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INFORMATION FLOWS IN THE NETWORK CONTROL CENTER OF DISTRIBUTION SYSTEM OPERATOR FROM THE ASPECT OF OUTAGE REPORTING

Master of Science Thesis

Examiner: Professor Pekka Verho
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ABSTRACT

Hannu-Pekka Lamminmäki: Information flows in the Network Control Center of Distribution System Operator from the aspect of outage reporting
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Due to the natural monopoly nature of the electricity distribution business, the operation of the Distribution System Operators is regulated by the authority. The Electricity Market Act appoints the Energy Authority to be responsible for the regulative measures. A new regulation period took place in the beginning of year 2016. The regulation model guides the operation of the Distribution System Operators, and for example the annual realized KAH values have direct economical impact on the DSOs via the allowed profit. Due to the occurred major disturbances during recent years, the requirements for the IT systems are increasing. The large amount of outages and increasing amount of reporting requirements increase also the role of automatization in the outage reporting.

One of the objectives of the thesis was to describe the IT systems used by a few Distribution System Operators and the information flows between the systems from the aspect of outage reporting. In order to find out what are the main reasons behind the particular IT system integration choices, representatives of five Distribution System Operators were interviewed. Information of the IT systems and the information flows between the systems were gathered, and the processes regarding the outage management and outage reporting were clarified. The objective was also to find out the used protocols, sources of the information and the communication types of the information flows related to the outage reporting. What information is required and what is the demand for the information are described as well. The operational objective of the thesis was to create a new outage report according to the needs.

As an outcome of the thesis the chosen Distribution System Operators' IT systems and information flows between the systems related to the outage reporting are described. For the reporting functions of ABB MicroSCADA Pro DMS600 product, development ideas were gathered from the Distribution System Operators and development requirements from the Energy Authority's documents and the Finnish Energy's outage statistics instructions. As a result requirements for new outage reports were discovered. The new outage reports are required as compulsory by the Energy Authority. During the thesis three outage reports were developed to represent the changed reporting requirements, and two entirely new reports were implemented with SQL language according to the new requirements. The implemented reports respond to the requirements regarding the distribution reliability requirement classes and the key figures of LV network outages defined by the Energy Authority.

TIIVISTELMÄ

Hannu-Pekka Lamminmäki: Tietovirrat sähköverkkoyhtiön käyttökeskuksessa keskeytysraportoinnin näkökulmasta
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Avainsanat: Tietovirrat, keskeytysraportointi, SQL, keskeytysten hallinta, valvomo, käyttökeskus, sähköverkkoyhtiö, käytöntukijärjestelmä, KTJ, käytönvalvontajärjestelmä, SCADA, rajapinnat

Sähkönjakelualan luonnollisen monopolin myötä sähkönjakeluyhtiöiden toimintaa säännellään viranomaisten toimesta. Regulaation toteuttaminen eli valvontamenetelmien laadinta on määrätty sähkömarkkinalaissa Energiaviraston vastuulle. Uusi valvontajakso alkoi vuoden 2016 alussa. Regulaatiomalli ohjaa sähkönjakeluyhtiöiden toimintaa, ja esimerkiksi vuosittaisilla toteutuneilla KAH arvoilla on suora taloudellinen vaikutus sähkönjakeluyhtiöihin sallitun tuoton kautta. Viime vuosina tapahtuneiden suurhäiriöiden vuoksi vaatimukset järjestelmille kasvavat entisestään. Keskeytyksien suuren määrän ja raportoinnin vaatimusten määrän kasvamisen vuoksi myös automatisoinnin merkitys raportoinnissa kasvaa.

Työn tavoitteena oli kuvata muutamien sähkönjakeluyhtiöiden käyttämät järjestelmät ja niiden väliset tietovirrat keskeytysraportoinnin näkökulmasta. Järjestelmien valintojen perusteiden selvittämiseksi haastateltiin näiden viiden sähkönjakeluyhtiön edustajia. Haastatteluissa kerättiin tietoa yhtiöiden järjestelmistä ja niiden välillä kulkevista tietovirroista sekä kyseisten yhtiöiden keskeytyksenhallintaan ja keskeytysraportointiin liittyvistä prosesseista. Tavoitteena oli selvittää keskeytysraportointiin liittyvistä järjestelmien välisistä tietovirroista niiden protokollat, tiedon lähteet, tiedon laatu, kommunikaatiotavat sekä lopullinen tarve tiedolle. Työn operatiivisena tavoitteena on luoda tarpeen mukaan uusi keskeytysraportti.

Työn tuloksena ovat kuvaukset valittujen sähkönjakeluyhtiöiden keskeytysraportointiin liittyvistä järjestelmistä ja niiden välillä kulkevista tietovirroista. ABB MicroSCADA Pro DMS600 tuotteen raportoinnille kerättiin kehittämistarpeita sähkönjakeluyhtiöiltä sekä kehitysvaatimuksia Energiaviraston viranomaisdokumenteista ja Energiateollisuuden keskeytystilasto-ohjeesta. Tuloksena huomattiin tarve uusille keskeytysraporteille, jotka Energiavirasto vaatii raportoitavaksi pakollisina. Lopulta työssä muokattiin kolmea keskeytysraporttia vastaamaan muuttuneita raportointivaatimuksia sekä toteutettiin kaksi täysin uutta raporttia SQL-kielellä uusien raportointivaatimusten mukaisesti. Tuotetut uudet raportit vastaavat Energiaviraston toimitusvarmuustasoihin liittyviin tunnuslukuvaatimuksiin sekä pienjänniteverkon keskeytysten tunnuslukuvaatimuksiin.

PREFACE

This Master of Science Thesis was written for ABB Oy (Power Grids, Grid Automation) between October 2015 and May 2016. The examiner of the thesis was Professor Pekka Verho from the Department of Electrical Engineering and the supervisor was M.Sc. Teemu Leppälä.

I wish to express my most humble thanks to the supervisor Teemu Leppälä who has given me invaluable guidance during the thesis process. I want to thank also Professor Pekka Verho for useful comments and feedback regarding the thesis and my superior Ilkka Nikander for giving me an opportunity to write the thesis about such an interesting and educational topic. Thanks also for all of the colleagues for giving advices and opinions during the process.

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Last but not least I want to thank my family and friends for all the support and happiness they brought me during the thesis process.

Tampere,

May 24th, 2016

Hannu-Pekka Lamminmäki

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LIST OF SYMBOLS AND ABBREVIATIONS

ABB	ASEA Brown Boveri
AMR	Automatic Meter Reading
AMI	Advanced Metering Infrastructure
API	Application Programming Interface
BSC	Balanced Scorecard
CAIDI	Customer Average Interruption Duration Index
CIM	Common Information Model
CIS	Customer Information System
CR	Cabling Rate
CSMS	Customer Service Management System
CSV	Comma-separated Values
DA	Distribution Automation
DAR	Delayed Autoreclosing
DCU	Data Concentrator Unit
DER	Distributed Energy Resources
DG	Distributed Generation
DLC	Distribution Line Carrier
DMS	Distribution Management System
DMS600	ABB MicroSCADA Pro DMS600
DMS600 NE	ABB MicroSCADA Pro DMS600 Network Editor, ABB NIS
DMS600 WS	ABB MicroSCADA Pro DMS600 Workstation, ABB DMS
DRR	Distribution Reliability Requirements
DRRC	Distribution Reliability Requirement Class
DSO	Distribution System Operator
ELCOM	Electricity Utilities Communications
ERP	Enterprise Resource Planning
ET	Energiateollisuus ry, the Finnish Energy
FDIR	Fault Detection, Isolation and Restoration
FLIR	Fault Location, Isolation and Restoration
FP	Feature Pack
FPP	Flexible Plug and Play
GIS	Geographical Information System
GOOSE	Generic Object Oriented Substation Event
GUI	Graphical User Interface
HF	Hotfix
HMI	Human-Machine Interface
HSAR	High Speed Automatic Reclosing
HSB	Hot Stand-By
HV	High Voltage
IEC	International Electrotechnical Commission
IEC-101	IEC 60870-5-101
IEC-104	IEC 60870-5-104
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
IoT	Internet of Things
IT	Information Technology
IVR	Interactive Voice Response
JSE	Järvi-Suomen Energia Oy

KAH	Keskeytyksestä Aiheutunut Haitta, Customer Outage Cost
KSAT	Koillis-Satakunnan Sähkö Oy
LAN	Local Area Network
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MDMS	Meter Database Management System
MED	Major Event Day
MMS	Manufacturing Message Specification
MO	Maintenance Outage
MRS	Meter Reading System
MS	Microsoft
MSSQL	Microsoft SQL Server
MV	Medium Voltage
NCC	Network Control Center
NDE	Non-Distributed Energy
NIS	Network Information System
NPV	Net Present Value
ODBC	Open Database Connectivity
OPC	Ole for Process Control
PDF	Portable Document Format
PG	PowerGrid, Tieto NIS
PiHa	Pienjänniteverkon Hallinta, LV network management features
PLC	Power-Line Communication
RAR	Rapid Autoreclosing
RTLS	Real-Time Locating System
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, IT system
SCIL	Supervisory Control Implementation Language
SQL	Structured Query Language
SSDTBI	SQL Server Data Tools – Business Intelligence
SSMS	SQL Server Management Studio
SSRS	SQL Server Reporting Services
SYS600	ABB MicroSCADA Pro SYS600, ABB SCADA
TAM	Telephone Answering Machine
TCP/IP	Transmission Control Protocol / Internet Protocol
TESV	Turku Energia Sähköverkot Oy
TSV	Tampereen Sähköverkko Oy
TUT	Tampere University of Technology
UI	User Interface
UPS	Uninterruptible Power Supply
VIRVE	Viranomaisradioverkko, Finnish authorities' telecommunications network
WAN	Wide Area Network
WMS	Work Management System
XML	Extensible Markup Language

1. INTRODUCTION

1.1 Background of the thesis

As the Distribution System Operators (DSOs) are operating in a natural monopoly business, the Electricity Market Act defines that the Energy Authority must regulate the operation of the DSOs in order to avoid malpractices in the business and to reduce excessive self-interest of the DSOs. During the recent years the reporting requirements of the Energy Authority (compulsory) and the Finnish Energy (optional) have been increased. The outage reporting is in major role in the operation of the DSOs today as it has direct economical impact on the DSOs via the regulatory methods of the Energy Authority. Each regulatory period of the Energy Authority stands for four years. A new, fourth regulatory period took place in the beginning of year 2016 and stands until the end of 2019. The reporting requirements have changed from previous periods causing development needs for the ABB MicroSCADA Pro DMS600 (DMS600) and its reporting functions. The direct standard outage compensation amounts for the customers are defined in the Electricity Market Act and the annual realized KAH (Keskeytyksestä Aiheutunut Haitta, Customer outage costs) values are noted directly in the quality incentive and the efficiency incentive of the regulatory methods.

Although large-scale renovation works have already began, the Finnish distribution networks are still vulnerable for the effects of major disturbances. In some cases the amount of annual outages can rise very high. Nonetheless, the outage reporting work has to be done in time. Hence the IT systems and the information flows between them are in even more responsible role of the DSOs' operation today. The amount and complexity of the required reports is so high that they have to be created automatically from the IT systems. This Master of Science Thesis covers the presented topic from the DMS600 software's point of view, as the IT systems have to be developed to meet the changing requirements of the Energy Authority and the whole distribution business environment.

1.2 Research problem and objectives

One of the objectives of this thesis is to describe the IT systems used by a few Finnish DSOs from the aspect of outage reporting. In order to find out what are the main reasons behind the particular IT system integrations of the DSOs, several customers are interviewed. Other reasons for the interviews are to find out the development ideas for the outage reporting functions of DMS600, gathering all the necessary information related to the IT systems and the reporting processes of the DSOs and clarifying the information flows between the IT systems from the aspect of outage reporting. The objective is to describe the information flow protocols, sources of the information, communication types, what information is required, and what is the requirement for the information.

As the new regulatory period of the Energy Authority took place from the beginning of 2016, there is a need to clarify what are the new requirements of the Energy Authority and what development needs it requires from the DMS600. The operational objective of the thesis is to create an entirely new outage report if requirements for new reports are found. The reports which required to exist but are not created during the thesis are described in the thesis as well.

1.3 Research methodology

The literature related to the topic brings a strong background for the thesis and especially the new requirement documents from the Energy Authority and the Finnish Energy are in important role because the latest reporting requirements are presented in these documents. Some of the information is also based on the internal documents of ABB.

The interviews of five Finnish DSOs are also a major part of the thesis. The description of the IT systems and the information flows between them, outage management process and reporting process of each company was possible because of the interviews. Also development ideas and other information were acquired from the interviews, and observing was used with some DSOs. The interviewed DSOs are Turku Energia Sähköverkko Oy, Tampereen Sähköverkko Oy, Leppäkosken Sähkö Oy, Elenia Oy and Järvi-Suomen Energia Oy. The interviewees were chosen so that they would have different kind of IT system integrations and different size and type of distribution network. Interviews were implemented mainly in the premises of the DSOs. The used interviewing method was a focused (semi-structured) interview [1], as the questions can not be exactly the same for all of the DSOs due to different IT system infrastructures.

The third part of the thesis includes the outage report implementations. The implemented reports represent the operative part of the thesis. Three outage reports were modified and two entirely new reports were created during the thesis. The reports were implemented to the SQL (Structured Query Language) Reporting Services of DMS600 and they were coded mainly in SQL language.

1.4 Structure of the thesis

The first chapter contains the introduction for the thesis. Second chapter presents important background information related to the topic in order that the reader may understand the information provided in the later part of the thesis. Chapter 2 presents shortly the Finnish electricity distribution system and the distribution automation, the IT systems used in the Network Control Center (NCC), communication technologies used in the distribution automation and common outage management processes.

The third chapter contains information of the electricity distribution regulation and outage reporting in Finland. The role of the Electricity Market Act, the Energy Authority and the Finnish Energy in the electricity distribution business is described in the Chapter 3. Also the most relevant information about the outage reporting requirements and regulation methods are covered. As the main aspect of the thesis is in outage reporting, the asset reporting and other reporting requirements are not covered in this thesis. The MicroSCADA Pro products and reporting with the DMS600 are presented in the fourth chapter. The latter part of the Chapter 4 consists of the information flows between the IT systems required for outage reporting. The sources of the information are described and used protocols are mentioned. The ABB systems are used as a basis in this chapter but integrations to other systems and to the distribution process are presented as well.

Chapter 5 contains the information acquired from the interviews. The IT system integration and information flows between each DSO's information systems are described. The reporting processes and the development ideas are presented as well. Chapter 6 covers the implementation of the outage reports. The needs for the implemented reports and outputs of the reports are presented. Chapter 7 gathers the most relevant results of the thesis according to the background information and documents, the customer interviews and the implemented reports. Further needs of development are presented as well. Finally, a conclusion of the thesis is made in the last chapter.

2. OUTAGE MANAGEMENT IN ELECTRICITY DISTRIBUTION SYSTEM

The information for the outage reports origins from the outage management process and the electricity distribution process. Hence the Finnish electricity distribution system along with the distribution automation is covered in this chapter. Also the IT systems used in the NCC, communication technologies used in the electricity distribution and outage management processes are described.

2.1 Electricity distribution system in Finland

The main function of electric distribution system is to transfer and distribute the generated electric power to customers. The transferred power usually originates either from the transmission network or from power plants that are connected to the distribution network. [2] Transmission network does not belong to the distribution system but is an own complex which is connected straight to the distribution system.

The total value of Finnish distribution networks is great. In 2008 the Replacement Value (RV) of the Finnish distribution system was around 12 billion euros. [2] Due to DSOs' massive investments in the distribution network and automation [3], it can be estimated that the RV has most likely increased from those days. The purpose of the investments is to increase the reliability and quality of electricity supply but also efficiency and quality incentives, which are related to the regulation of DSO's operation. The objective is to avoid outages and hence minimize the total costs of electricity distribution. Typically the MV network is built by using overhead lines at rural areas and underground cables at densely populated areas. On 2009 Elenia Oy decided to carry out a strategy which reduces the impact of storms, snow, wind and other weather conditions by underground cabling the new and renovated distribution network completely. This weather-proof network reduces the impact of major disturbances. [3], [4] In addition to conductors, the distribution system includes many other components such as transformers, circuit breakers and disconnectors, which are called as the primary components of distribution system. [2]

2.1.1 Distribution network

Finnish distribution network consists of regional networks (110 kV and 45 kV), medium voltage (MV) substations (110/20 kV, 45/20 kV), MV networks (20 kV), distribution transformers (20/0.4 kV) and low voltage (LV) network (0.4 kV) [2]. In reality, the voltage levels vary from these values depending on the decisions made by DSOs. There are still DSOs in Finland that use 10 kV or even 6 kV voltage levels in their distribution network. For example Turku Energia Sähköverkot Oy (TESV) uses 10 kV MV network in the city area [5]. The Energy Authority defines in its decree for electricity network operation indices that LV network includes 0.4 kV and 1 kV voltage levels. MV network is considered as 1–70 kV network and high voltage (HV) network as a 110 kV network. [6] In the latest Outage statistics instructions (9/2014) of the Finnish Energy (ET, Energiateollisuus ry) the MV and HV networks are defined differently. In ET's instructions MV network is considered to be over 1 kV but under 110 kV and HV network includes networks having at least 110 kV voltage level. [7] Because the definitions of MV and HV networks are not unambiguous, a suitable definition shall be presented for this thesis. In DMS600 reporting the voltage levels are traditionally defined as follows:

- LV network – 1 kV or under
- MV network – Over 1 kV but at most 70 kV
- HV network – Over 70 kV

These definitions are used also in this thesis. They are reasonable as they cover every voltage level that may exist, but are also found to be valid in practice. [8] The consequence for the IT systems that are handling the outages and generating the outage reports is that the initial outage data has to contain the voltage levels for every outage and outage step.

MV network lines beginning from the primary substation are called as feeders. The feeders are protected with circuit breakers but there may exist also overcurrent relays, earth fault relays and reclosing relays. In the overhead line network there is no overcurrent protection for the load current but overcurrent relay is responsible for the short-circuit protection. The MV network is used as a radial network even though parts of it are often designed and built to a meshed form. The LV networks are usually built and used in radial form. Over 90 % of outages experienced by customers occur in the MV network. [2] Therefore it is essential to invest in MV networks and in the distribution automation.

2.1.2 Distribution automation

In addition to the primary components of distribution network there are also secondary components and systems related to the distribution system. These are for example protection relays and other Intelligent Electronic Devices (IEDs), Remote Terminal Units (RTU), voltage measurement and other relays at substations, fault indicators at line sections, Automatic Meter Reading (AMR) devices at customer points, Meter Reading Systems (MRS), Supervisory Control and Data Acquirement -system (SCADA) and Distribution Management System (DMS), which are often located at the NCC. In addition, there are related systems such as Network Information System (NIS), Customer Information System (CIS), Meter Data Management System (MDMS), and so on. [2]

All of the secondary components and systems form a wide integrated entity called *Distribution Automation* (DA). Between these components and systems flow great amount of information of the distribution network and its behavior. With these components and systems it is possible to plan, monitor, manage and operate the distribution network, which are the basic functions of DA. [9] The entity of DA enables DSOs to report strictly specified outage reports for the Energy Authority and for the Finnish Energy. The main reasons for using DA are to reduce total costs of the whole distribution operation and to enhance the usability of the distribution network mostly by increasing utilization rate and reliability [9]. According to authors [9] and [2], the DA can be divided to five different levels of automation. As described in the Figure 1, from top to bottom they are utility level, NCC level, substation level, feeder level and customer level.

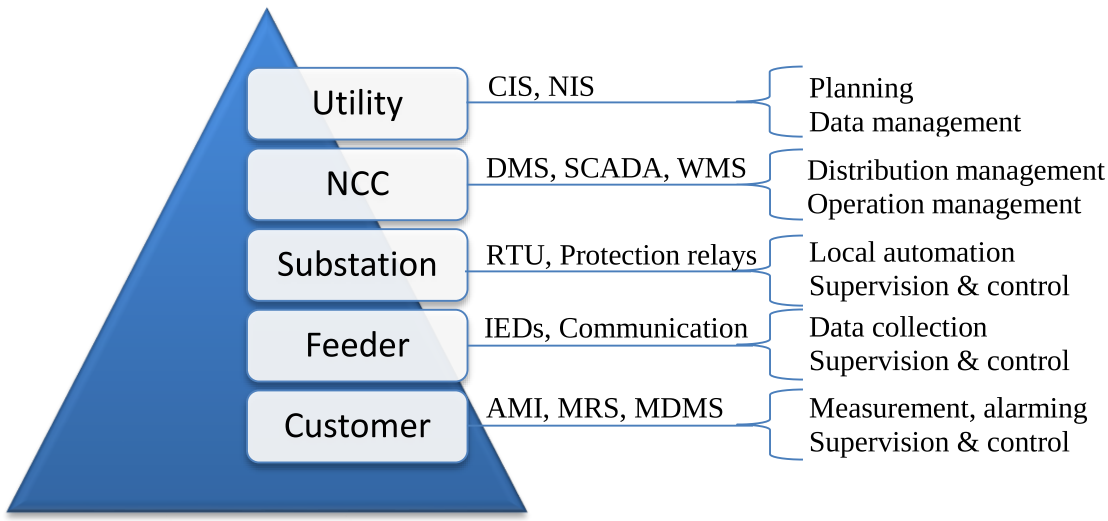


Figure 1. *Hierarchy of the five levels of distribution automation applications (adapted from [9] and [10]).*

Every automation level has different tasks and functions. DA at **utility level** focuses on the utilization of the information and applications provided by different information systems such as NIS, CIS, DMS and SCADA. Vital functions at utility level are e.g. planning of backup connections, switching planning for Maintenance Outages (MO), data transmission between information systems, and managing the databases which include for instance the energy consumption data of individual customers. [2], [11] At **NCC level** DSOs exploit the use of DMS and SCADA systems. These systems enable DSOs to monitor and control the state of the distribution network and manage the outages. During outages operational personnel plan and decide the switching changes from the NCC. Today, as remote controlled disconnectors and other switches have become more prevalent, most of the switching changes are also operated by the personnel in the NCC. [2]

Substation level includes the operation of protection relays along with control of switching components. Also voltage and current measurements and voltage regulation performed by tap changers are usual functions of substation automation. Substations may also have a possibility to use SCADA locally in case it can’t be done from NCC remotely. [2] **Feeder level** automation covers the operation of remote controlled disconnectors and the voltage and current measurements that exist in the network. Also the operation and data transmission of fault indicators belong to feeder level. [2] According to [9], the most important function of feeder automation is to decrease the durations and the extents of outages occurred in the distribution network.

Customer level automation enables DSOs to read customer's energy meter remotely and in real-time. This withdraws the need of on-site reading which was common before the AMR devices. Customer automation has plenty of applicable possibilities in the future and it has already been under drastic change in Finland. According to the regulation issued by Council of State in 2009, at least 80 % of the distribution network's customers shall have an hourly metering equipment that can be remotely read and controlled through a communication network by the end of 2013. [12]. Customer level automation includes also functions for alarmings, tariff control and remote load switching and controlling. The load switching means services provided for customer, e.g. setting heating on to a holiday house by customer's request. The control of load could be e.g. temporary reduction of customer's heating load during peak hours. [2] Figure 2 below describes how the entity of DA is divided to five different levels of automation.

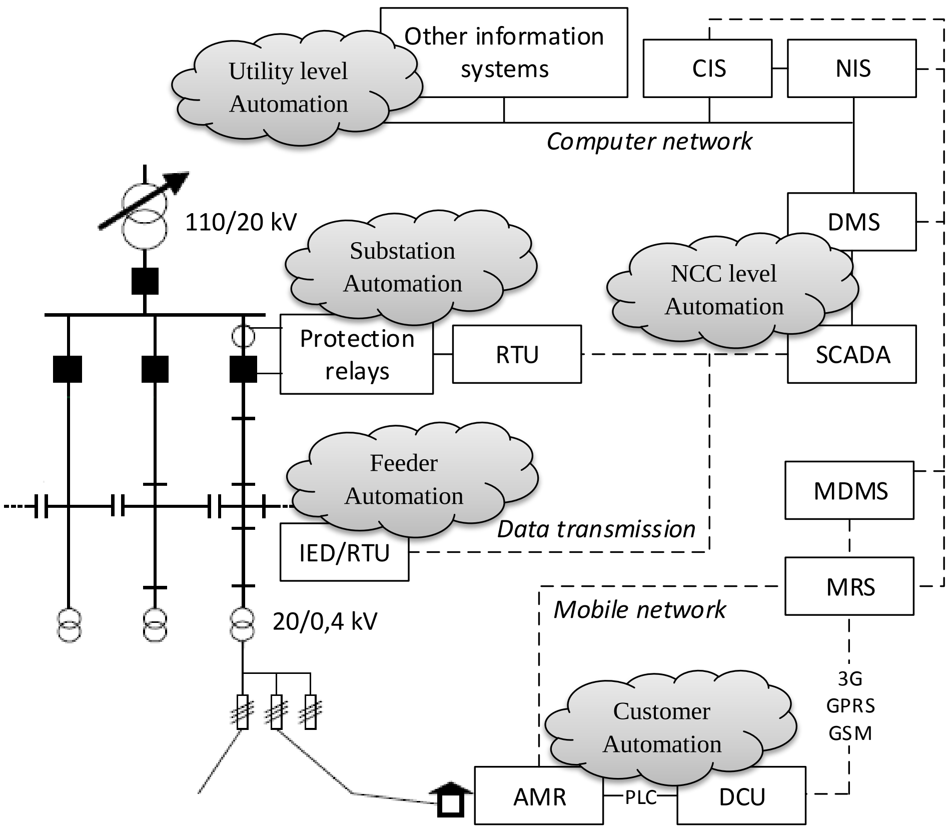


Figure 2. *The interconnection of different levels of distribution automation to the distribution process (adapted from [2] and [11])*

The primary process is presented in the left side of the Figure 2. In the right side are the different automation levels (secondary process) and their connection to the primary process. Wireless data transmissions are marked with dashed lines but some of them could have been implemented also with wired connections. Relay Terminal Unit (RTU) under substation automation and feeder automation discusses with relays and meters and transmits the necessary data to NCC and vice versa. [2] Some devices in the substation may have individual communication buses and therefore don't have to use RTU as a communication gateway [9]. From the view of distribution operation all mentioned distribution automation levels and the communication technologies between them are crucial.

It has to be noted that today strict regulation and reporting requirements by authority affect to the operation in all of the DA levels. The amount of data transmitted from the distribution network to NCC and hence to other appropriate stakeholders has increased greatly during last years. The main concentration of this thesis is on NCC level of distribution automation but reaches also other levels as customer, feeder and substation levels are the sources of the outage and customer data needed for outage reporting, which in turn is done at the NCC and utility levels.

Figure 3 below presents how the distribution process acts as a source of the data, which is first gathered from the process by different measurement devices. After the initial measurement the data is converted to a consistent or even standard format. Next the data is filtered and the irrelevant part of it is left out of notice. The raw data is also processed, with e.g. informative calculations, categorization, sorting methods or by combining larger amount of data. This is actually the process point when the *data* transforms into *information*. Usually the transformation happens at the latest when arriving to the Network Control Center (NCC) of Distribution System Operator (DSO).

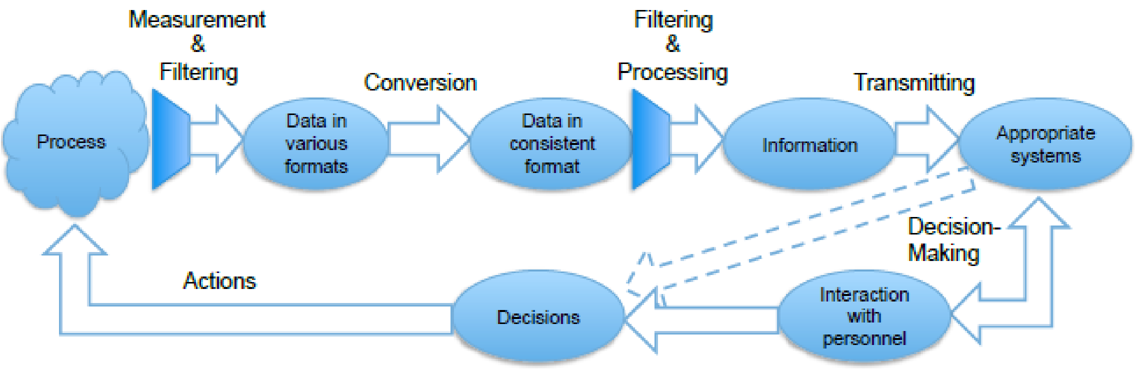


Figure 3. *The process flow from the distribution process to the IT systems in the NCC and backwards [10].*

Everything that travels through a Human-Machine Interface (HMI) are considered as *information flows* as well. The main focus of this thesis is actually more on the *information flows* than on the *data flows*. It is important to understand the origins of the information, and thus the distribution process communication is explained. As the *data* is transformed into *information* and the appropriate systems are able to represent the information in more informative forms, the decision-making in the NCC becomes definitely easier. These decisions then have an impact back on the distribution process, and so on.

2.2 Network Control Center

The Network Control Center (NCC) can be considered as the brains of the distribution system operation. Without the NCC and its information systems it would be very hard to supervise and manage the distribution network. From the operational point of view the most important functions of DSOs are managed from the NCCs. The significance of NCC in the DSO's operation increases during major disturbances. To the consequences of the major disturbances can be affected most with a well-organized, enough automatized and practiced NCC operation. Yet the importance of NCC cannot be understated in the normal situations of network management as it is the place where the whole distribution network is operated. Figure 4 presents a common look of modern NCC. As can be seen from the figure, different means of communication and information systems are used.

Figure 4. *A common look of modern Network Control Center [13].*

From distribution network management and operation point of view, in addition to CIS, perhaps the most critical information systems used by DSOs are SCADA, DMS and NIS. All of these systems are provided by ABB in its product portfolio [14]. The ABB MicroSCADA Pro product is covered more specifically in chapter 4, but the common basics of the mentioned information systems, such as the main functions and roles in the distribution system operation, are covered in the next three subchapters.

2.2.1 Supervisory Control and Data Acquisition –system

The word SCADA is an abbreviation of Supervisory Control and Data Acquisition, and it is an information system widely used in industrial and other applications. For DSOs it is a very crucial part of the distribution network control and operation. It is an information system between the distribution primary process and the DMS, and is usually used in the NCC. SCADA system is connected to the most critical parts of primary process in real time, traditionally via RTUs that are located in the network [9]. According to [2], SCADA's most important task is to supervise the distribution network in real-time. Hence, the main functions of SCADA in electricity distribution business are:

- Event data management
- Management of network switching state
- Remote controlling, configuration and measuring
- Reporting

Due to event data management it is possible to receive real-time information of network events such as operation of protection relays, switching changes related to protection relays' operations, switching state changes and operations of tap-changers. Management of network switching state allows operators to monitor the current switching state of the distribution network, whereas remote controlling enables the operators to control the disconnectors and circuit breakers remotely from the NCC. Also controlling of customer loads is possible via customer automation. Remote measuring includes the measurement of transformer temperatures, busbar voltages and the load currents of MV feeders but also the configuration values and fault currents of protection relays can be received from network. The configuration of these protection relays can be done from NCC remotely. [2] All of the gathered data is stored in the databases of SCADA system [9].

SCADA provides critical functions for the operation of distribution system, so it is important to be in action in any case, also when everything else is without power. The reliability can be increased with Uninterruptible Power Supply (UPS) devices and Hot Stand-By (HSB) systems. [2] The HSB is useful when the hot SCADA server is not functioning properly and UPS can be used during power outages. For further information of SCADA system, the basics of ABB's MicroSCADA Pro SYS600 are presented in chapter 4.1.

2.2.2 Distribution Management System

Distribution Management System, DMS, is an information system that supports the SCADA and NIS by various means. These are related to maintenance of the switching state, management of the network topology, outage management, network operations planning, reporting and statistics. Even though DMS supports SCADA and NIS, it has to use the information provided by these and other systems. [9] The DMS is very important part of NCC operator's daily work. In terms of IT systems DMS is located between SCADA and NIS, but there are also plenty of other information systems and services that are interfacing with DMS: Work Management System (WMS), MRS, Customer Service Management System and several notification services, for instance.

Whereas SCADA just gathers and transmits all the relevant information of distribution process and provides the possibility to control the network, DMS is more intelligent information system. SCADA does not include any complicated calculations and analysis or advanced processing of the data but DMS is able to manage all of that. DMS can for example locate faults, support the operator in fault isolation, manage the network topology, monitor the switching state, analyze the real-time load flow calculation, report faults, show and control the location of work groups in the network, and much more. [2]

The outage management and outage reporting functions in ABB MicroSCADA Pro product are included in chapter 4.2 and its subchapters. That chapter contains also some general information about MicroSCADA Pro DMS600 Workstation.

2.2.3 Network Information System

The Network Information System, NIS, presents the geographical relation of the network and provides the geographical model also for the DMS. It supports the operating functions of DSO. E.g. short-circuit calculations can be carried out in NIS already at the planning phase. This advises the DSO to plan the network reasonably so that also the management of fault situations is considered. In addition to functions related to network calculation, NIS includes also databases having technical information of primary substations, MV network, secondary substations and LV networks all the way to the customers. [9]

According to [9], the main functions of NIS are planning and maintenance of the network. Also the network information management and network calculations are considered as the main functions of NIS. The calculations may include e.g. calculating the maximum powers and currents, power and energy losses, potential drops and rises and fault currents. The calculations are done separately to different parts of network, and also the functioning of relay protection can be checked. [15]

In principle the NIS is not the most crucial information system when discussing of the outage management and reporting but it is a crucial part of system integrations since SCADA, DMS and NIS are co-operating so closely together and NIS provides plenty of data for DMS; even for outage reporting. Moreover, the NIS receives the customers and their energy data from CIS and saves the customer information in its database. The DMS then uses this annual energy data and other customer information when managing e.g. the outage information and producing the outage reports. It is important that the integration of NIS with the other IT systems is simple and doesn’t cause any unnecessary problems during the operation. One solution for the integration problems would be to purchase as many information systems as possible from the same manufacturer, but currently in Finland only ABB provides all the SCADA, DMS and NIS systems. The fundamentals of ABB MicroSCADA Pro DMS600 Network Editor are presented in chapter 4.3.

2.2.4 DMS, NIS and SCADA systems in Finland

ABB MicroSCADA Pro consists of DMS600 and SYS600. The DMS and NIS belong under product DMS600 and the SCADA lies under SYS600. In other words, ABB provides all three mentioned IT systems. Earlier the SCADA system was the only mandatory tool used by NCC operators. In recent years the use of SCADA and DMS has been somewhat overlapping as the significance of using DMS in distribution system operation has increased. This has led us to a situation where maintaining two systems with similar functions might not be economically nor technically reasonable in all cases. An alternative solution would be to combine these systems into one wider and more advanced IT system.

Siemens has already combined SCADA and DMS systems into Spectrum Power Advanced Distribution Management System (ADMS) [16]. Also Schneider Electric has their own ADMS, having merged SCADA, OMS, DMS and EMS features into one comprehensive solution. [17] However, as will be presented in the chapters 5.2 and 7.1.3., combining of these systems is not always considered reasonable. Another solution would be leaving the SCADA in the background and let the DMS take care of the User Interface (UI) alone. ABB in turn will combine the SCADA and DMS systems first into one common UI and later into one common information system. The combined UI of SYS600 and DMS600 systems is called as *MicroSCADA Pro WebUI*. More information of the WebUI can be found e.g. from the M.Sc. Thesis of Manninen published in 2014. [18]

The latest comprehensive research on the DSOs' IT systems is published in 2005 by Tampere University of Technology (TUT) and Lappeenranta University of Technology (LUT) [19]. The research report is an extension of the M.Sc. Thesis (2004) of Toivonen [20]. Even though the research is over 10 years old and is not fully correct today, the guidelines and the most commonly used IT systems are mainly the same today, although the product names may have been changed. Table 1 below presents some of the common DMS, NIS and SCADA systems in Finland divided by the system provider.

Table 1. *Common DMS, NIS and SCADA systems in Finland.*

Provider	SCADA	DMS	NIS
ABB Oy	MicroSCADA Pro SYS600	MicroSCADA Pro DMS600 (WS)	MicroSCADA Pro DMS600 (NE)
Trimble Solutions Oy	-	Trimble DMS	Trimble NIS
Siemens Oy	SINAUT Spectrum	Spectrum Power DMS	-
Tieto Oyj	-	-	PowerGrid
Netcontrol Oy	Netcon 3000	-	-
Schneider Electric	ADMS	ADMS	-

The Spectrum SCADA is used in UNIX-environment. One of the interviewed DSOs uses Spectrum. MicroSCADA Pro product family works in Microsoft (MS) Windows operating system, as well as Trimble products, Siemens Spectrum Power DMS and Tieto PowerGrid (PG) [8], [11]. Those DSOs that are using ABB's or Trimble's NIS systems have usually purchased the DMS system from the same provider [11]. Tieto doesn't have a

DMS system so the DSOs using Tieto PG NIS have had to purchase the DMS system from another provider [8], [11]. MicroSCADA Pro is compatible with Tieto PG NIS [8].

2.3 Communication in distribution automation

The DA requires a lot of continuous communication between the primary process and the NCC. Many things affect to the decision of communication solution, as different communication technologies are suitable for different types of needs. Some of the data flows are time-critical, meaning that the communication should be fast enough. Other common requirements are related to capacity, reliability and cost-efficiency. [2] Also the distance between the communicating units is in crucial part as the substations in the city area are often connected by wired solutions and the furthermost components are usually used by wireless communication. All of the requirements affect to the choice of suitable communication technology. [9], [21] Traditional communication technologies used by DSOs are:

- Optical fiber (increasing) and Cable connection (copper, decreasing)
- Microwave link connection
- Radio telephone network and Packet radio network
- Mobile network (GSM/GPRS, today also 3G and 4G)
- PLC (Power-Line Communication) or DLC (Distribution Line Carrier)
- Landline telephone network (decreasing)
- Satellite network (rarely, backup connection)

Optical fiber is used in the backbone networks between substation and NCC – especially when substation is close by, e.g. in the city areas. The amount of copper connections is decreasing. Also Microwave link connections are used mostly between substation and NCC. [9] PLC or DLC technology has been used traditionally in control of street lights and loads but today they are used in two-way communication of AMR-meters [9], [22]. Using PLC technology at customer automation is covered in chapter 2.3.4. Radio telephone networks can be used to control the disconnectors as the capacity, reliability, cost-efficiency and the speed of the network are sufficient for it [2]. The Packet radio network is based on a radio network constructed of several inexpensive and low-powered radios. The operating time is a few seconds. The basic structure of Packet radio network is presented in Figure 5. When a message is sent from the central station (MS in the figure), all of the disconnector stations within the 30 km distance can receive the message. In this case stations A1 and B1 can receive the message and pass the message forward. The message sent by B1 can be received by B3, which then operates as the message has ordered and sends a receipt of the operation back towards the central station. [2]

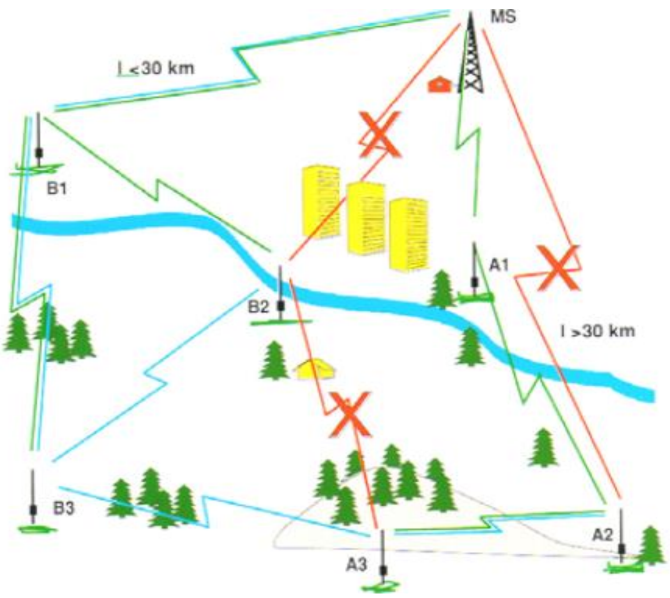


Figure 5. *The basic data communication principle of a packet radio network [2].*

Today one important communication method is mobile network, including the common GSM, GPRS, 3G and 4G technologies. For example Elenia uses 3G/4G network as their primary communication method for remote control of substation automation. A duplicated connection is needed because the connection between NCC and substations is crucial. The secondary backup-connection is organized with satellite-IP network and it is needed when the wireless broadband network is out of use or the substation has a bad network coverage for some reason. The slower GPRS network is used mainly at the feeder level and the customer level is connected via GSM or GPRS. All in all, these and other wireless communication methods are reasonable when the distances between substations and other parts of the distribution network are relatively long. [10], [23]

Today it seems to be a trend that the DSO buys the communication solution as a service from third party, at least for larger DSOs [24]. This decision allows the DSOs to focus on their core functions such as electricity transmission and distribution, leaving the telecommunication companies to take responsibility of used communication solutions [21]. One reason is that when distribution automation extends e.g. to secondary substations, it forces the DSOs to consider alternative solutions because they are not able or don't have resources to reliably maintain the communication solutions [25]. The service providers often sell various service packets. Common solution is for example a turnkey contract where the service provider takes care of the whole communication process. For example Emtele Oy and Helen Sähköverkko Oy have signed in 2014 a long-term service agreement which is based on a turnkey contract. It covers the installation and maintenance of remote control and monitoring devices and functions on the secondary substations. The provided life cycle service includes a wide set of functionalities, such as remote control of switch-disconnectors, fault indications in the MV network, secondary substation condition monitoring and so on. [24] Elenia Oy has a communication service contract with Emtele Oy who is responsible for the functioning of communication network and devices in Elenia distribution network. The Emtele's communications network in Elenia is called as Field-Com. However, a turnkey contract is not the only case as there are multiple other solutions for DSOs to consider. Some of the service options cover only the telecommunication devices and the maintenance and operation of distribution automation communication is done by DSOs themselves. AJECO Oy is another communication service provider having experience on working in the energy business. Their service solution is called DSiP (Distributed Systems intercommunication Protocol), which enables the use of different parallel operators so that it seems like a single communication line. When a fault occurs in the main communication solution, the DSiP changes to the backup connection automatically. Unlike Emtele, AJECO manufactures also the devices used in communication. [25]

2.3.1 Standard communication protocols

One of the most significant standard creating organization in the field of electric power systems is the International Electrotechnical Commission (IEC) [26], [27]. IEC is founded in 1906 and since then it has provided international standards for companies, industries and governments. The IEC is one of the three global sister organizations IEC, ISO and ITU which all develop global standards. [27] Even though the international standards are generally preferred, a lot of industrial standards are still in use today. This chapter presents some of the commonly used communication protocols. First the communication protocols between the IT systems are presented and after that the chapter covers the protocols used in the distribution primary process.

The **Common Information Model (CIM)** is a standard including two IEC-standards, **IEC 61970** and **IEC 61968**. Whilst e.g. the IEC 61850 focuses on controlling of the electricity network, the CIM manages more in the enterprise level. [8] The CIM comprises a mutual information model for data transmission in the distribution business. CIM defines the interface specifications for the different IT systems used by DSOs. Hence the objective of this wide standard is to ease the integration of IT systems with standard interfaces. [11] IEC 61970 defines the object models for data transmission between the electrical energy systems and IEC 61968 defines standards for exchanging information between electricity distribution information systems, such as DMS, MRS and WMS [28], [29].

The information systems have own communication protocols for data transmission. ABB MicroSCADA Pro product uses **OPC** (Ole for Process Control) protocol between SCADA and DMS. A newer technology OPC Unified Architecture (OPC-UA) is based on WebService but it is not yet used with MicroSCADA Pro product. However, WebService technology is used in some of the interfaces of the MicroSCADA Pro. [8] The data transmission in the NCCs is usually implemented with Ethernet network. In these networks the speeds of data transmission can exceed 10 Gb/s. Therefore it is suitable for internal communication of NCC but also for communication between the substations and the NCC. [30] Also **SCIL-API** is used in communication between SCADA and DMS systems in ABB's softwares, but this protocol is relatively old and thus becomes more and more rarely used [8]. **ELCOM-90** (Electricity Utilities Communications) is yet another protocol used in SCADA communication, and **ICCP** (Inter-control Center Communications Protocol) can be used in communication between separate SCADA-systems [31]. The **TCP/IP** (Transmission Control Protocol / Internet Protocol) is the basic communication language of the Internet but it can be used also in private networks. In the TCP/IP protocol every device has its own static IP address. The IP address consists of four numbers separated with dots. Each of them is defined between 0–255. There are also special IP addresses such as 127.0.0.1 (localhost) which refers to the device itself. The TCP/IP based data transmission protocols are used in the communication between the IT systems in the NCC but also between the NCC and the distribution network. [32]

In 1990 the **IEC 60870-5** standard was published and is still updated regularly. It is used widely all over the world. It has replaced and is still replacing some of the manufacturer-specific protocols. Its main advantage is the openness, allowing the DSOs to use different manufacturers' products together. IEC 60870-5 standard has been designed to minimize the transmission bandwidth for point-to-point connections. [28] As the reliability is a major part of distribution business, the changes occur quite slowly. Also the lifespan of the components is usually long. Hence many of the older systems and devices are still going to be used for a while, although there are many advantages awaiting with the new products and standard protocols. [28] The IEC 60870-5-101 **(IEC-101)** and IEC 60870-5-104 **(IEC-104)** protocols are widely used in communication between substations and SCADA system. The IEC-101 standard is defined to be suitable for power system monitoring, control and associated communication in the electric power systems. It is planned to be used in series communication with the SCADA system and processes with long distances. The maximum data transmission speed with IEC-101 is 19200 baud. [25] The application layer of IEC-104 standard is based on the IEC-101, so the IEC-104 is an extension of IEC-101. However, the IEC-104 does not support all of the functions available with the IEC-101 and changes have been made in transport, network, link and physical layers' services with IEC-104. The IEC-104 uses an open TCP/IP interface and the most important advantage is that it enables simultaneous connections between several devices and services via a standard network. [33]

The new object-based **IEC 61850** standards and the standards based on them are probably the most important protocols in the future DA. The IEC 61850 standard is developed for substation automation communication. IEC 61850 standards are based on new Manufacturing Message Specification (MMS) version ISO 9506:2003, which means that the compatibility with other automation fields is enhanced. The 61850 protocols exploit the established standards such as TCP/IP, but it is not suitable for time-critical data transmission. Therefore an own protocol called GOOSE (Generic Object Oriented Substation Event) is developed. GOOSE is able to send event data via IP network simultaneously to multiple predetermined points without handshaking signals and acknowledgements. [28] GOOSE also enables the peer-to-peer communication, so every IED can communicate to each other. The amount of failure sensitive connection cables reduces, which also reduces the costs of DA. The protocol divides data into logical groups, which are further divided into Logical Nodes (LN), of which each is defined to contain different kind of data. Figure 6 presents the IED as a container (physical device). [34]

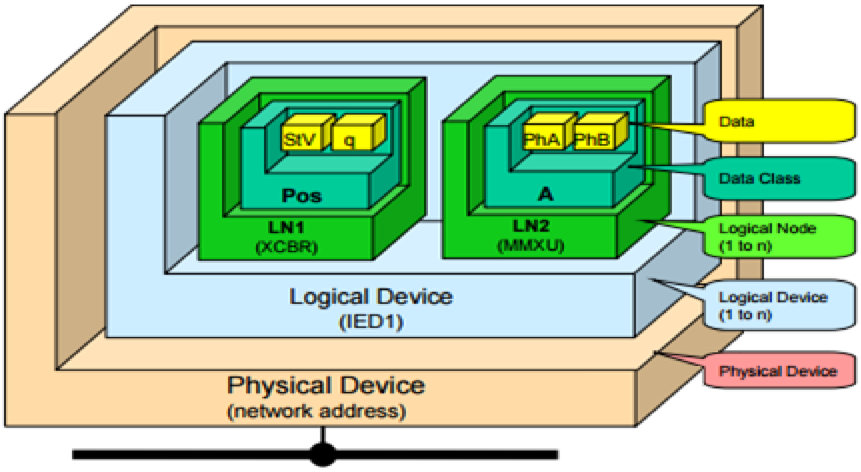


Figure 6. *Illustration of an IED using IEC 61850 protocol's logical groupings [34].*

Control applications of IEC 61850 demand that the control message has to be sent within 4 milliseconds from the actual event. However, IEC 61850 devices can be easily connected to each other with a Local Area Network (LAN), which is fast enough to fulfill this requirement. [34] One objective of IEC 61850 is to transform the future IEDs into easily connectable Flexible Plug and Play (FPP) devices [35]. IEC 61850 emphasizes the need of security more than before, but it also eases the security implementations as the qualified solutions commonly used in TCP/IP networks can be exploited. [28] The security-related questions of distribution automation is further discussed in [28]. Even though plenty of protocols related to substation automation exist worldwide, the IEC 61850 is the first one providing a standardized method for communications and integration. It supports the substation automation systems having multi-vendor IEDs connected together. The applications of IEC 61850 are not restricted only to substation automation, but it can be used with IEDs all over the power network. Unlike other protocols, IEC 61850 includes historical type transfer files that can be brought to the NCC for more specific studying. It also enables offline trending, which lowers the data update rates from a second to milliseconds. [36] All in all, the IEC 61850 devices can be described to be easy for design, specification, configuration, setup and maintenance.

In addition to IEC 61850, also e.g. **IEC 60870-5-103 (IEC-103)**, SPA (Strömberg Protection Acquisition) and LON protocols are used in the substation level of communication. However, SPA and LON are not standard protocols as they are developed by ABB and Echelon Corporation. The IEC-103 standard transmission protocol defines the interoperability requirements between protection equipment and control system devices in a substation [37]. IEC-103 protocol allows to connect several protection relays to one RTU. The IEC-103 allows the connection to be carried out e.g. via optical fiber, and the transmission speed is specified to be maximum of 19200 baud. However, as the IEC-103 protocol includes a possibility for proprietary vendor-specific function extensions, the interoperability between different vendors' devices cannot always be ensured. [38] **SPA** is an old serial Master-Slave protocol for point-to-point communication and is still used in substations. It is developed by ABB and it was designed to be used for distributed protection and control. The transmission speed of SPA is maximum of 9600 baud. [39] **LON** is an abbreviation of Local Operating Network, indicating that it is designed for short-range communication. Usually the LON connected devices don't need to transfer a large amount of data but need fast response times. It is open and peer-to-peer type protocol, allowing the IEDs to communicate with each other (horizontal communication). The network is connected into a star-form and the communication speed is maximum of 1.25 Mbits/s when connected via optical fiber. [40]

While the IEC-60870-5 protocol family was under development, there was a need to develop a standard allowing the communication between different SCADA manufacturers. The universal **DNP 3.0** protocol is developed by General Electric (GE) and it is based on IEC-60870-5. Today DNP 3.0 works with TCP/IP networks. It is one of the most commonly used protocols between IEDs and RTUs but it can be used also in communication between substations and the NCC. The communication is based on Master-Slave principle. [31] **Modbus** is another messaging protocol providing Master-Slave communication between devices. It is an open serial communication protocol developed by Modicon. Each Master device can handle up to 247 Slave devices. Modbus is widely used in industries and it is another common protocol used to connect SCADA with RTUs. Modbus can be used also in communication between IEDs and RTUs. A typical transmission speed of Modbus is 9600 baud. [31], [41]

2.3.2 Primary substation automation communication

A large amount of data is gathered from the primary substations and their feeders to the primary substation's data acquisition terminals. This data is gathered by local automation and it is provided for remote or local SCADA systems. The primary substation automation consists of two levels: lower feeder level and higher substation level. The feeder level includes protection relays and control units for every feeder. In case of faults these units act individually by tripping the circuit breaker automatically and thus isolate the faulted network from other feeders. [9] An IED is a device having communications port for transferring analog status or control data via a proprietary or standard transmission format [26]. Often these microprocessor-based IEDs are equipped also with communication buses and therefore are able to act as data communication gateways for local or remote SCADA systems. They also process the data already in the substation. In these cases the IEDs may construct an own internal but also external communication network and thus replace the functionality of traditional RTU. [9], [21] Traditionally RTU has contained all the necessary interfaces, and it has converted the data to the right form in order to send it to SCADA in NCC. The RTU has usually had several inputs and outputs, and therefore also the amount of data cables in the substations has been fairly high. [21] An example of ABB RTU560 product is presented in Figure 7.

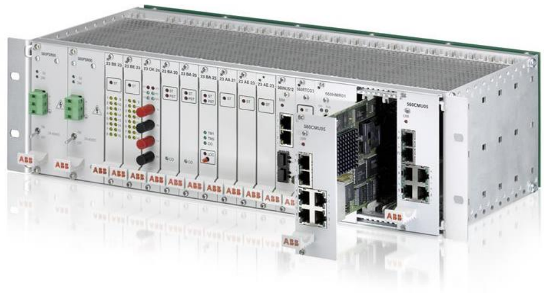


Figure 7. *ABB Remote Terminal Unit RTU560 product image [42].*

All data gathering devices are connected with a mutual communication bus, which transmits the data directly or if necessary via telecommunications unit to SCADA systems. The following important data is provided for the SCADA systems from the protection relays, fault indicators, control units and other IEDs: [9]

- Events with timestamps
- Electrical metering data
- Position indication data from switches (circuit breakers, disconnectors, reclosers)
- Data registered during disruptions
- Settings and parameters of the devices

Accordingly, the local or remote SCADA system can send the following messages to the units: [9]

- Control commands
- Settings and parameters of the devices
- Time synchronization messages

Using a mutual communication bus reduces the amount of data cables and enables a larger scalability of the system. It also simplifies the connection systems at the substations and provides a possibility to monitor the message transmissions. It is possible to monitor the condition of tripping circuits, and the metering data can be received from protection relays. Every device sends event data with timestamp of detections, trippings, start-ups, and so on. [9] Nowadays the time synchronization for the IEDs in the substation can be done also by using GPS system [21]. Also the maximum fault currents, fault counters, voltage and current measurements and reasons for detection or tripping can be included in the messages. Often the devices can calculate the powers, energies and power factors and send them to SCADA. The local SCADA systems used in the substations include the same main functions as the remote SCADA system, but often their software and hardware are stripped-down versions of the system used in NCC. [9]

One modern way to implement the control and protection systems would be to integrate all or almost all of the protection functions to one device. The benefit is that costs would reduce as the amount of protection relays would decrease and also the maintenance would be more inexpensive. Nevertheless, this has not been yet the trend in reality, mainly because these are the most critical parts of the network management and the DSOs don't want to risk the reliability of the distribution network due to relatively small cost savings. The new type of integrated systems may include bugs and flaws that are very hard to notice in the testing phase, which again could cause serious problems. [21]

One major challenge with the digitalized communication systems in primary substation automation have been the lack of international standard protocols. This has led to the fact that DSOs may have been forced to purchase all of the related devices from the same manufacturer in order to ensure the full collaboration of the system. The problem is slowly going to disappear due to completion of standard series IEC 61850, but it has been noticed that the current standards don't yet guarantee the full cooperation of different manufacturers' devices with each other. The reason is that although the features of different devices are specified to be the same, the implementation may have been done differently. [21] Figure 8 represents an example of how primary substation communication could be implemented. This example is using combined IEC 61850 and LON based communication. All of the IEDs using IEC 61850 are connected into common communication bus. The communication gateway handles the communication towards the NCC.

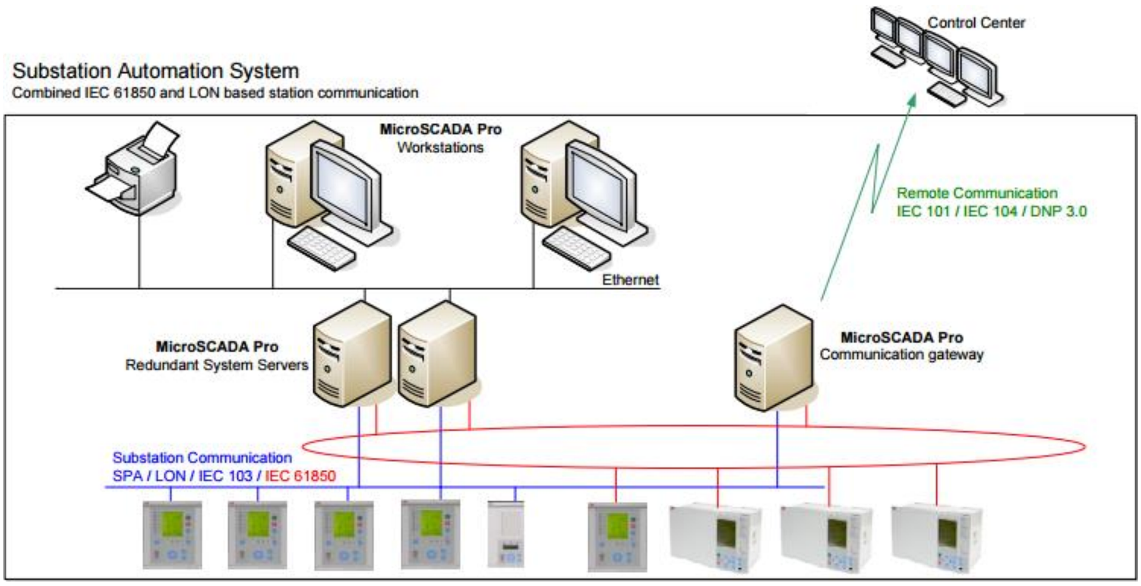


Figure 8. *An example of combined IEC 61850 and LON based primary substation automation communication [43].*

The internal substation communication from the protection equipment can be dealt also with IEC-103 standard. For the external communication of substation automation there are standards IEC-101 and IEC-104, which list the collaboration requirements for the communication. [37] As can be seen from Figure 8, the IEC-101 and IEC-104 protocols are used in communication between the substation's communication gateway and SCADA in the NCC. [21] More information of the standard communication protocols is provided in chapter 2.3.1. The most commonly used telecommunication technologies between SCADA and substations are covered in chapter 2.3.

2.3.3 Feeder and secondary substation automation communication

Feeder automation has been in use already a long time. Feeder automation consists of the functions and communication of different IEDs along the feeders in the distribution network. E.g. fault indicators, disconnectors, circuit breakers, reclosers and measurement devices are used along the feeders. [44] The communication from these devices is usually implemented with wireless solutions because the distances are usually long to the NCC and between the devices as well. In some cases concentrator units are used in communication. This concentrator gathers the transmitted data of several nearby devices and sends the data further into the NCC, and backwards. Radio network can be used in feeder automation communication but today also 3G is becoming more common. Another used communication solutions are e.g. RS232, Ethernet, GSM and GPRS. Used protocols are e.g. IEC-104, IEC-101, DNP 3.0 and Modbus but also other protocols may be used. Feeder automation communication is a relevant part of outage management as the fault is often isolated with the help of remote-controlled disconnectors and the fault can be located with fault indicators. [44]

The feeder automation usually ends to the secondary substations. Secondary substation automation is part of DA, but traditionally it has not been used widely. Secondary substations are also known as MV/LV transformer substations. The secondary substation automation locates between the feeder automation and customer automation, and it provides several advantages related to fault indicating and locating, but also in monitoring the voltage quality. Although it is not used widely yet, a recent trend is that some DSOs have considered to use secondary substation automation in order to collect more accurate measurements of network voltages and currents and to enhance the precision of fault location. The purpose is not to replace the traditional automation with these new functionalities but to support the existing primary substation automation and other DA. [23]

In the future the amount of Distributed Energy Resources (DER) and Distributed Generation (DG) connected in the network will increase. This will increase the need of secondary substation automation as the distribution system will become more complex. At some point these resources are combined with electric vehicle charging, electricity micro production and smart load control (demand response). [23] This complex entity is known as Smart Grids, which will require new devices, automation and solutions to monitor and manage two-way power flows, control the loads smartly and protect the network and people reliably regardless of the challenges coming with the new DG units. As the main impacts of Smart Grid concept hit near the customer points, the secondary substation automation and AMI are very crucial parts of the future distribution process.

However, already today there are needs for secondary substation automation. Elenia Oy has considered using the secondary substation automation at least for fault indication and measurement purposes. Strict regulation enforces some DSOs to extensive cabling, which increases the need for secondary substation automation because the faults are harder to be located in cabled networks. The M.Sc. Thesis of Kauppi (2014) covers this subject. Thesis presents automation functionalities that may be useful in the secondary substations. [23] These functionalities and their descriptions are presented in the Table 2 below.

Table 2. *Useful functionalities of secondary substation automation (adapted from [23]).*

Functionality	Description
Fault indication, 20 kV	Short-circuit, earth fault, directions, distances
Phase fault indication, 20/0.4 kV	Indication of voltage asymmetries and phase faults
Indication of blown LV fuses	E.g. indicator for blown fuses at LV side
Disturbance data registering	Remotely readable
Remote setting and configuration	Remote control and configuration, mass updating
Temperature measurements	Transformer and transformer substation temperatures
Fire indication and alarming	E.g. smoke indicator
Access/visiting monitoring	Door sensor, burglar alarm
Recognizing of graffiti paintings	Motion sensor, spray sensor, web-camera
Electricity quality information, 20/0.4 kV	Voltage levels, currents, harmonics, voltage dips, etc.
Control of air hatches and fans	Control based on temperatures
Condition monitoring of batteries	Indication for battery replacement needs
Automatic fault zone isolation	-

The communication solution is a major part of designing the secondary substation automation. In order to read the measurement and switching state datas, fault indications, disturbance recordings and alarms remotely, the communication network has to be reliable. Communication inside the secondary substation from sensors to the communication gateway can be implemented with wired but also with wireless solutions. Wired solutions are more laborious to implement as retrofit installations as there may not be enough space for additional wires and the routes and holes have to be made separately. Hence the secondary substation automation should be taken into account already in planning and manufacturing phase of transformer substations. [23]

Netcontrol's NMS100 hosts an RTU controller and it uses a back-up battery if the supplied power is disrupted. The NMS100 is able to use DNP 3.0, IEC-101 and IEC-104 protocols to connect the device directly into SCADA system. Another solution is Netcon

100 which includes also monitoring of LV and MV networks, fault indication, etc. These parts of the product are implemented with separate modules. [45] ABB provides RTU devices for secondary substation automation, and the basic RTUs usually need separate devices (IEDs) to act as sensors and fault indicators. One example is the RTU540 series. [46] The communication between the secondary substation and SCADA may be arranged with GPRS or 3G/4G communication technology [23], similarly as with primary substation automation. The communication inside the secondary substation from IEDs to RTU can be arranged e.g. with Modbus or IEC-61850 protocol [8].

2.3.4 Advanced Metering Infrastructure

An Advanced Metering Infrastructure (AMI) has become familiar via Smart Grids concept and it basically covers the outage management in customer level of DA. An AMI consists of a combination of components and systems, including the communication and information management. This entirety provides information to appropriate stakeholders such as DSOs. Usually the AMI involves an Automatic Meter Reading (AMR) device at household of an individual customer. This intelligent device communicates through a communication network and transmits the information to the MRS. [47] Used communication network can be a combination of different telecommunication systems, such as PLC and GPRS, 3G or optical fiber. [48], [49] The communication can be implemented also straight from the AMR meter to MRS via mobile network [10]. Traditionally the DSOs haven't had AMI functionalities but only remote energy metering features.

The capacity of PLC technology is sufficient for broader applications if the LV network is used only as a data transfer bus and there is a Data Concentrator Unit (DCU) which can pass the data forwards using other communication method [2]. With PLC technology multiple AMR devices are connected to a DCU which is located usually at MV/LV substation. DCU gathers data from AMR devices through PLC technology at certain specified intervals or when requested, and sends them forward to a MRS. The data can be delivered also for MDMS. 3G, GSM, GPRS and optical fiber are used in communication between DCU and MRS. MRS just collects the data DCUs have gathered and stored, and finally MRS transmits the data to MDMS for further data storing, management and processing purposes. Sometimes the whole meter reading infrastructure with AMR meters and communication is called as MRS [10]. At MDMS point the *data* provided by AMR is transformed into processed *information*. MDMS can be used as an own application or it can be connected to the NIS or CIS providing the information in processed, filtered and categorized form. In case of real-time alarmings, measurements and outage recordings the MRS is connected to DMS. [49] The MDMS is taking the responsibility of energy data management from CIS, as CIS is not necessarily capable of handling such large amounts of data the hourly-basis energy measurement would require. [10] Figure 9 represents a basic structure of PLC and 3G/GPRS connected AMI system.

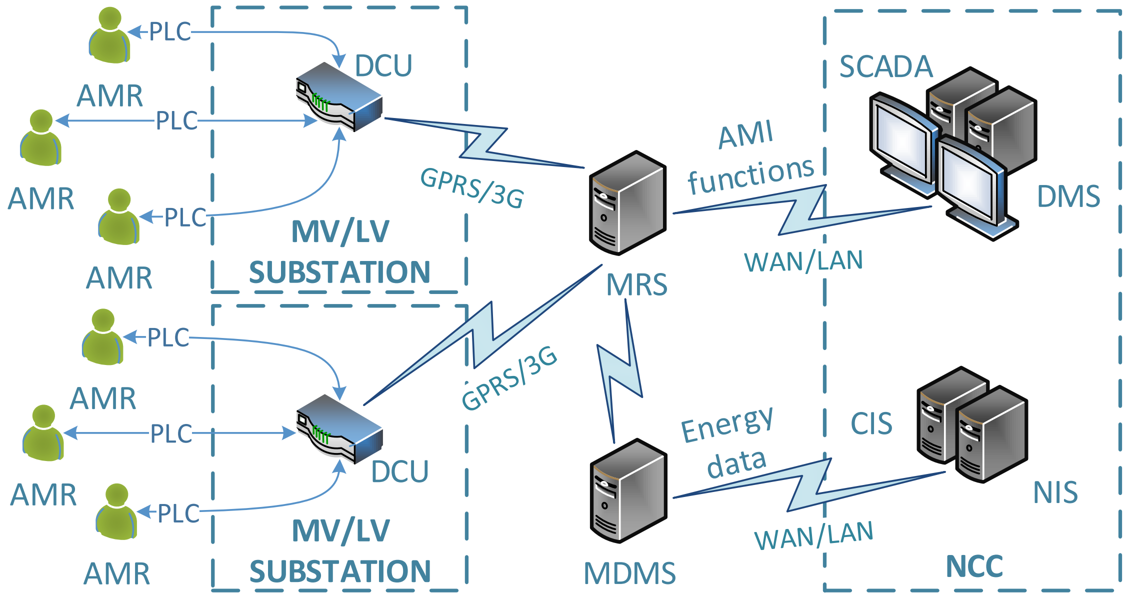


Figure 9. *Simplified network diagram of PLC and 3G/GPRS connected AMI.*

For example Turku Energia Sähköverkot Oy (TESV) transfers the data from AMR meters to DCUs via PLC connection by using DLMS-protocol (Device Language Message Specification). The powers and other allowed values for the signal are specified precisely in the SFS-EN 50065-1 standard. Some of the AMR meters include a GPRS-module which is able to transfer the data straight to the MRS. In some cases also Radio Frequency (RF) Mesh technology is used. [50] As described, communication between AMR device and MRS can be carried out with various technologies. In rural areas it is often implemented with GSM/GPRS or 3G connections because they cover over 99 % of consumer points in Finland [51]. At densely populated areas PLC is the most common communication solution having lower costs than GSM/GPRS and 3G with high meter densities. [52] Wireless technologies at densely populated areas could jam the communication network if great quantity of AMR devices sent messages at same time [53].

Traditionally the electricity meter has been read locally from the meter; hence this new remotely managed system reduces the total costs of meter reading. However, today this is not the only application of AMI as there are plenty of new applications that are already in use or will be implemented by using these intelligent devices. Actually, electricity is not even the only energy form that is controlled via AMI as also the use of water and gas can be measured and controlled. [47] Most typical DA functions of AMI are: [2]

- hourly energy measurement
- voltage quality measurement and recording
- **outage recording (short and long outages)**
- **alarming (unsupplied customer, specific algorithms)**
- **disconnecting and reconnecting of service**
- load control

Although every function may be crucial for DSO's operation, the three bolded functions are the most important ones for this thesis. Hence they are covered in the next paragraphs. An advanced AMR device is able to record all outages, which enables DSOs to produce precise customer-specific outage statistics and reports. This recorded information can be exploited also in customer service and in standard compensation procedure [2]. Customer service can be improved because there are more data available of starting time and length of the fault. Additionally, the DSO is able to see how far the outage area reaches and thus is able to evaluate the extent and duration of fault for customers. Customers can be informed of LV faults automatically via SMS messages which facilitates the work of customer service as the customers don't have to call to the customer service. [54]

It is possible to integrate several alarming settings to the AMR device. The device is able to notify DSOs for example if the customer is unsupplied. However, it's not wise to notify of every outage because in that case a MV fault would cause every AMR device to alarm, which could jam the telecommunications network. Hence the alarming functions are suitable mainly for LV faults, but with specific algorithms the AMR device is able to inform the DSO also of MV conductor's phase failure which cannot be recognized by MV-level protection. Also the 2-phase fault indication is based on specific algorithms which monitor the voltage asymmetries. [2] However, this is not a major problem as most of the MV faults are registered with substation and feeder automation as well. An AMR device is suitable also for indicating the 1-phase and 2-phase fuse blows and notifying of a broken neutral conductor, which is dangerous for the consumer [2]. An important function of AMR meters is the verification of restoration at individual customer point. This enables the DSO to check whether the customer really has supply restored after the interruption, and the DSO is not enforced to blindly trust on the situation in the MV network. [22] With AMI the LV outage reporting becomes more precise. Traditionally the starting times and ending times of LV faults are based on customer contacts and since have always been estimations. Also the reporting work becomes more fluent with AMI, as not all of the information has to be added manually. The support for fault management and reporting is important especially during major disturbances. [55] In case of problems in individual customer's network, it can be disconnected from and reconnected to the network [56].

2.4 Outage management process

Electricity supply interruption is an unwanted situation where customer is unsupplied from the distribution network. Usually power outage is a consequence of a HV, MV or LV network fault but can occur also due to planned maintenance works in distribution network. The reason of power outage rarely origins from HV network as it is usually better protected from storms, snow, wind and other difficult weather conditions which often cause faults to MV network. In addition, HV network is usually used in loop, thus a single fault does not necessarily cause an outage. Up to 90 % of faults in MV network are short-term temporary faults which are cleared by rapid and delayed autoreclosings

[57]. Rapid autoreclosing (RAR), alternatively high speed automatic reclosing (HSAR), lasts typically for 0.2–0.4 seconds. Delayed autoreclosing (DAR) lasts for 30–120 seconds depending on relay settings [58], [21].

Standard SFS-EN 50160: "Voltage characteristics of electricity supplied by public distribution systems" gives the acceptable limits and the criteria for voltages, mostly concentrating on the power quality. Hence it defines also the characteristics of power outage; an interruption is considered as a situation where the magnitude of voltage is less than 1 % of the nominal at customer's connection point. [59], [60] According to the Finnish Energy, the power outages are divided into two main groups: unanticipated outages and planned outages. Planned outages usually occur due to predetermined maintenance works in the distribution network or due to distribution restrictions made by authority. With planned outages, customers have been informed in advance and the outages are controlled. If a planned outage is not informed to the appropriate customers early enough, it is considered as an unanticipated outage. As presented in Figure 10, unanticipated outages are categorized again into short and long outages. Unanticipated outage may be a consequence of momentary or sustained fault in the distribution network. Outage is considered to be a sustained interruption if it remains over three minutes, and is thus categorized as a long outage. Correspondingly, a momentary interruption is considered as a short outage if the duration is less than three minutes. They mainly consist of autoreclosings. [7]

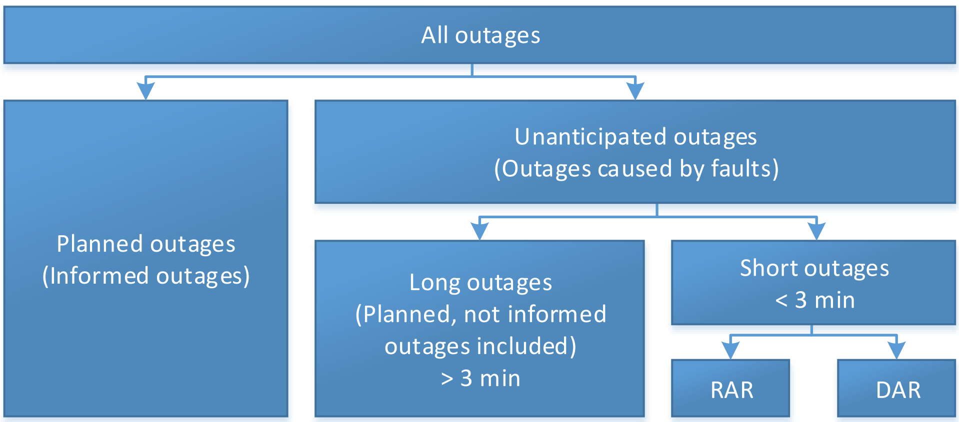


Figure 10. *Outage categorization (adapted from [7]).*

It is crucial for DSOs to manage the outage situations well in order to minimize the duration and extent of the outage and thus reduce the outage costs, but it is also essential to invest in prevention and avoiding of outages. *Internet of Things* (IoT) is a new philosophy which is an alternative for both managing the communications for outage management and other distribution automation but also preventing the outages from happening. In short, the IoT can be defined as *"a global infrastructure for the information society, enabling advanced services by interconnecting (physical and virtual) things based on existing and evolving interoperable information and communication technologies"* [61]. However, the "*things*" are not the only ones connected to each other via Internet, which is one reason why ABB uses a modified term of IoT as follows: *"Internet of Things,* *Services and People – IoTSP"* [62]. One example of IoT reducing the outages in the distribution network is that every IED senses the environment but measures also itself and is able to send a service call to the manufacturer when necessary, and the sent message includes information of the spare parts and equipment needed for the maintenance work.

There are already some advanced services in use that could be ranked among the IoT philosophy. For example *Elenia Mukana* mobile application allows (among other functions) customers to check if their connection point is supplied or not. The service performs daily connection tests to the advanced AMR meter and shows the state of the latest contact. The connection may fail for multiple reasons: the supply is disconnected from the main switch, the communication link is having a failure or there is a power failure in the distribution network. The customer can also perform his/her own inquiries towards the AMR meter to see the current situation. However, this is only one example, and integrating the IoT philosophy with the electricity distribution is such a wide topic that it could provide work for one or more master's theses.

The most common types of outage management scenarios are based on the following interruption situations: MV network faults, LV network faults and Maintenance Outages. These scenarios are described within the next subchapters in order to clarify the basis of outage management process in distribution network and NCC. These scenarios together with the whole outage management process provide important data for DSO, which is then capable of responding to the outage reporting requirements and develop its operation with help of internal reporting. As will be stated in the later part of the thesis, customer notification is very important part of outage management process but it is not described more specifically in the following chapters as they will concentrate on the interruption management itself.

2.4.1 MV Fault

Medium voltage faults are the unanticipated outages occurred at the MV network side of distribution network. As described in chapter 2.1.1, the MV network includes the networks having more than 1 kV but at most 70 kV voltage levels, usually being around 21 kV or 45 kV. Traditionally MV faults have been detected automatically and the fault location is calculated using fault current. Today also customers are able to notify for MV faults and threatening situations. For example *Elenia Mukana* mobile phone application allows the user to fill a form of a situation that threatens the distribution network, and take a picture e.g. of a tree which is fallen on the transmission line and send it to the DSO. The application also saves the coordinates of the place where the picture is taken and therefore provides crucial geographical information for the DSO as the fault location is known exactly. [63] This service enables DSO to take anticipatory measures to prevent the possible upcoming MV network faults as well. Using the philosophy of IoT (or IoTSP) is a potential solution for proactively reducing and preventing the network faults in the future, as described in chapter 2.4.

When a fault occurs in MV network, the affected protection relay acts immediately and circuit breaker trips. Usually circuit breaker is located at the primary substation but sometimes also along the feeder. The operating times and fault current limits of relay protection should be configured so that the correct circuit breaker trips and the selectivity criteria will be fulfilled. This will minimize the network included in the fault zone. Next, the auto reclosing operations are launched to remove the momentary faults from the network, such as a branch fallen at a transmission line. NCC receives information of the fault immediately after the switch has operated and RTU has sent the changes of switching states to SCADA. SCADA transmits a fault package to DMS which then creates a fault into the system if the auto reclosings did not remove the fault and the circuit breaker remains open. DMS is able to manage the fault situation semi-automatically, and shows the relevant information of the faults to the NCC operative personnel, operators.

The more specific description of using DMS in outage management and outage reporting is covered in chapters 4.2.1 and 4.2.2. Nevertheless, when the operators have dealt with the fault and the fault isolation is done, the work crew can locate the faulted components from the network and start repairing them. In some cases the fault zone can be reduced even more at this point. When repairing the underground cabled network, the repairing is usually much slower as the fault location may not be exactly clear. Even if the fault is precisely located, the underground cable has to be dug up from the ground in order to repair it, and it often takes a lot of time. [23] However, the fault frequency with underground cables is much lower than with overhead lines. The fault ends when all of the customers are supplied again. After the fault is repaired and supply is restored to all customers related to the fault, a report is created for internal and external reporting purposes.

2.4.2 LV Fault

Low voltage faults are the unanticipated outages occurred at the LV network side of distribution network. As described in chapter 2.1.1, the LV network includes the networks having at most 1 kV voltage levels, usually being 0.4 kV or 1 kV. Traditionally the LV faults haven’t been detected automatically by DSOs, and it has required the customer to notify the DSO that he does not have power or that he is experiencing a strange behavior of LV network. Therefore LV faults were cleared with a simple fuse protection where the fuse is blown due to increased current in fault situation of LV network. NCC did not receive any information about the occasion automatically. [55] Neither was the automatic detection of broken neutral conductor in use until the AMI with advanced AMR meters became common.

An example of traditionally managed LV fault could proceed somewhat like the following description. At the beginning of the process, the LV network’s three phases are short-circuited for some reason. Because the fuse has blown in the secondary substation, the customer notices that he doesn’t have supply and thereby contacts the DSO. The DSO doesn’t necessarily know where exactly the fault is located but tries to find it out. Field crew is sent to the LV network in order to locate and repair the fault. The field crew doesn't know what kind of problem is awaiting, and can't therefore choose for example appropriate tools and equipment in advance. After the fault is located and repaired, the supply can be returned to the LV network by the work crew, as remote controlling was traditionally not often possible.

Today the automatic detection of LV faults can be carried out with advanced AMR meters, as they are able to monitor the LV network and provide spontaneous event or alarm information to NCC without separate inquiries towards the AMR meters. [55] However, the spontaneous alarming is not in use everywhere because it has been noticed that it loads the communication network a lot, as the amount of unnecessary alarms can be quite high. Therefore in some cases the DSOs use currently manual or scheduled inquiries to check if everything is in order at the customers' connection points. When acting correctly, also the spontaneous alarming should be possible. Anyway, it depends extensively on communication solutions, as mentioned in chapter 2.3.4.

The advanced AMR meters can separate the fault types automatically and inform NCC about them immediately. If a neutral conductor is broken, the AMR meter may automatically isolate the customer from the network in order to avoid life-threatening situations. By combining the received event data from AMR meters and the topological network model, the DMS may be able to find the original reason for the fault and even locate the faulted component. This eases and quickens the management of LV network outages as the faults with reasons can be presented in NCC almost in real time. Of course it facilitates the work of the field crew too, because they can see the same information from their mobile applications. [55]

2.4.3 Maintenance outage

The third scenario for outage management is due to the Maintenance Outages (MOs). The MOs can be planned to both the LV and MV side of the distribution network. The MOs are outages that are always informed in advance to the related customers, before the maintenance operation has been started. The informing can be done via SMS messages, E-mail and by letter, for instance. Unlike in the MV and LV faults, with MOs the switching plans and the duration of the work is known in advance. As the name *Maintenance Outage* indicates, the MOs are usually needed in order to maintain the condition of the distribution network. If the work cannot be done with supplied network, the supply is interrupted and outage is necessary. [64] The reasons for MOs are e.g. extending the network, switching components such as transformers to new ones, repairing decayed wooden poles in the network, etc.

If the DSO has forgot informing the customer or if it is not done early enough, the outage cannot be considered statistically as a MO but as a normal unanticipated outage. This may happen e.g. due to an urgent need for MO or human mistake. Also malfunctioning of IT systems, such as the SMS sender application of DMS could cause these problems. The consequences would be at least unsatisfied customers and increase in the DSO's outage costs. The outage costs are increased at least via customer outage cost calculations needed for regulation purposes, as the €/kW and €/kWh KAH-calculation unit prices are higher for normal outages than for maintenance outages. The regulatory outage cost calculation is explained more specifically in chapter 3.3.2. Sometimes a major disturbance or other reasons cause that the maintenance outage has to be rescheduled for later period. In that case the customers have to be informed again of changed schedule. Usually this has no further consequences for the DSO costs.

The outage management process for maintenance outage starts when the DSO notices a need for change or maintenance work in the network. For example the network planner could decide that an old transformer shall be renovated. This work cannot be done when the transformer is supplied, i.e. interruption is necessary if there is no reserve power. When the work scheduling is done, the switching planner is able to create the switching plans for the MO. The switching plans include controlling of remote-controlled disconnectors but also manually controlled disconnectors which are managed by the work crew in the field. The switching plan is planned so that as few customers as possible will have an interruption. In the MV network the supply can often be brought from the other side of the network with simple switching operations, which means that sometimes e.g. maintenance operation for 1 km of 20 kV line does not cause any interruptions to the customers. In addition to switching plan's disconnector operations also manual locking and marking of disconnectors has to be done. This prevents the possible accidental remotely or manually controlled operations of these disconnectors. After the network is unsupplied, it has to be ensured that there exist no voltage, and the unsupplied network has to be grounded from both sides of the work site. The switching plan is then tested in advance, to confirm that the voltage levels elsewhere in the network stay between acceptable limits and the protection is sufficient even after the switching changes.

The work crews in the field can see from the WMS that a certain maintenance outage is in progress, but cannot necessarily see which phase of it is in operation. Thus, a frequent communication between the NCC and the work crew is important for safety and efficiency reasons. The supervisor of the work executes the switching plans and guides the work crew to execute necessary operations to manually controlled switches. The supervisor also informs the work crew when the supply is disconnected and it is safe to start the securing and initialization works in the field. The work crew informs the NCC when the work is done and the supply can be returned. Often the switching operations can be done in reverse order to supply the network again. The MO ends when the supply is returned to all customers, and the affected customers shall be also informed about the return of supply. With reserve power or backup supply some of the maintenances can be done without causing an interruption for any customers [64].

3. ELECTRICITY DISTRIBUTION REGULATION AND OUTAGE REPORTING IN FINLAND

Some kind of reporting has always existed in the electricity distribution operation. However, the early reporting may have been in a completely different form and extent than today, and it hasn't been required for external purposes. Nonetheless, most of the DSOs have considered the internal reporting purposes to be so important that they have organized automatized reporting functions for their own benefit. Today the situation is different and compulsory outage reporting has increased. In Finland the electricity market has been liberated since 1995, and as the distribution business is a natural monopoly, the DSOs don't have local competitors. Therefore the business has to be supervised and regulated by the authority. The basis of the regulation and outage reporting is defined in the Electricity Market Act. This chapter explains how the regulation related to outage reporting is organized and what outage reporting is needed for the Energy Authority and for the Finnish Energy (ET).

Development of the internal outage reporting gives new tools to the DSOs for observing the amounts, durations, causes and locations of the outages. Diverse reporting functions can be exploited e.g. when considering the development needs of the network. It is important that every outage is stored and reported properly and customer-specifically. This enables the DSOs to provide the compulsory reports for the Finnish Authority, but also observe the outages related to specific customers if the customers request the information.

3.1 Electricity market act

It can be stated that the Finnish electricity market act is the basis for all operation related to the electricity distribution. It provides the most fundamental rules and regulation for the business, regulation and outage reporting requirements. The electricity market act is enacted by the Finnish government and it includes definite and less definite statutes, which are then applied to practice by the Finnish Energy Authority. Also the Finnish Energy follows the changes in the law and even tries to act proactively in its outage reporting requirements. These organizations and their role in the Finnish regulation and outage reporting requirements are covered in the following chapters.

The new electiricty market act came into effect in 1.9.2013. It was enacted mainly because of the long major disturbances the Finnish distribution business has experienced during recent years. The new law obligates the DSOs for several new responsibilities compared to earlier law enactment. The following subchapters cover two of those related to outage reporting.

3.1.1 Interruptions caused by storm and snow load

The new Electricity Market Act requires the DSOs to plan the network so that there will be no outages for single customer caused by storm or snow load which have durations of more than 6 hours in the town plan area and 36 hours in the other area respectively. An exception are customers which are located in islands without a bridge or other fixed connection or without regularly operating ferry traffic connection. Another exception are those customer points that have had maximum annual electricity consumption of 2500 kWh during three previous calendar years and meeting the defined requirements would cause exceptionally great investment costs due to a remote location from other customer points. [65]

The Electricity Market Act defines that these requirements must be fulfilled by the end of year 2028. All households and holiday houses belong under this definition. The requirements come into effect step by step, since in the end of 2019 at least 50 % of the customers excluding holiday houses must fulfill the requirements and in the end of 2023 at least 75 % of the customers excluding holiday houses have to be covered by the requirements. The purpose is to reduce the outages and outage durations caused by major weather events which have been relatively common during the recent years. The Energy Authority acts as a supervisor and requires updates every second year to the DSOs' development plans, where the DSOs define actions leading to fulfillment of the requirements. The need for development plans is originally prescribed in the Electricity Market Act. [65]

3.1.2 Standard compensation for continuous interruption

The electricity market act defines standard compensations for customers in situations where interruption times exceed 12 hours. The DSO has to deliver these compensations for customers automatically, without separate requests. The compensations have to be taken into effect if the DSO is not able to prove that the interruption was caused by an obstacle beyond its possibilities of influence. [65]

The amounts of the standard compensations are based on the annual system service fee of the customer. The compensation levels defined in the law are listed below in percents of the annual service fee: [65]

- 10 %: the interruption time has been at least 12 hours, but less than 24 hours
- 25 %: the interruption time has been at least 24 hours, but less than 72 hours
- 50 %: the interruption time has been at least 72 hours, but less than 120 hours
- 100 %: the interruption time has been at least 120 hours, but less than 192 hours
- 150 %: the interruption time has been at least 192 hours, but less than 288 hours
- 200 %: the interruption time has been at least 288 hours

The maximum amount of standard compensation is increased in the new Electricity Market Act and it is currently 200 % of the annual service fee or 2000 euros [65]. Earlier the compensation amounts had been limited into maximum of 700 euros and 100 % of the annual service fee [66]. If the standard compensation of continuous interruption has been paid to the consumer, he is not eligible for other price reductions from the same interruption [65].

3.2 The Energy Authority and the Finnish Energy

The Energy Authority is an expert authority organization, which belongs under the Ministry of Trade and Industry. In the electrical engineering field its main functions are to supervise and advance the operation of electric markets and to create premises for the emissions trading system. In the distribution business the Energy Authority takes care of the authoritative tasks related to the Electricity Market Act, including one important mission to supervise and control the pricing of the transmission of electrical energy. [2]

The Energy Authority is responsible for the distribution business regulation. It requires the Finnish DSOs to annually report data of their network and operation, which enables the Energy Authority's supervisory and regulatory functions. [67] A wide amount of the reported data is related to other functions than outage reporting but in this thesis the focus is on outage reporting, hence other parts are left out of the thesis.

The Finnish Energy is an organization related to industrial and labour market policy. It has a wide set of functions in the electricity field and almost all of the Finnish DSOs are members of it. [2], [68] Also ET requires reporting from the DSOs but it is not directly related to the regulation of distribution business. Although the reporting for ET is not compulsory for the DSOs, a great share of the Finnish DSOs are willing to deliver the reports for ET. On the contrary, ET is an organization that represents the DSOs and therefore delivers and shares information and provides education. [68] The outage reporting requirements needed for ET are more advanced and complex than for the Energy Authority and they are explained in chapter 3.5.2.

3.3 Regulation

In 30th November 2015 the Energy Authority published the new regulative supervisory methods for the next two regulation periods. The fourth period will stand during years 2016–2019 and the fifth period during years 2020–2023. [67] In this thesis only those parts of the regulation are studied which are related to the outage reporting.

The regulation has continued already over three regulatory periods and since the beginning the objectives of regulation have developed along the time. The basic idea has however remained through the regulatory periods, and the main objectives of the current regulatory period are to control the reasonable pricing and allowed revenue of the DSOs. [69], [67]

3.3.1 Quality incentive and efficiency incentive

The Energy Authority's regulation affects to the need for outage reporting by two different incentives: *quality incentive* and *efficiency incentive*. In the fourth regulatory period the objective of quality incentive is to encourage the DSOs to develop the quality of electricity transfer and distribution. At least the reliability level defined in the Electricity Market Act shall be achieved but one target of Energy Authority is to guide the DSOs to enhance the quality of electricity transfer and distribution spontaneously towards better reliability levels than the minimum level. [67]

The major change is that the customer outage cost (KAH) values are from now on taken into account entirely, compared to earlier regulative periods where only half of the outage costs affected into the allowed revenue of DSO. This increases the importance of distribution reliability development in the future. When calculating the allowed revenue, the quality incentive is taken into account by comparing the realized outage costs to the reference level. The actual KAH value is subtracted from the reference KAH value and the resulting value has an influence on the allowed profit of the DSO. However, the latest regulation methods for the fourth and the fifth regulation period define floor and ceiling levels (limits) for the quality incentive. Hence if the remainder of the actual and reference KAH values exceeds a certain value, the exceeding part will not be taken into consider when calculating the DSO's realised adjusted profit. By definition, the bonus or sanction of the quality incentive in the realized adjusted profit shall not be more than 15 % of the reasonable return for the year in question. [67]

The objective of the efficiency incentive is to encourage the DSO for more cost-effective operation. According to this incentive the DSO operation is cost-effective when the operational inputs (costs) are small enough compared to the operational outputs. This incentive is interesting because it has the regulatory customer outage costs (KAH) as one of its output variables. The outage costs in this incentive take into account the costs caused by outages and the costs caused by avoiding the outages. According to Energy Authority these outage costs are only a by-product but not an ordinary output variable, and they are modelled as an undesirable output variable. [67]

The data gathered for the calculation of these incentives is defined in the Energy Authority's regulation decree on the key figures of electricity network operations and their publication. These incentives have an impact on the allowed revenue of the DSOs according to the regulation model. A more comprehensive summary of the used regulation methods in the fourth and fifth regulatory periods can be observed in the Appendix B [67].

3.3.2 Customer outage cost

Customer outage costs (KAH) are calculated in order to define the amount of bonus in the quality incentive and the efficiency incentive of the DSO. Hence the KAH values eventually determine the allowed profit of the DSO as well. Correspondingly, the allowed profit defines how much the DSO may charge for the electricity transmission. [67] This means that the customer outage cost calculations indeed convert into DSOs' money via the authoritative regulation methods [70]. Unlike previously, onwards 2016 the full KAH values are taken into account in the regulation [67].

The calculated customer outage costs are the actual KAH value and the reference KAH (KAH_{ref}) value. The KAH_{ref} calculation is based on an average value of two previous regulatory periods (8 years). Thus in the fourth regulatory period the reference value shall be calculated from the years 2008–2015. When calculating the KAH_{ref}, the effects of major disturbances are not ignored in the calculation even though the impact of the quality incentive in the allowed profit calculation has been made reasonable in the previous regulatory periods as well. This will compensate the costs caused by major disturbances to the DSOs. [67]

The KAH calculation takes into account the customer outage cost unit prices, energy transmitted to the customers, consumer price index and different outage periods. The unit prices needed for KAH calculation are presented in the Table 3. The outage unit prices are defined in the value of year 2005, but it is taken into consider with consumer price indexes. [67]

Table 3. *The unit prices for the customer outage cost calculation (adapted from [67]).*

Unexpected outage		Planned outage		Delayed autoreclosing	Rapid autoreclosing
$\boldsymbol{h_{E,unexp}}$	$h_{W,unexp}$	$h_{E,plann}$	$h_{W,plann}$	h_{AJK}	h_{PJK}
€ / kWh	€ / kW	€ / kWh	€ / kW	€ / kW	€ / kW
11.0	1.1	6.8	0.5	1.1	0.55

The KAH_{ref} value is weighted with the customer energies in order to get the KAH_{ref} and the actual KAH comparable in terms of transmitted energy. In the fourth regulatory period the KAH_{ref} and KAH values are calculated for the MV and HV networks. The KAH_{ref} and actual, realized KAH value calculations are presented in the Appendix G.

3.4 Reliability indices

The Institute of Electrical and Electronics Engineers (IEEE) defines globally approved indices in its guide for electric power distribution reliability indices. The indices are based on IEEE 1366-2012 standard which is a revision of earlier IEEE 1366-2003 standard. The guide document divides the indices into sustained interruption indices, load based indices and other (momentary) indices. The document also presents the main idea of Major Event Day (MED) classification, which is used to identify certain days having major events for statistical and other studying purposes. The MED days are identified with SAIDI but all indices for the MED days should be calculated. [71] The most commonly used reliability indices in Finland are presented below with equations.

SAIFI (System Average Interruption Frequency Index) indicates how often the average customer experiences a sustained interruption during a predefined time period. Use of SAIFI by the DSOs is usually related to the prevention of faults in certain areas [72]. The SAIFI can be calculated using the equation (3.1) presented below: [71]

$$SAIFI = \frac{\sum N_i}{N_T} = \frac{CI}{N_T}, \tag{3.1}$$

where

N_i	Number of interrupted customers for each sustained interruption event during the reporting period
N_T	Total number of customers served for the area
CI	Total number of customers interrupted

SAIDI (System Average Interruption Duration Index) indicates the total duration of interruption for the average customer during a predefined time period. It is used to identify the MEDs but DSOs can use SAIDI to inspection and reduction of fault amounts and durations as well. SAIDI can be calculated with equation (3.2) [71]

$$SAIDI = \frac{\sum r_i N_i}{N_T} = \frac{CMI}{N_T}, \tag{3.2}$$

where

r_i	Number of interrupted customers for each sustained interruption event during the reporting period
CMI	Customer minutes of interruption

CAIDI (Customer Average Interruption Duration Index) indicates the average time required to restore the supply. The DSOs may use CAIDI to observe and reduce the impacts of the faults but not the fault amounts. CAIDI can be calculated from SAIDI and SAIFI with equation (3.3): [71], [7]

$$CAIDI = \frac{CMI}{CI} = \frac{SAIDI}{SAIFI}. \tag{3.3}$$

MAIFI (Momentary Average Interruption Frequency Index) indicates the average frequency of momentary interruptions. MAIFI is basically the same as SAIFI but is used for momentary interruptions and it is strictly related to the amount of autoreclosings in the network. MAIFI can be calculated with equation (3.4): [71]

$$MAIFI = \frac{\sum IM_i \, N_{mi}}{N_T}, \tag{3.4}$$

where

IM_i	Number of momentary interruptions
N_{mi}	Number of interrupted customers for each momentary interruption event during the reporting period

The smaller the calculated indices in the equations (3.1)–(3.4) are, the more reliable the distribution operation is. The authority does not require DSOs to report the IEEE's standard reliability indices but ET mentions these in its outage statistics instructions. These may be beneficial for the DSOs to calculate for the internal use as well, as stated in the chapter 3.5.3. The reporting service provided by ABB includes these indices in its reports.

3.5 Outage reporting requirements

The reporting has taken a more important role in DSO's operation due to the strict regulation of the authority [67]. Thus it has a heavy impact on the economic side of the DSOs as well. The outage reporting requirements changed again when the fourth regulatory period came into effect. Also the Finnish Energy has earlier (in 2009) gathered outage reporting information only from the LV and MV side of the distribution network but the current requirements (since 2015) are broader as the outage reports are gathered customer point-specifically regardless of the voltage levels. [73], [7] The Figure 11 presents how the Electricity Market Act, Energy Authority and the Finnish Energy are linked together. This representation compresses the main points of chapter 3 into single figure.

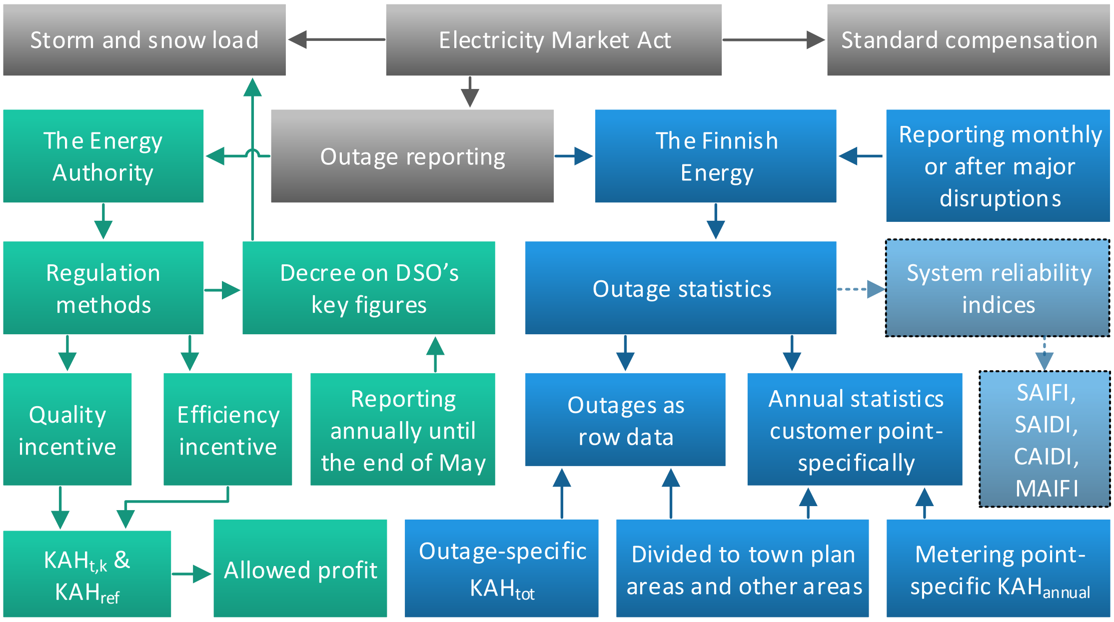


Figure 11. *A general summary of outage reporting for the Energy Authority and the Finnish Energy in Finland.*

This figure acts as a general summary of outage reporting in Finland. It can be noticed how the Electricity Market Act (gray) is a base for all of the reporting and regulation. As can be seen, the Energy Authority (green) takes care of the DSOs' regulation and requires the DSOs to report certain outage (and other) information which then affects to the allowed profit of the DSO. The Finnish Energy (blue) has non-mandatory requirements in the outage reporting. As described in the figure, it requires the outages to be reported as row data but also outages customer point-specifically. The system reliability indices are marked with dashed lines because they are not actually requested by the Finish Energy but are still mentioned in the instructions for outage statistics and they are commonly used in DSOs' internal reporting.

Those parts of the Figure 11 which aren't described yet will be covered during the next subchapters. The outage reporting requirements are divided into three classes: requirements from the Energy Authority, requirements from the Finnish Energy and the reporting for DSO's internal purposes. The requirements are described in the next subchapters.

3.5.1 Requirements from the Energy Authority

According to Energy Authority's latest regulation decree on the key figures of electricity network operations and their publication, published in 30th November 2015, the outage reporting should take into consider only those outages, which have caused an interruption to electricity supply to one or more customers in any voltage level. This decree came into effect in 1st January 2016. The required information consists of financial key figures, network structure and asset reporting, but also the technical electricity distribution quality key figures. [74] The technical key figures are more interesting in this thesis. The decree came into effect the 1st January 2016. The financial key figures and network asset reporting can be further studied e.g. from the Master of Science thesis of Kinnunen (2014) and from the website and documents of the Energy Authority [75], [76].

The key figures describing the quality of electricity distribution operation divide the outages depending on the cause of the outage. The outage reporting requirements include all LV, MV and HV levels but in addition there is a separate part for indices describing the impacts on customers. Definitions for the voltage levels can be found in chapter 2.1.1. The key figures don’t take into account those outages which are requested by a customer and are not causing any outages to other customers. The Energy Authority requires DSOs to report outage statistics annually. [74]

The outage reporting of HV network consists of those outages which have been caused by an interruption occurred in the HV network. The HV network reporting includes the annual number of interruptions, the average annual number of interruptions in the HV network connection points, the average annual duration of interruptions in the HV network and the electricity not transmitted in the HV network. More specific requirements are listed in the Appendix C, where the required key figures describing the quality of electricity distribution operation are translated into English. [74] As can be studied from the Appendix C, the outage reporting of MV network includes all unanticipated and planned outages including rapid and delayed autoreclosings. The DSOs have to report also average outage durations and amounts. Because some of the reported indices are weighted by customers’ annual energies, the energy data is needed in these reporting requirements as well as in the regulatory outage cost calculations. The LV network outage indices are mainly the same as with MV network but the LV network indices exclude the rapid and delayed autoreclosings.

The equations needed for calculating the required outage indices are listed in the Appendix D. The Appendix D originates from the Energy Authority’s decree on key figures and certain parts of it are translated to English in this thesis [74]. The HV network outage indices can be calculated with equations presented in chapters 1.1 and 1.2 of the Appendix D. Correspondingly, the MV and LV network outage indices can be calculated with equations presented in chapters 1.3 and 1.4 of the Appendix D. These equations have been changed from the previous regulatory period and the calculations regarding the HV and LV networks are almost entirely new. Hence the reports related to these outage indices have to be updated to meet the new requirements from the Energy Authority.

Unlike previous requirements, the latest decree requires the DSOs to report directly the amounts of customer points which don’t fulfill the level of security of supply defined in the article 51§ of Electricity Market Act [65], [74]. These requirements are presented along with the indices describing the impacts of interruptions on customers. The requirements can be studied from the section (3.19) of Appendix C where this part of the decree is translated. The DSOs deliver the required reports usually via an online-based regulatory data system provided by the Energy Authority. The required information has to be provided for the Energy Authority annually until the end of May. [74]

3.5.2 Requirements from the Finnish Energy

Requirements from the Finnish Energy have changed from the beginning of year 2015. Since then ET has required the metering point-specific outage reporting compared to previous substation level reporting. It means that every customer who experiences an outage has to be saved into the database with the corresponding outage data. Onwards 2015 the outages in every voltage level is monitored metering point-specifically. ET justifies the relevance of this requirement so that because the DSOs have to serve their customers as well as possible, also the monitoring of the outage statistics has to be customer-oriented and comprehensive. The effects of outages on customers are the same regardless of the origin of the outage. The reason and duration of the outage must be possible to tell to the customer in all cases. In the new reports the reliability requirement classes are also divided into the Town plan area and Not town plan area. According to ET, the history data has to be stored and saved at least from the previous regulatory period. [7]

The objective is that the IT systems are capable of creating the necessary reports automatically and comparably in all situations. All voltage levels with their KAH values have to be taken into account in the new outage statistics model. ET's another objective is that their and Energy Authority's reports shall be harmonized. The ET's instructions for outage statistics mention that there might be coming changes in legislation related to the outage report clarifications for the customers. More specifically the Energy Market Act may obligate the DSOs to clarify the outages for the customers in the future. This would support the harmonization need. The new instructions try to take into account also those needs of authority which are under modification. Therefore the ET's metering point-specific reports will take these prospective changes in the legislation into account. [7]

The ET would like the reports to be compiled every month or at least after major disturbances. This would allow the DSOs to exploit the reports in customer communication, and thus the reports are in use also when compiling the national outage statistics. [7] The national outage statistics are gathered already over several decades [77]. The monthly reports for ET are beneficial for the DSOs also because it allows them to notice and check suspiciously extent, long or otherwise incorrect outage reports early enough. It is easier to notice these problems from the monthly reports than from the great amount of annual reports because the recent events are better in mind and there are less events to observe. Today there is a tool in the DMS600 which enables the user to search and manage the duplicated outage reports straight from the DMS program [8]. However, a common practice for reporting is that the reports for the ET are compiled only once a year, at the latest before the end of March [8].

The ET's frames and definitions for the distribution network are presented in the Appendix H. The figure in the Appendix H is based on the ET's instructions for outage statistics and it is translated into English. It explains the voltage levels, the locations of fault and the different alternatives of network types needed for the outage reports of ET. The required information of the faults are presented in the Appendix I. It can be seen from the Appendix I that what information has to be reported for which voltage level. This figure also defines some events out of the scope of the outage reporting; for example the location of the fault doesn't have to be reported in case of autoreclosings. These two figures also present all of the fault information codes needed for outage reporting for the ET, for example location *A1 Substation* or fault type *VT1 Short circuit*, and so on.

In the **Outage row report** each outage is presented with a single row. The outages are numbered starting from number 1. The Outage row report includes all voltage levels and information about the interruption type, reason of interruption, fault location and fault type, as they are presented in the Appendix I. The reported indices in the Outage row report are Kpe, Kpk and Kph but also the outage-specific customer outage cost KAH_{tot} is calculated according to the equation (3.5). Moreover, the report includes the following information presented and defined in the Table 4. [7]

Table 4. *Definitions for the information required in the outage row report.*

Reported information	Definition
DSO code	DSO code defined by the Energy Authority
Outage No	Consecutive numbering separating the outage events from each other
Voltage level	HV, MV and LV
Interruption type	Interruption type (as presented in the Appendix I)
Reason of interruption	Reason of interruption (Appendix I)
Fault location	Location of the fault in the distribution network (Appendix I)
Fault type	The type of fault in the interruption (Appendix I)
Started	Starting time of the outage event separated into different columns [aaaa] [mm] [dd] [h] [min] [s]
Ended	Ending time of the outage event separated into different columns [aaaa] [mm] [dd] [h] [min] [s]
Duration	Total duration of the outage in hours [h], with at least three decimals, for example 20 min = 0,333 h
$\boldsymbol{Kpe}$	Total annual energy of metering points affected by interruption [MWh]
$\boldsymbol{Kpk}$	Total number of metering points affected by interruption [pcs]
$\boldsymbol{Kph}$	Total interruption time of metering points [h], with at least three decimals
$\boldsymbol{KAH_{tot}}$	KAH_{tot} is calculated according to equation (3.5)
Town plan area	Metering point is located in the town plan area
Not town plan area	Metering point is located outside the town plan area

The outage-specific customer outage cost KAH_{tot} needed for the Outage row report is calculated in the DMS system and it is based on the common load curve types or actual load curves achieved from the hourly-basis metering. Moreover, the KAH_{tot} exploits the estimation of annual energy consumptions and the information of hourly-basis powers in the network. Calculation of the outage-specific customer outage cost KAH_{tot} can be executed with equation (3.5):

$$KAH_{tot} = \sum_{i=1}^{a} \left[ka_{kp}(i) \cdot h_E + h_W\right] P_{kp}(i) \cdot \left(\frac{KHI_{k-1}}{KHI_{2004}}\right), \tag{3.5}$$

where

a	Number of metering points that experienced interruption [pcs]
$ka_{kp}(i)$	Outage duration for metering point i [h]
h_E	Unit price of disadvantage for the outage period in the value of year 2005 [€/kWh]
h_W	Unit price of disadvantage for the outage amount in the value of year 2005 [€/kW]
$P_{kp}(i)$	Disconnected power of the metering point i in the starting time of the interruption [kW]
KHI_{k-1}	Consumer price index in year $k - 1$ (average of indexes in the
KHI_{2004}	Consumer price index in year 2004

The **Metering point-specific outage report** includes all interruptions experienced by metering points [7]. Therefore the DMS must have correct up to date switching states in the LV networks in order to get the proper metering points to the outage reports [8]. A single row in this report consists of all outages the metering point has experienced during the year. The reported information are the metering point's code, reliability requirement classes (town plan area / not town plan area) according to the Electricity Market Act (588/2013) and annual energies. The actual outage data is filled in the customer network's or own network's columns depending on where the fault has occurred. The reported indices are Ask (total number of customers affected by interruption) and Ash (total interruption time of customer) but also the metering point-specific $KAH_{annual} \approx KAH_{t,k}$ is calculated. The Ask value is required for all untanticipated outages in the feeding customer HV or MV network, unanticipated outages and planned interruptions in own HV, MV and LV network and for autoreclosings (RARs and DARs) as well. Of these mentioned cases Ash is not required in case of autoreclosings and the metering point-specific KAH_{annual} is not required in outages which are caused by the feeding customer HV or MV network. The definitions for the information required by the Metering point-specific outage report are listed in the following Table 5.

Table 5. *Definitions for the information required in the Metering point-specific outage report.*

Reported information	Definition
DSO code	DSO code defined by the Energy Authority
Metering point number	Metering point-specific identifier [number]
Reliability requirement class	According to the reliability requirement classes defined in the Electricity Market Act (588/2013)
Annual energy	Annual energy of the metering point [kWh]
$\boldsymbol{Ask}$	Total number of customers affected by interruption
$\boldsymbol{Ash}$	Total interruption time of customer
HV, MV, LV	Voltage level where the fault occurred
$\boldsymbol{KAH_{annual}}$	Calculation of the KAH_{annual} is explained below

The metering point-specific KAH_{annual} calculation can be done almost in the same way as in the Energy Authority's $KAH_{t,k}$ which is defined in the equation (2) of Appendix G but the consumer price indexes differ a little bit due to changes in the years. When the $KAH_{t,k}$ uses indexes KHI_k and KHI_{2005}, the KAH_{annual} uses analogously indexes KHI_{k-1} and KHI_{2004}, similarly as they are presented in the equation (3.5). In the third regulatory period these two KAH values were exactly the same but this slight change has been made for the fourth and fifth periods.

During the **major disturbances** compiling the statistics according to these mentioned requirements is not always possible due to the large amount of work in a short time period, switchings that are performed almost at the same time, exceptional supplying conditions and the mistakes caused by human error. In order to manage through these situations the DSOs are allowed to combine interruptions into one event to simplify the documentation work and the compilation of statistics without letting it to influence on the customer hours or amounts. The outages occurred in the LV network have to be reported separately. [7]

3.5.3 Internal reporting

In addition to reporting for Energy Authority and ET, there is a third function for reporting: the DSO's internal reporting. Some kind of internal reporting has always existed, regardless of whether there have been external reporting requirements or not. Usually the DSOs have used internal reporting in some measure but in early days the operation hasn't necessarily been determining and the reporting methods may have been rather primitive but still effective. One example is using pins to mark the exact fault locations in the map. This helps the DSO to focus the maintenance and renovating work in the correct places.

The objective of internal reporting is to compose an overall picture of the current form of the company's different functionalities. The reporting may include information related to the financial but also technical and functional aspects. A broader perspective of internal reporting usually tries to answer to the following questions: [78]

1. How have we managed?
2. Why have we managed like this?
3. Where are we going to?

The internal reporting is intended for the company's own use and benefit. The DSOs' internal outage reports are mainly technical information and often the purpose is to exploit the achieved information in the consideration of development needs or network planning. Other purposes are to organize and prioritize the maintenance works and hence reduce the outage amounts and durations which are causing costs for the DSOs. Calculating and observing the reliability indices presented in chapter 3.4 is one way of implementing the internal reporting. Using these standard indices is a common and efficient way because they enable the DSOs to develop their own operation and planning. However, there are DSOs of different size and type, of which everyone has its own needs and its own ways to act. Thus the needs for internal outage reports differ depending on the DSO.

Usually the internal reports are intended to support the decision making of the management staff. Also operating personnel have needs for internal reporting in order to control and develop the DSO's daily operation as well as possible. As for the network development unit, it would be crucial to get the reported outages based on the interruption locations, e.g. divided by the feeders. The construction and maintenance unit may benefit from the same location-based outage reporting but also visual representation of the outage reports may be considered as useful. [79]

4. INFORMATION FLOWS IN THE NETWORK CONTROL CENTER WITH ABB MICROSCADA PRO

The MicroSCADA Pro product portfolio consists of the following products: SYS600C, SYS600 and DMS600. The SYS600C is a compact computer with preinstalled MicroSCADA Pro SYS600 system and it manages the real-time process information. The SYS600C is used in both industrial and electrical utility applications, but it is normally not used in the NCC, so it is left for minor notice in this thesis. [80] All of the MicroSCADA Pro products run on PCs using MS Windows operating system [13].

One of the objectives of this thesis was to describe the information flows in the NCC from the aspect of outage reporting. This thesis focuses on the information flows with the ABB MicroSCADA Pro product but some other products are considered too, mainly via the DSO interviews. Therefore it is essential to first describe the basic functionalities of MicroSCADA Pro, paying attention to the outage reporting and management.

4.1 MicroSCADA Pro SYS600

The latest version of MicroSCADA Pro SYS600 is 9.4 FP2 (Feature Pack 2) [81]. The SYS600 is also known as MicroSCADA but as it easily confuses with MicroSCADA Pro, the SYS600 is preferred in this thesis. The upper level basic functionalities of SCADA systems are presented in the chapter 2.2.1 but this chapter presents shortly some more specific information about SYS600.

The trends display and the process display of SYS600 are presented in Figure 12. The trends display collects and shows data in numerical and graphical forms. Any data available in the process database can be presented. The topology of the network is described in the process display. The DSOs usually have several different process display images in the SYS600. For example all of the primary substations may have its own process display image, and there might be also a more complex display which includes all or several substations. The switches can be operated straight from the process display because the SYS600 process points are linked into the primary distribution process. However, the outage management is normally done with the DMS system which allows also the outage reporting functions. In the fault situations the SCADA sends a fault package to the DMS with the relevant information, and the DMS is then able to take care of the fault. The fault package is sent via OPC or SCIL-API connection. [8] The communication link between the SYS600 and the RTUs or IEDs in the primary process may use various types of protocols such as 60870-5-10x, IEC 61850, DNP, Modbus, LON, SPA and so on [30]. The main facts of these protocols are described in the chapter 2.3.1.

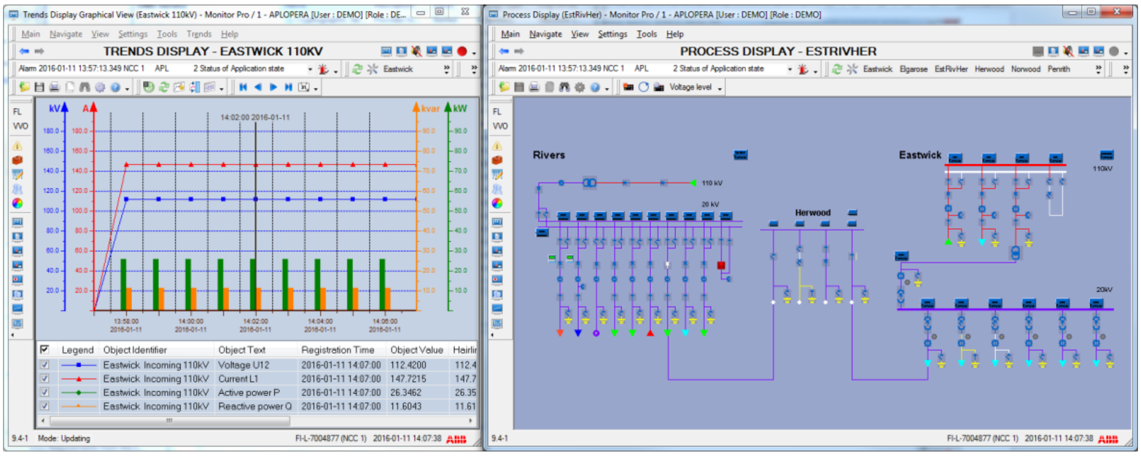


Figure 12. *The trends display and the process display of SYS600 9.4 FP1 in ABB demo environment.*

Both event display and alarm display of SYS600 is shown below in the Figure 13. These two displays are individual windows and can thus be shown separately in different monitors. The event display lists the events which are stored in the event database of SYS600. The event list can be filtered and sorted in order to separate the irrelevant information from the the relevant information. The alarm display shows accordingly the alarms of the system as a list. The list is divided into persisting and fleeting alarms. Both of the displays allow user to configure and even predefine the colors and layout of the displays.

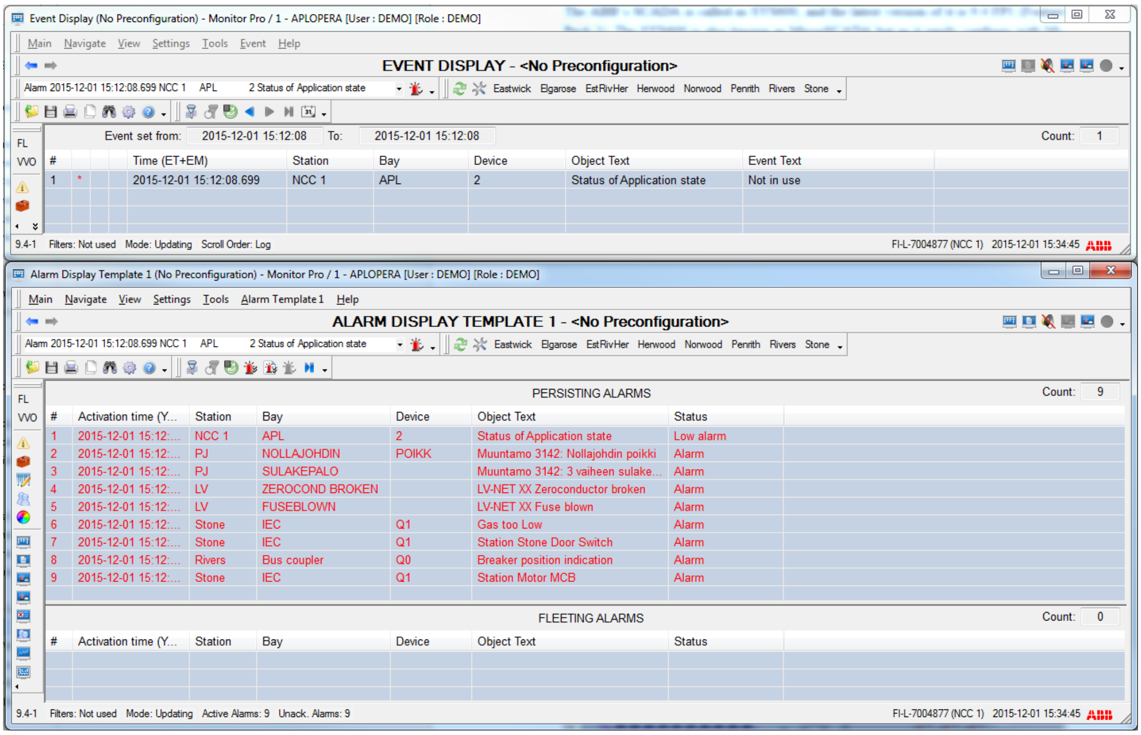


Figure 13. *The event and alarm displays of SYS600 9.4 FP1 in ABB demo environment.*

The configuration of all of the displays is crucial as there are different sized DSOs which needs and working methods may vary a lot. Although the SYS600 sends the fault packages, it is not used to create reports of the faults. The SYS600 only gathers the measuremens, switching events and other relevant data and delivers them for the DMS system which then handles the reporting of the outages semi-automatically.

4.2 MicroSCADA Pro DMS600 Workstation

ABB MicroSCADA Pro DMS600's latest released version is 4.4 FP1 HF2 (Hotfix 2). The DMS600 consists of two main applications: Workstation (DMS600 WS) and Network Editor (DMS600 NE). The DMS600 WS represents mainly the features of traditional DMS, and the DMS600 NE accordingly covers the NIS functions.

The Graphical User Inteface (GUI) of DMS600 WS is presented in Figure 14. In the right side of the picture is located the Connection Status Info Bar, which indicates the connection statuses of different components. The two open dialogs are Switch Control dialogs for a circuit breaker (upper) and a disconnector (lower). The coloring of the switches in the substation indicates whether the switches are open or closed.

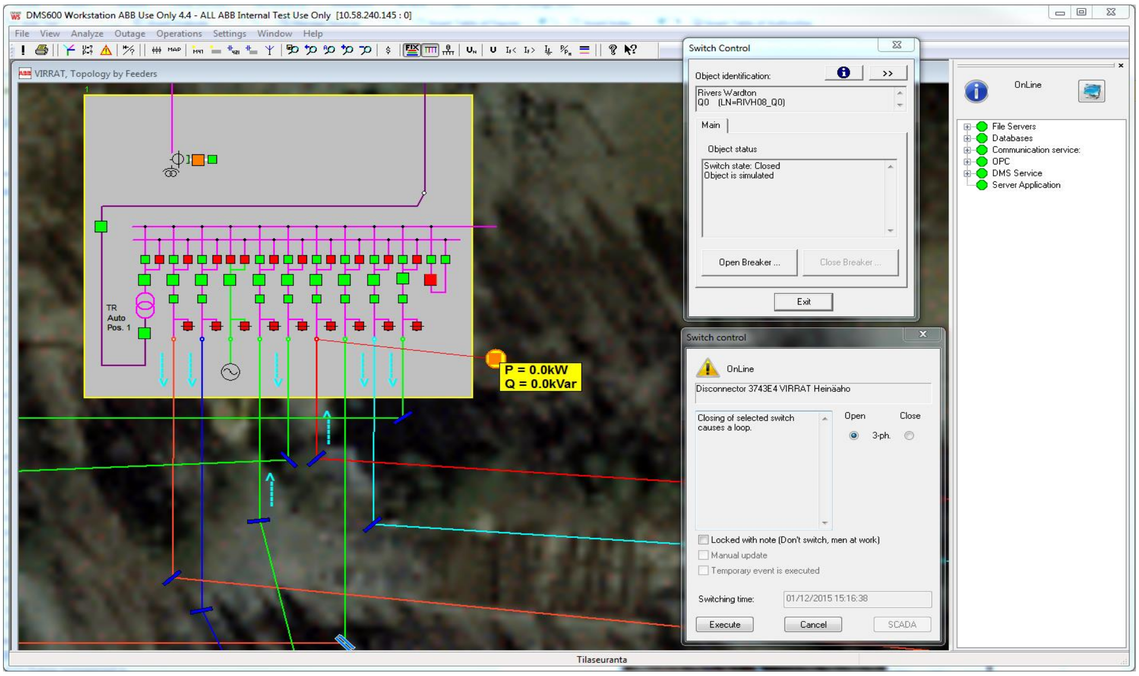


Figure 14. *The GUI of DMS600 WS with circuit breaker's and disconnector's switch control dialogs.*

The DMS600 WS facilitates the outage management situations as described in the chapter 4.2.1 but provides also many other supporting functions for the SCADA, as stated in the chapter 2.2.2. Whereas e.g. Trimble DMS uses ELCOM-90 standard to interface with the SCADA system, the ABB's DMS600 uses mainly OPC connection but in some cases also

SCIL-API is still used. The information flows towards other IT systems can be implemented with transfer files, database connections or via MS's COM-interface. [11], [8]

DMS600 databases consist of DMS and Network databases. The Network database includes the network asset information and other mainly static data but the DMS database comprises of more dynamic information such as the outage reports and the switching states which have to be up-to-date all the time. The databases are based either on Oracle or Microsoft SQL Server. The SQL Server Management Studio (SSMS) is the main tool for managing the SQL server databases, and the SQL Server Reporting Services (SSRS) is used to create, manage and share the required reports.

4.2.1 Outage management in DMS600

As the system receives the fault package from SCADA, it adds the fault to the ongoing faults list. DMS600 allows users to create faults also manually. At the same time the network topology of DMS is updated to represent the current situation. The operator can choose a specific fault from the list to be treated. First operator takes responsibility of the fault. As the fault is selected, the DMS colors the faulted part of the network as shown in Figure 15. DMS calculates the possible fault locations and shows them in the map as yellow lightning symbols. The possible fault locations are based on the calculated electrical distance of the fault which is again based on the fault current. This is reliable with short-circuit faults but does not necessarily work with the earth faults. As can be seen from the figure, there are several possible fault locations.

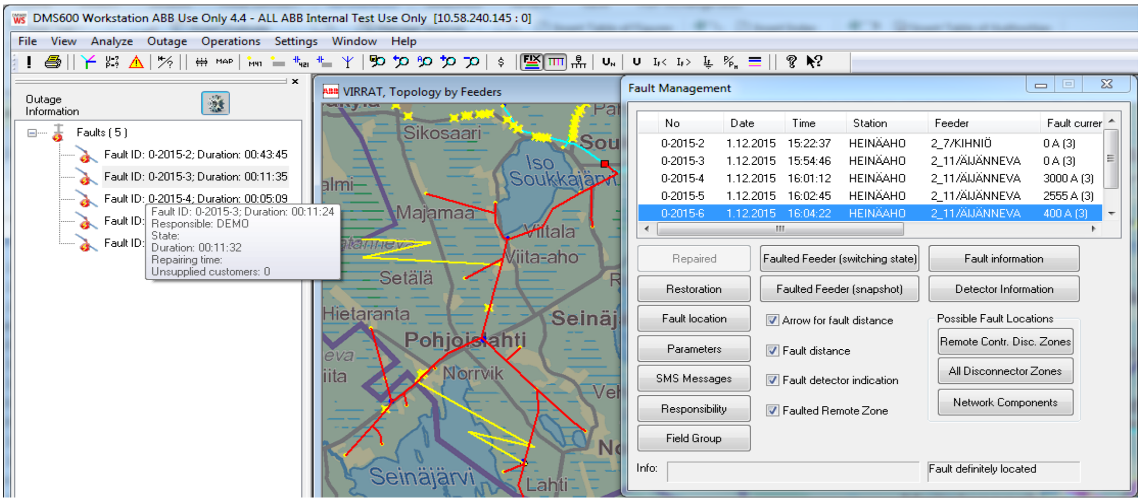


__Figure 15.__ The outage information bar and fault management dialog during a fault in DMS600 WS.

DMS also offers a switching event list which allows operators to isolate the fault and restore the electricity supply to as many parts of distribution network as possible, thus minimizing the outage costs. The isolation of the fault is simple if the fault location is known but sometimes the isolation must be performed with experimental switchings. The extent of outage decreases, and therefore it can also be noted that an outage can consist of several outage areas which play a significant role in outage reporting, discussed more specifically in chapters 3 and 4.2.2. The isolation is done by operating the manually and remotely controlled disconnectors. Finally, the work crew can locate the faulted components from the network and start repairing them. In some cases the fault zone can be reduced even more at this point. The tool used for the field crew management is called as Work Management System (WMS) and the information flows between it and DMS are described in the chapter 4.4.3. The fault ends when all of the customers are supplied again.

The DMS contains also functions to manage the faults of the LV network. The management of LV network faults is eased as DMS supports the operator e.g. in the state monitoring of LV network, maintaining of the switching states, management of disruption situations and in customer service related functions. When a fault occurs in the LV network, the operator can observe the LV networks and its components by finding a fault related customer from the network and check if other customers in the same LV network are supplied or not. The operator is also able to see if the cause of the interruption actually origins from the MV network. The information of the faults may be received from customer calls or automatized alarming functions of AMI. The operator may also receive information about the related component, feeding switch and fuse. Based on the location of fuses and the customer's interruption notification the fault location can be defined. [2]

Fault Detection, Isolation and Restoration (FDIR) is a DMS600 tool which automatically detects, isolates and restores a fault. The needed operations can be executed with remote controlled switches. However, the FDIR can be used only if the fault is located confidently enough, which is often not the case due to e.g. looped network or insufficient fault information in a branched network. [18] The locating is usually based on the fault indicators, fault currents and fault impedance calculations. The received fault package usually includes information about the fault current but can include also other information for the FDIR. [8] One benefit for the DSOs is that in cases of major disturbances the operators have more time to focus on the overall situation as the FDIR automatically handles some of the faults [18]. FDIR works together with the Sequencer of SYS600 so that FDIR creates the list of necessary switching operations for the sequencer in order to isolate the fault zone. FLIR (Fault Location, Isolation and Restoration) is a corresponding tool which works at least with combination of Trimble DMS and Netcon 3000 SCADA systems [82].

4.2.2 Outage reporting in DMS600

The outage is considered to end when the fault is repaired in the network and supply is restored to all customers related to that outage. In case of LV faults, the information source can be the customers or e.g. an Advanced Metering Infrastructure, as described in the chapter 2.3.4. As the outage management is done, the DMS600 WS prompts a dialog asking if the operator wants to create a report of the fault immediately. When the report is created, the report management window presented in the Figure 16 will appear.

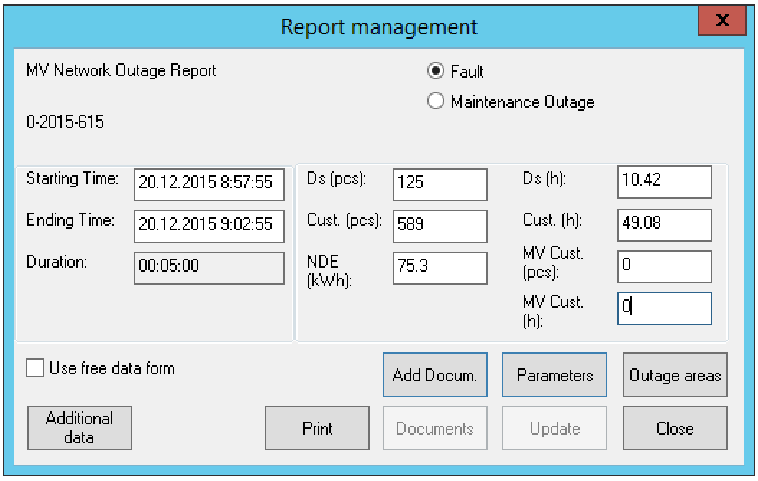


Figure 16. *The report management window in DMS600.*

The DMS600 allows users to create fault reports also manually afterwards. The above report data is initialized automatically by DMS, and the operator just checks and approves the report. If the data is not initialized correctly, the operator can modify the report immediately or afterwards, even after the report is archived. However, directly from the Report management window the information can not be modified. As can be seen from the Figure 16, the starting time and ending time as well as the duration of the fault are reported. When creating the outage report, the *Additional data* has to be opened in order to fill the outage reason, fault reason and the location of the fault to the report. The prompted window is shown in the Figure 17.

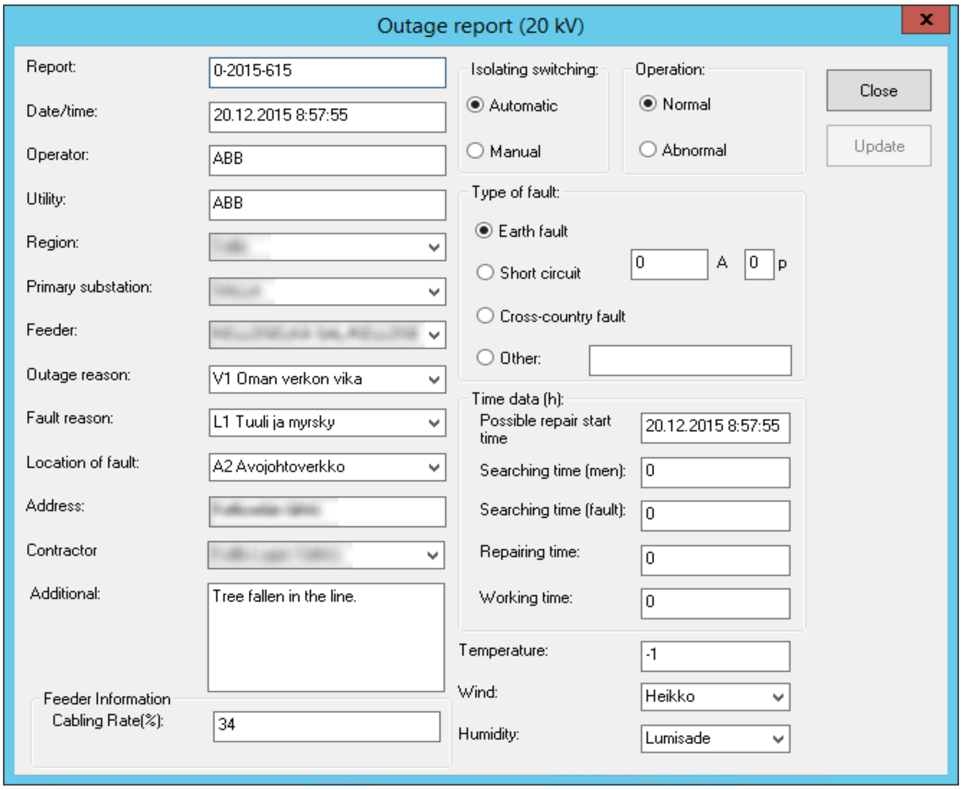


Figure 17. *The additional information of a DMS600 outage report.*

Some of the information in the *additional data* is initialized automatically but some of it has to be filled manually. For example the feeder's *Cabling Rate (%)* information may be calculated automatically for the report but the exact location of fault is filled automatically. When the necessary information is filled and the outage report is archived, the fault is moved to the reported outages table in the DMS database. The database can then be accessed by the SQL Server Reporting Services, which is needed to create, manage, publish, modify and share the reports, as stated in the chapter 4.2. The SSRS has been in use since DMS600 4.4 version. The created reports are used in a website-based UI and the reports can be also exported from the website when necessary. [8] During the thesis reports are created and modified with SQL Server Data Tools – Business Intelligence (SSDTBI) tool. More information about these reports can be found in chapter 6.

4.3 MicroSCADA Pro DMS600 Network Editor

The DMS600 NE is a MicroSCADA Pro DMS600 application, which is not directly related to the outage reporting or management, but since it provides crucial information for the outage management and reporting process, it cannot be left out of the thesis. This information is customer information data, network geographical information, network asset, maintenance, condition and topology data, and so on. DMS600 NE creates the binary database for DMS600 WS and affects greatly to the integration of the NCC's IT systems, which is another reason to take it into account in this thesis. As described in chapter 2.1.2, the DMS600 NE belongs to the utility level of DA. It is used mainly in network planning, network load flow calculations, fault current calculations and network protection and reliability analysis. It allows users to edit the network and manage the information related to the network assets. The GUI of DMS600 NE is presented in Figure 18.

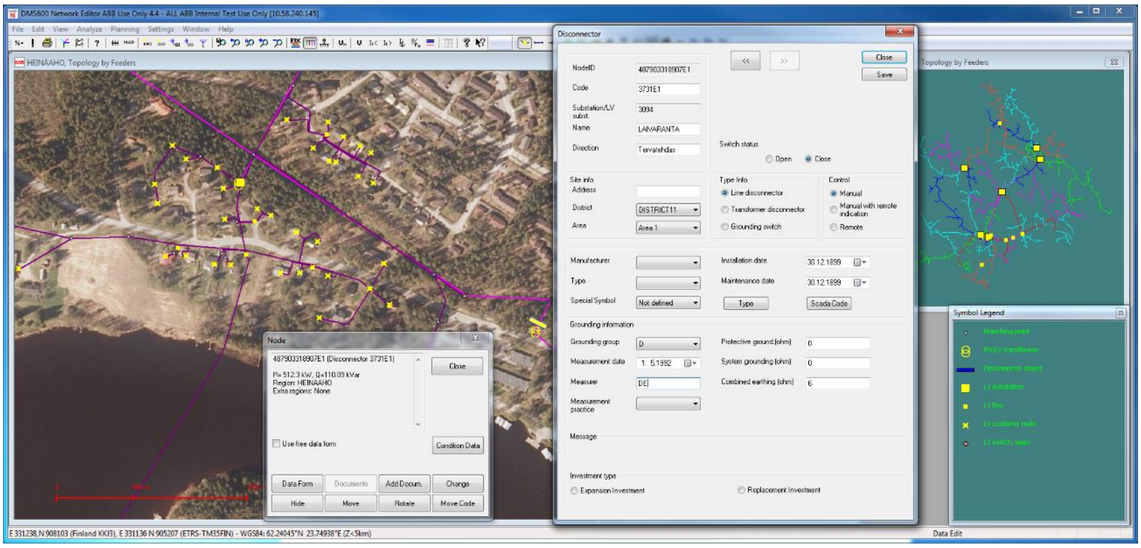


Figure 18. *The GUI of DMS600 NE with feeder topology coloring, open disconnector data form dialog and open LV network in the map.*

The figure shows how the coloring of the network can provide quick information of the network topology. Also the open dialog shows how editing the disconnector data form looks like. Symbol legend explains the meanings of different symbols in the network. The data of DMS600 NE is saved in the network SQL database and the data can be accessed by all the necessary applications. The CIS provides the specified customer information data straight to the network database via customer import SQL procedures. The DMS600 systems have access to these databases and therefore can show the right customers in the correct places of the network. [8] Due to the Metering point-specific outage reporting the customer information is playing an important role in the reporting as well.

4.4 Information flows in the Network Control Center

This chapter presents what information flows in general are flowing in the NCC that are related to the outage reporting. The outage reporting functionality is implemented to work with information provided by DMS600 and its databases, which is why the information flows usually travel through DMS at some point. Therefore DMS is somewhat in the central of these information flows regarding outage reporting. As there are several different IT systems, interfaces and stakeholders related to these information flows, the whole entity was reasonable to divide into smaller segments:

- Information flows coming to NCC from the distribution process
- Information flows between DMS and external SCADA
- Information flows between DMS and other IT systems
- Information flows towards outage reporting and external communication

These mentioned four segments and their connection to the DMS system in the NCC is presented in the Figure 19. The arrows represent the direction of the information flows. As can be seen, the information between DMS and other IT systems is bidirectional but other information flows are usually unidirectional, either from or to the DMS system.

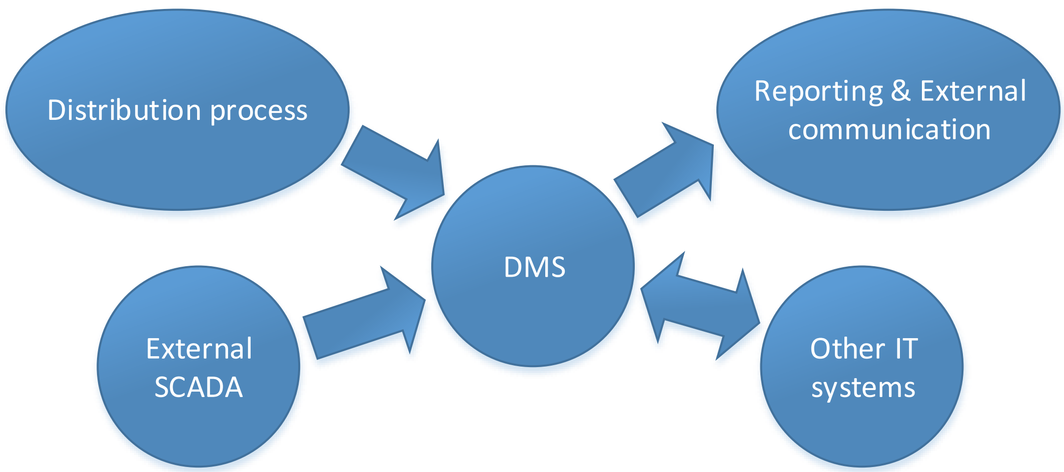


Figure 19. *Information flows related to the outage reporting divided into four segments.*

This chapter discusses the presented topic mainly from ABB products' point of view, but for example the information flows between SCADA and DMS are more interesting if other one of the systems is provided by another manufacturer. Each mentioned part is presented in its own subchapter. If not separately mentioned, an assumption is that the discussed NIS, DMS and SCADA systems belong to the ABB MicroSCADA Pro product.

4.4.1 Information flows from the distribution primary process

The sources of the information flows coming from the distribution process are for example AMR meters and RTUs. In the future there will be more IEDs which can communicate to NCC individually. The information flows between the distribution primary process and the NCC are presented in the Figure 20. The ABB products and services are presented with blue color, third party services as orange color and the distribution process with yellow color. The field work groups are located with GPS by external Real-Time Locating Systems (RTLS) and the coordinate information and work crew data is brought to the DMS600 with a separate interface called WorkGroupUpdater. When the NCC personnel is aware of the locations of the field work crews, organizing the remaining work becomes more efficient, especially during the major disturbances.

Some of the information of the MV faults is delivered from the distribution process automatically, usually through RTUs. First the IEDs at the substation send the message to the RTU by e.g. IEC-61850 or IEC-103 standard protocols. The RTU converts the data into e.g. IEC-101 or IEC-104 protocol messages and sends it to the remote SCADA system. The SCADA creates a fault package and sends it towards DMS by OPC connection, as shown in the top of the Figure 20. The SCADA's OPC Server takes care of the OPC communication, and the fault package is received by the OPC Client of DMS. DMS-Socket (Socket) brings the fault information finally to all of the DMS instances. [8] The information SCADA receives from the primary process automatically includes at least the fault durations, the type of the fault (earth fault, 2-phase short circuit, 3-phase short circuit) and the measured fault current. Information from the fault detectors is also received. All this information is transferred to the DMS and used also for outage reporting. [54] However, not all information can be acquired automatically even from the MV network. WMS is often used in LV fault reporting but it is possible to be used also in MV network reporting. The field work crew can add the missing information of the fault to the WMS which then transmits the information for the DMS. At least the reason of interruption and the exact fault location can be added manually by the work crew as the fault is being repaired.

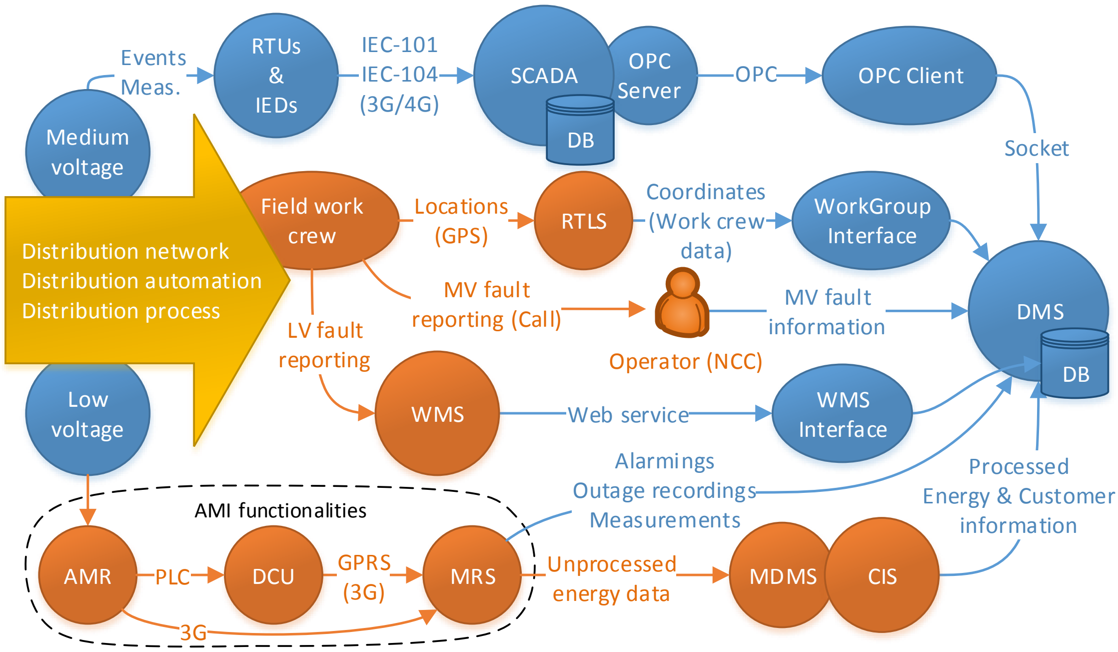


Figure 20. *Information flows from the distribution primary process to the NCC.*

As presented in the Figure 20, the LV side consists of the AMR, MRS and MDMS systems but also WMS can be used in the LV network outage management and reporting. MRS system can be integrated to the DMS system and it provides e.g. the alarming data, outage recordings and measurements. As presented in the Figure 20, often the MDMS delivers the energy data for the CIS. CIS is then integrated to the NIS and provides the energy data with the customer data. The integration of DMS with WMS is discussed more specifically in chapter 4.4.3. In this context it is reasonable to mention that LV reporting information can be brought to the DMS via WMS systems as the LV side of automation often does not provide even alarmings automatically. ABB does not provide WMS systems but e.g. CaCe, GridWise and Newelo can be integrated with the DMS600 [8]. The functional principle of AMI is already presented in the chapter 2.3.4 and the presented solution suits here as well. Hence it is not described more specifically in this chapter.

4.4.2 Information flows to DMS600 from external SCADA

Sometimes the DSOs have ABB’s MicroSCADA Pro DMS600 system but they use a third party SCADA system. For example Turku Energia Sähköverkot system integration consists of ABB DMS600 WS, Tieto PowerGrid (PG) NIS and Siemens Spectrum SCADA. In this case the information flows between DMS and SCADA were earlier implemented with ELCOM-90 protocol but currently IEC-104 RTU standard protocol is preferred. The SYS600 works in the middle as an interface. It receives IEC-104 messages from Spectrum, converts them and transmits to DMS600 with OPC protocol. This case is presented in the Figure 21. In the figures of this chapter ABB products are colored blue and 3rd party products and services are presented with orange color.

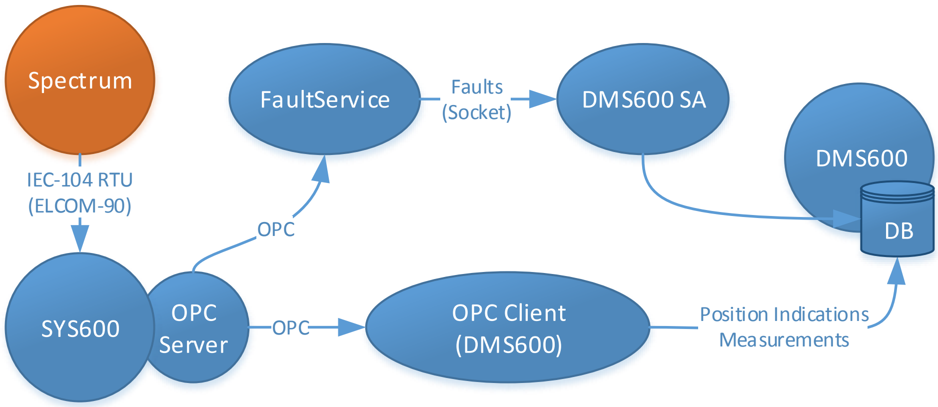


Figure 21. *Information flows between Spectrum SCADA and DMS600.*

In the IEC-104 protocol way of thinking the SYS600 acts as a *Master* device and Spectrum as a *Slave*. Therefore in the system point of view the Spectrum SCADA can be compared to a normal RTU station which gathers data and delivers it into the SYS600 with IEC-104 protocol.

In case the used SCADA is Netcon 3000, the system looks a little different. The information flows between Netcon 3000 SCADA and DMS600 are presented in the Figure 22. The Netcon 3000 SCADA system and Netcon Gateway (Netcon GW) communicate with Netcontrol's specified communication method and protocol. SYS600 is not used as an interface like with the Spectrum. On the contrary Netcon GW together with the iFIX OPC Server convert the information into such form that OPC communication can be used henceforth.

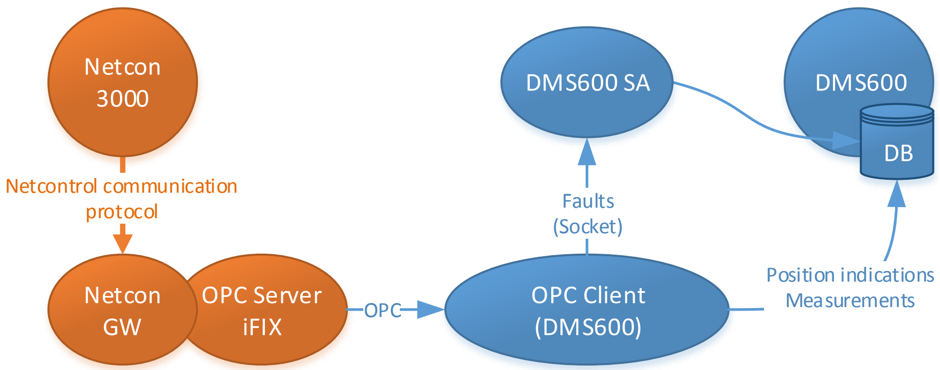


Figure 22. *Information flows between Netcon 3000 SCADA and DMS600.*

The DMS600's OPC Client receives the position indication informations and fault informations and delivers them either straight to the DMS600 database or in case of faults to the DMS600 SA. In this case the fault packages are not created by the FaultService (could be used as well) but a traditional method is used. Similarly than in case of SCIL-API interface, the fault packages are created by DMS600 SA. The SCIL-API interface is still in use in some cases of SYS600 and DMS600 integration. However, in all cases the same information flows exist, only the routes may vary slightly, as presented in the figures.

4.4.3 Information flows between DMS600 and other information systems

The CIS is one of the most important information systems in the whole electricity distribution business, having a major role also in outage reporting. The CIS provides all of the customer information related to the distribution network, and it is required also for outage reporting. The connection between CIS and DMS is implemented usually through NIS. More specifically in the DMS600 case the DMS600 NE tool receives the information about different customers from CIS and the DMS600 WS has then access to the Network-database. This allows the system to calculate how many customers belong to a specific outage. In case the DSO uses DMS600 WS but the NIS is PowerGrid (PG), the DMS600 NE acts between PG NIS and DMS600 WS as an interface. The CIS provides the required customer information for the PG NIS, which again delivers them to the DMS600. The PG NIS also provides the network information. Both customer and network information are delivered with specified transfer files *Network.txt* and *Customer.txt*. DMS600 NE reads and converts *Network.txt* into binary data form which is understood by DMS600 WS. Customer.txt file is brought directly to the DMS600 NE database by using SQL procedures. PG creates the files by a schedule or when requested. The connection between DMS600 and other related information systems is presented in the Figure 23. The ABB products and interfaces are presented as blue color and other products as orange color.

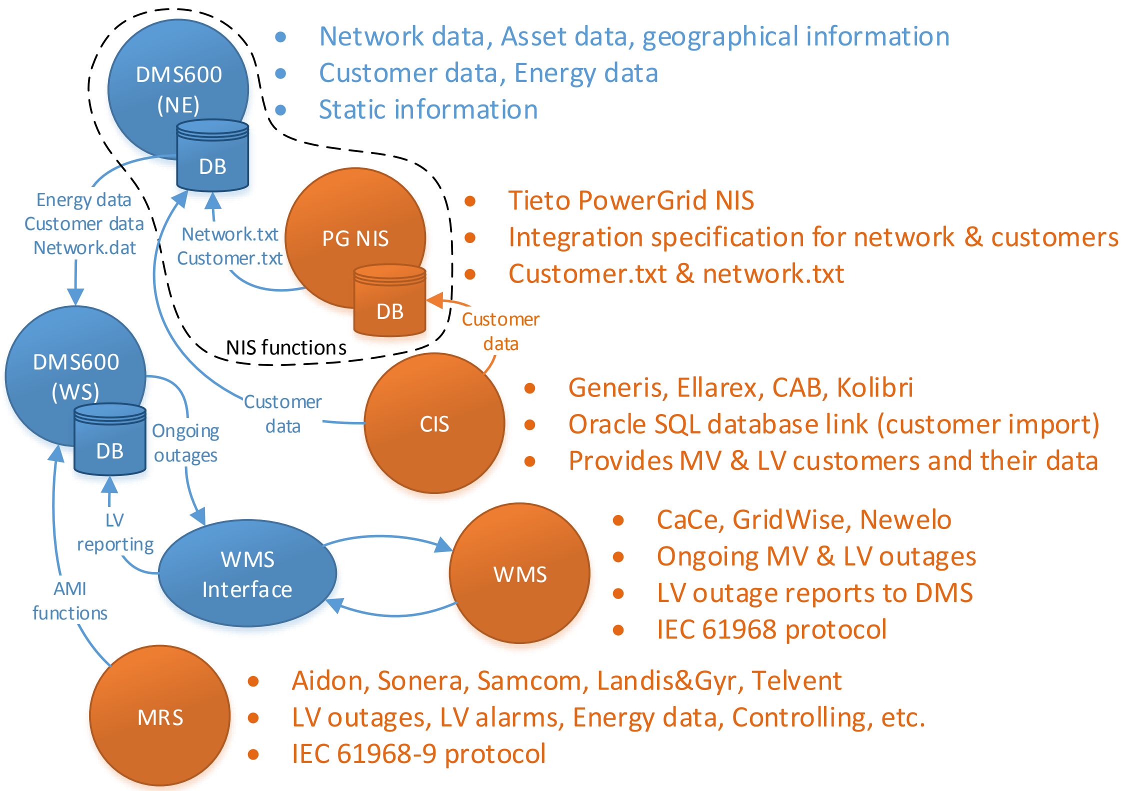


Figure 23. *Information flows between DMS600 and other IT systems.*

Several WMS systems can be used with DMS600 software. As presented in the above figure, CaCe, GridWise and Newelo are used with DMS600. It requires a specific WMS interface, which is presented in the figure. The WMS interface delivers the ongoing MV outages and MOs from DMS600 to the WMS software. The LV outage and MO reports created or modified in DMS600 can be delivered to the Newelo WMS via this interface. With CaCe it is not possible. In addition, the WMS interface brings information from the WMS to the DMS600. The incoming information can be LV outage reports. The DMS–WMS interface is implemented with IEC 61968-100 standard protocol. [8]

If the DSO does not have AMI functionalities, the LV faults can be created manually with WMS. The manually created LV faults are usually based on customer contacts, and the fault details are delivered to the DMS. In case the information has to be updated during the outage management, it can be done via both WMS and DMS. When the supply is restored and work crew has marked the ending time to the WMS, the report is updated also to the DMS. Work crew can also inform the NCC that the fault is repaired, on which case the information is updated first to the DMS and then the message is sent from DMS to WMS. [64] When the fault is over and the supply is restored, the DMS can be used to archive the outage report for later observation and for compulsory outage reporting for the Energy Authority [8]. All in all, the integration with WMS provides important information for the DMS related to both internal and external outage reporting. This information can be for example interruption type, reason of interruption, fault location, outage starting and ending times and fault type. [7], [6]

In case the DSO has AMI functionalities, the LV outage management resembles more of MV outage management. The information that customer does not have supply comes automatically to the DMS and the customers don’t have to contact the DSO because the SMS notification messages can be sent to the customers with this alarming information. In some cases the DSOs have also LV network controlling abilities but often only alarming functions are in use as many DSOs have purchased the current AMR meters initially for energy metering purposes. Hence the controlling abilities are challenging to implement afterwards to the meters, but at least alarming functions can be retrofitted to some of the traditional energy meters [83]. There are several companies that are working in the energy metering business or provide meter reading services in Finland. These are e.g. Aidon, Sonera, Landis&Gyr, Samcom, Schneider Electric (Telvent), Kamstrup and Empower (Mitox). [8] The information flows from MRS to DMS usually include at least the customer energy data but also LV network alarms and outage data can be provided. If the AMI functionalities are not in use, the MRS can be connected to CIS instead of DMS. In this case the CIS provides the customer energies to the NIS which delivers the data even further to the DMS for reporting and other purposes. [84]

Enoro’s Generis, Tieto’s CAB, CGI’s Kolibri and Empower’s Ellarex are common Customer Information Systems used by DSOs [8]. In addition, in the beginning of 2016 Empower IM has taken EnerimCIS in use in Elenia [85] and a contract is made with Caruna as well [86]. The basic functionality is that the database of Customer Information System and DMS600's SQL databases are linked and the information is transmitted straight from the database to another. With Generis the customer information is in the Oracle database which is linked with the NIS database. The customer information is brought to the NIS database with Customer Import SQL procedures. After the Customer Import the DMS can access the NIS database and hence exploit the customer information and energy consumption data e.g. in the outage reporting. [8] In some cases the information can be transmitted also backwards. The required information from NIS to CIS can be e.g. coordinates and the fresh substation codes of customers. The related substation codes change when the switching state of the network changes. [84]

4.4.4 Information flows for the outage reporting and external communication

This subchapter covers the information flows that are needed e.g. to customers for notifying purposes and to authorities for regulation and outage reporting purposes. The information flows in this chapter can be further divided into following groups:

- Outage compensation for customers
- SMS fault notification to customers
- Telephone Answering Machine (TAM) communication
- OutageInfo web service for customers and 3rd party applications
- Notification towards Media and Rescue Authority in case of significant outages
- Outage reporting towards Energy Authority, ET and for internal use

All of these information flows are covered in the Figure 24. Also the related interfaces and other appropriate information are described. As can be seen, all information flows are originated from DMS and the destination is either the consumers, Media, Rescue Authority, Energy Authority, ET or the DSO itself. Again the ABB products and services are presented with blue color and others with orange color. The reporting for DSO itself is drawn to the figure with a dashed gray line because instead of external communication it is internal reporting and hence differs from other information flows.

According to the interviews the external communication is regarded as a very important function of DSO operation [83]. It is also compulsory as the Electricity Market Act states that the DSOs have to inform the customers immediately when the supply for the electricity users is interrupted. The estimated duration and extent of the fault must be given as well. [65] In addition, a consumer survey published in 2012 shows that unawareness of the outages causes most of the harm for the consumers in case of short and long outages [87]. This increases the role of notification in the DSOs' operation.

The outage compensations are delivered to the customers by first exporting the outage statistics with customer points and outage durations from the DMS600. Some DSOs use the Outage compensation report provided by the DMS600 Reporting Services. This output data is provided for the CRM or other IT system which calculates the amounts of outage compensation in euros and directs the compensations to correct customers. Often the outages are compensated in the incoming invoices. In case of more significant outages, also the Media becomes interested in the outages and the whole situation. Especially during major disturbances there is a need to extend the notifications towards the Media. According to the Electricity Market Act, the cooperation with authorities such as the Police, the Local Authority, the Road Authority and the Rescue Authority is compulsory in case of electricity distribution interruptions [65]. In practice this means at least a properly organized notification and other communication between the DSOs and the authorities.

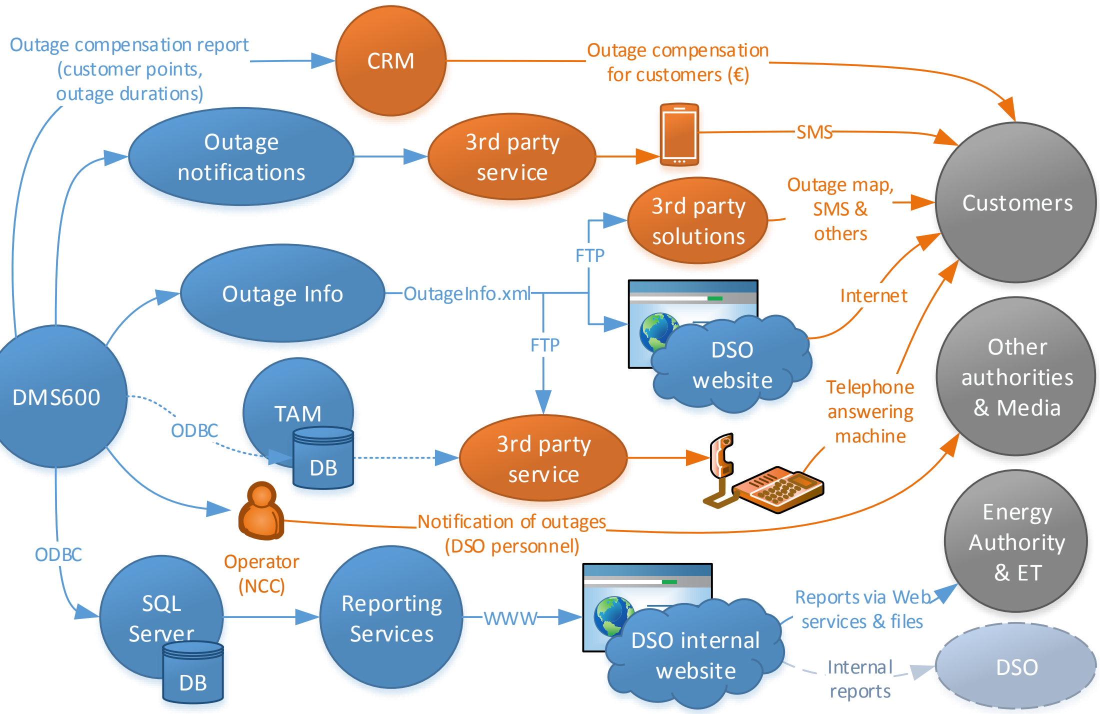


Figure 24. Information flows for outage reporting and external communication.

The OutageNotifications is a WebService based DMS interface which enables the event-based SMS messaging to the customers. The SMS messages are sent automatically to notify all customers in the fault zone when the fault begins and when the service is returned. After receiving the message the customer is sure that the DSO is aware of the fault. Therefore the customer can wait for the service to be returned without disturbing the fault management process by calling to the NCC. Estimated repairing time can be sent to the customers as well. This interface allows the DSOs to send SMS messages of the MOs in advance but also more specific information during the maintenance outage. In addition there is a possibility to create a free-form message for a group which has previously received messages. This enables the DSOs to correct or specify the previously sent messages in exceptional cases. Tietokoura Oy and InPulse Works Oy are two example companies providing 3rd party SMS services which can be integrated to the DMS600 [8].

The OutageInfoSender interface creates OutageInfo.xml file from the DMS600's information. File can be used for several purposes but in the common ABB solution it provides the necessary information for the OutageInfo web service, which is located on the DSO's website. The purpose of OutageInfo is to show the current interruptions and maintenance outages in the distribution network as a snapshot. Also history data and upcoming maintenance outages can be presented in the service. Customer can zoom closer to observe more precise situation in the map. The substations which are related to the outage are shown in the map and the amount of unsupplied customers are presented. The outage code, starting time and estimated ending time (if available), type of outage and description are included in the OutageInfo.xml file, as well as the coordinates, areas and codes of related MV/LV substations. An example of OutageInfo Web User Interface is presented in the Figure 25. A 3rd party solution is for example an application created by Samcom in collaboration with ABB. This 3rd party application is able to provide corresponding web service than the original ABB OutageInfo, and it can be used also to send SMS messages to the customers during the fault management. The whole solution including the web service and the SMS messages are based on the OutageInfo.xml file. If file transferring over FTP (File Transfer Protocol) is needed, the FileTransferComponent interface can be used. [8]

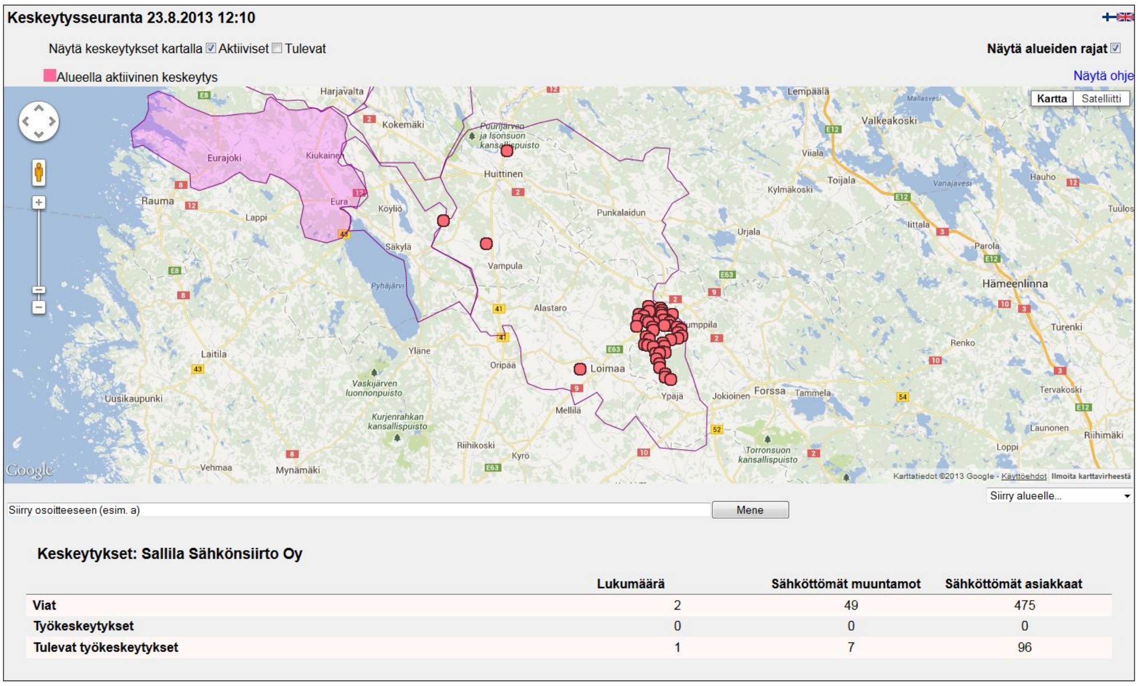


Figure 25. *OutageInfo Web UI of Sallila Sähkönsiirto Oy [8].*

Telephone Answering Machine (TAM) is used to inform customers about the faults in the network because the calls from customers may disturb the outage management process. Customers are informed of the extent and estimated duration of the outages. [54] Previously TAM was functioning so that outage information was saved to a separate TAM database by the DMS600 WS instance which handled the outage. Capricode Systems Oy took care of the process from the TAM database towards the customers. This method is still used by some DSOs. However, a newer version of TAM is based on the OutageInfo.xml file which is transferred to Capricode via FTP. This file contains all the necessary information for the TAM. The DSO can define the messages which are read to customers calling to the NCC. Often the distribution network is divided into regions, of which the customer can choose the interesting one. Usually if the automatic answer is not enough for the customer, he is let to speak with the customer service or NCC personnel, depending on the situation. According to the interviews, the messages of TAM have to be short enough so that the customer has patience to listen them completely [83], [84]. However, as the automatic outage-related SMS messages and the OutageInfo web services (outage map) have become more common, TAM is not used as much as before [8].

The reporting of DMS600 is implemented with the SQL Server Reporting Services. The Reporting Services creates the reports based on DMS and Network databases. As shown in the Figure 24, the reports are used with a browser in the DSO's internal website. The user can define suitable parameters for the reports, which can be printed in the browser but also exported. Supported file formats are XML, CSV, PDF, MHTML, Excel, TIFF and Word. As the reports are created, the DSO checks that they are valid and delivers the reports for the appropriate stakeholders. Excel files are used to deliver the reports for the Finnish Energy. The Energy Authority has a web service in order to receive the required reports. The internal reporting of DSO can exploit any of the mentioned file formats, depending on the need and practice.

4.5 A reference Information System integration

In this comprehensive reference IT system integration the NIS, DMS and SCADA systems are acquired from the same provider. This ensures that the amount of unnecessary integrations gets minimized and that the integrations between these information systems are not done with retrofit installations which may not be as reliable and simple as the originally planned integrations, but are often more complex implementations.

In the reference system integration the field work crew updates the fault information straight to a mobile WMS system. This is done in all cases, whether it is a case of LV, MV or HV maintenance outage or LV, MV or HV fault. In case of MV and HV faults, the basic data for the outage report comes from the SCADA. However, some of the information has to be added to the report manually and thus WMS is used. Hence this would harmonize the outage reporting process between LV, MV and HV network outages. Currently most DSOs add this additional data to the report manually in the NCC. However, e.g. the DMS–WMS interface of DMS600 would already allow the MV reporting functions. The work crew could add the estimated repairing time to the mobile WMS when the fault is located. Also the outage reason, fault reason, fault location and other manually added data can be set to the mobile WMS. This would fasten the customer service as the SMS messages can be sent in the same moment the work crew sends this outage information to the DMS. This decreases the need of unnecessary calls from the work crews to the NCC operator, or at least decreases the call durations. Hence this solution is chosen in the reference IT system integration. Especially during the major disturbances the importance of these features become crucial. In the reference system integration the work crew would call to the NCC only when the issue is security related, e.g. before the switching operations. The reference IT system integration is presented in the Figure 26.

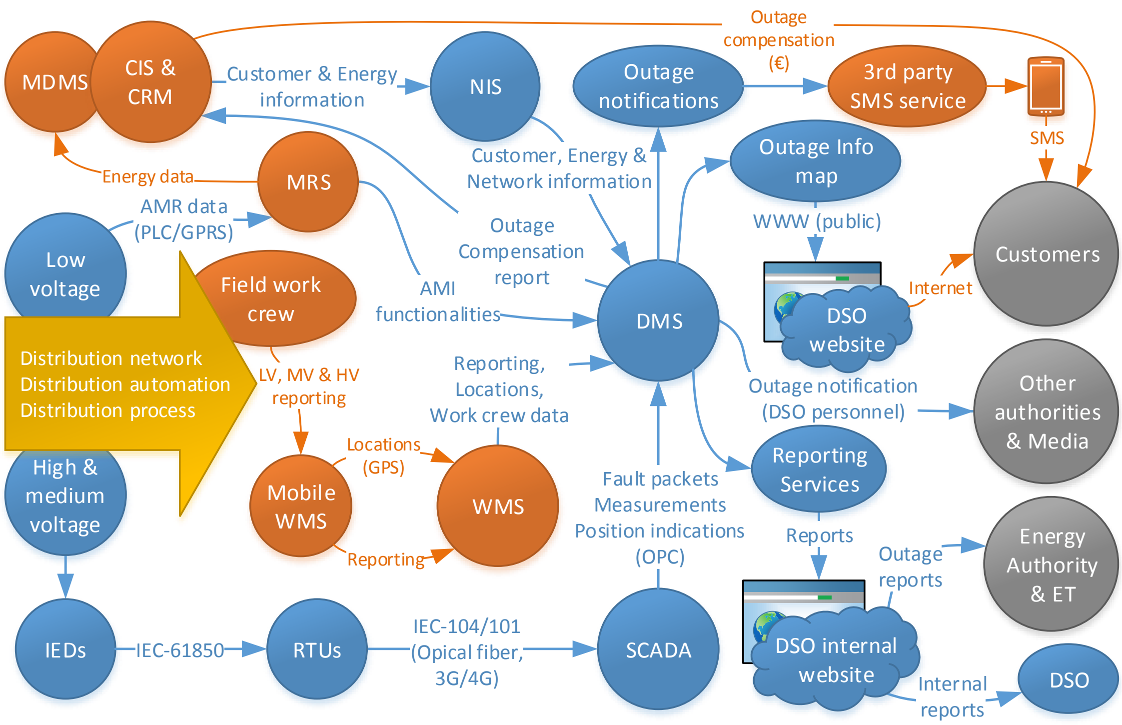


Figure 26. *A reference information system integration and information flows between the systems from the aspect of outage reporting.*

As IEC-61850 is a standard communication protocol for substation automation and is becoming more common solution in the future, it is a reasonable solution for the communication protocol between the IEDs and RTUs in the reference system. The reference system uses mainly IEC-104 protocol between RTUs and SCADA. This communication would be implemented with optical fiber at least for some of the primary substations. However, in some cases it might be more cost efficient to use 3G/4G connections. This happens usually in the rural network area if there is no optical fiber network close by.

The reference system uses advanced AMI functionalities. The MRS is connected into the DMS which shows the AMR alarmings, enables the inquiries for the AMR meters and makes the controlling functions of AMR meters possible. The job order is created automatically by the system when alarmings occur. The work management is done with the WMS. The AMR meter inquiries enable the DSO's customer service to check the outage history of a specific customer also directly from the AMR meter, if the information provided by the DMS has to be verified. If compared to the interviewed DSOs, this reference system resembles most of the IT system integration of Leppäkosken Sähkö Oy.

5. THE INTERVIEWS OF DISTRIBUTION SYSTEM OPERATORS

The general objectives of the interviews as well as the chosen interviewees are presented in this chapter. The chapter provides the relevant material of the customer interviews. The IT systems of the interviewed DSOs are described in this chapter as well, not to forget the information flows between the systems from the aspect of outage reporting. The interviews were implemented with a method called focused (semi-structured) interview [1]. The interviews were recorded and further analyzed afterwards. There was a basic structure for the interviews but the questions differed between the interviews, and the form of interviews was mainly discussing. This was considered as a good method as the same questions would have not been reasonable to ask from all of the DSOs due to the different IT system integrations. The duration of the interviews was around 2 hours on average.

The DSOs are divided into small, medium-sized and large companies. The definitions are deduced from the Electricity Market Act and from a document provided by the Finnish Economy Committee [88], [65]. The definitions listed below are used in this thesis.

- Customers < 18 000 — Small
- 18 000 ≤ Customers < 50 000 — Medium-sized
- 50 000 ≤ Customers — Large

The Electricity Market Act also mentions the limiting values of annually distributed energies which are at most of 200 GWh for small DSOs and at least of 500 GWh for large DSOs, respectively.

5.1 General objectives

The information flows and interfaces in the NCC with ABB's softwares from the aspect of outage reporting are described in the chapter 4. One objective of the interviews was to clarify the main reasons why the DSOs have chosen the certain software integrations. The requirements and developmend ideas related to the outage reporting were also gathered, if there were any. The interviews gave specific information of the DSOs' systems and outage reporting processes which then could be described in the thesis.

The interviews were implemented by face-to-face meetings with the DSO representatives. Some of the DSOs wanted that more than one representative would participate to the interview, which turned out to be useful as often one person is not able to answer to such wide range of questions. This method also caused a lot of discussion on the topic. Most of the interviews were arranged on the DSOs' premises.

5.2 Interviewees

The interviewees were chosen carefully to ensure that a wide perspective of the field can be covered. Five DSO interviewees were chosen, and each of them has a unique IT system integration. Among the chosen interviewees there are different sizes of DSOs and some of them are operating mainly in the town plan areas and others mainly in rural areas. The chosen DSO interviewees are listed below:

1. Turku Energia Sähköverkko Oy (TESV)
2. Tampereen Sähköverkko Oy (TSV)
3. Leppäkosken Sähkö Oy
4. Elenia Oy
5. Järvi-Suomen Energia Oy (JSE)

The information systems used by the interviewees are listed in the Table 6. Only Leppäkosken Sähkö of these DSOs has all SCADA, DMS and NIS systems from the same provider (ABB).

Table 6. *The SCADA, DMS and NIS systems used by each interviewed company.*

DSO	SCADA	DMS	NIS
TESV	Spectrum	MicroSCADA Pro DMS600	PowerGrid
TSV	MicroSCADA Pro SYS600	Trimble DMS	Trimble NIS
Leppäkoski	MicroSCADA Pro SYS600	MicroSCADA Pro DMS600	MicroSCADA Pro DMS600
Elenia	Netcon 3000	Trimble DMS	Trimble NIS
JSE	Netcon 3000	MicroSCADA Pro DMS600	PowerGrid

Each following subchapter contains more specific information about the DSO in question. Also the used WMS, CIS and other IT systems are described in the next subchapters.

5.2.1 Turku Energia Sähköverkot Oy

In 2014 Turku Energia Sähköverkot Oy supplied about 77 500 distribution network customers [89]. According to the definitions mentioned earlier in the thesis, TESV is a large DSO, having more than 50 000 serviced customers and over 500 GWh of energy distributed annually [88], [65]. TESV provides employment directly for 45 people. The speciality of TESV is that it owns plenty of 10 kV network and it operates mainly on town plan areas. The effect of major disturbances is relatively low due to increasing and already extensive underground cabling. [90] This reduces also the work needed for outage reporting and might have an influence on the extent of internal outage reporting.

Figure 27 represents the TESV distribution network area. Although TESV supplies such many customers, it can be seen that the network area is relatively small. There are also several islands in the southwestern network area. In 2014 the total network length of TESV was over 2460 km including LV, MV and HV networks. TESV owned about 80 km of HV network. [89]

Figure 27. *The distribution network area of Turku Energia sähköverkot Oy [91].*

The DMS, NIS and SCADA systems of TESV are listed below:

- DMS ABB MicroSCADA Pro DMS600 (WS)
- NIS Tieto PowerGrid
- SCADA Siemens Spectrum

All of these systems are under maintenance contract. It has to be noticed that DMS, NIS and SCADA are all from different providers. This affects greatly to the integration of the IT systems. The integration is more complex as it would be if systems were purchased from the same provider. The ABB's MicroSCADA Pro product family acts in the middle as integrative components. Further explained, the MicroSCADA SYS600 is installed between Spectrum and DMS600, and acts there as a gateway. On the other side, DMS600 NE is installed between PowerGrid (PG) and DMS600 WS. NE receives the network data as text file, reads and converts it into a binary data form which is understood by WS. The PG NIS provides the text files regularly every day but also when separately requested. The customer data is brought to DMS with a separate file, also created by PG. This data is brought directly to the DMS600 databases using SQL procedures. DMS600 NE is used also to create temporary network for the DMS600 when necessary. The complexity of the whole integration of different systems obviously causes some challenges but according to the interview of TESV, the interface between Spectrum and MicroSCADA has worked reliably enough after the IEC-104 RTU interface implementation. [83]

Reliability, price and remote access aspects were considered as the most critical aspects when purchasing a new SCADA system. According to the TESV interview, the SCADA system must be always online and ready. The service provider should also be reliable and operating even after several years of the software implementation, because the maintenance service for the software should be provided for about 10 years ahead. According to the interview, also DMS is a crucial information system because without it the daily operational functions would be very difficult. Creating the switching plans and managing the distribution network would be difficult, for instance. Therefore the same criteria as with SCADA applies also with DMS but according to the interview, the usability of the system is emphasized with the DMS because it provides a wider range of features. According to TESV, the information systems should include standard interfaces as much as possible in order to ensure (at least theoretically) the compatibility with other systems. In the past DMS was considered more just as a support for the SCADA system but nowadays it has much wider functions which must be taken into account when choosing a suitable system. These functions include also the possibility for outage reporting. According to the interview, all information systems should today have strict information security policy. [83]

It must be possible to integrate NIS with DMS and SCADA. However, outage reporting was not one of the aspects which were considered when choosing the NIS system over ten years ago, but the connection with the CIS was important. The main reason TESV has ended up with this described integration of IT systems origins from the past. The NIS and DMS systems were purchased around years 2004 and 2005 from the same supplier but in the background there were two separate manufacturers. This has led to the current situation. When choosing this integration TESV had taken into account that there was another large DSO which had exactly the same IT systems. This convinced TESV that the chosen integration will work and the systems and integrations will be developed also in the future. A weakness of this situation is that it can be difficult to get all manufacturers around the same table to discuss about the development of the systems. However, according to the interview it is also considered as risk management to have systems from different manufacturers. This spreads the risks, and if one manufacturer stops providing services or developing the systems, all of the systems are not in problems at the same time. [83]

According to the interview, the work required for outage reporting has increased greatly due to the Metering point-specific outage reporting. The easiness of outage reporting is considered to be important because for example the compulsory Metering point-specific outage reporting does not turn a direct profit for the DSO itself. However, reducing the KAH values would have influence on the DSO’s allowed profit but according to the interview TESV didn’t consider the entity of outage reporting as a very profitable function.

The most relevant MV outage information comes automatically to the DMS system and the amount of manual work is thus minimal. However, for example the cause of the fault has to be added manually as it is not received automatically from the primary process. This information is received via phone from the work crews and it is added to the DMS by the NCC operator. In case of HV outages the information is not necessarily received automatically from the primary process so the outage reporting is mainly manual. [83]

The LV network outages come to the DMS through CareCenter (CaCe) WMS, and the information for the LV network reports origins usually from the customers who call to the customer service or straight to the NCC outside office hours. The information related to the fault is added to CaCe completely manually. CaCe is used also in work management. The LV outage report is first created when receiving the information of the fault, but when repairing the fault, the outage report is updated by the NCC according to the information of the work crew. All changes and updates are done to the CaCe and the changes flow automatically to the DMS which finally handles the outage reporting further. [83] The information flows between the IT systems of TESV from the aspect of outage reporting are presented in the Figure 28. Blue color represents the systems or products of ABB and orange color other products.

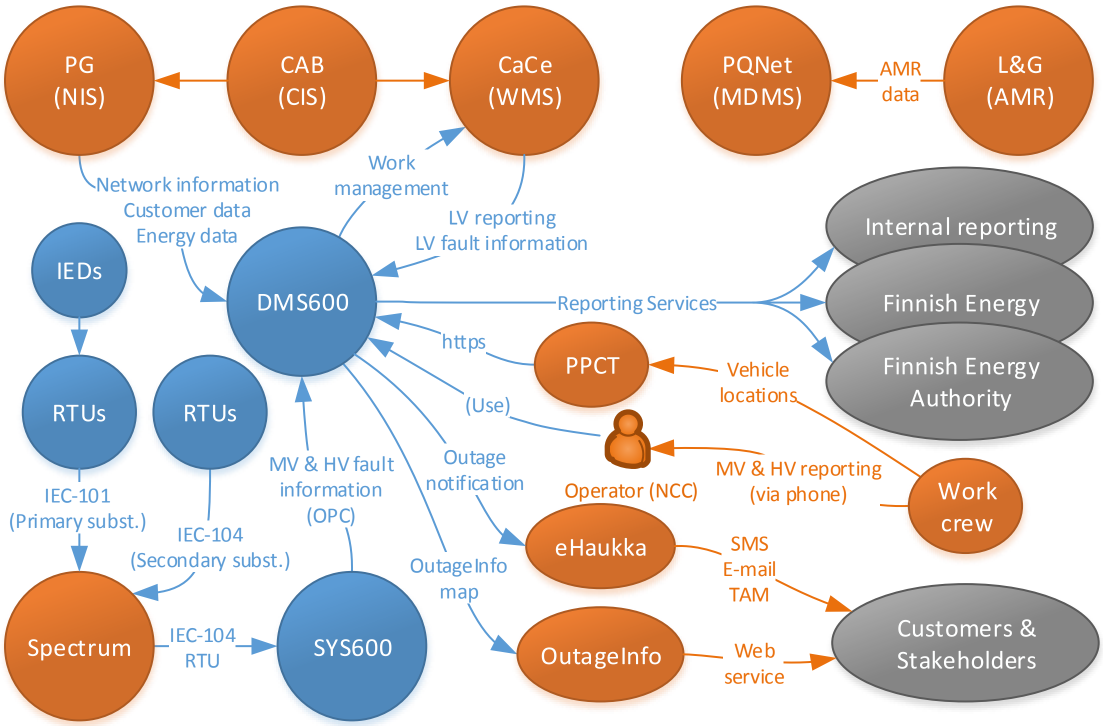


Figure 28. *Information flows between the IT systems of TESV.*

TESV uses Landis&Gyr's energy meters, which were once acquired mainly for energy metering purposes instead of AMI functions or even alarming functions. In case of AMI this reporting work could be done with more automation but it would require compatible smart meters which are able to send the fault information to a MRS system which again should be connected to DMS. Even if these functions were automatized, the DSO would have to verify the automatically filled or initialized report. On the other hand, the AMI would provide more versatile benefits for the DSOs than only semi-automatic LV outage reporting. Using the AMI enables the remote LV network management and alarming functions, for instance. This would facilitate the work of customer service and system operators, and the fault management would be faster. As the AMI would require purchasing new smart meters, TESV has upgraded the current meters so that they record the faults. This enables TESV to get the fault information from the LV networks, but only retroactively because the information from the energy meters is provided to a file once per a day. Hence this solution does not yet provide real-time alarming functions. The PowerQ's PQNet MDMS software reads the file but is not connected to the DMS600. Currently TESV has to use two different systems in order to clarify the precise outage durations for the customers because in CaCe (and hence also in DMS600) the starting time of the LV fault is registered when the customer calls to the customer service but the PQNet includes more precise starting times. However, it should be possible to bring the alarming functions also straight and in real-time to DMS600 with a proper integration implementation with Landis&Gyr meters and a modification to the reporting process. [83]

According to the interview the SAIDI is one of the indices which are used in the internal reporting and with the Balanced Scorecard (BSC). SAIDI has influence on the bonus payments of the company as well. Also KAH values are monitored and obviously the target is to reduce the costs caused by KAH. These and other information is reported for the management personnel. The monthly reports indicate the current state of the distribution business. The main tool for internal reporting is currently MS Excel. However, the outage reports used in the internal reporting originates mostly from the reports created by DMS600. The TESV representatives consider that the reporting for EV and ET causes plenty of additional work. If the benefits of the compulsory reporting can be pointed out, the TESV representatives might consider it somewhat reasonable and fair in the regional monopoly business. On the other hand, too much of bureaucracy causes only meaningless work and unnecessary costs for the DSOs and therefore also for the customers. [83]

TESV considers that the information flows related to the customer notification are very important as they will get immediate contacts from the unsatisfied customers if there are outages and the customers are not informed that the DSO knows about it. Hence the outage info map, SMS and E-mail messages and the voice messages of TAM towards customers are crucial. Also TESV's internal notification and notification for media, authorities and other stakeholders is implemented through eHaukka. PG system provides the energy consumption data which allows DMS to calculate KAH values for outage reporting. KAH values are important as they have a direct impact on the profits of the DSO. Only minor development ideas for the reporting came out during the interview and they were mainly related to the user-friendliness of the reporting process. One example was that filling the reports in DMS600 should be such that after the fault reason is choosed, the next dialogs should not propose impossible options for the chosen fault reason. [83]

5.2.2 Tampereen Sähköverkko Oy

Tampereen Sähkölaitos is a consolidated corporation which is owned by the City of Tampere. The corporation has server its customers already since 1888. The corporation consists of Tampereen Sähkölaitos Oy which is the parent company of the corporation, and Tampereen Sähköverkko Oy and Tampereen Vera Oy, which are its subsidiary companies. Tampereen Energiantuotanto Oy, Tampereen Kaukolämpö Oy and Tampereen Sähkömyyynti Oy merged into Tampereen Sähkölaitos Oy in the end of year 2015. [92] Figure 29 presents the new organization chart which is valid since beginning of year 2016.

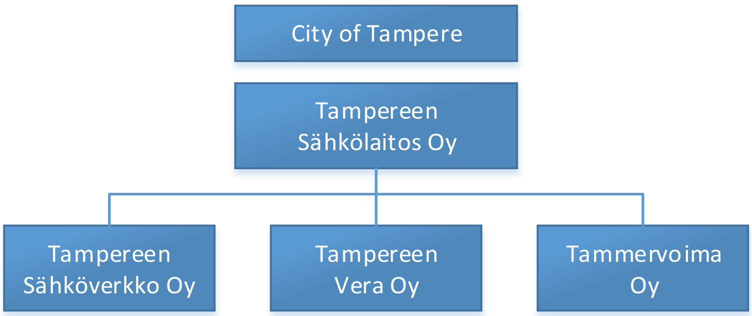


Figure 29. *New organization chart of Tampereen Sähkölaitos Oy from the beginning of year 2016 (adapted from [92]).*

In 2014 Tampereen Sähköverkko Oy (TSV) supplied over 142 000 distribution network customers [89], which makes it a large DSO. The whole Tampereen Sähkölaitos Corporation provides employment for about 400 people. Figure 30 represents the TSV distribution network area divided into six regions [93]. The density of customers near Tampere city in the four smallest regions is great compared to the two largest Teisko Northern and Teisko Southern regions which are the two northmost areas in the Figure 30. The Teisko regions are mostly not town plan area. In 2014 the total network length of TSV was over 3 750 km, of which about 80 km was HV network. [89].

Figure 30. *The distribution network area of TSV divided into six regions [93].*

The DMS, NIS and SCADA systems of TSV are listed below.

- DMS Trimble DMS
- NIS Trimble NIS
- SCADA ABB MicroSCADA Pro SYS600

The NIS was taken into use in 1997 and the DMS was purchased in 2001 but officially it was taken into use in 2002. The SCADA has been in use already since 1999. The current CIS was taken into use in 2008. The IT systems of TSV are presented in the Figure 31. The most relevant information flows related to the outage reporting between the systems are described as well. The Generis CIS provides the customer and energy data for the Trimble NIS within a specified schedule. This data is used in outage reporting which is implemented with the Trimble DMS. However, Trimble NIS provides information also back to the Generis. For example coordinates and substation information of the customers are delivered to the CIS. This has to be done because the switching states of the LV networks may alter and hence the substation which supplies a certain customer may also change. The substation information of the customers is stored and updated in the NIS database according to the switching state of the network. Compared to the DSOs using DMS600 and SYS600, there is a difference as TSV does not have the remote-controlling functions of Trimble DMS in use. Their objective is to take these features in use in the future because of the increasing amount of substation automation. [84]

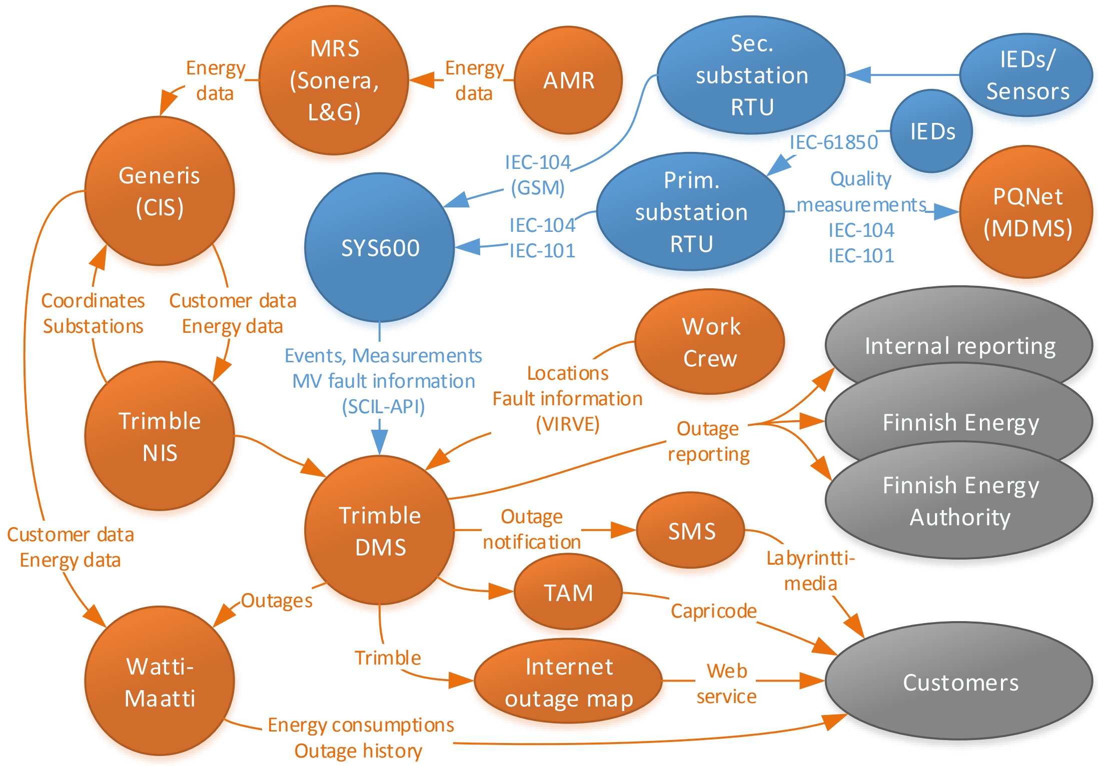


Figure 31. *Information flows between the IT systems of TSV.*

As presented in the Figure 31, TSV has purchased two separate MRS services from Sonera and Landis&Gyr (L&G) and both of them are connected to the Generis. The Sonera MRS includes approximately 100 000 meters for smaller, under 63 A customers, and the L&G MRS consists of larger meters, most of them being current transformer meters. The substation information is needed in the CIS as some of the AMR meters are used by PLC connections with DCUs located in the substations. Alarmings and other AMI functionalities are not used in TSV. The meters would support inquiries from the DSO's systems and therefore could indicate if the customer is supplied or not, even though the AMR meters were purchased originally for energy metering purposes. However, the two parallel MRS systems would cause challenges in the integration with the DMS, and therefore the integration is not implemented and these functionalities are not in use. [84]

The outage notification is implemented with various parallel systems. The SMS service provided by Labyrinttimedia sends SMS messages during the faults to the related customers. The TAM provided by Capricode in turn eases the work of customer service as it takes care of many customers who call the NCC. Third application is the Outage map (Outage info) which is Trimble's product. Outage map is a web service which shows the amount of unsupplied customers, faults and maintenance outages in the map. The distribution area of TSV is divided into six areas in the outage map, as can be seen from the Figure 30. If the customers want to achieve information of their outages afterwards, it can be done by using the WattiMaatti web service. Enoro's WattiMaatti is a service for customers to monitor their energy consumptions but also the outage history information is provided. In addition to SMS messages, also e-mail messages are provided for the customers if they have chosen to receive them. [84]

PQNet, provided by PowerQ, is a MDMS which is used to monitor the quality measurements in the primary substations. The RTUs in the substations send the data to the PQNet. PQNet is a separate IT system which is not connected to the other systems. PQNet is not located in the TSV's premises but is used through a web application. If the quality of electricity is not monitored, there might occur outages because of the bad quality, e.g. caused by too high or low voltages. RTUs however provide crucial information about MV network's events, measurements and faults as well. Although outage reporting receives plenty of information automatically from the primary substations, the outage reporting has not been considered much when TSV has planned the substations, the related devices and communication in the early days. The communication between RTUs and SYS600 (SCADA) is implemented with IEC-104 protocol and IEC-101 is used as a backup. Optical fiber is used as primary connection and copper cable as secondary connection. SYS600 delivers this information also for Trimble DMS which uses the information for outage reporting, amongst other things. SYS600 is connected to Trimble DMS via SCIL-API protocol. Currently operating the switches is not possible from the DMS but one objective is to enable it. The need for this becomes more relevant later on as according to the interview TSV will take in use new secondary substation automation in the near future. Currently the secondary substation automation is connected via GSM to the NCC and the substations have REC-615 devices. [84]

TSV uses HeadPower WMS in planning and construction but it is not connected to the DMS system. Hence WMS is not used in outage management. When communication is necessary between the NCC and the field work crew, it is done by communicating over the VIRVE network (Viranomaisradioverkko, government official radio network), which is the Finnish authorities' telecommunications network. The communication is needed when repairing the faults in the network. This is a reliable communication solution as it works even if there is a larger power outage where the mobile networks cannot be used. All of the information related to the faults cannot be acquired automatically and therefore they are received manually from the work crew. Thus some of the information flows related to the fault information given by the work crew are actually talk. The work crews are located with an application created by F-Solutions. This application locates the VIRVE phones and the location information is provided for the DMS which shows the work crew locations in the map. [84]

According to the interview, the most important aspects when purchasing a new SCADA system are reliability and usability. The system has to work on any circumstances. Learning the user interface and using the SCADA system has to be simple enough. On third comes the connectivity and interfaces to other devices and IT systems. When TSV was purchasing the DMS system, the most important requirement for the system was that it has to support a schematic (topological) view which enables the operator to see the state of the network at single glance. There are no automatization which would draw the schematic view from the geographical view so the digitizing work has to be done twice. According to interviewees this view is useful especially in the city areas as picturing the topology of the network and different fault situations is faster. With the geographical view the operator would have to open substation diagrams separately in order to observe the situation. Correspondingly, the most important criterion for the NIS was the support for a precise location map which is used in TSV's own operation (planning and constructing). Also today it would be the key function. This location map is a feature of Trimble NIS which contains the precise underground structures of electricity network, streetlight network, district heating network and the spare pipes. Also the depth information of different cables and pipes is included in the map. The information related to the location map is stored in the same database as other network information. According to the interview the reporting requirements (especially outage reporting but also asset reporting) would also stand out when choosing suitable DMS and NIS systems today. These are considered interesting because the network asset values and KAH values affect on the allowed profit of TSV. The interviewees also considered that without DMS the daily operation would be impossible today as creating the reports without DMS would be so laborious. The interviewees see that it is a basic requirement that the IT systems gather relevant and correct data, but the question is how advanced the data processing is and how well the information is presented to the user. According to the interview, it does not matter if SCADA, DMS and NIS systems are separate IT systems or a combined all-inclusive system as long as the communication between the systems and towards other systems works. Today these systems are so tightly connected that they have to be considered as a whole. In addition, it is important that there is only one place where the information (e.g. related to a component) is set and those systems or functions that need this information get it automatically. [84]

TSV exploits the outage and other reports created for authority also for their own benefits. The company uses those reports as basis and modifies them according to their needs. Internal reporting is exploited mainly by the management team. The outage reports for internal needs are monitored every month and the network asset value every fourth month. KAH values are reported monthly because it affects directly to the allowed profit. They are compared to the reference KAH values. Those feeders which cause most of KAH are listed and the purpose is obviously to reduce the total KAH values. The outage amounts are listed and divided by voltage levels and fault types. Network asset values and information about the demolished components are also interesting for the management team. [84]

5.2.3 Leppäkosken Sähkö Oy

Leppäkosken Sähkö is a consolidated corporation which consists of Leppäkosken Sähkö Oy and its subsidiary companies Leppäkosken Energia Oy and Leppäkosken Lämpö Oy. In addition also subsidiary companies FC Energia Oy and FC Power Oy belong to the corporate group. [94] Together with eight other DSOs Leppäkosken Sähkö uses the services of Satapirkan Sähkö Oy (SPS) [95]. Eight of these DSOs have unified their DMS, NIS and SCADA systems so that the maintenance of the systems is outsourced for the SPS and all of the subcompanies are using basically the same systems.

In 2014 the network length of Leppäkosken Sähkö was over 4 150 km. During that year Leppäkosken Sähkö supplied almost 29 000 customers and therefore is a medium-sized DSO. The DMS, NIS and SCADA systems of Leppäkosken Sähkö are listed below.

- DMS — ABB MicroSCADA Pro DMS600 (WS)
- NIS — ABB MicroSCADA Pro DMS600 (NE)
- SCADA — ABB MicroSCADA Pro SYS600

Hence all of these three IT systems are provided by ABB. Leppäkosken Sähkö was interviewed in order to describe all of the IT systems and their connections related to the outage reporting. The most critical features of these three systems were discussed, and development ideas related to the outage reporting were gathered.

Figure 32. *The distribution network area of Leppäkosken Sähkö Oy (No.5) and 8 other DSOs which are customers of SPS Oy [95].*

The CIS used by Leppäkosken Sähkö Oy is Tieto CAB which delivers the customer data for the DMS600. The energy data is provided to the DMS600 by Tieto EDM (Energy Data Management), which again is connected with Aidon Gateware MRS. Aidon AMR devices provide energy data and alarmings for the Gateware which delivers the alarmings for the DMS600 and the energy data for the EDM. Leppäkosken Sähkö has also a few Landis&Gyr AMR devices but the majority of the devices are provided by Aidon. For customer service Leppäkosken Sähkö has a separate CSMS system called Contact Manager. According to the interview, Leppäkosken Sähkö is considering to use the AMI functionalities in the future. [96] In Leppäkosken Sähkö these functionalities are generally called as PiHa (Pienjänniteverkon Hallinta, LV Network Management) features. The PiHa concept is originated from a co-operating project of several companies and TUT. The project was based on the integration of new generation AMR devices, communication solutions and the DMS system. The project was piloted in Koillis-Satakunnan Sähkö Oy during 2006 and 2007. [55] Leppäkosken Sähkö Oy will pilot their PiHa features during 2016 and after the piloting season the features are taken in use if there will not be excessive difficulties. According to the interview, only three subcompanies have Aidon’s AMR meters, which may restrict an extended use of these functionalities with every subcompany in the near future. [96]

The CaCe WMS belongs to the product family purchased from Tieto, but according to the interview, it is not widely used. Instead, the Newelo WMS is used in work management and reporting purposes. DMS600 provides the necessary work management information for Newelo, including MV faults, LV faults, MV maintenance outages, LV maintenance outages and network structure information. Newelo is connected to the Newelo Mobile applications which are used by the work crews. The work crews make their reporting work to the Newelo Mobile and also receives the necessary information of the works via the mobile application. The mobile applications are used with tablets in Leppäkosken Sähkö, and e.g. the necessary LV fault information for the Energy Authority’s reports are provided. The mobile devices are also located when the Newelo Mobile application is used, and the located work crews are shown in the map in DMS600 (WS). With MV faults the information flows between the NCC and the work crew are at least partly in a form of speaking. Practically the mobile phones are used, but also the radio network is exploited during major disturbances. For security reasons the NCC is obligated to lead the switching operations with these higher voltages via phone, so the necessary fault information is delivered in the same time. [96]

Leppäkosken Sähkö has a service agreement with Posti (Posti Group Oyj, Finnish postal office owned by the state), which takes care of sending the notification outage cards prior to the maintenance outages are carried out. Then again, Leppäkosken Sähkö uses SMS services provided by Samcom. The SMS services are used for fault notification and maintenance outage notification for the customers. The SMS messages are sent when the outages are starting and ending. Leppäkosken Sähkö considers the SMS services to be a crucial part of notification today, as the SMS messages are an efficient way to reach the customers. On the other hand, the IT systems have to work properly because the SMS messages shall not be sent to the wrong customers. In the future the purpose is to further increase the share of SMS messaging in the notification services. [96]

The basic NCC operation is outsourced for the SPS Oy and only during major disturbances the NCC of Leppäkosken Sähkö is occupied. This is done in order to make the fault management more efficient. The LV faults informed by customers are taken care by the NCC personnel. The operator creates the LV fault straight to the DMS600 according to the given information. If the NCC of Leppäkosken Sähkö is occupied, Newelo WMS is used to create LV faults in the system. As can be seen from the Figure 33, Leppäkosken Sähkö uses a TAM service provided by Capricode. The TAM is integrated with DMS600. It is used to enhance the customer service but also to reduce the amount of disturbing customer calls. [96]

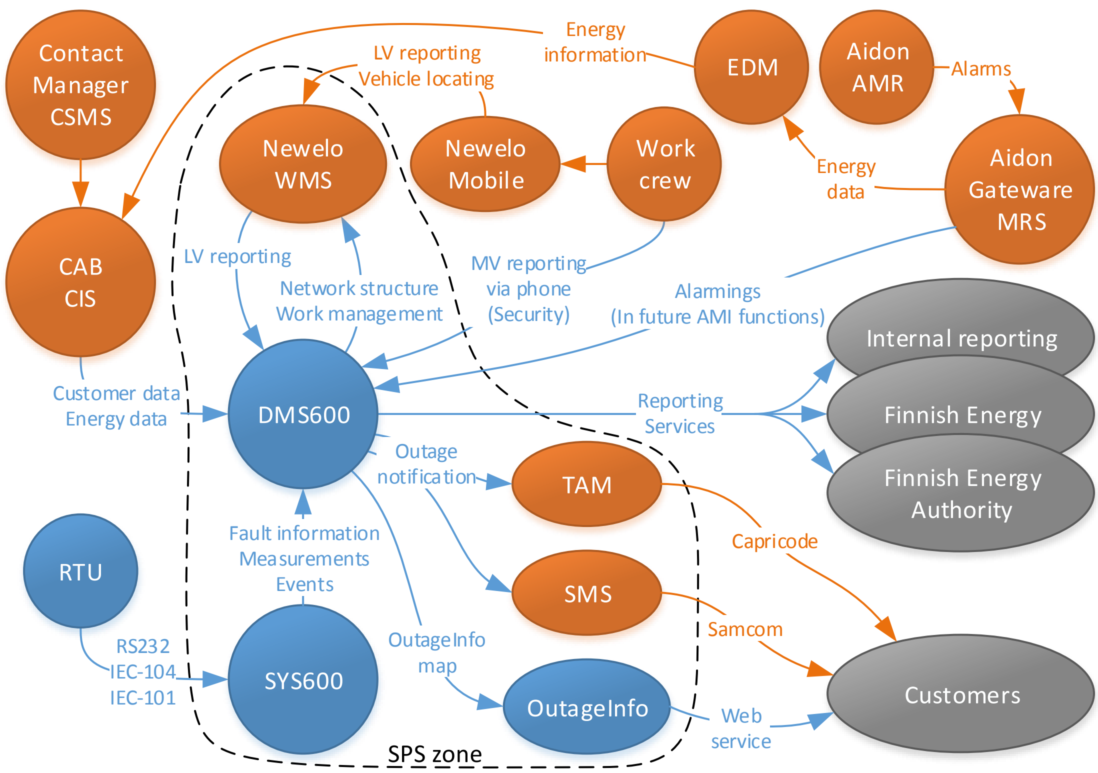


Figure 33. Information flows in the information systems of Leppäkosken Sähkö Oy.

Connections between substations and SYS600 are implemented with optical fiber and copper cables. The share of these connection methods is somewhat even. Optical fiber is used only where it is cost-efficient, which leaves the furthest locations for the copper cable connection. The connections from RTUs towards the NCC use serial communication, IEC-104 and IEC-101 protocols. Today the serial communication protocols are still the majority but IEC-104 is considered to be more common in the future as the new substations will be using IEC-104. Leppäkosken Sähkö owns the primary substations and according to the interview Leppäkosken Sähkö owns also HV network today, as a part of the HV network which was previously property of SPS belongs currently to Leppäkosken Sähkö. [96] In 2014 the situation was different as the statistics of the Finnish Energy shows that Leppäkosken Sähkö had zero kilometers of HV network [77]. Secondary substation automation is not used, but some simple switching stations exist. However, the current solutions for the transformer substations have been made so that retrofit installations for the secondary substation automation is possible. [96]

Leppäkosken Sähkö considers the reliability to be the most important aspect when purchasing a SCADA or DMS system. After the reliability come the features the products can provide. According to the interview, when using the DMS system today, the interest is often in the outage reporting and the objective is to analyze and reduce the KAH costs. Today the reporting is a crucial function of NIS as well. The reporting of Network Asset Values such as the RV and the Net Present Value (NPV) for the Energy Authority is in important role. From the view of Leppäkosken Sähkö the used interfaces don’t necessarily have to be standard interfaces. Their experience shows that it has been possible to get the interfaces working in any cases if necessary. Hence the fact whether the implementation is done with standard open interfaces or vendor-specific interfaces is not such crucial. However, Leppäkosken Sähkö prefers modular solutions overall because e.g. some of the smaller DSOs belonging to the SPS Oy’s service don’t need all of the features the bigger DSOs do. The basic idea is that all of the DSOs wouldn’t have to pay for the features that only some of the DSOs need. [96]

According to the interview, Leppäkosken Sähkö would appreciate if all the information which can be provided with reports, would be also possible to see straight in the map of DMS. Another important viable feature of DMS600 would be to show the costs caused by outages (KAH). Even further taken, the development idea is that the costs of the outages would be beneficial to see in real-time when the outage is still active. This would be a very efficient tool to prioritize the outage management operations especially during major disturbances. If the NCC operator could directly see the outages causing relatively much costs, those outages would be prioritized to be handled first. This optimization would reduce the overall costs of DSO but also focus the outage management resources into the correct locations of the network. [96]

According to the interview, the RV of the whole network should be automatically estimated by the NIS for the future years. The information needed for the estimation calculation could be gathered from all of the network plans having estimated implementation dates. The estimation should take into account the current network situation and all of the network plans. This would be beneficial when the DSO tries to explain and verify to the Energy Authority that the development plans they have made in order to respond to the Distribution Reliability Requirements (DRR) sufficiently. After the *Caruna-case* (see [97], [98] and [99]) Leppäkosken Sähkö evaluates also that the authority supervision might experience some changes in the future and that the criteria might be changed due to such raises in the prices. [96]

Leppäkosken Sähkö reports and analyzes the KAH values monthly for internal purposes. The fault-specific KAH values are also considered as useful, and they can be used to find reporting mistakes in the system. In the LV side the outage reporting divided by fault types is important as well. Some of the reports which are needed e.g. for internal purposes every month would be beneficial to get automatically out of the reporting service. The reports could be sent e.g. to the specified emails in a certain day of month and in a certain form of data. [96]

According to Leppäkosken Sähkö the biggest change in the information flows during the recent years are the mobile applications. Another one are the AMI (PiHa) functionalities which are already in use in some DSOs. This reduces the unnecessary visits in the service points, enhances the working of customer service and fastens the outage management. The AMI functionalities also notice the faults in the customer's network immediately, without the need to travel on site. Leppäkosken Sähkö considers also the up-to-date map information in the Newelo as a useful functionality. [96]

5.2.4 Elenia Oy

During 1995–2000 Vattenfall acquired six somewhat large local DSOs from Finland. Later in 2012 Elenia bought Vattenfall's Finnish electricity distribution and heating businesses. Elenia is owned by Ilmarinen Mutual Pension Insurance Company, Goldman Sachs and 3i. Elenia (excluding Elenia Lämpö) provides employment for about 270 people. [100] It owns plenty of rural area network and has experienced the effects of major disturbances during recent years. Hence Elenia has decided to build the new and renovated network with underground cables. [3], [4] It is predictable that in the future the effects of major disturbances will be relatively low due to increasing and already extensive underground cabling. According to the Energy Authority's documents, in 2014 Elenia had over 414 400 network service customers in its electricity distribution system and is thus a large DSO. The total length of distribution network was over 66 700 km. Elenia also owned over 1000 km of HV network. [89] From the Figure 34 can be seen that the distribution network area of Elenia Oy is quite large, and actually Elenia is the second largest DSO in Finland [101].

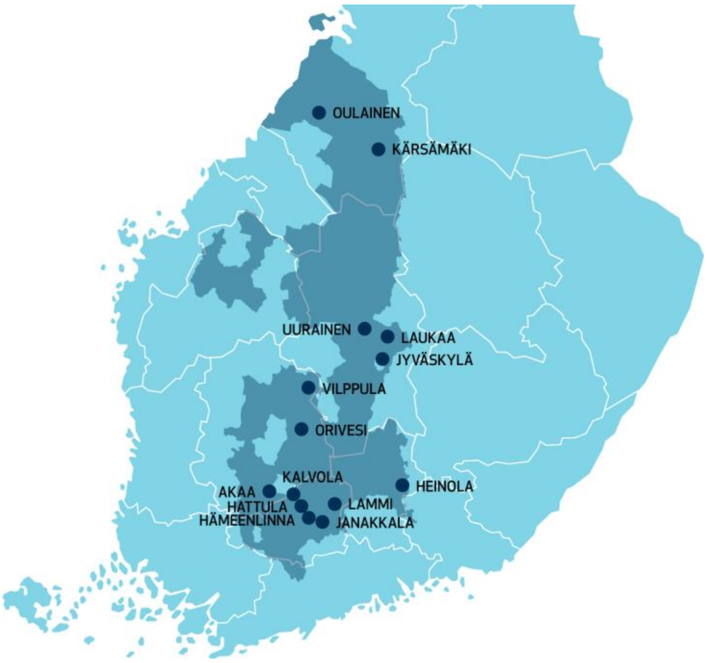


Figure 34. *The distribution network area of Elenia Oy [102].*

Elenia Oy's DMS, NIS and SCADA systems are presented below.

- DMS Trimble DMS
- NIS Trimble NIS
- SCADA Netcontrol Netcon 3000

Netcon 3000 SCADA was acquired in 2001 and after that it has been upgraded in 2009 and during 2013–2014 the capacity has been extended. NIS is used long time before the millennium but the integration of the current DMS, NIS and SCADA systems is combined after the Netcon 3000 SCADA was acquired. The integration between SCADA and DMS is implemented with a standard protocol. An important reason today for the acquirement of Netcon 3000 SCADA would be the integration with the Trimble DMS and their common FLIR functionality, which has been in use for about five years. According to the interview, taking a new SCADA system in use is probably a lot more expensive than updating a current one. Hence if the new SCADA system was considered to purchase, it would be important to see what are the additional values that the new SCADA could provide in the long term compared to the current system and its integration. Such additional value could be for example an integration with DMS (and NIS) having a functionality which would not require double documentation of the distribution network. If a new network is drawn into the NIS, the integration would make the same change also to the SCADA system. However, this kind of functionality has not yet been presented to Elenia. Another value would be the development of the self-monitoring functionalities of the SCADA related to the connections to the distribution process. In addition to the reasons related to the business benefits and technological solutions, Elenia mentions the operative costs occurred in the life cycle of the systems. This reason applies to all of the systems.

When acquiring a new system, it is important for Elenia that the system provider can present its roadmap for the future years. Elenia has its own roadmap which has to be compared to the roadmaps of the system providers. If, for example, SCADA provider can not show the roadmap of the future and upcoming features, Elenia has to make the evaluation based on earlier accomplishments of the provider. [103]

The communications between the substations and NCC are implemented with standard IEC protocols. The network uses TCP/IP protocol and mainly 3G/4G with primary substations and 2G with secondary substations. In addition to the FieldCom service from Emtele, Elenia takes care of about 400 disconnector station connections on their own. [103]

Elenia trains their employees to a certain level in operations supervising. This includes information of how to use SCADA in certain level in order to manage the major disturbances as well as possible. Hence the usability of SCADA is in an important role. According to the interview, more important than the amount of IT systems is that the amount of different UIs is little. [103] As described in the chapter 2.2.4, the MicroSCADA Pro WebUI is going towards this direction. One major challenge in the Elenia's NCC is that currently the operator is not able to control the switching devices directly from DMS because the SCADA-DMS integration does not support it. According to the interview, the SCADA system has to be always online and usable. Hence for Elenia it is hard to believe that SCADA and DMS system would be combined into single entity. One important function of NIS is the asset management, including the management of the ages, amounts and values of the network components. Another is the network condition management and the functions related to the development and planning of the network. Correspondingly for DMS one important aspect is to exploit the automation which exists in the distribution network. The evaluation of the customer impacts and the customer communication is also considered to be important. In both NIS and DMS the basis of the operation origins from the authority requirements which have to be fulfilled. [103]

Elenia uses Microsoft AX as ERP (Enterprise Resource Planning) system. AX handles for example the job order procedure and material management amongst other ERP functionalities. The job orders go from AX to contractor and the receipts back to AX. In addition there is also a separate Contractor Portal which allows the contractors to use NIS functions through a Citrix remote service. Elenia doesn't have separate WMS system in addition to the ERP but the work management is handled partly from ERP and partly from NIS, and the fault job orders are created straight from the DMS. [103] The IT systems of Elenia Oy related to the outage management and reporting are presented in the Figure 35.

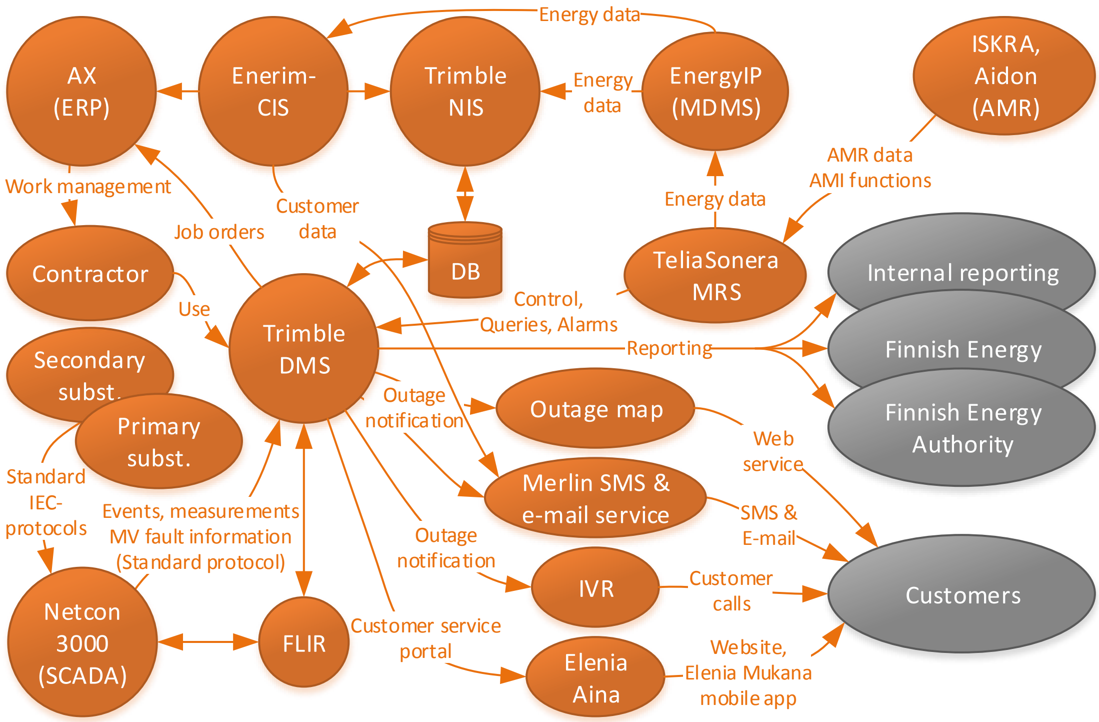


Figure 35. *Information flows between the IT systems of Elenia Oy.*

The communication between the work crews and NCC is implemented with a Group Call System provided by Capricode. According to the interview, the most important systems related to the outage management are indeed SCADA, DMS and Group Call System. During the interview turned out that the communication via Group Call System is somewhat congested during major disturbances. In further details, the work crews must contact the NCC before acting in the fault zone, but the operator may have several work crews waiting for their turn to speak with the operator. [103] Hence this may often cause a bottleneck in the fault management process. This is further discussed in the Results chapter.

The AMR meters are connected into TeliaSonera MRS which is again connected to eMeter EnergyIP MDMS. EnergyIP delivers the data for NIS and CIS. Most of the AMR meters in Elenia's distribution network are Iskra AMR meters but e.g. Aidon AMR meters exist as well. Mobile networks are used in communication. Inquiries for the meters and spontaneous alarmings are in use today and the service disconnection function can be used with new meters. Elenia has installed the first AMR meters over 10 years ago and since then has upgraded the softwares of these meters in order to get the wanted, more advanced functions available. Automatic validation for the energy measurements is done before the information is brought to the CIS. [103]

In Elenia the location information of work crews is not traditionally brought to the DMS as the work management belongs to the contractors and the contractors make the decisions on which work crew takes care of which fault. However, currently there is an ongoing pilot where work crew locations of a single contractor is brought to the DMS. [103]

To ensure a good customer service, Elenia provides a customer web portal Elenia Aina. In addition, Elenia has taken in use mobile application Elenia Mukana which is customer's own portal. Furthermore, there are Internet outage map web service based on the network topology of Trimble DMS, and IVR (Interactive Voice Response) phone service which is a corresponding service to TAM. Also SMS messages and E-mail messages are sent during outages, not to forget the direct customer service available for the customers. [103]

In Elenia the LV outage management process starts when customer calls to Elenia customer service (to NCC outside office hours) or a spontaneous alarm comes from the AMR meter. The fault is created into the DMS by NCC and the contractor has an employee who receives a message that there is a fault in the system, and then takes care of these LV faults existing in the network by sending a work crew to repair the fault and updating the information of the fault. When the work is done, the reporting and validating of the fault is done straight to the DMS by the contractor. In Elenia the work crew has the responsibility to estimate the fault duration when the fault is located and the fault reason is known, because it has the best information to do that. [103]

Elenia performs several different kind of internal reporting. In the weekly basis the NCC operators report the most important events and key figures of the week. Elenia gives voluntarily compensation to the customers which have faced outages with a duration more than 6 hours. Amounts of long outages (> 3 min), amounts of outages having durations more than 6 h with main reasons for the exceedings, and the amounts of outages which are close to the official outage compensation limit (12 h) are reported weekly. These reported values are built with access queries directly from the databases. Furthermore, there are monthly reports where the key figures caused by major disturbances are separated from the other data. These reports contain SAIDI, SAIFI, CAIDI and MAIFI indices. The indices are proportioned to the last 12 months. Other reported characteristics are the cumulative and monthly amounts of MV faults, LV faults, MOs and autoreclosings. Obviously the KAH-costs are monitored closely because the regulation model takes them into account and hence KAH-costs have a direct impact on the allowed profit of the DSOs. Other followed figures are the e.g. amounts of sent SMS messages, customer satisfaction for the fault services, outages divided by durations, SAIDI of MOs and the Elenia's share of the live-line workings. An example of anticipatory measures done in Elenia is monitoring the repetitive autoreclosings by feeders, which causes proactive actions if the reclosing frequency is too high. Thus there are a lot of information that is monitored regularly and hence a more specific observation is done only when necessary. The reporting for the Finnish Energy and the Energy Authority is done with Trimble's reporting tool to ensure that the reports are similarly produced in every DSO who are using Trimble DMS. These reports are created semi-automatically just by pressing a button. [103]

According to the interview of Elenia, it would be beneficial to have a report which lists the most expensive sections in the network delimited by disconnectors. The same method can be used also e.g. for the LV networks and whole feeders. This would facilitate the investment process because the DSO would know in which locations are the most important investment targets. Such reports would need specific fault location history data. Elenia renovates a lot of overhead lines from the network and replaces them with underground cables during the next years, so the allocation of the underground cabling is an important part of their operation and these reports would give valuable information. An advanced solution for reports related to the investment allocation would be such that the reports would automatically inform the user where and what kind of investments are needed. [103]

5.2.5 Järvi-Suomen Energia Oy

Järvi-Suomen Energia Oy (JSE) belongs to the Suur-Savon Sähkö Oy consolidated corporation. During 2014 JSE responded of the electricity distribution for over 100 000 customers including about 1 134 GWh of distributed energy [104]. Hence it is a large DSO. In 2014 the network length of JSE was almost 27 500 km, of which over 400 km was HV network [89]. A great share of the JSE's distribution network is located in not town plan area. The distribution network area of JSE is presented in the Figure 36.

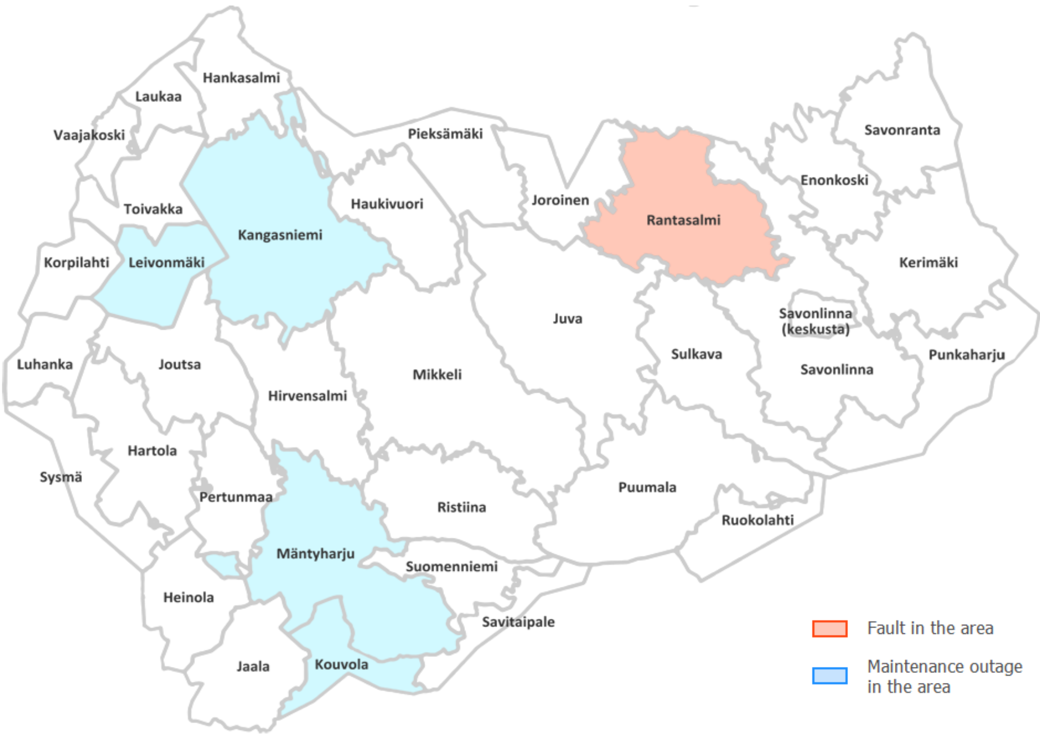


Figure 36. *The distribution network area of JSE presented in the outage info map. Red color indicates a fault in the area, blue color a maintenance outage (adapted from [105]).*

About 40 % of the primary substations are connected to SCADA by optical fiber. Currently the rest use mainly a radio link communication. The share of optical fiber connections is strongly increasing in the future. Tosibox 3G plug & play connectivity solutions are used as a backup communication method between some primary substations and

SCADA if other solutions are not possible. Additionally, a few GPRS connections exist as well. The amount of substation automation is relatively little. A common solution in JSE is that several disconnector stations are connected to a single gateway with Netcon 8810 protocol and radio link communication. Some of the disconnector stations don't understand Netcon 8810, so they use IEC-101. The gateway then uses IEC-101 protocol to communicate with SCADA. The IEDs in the primary substations are connected to RTUs with SPA, Netcon 8830 and IEC-61850 protocols. Most of the connections are using SPA but all the new connections use IEC-61850 which will become more common in the future. The RTUs communicate to SCADA primarily with IEC-101 and IEC-104 protocols. [106]

The DMS, NIS and SCADA systems used by JSE are listed below.

- DMS: ABB MicroSCADA Pro DMS600 (WS)
- NIS: Tieto PowerGrid
- SCADA: Netcontrol Netcon 3000

Netcon 3000, which was acquired in 2010, is connected to DMS by OPC. A common OPC connection of Netcon 3000 and DMS600 systems is presented in the chapter 4.4.2. Netcon 3000 was considered as the most reasonable solution in the time of decision. The features and services of different providers were evaluated and rated. The usability of SCADA and technical support are considered to be crucial. Because there is very much of reconstruction work in the network during these times, JSE considers that the easiness of configuration of SCADA is important as well. Correspondingly, DMS600 was acquired in 1999 and PG during 2004–2005. The network, customer and energy information from PG to DMS600 is delivered with transfer files (network.txt and customer.txt). The IT systems used by JSE are shown in the Figure 37, which also presents the information flows between the systems from the aspect of outage reporting. According to the interview, the most important requirement for DMS is reliability and second comes the outage reporting. The system has to provide reliable outage statistics and reports. Today the outage reporting has to be automatic and smooth. As JSE has plenty of experience from major disturbances, they consider that all the possible features cannot be added to DMS, or at least it has to be ensured that the basic outage management and reporting is not compromised because of the new features. JSE admits that there might have been some difficulties because all of the DMS, NIS and SCADA systems are acquired from different providers but the disadvantages are relatively little so it hasn't affected very much to the selection of these systems. According to JSE, it is also part of risk management that all of these systems are not purchased from the same provider. Commitment to a single provider isn't necessarily considered as the most desirable option. [106]

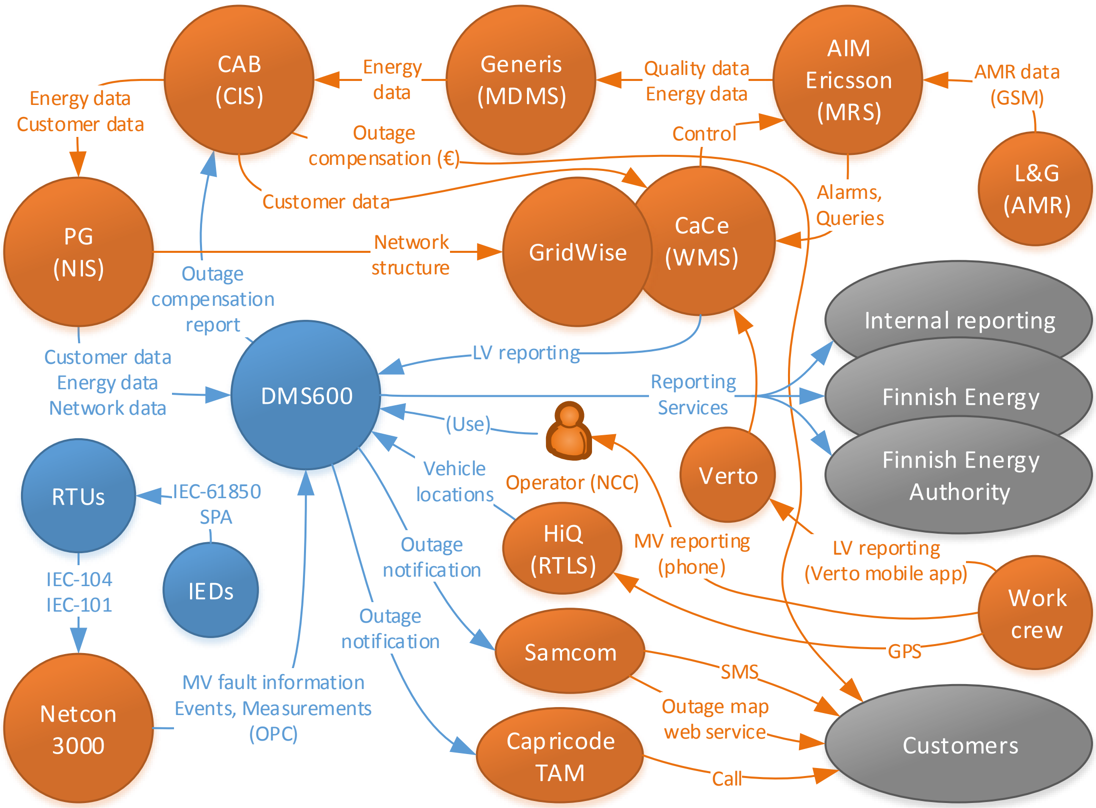


Figure 37. *Information flows between the IT systems of JSE.*

As can be seen from the Figure 37, the LV reporting is implemented with help of WMS interface. Tieto CaCe WMS is used to create the reports for LV faults and MOs. Also the AMI functionalities will be used. Most of the AMR meters are L&G meters but they are property of JSE. The AMR data is read to the Ericsson's AIM (MRS) system, which will provide time-sensitive data for the integration of GridWise and CaCe. This information consists mainly of spontaneous alarmings and answers for the queries of AMR meters. Also control functionalities of AMR meters can be used. In the beginning of the LV outage management process the customer usually calls to the customer service. The customer service enters the fault to CaCe. This information is delivered also to the DMS600 automatically. In the near future information of a missing phase, three-phase outage and neutral conductor fault will be delivered to the CaCe automatically from the AMR meters. This is in testing phase but a decision has been already made to bring the functions to the production environment. The operator receives the information and orders the repair job from the contractor by setting the name of the contractor to CaCe. During the office hours the work crew gets the order from the supervisor who schedules the job for the correct work crew. Outside office hours Verto schedules the job automatically for a work crew. When repairing the fault, the work crew uses Verto mobile app to add the necessary information to the report. The created CaCe LV reports are transferred automatically to the DMS600 which also automatically fills DMS600 LV reports according to the information provided by CaCe. If the LV report is initially created to the DMS600, it currently can't be shown in CaCe as the information flow for LV reports is unidirectional from CaCe to

DMS. However, the MV reports can have bidirectional information flows between CaCe and DMS600. In JSE the MV reporting is implemented so that the work crew calls to the NCC operator before any actions or switching operations in the field. This is a matter of security. During these phone calls also the necessary reporting information is provided for the operator, who then adds them to the MV report in DMS600. This is done because JSE should check and archive the reports anyway in some point. Hence mobile applications are not used in MV reporting. According to the interview, during major disturbances the communication via the Group Call System is often congested. [106]

When MV fault occurs in the network, SCADA creates a fault package and sends it to DMS which creates an ongoing fault and opens a fault management dialog. The fault information is transferred also to CaCe. First the fault zone is isolated with remote switching operations and at this point the fault duration is first estimated. The information of a secondary substation related to the fault is defined to the fault data. This information is then transferred to contractors via Verto. In cooperation with the contractor the fault is isolated even more precisely with manually controlled disconnectors and the estimated duration is further defined. The contractor finds the fault and calls back when the reason is found. Again the fault duration is estimated more precisely. The outage management state is also updated during the process. The estimated duration goes to the Outage map web service and TAM but is sent also directly to the customers via SMS. However, JSE stated that it is more important that the outage management features itself are working than the notification functions. The outage management process can not be compromised by any less important features. The switching states have to be 100 % correct because it is also a matter of security. [106]

The MRS system provides the time-insensitive data for the Generis MDMS system, which processes the data further and sends the energy data for CAB CIS. CAB sends the energy and customer data for PG NIS. PG NIS provides the network structure for the integration of GridWise and CaCe, and the network information, customer information and energy information for DMS600 which then uses this information on reporting. With this network structure information it is possible for GridWise to show the customers and AMR alarmings in the geographical view. [106]

The outage compensation reports are created from the Reporting Services and the results are brought to Excel. This report includes all the relevant source information in order to calculate the real compensation amounts in money. The Excel file is used to transfer the information into CAB which then directs the compensations to correct customers and calculates the exact compensation amounts in money for each related customer. Also ClickView reporting utility is used to process the data even further. For internal use JSE creates reports monthly. The SAIDI, SAIFI, CAIDI and MAIFI indices are followed monthly and compared to previous months. One of the most important followed indices is KAH. The key figures describing the quality of electricity distribution operation (defined by the Energy Authority) are followed regularly as well. [106]

6. IMPLEMENTATION OF THE OUTAGE REPORTS

This chapter describes the outage reports which were created or modified during the thesis. As the Distribution Reliability Requirement (DRR) report demanded most work, it is presented in a most detailed form. This chapter presents the usage and output of the reports. Also reasons why each of the reports are required are described. All the implemented reports are in Finnish. Translations in English will be probably done in the future.

The implemented reports can be used in Microsoft SQL Server Reporting Services (SSRS). The code was written with Microsoft Visual Studio with an additional module called SQL Server Data Tools – Business Intelligence (SSDTBI). The used programming language was mainly SQL but also Visual Basic was used. Also the earlier reports are implemented with the same tools, and there was no reason to change the method with the new reports. The implemented reports were tested mainly on the testing environments which are based on the real production environments, but two real production environments (JSE and Oulun Seudun Sähkö) were used in testing as well.

6.1 Distribution reliability requirement report

This chapter presents the implementation of the DRR outage report which was created during the thesis. The first subchapter contains background information of the report and describes what data is necessary to exist so that the report can be implemented. Modifications for the DMS600 have to be made in order to get the new report working properly. Also the original demand for the report is presented. The second subchapter describes shortly the basic idea how the report is implemented, and the last subchapter finally presents the output of the report.

6.1.1 Background and needed information

The original requirement for the implemented DRR report came from the authority side. The Energy Authority’s requirements can be studied more specifically from the Appendix C. The requirements are translated into English for this thesis. The number of this specific requirement is (3.19). However, the Energy Authority’s requirement was to gather only the amounts of those customer points which have not fulfilled the level of security of supply required by the Electricity Market Act. A Finnish DSO Järvi-Suomen Energia (JSE) had more advanced reporting requirements than the original requirement. There was a need to create a report which would list all of the customer points that have not fulfilled these DRRs. The user should be able to filter the report so that only those customer points are shown, which have outages exceeding the DRR level. JSE proposed to divide the customers into at least four categories, of which each has an own limit for outage durations. The categories are based on the information in the Electricity Market Act. Each customer point belongs to one of these categories. Each customer node's category information is stored in the LV_CUSTOMER_NODE table in the Network-database. These four categories are described below.

1. Customer points located in the town plan area
2. Customer points located outside the town plan area
3. Customer points located in island having no bridge connection, other corresponding permanent connection or a regularly running ferry connection
4. Customer points having maximum annual energy consumption of 2500 kWh during three previous calendar years, and the investment costs required to fulfill the defined security of supply criteria would be exceptionally high due to a distant location of the customer point

It has to be noted that both categories three and four belong to the part c) of requirement (3.19) presented in the Appendix C. For these two categories the DSOs are allowed to define their own outage duration limits. This report separates these two categories because the DSOs might want to give them different duration limits. According to the Electricity Market Act, the first category with customer points located in the town plan area has a maximum outage duration of 6 hours. Correspondingly the second category containing the customer points located outside the town plan area has a maximum outage duration of 36 hours. Only faults with fault reasons related to storm and snow load are taken into consider when listing the customer points. For more details, see chapter 3.1.1.

In order that the report would be feasible, the described categories have to exist in the LV_CUSTOMER_NODE table. Also, the faults have to be archived to the annual fault archive tables in the database. For example, for year 2016 these tables are FLT_RPT2016, RC_RPT2016, MV_RPT2016, MO_RPT2016 and LV_RPT2016. In addition, the OTG_STEP2016 and OTG_STEP_AREA2016 tables are used as a source data. The table references and required information for the DRR report is presented in Figure 38.

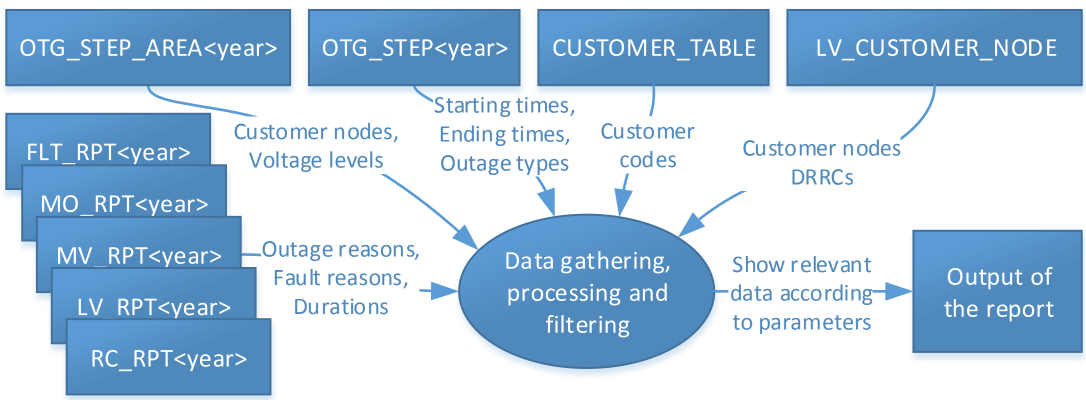


Figure 38. *Table references and information needed for the DRR report implementation.*

The end-user doesn't have to know about these tables, as DMS600 takes care of creating the necessary records for the defined fault archive tables when the end-user archives the reports with the DMS600 WS. The outage information has to include outage types, fault reasons, outage durations with starting and ending times and all the customer points related to the outages.

6.1.2 Implementation

Modifications for the Network database had to be done in order to get the new report working. A new column, DRRC (Distribution Reliability Requirement Class), was added to the LV_CUSTOMER_NODE table. This column contains information of every customer node's DRRC. Järvi-Suomen Energia, which originally requested for the report, uses PG NIS. It is specified that PG is the origin of the DRRC information. The DRRC information is brought to DMS600 with customer import SQL-procedure from the Customer.txt file. Thus, in PG environment the CUSTOMER table is the origin of the DRRC information. With DMS600 the basic operating principle is that the ShapefileTool brings the initial DRRC information to the database including the division to the Town plan area and Not town plan area. The rest of the classes for the customers will be modified straight from the DMS600. An individual customer can be choosed from the geographical network view and the category will be possible to see from the *free data form*, as presented in the Figure 39.

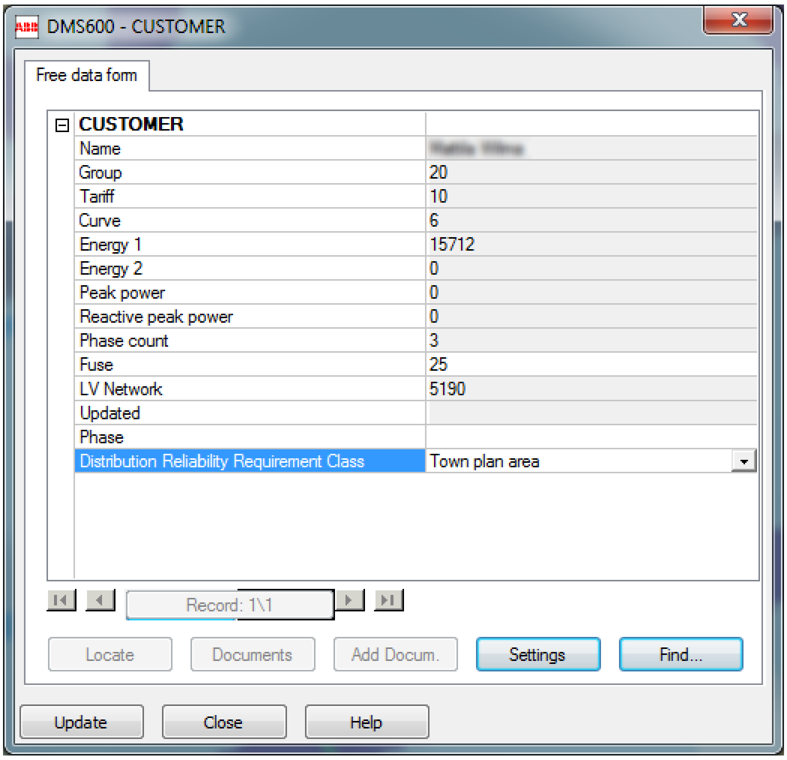


Figure 39. *The DRRC category of a customer point in DMS600.*

However, as it is more reasonable to set the DRRC for a whole customer node than just a single customer point, an improvement will be made to the DMS600 which allows this operation to be done via normal *data form* of customer node, as presented in the Figure 40. When the DRRC is set to a customer node, all of the customer points behind that node will have the same DRRC. As this improvement is not yet implemented to the DMS600, the Figure 40 is just a sketch which works as a proposed solution. In addition, there is a need for a more advanced tool which allows the user to set the DRRC for a whole LV network. This would require a similar implementation for the data form of MV/LV transformer than is presented in the Figure 40 for the customer node. This would fasten the work of DMS600 users because e.g. a whole LV network can be located in an island.

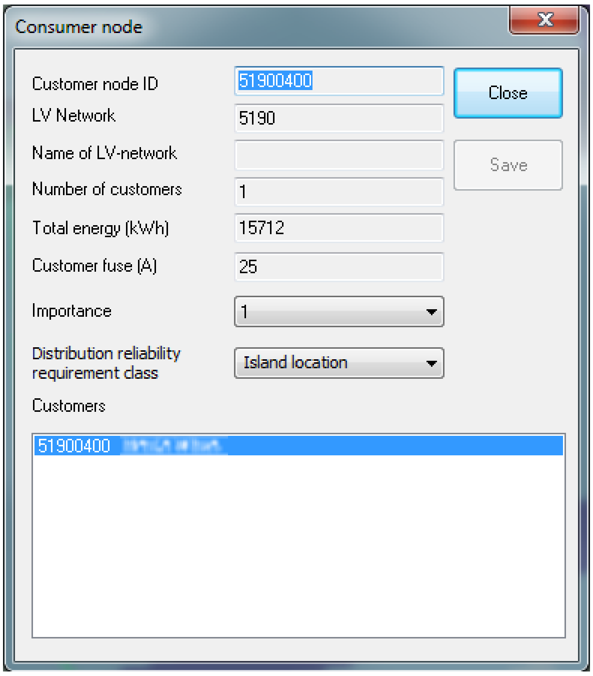


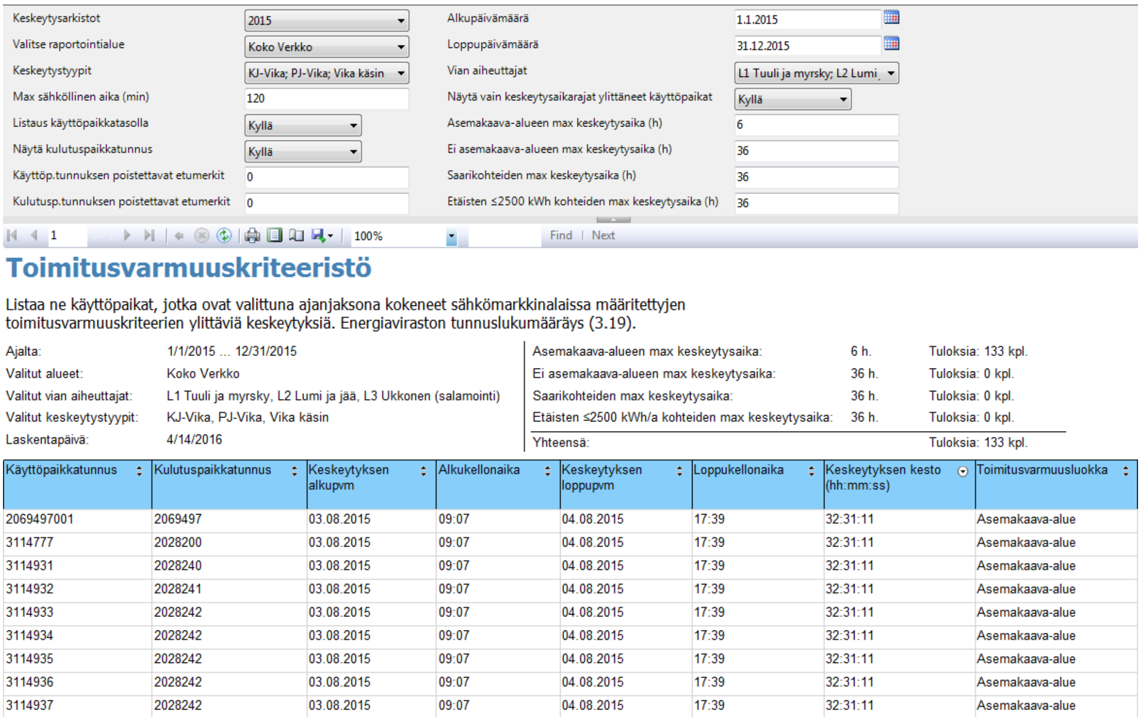
Figure 40. *Changing the DRRC category for a customer node in DMS600.*

As the division to the ”Town plan area” and ”Not town plan area” is done every time the ShapefileTool is ran, the ShapefileTool shall not overwrite the data which has been modified manually. For example if the ”Not town plan area” has been changed to a class ”Island location” for certain customers, the ShapefileTool shall not overwrite this data. Hence the basic rule is that the ShapefileTool’s DRRC data can be brought for all of those customers which doesn’t have DRRC class as ”Island location” or ”Remote location with at most 2500 kWh consumption”. When the customer import brings new customers to the database, the DRRC categories are defined to be ”Not town plan area” as default for those customers. However, they will get correct values when the ShapefileTool is ran. Thus, there is a need for a scheduled run of ShapefileTool because the DMS600 system is increasingly dependant on its operation.

6.1.3 Output and usage of the report

The report user can define the starting date and ending date for the report. This limits the outages for a certain time period the user wants to observe. User is also able to define the desired outage duration limits for every category before running the report and hence see directly in the report manager how changing the limits affects to the results.

The parameters, metadata and results of the implemented report are presented in the Figure 41. The report parameters are shown in gray background in top part of the report. The rest of the report are results. The results include the metadata which is in the middle part and the result table which is located in the bottom part. The metadata is needed in order to ensure afterwards that the used parameters were as desired. The metadata also calculates the amount of results separately for each of the DRRCs.



Keskeytysarkistot	2015	Alkupäivämäärä	1.1.2015
Valitse raportointialue	Koko Verkko	Loppupäivämäärä	31.12.2015
Keskeytystyypit	KJ-Vika; PJ-Vika; Vika käsin	Vian aiheuttajat	L1 Tuuli ja myrsky; L2 Lumi_
Max sähköllinen aika (min)	120	Näytä vain keskeytysaikarajat ylittäneet käyttöpaikat	Kyllä
Listaus käyttöpaikkatasolla	Kyllä	Asemakaava-alueen max keskeytysaika (h)	6
Näytä kulutuspaikkatunnus	Kyllä	Ei asemakaava-alueen max keskeytysaika (h)	36
Käyttöp.tunnuksen poistettavat etumerkit	0	Saarikohteiden max keskeytysaika (h)	36
Kulutusp.tunnuksen poistettavat etumerkit	0	Etäisten ≤2500 kWh kohteiden max keskeytysaika (h)	36

1 100% Find | Next

Toimitusvarmuuskriteeristö

Listaa ne käyttöpaikat, jotka ovat valittuna ajanjaksona kokeneet sähkömarkkinalaissa määritettyjen toimitusvarmuuskriteerien ylittäviä keskeytyksiä. Energiaviraston tunnuslukumääräys (3.19).

Ajalta:	1/1/2015 ... 12/31/2015
Valitut alueet:	Koko Verkko
Valitut vian aiheuttajat:	L1 Tuuli ja myrsky, L2 Lumi ja jää, L3 Ukkonen (salamointi)
Valitut keskeytystyypit:	KJ-Vika, PJ-Vika, Vika käsin
Laskentapäivä:	4/14/2016

Asemakaava-alueen max keskeytysaika:	6 h.	Tuloksia: 133 kpl.
Ei asemakaava-alueen max keskeytysaika:	36 h.	Tuloksia: 0 kpl.
Saarikohteiden max keskeytysaika:	36 h.	Tuloksia: 0 kpl.
Etäisten ≤2500 kWh/a kohteiden max keskeytysaika:	36 h.	Tuloksia: 0 kpl.
Yhteensä:		Tuloksia: 133 kpl.

Käyttöpaikkatunnus	Kulutuspaikkatunnus	Keskeytyksen alkupvm	Alkukellonaika	Keskeytyksen loppupvm	Loppukellonaika	Keskeytyksen kesto (hh:mm:ss)	Toimitusvarmuusluokka
2069497001	2069497	03.08.2015	09:07	04.08.2015	17:39	32:31:11	Asemakaava-alue
3114777	2028200	03.08.2015	09:07	04.08.2015	17:39	32:31:11	Asemakaava-alue
3114931	2028240	03.08.2015	09:07	04.08.2015	17:39	32:31:11	Asemakaava-alue
3114932	2028241	03.08.2015	09:07	04.08.2015	17:39	32:31:11	Asemakaava-alue
3114933	2028242	03.08.2015	09:07	04.08.2015	17:39	32:31:11	Asemakaava-alue
3114934	2028242	03.08.2015	09:07	04.08.2015	17:39	32:31:11	Asemakaava-alue
3114935	2028242	03.08.2015	09:07	04.08.2015	17:39	32:31:11	Asemakaava-alue
3114936	2028242	03.08.2015	09:07	04.08.2015	17:39	32:31:11	Asemakaava-alue
3114937	2028242	03.08.2015	09:07	04.08.2015	17:39	32:31:11	Asemakaava-alue

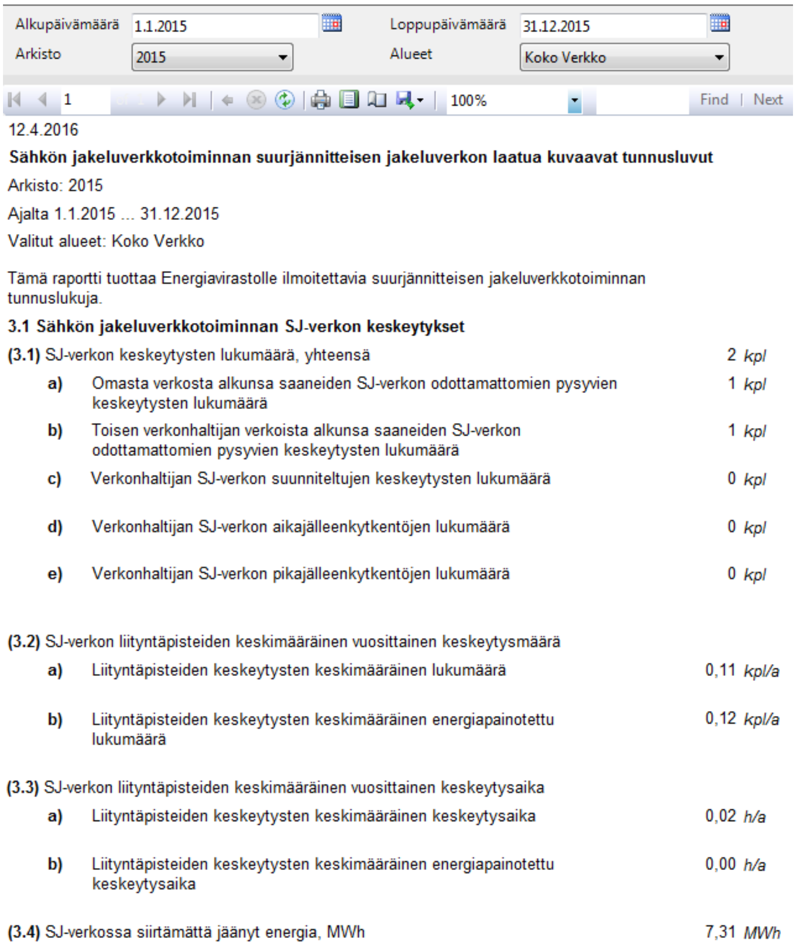
Figure 41. *Parameters, metadata and result table of the Distribution Reliability Requirement report.*

The report parameters are automatically initialized as specifically as possible in order that the user will get the required data for the Energy Authority with minimum effort. For example the outage types, maximum supplied time, town plan area and not town plan area maximum outage limits and fault reasons are initialized to match the Energy Authority's requirement (3.19) presented in the Appendix C. Also the whole year of the selected outage archive is used as a default value. Of course it is also possible to try other parameters than the defaults, e.g. in order to study the occurred outages more precisely. Hence this report meets the requirements defined by the Energy Authority but in the same time offers a more advanced tool for the DSOs to observe the outages in more detail.

6.2 Key figures of outages occurred in the HV network required by the Energy Authority

Some of the Energy Authority's requirements related to the key figures of outages in the HV network have changed from the previous regulatory periods. Modifications have been made for the figures (3.2) and (3.3) as the requirements changed for the fourth regulatory period. Also the old requirements (31) and (32) were removed from the requirements.

The new requirements can be found in the Appendix C and the requirement changes are gathered to the Appendix F. This report uses the new equations defined by the Energy Authority. The equations used for the HV network are presented in the sections 1.1 and 1.2 of Appendix D. The HV network key figures report is presented in the Figure 42.



Alkupäivämäärä 1.1.2015 Loppupäivämäärä 31.12.2015
Arkisto 2015 Alueet Koko Verkko

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12.4.2016

Sähkön jakeluverkkotoiminnan suurjännitteisen jakeluverkon laatua kuvaavat tunnusluvut

Arkisto: 2015

Ajalta 1.1.2015 ... 31.12.2015

Valitut alueet: Koko Verkko

Tämä raportti tuottaa Energiavirastolle ilmoitettavia suurjännitteisen jakeluverkkotoiminnan tunnuslukuja.

3.1 Sähkön jakeluverkkotoiminnan SJ-verkon keskeytykset

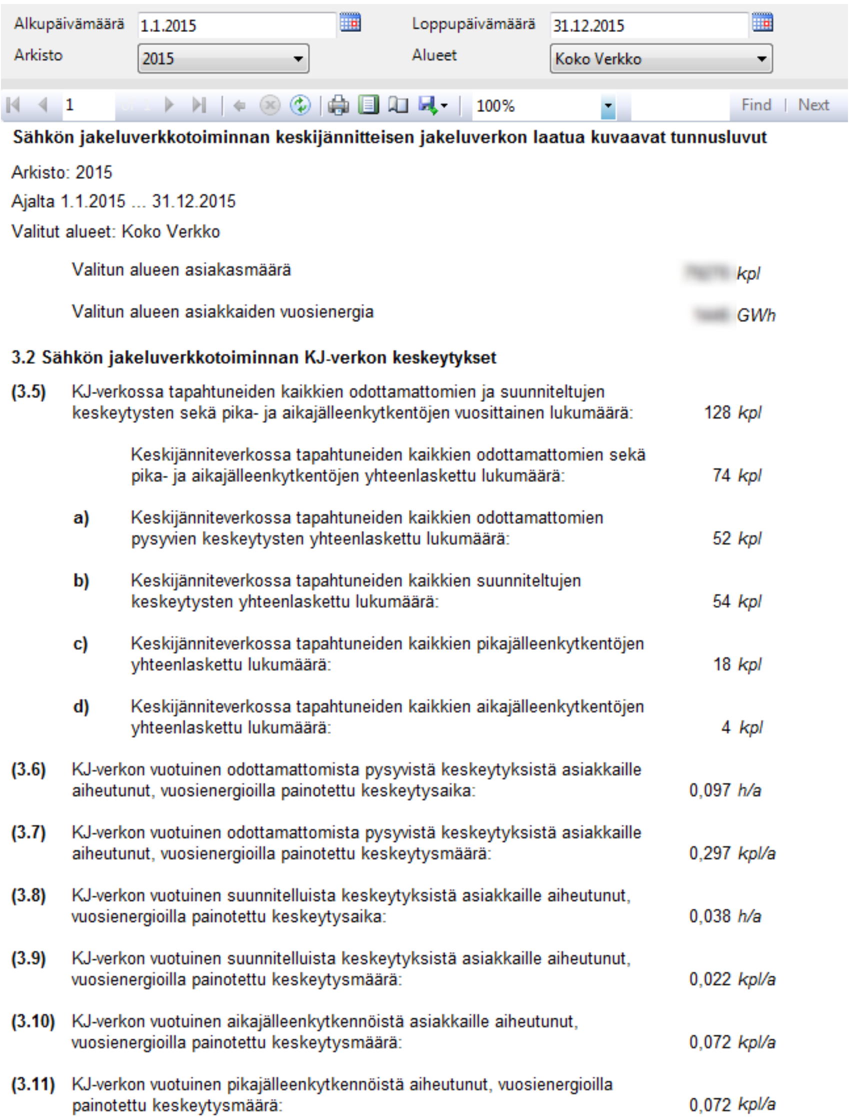
(3.1) SJ-verkon keskeytysten lukumäärä, yhteensä	2	*kpl*
a) Omasta verkosta alkunsa saaneiden SJ-verkon odottamattomien pysyvien keskeytysten lukumäärä	1	*kpl*
b) Toisen verkonhaltijan verkoista alkunsa saaneiden SJ-verkon odottamattomien pysyvien keskeytysten lukumäärä	1	*kpl*
c) Verkonhaltijan SJ-verkon suunniteltujen keskeytysten lukumäärä	0	*kpl*
d) Verkonhaltijan SJ-verkon aikajälleenkytkentöjen lukumäärä	0	*kpl*
e) Verkonhaltijan SJ-verkon pikajälleenkytkentöjen lukumäärä	0	*kpl*
(3.2) SJ-verkon liityntäpisteiden keskimääräinen vuosittainen keskeytysmäärä		
a) Liityntäpisteiden keskeytysten keskimääräinen lukumäärä	0,11	*kpl/a*
b) Liityntäpisteiden keskeytysten keskimääräinen energiapainotettu lukumäärä	0,12	*kpl/a*
(3.3) SJ-verkon liityntäpisteiden keskimääräinen vuosittainen keskeytysaika		
a) Liityntäpisteiden keskeytysten keskimääräinen keskeytysaika	0,02	*h/a*
b) Liityntäpisteiden keskeytysten keskimääräinen energiapainotettu keskeytysaika	0,00	*h/a*
(3.4) SJ-verkossa siirtämättä jäänyt energia, MWh	7,31	*MWh*

Figure 42. *Report of the key figures of outages occurred in the HV network.*

The new HV network outage report is able to calculate also the key figures related to the outages caused by DARs, RARs and planned outages. It wasn't possible to get these key figures with the previous reports. This development enables the parts *c), d)* and *e)* of figure (3.1) to be working in the report. As can be seen from the Figure 42, the amount of outages caused by interruption in the HV network may often be quite low.

6.3 Key figures of outages occurred in the MV network required by the Energy Authority

Only minor changed for the key figures of outages in the MV network were made. The requirements are the same than they were in previous regulatory period but the calculation equation behind the key figures changed. Earlier the calculation was based on outage information of each LV network and from now on the calculation has to be done metering-point specifically based on outages of single customers. The MV network key figures report is presented in the Figure 43.



Alkupäivämäärä 1.1.2015 Loppupäivämäärä 31.12.2015
Arkisto 2015 Alueet Koko Verkko
1 100% Find | Next

Sähkön jakeluverkkotoiminnan keskijännitteisen jakeluverkon laatua kuvaavat tunnusluvut

Arkisto: 2015
Ajalta 1.1.2015 ... 31.12.2015
Valitut alueet: Koko Verkko

	Valitun alueen asiakasmäärä	*kpl*
	Valitun alueen asiakkaiden vuosienergia	*GWh*

3.2 Sähkön jakeluverkkotoiminnan KJ-verkon keskeytykset

(3.5)	KJ-verkossa tapahtuneiden kaikkien odottamattomien ja suunniteltujen keskeytysten sekä pika- ja aikajälleenkytkentöjen vuosittainen lukumäärä:	128 *kpl*
	Keskijänniteverkossa tapahtuneiden kaikkien odottamattomien sekä pika- ja aikajälleenkytkentöjen yhteenlaskettu lukumäärä:	74 *kpl*
a)	Keskijänniteverkossa tapahtuneiden kaikkien odottamattomien pysyvien keskeytysten yhteenlaskettu lukumäärä:	52 *kpl*
b)	Keskijänniteverkossa tapahtuneiden kaikkien suunniteltujen keskeytysten yhteenlaskettu lukumäärä:	54 *kpl*
c)	Keskijänniteverkossa tapahtuneiden kaikkien pikajälleenkytkentöjen yhteenlaskettu lukumäärä:	18 *kpl*
d)	Keskijänniteverkossa tapahtuneiden kaikkien aikajälleenkytkentöjen yhteenlaskettu lukumäärä:	4 *kpl*
(3.6)	KJ-verkon vuotuinen odottamattomista pysyvistä keskeytyksistä asiakkaille aiheutunut, vuosienergioilla painotettu keskeytysaika:	0,097 *h/a*
(3.7)	KJ-verkon vuotuinen odottamattomista pysyvistä keskeytyksistä asiakkaille aiheutunut, vuosienergioilla painotettu keskeytysmäärä:	0,297 *kpl/a*
(3.8)	KJ-verkon vuotuinen suunnitelluista keskeytyksistä asiakkaille aiheutunut, vuosienergioilla painotettu keskeytysaika:	0,038 *h/a*
(3.9)	KJ-verkon vuotuinen suunnitelluista keskeytyksistä asiakkaille aiheutunut, vuosienergioilla painotettu keskeytysmäärä:	0,022 *kpl/a*
(3.10)	KJ-verkon vuotuinen aikajälleenkytkennöistä asiakkaille aiheutunut, vuosienergioilla painotettu keskeytysmäärä:	0,072 *kpl/a*
(3.11)	KJ-verkon vuotuinen pikajälleenkytkennöistä aiheutunut, vuosienergioilla painotettu keskeytysmäärä:	0,072 *kpl/a*

Figure 43. *Report of the key figures of outages occurred in the MV network.*

As can be seen from the Figure 43, the numbering and structuring of the report has changed from the report in the previous regulatory period but there are no other visible changes to the actual reporting requirements. The calculation equations of the MV network reporting requirement changed in the background from LV network based to metering-point specific. The new equations can be found in the Appendix D.

6.4 Key figures of outages occurred in the LV network required by the Energy Authority

The LV network reporting requirements are almost entirely new. During previous regulatory periods there were no separate section for the outages occurred in the LV network. Only the number (3.12) of these new report's requirements was required also earlier. However, this previous reporting requirement (earlier number 25) included only unanticipated outages. Because of the new requirements there was a need to create a totally new report for the LV network outages. The implemented LV network key figures report is presented in the Figure 44.

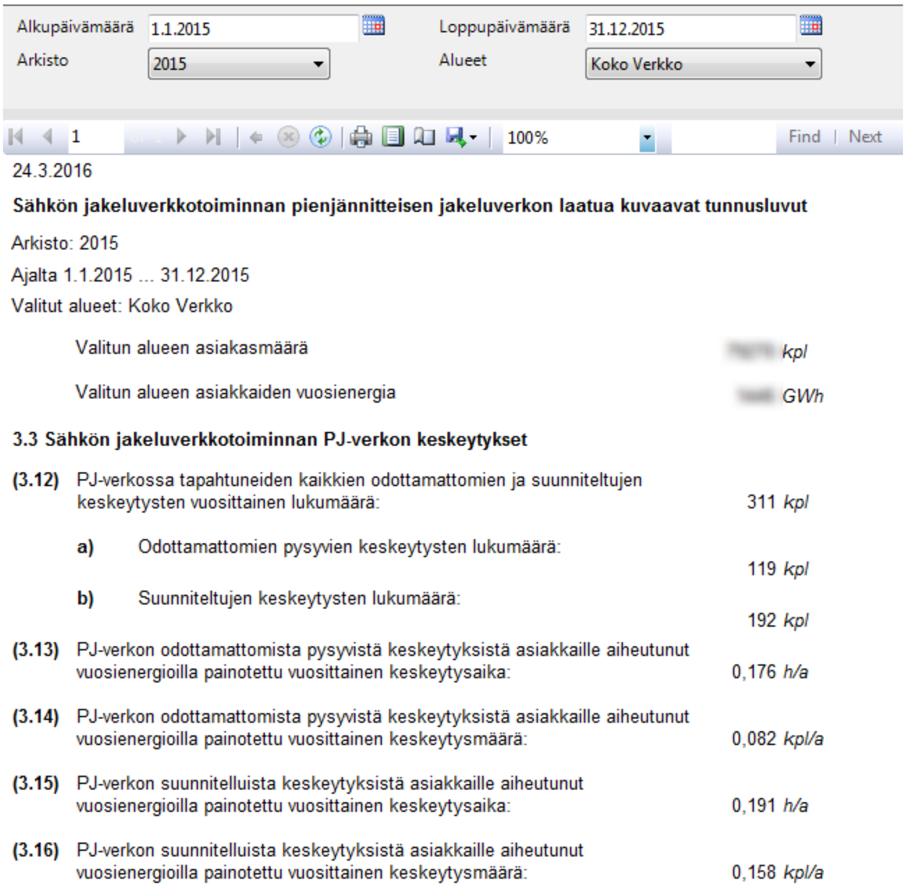
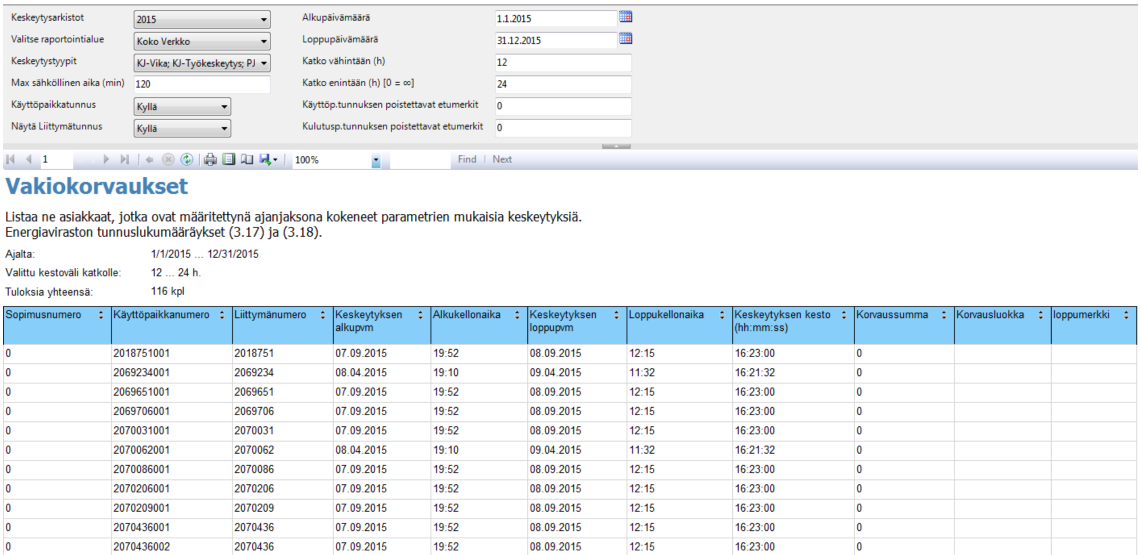


Figure 44. *Report of the key figures of outages occurred in the LV network*

This report provides the results directly in the form of Energy Authority's requirements. The figures (3.13) – (3.16) are weighted by annual energies. The equations used in calculation of these figures are also defined by the Energy Authority. The translated versions of the equations and their definitions are presented in the sections 1.3 and 1.4 of Appendix D.

6.5 Outage compensation report

Outage compensation report is used by DSOs to get customer specific information about the outage compensations. The user can define limits for the outage durations and the report lists every customer who has experienced an outage within the defined limits. Also the starting times and ending times of the outages are provided separately for every customer. This information is also required by the Energy Authority. More specifically the requirements are defined in sections (3.17) and (3.18), as presented in the Appendix C. However, as this report can not provide the values directly in euros, the DSOs have to export the results e.g. to their CRM which takes care of the billing. In the CRM system the compensation amounts are calculated also in euros, and the compensations are directed to the related customers. The outage compensation report is presented in the Figure 45. The top part with gray background consists of the parameters, the middle part includes the metadata and the bottom part consists of the result table.



Keskeytysarkistot	2015	Alkupäivämäärä	1.1.2015
Valitse raportointialue	Koko Verkko	Loppupäivämäärä	31.12.2015
Keskeytystyypit	KJ-Vika; KJ-Työkeskeytys; PJ	Katko vähintään (h)	12
Max sähköllinen aika (min)	120	Katko enintään (h) [0 = ∞]	24
Käyttöpaikkatunnus	Kyllä	Käyttöp.tunnuksen poistettavat etumerkit	0
Näytä Liittymätunnus	Kyllä	Kulutusp.tunnuksen poistettavat etumerkit	0

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Vakiokorvaukset

Listaa ne asiakkaat, jotka ovat määritettynä ajanjaksona kokeneet parametrien mukaisia keskeytyksiä.
Energiaviraston tunnuslukumääräykset (3.17) ja (3.18).

Ajalta: 1/1/2015 ... 12/31/2015
Valittu kestoväli katkolle: 12 ... 24 h.
Tuloksia yhteensä: 116 kpl

Sopimusnumero	Käyttöpaikkanumero	Liittymänumero	Keskeytyksen alkupvm	Alkukellonaika	Keskeytyksen loppupvm	Loppukellonaika	Keskeytyksen kesto (hh:mm:ss)	Korvaussumma	Korvausluokka	loppumerkki
0	2018751001	2018751	07.09.2015	19:52	08.09.2015	12:15	16:23:00	0		
0	2069234001	2069234	08.04.2015	19:10	09.04.2015	11:32	16:21:32	0		
0	2069651001	2069651	07.09.2015	19:52	08.09.2015	12:15	16:23:00	0		
0	2069706001	2069706	07.09.2015	19:52	08.09.2015	12:15	16:23:00	0		
0	2070031001	2070031	07.09.2015	19:52	08.09.2015	12:15	16:23:00	0		
0	2070062001	2070062	08.04.2015	19:10	09.04.2015	11:32	16:21:32	0		
0	2070086001	2070086	07.09.2015	19:52	08.09.2015	12:15	16:23:00	0		
0	2070206001	2070206	07.09.2015	19:52	08.09.2015	12:15	16:23:00	0		
0	2070209001	2070209	07.09.2015	19:52	08.09.2015	12:15	16:23:00	0		
0	2070436001	2070436	07.09.2015	19:52	08.09.2015	12:15	16:23:00	0		
0	2070436002	2070436	07.09.2015	19:52	08.09.2015	12:15	16:23:00	0		

***Figure 45.** Outage compensation report's parameters, metadata and result table.*

Changes were made to this report during the thesis as earlier it was not possible to define the upper limit for outage duration in the parameters. This has obviously caused unnecessary work for the DSOs because they have had to parse the required information from the results. In addition, the new report shows more metadata from the results, such as the number of given results and the chosen outage duration limits. From now on, interactive sorting is also enabled to this report, which allows the user to sort the results afterwards by any of the columns. Also the duration of each outage is now presented in the results table.

7. RESULTS AND ANALYSIS

The main objectives of the thesis were to describe the IT systems of interviewed DSOs and the information flows between them from the aspect of outage reporting, achieve information of the reasons behind the choices of the IT systems and get development ideas from the customers and requirements from authorities' documents. Thus some of the results are presented in the chapters 5 and 6 but this chapter gathers the most relevant results from the customer interviews, compresses the implemented and modified outage reports into single subchapter and lists the further needs of development for the DMS600.

7.1 Distribution System Operator interviews

This subchapter contains the main results of the DSO interviews. The interviewed DSOs were Turku Energia Sähköverkot Oy, Tampereen Sähköverkko Oy, Leppäkosken Sähkö Oy, Elenia Oy and Järvi-Suomen Energia Oy. The interviews related to each customer are covered in the subchapters of chapter 5. Also the IT system integration of each DSO is presented and described in the same chapter. The fault management process and reporting process of each interviewed DSO are described in the chapter 5 as well. This chapter gathers the most relevant comprehensive results of the interviews.

7.1.1 Differences between the systems

Compared to ABB MicroSCADA Pro DMS600 software users, there is a comprehensive difference in the outage management process of Elenia because unlike with Trimble DMS, the contractors and work crews rarely use DMS600. Instead, the fault reporting is usually implemented with a separate WMS system which is integrated to DMS with a DMS–WMS interface. For example in Leppäkosken Sähkö the work crews use Newelo WMS mobile application which allows the work crews to report the LV faults straight to the WMS directly from the fault location. The WMS delivers the information automatically to the DMS600. This implemetation reduces the need of unnecessary speaking and would thus enhance the efficiency of the process and e.g. broaden the bottleneck in the NCC Group Call System.

In addition, in the LV outage management process the AMR meter alarmings could automatically create a fault in the system when necessary, and the information should be delivered straight to the work crew who takes care of faults in that area in the distribution network. Sometimes it is challenging to let the systems decide of the validation of the spontaneous alarmings because there are a lot of alarmings which don't cause immediate additional measures. Hence e.g. in Elenia the validation is currently done by the NCC personnel. However, some automatic validations could be implemented to the DMS systems. The DMS system could leave the validation for the personnel in uncertain situations, for example if the AMR meter alarming reason is undervoltage or overvoltage. Voltage limits for the validation could be given. However, if the AMR meter alarming reason is most likely a real fault in the LV network, the job order could be created automatically and the personnel could still make a final validation if the situation causes additional measures or not. Although the AMI features have been available a long time, many of the DSOs don't have them in use or have only some of the possible features.

Another difference between the IT system features of the interviewed DSOs is the controllability of the remote-controlled switches directly from the DMS system. TSV, JSE, TESV and Elenia don't yet have the remote-controlling functions of DMS in use but some of them are planning to implement them in the future. Leppäkosken Sähkö is the only interviewed DSO which is able to control the switches straight from the DMS system, which obviously facilitates the work of NCC operators.

Some of the DSOs have acquired all the DMS, NIS and SCADA systems from separate providers. Some of the DSOs mentioned that acquiring the systems from separate providers is considered also as risk management. This way the contacts to different providers remain and if some system provider will discontinue the development and supporting work for their products, the DSO would not lose the support for all of the systems in the same time. However, such information system integration is often more difficult to implement and modify. If there will be development in any of the systems, it may require additional work for the integration and additional communication between the system providers in order to get the new features in use. According to the interviews, it may be also more difficult to get all system providers around the same table to discuss about problems or development than it would be with single system provider. In addition, for example the above-mentioned controllability directly from the DMS is often not possible when the DMS and SCADA systems are acquired from different providers. In comparison, this would be possible in the MicroSCADA Pro SYS600 and DMS600 integration.

7.1.2 The acquirement reasons for the separate IT systems

A common conclusion from the customer interviews is that SCADA is considered as a basic information system for gathering the data from the primary process and enabling the controlling functions of remote controlled devices. SCADA delivers the information for the DMS which usually takes care of the more advanced functions such as outage reporting. In several interviews turned out that SCADA has to be working and online 100 % of the time. The advanced features are considered more important for DMS than for SCADA, and the DSOs seem to expect improvements and additional features mainly for the DMS system rather than SCADA. The only development aspects regarding SCADA that appeared in the interviews were related to the usability and self-analyzing features of the system. With more advanced self-analyzing features SCADA would be able to inform the user of any errors and failed behaviors of the system. For example if there are any problems in communication with other systems or devices, SCADA could inform the user what exactly has happened. Another important aspect is the usability: it has to be easy to learn to use the SCADA system. Furthermore, the configuration of the SCADA system has to be simple because some DSOs will have plenty of new switches and substations in the network. Also the price, connectivity and interfaces were considered to be important, as well as reliability and perseverance of the system provider.

As the compulsory reporting for the Energy Authority has increased during recent years, the reporting function has become more important in the operation of DMS. In addition, most of the DSOs voluntarily deliver several reports for the Finnish Energy as well. The reporting is done with DMS and it is one of the features that has been developed during recent years. Some of the DSOs have acquired the systems over 10 years ago and at that time the reporting may have not been in such important role.

The DSOs which are operating mainly in the city areas have different perspective to some parts of distribution operation than those who are operating in the rural areas. For example TSV considered the schematic view to be vital feature in the DMS when they were choosing the systems years ago – and is still actively using it. The demand for this feature comes from the operating environment as the Tampere city is densely populated and constructed area. For the operator it is easier to see the situation of the network with a glance from the schematic view than from the geographical view. Correspondingly in the rural area networks it is very important to see the situation in the map as the distances are great and the work order has to be planned according to the geographical relations of the faults and work crews. Also the customer communication seems to be emphasized especially in the DSOs operating in the city areas. This may be due to the fact that the effects of disturbances are relatively low in the city areas and thus the customers are not got used to the outages. In comparison JSE, which is operating mainly in rural areas, mentioned that the outage management itself and the remote-controllability of the switches are prioritized as more important than the customer communication. As earlier the DMS was more just supporting the SCADA, today it consists of more advanced features, of which one important feature is the switching planning. Many DSOs mentioned that the usability of DMS is important because of the wide variety of features, and that without DMS the daily operation of the electricity distribution, including outage reporting, would be very difficult. Hence the role of technical support is considered to be important as well.

Another feature which is definitely more important to DSOs operating in the city areas is the location map. The location map includes very specific information of the locations and depths of underground cables, municipal water pipes and other network structures underground. This is crucial for the DSO in order to build the network in the city areas and repair the faults occurred in the underground cables. According to the interview of TSV, the location map was the decisive feature in choosing the NIS system as during those days Trimble NIS was the only option already having the location map feature included in the system. Naturally with the DSOs operating mainly in the rural areas such features may not be considered as important.

The integration possibilities with other IT systems are usually considered when purchasing DMS, NIS or SCADA systems. Hence the entire outage management and reporting processes have to be taken into consideration as well.

7.1.3 IT system integrations in the NCC

It is common that the DSOs don't acquire or change the SCADA, DMS and NIS systems in the same time. The weight of history is heavy in the integration of IT systems. The current system integration can be a result of decisions made over 10 years ago. According to the interviews, the IT systems have developed from those days, but above all the operating environment has changed during these years. The amount of reporting requirements and regulation from the authority has increased and the role of customer notification and communication has become more relevant.

If the decisions related to the purchasement of IT systems could be done from a clean slate, the decisions might be somewhat different in some of the DSOs. However, in practical terms it is not very easy nor non-problematic to change the whole system integration at once, which means that the changes to the IT systems in this field are quite slow and often not desirable. According to the interviews, the DSOs usually consider that they have well working IT systems, but some of the interviewees admit that there is still development work to do. Today there are a lot of information available but it is more about how advanced is the processing, presenting and utilization of the information. According to the interviews, the information should be only in a single place and the amount of required duplicate work (e.g. the double documentation of the network) should be minimized.

According to the interviews, the current division of the IT systems is generally considered to be quite reasonable. The most common opinion was that this division works quite well from both distribution operation and technical system integration point of views. The larger systems than currently are used, are considered to be too complex and the DSOs are afraid that it would cause problems to the reliability. For example if the DMS and SCADA would be integrated into a larger single system, it would mean that the whole packet has to be as reliable as SCADA alone was earlier. In addition, if malfunction occurs in the DMS functions of the integrated system, there is a need to get the SCADA running as fast as possible. Hence it should be possible to at least start the old type SCADA UI without DMS functions. As described in the chapter 2.2.4, MicroSCADA Pro Web UI will be a new UI for the combination of SCADA and DMS. This is quite reasonable solution because in the background the SYS600 and DMS600 are still separate systems. Therefore it will be probably possible to run only SCADA if DMS is having problems. Furthermore, it would be beneficial if the Web UI had the intelligence to automatically drop those functions which are not working properly so that the whole UI would not be entirely unusable during a malfunction. In turn, if the IT systems would be smaller than now, it would bring more integration requirements and more complex structure to the IT systems. However, in the future the most flexible IT systems shall be well scalable, using modular structure and standard interfaces, which eases the integration with other systems. In ideal case if the standard interfaces were used, implementing the new interfaces and features to the systems would be easier and the DSO could just order an interface or functionality from the provider without thinking about the compatibility issues. Today the information security of the systems is emphasized as well. Elenia mentioned the FLIR to be very important in the integration of SCADA and DMS systems, and it is used efficiently in the outage management. Elenia considered also that the operative costs in the life cycle of the systems are important with all systems, and that the amount of separate UIs should be minimized.

There are differences between the IT systems of the DSOs but the basic infrastructure is somewhat same in every interviewed DSO. Similar kind of information systems are basically used, as most of the DSOs have SCADA, DMS, NIS, WMS, CIS and MRS systems and the features of the systems are quite same. However, there can be differences in the practices and processes between the DSOs.

7.1.4 Outage management and reporting processes

As the changes to the IT system integrations are slow in this field and a same information system can be used for decades, it is important to clarify the needs of the DSO specifically not to forget the needs of the future. For example many DSOs acquired the AMR meters when the automatic energy reading became compulsory according to the new legislation. However, as the first energy meters were developed mainly for energy reading, they may lack features which are required in order to use the AMI functions. Hence those DSOs which considered the AMR meters to be used for more advanced functions than only energy reading, have recently gained benefit from the planning work in the past. Correspondingly there might be DSOs having needs for AMI functionalities but have no possibility to implement the features to the current AMR meters in a cost-effective way. Hence if the decisions are done too early or in hurry, some of the benefits can not be acquired from the systems or devices. On the other hand, some DSOs want to be in the forefront of the development and the customers of these companies may have gained the benefits of the AMR meters longer than those who have recently installed the meters.

There are slight differences in the outage management and reporting processes of the DSOs. From the outage management and reporting point of view the largest differences and development targets can be found in the WMS systems and from the integration of WMS and DMS systems. With all interviewed DSOs the basic information of the MV network faults come to DMS through SCADA. This includes e.g. exact starting and ending times of the fault. However, all required reporting information can not be achieved automatically from the primary distribution process and hence other solutions have to be used. According to the interviews, with MV outages the work crews have to call to NCC and the operators set the required reporting information straight to the DMS. However, another solution for MV fault and maintenance outage reporting using WMS is presented in the chapter 4.5. The LV network reporting is usually done by using WMS but the conventions vary from DSO to another. Usually the process differs on the fact that who is the person that adds the definitions to the reports. It can be the NCC operator (TESV and TSV), the work crew in the field (Leppäkosken Sähkö and JSE) or even a separate employee of the contractor (Elenia). Elenia and TSV are using Trimble DMS and there is no DMS-WMS integration in use. In Elenia the contractors use directly the DMS in outage reporting but in TSV all the reporting work is done in the NCC by the operators. The information is received from the work crews in the field via VIRVE. Thus the information flow protocol is talk. Unlike with Elenia and TSV, other interviewed DSOs exploit the WMS systems in reporting. According to the interview of Leppäkosken Sähkö, the Mobile WMS is one of the useful features that has developed in the recent years.

According to the interviews, the KAH values are generally considered to be the most important figures of the outages. All of the interviewed DSOs are monitoring the occurred KAH values regularly and evidently try to decrease the values because according to the Energy Authority's regulation methods the KAH values have direct influence on the allowed profit of the DSO. In some of the interviewed DSOs the occurred KAH values are taken into account in the company's BSC as well.

According to the interviews, the Group Call Systems used in the NCC are often congested during major disturbances. This may cause a bottleneck in the fault management and reporting process. The time the work crews have to wait in the phone without acting is a waste of resources and causes inefficiency. An alternative solution for the communication between the NCC and work crews could be implemented or the current solution enhanced, but the security has to be always prioritized first. The current solution could be enhanced for example by providing a possibility to send SMS messages to the NCC operators in case that the information flow towards the NCC does not particularly require direct speaking. It could be useful with non-complex messages which can't cause any security issues. This would allow the operator to browse the upcoming messages in the display whilst speaking in the phone with other work crew. The message browsing could be possible because there are situations when the work crew is, for instance, moving from place to place or performing the actions, and there is no speaking during these moments but the communication line may still remain open. With this alternative communication solution the need for speak communication would be decreased.

Another solution to enhance the fault management operation is prioritizing the calls (and possible SMS messages) automatically according to some given parameters, which could minimize the waste of resources. In addition, the MV fault reporting should be developed so that all possible information is added straight to the information systems. The fault reasons could be added straight to the IT system with a mobile application of a WMS, for instance. The estimated outage duration should be possible to update to the systems in other ways than calling to the NCC and disturbing the operator's work. This would again reduce the amount of unnecessary speak communication towards the operator. In addition, if all possible information is added straight to the system by the work crew, those misunderstandings that may occur in the speak communication between the work crew and NCC would be reduced.

7.2 Implemented and modified outage reports

One of the objectives of this thesis was to clarify if there are any development needs or new requirements for the outage reports created from the DMS600. During the thesis came out several requirements related to the changed requirements of the Energy Authority but also several development ideas for the reports for DSOs' internal use. Development ideas were gathered to this document and some of the required reports were implemented during the thesis. All of the implemented and modified reports during the thesis were originally required by the Energy Authority. Total of five reports were created or modified. These outage reports are presented in the Table 7.

Table 7. *Implemented outage reports, their work information and the requirement number of the Energy Authority.*

Report	Status	Requirement number of the Energy Authority
Distribution reliability requirement report	New	(3.19)
Key figures of outages in the HV network	Modified	(3.1) – (3.4)
Key figures of outages in the MV network	Modified	(3.5) – (3.11)
Key figures of outages in the LV network	New	(3.12) – (3.19)
Outage compensation report	Modified	(3.17) – (3.18)

Table 7 shows the work information for each report, which indicates whether the report is entirely new or modified and developed from an existing one. The last column describes the need for each report as it links the reports to the Energy Authority's requirements. The translated requirements of the Energy Authority can be studied from the Appendix C. A comprehensive cross reference table of the changed requirements of the Energy Authority related to the outage reporting is presented in the Appendix F. Although all of the implemented reports are originally required by the Energy Authority, the Distribution reliability requirement report was implemented within limits of JSE's requests. More specific information of each report is presented in the chapter 6.

In addition, also several smaller fixes to the existing outage reports were implemented during the thesis. These included mainly bug fixes or minor developments to the reports. After the requirements published in 2014 there haven't been any new instructions from the Finnish Energy but some of the current reports needed to be fixed. For example the Outages as row data (ET - Keskeytykset rivitietona) report was fixed as it was listing outages divided to outage areas but according to the Finnish Energy each outage should be listed with one row in the report.

7.3 Further needs of development

The further development needs and ideas that are not implemented during the thesis are described in the following subchapters. These needs include the requirements for the DMS600 from the Energy Authority and the Finnish Energy, the development ideas for the DMS600 according to the interviews and the development ideas to the Reporting Service reports provided by the DMS600.

7.3.1 Requirements for the DMS600 from the Energy Authority and the Finnish Energy

Currently the Metering point-specific outage report uses the estimated energy of customers at least with some of the DSOs. However, it is stated in the ET's reporting requirements that if it is possible, the measured value should be used instead of the estimated value. Currently the used value depends on what is the information the CIS provides to the DMS600 via the customer import. Hence there is a need to develop the customer import procedures so that the estimated energies would be always added to a separate ENERGY_MEASURED field in the database in order to classify the sources of the energy information. After that the report should always use this measured value if it exists.

The Distribution reliability requirement report was created during the thesis. In PG environments PG is defined to be the master database for the DRRC information and this information is brought to DMS databases through customer import. However, further development work for the DMS600 is required because it has to be possible to give the DRRCs to the customers straight from the DMS600's network view. The proposed solution for this functionality is such that the ShapefileTool is improved so that it will have an additional and optional feature which adds the Town plan area and Not town plan area information to the LV_CUSTOMER_NODE table. This feature should be possible to be enabled or disabled from the selection box in the ShapefileTool's GUI. The SQL query of this improvement for the ShapefileTool was implemented during the thesis and it is presented in the Appendix E. The query is implemented so that nothing is done in PG environments. Because the connection point of customer to the distribution network is the same for all of the customers behind a single connection point, the reliability level of the DSO's network has to be same for these customers. Hence the DRRC information has to be implemented to customer point level but is not especially required for the customer points. In the DMS600 NE environments the information is specified to exist in LV_CUSTOMER_NODE table and in PG environments in the CUSTOMER table. Nevertheless, to make the manual controlling of the DRRCs possible in the DMS600, the data form of customer point has to be improved. Even though the ShapefileTool initialized the DRRCs according to the Town plan area and Not town plan area division, it has to be possible to change the DRRC directly from the data form of customer node. This is needed, because in addition to these two automatically initialized classes, there are also customer points located in island or customer points which have maximum annual energy consumption of 2500 kWh and are in distant location (see the exact definitions for the DRRCs in the chapter 6.1). For these two so called "local circumstances" the DSOs may define the maximum outage durations by themselves. This improvement will be implemented into the 4.4 FP1 HF3 version of DMS600 by the R&D team. In addition, the customer import has to be improved for the customers having PG NIS so that the DRRC information is brought into the CUSTOMER table for every customer.

7.3.2 Development ideas for the DMS600 from the interviews of DSOs

Development ideas for the DMS600 were gathered during the interviews. Currently, when adding fault information data to a MV maintenance outage report in the DMS600, the *Additional* information is not initialized automatically by DMS600 from the maintenance plan. Currently the operator has to copy and paste the additional information from the plan to the MO report. This information should be initialized to the MO report automatically by DMS600.

It is defined that the disconnected power of the metering point in the starting time of the interruption shall be used in the KAH_{tot} calculation for the Finnish Energy (Outages as row data). According to the interviews, this KAH_{tot} would be very efficient way to prioritize the ongoing outages in the distribution network. It would be extremely beneficial during the major disturbances, but it requires that the DMS system could calculate and show the KAH_{tot} costs automatically and in real-time for every outage. Prioritizing the outages with the presented method leads to faster returning of the service to those parts of the network which have the most KAH_{tot} costs. This is an efficient way to minimize the harm caused by the outages. As this would decrease the occurred total KAH costs, it would also increase the allowed profit of the DSO, as defined in the quality incentive of the regulation methods. The customers would also benefit from this kind of prioritizing method as the most critical parts of the network would get the supply returned fastest. However, it would be reasonable that some critical customers were prioritized even higher than the KAH_{tot}, and hence a combined prioritizing method should be implemented for the critical customers and KAH_{tot} costs. The total KAH value of the outage should be calculated automatically and shown in the report management window (see Figure 16).

According to the interviews, all the information which can be provided with reports, should also be possible to see straight in the map of DMS system. This method would be more informative as the actual locations and the network topology is always connected to the given information. The desired functionality could work so that the user chooses an area from the map by drawing a rectangle or a polygon which gives borders for the network area. The user could see the same information than the report would give from that area directly. Another possible implementation for this feature is the trace (downstream or upstream) functionality, which defines the borders for a desired area. The related sections are colored in the map and a separate pop-up dialog could show the relevant information of this area. This could be used to obtain information from a certain branch or a whole feeder. The interesting information could be e.g. what is the total power used in the chosen area, what is the whole energy amount used by customers located inside the area or KAH costs which have been realized in the area in a specific timespan.

The fault durations of the ongoing faults are estimated usually by the work crews when the fault is located and they are aware of the fault reason. The work crews see the situation better in the field and especially during major disturbances NCC operators are very busy. It would be beneficial if the work crew could take a picture of the fault and add it to a mobile application before repairing it. In many cases this would be faster and more informative way to document the reason of the fault because the work crew wouldn't need to describe the problem in words or the description could be shorter. Also the NCC personnel wouldn't have to use their time to add the fault reasons to the system. Even better, the system should be able to send this same picture automatically to those customers in the outage zone who have been subscribed to such service. The customers would most likely be less unsatisfied and more understanding because they can see the challenges the DSO is encountering. These pictures could be used also with other external communication, for example in the social media and they could be sent for the media as well. Furthermore, as the picture is worth a thousand words, the occurred faults and fault reasons can be analyzed more specifically afterwards and additional measures can be taken in order to reduce the outages in the future.

7.3.3 Development ideas for the Reporting Service reports

According to the interviews, some DSOs considered that it would be useful to get the reports created automatically by a defined schedule. Today the amount of reports required by the authority is high and in the future the amount may increase even more, not to forget the internal reporting. Therefore it is essential for the DSOs to get the reports automatically. The proposed solution is that DMS600 creates the reports out of the Reporting Service automatically and sends them e.g. to the emails of some predetermined persons or saves the reports into a specified folder, which can be accessed by all the necessary persons. Even further, it would be beneficial if the report parameters could be defined in advance and some of the parameters (such as the timespan) could be given dynamically. Also, it should be possible to define the file format of the exported report in advance.

Another desire was that the reporting service should provide graphical information of the most important reports. This could include e.g. pie charts, bar charts, other diagrams or even information in geographical view. Currently the graphical versions of the reports are often created with other programs which causes additional work for the DSOs. It would help if the reporting service created the defined reports by a schedule and saved them into a predetermined location. This would automate the use of external reporting systems for example in visualization purposes.

In addition, there is a need for a report which shows the cumulative KAH values monthly. It would be better if this report was also in graphical form – presented with a bar chart. The report should show either the values from the beginning of the year or sliding values from previous 12 months. According to the interviews, the KAH values are the most intensively followed single figures given by the reports.

There is also need for translated reports in the future as the non-Finnish customers could use the reports provided by the Reporting Services. A support for the international reports has existed already for a while but more translation work has to be done. The translation work is needed for all reports that are interesting for the non-Finnish customers. Even though there might not be similar reporting requirements abroad, the customers could still consider these reports as useful.

The requirements of the Energy Authority for the key figures of outages in the distribution network have been updated and the required reports were implemented. However, the DMS600 Reporting Services has previously included a report which calculates also the KAH value from the information provided by MV network outage key figures report. Hence this KAH report has to be implemented with the new MV network outage key figures as well. The new regulatory model uses also HV network KAH values. However, there were inconsistencies between the regulatory model and the required outage reports of the Energy Authority because the HV network outage key figures report does not include all the necessary information required for the HV network KAH calculation. For example the annual average outage duration of MOs occurred in the HV network is not required in the decree but is needed in the KAH equation. The contradiction was found during the thesis. The Energy Authority was contacted due to the contradiction and the inconsistency was admitted. The Energy Authority promised to inform the DSOs and other appropriate stakeholders (such as the system providers) of the case after the Energy Authority has made a decision on how to proceed. Hence the HV network’s KAH report shall be implemented after the Energy Authority has published the instructions regarding the issue. [107]

8. CONCLUSIONS

The electricity distribution business has developed during the recent years as the role of customer communication and outage notification has become greater in major disturbances, maintenance outages and in single fault situations regardless of whether the outage is located in the MV, LV or HV network. This may be due to the fact that the society is so intensively dependant on the electricity today. According to the interviews, customer communication is emphasized especially in those DSOs who are operating mainly in the town plan and city areas but also other DSOs consider it very important. The DSOs operating in the city areas have usually more underground cable, shorter distances between the network components and less impacts of the natural phenomena than other DSOs. In turn, some of the countryside DSOs see that it is more important that the remote-controlled switches are really controllable and that the switching states in the systems are up-to-date as they have probably experienced such difficulties. The amount of outages and problems related to the remote-controlling functions with the DSOs operating in the city areas may be so little that the customer communication is and should be in the higher level, because the remote-controlling of the switches and other basic functions are so reliably working.

The IT systems of the interviewed DSOs are presented in the thesis and a reference IT system integration is also described. Roughly viewed the infrastructures of IT systems of the DSOs look rather similar but there are also differences between the integrations. According to the interviews, there are many reasons which justify these slight differences, and also the conventions, history and the people who use the systems have influences on the decisions of the IT system integrations. Hence there is no universal right or wrong answer for the IT system integrations but all of the described solutions have their benefits and disadvantages.

The fourth regulatory period started in the beginning of year 2016. The new requirements of the Energy Authority caused that the reports of DMS600 reporting services were developed and five new or modified reports were implemented. Most of the work was required because of the new Distribution reliability requirement reporting. In addition to the creation of the outage report it was compulsory to make changes to the DMS600 UI and databases. All the necessary work was gathered during the thesis and the new feature including DRR reporting will be implemented by R&D to the next DMS600 version 4.4 FP1 HF3. This version shall be installed to the customers early before the DSOs have to deliver the reports to the Energy Authority in the end of May in 2017. Also further development needs for the reports is needed because the KAH reports of MV and HV network outage key figures shall be implemented.

The whole distribution network infrastructure will be under drastic change in the future. There will be power flows towards both directions in the distribution network due to the increasing amount of distributed generation. The demand response and electricity vehicles with drainable batteries will also bring great impacts on the distribution network. The faults will require more advanced means of protection and management and the reporting requirements will most likely change along the other changes in the network step-by-step. According to the Outage statistics instructions of ET there is also a desire to unify the outage reporting requirements of ET and the Energy Authority. Hence the amount of compulsory outage reporting can further increase in the future.

One of the most important inputs for the thesis came from the interviews of Distribution System Operators. In three of the interviews only one representative of the DSO was present in the interview. Because the topic is wide, it would have been better if at least two DSO representatives were interviewed in each DSO to get different and wider perspectives and more discussion on the answers. Furthermore, because the number of interviewed DSOs is relatively low, all of the results of the thesis can not be directly generalized without criticism. In addition, especially in those cases where only one DSO representative was interviewed, the perspective on the topic may have been a little narrow and some of the results may have been affected by personal opinions. On the other hand, it is not a problem as a subjective view is also valuable information. In addition, also NCC operators and work crew members could have been interviewed, which could have brought a different perspective to the interviews. Without the interviews creating such specific descriptions of the IT systems and the information flows between the systems would have not been possible. It was also necessary to hear the reasons of the IT system acquirements from the DSOs but these results were somewhat predictable. In addition, the opinion and needs of an interviewed DSO, Järvi-Suomen Energia, were also considered when the DRR report was specified and implemented. Hence the value and contribution of the interviews for this thesis was great.

This thesis was written for ABB Oy and is done on the basis of the ABB MicroSCADA Pro product portfolio. Development ideas were gathered for the MicroSCADA Pro DMS600 product and its outage reporting functionalities. Hence the ABB products are emphasized in the thesis and the technical perspective is present in most parts of the thesis. Other perspectives shall be surveyed separately, if considered necessary.

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APPENDIX A: QUESTIONNAIRE FOR THE DISTRIBUTION SYSTEM OPERATORS

This is the questionnaire for the chosen DSOs' representatives. The questionnaire starts with basic information of the IT systems, moves towards more profound questions and finally to the information flows between the systems from aspect of outage reporting.

Basics of the IT systems

1. What IT systems you currently have in use or are interconnected with?
    a. SCADA
    b. DMS
    c. NIS
    d. CIS / CSMS
    e. WMS
    f. MRS / MDMS
    g. Other systems that affect to the outage reporting, what?
2. When are these systems purchased (especially a, b and c)?
    a. SCADA
    b. DMS
    c. NIS
3. For which IT systems you have a valid maintenance contract?

Planning and reasons behind the choices of IT systems

4. What are the main reasons for chosen individual IT systems (esp. a, b and c)?
    a. SCADA
    b. DMS
    c. NIS
5. The systems a, b and c are/aren't from the same provider:
    a. What were the main reasons behind this integration choice?
    b. What kind of advantages you have accomplished by this choice?
    c. Can you mention any disadvantages related to this choice?
    d. Have you experienced any problems within the integration or co-operation of different producers' IT systems?
6. What are the three most important functions of these systems related to the outage reporting in your opinion?
7. What are the main functions you would most like to be further developed in outage reporting (can be related to the whole reporting process)?
8. Which are the IT systems that you are going to renew next, and when?
    a. Which facts weight most in your decision making?
    b. What do you think of the support for open standard interfaces?

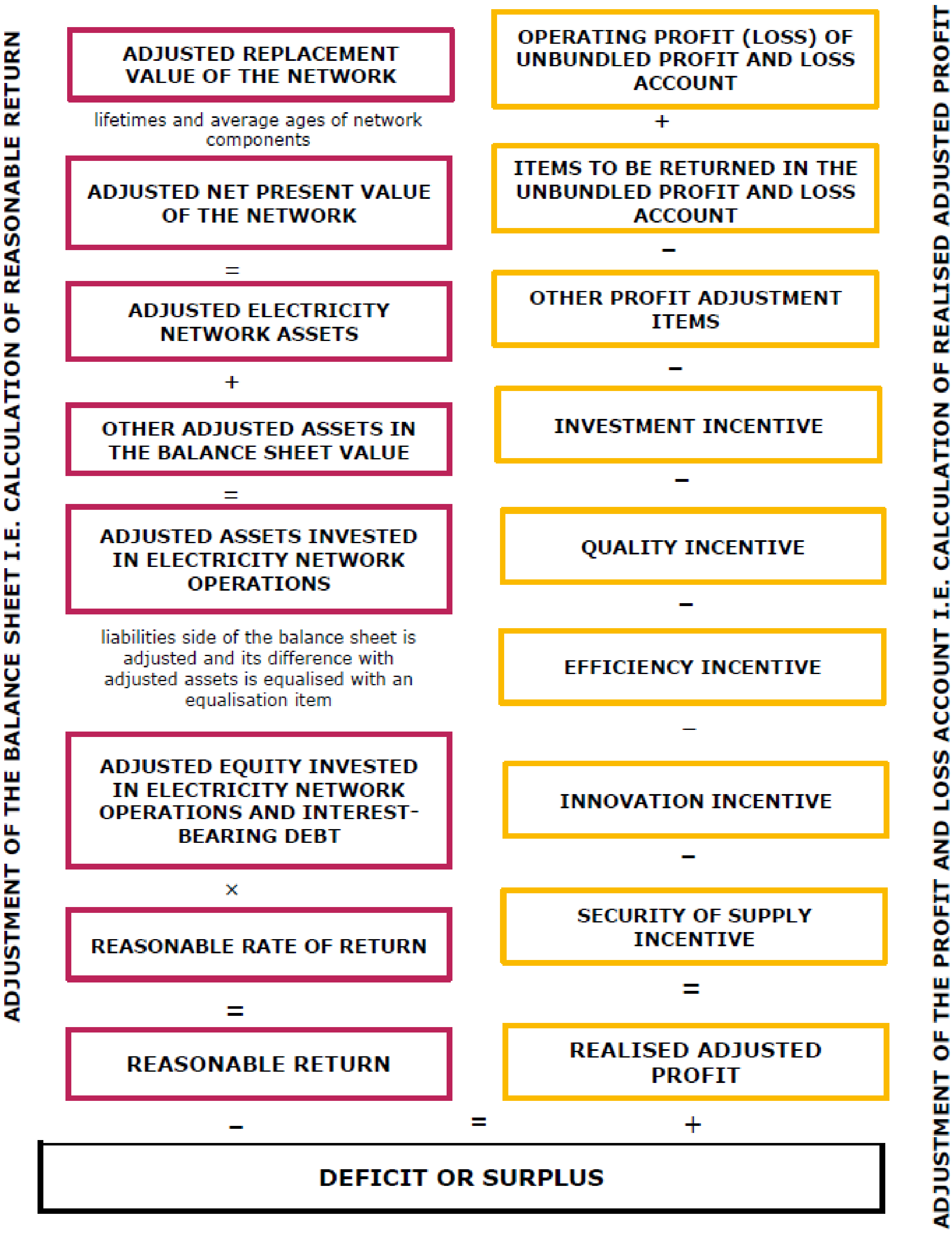
9. What kind of IT systems and integrations you consider successful in the future?
    a. Do you believe that some of the IT systems will be merged into one entity?
    b. Or do you believe they will be separated to even smaller pieces?
    c. What are the functions or services you would consider to pay for in the future?

Interfaces, information flows and outage reporting

10. Name a few most important information flows related to outage reporting
    a. What kind of information? (e.g. fault durations, cause of fault, etc.)
    b. What are the sources of the data? (e.g. MRS, IED, CSMS, WMS, etc.)
    c. What are the used protocols? (e.g. IEC-104 or 101, OPC, TCP/IP, etc.)
    d. What kind of communication type is used? (e.g. 3G, GPRS, LAN, etc.)
    e. What for these information flows exist? (internal/external reporting, etc.)
11. Do you exploit the outage reporting information for the company's own purposes? How?
12. What are the missing information flows or reports that would be useful now or in the future?
    a. For internal reporting
    b. For external reporting (authority and others)
13. Which existing information flows or reports require developing?
    a. Do some reports lack information?
    b. Is there a need for more specific information flows?
    c. Development ideas related to the handling of information in particular phases of reporting process (e.g. something requires too much work atm.)
    d. Are there any further automatization needs?
14. Are you able to provide a fresh system diagram of your NCC's IT systems and their integration for the thesis?

APPENDIX B: THE REGULATION METHODS FOR THE FOURTH AND THE FIFTH REGULATORY PERIODS

This figure contains the regulation methods for the fourth and the fifth regulatory periods, defined by the Energy Authority [67]. The most important parts of the figure regarding this thesis are the efficiency and quality incentives.



APPENDIX C: THE KEY FIGURES DESCRIBING THE QUALITY OF ELECTRICITY DISTRIBUTION OPERATION

These key figures were translated for the thesis from the decree of Energy Authority published in 30.11.2015 [74].

3 The key figures describing the quality of electricity distribution operation

3.1 Interruptions of electricity distribution operation in the HV network

(3.1) The annual number of interruptions in the HV network

a) Average annual duration of sustained unanticipated interruptions caused by fault in DSO's own HV network [pcs]
b) Average annual duration of sustained unanticipated interruptions in HV network caused by fault in other DSO's network [pcs]
c) Number of planned interruptions in the DSO's own HV network [pcs]
d) Number of delayed autoreclosings in the DSO's own HV network [pcs]
e) Number of rapid autoreclosings in the DSO's own HV network [pcs]

(3.2) Average annual number of interruptions in the connection points of HV network

a) Average annual number of interruptions in the connection points of HV network [pcs/a]
b) Average annual number of interruptions in the connection points of HV network weighted by annual energies [pcs/a]

(3.3) Average annual duration of interruptions in the connection points of HV network

a) Average annual duration of interruptions in the connection points of HV network [h/a]
b) Average annual number of interruptions in the connection points of HV network weighted by annual energies [h/a]

(3.4) Total annual amount of electricity not transmitted in the HV network [MWh]

3.2 Interruptions of electricity distribution operation in the MV network

(3.5) Total annual number of unanticipated and planned interruptions in the MV network including rapid and delayed autoreclosings

a) Unanticipated sustained interruptions [pcs]
b) Planned interruptions [pcs]
c) Rapid autoreclosings [pcs]
d) Delayed autoreclosings [pcs]

(3.6) Customer's average annual duration of interruptions weighted by annual energies, caused by unanticipated interruptions in the MV network [h/a]

(3.7) Customer's average annual number of interruptions weighted by annual energies, caused by unanticipated interruptions in the MV network [pcs/a]

(3.8) Customer's average annual duration of interruptions weighted by annual energies, caused by planned interruptions in the MV network [h/a]

(3.9) Customer's average annual number of interruptions weighted by annual energies, caused by planned interruptions in the MV network [pcs/a]

(3.10) Customer's average annual number of interruptions weighted by annual energies, caused by delayed autoreclosings in the MV network [pcs]

(3.11) Customer's average annual number of interruptions weighted by annual energies, caused by rapid autoreclosings in the MV network [pcs]

3.3 Interruptions of electricity distribution operation in the LV network

(3.12) Total annual number of unanticipated and planned interruptions in the LV network

a) Unanticipated sustained interruptions [pcs]
b) Planned interruptions [pcs]

(3.13) Average annual duration of interruptions weighted by annual energies, caused by unanticipated interruptions in the LV network [h/a]

(3.14) Average annual number of interruptions weighted by annual energies, caused by unanticipated interruptions in the LV network [pcs/a]

(3.15) Average annual duration of interruptions weighted by annual energies, caused by planned interruptions in the LV network [h/a]

(3.16) Average annual number of interruptions weighted by annual energies, caused by planned interruptions in the LV network [pcs/a]

3.4 Indices describing the impacts of interruptions on customers

(3.17) Annual amount of paid standard compensation according to the Electricity Market Act divided by interruption durations

a) 12–24 hours [€]
b) 24–72 hours [€]
c) 72–120 hours [€]
d) 120–192 hours [€]
e) 192–288 hours [€]
f) Over 288 hours [€]

(3.18) Annual amount of standard compensated customers according to the Electricity Market Act

a) 12–24 hours [pcs]
b) 24–72 hours [pcs]
c) 72–120 hours [pcs]
d) 120–192 hours [pcs]
e) 192–288 hours [pcs]
f) Over 288 hours [pcs]

(3.19) Annual amount of customer points which have not fulfilled the level of security of supply required by the Electricity Market Act

a) Annual amount of customer points located in the town plan area which have not fulfilled the level of security of supply required by the Electricity Market Act [pcs]
b) Annual amount of customer points located outside the town plan area which have not fulfilled the level of security of supply required by the Electricity Market Act [pcs]
c) Annual amount of customer points which have not fulfilled the level of security of supply for the local circumstances defined by the DSO [pcs]

APPENDIX D: THE EQUATIONS NEEDED FOR CALCULATING THE REQUIRED OUTAGE INDICES

1.1 Calculation of the interruption amounts in the HV network

a) Average annual amount of interruptions in the connection points

$$k_{KA} = \frac{\sum_{i=1}^{m} n_i}{m},$$

where

n_i	Amount of interruptions in the connection point i [pcs]
m	Total amount of connection points supplied by the voltage level in question [pcs]

b) Average annual amount of interruptions in the connection points weighted by annual energies

$$k_E = \frac{\sum_{i=1}^{m} W_i n_i}{W_{TOT}},$$

where

W_i	Amount of annually transmitted energy through the connection point i [MWh]
W_{TOT}	Total annual amount of transmitted energy through the voltage level in question [MWh]

1.2 Calculation of the interruption durations in the HV network

a) Average annual duration of interruptions in the connection points

$$t_{KA} = \frac{\sum_{i=1}^{m} \sum_{j=1}^{n} t_j}{m},$$

where

t_j	Duration of the interruption j of the connection point i [h]
n	Amount of interruptions in the connection point i [pcs]

b) Average annual duration of interruptions in the connection points weighted by annual energies

$$t_E = \frac{\sum_{i=1}^{m} W_i \left(\sum_{j=1}^{n} t_j\right)}{W_{TOT}}.$$

1.3 Calculation of interruption amounts in the MV and LV networks

Customer's average annual number of interruptions weighted by annual energies

$$k_E = \frac{\sum_{i=1}^{m} n_i}{m},$$

where

n_i	Amount of interruptions in the customer point i [pcs]
W_i	Amount of annually transmitted energy through the customer point i [MWh]
m	Total amount of customer points supplied by the voltage level in question [pcs]

1.4 Calculation of interruption durations in the MV and LV networks

Average annual duration of interruptions in the customer points weighted by annual energies

$$t_E = \frac{\sum_{i=1}^{m} W_i \left(\sum_{j=1}^{n} t_j\right)}{W_{TOT}},$$

where

t_j	Duration of the interruption j of the customer point i [h]
n	Amount of interruptions in the customer point i [pcs]

APPENDIX E: QUERY FOR THE SHAPEFILETOOL TO INITIALIZE THE DRRC INFORMATION OF THE CUSTOMERS

This SQL query initializes the DRRC information of the customer nodes in LV_CUSTOMER_NODE table. This initialization job can be done optionally from the ShapefileTool's new GUI. The data is overwritten only for those customer nodes which don't yet have DRRC information or belong to Town plan area or Not town plan area classes (NULL or classes 0, 1 or 2).

```
-- This statement ensures that this is done only in DMS600 NE environments.
IF ((SELECT COUNT(*) FROM LV_CUSTOMER_NODE) > 0)
BEGIN

-- Query can be continued only if DRRC column exists.
IF ((EXISTS (      SELECT *
                   FROM   INFORMATION_SCHEMA.COLUMNS
                   WHERE             TABLE_NAME   = 'LV_CUSTOMER_NODE'
                               AND   COLUMN_NAME = 'DRRC')))
BEGIN

      -- Initialize all 'Town plan area' and 'Not town plan area' DRRCs to NULL.
      UPDATE LV_CUSTOMER_NODE
      SET DRRC = NULL
      -- Initialize only DRRC 1 and 2 (and 0).
      WHERE DRRC <= 2


      -- Query to set the DRRC = 1 (Town plan area) values.
      UPDATE LV_CUSTOMER_NODE
      SET DRRC = 1
      FROM
      (
            SELECT lvcn.CUSTOMER_NODE
            FROM LV_CUSTOMER_NODE lvcn, METADATA_NODE mn
            WHERE mn.NODECODE = lvcn.NODECODE
            AND mn.METADATA_KEY = 'kaavanro'
            -- Do not overwrite the DRRC 3 and 4 (and others).
            AND lvcn.DRRC is NULL
      ) Asemakaava
      WHERE Asemakaava.CUSTOMER_NODE = LV_CUSTOMER_NODE.CUSTOMER_NODE


      -- Set the rest of NULL values to DRRC = 2 (Not town plan area).
      UPDATE LV_CUSTOMER_NODE
      SET DRRC = 2
      WHERE DRRC is NULL

END
END;
```

APPENDIX F: THE CROSS REFERENCE TABLE OF THE CHANGES TO THE ENERGY AUTHORITY'S REPORTING REQUIREMENTS

This cross reference table shows how the Energy Authority's reporting requirements have changed to the fourth regulatory period. In the left side are the old requirement numbers, and the right side shows the new requirements numbers with additional notices.

3 The key figures describing the quality of electricity distribution operation

OLD	→	NEW	*Additional information*

3.1 Interruptions of electricity distribution operation in the HV network

(30)abcde	→	(3.1)abcde	*(NB: c, d and e available!)*
(31)abcde	→	(---)	
(32)abcde	→	(---)	
(33)abcde	→	(3.2)ab	*(NB: requirements changed!)*
(34)abcd	→	(3.3)ab	*(NB: requirements changed!)*
(35)	→	(3.4)	

3.2 Interruptions of electricity distribution operation in the MV network

(26)abcd	→	(3.5)abcd
(17)	→	(3.6)
(18)	→	(3.7)
(19)	→	(3.8)
(20)	→	(3.9)
(21)	→	(3.10)
(22)	→	(3.11)
(23)	→	(---)
(24)	→	(---)

3.3 Interruptions of electricity distribution operation in the LV network

(25)	→	(3.12)ab	*(NB: Also planned outages!)*
(---)	→	(3.13)	*(NB: New requirement!)*
(---)	→	(3.14)	*(NB: New requirement!)*
(---)	→	(3.15)	*(NB: New requirement!)*
(---)	→	(3.16)	*(NB: New requirement!)*

3.4 Indices describing the impacts of interruptions on customers

(27)abcd+sum	→	(3.17)abcdef	*(NB: change in law -> more hours!)*
(28)abcd+sum	→	(3.18)abcdef	*(NB: change in law -> more hours!)*
(---)	→	(3.19)abc	*(NB: New requirement!)*

APPENDIX G: EQUATIONS FOR THE KAH CALCULATIONS FOR THE MV AND HV NETWORKS

In the fourth regulatory period the KAH_{ref} is calculated for MV network with the following equation (1): [67]

$$KAH_{ref,k} = \frac{\sum_{t=2008}^{2015} \left[KAH_{t,k}^{MV} \cdot \left(\frac{W_k}{W_t} \right) \right]}{8}, \tag{1}$$

where

$KAH_{ref,k}$	Reference level of regulatory outage costs for year k [€]
$KAH_{t,k}^{MV}$	Realised regulatory outage costs in the MV network in year t in the value of money for year k [€]
W_k	Volume of transmitted energy in year k [kWh]
W_t	Volume of transmitted energy in year t [kWh]

The actual, realized KAH value calculation for MV network is presented in equation (2): [67]

$$KAH_{t,k}^{MV} = \begin{pmatrix} KA_{unexp,t}^{MV} \cdot h_{E,unexp} + KM_{unexp,t}^{MV} \cdot h_{W,unexp} + \\ KA_{plann,t}^{MV} \cdot h_{E,plann} + KM_{plann,t}^{MV} \cdot h_{W,plann} + \\ DAR_t^{MV} \cdot h_{DAR} + RAR_t^{MV} \cdot h_{RAR} \end{pmatrix} \cdot \left(\frac{W_t}{T_t} \right) \cdot \left(\frac{KHI_k}{KHI_{2005}} \right), \tag{2}$$

where

k	Year 2016, 2017, 2018 or 2019
t	Year 2008, 2009, 2010, 2011, 2012, 2013, 2014 or 2015
$KA_{unexp,t}^{MV}$	Outage period caused by unexpected outages in the MV network, weighted by annual energies [h]
$h_{E,unexp}$	Unit price of disadvantage for the outage period, caused by unexpected outages [€/kWh]
$KM_{unexp,t}^{MV}$	Outage period caused by unexpected outages in the MV network, weighted by annual energies [h]
$h_{W,unexp}$	Unit price of disadvantage for the outage amount, caused by unexpected outages [€/kW]
$KA_{plann,t}^{MV}$	Outage period caused by unexpected outages in the MV network, weighted by annual energies [pcs]
$h_{E,plann}$	Unit price of disadvantage for the outage period, caused by planned outages [€/kWh]
$KM_{plann,t}^{MV}$	Outage period caused by planned outages in the MV network, weighted by annual energies [h]
$h_{W,plann}$	Unit price of disadvantage for the outage amount, caused by planned outages [€/kW]

DAR_t^{MV}	Outage amount caused by delayed autoreclosings in the MV network, weighted by annual energies, number [pcs]
h_{DAR}	Unit price of disadvantage for the outage amount, caused by delayed autoreclosings [€/kW]
RAR_t^{MV}	Outage amount caused by rapid autoreclosings in MV network, weighted by annual energies [pcs]
h_{RAR}	Unit price of disadvantage for the outage amount, caused by rapid autoreclosings [€/kW]
T_t	Number of hours in year t
KHI_k	Consumer price index in year k
KHI_{2005}	Consumer price index in year 2005

In the fourth regulatory period there are separate KAH calculation equations for HV DSOs. In HV distribution network case the reference level of regulatory outage costs is calculated with equation (3) [67]

$$KAH_{ref,k} = \frac{\sum_{t=2008}^{2015} \left[KAH_{t,k}^{HV} \cdot \left(\frac{W_k}{W_t} \right) \right]}{8}, \tag{3}$$

where

$KAH_{t,k}^{HV}$	Realised regulatory outage costs in the HV distribution network in year t in the value of money for year k [€]

The actual, realised regulatory outage costs calculation in the HV distribution network in year t in the value of money for year k is presented in equation (4). [67]

$$KAH_{t,k}^{HV} = \begin{pmatrix} KA_{unexp,t}^{HV} \cdot h_{E,unexp} + \\ KM_{unexp,t}^{HV} \cdot h_{W,unexp} + \\ KA_{plann,t}^{HV} \cdot h_{E,plann} \end{pmatrix} \cdot \left(\frac{W_t}{T_t} \right) \cdot \left(\frac{KHI_k}{KHI_{2005}} \right), \tag{3}$$

where

$KA_{unexp,t}^{HV}$	Average outage time of connection points caused by unexpected outages in the HV distribution network [h/connection point]
$KM_{unexp,t}^{HV}$	Average outage amount of connection points caused by unexpected outages in the HV distribution network [pcs/connection point]
$KA_{plann,t}^{HV}$	Average outage time of connection points caused by planned outages in the HV distribution network [h/connection point]

Unlike previously, in the fifth regulatory period starting from 2020, the regulatory outage costs in the DSO's HV distribution network are also taken into account in the KAH_{ref} calculation. The corresponding KAH_{ref} and KAH calculation equations are presented in the Energy Authority's regulation methods document: see equations (22)–(24) from [67].

In the fifth regulatory period also the interruptions occurred in the HV distribution network are taken into account in the realised KAH calculations. Hence the quality incentive is affected by the sum of two components, as presented in the equation (5) below. [67]

$$KAH_t = KAH_t^{MV} + KAH_t^{HV}, \tag{3}$$

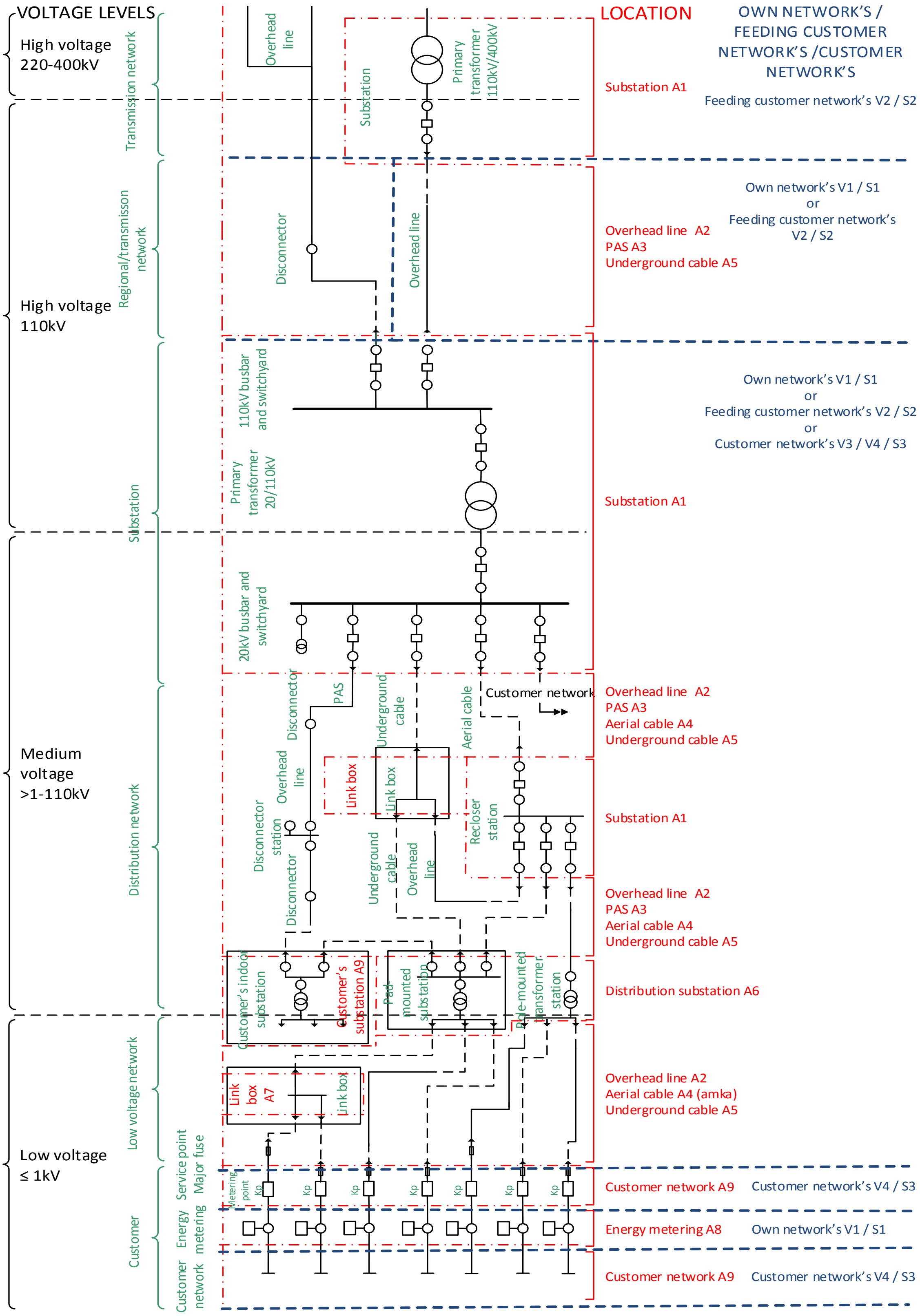
where

KAH_t	Total realised regulatory outage costs calculated in year t [€]
KAH_t^{MV}	Realised regulatory outage costs in the MV network in year t [€]
KAH_t^{HV}	Realised regulatory outage costs in the HV network in year t [€]

The KAH_t^{MV} in the equation (5) can be calculated according to equation (2) presented above, but KAH_t^{HV} has to be calculated with equation (24) presented in the Energy Authority's regulation methods –document [67]. The difference to the original equations in these calculations is that t comes now equal to k, and it means the year under review.

APPENDIX H: THE DISTRIBUTION NETWORK DIVISION BY THE FINNISH ENERGY

This figure presents the network division with voltage levels and other definitions of the outage reporting for the Finnish Energy (adapted from [7] and [69]).



APPENDIX I: THE REQUIRED INTERRUPTION INFORMATION FOR THE FINNISH ENERGY AND THE RELATED CODES

This figure presents the possible interruption types, reasons of interruption, location and fault types of each voltage level for the Finnish Energy (adapted from [7] and [69]).