gain perspective, the assessment was also conducted on cases without FLIR.

***Table 8.3.*** *Profitability calculation results for case 6 without FLIR in use.*

| | Investment costs (k€) | Communication network and IT costs (k€) | COC savings without FLIR (k€) | Payback period (a) | IRR (%) | Net present value (k€) |
|---|---|---|---|---|---|---|
| Urban | 887,0 | - | 46,5 | 40,0 | -0,2 % | -402,7 |
| Rural | 154,5 | - | 34,6 | 4,9 | 15,9 % | 73,1 |

***Table 8.4.** Profitability calculation results for case 6 with FLIR in use.*

| | Investment costs (k€) | Communication network and IT costs (k€) | COC savings without FLIR (k€) | Payback period (a) | IRR (%) | Net present value (k€) |
|---|---|---|---|---|---|---|
| Urban | 887,0 | 20,0 | 49,3 | 34,5 | 0,3 % | -385,6 |
| Rural | 154,5 | 20,0 | 65,0 | 3,5 | 32,1 % | 194,1 |

The results are presented in Table 8.3 and Table 8.4. Clearly in both cases the addition of automation is highly profitable in rural network and unprofitable in more urban network. The implementation of FLIR is beneficial in both environments, but it has notably greater effect in the rural area. Clearly the addition of automation is a potential business case, but the initial reliability level of the network has to be somewhat lower.

The COC improvement is the supporting factor in these calculations. It has a major impact on the cash flow in the first few years after the initial investment. Therefore all other simultaneous reliability improving actions diminish the advantage gained in this scenario. As demonstrated earlier in Figure 7.13, the current trend of increasing weather-proofing rate of the network decreases the potential COC savings.

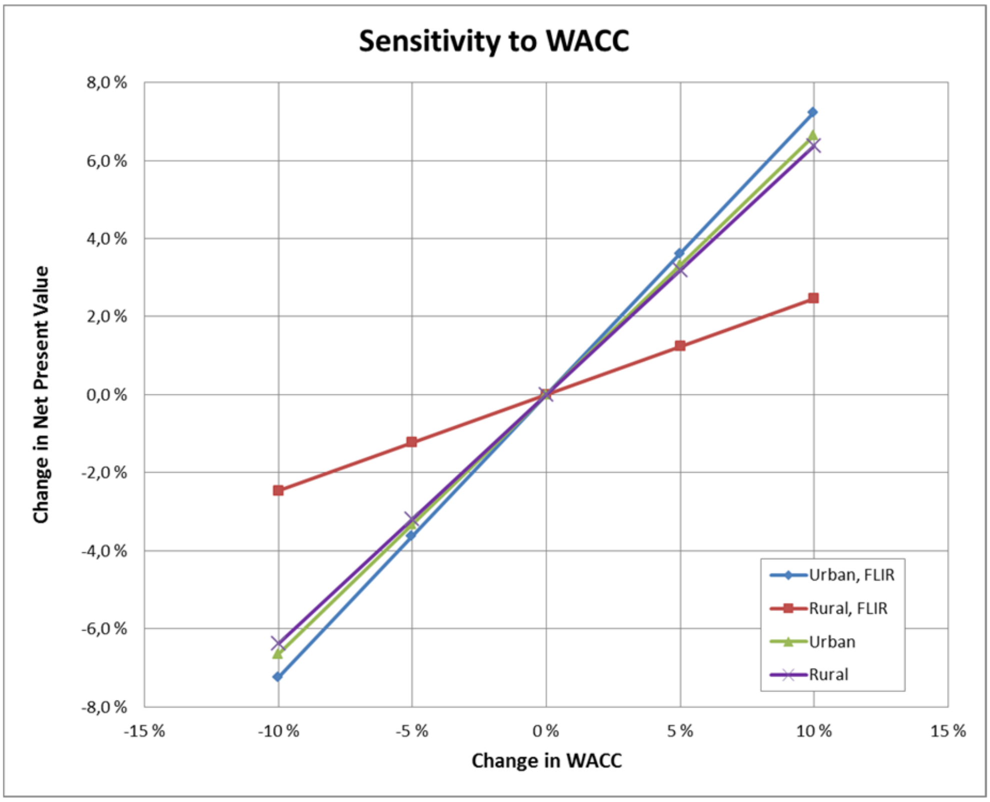


***Figure 8.3.** Profitability calculations sensitivity to regulatory WACC changes.*

The sensitivity of the profitability calculation was estimated in relation to the regulatory WACC and customer outage cost improvement. Results are presented in Figures Figure 8.3 and Figure 8.4. Both parameters show a positive linear response. The slope varies according to the parameter and the environment. In the rural area the addition of FLIR has also relevance whereas in the urban area the graphs are virtually identical regardless of FLIR.

In general, the calculation model is less sensitive to WACC changes than COC variation. This is typical of investment with emphasis on automation because of low investment costs compared to the benefits gained. A ten percentage change in WACC leads to a two to seven percentage variation in net present value of the investment. The significance of customer outage costs in reliability based investment calculation is again emphasized by the Figure 8.4. A ten percentage change has a five to over twenty percentage effect on the end results.

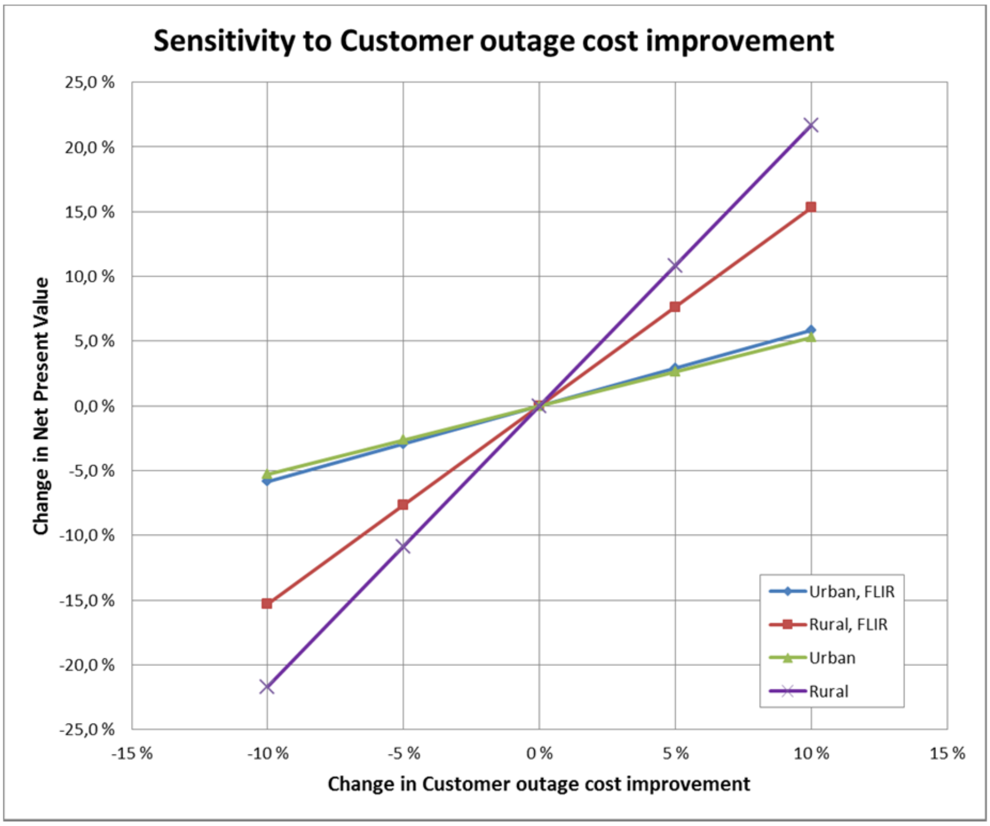


***Figure 8.4.*** *Profitability calculations sensitivity to COC improvement changes.*

Based on these results and two individual examples only indicative conclusions can be made. The whole network has to be considered if a partial or whole ICT system renewal is contemplated. The network areas chosen for this analysis represent extremities and do not provide enough tools for an extensive analysis. Additionally, the exact cost of the renewal project is a key factor in such analysis although naturally other important drivers that have major impact arise such as operational reliability, security or risks of implementation project. It would still seem that the discussed solution has economic potential to succeed in some operational environments.

# 9. CONCLUSIONS

The focus on this study has been on two reliability related electricity distribution network functionalities, which may be considered smart in comparison to the traditional network of the past. The development of information technology enables more complex and integrated network protection functions that benefit both the customer and the DSO. The society has also recognized its dependency on the electricity and the security of supply has gained emphasis even on a legislative level.

The presented methods included the addition of consecutive protection zones to medium voltage distribution network and the introduction of automated fault location, isolation and restoration sequences. Both have several alternative operation principles that impose more requirements on information and telecommunications system than before.

The choice of suitable implementation option depends on the current available technology as well as longer term strategic choices. For instance, newer relays and RTU's might do with a software update but will the older ones be upgraded in mass rollout or at the end of their lifetime. A choice of communication technique for the future is a major issue on its own.

The reliability improvement was established with simulations conducted with Trimble NIS and its Reliability based network analysis tool. It was shown that both the increase of protection zones and the FLIR have positive effect on widely used reliability indices and lower the customer experienced disadvantage denoted by customer outage costs. The benefit gained from FLIR has correlation with the level of automation in the distribution network but especially in the fault prone rural areas the fault location alone improves the reliability level.

The advantages obtained were much higher in rural environment, where the cabling rate is still low in the medium voltage network. Therefore the improvement potential is substantially higher than in the already quite secure urban areas. Most of the key points of the rural network are equipped with older disconnector stations and the further development of reliability is harder and more expensive.

The current trend of medium voltage cabling or otherwise lowering the vulnerability to weather conditions will reduce the benefits of the introduced functionalities in ten to fifteen year timeframe. This was verified separately for the surveyed rural environment. In the structurally mixed network the separation of different parts of the feeder as own protection zones could be considered as one alternative for final long-term network structure.

Financially the viability of the implementation depends mostly on the structural state of the present distribution network and the features of the current operational IT systems and field communication equipment. Especially the FLIR requires real time data transmission and controllability of the deployed disconnectors, which is impossible to accomplish efficiently with old fashioned polling radio modems. While reliability advantages can be achieved also in the densely meshed and mostly cabled network, financially the introduction of more advanced protection schemes is only justified in rural network.

On the other hand, the requirements and specifications of these functionalities can be considered when renewing old systems one by one at the end of their lifetime or when making choices of future field equipment types. This way the development comes naturally and presumably with a lower total cost, but a clear vision of the future target is mandatory.

The estimates presented in this study can be refined with further research. If the actual method of execution for the proposed functionalities is chosen, the system requirements arising can be specified and a cost estimate may be formed. The analysis of the potential reliability benefits is improvable by broadening of the sample areas or by categorizing the network areas and finding a representative primary substation for analysis in each category. The change in operational expenditures is also an area where a more detailed comparison of the maintenance expenses of the old communication network versus the available new options is needed.

## REFERENCES

Administrator's Guide. 2012. 12.2nd ed. Tekla NIS Software Manual. Espoo, Tekla.

Aguero, J.R. 2012. Applying Self-Healing Schemes to Modern Power Distribution Systems. Power and Energy Society General Meeting, San Diego, California, USA, July 22-26, 2012. Piscataway, NJ, Institute of Electrical and Electronics Engineers. pp. 2766-2769.

Azevedo, G.P., Feijo, B. & Costa, M. 2000. Control Center Evolve with Agent Technology. Computer Applications in Power 13, 3, pp. 48-53.

Bayliss, C. & Hardy, B. 2007. Transmision and Distribution Electrical Engineering. 3rd Edition ed. Burlington, Newnes. 1010 p.

Brand, K.-., Lohmann, V. & Wimmer, W. 2003. Substation Automation Handbook. Bremgarten, Utility Automation Consulting Lohmann. 397 p.

Cluster for energy and enviroment. CLEEN Oy. Smart Grids and Energy Markets research program [WWW] [accessed on 6.2.2014]. Available at: http://www.cleen.fi/en/sgem.

Gers, J.M. & Holmes, E.J. 2004. Protection of Electricity Distribution Networks. 2nd Edition ed. London, Institution of Electrical Engineers. 360 p.

Ghorbani, J., Fallah, Y.P., Choudhry, M.A. & Feliachi, A. 2013. Investigation of Communication Media Requirements for Self Healing Power Distribution Systems. Energytech, Cleveland, Ohia, USA, May 21-23, 2013. Piscataway, NJ, Institute of Electrical and Electronics Engineers. pp. 245-251.

Heckel, J. 2009. Smart Substation and Feeder Automation for a Smart Distribution Grid. 20th International Conference on Electricity Distribution, Prague, Czech Republic, June 8-11, 2009. CIRED. pp. 722-725.

Higgins, N., Vyatkin, V., Nair, N.C. & Schwarz, K. 2011. Distributed Power System Automation With IEC 61850, IEC 61499, and Intelligent Control. IEEE Transactions on Systems, Man, and Cybernetics, Part C: Applications and Reviews 41, 1, pp. 81-92.

Horsmanheimo, S. Reliability of Wireless Networks in Smart Grid Enviroment [WWW] [accessed on 7.2.2014]. Available at: http://www.cleen.fi/en/SitePages/resulthighlights.aspx?fileId=1961&webpartid=g_54fff7f1_3a28_4ce6_8ac0_81baa9f4eeac.

Hou, D. & Dolezilek, D. IEC 61850 – What It Can and Cannot Offer to Traditional Protection Schemes [WWW]. Schweitzer Engineering Laboratories, Inc. 2008 [accessed on 7.1.2014]. Available at: http://www.selinc.com/WorkArea/DownloadAsset.aspx?id=3546.

Hura, G.S. & Singhal, M. 2001. Data and computer communications: networking and internetworking. Boca Raton, CRC Press. 1168 p.

Häiriötiedote 14.12.2013 [WWW]. Fortum Oyj. 2013 [accessed on 4.5.2015]. Available at: http://www.fortum.com/countries/fi/yksityisasiakkaat/asiakaspalvelu-ja-ohjeet/ajankohtaista-2/pages/seija-myrskyn-korjaustyot-edenneet-hyvin---paivan-aikana-sahkot-palautettu-valtaosalle-fortumin-asiakkaista.aspx

Jamasb, T. & Pollit, M. 2001. Benchmarking and regulation: international electricity experience. Utilities Policy 9, 3, pp. 107-130.

Järventausta, P., Mäkinen, A., Kivikko, K., Verho, P., Kärenlampi, M., Chrons, T., Vehviläinen, S., Trygg, P. & Rinta-Opas, A. 2007. Using advanced AMR system in low voltage distribution network management. 19th International Conference on Electricity Distribution, Vienna, Austria, May 21-24, 2007. CIRED. pp. 560-563.

Järventausta, P., Repo, S., Rautiainen, A. & Partanen, J. 2010. Smart grid power system control in distributed generation environment. Annual Reviews in Control 34, 2, pp. 277-286.

Jecu, C., Raison, B., Caire, R., Chilard, O., Grenard, S., Deschamps, P. & Alibert, P. 2011. MV distribution protection schemes to reduce customers and DGs interruptions. PowerTech, Trondheim, Norway, June 19-23, 2011. IEEE. pp. 1-7.

Keränen, L. 2009. Usefulness of AMR Data in the network operation. Master's thesis. Tampere. Tampere University of technology, Master's Degree Programme in Electrical Engineering. 59 p.

Keskeytystilasto 2012 [WWW]. Energiateollisuus ry. Helsinki. 29.5.2013 [accessed on 23.8.2013]. Available at: http://energia.fi/sites/default/files/keskeytystilasto_2012.pdf.

Kimura, S., Rotta, A., Abboud, R., Moraes, R., Zanirato, E. & Bahia, J. Applying IEC 61850 to Real Life: Modernization Project for 30 Electrical Substations [WWW]. Elektro Eletricidade e Serviços, S.A. and Schweitzer Engineering Laboratories, Inc. 3.4.2008 [accessed on 7.2.2014]. Available at: https://www.selinc.com/WorkArea/DownloadAsset.aspx?id=3511.

Koli, Petteri; Vähälä Antti. System Managers, Network Operations IT, Caruna, Espoo. Interview 15.10.2012.

Koponen, E. 2013. The utilization of medium voltage network fault data in asset management. Master's thesis. Espoo. Aalto University, School of Electrical Engineering. 87 p.

Kuru, J., Ihonen, T. & Haikonen, J. 2013. Control-center-based automatic fault isolation and restorations system for rural medium voltage networks. 22nd International Conference on Electricity Distribution, Stockholm, Sweden, June 10-13, 2013. Red Hook, NY, Institution of Engineering and Technology. pp. 2023-2026.

L 1.9.2013/588. Sähkömarkkinalaki

Lakervi, E. & Holmes, E.J. 2003. Electricity distribution network design. 2nd Edition, reprinted with revisions ed. London, Institution of Electrical Engineers. 325 p.

Lakervi, E. & Partanen, J. 2008. Sähkönjakelutekniikka. Helsinki, Gaudeamus Helsinki University Press. 285 p.

Laverty, D.M., Morrow, D.J., Best, R. & Crossley, P.A. 2010. Telecommunications for Smart Grid: Backhaul solutions for the Distribution Network. Power and Energy Society General Meeting, Minneapolis, USA, July 25-29, 2010. IEEE. pp. 1-6.

Löf, N. 2009. Pienjänniteverkon automaatioratkaisuiden kehitysnäkymät. Diplomityö. Tampere. Tampereen teknillinen yliopisto, Sähkötekniikan koulutusohjelma. 116 p.

Mackiewicz, R.E. 2006. Overview of IEC 61850 and Benefits. Power Engineering Society General Meeting, Montreal, Canada, June 18-22, 2006. IEEE. pp. 623-630.

Matsuda, S., Yasumasa, W., Asirizal, I.I., Katayama, S., Okuno, K. & Kasuga, K. 2011. Issues overcome in the design and application of IEC 61850-compliant substation automation systems. International Conference on Advanced Power System Automation and Protection, Beijing, China, October 16-20, 2011. IEEE. pp. 198-202.

Northcote-Green, J. & Wilson, R. 2007. Control and Automation of Electrical Power Distribution Systems. Boca Raton, CRC Press. 464 p.

Pörssitiedote 5.1.2012 [WWW]. Fortum Oyj. 2012 [accessed on 4.5.2015]. Available at: https://www.fortum.fi/fi/media/Pages/tapani-myrskyt-katkoivat-sahkot-laajoilta-alueilta-ja-aiheuttivat-fortumille-noin-45-miljoonan-euron-kustannukset.aspx

Sähkön jakeluverkkotoiminnan ja suurjännitteisen jakeluverkkotoiminnan hinnoittelun kohtuullisuuden valvontamenetelmien suuntaviivat vuosille 2012-2015 [WWW]. Energiamarkkinavirasto. Helsinki. 2011 [accessed on 7.2.2014]. Available at: http://www.energiavirasto.fi/documents/10179/0/Sahkonjakeluverkko_suurjannitteinen_jakeluverkko_suuntaviivat_2012_2015.pdf/e9de867e-513b-4ce5-84d2-322e1c585ba0.

Sauter, T. & Lobashov, M. 2011. End-to-End Communication Architecture for Smart Grids. IEEE Transactions on Industrial Electronics 58, 4, pp. 1218-1228.

Silvast, A., Heine, P., Lehtonen, M., Kivikko, K., Mäkinen, A. & Järventausta, P. 2005. Sähkönjakelun keskeytyksestä aiheutuva haitta. Teknillinen korkeakoulu, Tampereen teknillinen yliopisto. 101 p.

Skendzic, V. & Moore, R. 2006. Extending the Substation LAN Beyond Substation Boundaries: Current Capabilities and Potential New Protection Applications of Wide-Area Ethernet. Power Systems Conference and Exposition, Atlanta, USA, October 29-November 1, 2006. IEEE. pp. 641-649.

Smart Grid R&D Multi-Year Programp Plan (2010-2014) - September 2012 Update [WWW]. U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability [accessed on 6.2.2014]. Available at: http://energy.gov/oe/downloads/smart-grid-rd-multi-year-program-plan-2010-2014-september-2012-update.

Strategic Research Agenda for Europe's Electricity Networks of the Future [WWW]. European Commission, Directorate-General for Research, Information and Communication Unit [accessed on 6.2.2014]. Available at: http://www.smartgrids.eu/documents/sra/sra_finalversion.pdf.

Strauss, C. 2003. Practical Electrical Network Automation and Communication Systems. Burlington, Newnes. 224 p.

Teknillisiä tietoja ja taulukoita -käsikirja. 2000. 9th Edition ed. ABB.

Valtari, J. & Verho, P. 2011. Requirements and Proposed Solutions for Future Smart Distribution Substations. Journal of Energy and Power Engineering 5, 8, pp. 766-775.

Verho, P., Pylvänäinen, J., Järvinen, J., Oravasaari, M., Kunttu, S. & Sarsama, J. 2005. Luotettavuuspohjainen verkostoanalyysi (LuoVa) - projektin loppuraportti. Tampere, Tampere University of Technology. Tampere University of Technology, Institute of Power Engineering. Research Report 6. 116 p.

Visions and Strategy for European Electricity Networks of the Future [WWW]. European Commission, Directorate-General for Research, Information and Communication Unit [accessed on 6.2.2014]. Available at: http://ec.europa.eu/research/energy/pdf/smartgrids_en.pdf.

# APPENDIX 1

## NETWORK COMPONENTS AND INDEX ADJUSTED UNIT PRICES FOR 2014

| Muuntamot | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| 1-pylväsmuuntamo | kpl | 5 040 |
| 2-pylväsmuuntamo | kpl | 6 700 |
| 4-pylväsmuuntamo | kpl | 7 710 |
| Kevyt puistomuuntamo | kpl | 9 170 |
| Puistomuuntamo, ulkoa hoidettava | kpl | 24 540 |
| Puistomuuntamo, sisältä hoidettava | kpl | 33 990 |
| Kiinteistömuuntamo | kpl | 53 590 |
| Erikoismuuntamo | kpl | 81 140 |
| Kaapeloitu erotinasema | kpl | 25 420 |
| 1 kV suojalaitteet | kpl | 2 040 |

| Muuntajat | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| 16 kVA | kpl | 3 360 |
| 30 kVA | kpl | 3 360 |
| 50 kVA | kpl | 3 430 |
| 100-160 kVA | kpl | 4 920 |
| 200 kVA | kpl | 6 450 |
| 300-315 kVA | kpl | 7 930 |
| 500-630 kVA | kpl | 10 160 |
| 800 kVA | kpl | 14 430 |
| 1000 kVA | kpl | 16 390 |
| 1250 kVA | kpl | 19 510 |
| 1600 kVA | kpl | 19 510 |
| 20/10 kV muuntajat | kpl | 250 990 |
| 10/20 kV muuntajat | kpl | 254 230 |
| 45/20 kV muuntajat | kpl | 279 120 |
| 20/20 kV säätömuuntajat | kpl | 205 550 |

| 20 kV ilmajohdot | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| Sparrow tai pienempi | km | 20 760 |
| Raven | km | 24 610 |

| | | |
|---|---|---|
| Pigeon | km | 26 570 |
| Al 132 tai suurempi | km | 29 930 |
| Yleiskaapeli 70 tai pienempi | km | 46 170 |
| Yleiskaapeli 95 tai suurempi | km | 48 910 |
| Päällystetty avojohto 35 - 70 | km | 30 020 |
| Päällystetty avojohto 95 tai suurempi | km | 32 160 |
| Muut | km | 20 760 |

| 0,4 kV ilmajohdot | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| AMKA 16 - 25 | km | 15 480 |
| AMKA 35 - 50 | km | 16 710 |
| AMKA 70 | km | 19 480 |
| AMKA 120 | km | 22 740 |
| Muut | km | 15 480 |

| 20 kV erottimet ja katkaisijat | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| Johtoerotin, 1-vaiheinen huoltoerotin | kpl | 320 |
| Johtoerotin, kevyt | kpl | 3 530 |
| Johtoerotin, katkaisukammioin | kpl | 5 170 |
| Kauko-ohjattu erotinasema, 1 erotin | kpl | 14 020 |
| Kauko-ohjattu erotinasema, 2 erotinta | kpl | 26 100 |
| Kauko-ohjattu erotinasema, 3-4 erotinta | kpl | 37 050 |
| Pylväskatkaisija, kauko-ohjattava | kpl | 17 170 |
| 20 kV katkaisija-asema | kpl | 81 140 |
| 20/20 kV säätöasema | kpl | 205 550 |

| 20 kV maakaapelit (asennus) | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| Enintään 70 maakaapeli | km | 24 520 |
| 95 - 120 maakaapeli | km | 32 290 |
| 150 - 185 maakaapeli | km | 37 940 |
| 240 - 300 maakaapeli | km | 45 390 |
| 400 - 500 maakaapeli | km | 84 920 |
| 630 - 800 maakaapeli | km | 151 030 |
| Enintään 70 vesistökaapeli | km | 41 040 |
| 95 - 120 vesistökaapeli | km | 43 000 |
| 150 - 185 vesistökaapeli | km | 46 730 |
| Kojeistopääte | kpl | 1 260 |
| Pylväspääte | kpl | 2 370 |
| Jatko | kpl | 2 010 |

| 0,4 kV maakaapelit (asennus) | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| Enintään 25 maakaapeli | km | 7 840 |
| 35 - 50 maakaapeli | km | 8 970 |
| 70 maakaapeli | km | 11 720 |
| 95 - 120 maakaapeli | km | 12 890 |
| 150 - 185 maakaapeli | km | 19 850 |
| 240 - 300 maakaapeli | km | 24 390 |
| Enintään 35 vesistökaapeli | km | 11 720 |
| 50 - 70 vesistökaapeli | km | 14 300 |
| 95 - 120 vesistökaapeli | km | 21 480 |
| Vähintään 150 vesistökaapeli | km | 22 910 |

| 0,4 ja 20 kV maakaapelit (kaivu) | Yksikkö | Yksikköhinta euroa/km |
|---|---|---|
| Helppo | km | 10 120 |
| Normaali | km | 23 110 |
| Vaikea | km | 66 000 |
| Erittäin vaikea | km | 128 240 |

| Jakokaapit ja jonovarokekytkimet | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| Haaroituskaappi | kpl | 660 |
| Kaapelijakokaappi, enintään 400 A | kpl | 1 390 |
| Kaapelijakokaappi, vähintään 630 A | kpl | 1 770 |
| Jonovarokekytkin, enintään 160 A | kpl | 300 |
| Jonovarokekytkin, 250 – 400 A | kpl | 440 |
| Jonovarokekytkin, 630 A | kpl | 660 |

| 45, 110 ja 400 kV johdot sekä erotinasemat | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| 45 kV puupylväsjohto | km | 45 440 |
| 110 kV kevytrakenteinen puupylväsjohto | km | 100 610 |
| 110 kV puupylväsjohto, yksi virtapiiri, yksi osajohdin | km | 133 930 |
| 110 kV putkipylväsjohto, yksi virtapiiri, kaksi osajohdinta | km | 158 930 |
| 110 kV teräsristikkopylväsjohto, yksi virtapiiri | km | 228 280 |
| 110 kV teräsristikkopylväsjohto, kaksi virtapiiriä | km | 291 020 |
| 110 kV maakaapeli, normaali olosuhde, 800 mm² tai alle | km | 454 370 |
| 110 kV maakaapeli, vaikea olosuhde, 800 mm² | km | 530 110 |

| | | |
|---|---|---|
| tai alle | | |
| 110 kV maakaapeli, normaali olosuhde, 1000 mm² tai yli | km | 751 890 |
| 110 kV maakaapeli, vaikea olosuhde, 1000 mm² tai yli | km | 887 120 |
| 400 kV teräspylväsjohto, harustettu | km | 195 820 |
| 400 kV teräspylväsjohto, vapaasti seisova | km | 346 200 |
| 45 kV erotinasema (1 erotin) | kpl | 20 560 |
| 110 kV johtoerotin | kpl | 24 880 |
| 110 kV kaukokäyttöinen johtoerotin | kpl | 36 780 |
| 110 kV johtoaluekorvaus | km | 22 720 |
| 400 kV johtoaluekorvaus | km | 31 370 |

| 45 kV sähköasemarakenteet | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| 45/20 kV sähköasema | kpl | 400 290 |
| 45 kV kentät 110 kV asemilla | kpl | 214 200 |
| + lisäkentät | kpl | 192 570 |

| Verkkotietojärjestelmä | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| Verkkotietojärjestelmä, perusosa | kpl | 119 010 |
| + asiakasmäärään perustuva osa | asiakasta | 6,5 |

| Asiakastietojärjestelmä | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| Asiakastietojärjestelmä, perusosa | kpl | 74 640 |
| + asiakasmäärään perustuva osa | asiakasta | 9,4 |

| Mittaustieto- ja tasehallintajärjestelmä | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| Mittaustieto- ja tasehallintajärjestelmä, perusosa | kpl | 136 310 |
| + käyttöpaikkamäärään perustuva osa | asiakasta | 6,5 |

| Käytönvalvontajärjestelmä | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| Käytönvalvontajärjestelmä, perusosa | kpl | 297 510 |
| + sähköasemakohtainen lisäosa | kpl | 9 740 |
| + erotinasemakohtainen lisäosa | kpl | 2 170 |

| Käytöntukijärjestelmä | Yksikkö | |
|---|---|---|

| | | Yksikköhinta euroa |
|---|---|---|
| Käytöntukijärjestelmä, perusosa | kpl | 21 640 |
| + liitettyjen järjestelmien määrään perustuva lisäosa | kpl | 21 640 |
| + sähköasemakohtainen lisäosa | kpl | 1 080 |
| + erotinasemakohtainen lisäosa | kpl | 540 |

| Käytönvalvontajärjestelmän viestiverkot | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| Viestiverkot, perusosa | kpl | 88 720 |
| + sähköasemakohtainen lisäosa | kpl | 5 410 |
| + kaapelimuuntamokohtainen lisäosa | kpl | 760 |

| Energiamittauslaitteet | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| Paikallisesti luettavat mittarit | kpl | 160 |
| Etäluettavat mittarit (63 A ja alle) | kpl | 210 |
| Etäluettavat mittarit (yli 63 A) | kpl | 760 |

| Sähköasematontit | Yksikkö | Yksikköhinta euroa/m2 |
|---|---|---|
| Suurkaupunkien kaava-alueet | $m^2$ | 70,4 |
| Muut kaava-alueet | $m^2$ | 2,7 |
| Kaavoittamaton alue | $m^2$ | 1,3 |

| Sähköasemarakennukset | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| Suurkaupunkien kaava-alueet | kpl | 854 660 |
| Muut kaava-alueet | kpl | 243 420 |
| Kaavoittamaton alue | kpl | 86 550 |

| Sähköasemat, 110 kV päämuuntajat | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| 6 MVA | kpl | 266 140 |
| 10 MVA | kpl | 300 750 |
| 16 MVA | kpl | 346 200 |
| 20 MVA | kpl | 389 470 |
| 25 MVA | kpl | 432 750 |
| 31,5 MVA | kpl | 504 150 |
| 40 MVA | kpl | 567 970 |

| | | |
|---|---|---|
| 50 MVA | kpl | 646 950 |
| 63 MVA | kpl | 768 110 |
| 80 MVA | kpl | 876 300 |
| 100 MVA | kpl | 973 670 |
| 220/110 kV muuntaja | kpl | 1 211 680 |

| Sähköasemat,<br><br>110 kV kevyt sähköasema | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| 110 kV kevyt sähköasema | kpl | 394 880 |

| Sähköasemat 110 kV kentät,<br><br>ilmaeristeinen sähköasema | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| Muuntajaperustus ja liitynnät ilmaeristeisellä asemalla | kpl | 57 340 |
| Ilmaeristeinen 1-kiskokojeisto, peruskenttä | kpl | 387 310 |
| + 1-kisko lisäkenttä | kpl | 246 660 |
| Ilmaeristeinen 2-kiskokojeisto, peruskenttä | kpl | 469 520 |
| + 2-kisko lisäkenttä | kpl | 328 890 |
| Ilmaeristeinen 3-kiskokojeisto, peruskenttä | kpl | 547 420 |
| + 3-kisko lisäkenttä | kpl | 387 310 |
| Suojaus- ja automaatio, peruskenttä (ilmaeristeinen) | kpl | 67 080 |
| + lisäkenttä | kpl | 19 040 |

| Sähköasemat 110 kV kentät,<br><br>kaasueristeinen sähköasema | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| Muuntajaperustus ja liitynnät kaasueristeisellä asemalla | kpl | 51 930 |
| Kaasueristeinen 1-kiskokojeisto, peruskenttä | kpl | 601 510 |
| + 1-kisko lisäkenttä | kpl | 361 340 |
| Kaasueristeinen 2-kiskokojeisto, peruskenttä | kpl | 701 040 |
| + 2-kisko lisäkenttä | kpl | 443 570 |
| Suojaus- ja automaatio, peruskenttä (kaasueristeinen) | kpl | 86 770 |
| + lisäkenttä | kpl | 31 800 |

| Sähköasemat,<br><br>20 kV kojeistot | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| Ilmaeristeinen 1-kiskokojeisto, peruskenttä | kpl | 21 420 |
| + 1-kisko lisäkenttä | kpl | 13 960 |
| Ilmaeristeinen 2-kiskokojeisto, peruskenttä | kpl | 32 780 |
| + 2-kisko lisäkenttä | kpl | 21 960 |

| | | |
|---|---|---|
| Kaasueristeinen 2-kiskokojeisto, peruskenttä | kpl | 49 760 |
| + 2-kisko lisäkenttä | kpl | 30 070 |
| Suojaus- ja automaatio, peruskenttä (asemakohtainen) | kpl | 21 420 |
| + lisäkenttä | kpl | 6 380 |

| Muut verkkokomponentit | Yksikkö | Yksikköhinta euroa |
|---|---|---|
| Kondensaattori 2,4 Mvar | kpl | 38 730 |
| Maasulun sammutuslaitteisto, 100 A | kpl | 135 240 |
| Maasulun sammutuslaitteisto, 100 A maadoitusmuuntajalla | kpl | 148 210 |
| Maasulun sammutuslaitteisto, 140 A | kpl | 157 950 |
| Maasulun sammutuslaitteisto, 140 A maadoitusmuuntajalla | kpl | 176 350 |
| Maasulun sammutuslaitteisto, 250 A | kpl | 164 440 |
| Maasulun sammutuslaitteisto, 250 A maadoitusmuuntajalla | kpl | 192 570 |
| Kuristin, alle 50 MVA | kpl | 51 930 |
| Kuristin, yli 50 MVA | kpl | 70 320 |
| Varavoimageneraattori, 50-110 kVA | kpl | 31 370 |
| Varavoimageneraattori, 250-350 kVA | kpl | 62 750 |
| Varavoimageneraattori, 700-1000 kVA | kpl | 205 550 |

# APPENDIX 2

## MEDIUM VOLTAGE OUTAGE STATISTICS FOR SELKÄ AND NIITTYKUMPU SUBSTATIONS IN 2009-2012

***Table 9.1.*** *The medium voltage outage statistic of Selkä substation in 2009-2012.*

| Outage | Feeder | Duration (h) | Energy not supplied (kWh) | Power (kW) | Customer outage cost |
|---|---|---|---|---|---|
| 2-2009Lounais-1106 | SLKJ07Q0 | 2,8 | 1902,43 | 1586,46 | 30 603,00 € |
| 2-2009Lounais-1449 | SLKJ02Q0 | 0,35 | 877,75 | 5086,8 | 22 470,00 € |
| 2-2009Lounais-955 | SLKJ06Q0 Koski TL | 2,32 | 883,52 | 1037,98 | 10 972,00 € |
| 2-2009Lounais-1050 | SLKJ10Q0 Mellilä | 1,89 | 449,61 | 2163,76 | 8 847,00 € |
| 2-2009Lounais-1719 | SLKJ10Q0 | 1,4 | 25,7 | 17,51 | 318,00 € |
| 2-2009Lounais-1991 | SLKJ06Q0 | 0,3 | 10,48 | 49,85 | 238,00 € |
| 2-2010-4775 | SLKJ05Q0/MARTTILA | 2,01 | 1161,75 | 3762,25 | 43 508,00 € |
| 2-2010-4522 | SLKJ06Q0/KOSKI_TL | 4,04 | 2699,16 | 1065,76 | 53 262,00 € |
| 2-2010-1932 | SLKJ06Q0/KOSKI_TL | 0,19 | 183 | 1049,68 | 3 691,00 € |
| 2-2010-2024 | SLKJ06Q0/KOSKI_TL | 0,05 | 36,21 | 1065,76 | 1 990,00 € |
| 2-2010-3035 | SLKJ06Q0/KOSKI_TL | 0,03 | 19,28 | 1065,76 | 1 611,00 € |
| 2-2010-2116 | SLKJ06Q0/KOSKI_TL | 0,04 | 3,75 | 1065,76 | 1 825,00 € |
| 2-2010Lounais-1199 | SLKJ07Q0 | 0,43 | 36,44 | 132,37 | 853,00 € |
| 2-2010-4524 | SLKJ07Q0/VILPPU | 4,05 | 3657,98 | 1203,74 | 60 455,00 € |
| 2-2010-8438 | SLKJ07Q0/VILPPU | 4,93 | 1331,35 | 2436,61 | 14 065,00 € |

| | | | | | |
|---|---|---|---|---|---|
| 2-2010-5411 | SLKJ08Q0/SORVASTO | 3,33 | 199,47 | 74,26 | 3 077,00 € |
| 2-2010-4528 | SLKJ10Q0/MELLILÄ | 9,95 | 4038,57 | 1107,51 | 68 986,00 € |
| 2-2010Lounais-1545 | SLKJ10Q0/MELLILÄ | 0,2 | 206,71 | 1087,6 | 3 633,00 € |
| 2-2010-3136 | SLKJ10Q0/MELLILÄ | 1 | 82,75 | 117,82 | 1 569,00 € |
| 2-2011-19922 | SLKJ06Q0/KOSKI_TL | 1,25 | 3161,61 | 5058,82 | 33 246,00 € |
| 2-2011-12634 | SLKJ02Q0 | 1,1 | 2954,18 | 6634,63 | 95 039,00 € |
| 2-2011-21480 | SLKJ10Q0/MELLILÄ | 5,17 | 3187,3 | 1087,6 | 30 752,00 € |
| 2-2011-2752 | SLKJ05Q0/MARTTILA | 2,55 | 2251,21 | 3596,02 | 41 766,00 € |
| 2-2011-2415 | SLKJ07Q0/VILPPU | 3,08 | 2412,76 | 1218,31 | 17 561,00 € |
| 2-2011-9420 | SLKJ10Q0/MELLILÄ | 5,06 | 2162,88 | 1087,6 | 39 760,00 € |
| 2-2011-20248 | SLKJ10Q0/MELLILÄ | 3,91 | 2026,69 | 1087,6 | 21 098,00 € |
| 2-2011-2768 | SLKJ06Q0/KOSKI_TL | 2,7 | 1798,23 | 2524,25 | 25 861,00 € |
| 2-2011-10989 | SLKJ07Q0/VILPPU | 2,07 | 1029,33 | 1218,31 | 15 632,00 € |
| 2-2011-3247 | SLKJ10Q0/MELLILÄ | 4,19 | 477,96 | 1087,6 | 6 344,00 € |
| 2-2011-11421 | SLKJ06Q0/KOSKI_TL | 1,24 | 409,69 | 1528,93 | 9 115,00 € |
| 2-2011-11373 | SLKJ09Q0/KAURANEN | 6,45 | 406,59 | 755,32 | 7 196,00 € |
| 2-2011-8253 | SLKJ06Q0/KOSKI_TL | 2,21 | 364,83 | 1065,76 | 6 940,00 € |
| 2-2011-11000 | SLKJ07Q0/VILPPU | 5,34 | 279,51 | 143,07 | 3 275,00 € |
| 2-2011-11478 | SLKJ10Q0/MELLILÄ | 10 | 246,28 | 221,74 | 4 822,00 € |
| 2-2011-22318 | SLKJ06Q0/KOSKI_TL | 0,96 | 217,51 | 167,02 | 2 159,00 € |
| 2-2011-549 | SLKJ08Q0/SORVASTO | 2,51 | 122,6 | 37,68 | 1 201,00 € |
| 2-2011-8741 | SLKJ08Q0/SORVASTO | 0,19 | 59,71 | 408,77 | 1 435,00 € |
| 2-2011-7548 | SLKJ06Q0/KOSKI_TL | 0,68 | 68,23 | 145,51 | 1 385,00 € |
| 2-2011-1941 | SLKJ07Q0/VILPPU | 4,26 | 76,33 | 14,57 | 774,00 € |

| | | | | | |
|---|---|---|---|---|---|
| 2-2011-3222 | SLKJ08Q0/SORVASTO | 1,02 | 63,08 | 54,18 | 743,00 € |
| 2-2011-10034 | SLKJ08Q0/SORVASTO | 1,52 | 11,59 | 16,37 | 323,00 € |
| 2-2012-17205 | SLKJ05Q0/MARTTILA | 11,83 | 6865,93 | 2174,27 | 143 861,00 € |
| 2-2012-15157 | SLKJ10Q0/MELLILÄ | 4,49 | 1372,46 | 1087,6 | 20 748,00 € |
| 2-2012-12774 | SLKJ10Q0/MELLILÄ | 2,48 | 1043,22 | 1087,6 | 12 679,00 € |
| 2-2012-14683 | SLKJ07Q0/VILPPU | 5,47 | 421,81 | 270,35 | 5 853,00 € |
| 2-2012-14435 | SLKJ07Q0/VILPPU | 2,07 | 404,02 | 270,35 | 5 206,00 € |
| 2-2012-13589 | SLKJ09Q0/KAURANEN | 0,24 | 305,78 | 962,66 | 4 160,00 € |
| 2-2012-67 | SLKJ10Q0/MELLILÄ | 2,08 | 301,79 | 107,04 | 2 950,00 € |
| 2-2012-10989 | SLKJ05Q0/MARTTILA | 3,55 | 289,39 | 53,04 | 2 440,00 € |
| 2-2012-17044 | SLKJ10Q0/MELLILÄ | 0,2 | 85,89 | 1087,6 | 3 867,00 € |
| 2-2012-227 | SLKJ08Q0/SORVASTO | 2,01 | 167,06 | 54,18 | 1 444,00 € |
| 2-2012-17229 | SLKJ10Q0/MELLILÄ | 0,03 | 16,51 | 1087,6 | 1 830,00 € |
| 2-2012-15865 | SLKJ10Q0/MELLILÄ | 7,36 | 100,13 | 22,57 | 2 123,00 € |
| 2-2012-48 | SLKJ08Q0/SORVASTO | 1,17 | 90,88 | 54,18 | 866,00 € |
| 2-2012-60 | SLKJ09Q0/KAURANEN | 0,75 | 45,78 | 38,31 | 411,00 € |
| 2-2012-8225 | SLKJ10Q0/MELLILÄ | 0,43 | 38,97 | 65,89 | 441,00 € |
| 2-2012-14703 | SLKJ10Q0/MELLILÄ | 0,42 | 29,15 | 65,89 | 431,00 € |
| 2-2012-12850 | SLKJ06Q0/KOSKI_TL | 0,07 | 10,04 | 132,6 | 277,00 € |
| 2-2012-14923 | SLKJ07Q0/VILPPU | 1,72 | 19,25 | 6,09 | 140,00 € |
| 2-2012-15515 | SLKJ06Q0/KOSKI_TL | 0,19 | 12,09 | 74,2 | 271,00 € |
| 2-2012-17326 | SLKJ10Q0/MELLILÄ | 0,4 | 13,45 | 58,17 | 368,00 € |
| 2-2012-19678 | SLKJ10Q0/MELLILÄ | 1,34 | 9,36 | 6,61 | 120,00 € |
| 2-2013-6393 | SLKJ02Q0 | 0,71 | 2106,5 | 6958,28 | 40 340,00 € |
| 2-2013-2501 | SLKJ07Q0/VILPPU | 3,43 | 2506,51 | 1889,77 | 29 256,00 € |

| | | | | | |
|---|---|---|---|---|---|
| 2-2013-3774 | SLKJ02Q0 | 0,5 | 1625 | 6353,23 | 40 803,00 € |
| 2-2013-3818 | SLKJ02Q0 | 0,3 | 1188,54 | 6028,32 | 29 561,00 € |
| 2-2013-9226 | SLKJ07Q0/VILPPU | 1,03 | 1418,94 | 1311,32 | 15 587,00 € |
| 2-2013-9136 | SLKJ09Q0/KAURANEN | 4,16 | 952,8 | 1468,59 | 14 520,00 € |
| 2-2013-4030 | SLKJ05Q0/MARTTILA | 5,81 | 895,37 | 1777,73 | 71 332,00 € |
| 2-2013-1519 | SLKJ09Q0/KAURANEN | 3,29 | 890,59 | 1813,31 | 10 273,00 € |
| 2-2013-5293 | SLKJ07Q0/VILPPU | 4,24 | 652,25 | 3970,53 | 14 675,00 € |
| 2-2013-3753 | SLKJ07Q0/VILPPU | 3,12 | 724,78 | 1722,86 | 12 210,00 € |
| 2-2013-3707 | SLKJ06Q0/KOSKI_TL | 4,3 | 735,59 | 1338,75 | 16 767,00 € |
| 2-2013-5199 | SLKJ07Q0/VILPPU | 0,16 | 312,14 | 2475,63 | 7 881,00 € |
| 2-2013-3550 | SLKJ08Q0/SORVASTO | 1,77 | 307,94 | 373,26 | 4 714,00 € |
| 2-2013-7006 | SLKJ06Q0/KOSKI_TL | 0,08 | 48,68 | 981,78 | 2 016,00 € |
| 2-2013-1150 | SLKJ07Q0/VILPPU | 0,65 | 69,07 | 76,52 | 747,00 € |
| 2-2013-3776 | SLKJ06Q0/KOSKI_TL | 1,23 | 60,19 | 49,94 | 861,00 € |
| 2-2013-3124 | SLKJ07Q0/VILPPU | 0,15 | 8,8 | 153,03 | 490,00 € |

***Table 2.*** *The medium voltage outage statistic of Niittykumpu substation in 2009-2012.*

| **Outage** | **Feeder** | **Duration (h)** | **Energy not supplied (kWh)** | **Power (kW)** | **Customer outage cost** |
|---|---|---|---|---|---|
| 6-2009-537 | NTK B24 Q0 | 1,66 | 4987,17 | 2386,27 | 37 858,00 € |
| 6-2009-1153 | NTK B23 Q0 | 0,9 | 1459,74 | 1526,09 | 13 958,00 € |
| 6-2009-567 | NTK B24 Q0 | 0,03 | 80,2 | 2604,23 | 3 959,00 € |
| 6-2009-939 | NTK B12 Q0 | 2,69 | 40,89 | 24,42 | 822,00 € |
| 6-2010-1007 | NTK B11 Q0/NTK B11 | 1,36 | 4113,52 | 17230,76 | 106 280,00 € |
| 6-2010-1036 | NTK B07 Q0 | 0,06 | 406,87 | 12993,6 | 25 613,00 € |
| 6-2010-116 | NTK B25 Q0 | 0,74 | 545,86 | 921,65 | 5 824,00 € |
| 6-2010-504 | NTK B12 Q0/NTK B12 | 1,88 | 27,36 | 24,42 | 584,00 € |
| 6-2011-4576 | NTK B19 Q0/NTK B19 | 0,28 | 500,42 | 9739,13 | 18 135,00 € |
| 6-2011-1710 | NTK B24 | 1,33 | 717,47 | 3216,83 | 33 312,00 € |

| | | | | | |
|---|---|---|---|---|---|
| | Q0/NTK B24 | | | | |
| 6-2011-1150 | NTK B12 Q0/NTK B12 | 3,7 | 176,61 | 24,42 | 1 132,00 € |
| 6-2012-2546 | NTK B11 Q0/NTK B11 | 1,02 | 2169,29 | 3886,45 | 42 659,00 € |
| 6-2012-17 | NTK B19 Q0/NTK B19 | 0,13 | 767,72 | 4869,57 | 14 353,00 € |
| 6-2012-1968 | NTK B22 Q0/NTK B22 | 0,9 | 428,57 | 713 | 6 273,00 € |
| 6-2012-2403 | NTK B05 Q0/NTK B05 | 2,01 | 12,05 | 2246,56 | 3 023,00 € |
| 6-2012-4060 | NTK B04 Q0/NTK B04 | 0,18 | 16,49 | 309,25 | 1 086,00 € |
| 6-2013-1576 | NTK B19 Q0/NTK B19 | 0,19 | 25,06 | 121,01 | 452,00 € |