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TAMPERE UNIVERSITY OF TECHNOLOGY

VILLE TUOMINEN
TESTING OF DECENTRALIZED DISTRIBUTION AUTOMATION SYSTEM - USE CASE COORDINATED VOLTAGE CONTROL

Master of Science thesis

Examiner: Prof. Sami Repo
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ABSTRACT

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The control and monitoring of the distribution network is going to go through some profound changes in the future, while the amount of distributed energy production, automation and controllable resources increase in the network. In such situation the assumption of unidirectional flow of energy from the production through transmission network and distribution network to customers might not be valid any more. Distributed energy resources, such as wind turbines and photovoltaic plants are often located near the consumption and connected to the distribution network instead of transmission network. With the use of novel network management tools and coordinated voltage control an acceptable state of the network can be maintained and the whole potential of the system utilized.

This thesis presents a new distribution automation concept developed in IDE4L project as well as the construction of the test environment and test results. The automation system of the IDE4L project is based on a decentralized, modular and hierarchical approach that aims to reduce the rigidity of a traditional control center based system while providing a large variety of features for network monitoring and control. The main parts of this system are substation automation units (SAU), that spread out the decision making and control of the network. Each SAU acts as an individual control unit that controls and monitors devices in that part of the network and delivers only necessary data to the higher level control center. The aim of this thesis is to investigate and list especially non-functional requirements to be tested on a decentralized automation system.

The main focus of testing is at the operation of the automation architecture and its non-functional requirements. The testing is conducted at the Real time digital simulator laboratory with actual intelligent electronic devices (IED) and SAU. Reliability and availability for the whole system and its components is studied with a theoretical approach. All other tests, such as failure and error handling, time performance and resource utilisation, are carried out with the laboratory set up. Testing did not bring up any major issues or constraints that would occur when the system size is scaled up, but some observations were made about the test set up as well as commissioning and interoperability of IEDs that should be considered.

TIIVISTELMÄ

VILLE TUOMINEN: Hajautetun sähkönjakeluautomaatiojärjestelmän testaus - Esimerkkinä koordinoitu jännitteensäätö
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Jakeluverkkojen monitorointi ja hallinta tulevat käymään läpi merkittäviä muutoksia tulevien vuosien ja vuosikymmenten aikana, kun lisääntyvä hajautetun tuotannon, jakeluatomaation ja ohjattavien resurssien määrä verkossa kasvaa. Hajautetut energiaresurssit, kuten aurinkopaneelit ja tuulivoimalat, ovat usein sijoitettu jakeluverkkoon melko lähelle kulutusta, eikä perinteinen oletus tehon yksisuuntaisesta virtauksesta korkeammalta jännitetasolta alemmalle välttämättä pidä enää paikkaansa. Hyödyntämällä uudenlaisia verkonhallintatyökaluja sekä koordinoitua jännnitteensäätöä pystytään nykyisen verkon tila pitämään sallituissa rajoissa ja maksimoimaan verkkoon liitettävän hajautetun tuotannon määrä.

Tässä diplomityössä esitellään uudentyyppinen hajautettuun arkkitehtuuriin perustuva sähkönjakeluautomaatiojärjestelmä, joka on kehitetty osana IDE4L-projektia. Lisäksi laboratoriotestijärjestelmän rakentaminen ja kokoonpano sekä järjestelmällä saadut tulokset on esitelty. IDE4L-projektissa kehitetty järjestelmä pyrkii hajauttamaan päätöksentekoa muuntamoille ja sähköasemille sijoitetuille muuntamoautomaatioyksiköille (SAU) ja tätä kautta tekemään järjestelmästä entistä joustavammman. Jokainen SAU toimii verkossa itsenäisenä valvonta- ja ohjausyksikkönä, joka monitoroi siihen kytketyviä laitteita niin muuntamolla kuin verkon varrella ja pystyy myös antamaan tarvittaessa näille laitteille uusia asetusarvoja. Tämä diplomityön tavoitteena on lisäksi selvittää hajautetulle automaatiojärjestelmälle kriittiset ei-toiminnalliset ominaisuudet ja miten niitä pystyttäisiin testaamaan.

Työssä suoritettujen testien pääpaino on automaatiojärjestelmän yleisen suorituskyvyn sekä työssä määriteltyjen ei-toiminnallisten ominaisuuksien sevittäminen laboratoriojärjestelmän avulla. Testit suoritetaan reaaliaikasimulaattorilaboratoriossa (RTDS), jossa simulointiin on kytketty myös fyysisiä laitteita sekä SAU. Luotettavuuden ja käyttövarmuuden analysointi on toteutettu laskennallisesti, kun taas muut testit, liittyen esimerkiksi häiriöiden ja virheiden sietokykyyn, mittaustarkkuuteen sekä resurssien käyttöön suoritetaan laboratoriojärjestelmän avulla. Testit eivät paljastaneet järjestelmästä mitään selviä ongelmakohtia tai rajoitteita vaikka järjestelmän koko kasvaisi, mutta joitain huomion arvoisia seikkoja ilmeni liittyen testijärjestelmään sekä laitteiden yhteensopivuuteen ja käyttöönottoon.

PREFACE

This Master of Science thesis was written in the Department of Electrical Engineering at the Tampere University of Technology. It was made as a part of the IDE4L-project, which is a demonstration project funded by the European Commission.

I want to thank my examiner Professor Sami Repo and supervisor PhD Anna Kulmala for all the guidance and advices during this work. I would also like to thank all the personnel at the Department of Electrical Engineering for providing an inspiring and pleasant working environment and in interesting topic for the thesis. Especially I wish to thank my co-workers Hannu Reponen and M.Sc Shengye Lu for all the assistance and co-operation during this project as well as M.Sc Ontrei Raipala for all the expertise with the RTDS laboratory. Finally, I would like to thank my family and friends for all the support and great memories throughout these years of studies.

Tampere, May 25^{th} 2016

Ville Tuominen

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LIST OF ABBREVIATIONS AND SYMBOLS

AI	Artificial Intelligence
ACSI	Abstract Communication Service Interface
ANM	Active Network Management
AVC	Automatic Voltage Controller
AVR	Automatic Voltage Regulator
CC	Control Center
CDC	Common Data Class
CID	Configured IED description
CVC	Coordinated Voltage Control
DER	Distributed Energy Resource
DG	Distributed Generation
DIED	Distributed Intelligent Electronic Device
DLMS/COSEM	Device language message specification/companion specification for energy metering
DMS	Distribution Management System
DSO	Distribution System Operator
FC	Functional Constraint
FS	Functional Requirements
GOOSE	Generic Object Oriented Substation Event
HEMS	Home Energy Management System
HIL	Hardware-In-The-Loop
HSR	High Availability Seamless Redundancy
ICD	IED capability description
IED	Intelligent Electronic Device
MMS	Manufacturing Message Specification
MTTF	Mean Time To Fail
MTTR	Mean Time To Repair
MU	Merging Unit
NFR	Non-Functional Requirements
NTP	Network Time Protocol
OLTC	On-Load Tap Changer
PC	Power Control
PLC	Programmable Logic Controller
PMU	Phasor Measurement Unit
PRP	Parallel Redundancy Protocol

PS	Primary Substation
PSIED	Primary Substation Intelligent Electronic Device
PV	Photovoltaic
RBD	Reliability Block Diagram
RTDS	Real Time Digital Simulator
RTU	Remote Terminal Unit
SAU	Substation Automation Unit
SCADA	Supervisory Control And Data Acquisition
SCD	Substation Configuration Description
SCL	Substation Configuration Language
SIL	Software-In-The-Loop
SM	Smart Meter
SQP	Sequential Quadratic Programming
SS	Secondary Substation
SSD	System Specification Description
SSIED	Secondary Substation Intelligent Electronic Device
STATCOM	Static Synchronous Compensator
SV	Sampled Value
VLAN	Virtual Local Area Network
XML	eXtensible Markup Language

1. INTRODUCTION

Electricity distribution and production is going through a profound change during next years or decades, while the production is no longer centralized to large power plants connected to the high voltage transmission grid, but more and more production is coming from smaller decentralized energy resources (DER) located closer to consumption in the distribution network. This causes a situation where the power flow in the network is not necessarily unidirectional from higher voltage levels to lower ones, as it has been in the traditional network. It is also not valid any more to assume that the maximum voltage of the network can be found at the substation, since even small production units along the feeder can result to higher network voltages near the DER unit. For a distribution network operator to be able to maintain adequate state in the network there are few different options, that can be divided into measures which include upgrades and changes in the network and to measures that improve the control and monitoring of the network. [1]

The DER hosting capacity of a distribution network can be improved by increasing the feeder size resulting to lower feeder impedance, connecting the DER units to specific feeders or to lower the voltage at the substation. The substation voltage can be decreased permanently only if it is guaranteed that the network state remains adequate also with the lower voltage level. Another way is to change the operating principle of the network by adding coordinated voltage control (CVC) methods to the network based on rule based or optimized control. [1] A novel control architecture of a distribution network is developed in the IDE4L project and includes decentralized distribution automation and coordinated voltage control methods. The automation concept is based on decentralized, hierarchical and modular design where the control of the network is distributed to substation automation units (SAU) located at both primary and secondary substations. The primary control of the network is executed by local control devices, such as automatic voltage control relays and automatic voltage regulators. Each individual SAU is controlling and monitoring the feeders leaving the substation and all the intelligent electronic devices (IED) located along them. In the case when local control devices are not able to maintain appropriate network state or the network state is too far from the optimum the CVC algorithm is able to provide new operating set points for the control devices. SAU also aggregates the measurements from the IEDs and transmits just the necessary data to the higher level control center.[2]

The objective of this thesis is to find out and list important non-functional requirements for a decentralized automation system along with possible suggestions and procedures to test them. A novel architecture for a decentralized distribution automation system developed in the IDE4L project is also presented. The building of the laboratory demonstration set up to real time digital simulator (RTDS) laboratory for the testing purposes of the automation system is also included to this thesis and devices and interfaces included to that are presented in chapter 4. The automation system concept and architecture is introduced in chapter 3 along with general introduction to non-functional requirements (NFR). Tests to define the performance and NFRs for the automation system are explained in the chapter 5 and results presented.

2. DISTRIBUTION NETWORK VOLTAGE CONTROL

In traditional distribution network the voltage control is mainly executed in the primary substation and the rest of the network is considered as passive network with unidirectional power flow towards the customers. Based on the assumption made about the unidirectional power flow the voltage profile of a radial distribution network feeder with only load can be seen in figure 2.1.

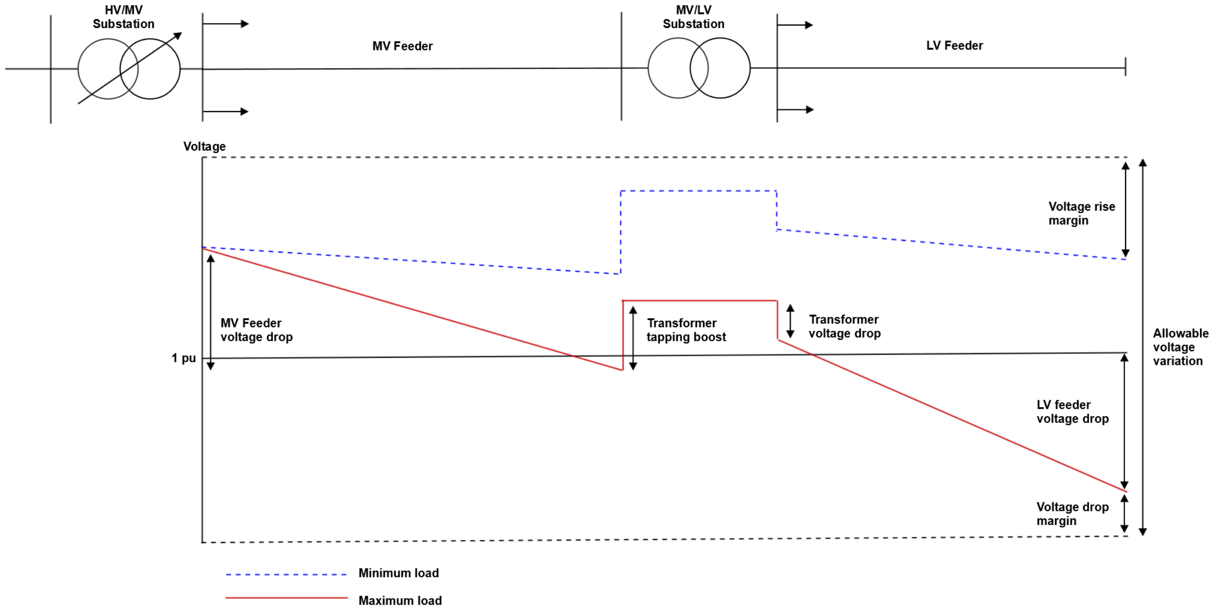


Figure 2.1 *Voltage profile of a traditional radial network feeder with only load. Adapted from [3, p. 12]*

Due to the fact that all the generation is located in the high voltage network the distribution networks highest voltage can be found from either of the substations and the voltage level will decline towards the end of the feeder. In figure 2.1 there are two different lines representing different loading conditions of the network. The blue line shows the voltage profile in the situation where the load is at it's minimum, which leads to highest voltage profile, and the red line shows the situation when the load is at it's maximum and the voltage drop along the feeder is at it's maximum too.

Traditionally the automatic voltage control of the distribution network has been located at the HV/MV substation where the voltage level of the MV network has been controlled with automatic tap changer. By raising the tap position at the primary substation the voltage level will rise in MV as well as in LV network fed by that transformer. The tap changer is controlled by a voltage control relay, that constantly monitors the secondary voltage of the transformer. Once the voltage drops below or rises above predefined levels of the relay a control signal is sent to the tap changer to alter it's position to restore the voltage at permissible level. [4]

Installation of distributed generation or other DERs to the distribution network is however causing problems for the traditional control system and can result in high costs to the network. Installation of distributed generation can cause voltage rise near the connection point of the generator, which limits the maximum DER hosting capacity of the network. [1] In the figure 2.1 the voltage rise margin in the minimum load situation basically defines the limit for the amount of distributed generation (DG) to be integrated in that LV network without performing any other changes to the network. If more DG are connected there is a possibility that in some situations the voltage at the last customer is too high. [3] There are several ways to solve the voltage rise situation: decreasing feeder impedance, changing the substation voltage, changing voltage at some other point of the feeder or control of real and reactive power flow in the network. Currently the issue is often solved by increasing the conductor size of the feeder, which results in decreased feeder impedance, or by having a specific feeder for the generator where higher voltage can be allowed. In this case the operating principle of the network stays intact, but there could be significant costs because of the change in network infrastructure and also because components may have been replaced prior to the end of their useful life. [1]

Methods to provide CVC to the distribution network vary a lot from simple control rule based system to system utilizing advanced optimization algorithms to control the whole network. These are the two extremities of CVC methods. Control rule based methods fit better for controlling the voltage in simple, often radial, networks where only few different control options exist. One of the simplest cases is CVC by controlling on load tap changers fitted in the substations power transformers, since the change of voltage level on the substation affects the voltage level of the whole distribution network. In this case the tap changer is controlled based on the state of the whole network rather than just local measurements from the substation as it is done traditionally. To the simple control rule based CVC it is also possible to add local voltage and reactive power control, such as generator automatic voltage regulators (AVR). These local control devices act normally a lot faster than the control at the substation and they are often enough to restore the voltage at its appropriate level. [1]

3. DECENTRALIZED AUTOMATION SYSTEM

The power distribution grid has typically consisted of high voltage to medium voltage transformation at primary substation (PS), medium voltage to low voltage transformation at secondary substation (SS) and finally customers connected to the grid mainly at low voltage level. The control and management of the grid has been executed by centralized control system where devices at PS are been monitored by control center (CC) and then controlled remotely with supervisory control and data acquisition (SCADA) and distribution management (DMS) systems. The DMS contains detailed network data and advanced DMS versions include also smart functionalities such as coordinated voltage control and low voltage network data on top of the information from PS equipment. [5]

This thesis was made as a part of the IDE4L project and the laboratory test set up presented was build to test the automation concept before field testing. The goal for the IDE4L project is to develop an active network management (ANM) system with significant amount of integrated distributed energy resources (DER) in the network and pinpoint issues and special features to take into account. One essential part of the ANM is distribution automation and how it will be integrated to power system management and other parties in electricity market. The utilisation of DERs to act as parts of the network management, instead of just being installed and left there to produce electricity, plays also a key role in this project.

Distribution automation makes it possible to control the medium and low voltage network as well as DERs and it includes automation on both primary and secondary substations, control center information systems and automation in customer premises, such as smart meters or charging stations for electric vehicles. Whereas the real-time monitoring of the network used to be located only at primary substation, it should now be expanded to secondary substation, low voltage network and to advanced smart meter monitoring at customer end in order to make ANM work properly. To make the active management of the whole network feasible the design work needs to be executed consistently. The system needs to be at the same time well coordinated to be able to control different parts of the network and to integrate technical and commercial decisions, but also to be distributed to use local parameters available to make real-time control decisions. In order to enable such system primary and secondary substations as well as DERs need to be equipped with control devices, such as substation automation units (SAU) and intelligent electronic devices (IED), to distribute the decision making and control to local sites. [2]

3.1 Decentralized distribution automation system of IDE4L

The automation architecture of IDE4L project is based on a hierarchical decentralized system, which smoothly integrates coordinated control of the network to IT systems. At the lowest level of the hierarchical architecture are IEDs, located at all voltage levels of the grid. There are IEDs controlling local resources, such as photovoltaic (PV) plants, as well as IEDs that are located at the secondary and primary substation and medium voltage network. They are further connected to substation automation units at the primary and secondary substation, which monitor and control all IEDs that are connected to them. The SAU at both substations is acting as the main intelligent unit of each specific monitoring and controlling area of the network. The distribution management system (DMS) works as a centralized and distribution network wide control and monitoring unit that provides the DSO an interface with a market operator and along with the commercial aggregator. The decentralization of automation enables also use of increased number of measurement sensors, for example from smart meters, to be used for network monitoring and control, which would be more difficult to establish with centralized system due to extensive amount of data to be transferred. [2]

In addition to the other important requirements and features presented in this chapter reliability is a crucial feature for distribution automation system and in general it can be described as follows: *Reliability is the probability of a device performing its purpose adequately for the period of time intended under the operating conditions encountered. [6]* There are always some main indices when defining the reliability of a system, although they are not necessarily the same for each case and should be chosen to suit the system in hand. There are, however, four indices that are generally termed as reliability indices and on the other hand reliability is often referred as a combination of all these four. These indices are all included in the general definition of reliability: probability, appropriate performance, time and operating conditions. Some good examples of additional indices for reliability are:

- the average time between failures,
- The average outage duration or device down-time caused by a failure,
- the expected loss in turnover due to a failure.

The suitable index or indices can be determined by using probability theory, but still there is no single formula that would work in every system. Appropriate performance, time and operating conditions are all engineering parameters, which depend solely on the system under study. [7, p. 2-3]

Time is also a critical part of the measurement data and the IDE4L automation and network management concept benefits from the large amount of real-time measurements received from various field devices. The measurement reading cycle for devices varies from few seconds to minutes, depending on the device type and importance of the measurements in question to ensure that algorithms at SAU have all the latest measurements and they are updated when the network state changes. The presumption and goal that adequate amount of real-time measurements are available for functions at SAU is directly linked to the reliability of the system and along to the availability of the system. The availability is a measure to represent the time the system is operable and all the devices and interfaces are functional. An availability of 100 % would mean that there are no gaps in the operation of the system within the defined time period. This does not necessarily mean that there could not be any failures, but it could be because the system is constructed in redundant way that a failure of one or perhaps several parts of the system is not causing the whole system to fail. [8] Reliability and availability as well as time characteristics and scalability of the system are further discussed in chapter 5

3.1.1 SAU

One of the main units in the whole distribution automation system in IDE4L project are the substation automation units. SAUs are located at both primary and secondary substations where they act as a monitoring and control unit for IEDs in the field, but also as a communication interface between field devices and higher level units, such as SCADA or DMS. [2]

SAU collects measurements and status information of devices located on the same substation or along feeders leaving the station, but it also takes care of network control and state estimation and state forecast. SAU includes multiple interfaces with different protocols for communicating with various types of devices:

- IEC 61850 manufacturing message specification (MMS), for network control
- Device language message specification/companion specification for energy metering (DLMS/COSEM) for smart meter communication
- IEC 60870-5-104, although in demonstrations this interface is realized by specific device, which does the mapping between IEC 104 and IEC 61850 MMS

protocols

- Web services, which provide meter data concentrator device or advanced meter management interface for SAU to receive smart meter data
- IEC 61850-90-5/C37.118 for exchanging information with phasor measurement Units (PMU)
- Modbus TCP [2]

The figure 3.1 represents the internal data structure of the SAU. Both primary and secondary SAUs are based on the same fundamental model and only the part of the network and IEDs under control are different.

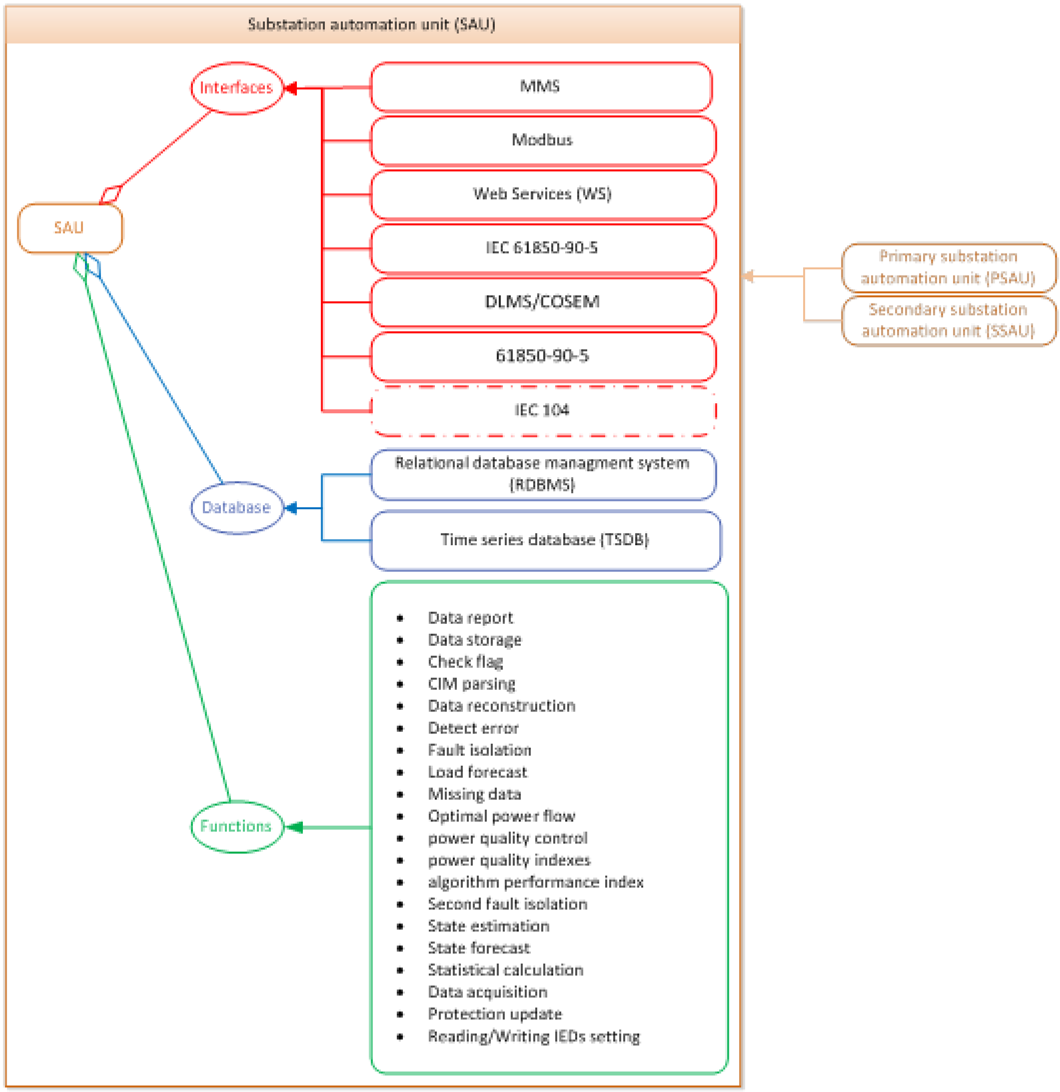


Figure 3.1 *The internal data structure of substation automation units concept. [2, p.49]*

A major part of the SAU, which eventually enables most of the functions listed in figure 3.1 to operate, is the database. Most of the data, such as measurements and state information, gathered from IEDs in the network are stored in the relational database management system as well as all the results from different algorithms, but time-series database is also implemented to support data received from PMUs. [2]

3.1.2 IED

An intelligent electronic device (IED) is the actuating part of the distribution automation system and especially important in decentralized system. IEDs spread the decision making and network control actions to broader area and away from the control center and closer to local sites, such as end customers and distributed energy sources. IED itself is quite inexact definition of devices that include intelligence to act autonomously, controlling and monitoring their part of the network or device connected to the network. Some devices numbered among the group of IEDs are Remote terminal units (RTU), smart meters, home energy management systems and primary controllers like voltage control relays. As the definition is a bit vague in this project a more specific classification of IEDs is being used, which can be seen in figure 3.2. The first separation is done by the location of the IED in the network: PSIED is located in the primary substation, SSIED in the secondary substation, DIED somewhere outside any substation and finally end customers Home Energy Management System (HEMS). [2]

The actual device types, allocated by their locations, can be seen in the right side of the figure 3.2, where for example both substations include an automatic voltage controller (AVC) for controlling the on load tap changer of each substation. The HEMS on the other hand acts as the interface towards commercial aggregator and also for user to manage possible DERs at ones premises. IEDs can also contain several types of interfaces, which are mainly mapped into IEC 61850 protocol with gateways or used as such, for example smart meter interfaces DLMS/COSEM which can be directly connected to the corresponding interface at SAU. [2, p.50]

3.1.3 Functions for use case

The substation automation unit includes several functions and algorithms that are vital in order to achieve proper network monitoring and control. For the secondary voltage control use case there are three main functions related to it: network state estimation, load and production forecaster and power control functions. The power

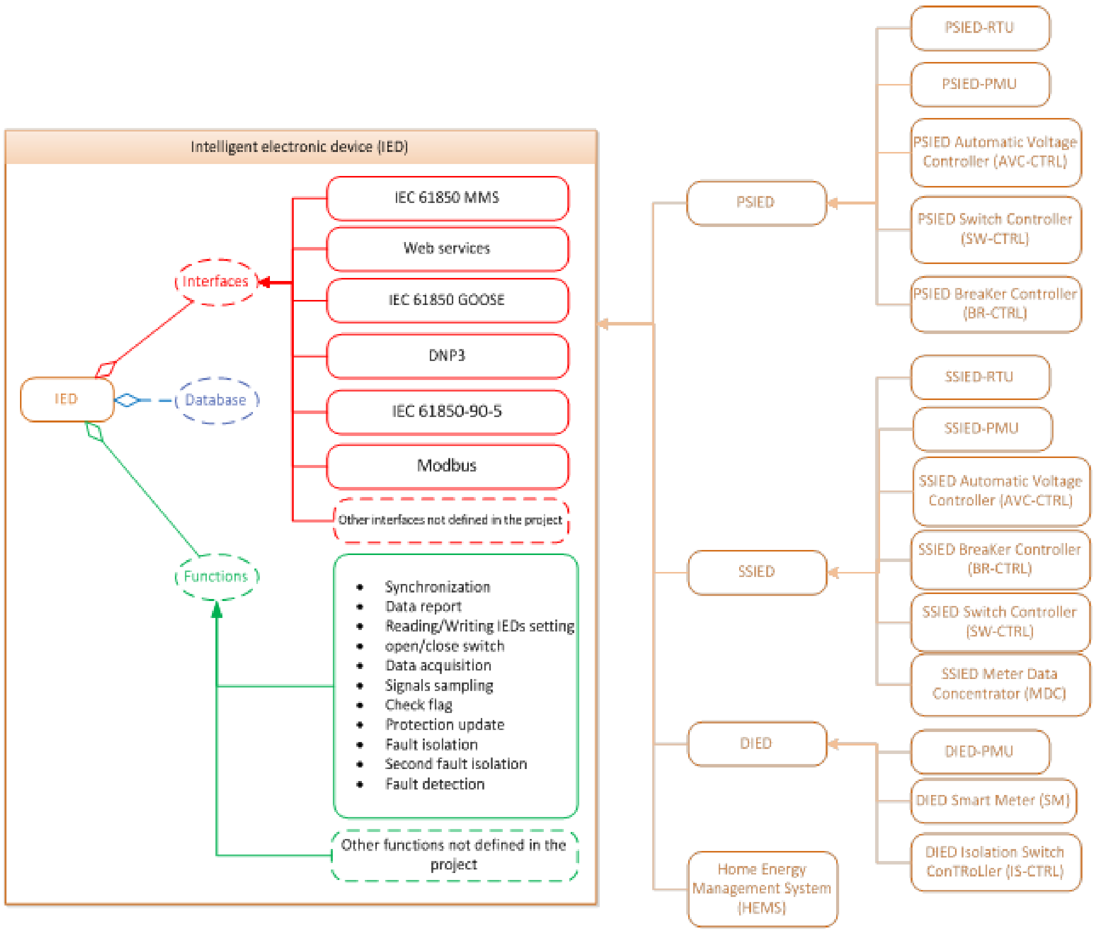


Figure 3.2 *The internal data structure of intelligent electronic device and the classification to different device types. [2, p.50]*

control algorithm enables the actual voltage control in real time, but it can not operate without the input data coming from the state estimator algorithm. The input data from load and production forecaster to state estimator on the other hand enables more precise state estimates to be calculated.

State estimation

Distribution network state estimation is being used to create as good estimate as possible of the current network state by utilizing all available measurements and other data. In current networks the state estimation is based on measurements from substation, line information and customer load profiles. The power flow and loading conditions of each feeder leaving the substation can be calculated precisely from the substation measurements including the busbar voltage measurement and power or current flow measurements from each feeder. Although with these measurements it is not possible to accurately define how the loading distributes within each feeder.[9] The increase of distributed energy resources and automation in distribution network makes it impossible to achieve realistic state estimation for the network with this type of system. In such network a real-time state estimation algorithm is needed and that requires additional real-time measurements from the network. [10] Increased automation and distributed resources also mean more active network management with for example automatic power and voltage control, which also requires real-time state estimations to be able to properly control the network. [9]

There are several versions of state estimation algorithms developed in the past and most of them use weighted least squares method for the calculations, but the choice of so called state variables have variation. State variables are variables in the network which are used as the basis for the state estimation calculation and they are mostly either node voltages and their phase angels or branch currents and their phase angles. In IDE4L project the main concern when selecting the state estimation concept is that it has to be suitable for medium and low voltage networks and has to have a proven record of it functioning since it will be used eventually in several field demonstrations included in the project. Both node voltage and branch current methods fulfil these requirements and both have their own strengths, but the branch current method was chosen based on the fact that people working on this project have more experience on that beforehand. [11]

Load and production forecaster

The load and production forecaster consist of two separate functions: load forecaster and production forecaster. The load forecaster can be divided into different categories depending on the time frame of the forecast and in this case the interest is on the short-term load forecasting, which includes day-ahead forecasting. Longer-term load forecasts can be utilized to address decisions regarding for example future investment decisions, but the long-term forecasting in IDE4L project is being used for example for next day's trade. The method a forecaster operates can be based on a statistical approach or Artificial Intelligence-based approach (AI).

The statistical model forecast the future load based on historical data and current data about for example weather and date as the AI-based model can handle complexity and is more flexible, but requires more data to be dependable. The production forecast on the other hand forecasts wind and photovoltaic energy with either physical models, statistical models or with AI-based models. Physical models try to forecast, for example for wind power plant, the wind reaching each of the turbines and from that how much they will produce energy. Basically the model is based on DERs location and to its technical and physical properties. When historical data of the energy production combined with meteorological forecasts are added to the system the model becomes statistical model and will be able to provide more accurate forecasts, especially in short-term time frame. There are multiple methods, such as Fuzzy logic, genetic algorithms or neural networks, to execute AI-based forecasting. Although all the forecasting methods are fairly light to run once the system is completely operational, AI-based methods are very data intensive in the beginning when it has to be taught to operate in that particular system while physical and statistical models can start operating with less initial data. The forecasting of load and production in IDE4L project is essentially based on statistical models, which are proven to work reliably and be robust. Forecasting algorithm is equipped with historical measurements and weather forecasts from a local weather station. [11]

Power control

The real time power control algorithm (PC) is the key function for the secondary voltage control and it is based on optimization. The algorithm uses for example the information about network losses and constrained real power of the DG units to formulate the objective function for the network optimization. [12, p. 43], [1, p. 35] The figure 3.3 presents the flowchart of the different steps for the power control algorithm.

The operation of power control algorithm includes nine different steps in a loop, as can be seen in the figure 3.3. The algorithm operates in an one minute loop, although possible to specify otherwise too, once it has been started and it has read all the static network data from the database. When the beginning of a new minute has been reached the algorithm checks if all the other algorithms needed for the PC have been executed and if all the necessary input data for the PC is available after which it moves to the next stage. If some of the input data is missing the algorithm moves to exceptional situation handling state 1 and does not finish the whole loop. In the situation where all the input data is available algorithm reads that from the database along with updated static network data if necessary. After the input data has been read and processed the optimization algorithm is called. It initialises the optimization problem on hand, runs a sequential quadratic programming (SQP) algorithm and with heuristic method assigns discrete variables.

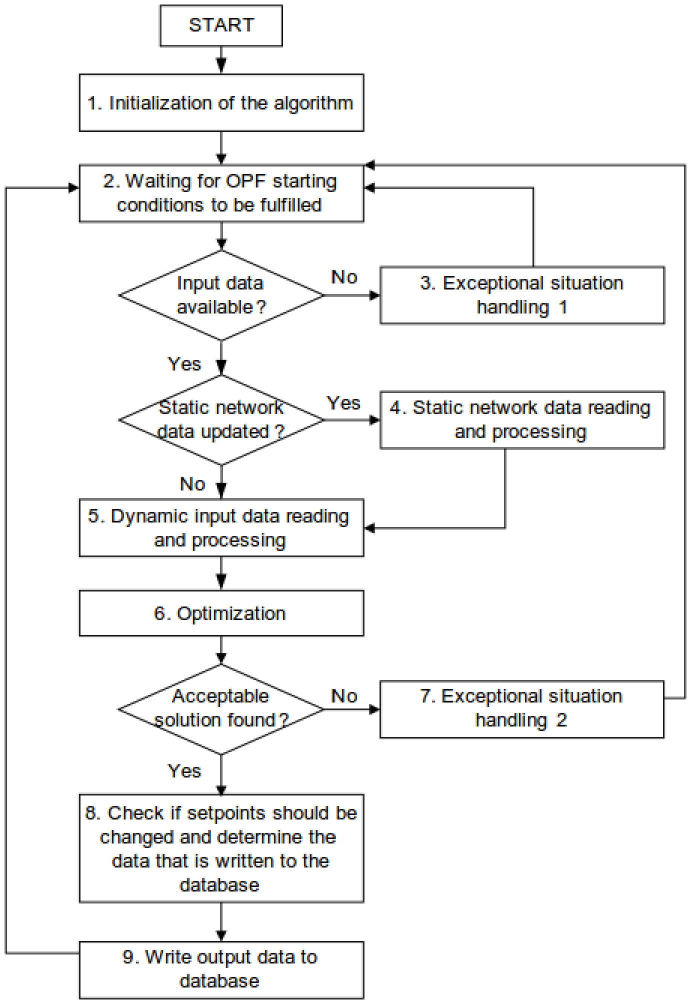


Figure 3.3 *Flowchart showing the real time power control algorithms operation principle. [12, p. 44]*

In case a suitable solution has been found for the problem the algorithm inspects if setpoints of the control devices need to be changed. The algorithm calculates objective functions with current setpoint and with new setpoints defined by the optimization and current setpoints will not be changed if the decrease of the objective function is not big enough to exceed a set limit. If the network state has been for some reason unacceptable before the optimization the setpoints will be changed to restore an admissible state. When the algorithm can not find a suitable solution it enters the exceptional situation handling state 2. Last step for the algorithm is to write all the output data to the database where different interfaces of the SAU will execute the actual transfer of the new setpoints to control devices. [12]

3.2 Hierarchy

The complete distribution automation system in IDE4L is based on a hierarchical architecture. Main reason to have a decentralized hierarchical architecture is on the other hand to divide and spread out the intelligence and decision making of the network control but also provide a clear connection point for external parties to network control through the control center. The control center monitors the state of the whole network, thus providing useful information for external parties that are more interested on the overall state of the grid. External parties on this case cover commercial aggregators, transmission network owner and electricity market parties. The actual network monitoring and control operates in co-operation with the tertiary control located at DMS by employing the decentralized decision making of IEDs and monitoring and possible control actions executed by SAUs. [2, p. 11]

The traditional way of controlling the distribution network is with a centralized control architecture, which is based on supervisory and data acquisition system (SCADA). At the bottom layer of the control architecture are primary devices that are directly interfaced with consumers, such as metering devices, generators or tap changers, and are able to perform some control actions locally. Primary devices are then interfaced with IEDs, which are on the secondary device layer and perform operation mode and setpoint changes of the primary devices and also interface them to the communication network. The IEDs are then all connected to the control center and this ensemble of IEDs, communication network and control center form the SCADA system. This control architecture can be seen in Figure 3.4

The traditional distribution network control often includes primary substation control, possible control of devices along mid voltage feeders and some IEDs at the secondary substation, but the state of low voltage network is mainly established by controlling the feeding mid voltage network state. Distribution network operators often control their network with a single SCADA system, which may face several issues when the amount of automation and distributed energy resources is increased and also expanded to the low voltage network. The increased automation and resulting increase of transported data in the communication network between secondary devices and control center may cause congestion and increased delays. In this case the accuracy and operating rate of control actions can be impaired. [13, p. 9-11] The proposed control architecture in IDE4l project can be seen in Figure 3.5. In the IDE4L project local control devices are referred as primary control devices and the secondary control is located at the SAU and it is capable of changing the operating setpoints of the primary devices. On top of that the tertiary control of the network

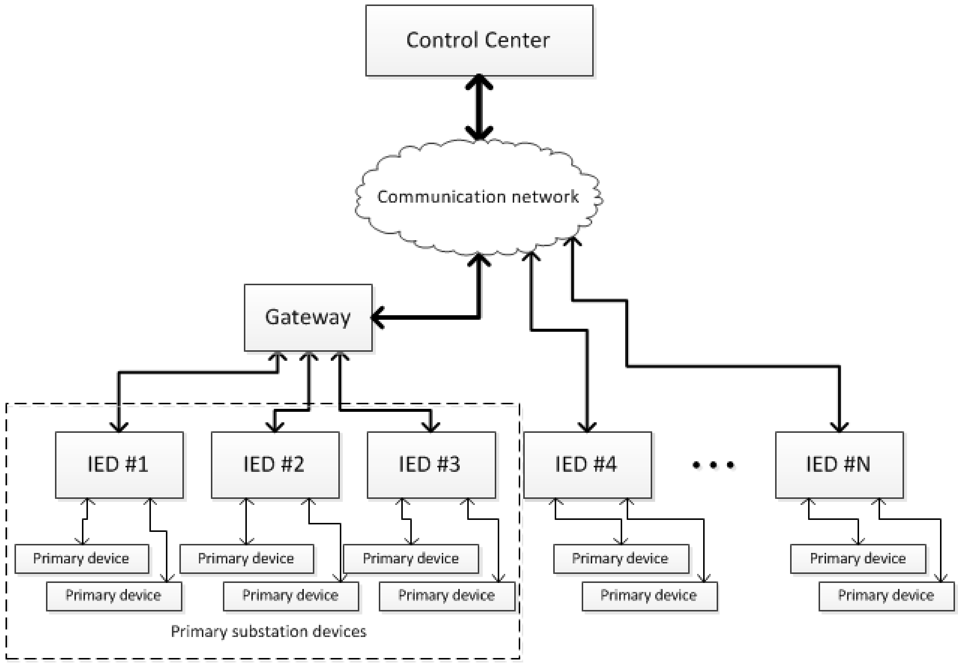


Figure 3.4 *Hierarchical architecture and data transfer amounts of a centralized network control system.*

is located at the control center level.

The difference of the hierarchical control center-primary substation-secondary substation control architecture on IDE4L project and of a legacy control system is the division of control actions, as represented in Figure 3.5. In this case the secondary network control actually operates on both primary and secondary substation and primary control at IEDs and DERs. The IDE4L system includes also different operational time scales, while the primary control works in real-time and possible control functions on substations in intra-hour scale, the tertiary control located at higher levels operates in day-ahead scale and determines the configuration limits for the secondary control. The aim in this hierarchical system has been to reduce the rigidity of a classical hierarchical system by dividing the control and decision making to separate intelligent modules, which both lead to partially autonomous control operations. By spreading the control from a centralized control center to distributed units, namely substation automation units, the data transfer is also reduced between control center and lower level devices. The connector line thickness in Figures 3.4 and 3.5 illustrates the scale of data transferred between hierarchical levels and as can be seen the main difference between these systems is the amount of data transferred between control center and SAUs. This increases the operation

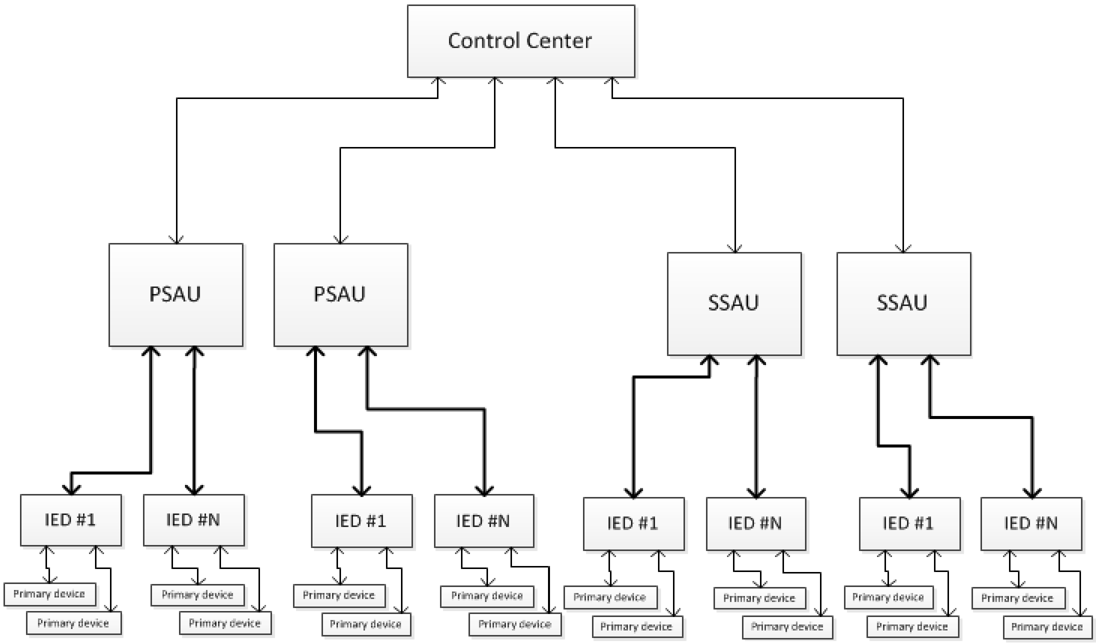


Figure 3.5 *Hierarchical architecture and data transfer amounts of the network control system proposed in IDE4L project.*

rate of automation in the network as well as overall hosting capacity of the network regarding automation and control devices, because all the data from IEDs is gathered to the SAU and only vital data will be forwarded to the control center. [2, p. 13-14]

3.3 Modularity

The centralized control architecture based on a SCADA system represents the state of the art network control system and can be designed to execute active network management and diverse smart grid related control actions. They are however realized by often custom developed and large software ensembles which makes them challenging to be used in other applications. This severely impairs the flexibility of the system, which is becoming more and more important feature of a network control system along with more complicated and advanced automation implementations. [14]

In the automation system of IDE4L a modular design has been used, which makes the system a lot more flexible. Modularity makes it possible to use full versions of specific features of the system only where they are truly needed and also leave out completely some features from certain points of the network where they would not be needed. Modular design also enables re-usability of monitoring and control architecture, since all the same implementations and features can be used when the basic architecture is the same. [2]

Modularity is in theory made possible by using same data structure of objects on different levels, such as the same internal construction of the SAU on both substations. In practice, use of IEDs that support or can be made to support common communication and automation protocols ultimately enables the modularity of the system. On top of that well defined and interoperable interfaces between devices, such as use of IEC 61850 as the main protocol for distribution automation and various interfaces of the SAU, make sure all parts of the system work flawlessly together. The whole automation system consists of modular and as much as possible independently working sets of functions and data that are both functionally and in some cases spatially divided, such as low voltage state estimation conducted at secondary substation and medium voltage state estimation at primary substation. [2]

3.4 Scalability

Distribution of automation and modular design of a system makes it possible to realise an easily scalable automation system. Scalability is especially important for distribution automation system, where there are a large number of network nodes, substations, end customers and distributed energy resources. The system needs to be able to adapt for changing, mainly growing, network size and connection points. It is expected, that a monitoring system that suits this kind of automation system architecture will be available with a capability to cover millions of measurement and data points within the next decade.

Modularity in automation in principal enables the adaptation of the network automation to network changes just by adding or removing some predefined modular automation system objects from the system model, for example IEDs. The distribution of intelligence to substation automation units and field devices reduces the need and amount of information to be transferred up to the control center level. In this case all the necessary data, such as measurements, are in real-time available for controlling IEDs and nearly as fast for SAUs, which can then further control IEDs if necessary. SAUs then pack and send necessary data to control center, thus reducing the communication traffic significantly between substations and control center. When the communication link to control center is no more a bottleneck of the communication system, the modular system can expand more easily. The next possible problematic could be the computing capacity of the SAU, but with today's powerful computers and fast Ethernet based communication it is unlikely to be an issue. [2, p. 9,10]

3.5 Non-functional requirements

Requirements for a system can be roughly divided into functional requirements (FR) and to non-functional requirements (NFR). All the features that describe what the system, for example software or automation system, should actually do are functional requirements. Non-functional requirements on the other hand are things that constrain the system, while they include for example quality and performance requirements. NFR are difficult to specify in comparison to FR, although they are equally important.

In software and information technology non-functional requirements are specified and standardized in ISO 25010. The standard divides NFRs in to eight different categories, which are: *functional suitability, reliability, performance efficiency, usability, security, compatibility, maintainability and portability* [15]. The NFRs are briefly described as follows,

- *Functional suitability*: how well the system provides stated functions under defined conditions
- *Reliability*: how well the system provides stated functions under defined conditions for a specified time period
- *Performance efficiency*: performance in relation to the amount of system resources used
- *Usability*: how well the system can be used by specified users to fulfil defined goals effectively, efficiently and satisfactorily
- *Security*: how well the system or product protects data and information by controlling the access of other persons or products based on their level of authorization
- *Compatibility*: how the system, product or a component interacts and exchanges information with other systems and performs its dedicated functions, while sharing the same hardware or software platform
- *Maintainability*: how effective and efficient it is to modify the system or a product by defined maintainers
- *Portability*: how effectively and efficiently a system, product or a component can be moved from one operational environment to another. [15]

Of course not all of the NFRs can be equally well met in every system and that is why it has to be decided which ones are most important for the system and then prioritize those. For example applications with graphical user interface usability is in key role and for safety-critical applications the system needs to be reliable and secure. [16]

In automation technology there is no standardized list of NFRs and especially for distributed systems it can be especially challenging to define which requirements should be prioritized. Some main requirements for distributed automation systems can still be listed, which would be above all *reliability, maintainability, performance efficiency, portability and compatibility.* All of those requirements have to be considered thoroughly when designing a distributed system. Other highly important NFRs are:

- *Analysability*: the grade to which a failure can be located and traced back in the system
- *Testability*: the level of effort needed for testing of the system including all preparation, testing and documentation
- *Time behaviour*: processing and response times within the system when performing its dedicated function in relation to a known benchmark
- *Resource utilisation*: the amounts and sorts of resources in use when the system performs its function in relation to a known benchmark.

Analysability and *testability* are important in any system, but NFRs such as *time behaviour* and *resource utilisation* create new challenges in distributed systems. As the amount of devices, such as programmable logic controllers (PLC), in the system increases response times can get significantly longer and cause problems for the execution of the process if not taken into consideration. The increased amount of devices can cause the system to run out of resources for all the devices too, which would require resource access control that further impairs the efficiency of the process. [16]

4. LABORATORY AND TEST ARRANGEMENT

The laboratory equipment and devices integrated to the demonstration set-up include several different IEDs, which are meant to act as parts of the coordinated voltage control scheme alongside the RTDS network simulation model and substation automation units. The complete test arrangement includes protection and control IEDs, remote terminal unit, smart meters and various communication and automation components.

4.1 Demonstration system

The laboratory demonstration is a part of the IDE4L project and the goal is to demonstrate and test distribution automation and network control system developed in this project with an example of coordinated voltage control in a network with distributed electricity generation. With experience gathered from the laboratory demonstration the concept will be tested in actual network field demonstrations. The communication interface is based mainly on IEC 61850 protocol. The system with all of the integrated devices related to coordinated voltage control and their communication interfaces can be seen in figure 4.1, along with the basic contents of the SAU.

In this laboratory environment both primary and secondary SAUs are implemented in the same SAU PC running a Linux Ubuntu operating system. The main part of the SAU is the database containing the whole network topology and where all measurement and state information gathered from field devices will be stored. Functions included in to both SAUs, such as state estimation and real time power control, get all their information from the database.

A network time protocol (NTP) server is also provided and it is been run on the SAU computer in Linux environment. It assures an uniform time for all the devices in the system, which allows all the measurements and reports to have a valid and reliable time stamp throughout the system. This is a vital prerequisite in order to properly and accurately test the system, especially the validity and timeliness of

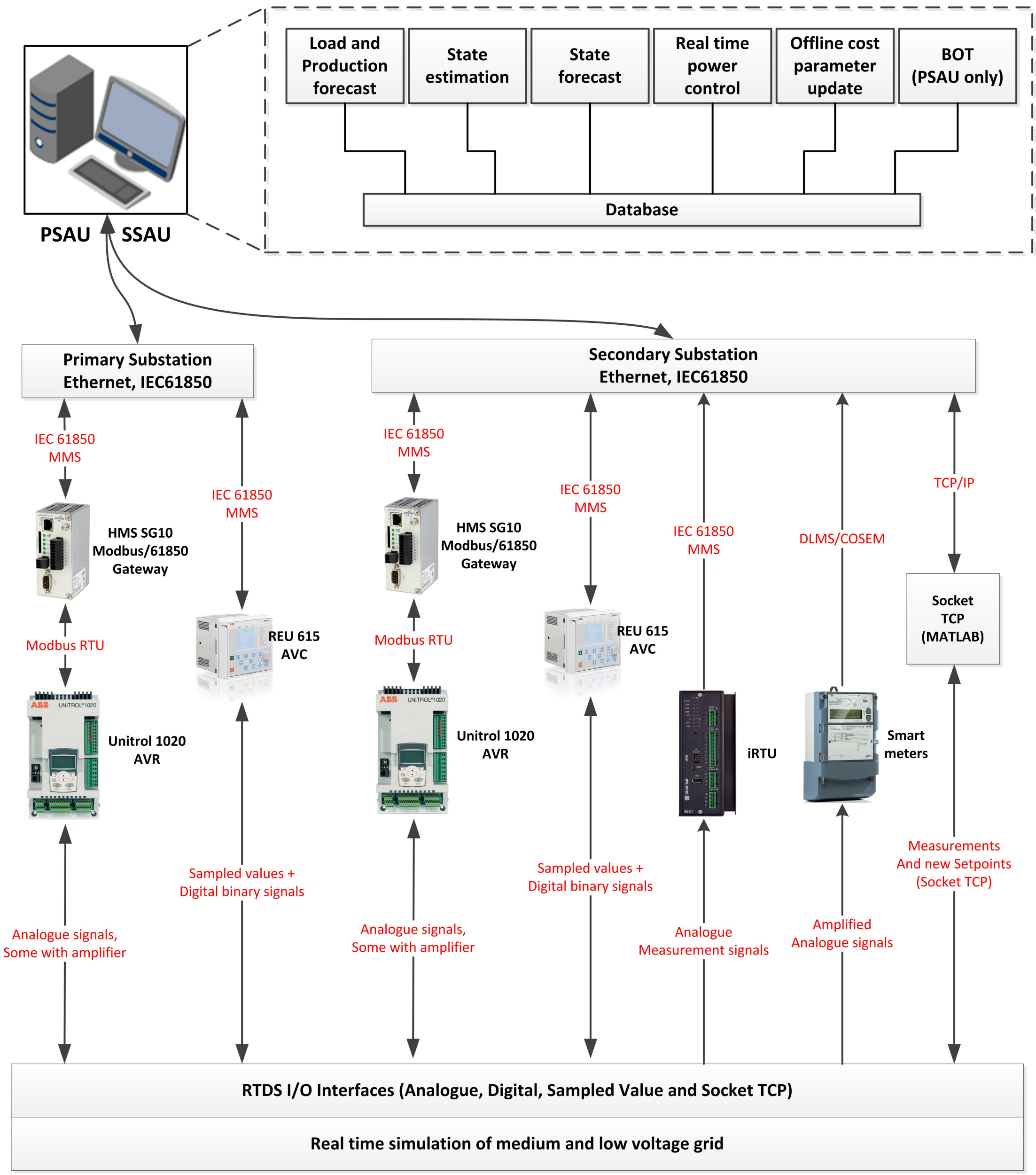


Figure 4.1 *A diagram of the demonstration system.*

transported values.

In normal situation smart meters are measuring electrical energy for invoicing purposes. In the IDE4L project they are supposed to report various measurement values, such as active and reactive power consumption levels as well as current and voltage magnitudes, to the SAU, AMM and meter data concentrator through DLMS/COSEM protocol. [2] The utilization of smart meters and RTU to deliver measurements from the low voltage network greatly increases the possibility to monitor and control the low voltage network. Added measurement capacity combined with low voltage state estimation algorithm at the secondary substation SAU makes it possible to increase the level of distributed automation in the low voltage network. [17]

4.2 IEC 61850

The latest development in the substation automation technology is the IEC 61850 protocol, which is not just a communication protocol, but a complete framework of how to engineer, specify and operate a substation automation system. Because of the development of communication technology the communication network bandwidth is no longer an issue and that is why the main communication method in the new protocol is a high speed Ethernet and TCP/IP bus connecting all the IEDs in the substation, thus reducing the need of copper wiring between devices. Biggest goals for the standard are high-speed communication between IEDs, high-availability of devices, interoperability of IEDs from different manufacturers and ease of configuration. [18]

Legacy substation protocols normally define the type of communication used and how the data should be arranged within the sent package, but not how the data should be stored and arranged within a device. This has lead to many different kinds of internal device configurations between manufacturers and increased the complexity of the commissioning and configuring of devices. All the IEDs based on the IEC 61850 standard include a same sort of internal data structure, which aims to the multi-vendor interoperability and easier commissioning regardless of the manufacturer. The functionality and structure of physical IEDs or the complete IEC 61850 based substation automation system is modelled with a standard defined substation configuration language (SCL). This is based on the eXstensible markup language (XML) and includes file types of system specification description (SSD), configured IED description (CID), IED capability description (ICD), substation configuration description (SCD), which all have the same base construction. [18]

In IEC 61850 standard a physical device which connects to the communication network can contain one or more logical devices, thus acting like a gateway for several logical devices that perform their dedicated task. Each logical device contains then one or several logical nodes, which are named service and data groups related to some power system function. Logical nodes are divided into name groups by their tasks so that for example all logical nodes associated with measurements begin with letter "M" and ones related to protection with "P". Each logical node again consist of one or more data Elements, each with an unique name. Data Names are defined in the standard and represent some data from the power system, such as operation counters, position indicators or measurement values. Each of the data elements follow a specification of the Common Data Class (CDC) defined in the standard. Every CDC contains a description of the data elements structure and type. All the objects defined in the CDC are then part of a set called Functional Constraints (FC) that divides those attributes further into categories. IEC 61850 includes also a variety of communication methods, which are presented in figure 4.2. [18]

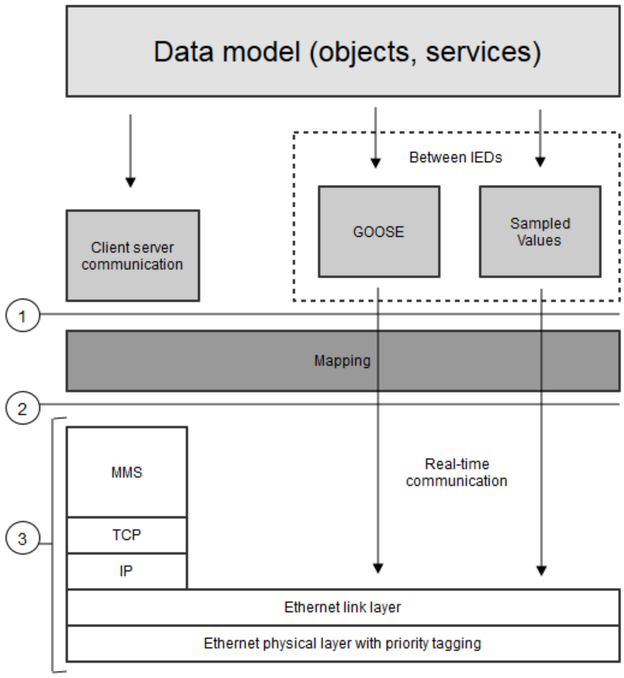


Figure 4.2 *Communication model of IEC 61850 standard. Adapted from [19, p. 10]*

IEC 61850 offers a standardized way of representing data model of IEDs with identical way. The mapping to communication protocols is done by abstract communication service interface (ACSI) models, number one in Figure 4.2, that specify the contents of the interface and ensures an identical behaviour of different IEDs from the network point of view. IEC 61850 also divides the communication system into two types of communication buses, number two in Figure 4.2: a process bus, which connects process devices and controllers in the bay level; and station bus, which connects process bus devices within the substation to station level devices, such as database systems or operators. Process bus communication includes sampled value (SV) and generic object oriented substation event (GOOSE) messages, which are considered as time critical services and are delivered in real time within the process bus. Process bus communication is mainly considered to be limited within a substation, but in case for example GOOSE messages are exchanged with IEDs located away from the substation the process bus has to be extended with virtual local area network (VLAN) to reach these IEDs. Station bus communication, section number three in Figure 4.2, can deliver messages related to network management, but also time critical messages and it is mapped in to manufacturing message specification (MMS) messages and to TCP/IP. MMS, SV and GOOSE are all transferred through Ethernet interface, but as we can see from figure 4.2 only client-server communication is mapped to MMS and to TCP/IP. Sampled Values are meant to deliver measurement data from measuring devices, such as current and voltage transformers, through a merging unit (MU) that simply packs the analogue input information and sends it as SV Process Bus communication stream through Ethernet. SV streams and GOOSE messages are multicast to the whole network, but only devices subscribed to the data will receive it. GOOSE messages mainly contain time critical information, such as circuit breaker status information and other network protection related signals and it is extremely important that these messages are transferred in real time.

4.3 Real time digital simulator

Real Time Digital Simulator (RTDS) is a power system simulator from the company RTDS Technologies Inc. and it can be utilized in real time network transient simulations and for testing actual power system components such as protection or control devices. RTDS Simulator consist of processor cards mounted in so called racks which are then installed in a cubicle with necessary input/output cards, power supplies and power entry components. A mid size cubicle can be seen in figure 4.3. The RTDS system at Tampere University of Technology consist currently out of two mid sized cubicles each containing one rack of cards.

Depending on the customers needs there are four different cubicles available that can house different amount of racks. Suitable cubicle size depends on the needed simulation capability, although cubicles can also be connected to each other to further increase the simulation capacity. All cubicles include DIN rails of various lengths for the installation of input/output cards which provide an interface for RTDS hardware to be connected with external devices such as protective relays or amplifiers. [20].

Figure 4.3 *A mid size RTDS cubicle with two racks of cards. [20]*

4.3.1 Hardware

There are several cards needed in the RTDS in order to be able to run real time network simulations. The actual calculation of the simulation model is done with processor cards, from which a PB5 processor card is the latest. One PB5 card contains two processors and the card is capable of simulating networks using a time step of 50 microseconds. PB5 card is presented in figure 4.4.

RTDS includes also Giga-Transceiver input/output (GTIO) cards for interfacing digital and analogue signals between external devices and the simulator. GTIO cards are connected to processor cards with fiber optical cables and the amount and types of GTIO depends on the devices being tested. There are four types of GTIO cards available: GT analogue input and output cards with 12 analogue channels available with a range of +/- 10 volts and GT digital input and output cards with 64 digital channels with a range of +5 volts to +24 volts. Figure 4.4 includes also a picture of a GTAO card. There are also digital I/O's on the front panel of the RTDS cubicle, which provide 16 dry contact type inputs and outputs with voltage level of 5 volts and also 16 High Voltage outputs. High Voltage panel can provide and receive digital signals up to 250 volts, which for example protective relays may need to indicate breaker status.

In order to interface different Ethernet based protocols used in the power net-

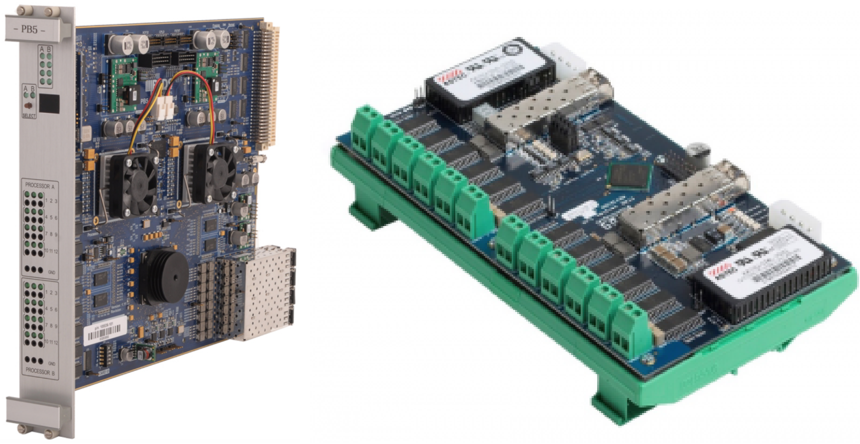


***Figure** 4.4 PB5 processor card and a GT analogue output (GTAO) card. [20]*

work, such as IEC 61850 GSE, there is Giga-Transceiver network communication card (GTNET) and a newer version GTNETx2, which is capable of operating two separate data streams and with different protocols at the same time. Available protocols for GTNET cards are: TCP/UDP socket communication, IEEE C37.118 data output streams, IEC 61850 GSE messaging, IEC 61850-9-2 sampled values, DNP3 communication, IEC 60870-5-104 protocol and playback of large data files.

In case the amount of I/Os needed exceeds the amount in one cubicle or there is a need to simulate networks larger than one rack can manage to calculate it is possible to connect several racks in to each other. In this laboratory demonstration the network size and need for I/O interfaces exceeds the capacity of just one rack and that is why both of the racks at the laboratory will be needed for the simulation. In ultimate situation up to 30 racks could be connected to same system. [20]

4.3.2 Software

Actual interface to be used on a separate PC for running RTDS is provided by a software called RSCAD, which has some similarities with some offline simulation software such as PSCAD. With RSCAD a user can do all the network modelling, simulation preparations, running simulations and analysing of simulation results. RSCAD consists of following modules:

- **FileManager** is the main window for organizing simulation files and launching other modules.
- **Draft** provides a graphical tool for network modelling simulation data input.
- **RunTime** is for running, controlling and acquiring results from simulations.

- **ComponentBuilder (CBuilder)** makes it possible to create user-defined components.
- **MultiPlot** is used for post analysis and marking of results.
- **Cable** - Calculation of cable characteristics
- **TLine** - Calculation of transmission line characteristics based on positive and zero sequence impedances or physical data.

RSCAD includes also an automated batch mode for running cases, analysing results and generating customized reports. User can define complete test sequences and customized reporting with a script file, which is based essentially on C-programming. RTDS supports also simulation model importing from other simulation tools such as PSS/E and MATLAB/Simulink. [20]

4.3.3 Testing in RTDS

With RTDS it is possible to execute various test procedures depending on the system under research. Basic idea for all the testing is real time testing, but the actual test arrangement can be very different if the simulator is used to test hardware or software, or both. Two testing and simulating scenarios for RTDS are Software-in-the-loop (SIL) and Hardware-in-the-loop (HIL), or as it is with the laboratory demonstration of this thesis, a combination of these. [21]

HIL and SIL simulations and testing have been widely used especially in automotive and aerospace industry, but systems like RTDS allow these simulations to be used effectively also in various fields of electrical engineering. Software-in-the-loop testing aims to test the performance and functionality of a software in simulated environment. SIL testing is not just for verifying that the software works like it is supposed to once it is finished, but also to be used during the development of the software. [21]

Hardware-in-the-loop simulation is a method for testing and developing control and supervision devices for possibly complex systems, such as distribution network. In HIL testing the system where the device under testing is supposed to be connected, is modelled in a computer environment and often simplified to reduce possible errors and malfunctions caused by the simulation model itself. The interface between the simulation and the test device is been emulated so that all the inputs for the device seem to be coming from a real system and also control signals from device cause corresponding actions in the model. In RTDS this emulation is executed by vast selection of digital and analogue I/Os, communication interfaces and protocols. In this thesis the medium voltage distribution network and the low voltage network with corresponding substations are modelled in RTDS and several voltage control, measurement and protection devices are been connected as HIL test devices to the RTDS' I/O interfaces. [22]

4.4 Integrated devices

In order to effectively and extensively demonstrate CVC in a power network in laboratory environment, it is crucial to also include actual control devices to the model instead of just simulating the whole automation system. That can provide essential information about issues concerning integration and interoperability of different IEDs and arise possibly some actual limitations on device functionalities. Also the SAU on both primary and secondary substation adds some complexity and connection links. In next sections there is an introduction to the most important integrated devices in the system.

4.4.1 ABB REU615

REU615 is a voltage protection and control relay from ABB and it can have either configuration A, which is intended for voltage protection and synchronism check in the medium voltage network, or configuration B, which is designed to work as automatic voltage controller (AVC) by controlling an on-load tap changer of a power transformer. Both configurations provide also protection supervision and measuring functions. In this demonstration case two REU615s are acting as AVCs on both primary and secondary substation, and the physical appearance of the relay can be seen in figure 4.5.

The configuration of REU615 can be done by using ABB's Protection and Control IED Manager PCM600, which is compliant with IEC 61850 and gives an opportunity to manage several IEDs in the substation. With PCM600 user can define communication protocols and edit parameter settings of IEDs. Most of the functionalities, for example measurements and supervision information, can also be seen from REUs local human machine interface (LHMI) and it can also be used to access and edit settings of the IED if needed.

REU615 supports various communication protocols such as IEC 61850, IEC 61850-9-2 LE, IEC 60870-5-103, Modbus and DNP3. REU615 includes both vertical and horizontal communication of the IEC 61850 standard by supporting the GOOSE and process-bus sampled value (SV) communication between IEDs and also IEC 61850 MMS as a client-server communication. The IED makes also possible to use two different Ethernet redundancy protocols, parallel redundancy protocol

Figure 4.5 *ABB REU615 tap changer control relay. [23]*

(PRP) and high availability seamless redundancy (HSR) protocol, which both rely on duplication of all information and are able to overcome failure of a cable or a switch in zero-switchover time. [23]

The main functionality of REU615 used in this demonstration is the capability to control an on-load tap changer (OLTC), thus regulate the voltage of power transformers lower voltage side. REU615 provides a possibility to use the manual or automatic control scheme of the OLTC and it can control single or multiple parallel transformers. In this demonstration there is only one single transformer on both substations and REU615 is controlling the OLTC in automatic mode. In order to perform OLTC control the IED needs voltage measurements from the secondary/regulated side of the transformer, in this case as sampled value communication, and current OLTC position information as digital signal from the RTDS. Possible control signals to change the tap position in the simulation are delivered from REU615 to the RTDS as a digital signals. Current measurements from the secondary side would be needed for over current protection and in case there were parallel transformers. Although in this case since the IEC 61850-9-2LE sampled value does not yet support the transfer of current measurements, there is only single transformer to control and REU615 is not acting as a protection device the relay can be used without current measurements. The connection to the SAU on the other hand is established based on the IEC 61850 protocol with measurements being sent from REU615 to the client at SAU as reports and possible new setpoints from the client to the REU615 are sent as MMS messages. The control of OLTC is based on a function represented in figure 4.6. [24]

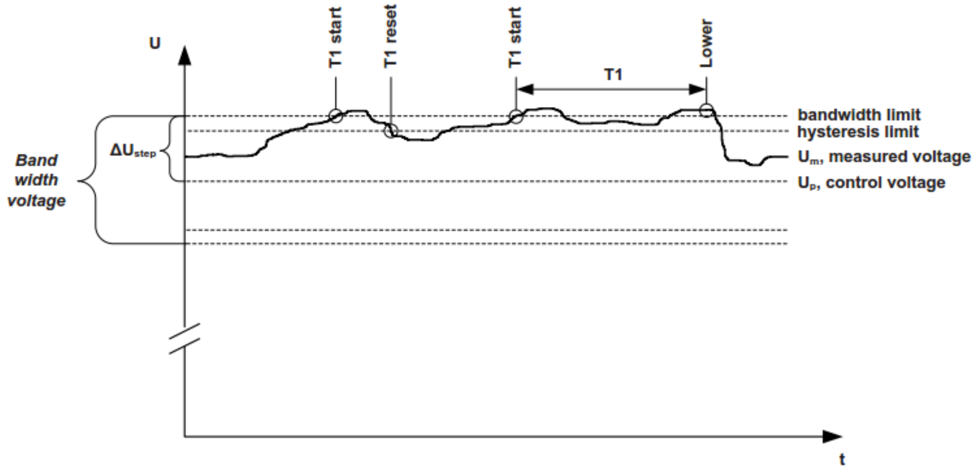


***Figure 4.6** The theory of the automatic voltage control functionality. [24, p. 828]*

Key parameters in the automatic control function are band center voltage, sort of nominal voltage level, and bandwidth voltage, which width is entered as percentage of the bandwidth voltage and it provides the function its control action triggering limits. As it can be seen in figure 4.6 when the measured voltage exceeds either higher or lower bandwidth limit a timer T1 is triggered. In case the voltage returns within permissible limits, those being the hysteresis limits, before the delay is exceeded, the timer is reset. If the voltage stays outside the bandwidth limits long enough a control command is sent to the OLTC to either lower or raise the tap position to restore an allowed voltage level. In case one change of the tap position is not enough to restore permissible level, another timer T2 with often shorter delay is triggered to schedule consecutive OLTC control signals. [24] The REU615 acts in the demonstration system autonomously controlling the voltage level of the whole low voltage network within its functional limitations by changing the tap position, but in case it can not restore the network voltage with current configuration the power control algorithm at SAU should detect this and define a new value for the band center voltage. In the laboratory the REU615 is providing phase voltage measurements and tap changer position value to the SAU.

4.4.2 ABB UNITROL 1020 and HMS Labline SG10

ABB's Unitrol 1020 is an automatic voltage regulator (AVR) for the excitation of indirectly excited synchronous machines and generators. It provides also various possibilities for controlling and regulating reactive power, power factor and field current of the motor or generator it is attached to. It takes machine voltage, current and network voltage as inputs and then defines the level of excitation depending on which operating mode has been selected. The AVR can be seen in figure 4.7.

Figure 4.7 *The front facing view of the Unitrol 1020 AVR. [25]*

Unitrol 1020 contains a PID controller for the voltage regulation and a switch-mode power supply to generate excitation currents up to 20 amperes. AVR has multiple operating modes, depending on how and what variable needs to be controlled. When operating in Manual-mode the AVR acts as a field-current regulator. In AUTO-mode it keeps the output voltage level on its setting value by controlling the level of reactive power and on the other hand when the VAR-mode is selected the AVR keeps the reactive power level in its setting value while letting the output voltage vary. Unitrol can also operate in PF-mode, when it regulates the power factor. The configuration of the AVR can be done with a spesific software CMT1000 or through the front panel of the device. CMT1000 provides also the possibility to observe all the measurements and events, control setpoints and tune the PID controller while the AVR is in operation.

The device offers a wide range of I/O's such as analogue and digital inputs and outputs, excitation current output and Remote Access with Modbus TCP through Ethernet port or with Modbus RTU through RS485 serial connection. With Modbus Remote Access the user can access and edit all the same parameters and registers as one can with the CMT1000 software. [25]

When integrating Unitrol to the RTDS the actual excitation current output of the AVR can not be connected to the simulator, since it can not handle such high currents. Instead it is possible to get the control signal for excitation as an analogue output from the Unitrol and that can be brought to the RTDS. In the RTDS that signal is then fed to a model simulating the behaviour of the switch-mode power supply of the Unitrol, thus providing same level of excitation current within the simulation. In figure 4.8 there is presented how the integration of the AVR and RTDS has been established.

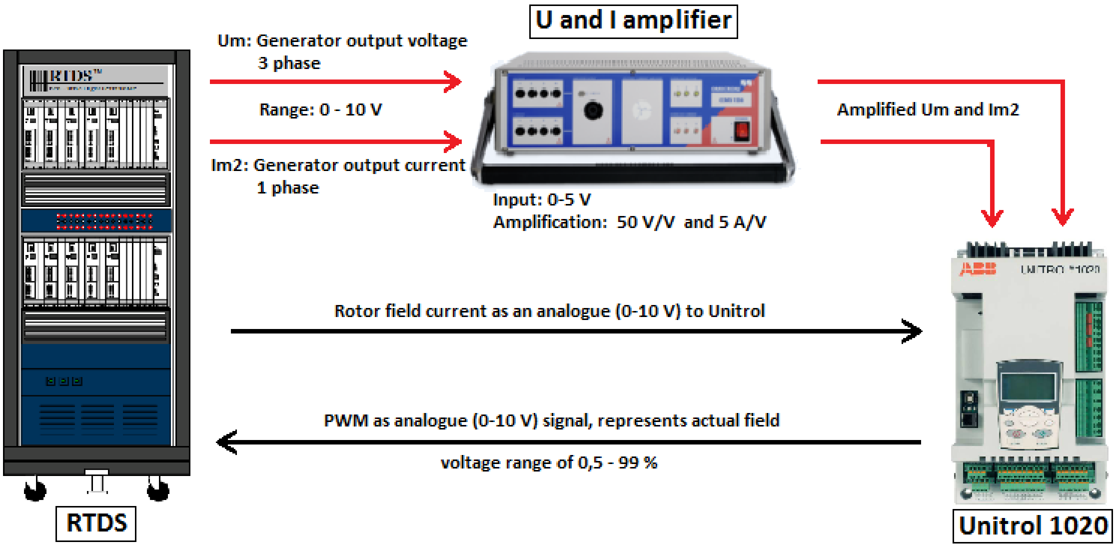


Figure 4.8 Connection diagram of Unitrol 1020 AVR and RTDS.

In the laboratory the Unitrol receives analogue voltage and current measurement signals from the RTDS, which are amplified to a correct level with an OMICRON CMA 156 amplifier. These signals are marked with a red colour in Figure 4.8. The measured field rotor current of the simulated generator from RTDS to Unitrol and the pulse width modulated control signal for the generator field voltage from Unitrol to RTDS are transmitted as analogue signals without amplification with the range of 0-10 V. These signals are marked in the Figure 4.8 with a black colour.

In order to achieve a remote connection to Unitrol from the SAU a protocol gateway is needed to map the information between IEC 61850 protocol used by SAU and Modbus RTU protocol used by Unitrol. The gateway in use is a Labline SG10 from company HMS and it can be seen in figure 4.9. It offers a wide range of features for remote control and management for smart electrical systems. It supports IEC 61850 client/server, IEC60870-5-104 server, Modbus RTU master and slave, Modbus TCP client and server protocols and offers Ethernet, serial (RS232/RS485/RS422), GSM/GPRS and digital I/O interfaces. [26]

Figure 4.9 *HMS Labline SG10 gateway used for mapping between IEC 61850 MMS and Modbus RTU protocols. [26]*

In the demonstration the SG10 is interfaced as a Modbus RTU master through RS485 serial connection for Unitrol by reading measurement and configured setpoint values from Unitrol's registers and writing new setpoint values to it in case provided by the power control algorithm at the SAU. On the other side the gateway is acting as a IEC 61850 server and delivering measurement and set point value data as reports to the corresponding client at SAU. The actual mapping between two protocols is done by a programmable logic controller (PLC) that is configured as function block diagram in the web based editor of the SG10.

4.4.3 iGrid iRTU

The iRTU is a remote terminal unit (RTU) from a company iGrid T&D which has specialized on control and automation of electrical facilities of various sizes. The iRTU series includes a wide range of RTUs and gateways for control and supervision of power stations and substations. An example of the devices can be seen in figure 4.10, although the iGW unit is not being used in this work.

The main tasks for devices of this series is to concentrate all data, whether it is digital, analogue or some device protocol based, coming from different sources and transmit that data to defined control centres or other IEDs and also to be able to control other devices, for example switches or circuit breakers. iRTUs can be equipped with analogue and digital inputs and outputs, but also with Ethernet interface and serial ports for RS232/RS422/RS485 communication, and the capacity of an iRTU unit can be expanded with additional iRTUe input/output extension

Figure 4.10 *Different device models from the iRTU series: iGW-B0C1 unit (left), iRTU-B0C1 unit (middle) and iRTUe-S0C1C1 unit (right). [27]*

units. iRTUe units can include different combinations of analogue and digital inputs/outputs and a total of 7 extension units can be connected to a single iRTU unit. [27]

In the demonstration the iRTU is acting as a data concentrator; receiving analogue signals from RTDS's GTAO cards representing measurement data from the low voltage side of the secondary substation. Because RTDS is scaling its analogue outputs as voltage in the range of -10 to 10 V with maximum output current being 5 mA and iRTU scaling its analogue inputs as current between 0-20 or 4-20 mA there is a need to connect voltage to current converters between the RTDS and the iRTU. The output from RTDS has to be scaled to produce signal between 0 to 5 volts, because those converters are operating with 0 to 5 V voltage input signal coming from RTDS and producing corresponding current output in the range of 4-20 mA to be provided for the iRTU's analogue inputs. The iRTU is operating as a IEC 61850 server and gathers all the data from its analogue inputs in to a dataset and sends it as a report to the SAU's IEC 61850 client. In this case the data transfer is unidirectional from iRTU to SAU since there are no control devices attached to the iRTU, thus no setpoints to be changed in the iRTU. In the laboratory set up the iRTU is delivering three phase current, real power and reactive power measurements from the secondary substation to the SAU.

4.4.4 Smart meters

The laboratory demonstration includes also smart meters (SM) from two manufacturers that are connected with an amplifier to analogue output ports of the RTDS. One SM is manufactured by Landis+Gyr and another by Kamstrup; both meters can be seen in Figure 4.11. The meter from Kamstrup is mainly designed to be used in domestic installations where as the Landis+Gyr meter includes more features for metering and monitoring and is more focused on industrial and other larger scale applications.

Figure 4.11 *Smart meters included in the demonstrations. On the right side Landis+Gyr E650 [28] and on the left side Kamstrup Omnipower [29].*

Both meters are equipped with three phase voltage and current measurement interfaces and power and energy metering. The communication between the meters and SAU is implemented by DLMS/COSEM meter reading protocol through Ethernet interface. The DLMS/COSEM client receives following measurements from both meters every minute: voltages, currents, real powers, reactive powers and power factors for each of the three phases as well as the complete produced and consumed real and reactive energy of the load.

The actual measuring systems of these two meters are different from each other and require slightly different connection set-up to interface them with RTDS. Landis+Gyr meter is designed to be equipped with external current and voltage measurement transformers, that would reduce those signals from the real network values to more adequate level. In this case both voltage and current signals for all three phases are fed directly from the amplifier to the meters terminals at proper level as they would be coming from measurement transformer. Kamstrup on the other hand should be connected straight between feeding network and load so that voltage and current would be at their nominal network level and all the power runs through the meter. Voltage and current can be brought up to proper low voltage network level with an OMICRON CMA 156 amplifier, but the amplifier gives out voltage and current signals in separate cables, which requires extra components to be used in the set-up. The connection diagram of Kamstrup meter is shown in figure 4.12. Neutral conductor for the current signals is drawn in the figure just to represent how it is connected in the terminals of the meter.

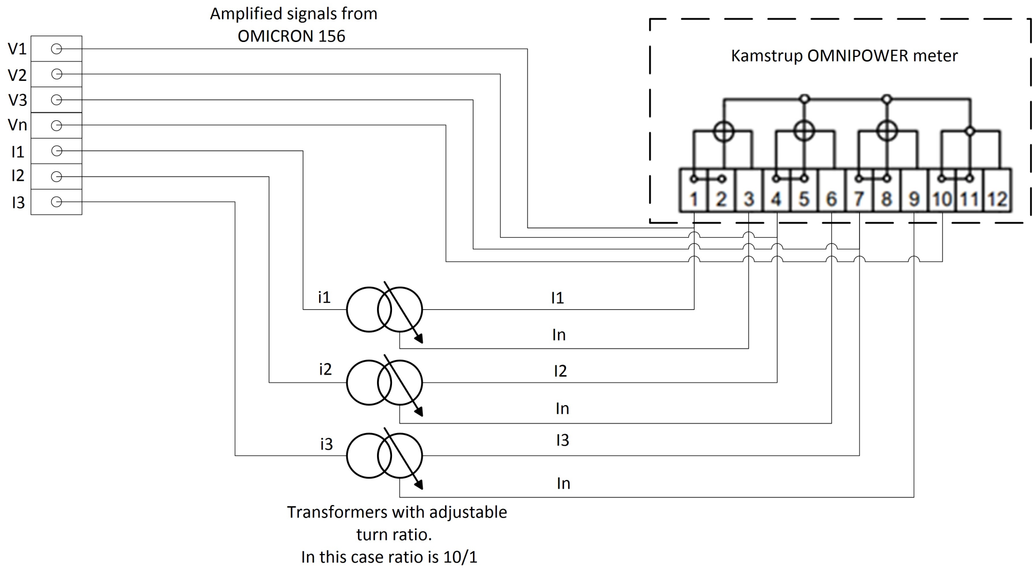


Figure 4.12 *Connection diagram of Kamstrup meter to RTDS.*

As can be seen from the figure 4.12 the amplified voltage and current signals are coming separately from the amplifier, but voltage and current signals for each phase should be connected to same terminal at the meter as they would be in real installation. There is also need for current transformers to raise the current level since, although the amplifier is capable of producing currents up to 25 A, it can not produce high currents for very long time. Turn ratio of these transformers can be changed, but in this set-up the ratio is 10/1, which gives out ten times larger current than what is fed to them from the amplifier. The connection for Landis+Gyr meter is more simplified, because all the signals are connected to separate terminals at the meter and the current level can be a lot lower resulting the load for the amplifier to be lower too.

4.5 Socket interface

RTDS includes also a possibility to use Socket based communication, named GTNET-SKT with GTNETx2 network communication cards. Socket protocol is used to form a communication interface with external devices by using transmission control protocol (TCP) or user datagram protocol (UDP) sockets over wide or local area network (WAN/LAN) [30]. In this demonstration the socket protocol is used to interface photovoltaic (PV) power plants and static synchronous compensator (STATCOM) modelled in RTDS, with the control interface on a computer. The socket interface is used to deliver real and reactive power measurements from PV plants in the simulation to a computer and then deliver back control values calculated by the power control algorithm to manage the real and reactive power levels of the plants.

In order to make the socket communication possible between the SAU and RTDS a Matlab interface is needed to perform the mapping of the data between these two. The Matlab is running on a separate Windows computer and it reads measurement values from the GTNET-SKT interface of RTDS and delivers it in correct form to the client in SAU. Then it also reads new setpoints for PV plants and STATCOMs, if provided by PC algorithm at SAU, from the database in the SAU and sends them back to RTDS. Both the measurement delivery as well as the setpoint checking and writing is executed in the same loop every five seconds.

The main reason to use GTNET-SKT in this demonstration is to be able to interface resources, which are only modelled in RTDS and do not have a real IED controlling them, with the SAU and also to be able to get more measurement data to the database. The amount of amplifiers is also one big constraint for getting actual analogue measurements out of the RTDS, since currently there are only three of them available. With GTNET-SKT component it is possible to get up to 300 different values, for example measurements, from RTDS and send equal amount of parameters to RTDS. It is also possible to use several GTNET-SKT components which all have the same capacity, assuming there are available GTNETx2 cards in the system.

5. TEST CASES

The non-functional requirement testing of the automation system of IDE4L project is done in RTDS laboratory using the demonstration system described in the chapter 3.

5.1 Availability and reliability

System can often be modelled as network of series, parallel or mesh connected components or as a combination of all aforementioned. From a reliability point of view components are in series if failure of one component results to failure of the whole system that is to say all the components must work in order to the whole system to work. Parallel components all must fail in order to cause a failure of the whole system, thus failure of one parallel component does not cause system to fail. The series connection is an example of a non-redundant system and parallel connection of a fully redundant system, but often systems are a combination of both series and parallel connections or more complex connections. The network modelling of the reliability is in many cases referred as a reliability block diagram (RBD).[7, p. 62-63]

The reliability of a single component can be obtained by using the failure rate of the component. Failure rate for a typical electronic component, often referred as a bath-tub curve can be seen in Figure 5.1. The first section of the curve represents the period when the failure is more probable because of for example manufacturing errors, configuration errors or faulty design, section two is often referred as the normal operating phase and faults in this section happen solely by coincidence. The last section is fatigue or wear-out phase, where the failure rate increases significantly mainly because of ageing. [7, p. 134]

In this thesis the reliability and availability assessment of the automation architecture is done by focusing on the second section of the figure 5.1, namely the normal operating phase. The RBD method is fairly simple and gives good results for qualitative and quantitative analyses, that is why it is been used in this thesis. Other methods could be for example fault tree, cut set and path set methods. [7] The reliability representation can also be simplified by using parameters such as mean time to fail (MTTF), mean time to repair (MTTR) and mean time between failures instead of the fail rate. These parameters can be used to calculate the other impor-

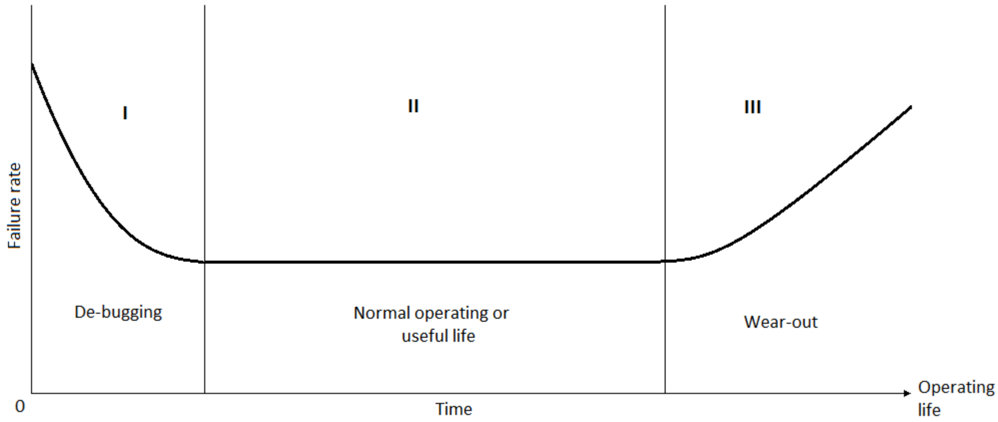


Figure 5.1 *Typical failure rate of electronic components as a function of time. Adapted from [7, p. 135]*

tant system feature, availability, which can be estimated with MTTF and MTTR. Calculation of the availability based on parameters MTTF and MTTR is as follows,

$$A = \frac{MTTF}{MTTF + MTTR} \tag{5.1}$$

for series connected components,

$$A_s = A_1 \cdot A_2 \tag{5.2}$$

for parallel connected components,

$$A_p = A_1 + A_2 - A_1 \cdot A_2 \tag{5.3}$$

where A is the availability of the given component. [8]

MTTF values used for different network components are listed in Table 5.1 along with corresponding availabilities. The mean time to repair (MTTR) in case of a failure is assumed to be 8 hours and that has been used to calculate availabilities. The reliability of communication links are considered to be very high compared to other components in the system and because of that they are not included in the calculations. [7], [31], [32], [33]

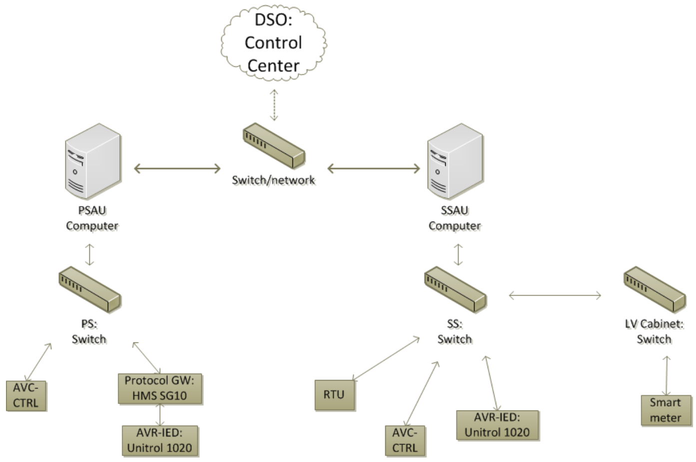
The automation system reliability and availability assessment is done for the laboratory demonstration system described earlier in chapter4, since it is based on the general automation architecture of IDE4L project. Because of the modular design of the automation system there are some parallel units that in case of a failure will not cause the whole system to fail, which increases the system reliability and

Table 5.1 *MTTF values and corresponding availabilities for system components.*

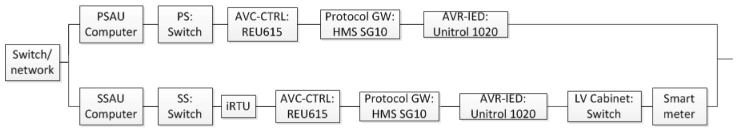
Component	MTTF(in years)	Availability
Control IED	150	0.999993912
RTU	150	0.999993912
Smart meter	150	0.999993912
Ethernet switch	50	0.999981735
Computer	3.528	0.99632
	7	0.99805

availability. The basic architecture for a distribution system operator point of view with one primary substation and one secondary substation can be seen in Figure 5.2 as well as the RBD representation of the system. The system includes Ethernet switches, monitoring and control IEDs, smart meters and computers. The reliability of a computer is fairly difficult to determine, since there are many components that can fail and each have different failure rates. Probability of failure for consumer PCs in an extensive study [34] has shown that 1 out of 190 computers will suffer a failure of CPU, which gives a MTTF of 3.528 years. The value is calculated based on the quantity of computers studied and the duration of the study, that are 950000 computers in 8 months. The computer includes also several other components that are perhaps just as likely to fail as the CPU, but no valid studies and failure rates were available by the time this thesis was written and that is why only the failure of CPU is considered here. The SAU is an important part of the automation architecture, but failure of one SAU computer does not cause the system to fail so it is assumed that there are no replacement hardware on site. This would result to a MTTR of few days rather than hours, while after the hardware has been acquired the computer needs to be configured properly to be able to operate as a SAU. MTTR assumed to be from 3 to 7 days the availability is then between 0.99768 and 0.99460 giving an average of 0.99632.

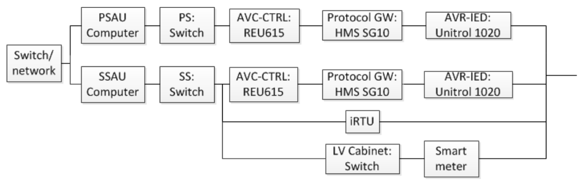
In the actual laboratory set up there is no control center or SCADA system available, so calculations are done only for SAU units. In actual set up both PSAU and SSAU are actually located in one single computer, but for this assessment they are considered to be separated and connected to each other through an Ethernet switch as seen in Figure 5.2. Although many of the devices in Figure 5.2 are physically parallel connected, they are in terms of monitoring and control functionality in series. All the components need to be operational for the system to operate as it



(a) Devices



(b) Model 1



(c) Model 2

Figure 5.2 *Network model of the automation system in laboratory and the RBD representations used for the reliability analysis.*

should. The devices can be modelled to be also functionally in parallel, since failure of one device is not causing the whole system to fail, but it decreases the accuracy of monitoring and state estimation and possibly affects the amount of controllable devices. In Figure 5.2 are presented both RBD models used in calculations: all devices in series and all control devices in series. Calculations were done for several operational states, which are listed in Table 5.2 along with corresponding results.

When the calculations are done for the whole system including both SAU computers and a switch connecting them, as in Figure 5.2, and assuming that every device needs to work in order to make the system work properly, it is clear that especially MTTF is greatly reduced compared to the values for individual components. The main reason for this is the low MTTF for computers, which can be clearly seen from the availability values calculated separately for SSAU and PSAU. Values

Table 5.2 Reliabilities and availabilities for the complete automation system as well as for different parts of it. Values with twice longer MTTF for the pc are also included for comparison. The model number refers to RBD models presented in Figure 5.2.

Section	Model	MTTF	Availability	MTTF PC
Whole system	1	1.88	0.99996642	3.528
PSAU only	1	3.09	0.99610186	3.528
SSAU only	1	2.80	0.99607154	3.528
Whole system	2	1.90	0.99996654	3.528
SSAU only	2	2.85	0.99610186	3.528
Whole system	1	3.13	0.99997774	7
PSAU only	1	5.47	0.99801649	7
SSAU only	1	4.63	0.99798611	7
Whole system	2	3.17	0.99997780	7
SSAU only	2	4.74	0.99801649	7

were calculated also for scenario where control devices must all be operational, but purely monitoring related IEDs can have failure without causing the whole system to fail. This means that iRTU and lv cabinet switch along with the smart meter are connected in parallel with control devices. This scenario affects RBD model only at SSAU, since at PSAU there are only control IEDs. As can be seen from Table 5.2 this scenario improves the MTTF of both the SSAU and whole system by about 1%. One fairly simple way to improve the system would be to add redundancy to the communication system by duplicating Ethernet switches, which results to parallel connection of two switches. By duplicating the Ethernet switches between SAU computers and IEDs all the MTTF would be increased by around 2%. By duplicating the switch between SAUs would increase the MTTF for the whole system by 1.3% and if all the switches were duplicated the overall MTTF would increase by 3.4%. The duplication of Ethernet switches does not have any significant affect on the availability.

Since the reliability of computers is significantly lower than other components the Table 5.2 includes also same MTTF and availability calculations with roughly twice as long MTTF time for computers for comparison. The failure rate value obtained from [34] is based on only consumer computers and includes a large variety of hardware, which could result to unnecessarily high failure rate. When observing the values calculated with MTTF of 7 years the effect on the MTTF values of the whole system is clear with MTTF for SSAU being increased 65% to 4.63 years, for

PSAU 76.9% to 5.47 years and for the whole system 65.8% to 3.13 years. Another critical variable is the MTTR for the computers, which will affect the availability of the system. The original 120 hours or 5 days is fairly conservative and could be decreased. In case the MTTR could be decreased to 48 hours it would increase the availability of SAUs with 0.3% and the whole system by 0.0015% resulting an availability of 0.99998105.

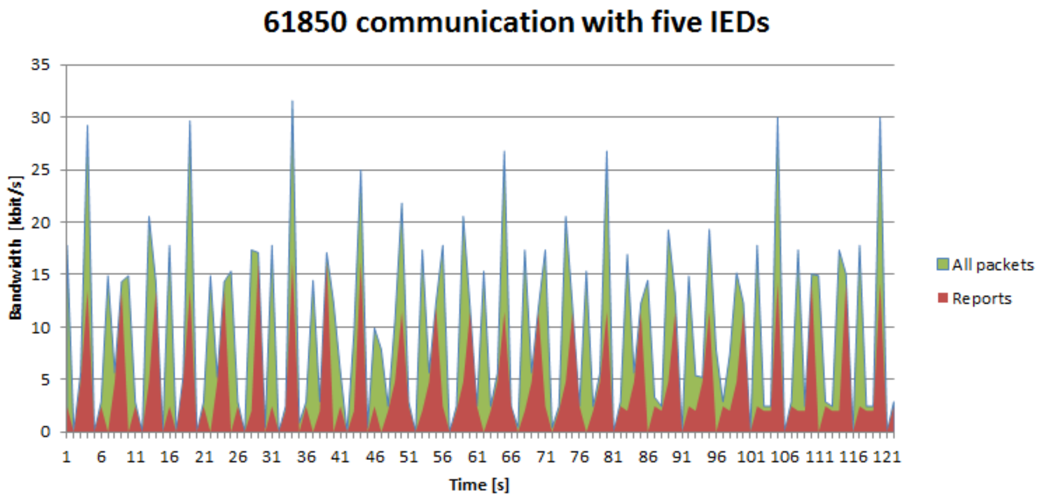
All the MTTF values for IEDs and Ethernet switches were from studies focusing mainly on communication and operation within a substation and because of this the values are possibly too optimistic. Also the assumption that communication links are extremely reliable might not be true, since some of the IEDs in the network are not connected to the SAU with Ethernet based communication links, but more likely with some public wireless connections. Analysis of reliability and availability is executed here with the data available , but for further development these aspects should be noted.

5.2 Resource utilisation and scalability

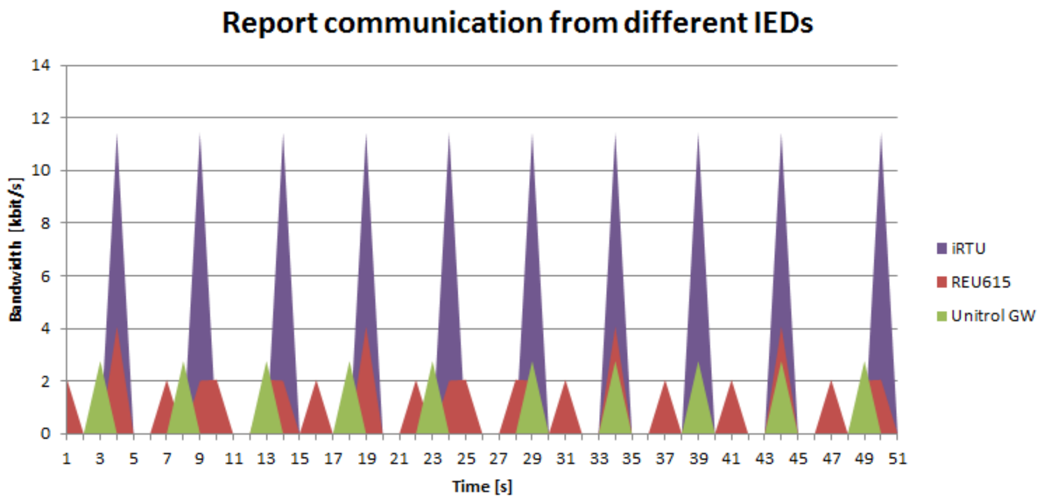
The performance of the automation system and ability to expand are important requirements for a decentralized system and are highly dependent on the resource utilisation of the system. In this case resources on the system are communication network capacity and speed as well as computing capacity of the SAU computer. Both remaining network capacity and computing capacity are decreased as the system size increases, which results to longer computing times and possibly congestion in the communication network. At some point the system exceeds its operational limits and can not increase in size any more and this would be important and practical to predict by analysing the scalability of the system.

The resource utilisation analysis for the laboratory set up is executed by studying the communication network bandwidth usage of different devices and interfaces. The IEC 61850 communication generates the most frequent traffic to the network, since all the measurements from the IEDs are delivered to the client with 5 second interval. The Figure 5.3 presents the IEC 61850 based traffic of all five IEDs.

The main communication link in the IDE4L automation architecture is Ethernet based, which is with its bandwidth of 100 Mbit/s or higher more than capable of delivering all messages between devices and is highly unlikely to develop into a limitation regarding system scalability. This can be seen also from the Figure 5.3 where the first graph presents the communication bandwidth usage for all the available 5 IEDs and the client in total and as reports only. In this case the average band-



(a) All client/server traffic.



(b) Reports from different IEDs

Figure 5.3 *Bandwidth usage of client/server communication of five IEDs and bandwidth usage of reporting from different IED types.*

width usage when considering all traffic is only about 9.5 kbit/s and for reporting only little over 4 kbit/s. Although it must be noted that as the second graph in Figure 5.3 shows the bandwidth usage of reports from different devices have major differences depending on the amount of measurements included in the report. When comparing the two graphs it is clear that the reporting from iRTU is responsible for most of the report based communication traffic. If the amount of data from all the IEDs as a report would be at the same level as the reports coming from iRTU the bandwidth usage would be about 17.5 kbit/s resulting to 27 kbit/s for all the client/server traffic with five IEDs. It is still a small amount of data and uses only about 0.027 % of 100 Mbit/s bandwidth.

The IEC 61850 communication is not all the data that is transferred in the communication network, while also the measurements from smart meters to DLMS/-COSEM client are transmitted in the same network. The reading frequency for smart meters in the laboratory set up is much lower than the one for IEC 61850 IEDs, being defined at 30 seconds. The Figure 5.4 shows the bandwidth usage of the two smart meters and although the interval for measurement reading is longer the amount of data differs from the ones delivered by the IEC 61850 reporting.

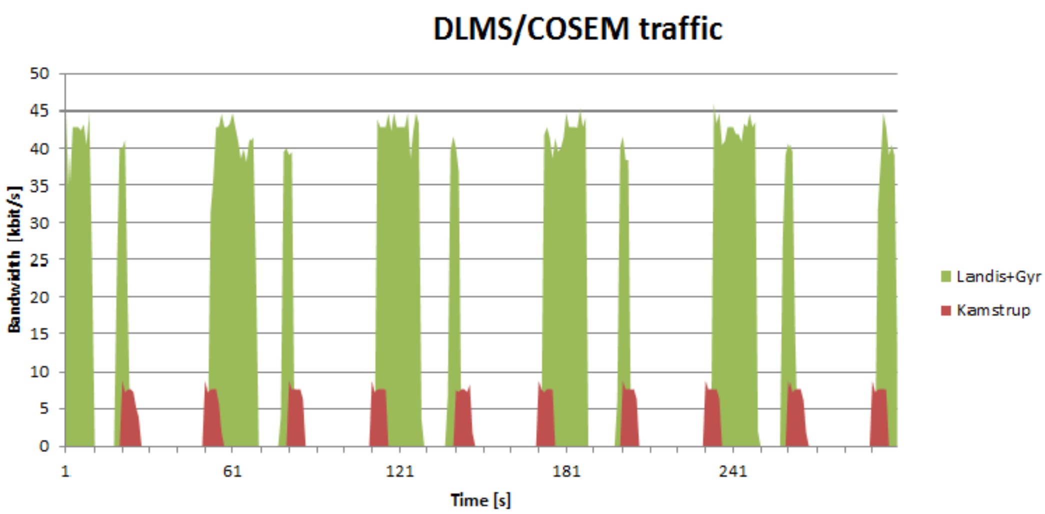
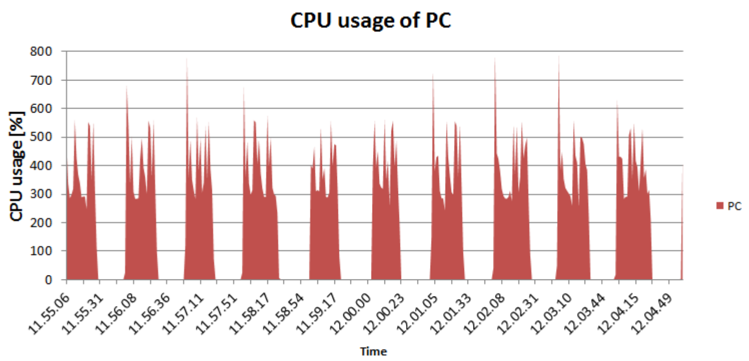


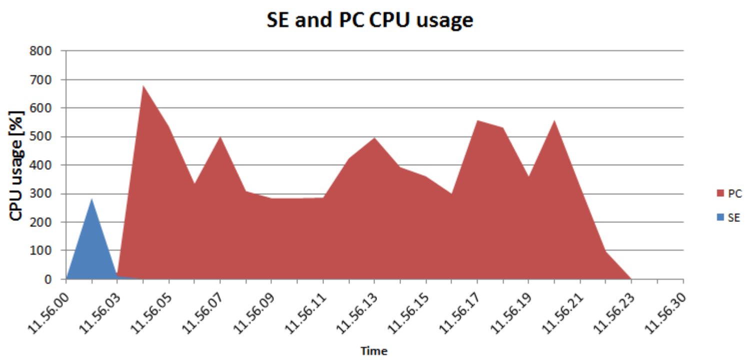
Figure 5.4 *Bandwidth usage of the DLMS/COSEM communication between two smart meters and the client.*

Both Kamstrup and Landis+Gyr meters are delivering same measurements to the DLSM/COSEM client at SAU, namely voltage, current, power, reactive power and power factor for each phase as well as consumed and produced energy values. Even though the measurements are identical the Figure 5.4 clearly reveals the significant difference in bandwidth usage for these two meters as the Landis+Gyr meter uses almost six times more bandwidth as the Kamstrup. As the amount of smart meters in the network is vast, when all the households are equipped with one, the difference in the bandwidth usage could affect the communication capacity and performance quite easily. To prevent the possible congestion in the network the reading interval could be increased or a measurement data aggregation device used to collect the data from a group of meters. The Kamstrup meter also represents more a device installed in households and Landis+Gyr with more features and better accuracy a meter that is intended for larger and commercial locations.

Important thing to consider is also the resource utilisation of SAU computer, namely CPU and memory usage of all the processes needed. The computer at the laboratory is quite well equipped with quadcore Intel i7 processor and 16 GB of RAM memory as well as a 250 Gb SSD hard drive. The resource utilisation of the SAU computer is studied in this thesis by observing the CPU usage of the functions and interfaces running on that computer in the laboratory. Figure 5.5 represents the CPU usage of state estimation algorithm and power control algorithm. The usage is represented in percent and the CPU of the laboratory computer has four physical cores and each core can handle two threads, which results to eight digital cores and because of that the complete processing capacity is 800%.



(a) Only PC



(b) Comparison of PC and SE

Figure 5.5 *The CPU usage of algorithms. First graph represents only the PC and the second one includes one operating cycle for both SE and PC to compare them.*

It is clear from the two graphs in Figure 5.5 that the most demanding functionality on the SAU computer is the power control algorithm. At some points it is reserving over half of the CPU capacity and an average usage for one operating cycle is around 400% for 20 seconds. In second graph of the Figure 5.5 one operating cycle for both SE and PC is plotted for comparison. The average usage for the SE is around 150 to 200% for about two seconds, which is significantly less than the corresponding values for the PC. The Figure 5.6 shows the CPU usage of the database and although it is occasionally using large amount of CPU, most of the time it is only few percent. The CPU usage of the two communication interfaces, namely IEC 61850 and DLMS/COSEM clients are presented in Figure 5.7 with same representation of percentage values.

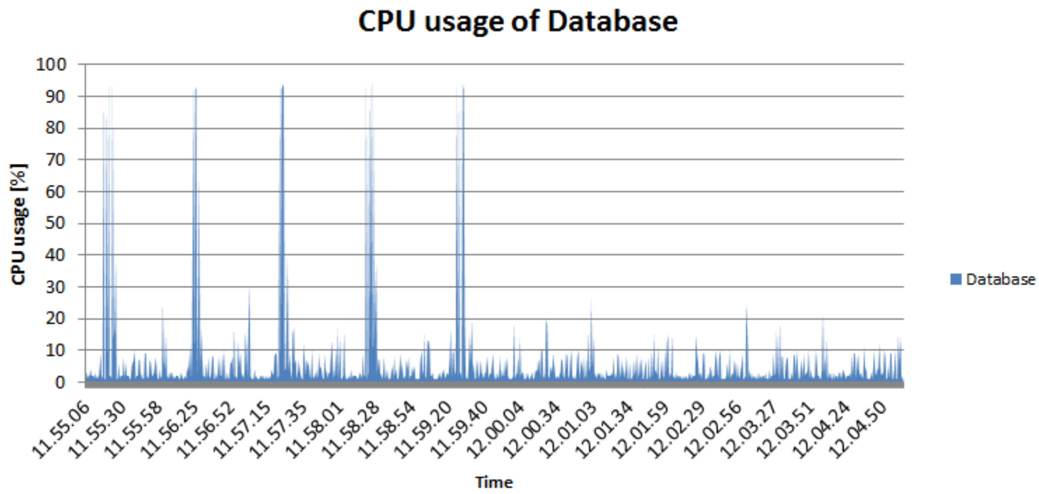
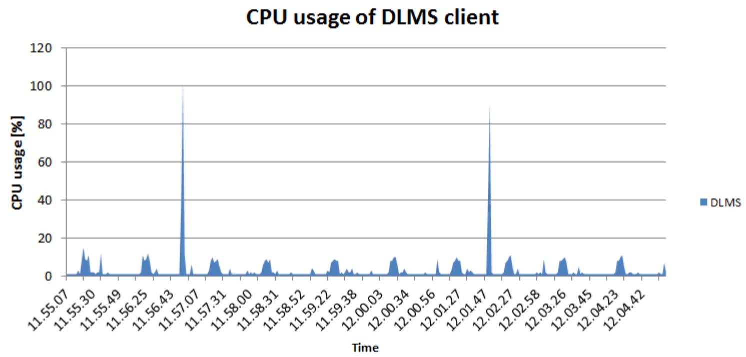
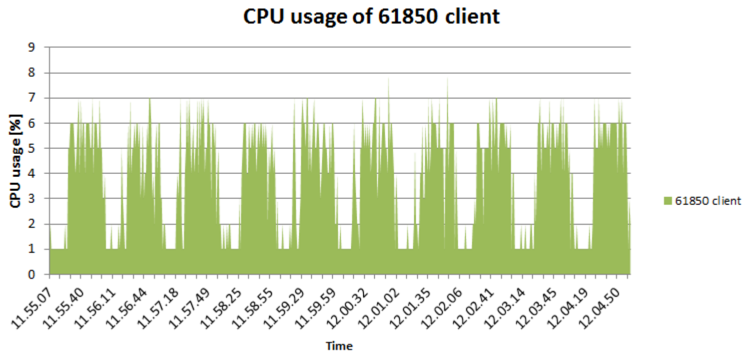


Figure 5.6 *CPU usage of the database.*

Both clients are very light to process once they are initialised and operating normally, as can be seen from Figure 5.7. Without considering the two high spikes appearing in the graph of the DLMS/COSEM client the computational need is very low at around 10% maximum. The IEC 61850 clients CPU usage is presented in the lower graph of the Figure 5.7 and it is on average only about four percent of the total 800% of the CPU capacity. In addition to the conclusions made in the reliability and availability analysis in section 5.1 the CPU usage studies also indicate that the type and performance of the SAU computer should be taken into serious consideration when setting up the system.



(a) DLMS client



(b) 61850 client

Figure 5.7 *The CPU usage of the two client interfaces at the SAU.*

5.3 Errors and failures

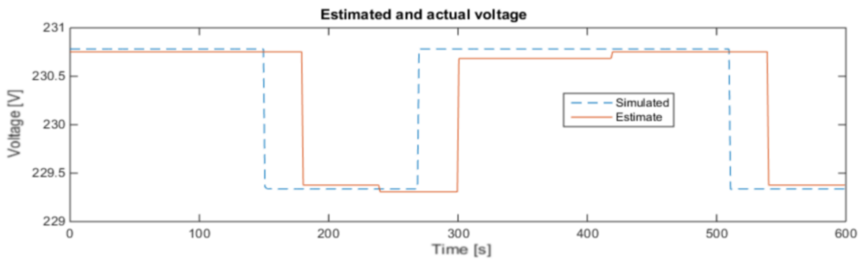
All tests are conducted for the low voltage network and with SSAU only, since the functionality and interfaces are practically identical for both SAUs.

5.3.1 Connection failures

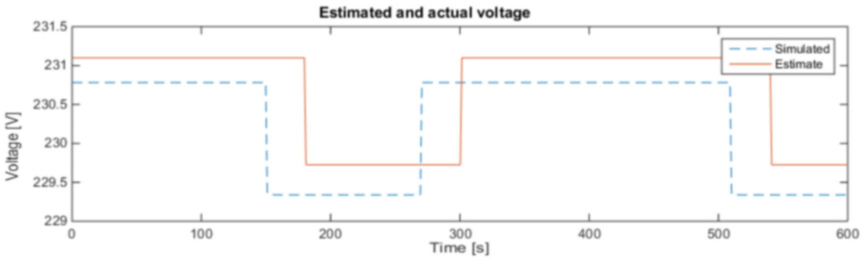
Connection between devices can be lost because of cable breakage or complete or partial device failure, for example failure of connection interfaces or communication ports. Communication links were assumed to have 100% reliability when reliability and availability of the complete automation system was analysed in section 5.1, but in reality they can fail despite being highly reliable. If multiple devices or crucial communication links fail at the same time, for example one centrally located Ethernet switch with no redundant connection, the system will eventually fail to operate, but in reasonable limits the system needs to be able to stay operable also in these situations and recover after the interruption is over. In laboratory tests both the IEC 61850 client and the DLMS/COSEM client developed for the SAU in this project were proven to be robust once configured properly and to be able to operate and recover when some or all of the connections to IEDs would fail. The failure of communication connections to IEDs can result to false or inaccurate measurements or deteriorate the level of network control, depending on the IED type.

The loss of measurement data because of failed communication link does not lead to the failure of SAU or network control, but when fewer measurement data is delivered to the SAU the accuracy of state estimation algorithm decreases. In Figure 5.8 for one node of the low voltage network is represented the effect of lost measurements to the accuracy and behaviour of state estimation. The simulation scenario in all situations is the same 10 minute run, where only the production of photovoltaic (PV) units is first at 150 seconds decreased by 70%, then at 270 seconds brought back at original level and then at 510 seconds decreased by 70% again.

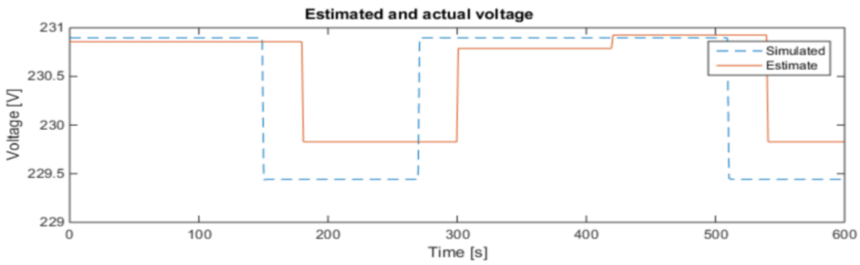
State estimator algorithm is capable of calculating an estimate for network state even without any real time measurements based only on the data received from the load and production forecaster algorithm. In this case the estimate is of course much more inaccurate than with all measurements available. In Figure 5.8 are presented both actual voltage in the simulation and the voltage estimate of the low voltage state estimator in three different situations. First graph is from the situation when all the measurements are available for the state estimator and it servers as a base case for comparison. In the base case the estimate follows the actual voltage very closely. Although there are some sections where the voltage changes in the network, but estimate does not update until the start of next minute when the algorithm is rerun. The other two graphs represent different situations where some of the real time measurements are missing for some reason. In graph b) the voltage measurement from the low voltage bus of the secondary substation is missing and in graph c) all the real and reactive power measurements from photovoltaic plants are missing. The lack of substation voltage measurement causes clearly a somewhat constant error on the estimate, in a way that it is always higher than the actual voltage. The error of the state estimation is slightly different when all power measurements are missing from the PV units. In this case the estimate is quite accurate when the production is at its nominal level, but has some error when the production is decreased. One way to investigate the performance of the state estimator is with a key performance indicator (KPI) defined in the IDE4L project [35], which equation is as follows,



(a) All measurements available.



(b) Voltage measurement from SS missing



(c) PV power measurements missing.

Figure 5.8 *Different scenarios of the effect of missing measurements*

$$LVSE = \frac{1}{N}\sum_{n=1}^{N}\sqrt{\frac{1}{T}\sum_{t=1}^{T}(\tilde{x}(t)_n - x(t)_n)^2} \tag{5.4}$$

where N is the number of studied state variables, T is the number of time intervals under study, $\tilde{x}(t)_n$ is the real instantaneous value of a state variable at time t and $x(t)_n$ is the estimated value of a state variable at time t. The state variable in this case under study is the network voltage and the KPI gives a performance index for the state estimator accuracy. [35] The Table 5.3 includes calculated KPI values and their difference to the base case value for different scenarios including the ones represented in the Figure 5.8.

At the time the testing of the low voltage state estimator was done there was no load and production forecaster operational at the laboratory and the pseudo

Table 5.3 KPI values calculated for the low voltage state estimator and their difference to the base case.

Scenario	KPI [V]	Difference [%]
Base case	0.56121	0
No SS voltage	0.73263	30.55
No PV powers	0.61162	8.98

measurements representing the input from the forecaster were hard coded to the state estimator algorithm. This has an effect on the accuracy of the estimate when the state in the network changes from the nominal and some measurements are missing. This can be seen especially in the graph c) in Figure 5.8 where the PV production changes and there is no measurements available from PV units, which results to higher voltage estimate than the actual value because the pseudo measurement for all PV units is higher than the actual value. The current method for predicting load and production changes in the network is based on load curves determined for different customer types.

5.3.2 Measurement error

Even when all the measurements are available there can be erroneous measurements because of inadequate connections or calibrations, which would result the measurements to be constantly inaccurate. The other reason for measurement errors is some sort of malfunction of a device or measurement instruments. The state and condition of measuring instruments, such as instrument transformers or cables, can be monitored and that way prevent possible failures, but measurement errors caused by a device malfunction, for example software error, are practically impossible to predict since they happen purely out of coincidence. By monitoring measured values from devices and comparing them to corresponding actual values in the simulation the equation 5.4 can be used to obtain the magnitude of error for each parameter. Table 5.4 includes measurements from different devices and with different reading frequencies where it has been possible to change.

The iRTU device is configured to receive analogue signals from RTDS that represent three phase power and reactive power as well as current measurements from the secondary substation. Measurements are sent from the device as IEC 61850 reports, that are as default configured to be sent every five seconds. The Table 5.4 includes average three phase errors for all monitored variables for iRTU and it is clear that

Table 5.4 Measurement error for each IED with different reading frequencies.

	5 s	10 s	15 s	30 s	60 s
iRTU, [A]	5.94	8.94	11.08	17.10	23.20
iRTU, [kW]	1.93	3.54	4.31	6.62	8.34
iRTU, [kVAr]	1.28	1.34	1.45	1.80	2.68
Kamstrup, [V]	-	-	-	0.284	-
Kamstrup, [A]	-	-	-	0.186	-
Landis+Gyr, [V]	-	-	-	0.275	-
Landis+Gyr, [A]	-	-	-	0.074	-

the reading frequency has a significant effect on the measurement accuracy. When the cycle time is increased to ten seconds the average error for current for example is increased by 50%, which is fairly large increase. Even with five second frequency the error for these variables is fairly large, but that can be explained quite well by focusing on the moments when the measured variables change in the simulation. The Figure 5.9 shows the behaviour of current measurements sent as a report from iRTU. The current for phase B is not visible in the graph, since it is exactly the same as the value for phase C.

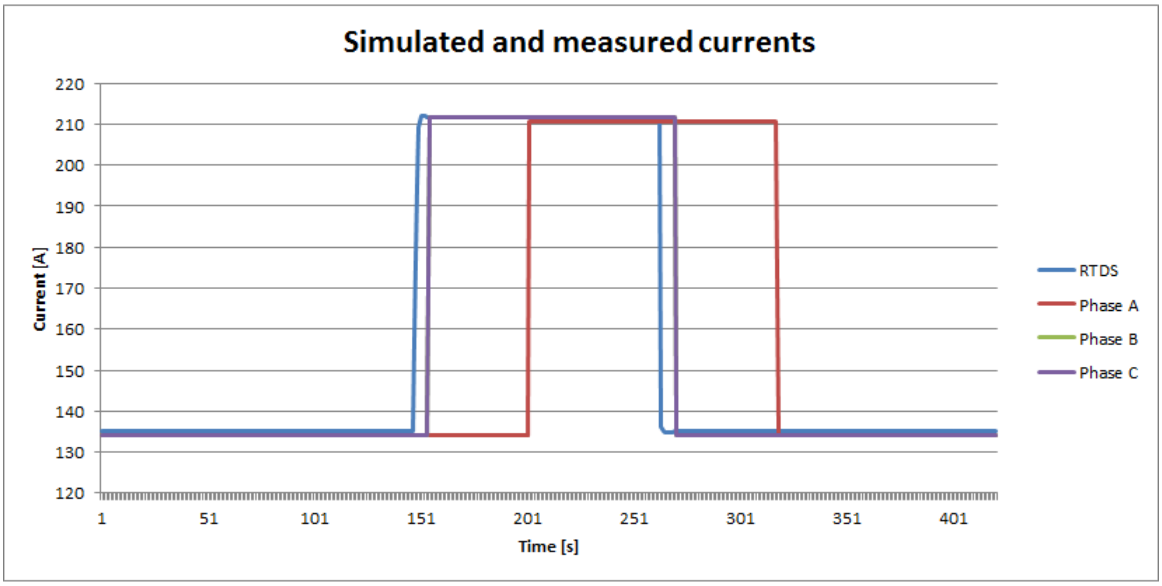


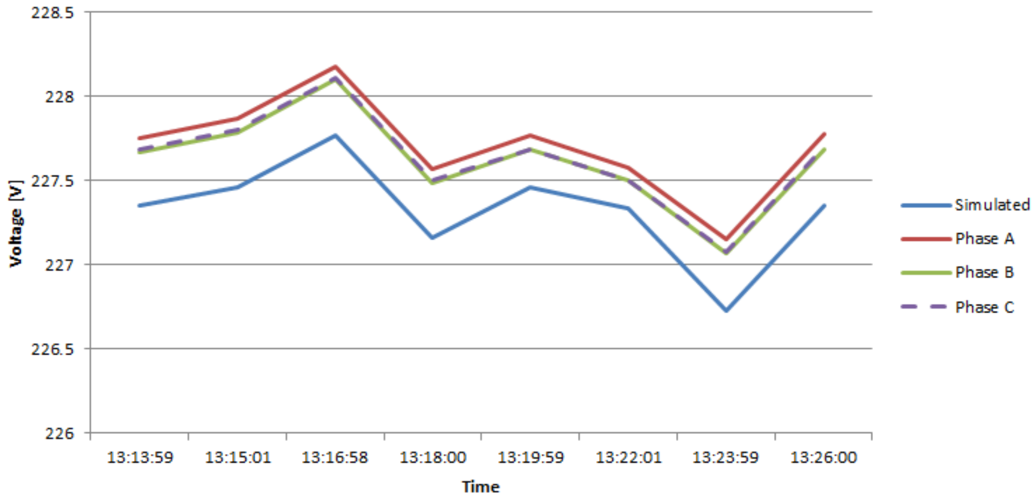
Figure 5.9 Measurement error from iRTU. Caused by non-simultaneous measurement data update.

For some reason all the phase measurements are not updated at the same moment in the report sent from iRTU, although the state of each phase is changed simultaneously in the simulation. This results a situation presented in Figure 5.9, where first the current is increased in the simulation and shortly after the report including new current measurements is transmitted to the SAU, but only phases B and C are actually containing the new current value. The measurement for the phase A is updated when the next report is sent after the defined cycle time. This delay occurs also for other measured variables and with other reading frequencies. This evidently explains the high error for the measurements even with high reading frequency and it has more significant effect with longer cycle times. When the network state is constant the errors for the variables monitored by iRTU are much better being roughly 0.6 amperes, 0.6 kW and 0.5 kVAr. The measuring accuracy for Landis+Gyr and Kamstrup smart meters were also calculated and corresponding errors are listed in the Table 5.4. Smart meters are both operating in our laboratory demonstration with 30 second reading frequency and are delivering voltage, current, power and energy measurements to SAU with DLMS/COSEM protocol. With this frequency the measuring error for voltage and current is very small. As described in section 4.4.4 the physical connections to the RTDS for these two meters are little different from each other, because of different measuring interfaces. This would most likely explain the difference in the current measurement, as the Landis+Gyr meter is connected directly to the amplifier where as the current for Kamstrup is fed through a current transformer. The error for voltage measurement is on the other hand almost identical and measured phase voltages as well as the actual voltage in the RTDS simulation can be seen in Figure 5.10.

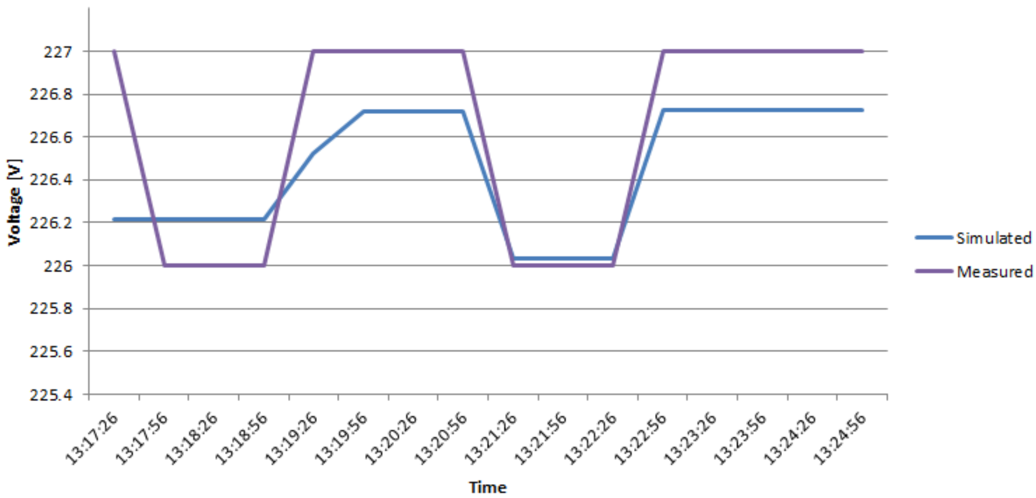
Although the voltage measurement error for both smart meters is almost the same when calculated for a three phase average, the actual measuring accuracy of the measurements sent to the DLMS client is different. This can be clearly seen from Figure 5.10 while the accuracy of the Landis+Gyr meter is 0.01 volts and the voltage curve follows the equivalent curve of the simulated voltage, but the voltage measurements sent from Kamstrup have the accuracy of only 1 volt so in this case it goes either over or under the simulated voltage. For the clarity of the situation the graph presenting the voltage measurement for Kamstrup meter is showing the measured value for phase A only.

5.3.3 Time Performance

Time synchronization is one essential part of any control system and especially important for decentralized systems, because all the devices and resources are not



(a) Landis+Gyr



(b) Kamstrup

Figure 5.10 *Voltage measurements from Landis+Gyr and Kamstrup smart meters and corresponding voltage levels in RTDS.*

in the same physical place, but they still need to communicate and operate with each other. If there is no synchronization or the accuracy of it is too low for the intended purpose devices might not be able to work or they will not work properly. There are different levels of synchronization accuracy needed depending on the application. While IEC 61850 based substation level process bus communication via sampled values or GOOSE messages requires synchronization accuracy of nanoseconds, many devices and systems can operate adequately with accuracy of second or milliseconds.

Since there are no protection or similar more time critical devices in the laboratory demonstrations the synchronization is performed with NTP server that can provide synchronization accuracy of few hundred milliseconds or better. The Figure 5.11 represents a situation where there are practically no actual synchronization between the SAU and the simulator and its effect on the performance of the state estimator algorithm at simulation situation as well as the result with proper synchronization.

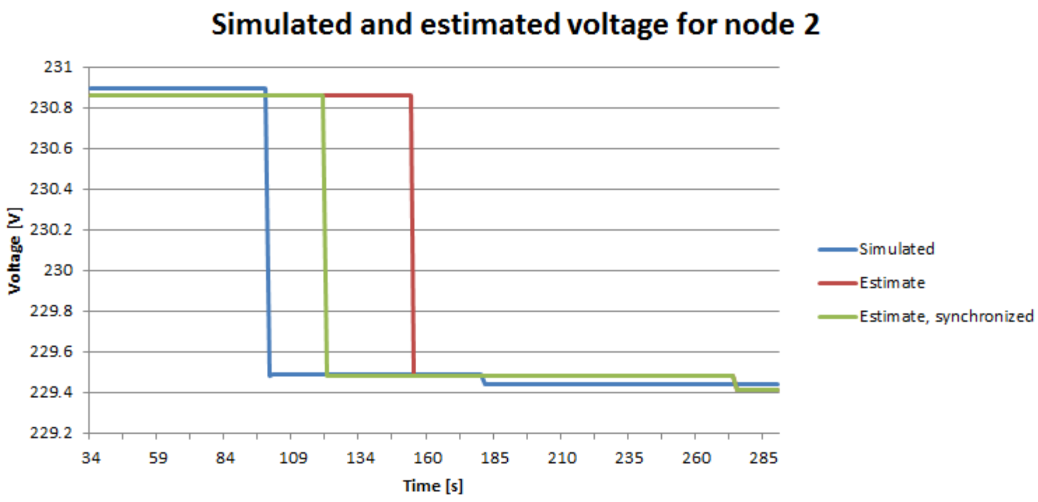


Figure 5.11 *Effect of poor time synchronization of the system to state estimator performance.*

The simulation run in the Figure 5.11 started at the beginning of a minute, which results the new state estimation to be calculated at 120 seconds, shortly after the voltage has changed in the system. In this case the synchronization is around 30 seconds off and causes the estimated voltage to stay at the old level that much longer. The error for the synchronized estimate is 0.397 V and for the non-synchronized almost twice as large 0.631 V within the timespan shown in the graph. This issue is however present only at the laboratory and makes the processing of the simulation results more complicated, while in the real network chances in network state happen randomly. This test is more about the overall importance of synchronization in automation systems and provides an example of possible outcome when the synchronization is poor.

To perform adequately the system needs to be not only synchronized, but also perform its tasks and communication within reasonable time limits. The performance of the communication link and IEDs can be observed by measuring response time for a message sent from client to the IED. Results are shown in Table 5.5

for different IEDs. The tests were conducted by both reading specific values from the IED and also by changing some parameters in the IED configuration. While the iRTU does not have any configuration that could be controlled with the client and ultimately the response times were practically identical for both monitoring and control for other IEDs only one value was calculated for each device.

Table 5.5 *Average delay times for IED response.*

IED	Response time [ms]
REU615	4.23
HMS SG10 and Unitrol	> 500
iRTU	69.07

The REU615 is clearly the fastest to response and execute parameter changes requested by the client with only few millisecond delay in the communication. The iRTU has significantly longer delay for communication, although all the requests from client were related to only monitoring and measurement reading and not configuration changes. The IEC 61850 server interface defined by the SCL-file on the iRTU is most likely slower and not as refined as the one provided by the manufacturer on the REU615, which could explain the longer response time for the iRTU. The iRTU is also not fully designed based on the IEC 61850 standard like the REU615 and may have some delay because of internal communication and data mapping between the server interface and rest of the device. The very long delay for the combination of Unitrol 1020 and the HMS SG10 gateway is mainly caused by the limitation of the Modbus RTU connection between the gateway and Unitrol. Modbus Master interface at the gateway reads all the defined parameters from the registers of the Unitrol on each predefined cycle that has to last long enough to be able to read all values. If the time for the reading cycle is too short the Modbus master can not get all the required parameters and enters an error state. The reading cycle time for the gateways Modbus interface is defined at 500 ms which is as short as possible and results inevitably to response times of over 500 ms. Also the gateway adds some delay to the communication, while the parameter mapping between IEC 61850 and Modbus protocol is achieved with a PLC running on a bus cycle time of 25 ms. If a new set point is provided for the Unitrol by the SAU it is fairly fast when it has been changed in the register, but the overall time when the information of the changed value is transmitted back to the client is very long compared to the other devices in the laboratory.

5.4 Commissioning and IEC 61850 characteristics

There are several very different devices when considering the commissioning of them. Physical connections to the RTDS are not considered in this section, because they are already introduced in Section 4.4. This section focuses on the internal commissioning work for IEDs and their communication interfaces and also the interoperability of devices based on the IEC 61850 standard.

IEC 61850 is the main protocol being used in the automation system of IDE4L project and most of the devices support this standard. Although IEC 61850 standard is aiming for effortless and seamless integration of IEDs and other services regardless of the manufacturer it still leaves quite a bit of room for interpretations, thus leading to very different implementations of the standard. Depending on the manufacturer and on their way of understanding the standard the actual commissioning work needed for different IED's vary greatly. When comparing the IEDs in the laboratory system it can be calculated on average how much work the commissioning and parameter setting of each device requires, which can be seen in table 5.6. This examination leaves out differences between configuration software provided by manufacturers, that include very different approaches and user-friendliness levels, but are extremely difficult to compare.

Table 5.6 *Number of parameters that need to be configured when commissioning each device and if an additional SCL file is needed to enable IEC61850 compatibility.*

Device	Number of parameters	SCL file needed
REU615	30	yes
iRTU	80	yes
Unitrol 1020	20	no
HMS SG10 gateway	30	yes

The laboratory test set up includes devices from all different categories in terms of IEC 61850 standard compatibility. The REU615 AVC is the only device that is fully based on the standard and all the functions and interfaces are designed accordingly. The iRTU on the other hand is not completely based on the standard, which makes it more flexible to operate with different protocols and in different applications, but it also adds up the configuration work needed to make it function properly. The iRTU can be configured to have an IEC 61850 server interface which can then be internally mapped to receive measurements from devices physical I/O-interfaces or deliver commands and information to the device sent from external IEC 61850 client.

This requires user to create a proper code for the server interface with SCL-language. The REU615 also requires the SCL-file to define the functionality of the IED, but that is automatically created and uploaded to the device by the configuration tool and requires no actual coding from the user. The Unitrol 1020 AVR on the other hand is based on Modbus protocol and does not support the IEC 61850 protocol at all and the remote connection for monitoring and control is established through a serial cable with Modbus RTU. To make it compatible with other devices and SAU the HMS SG10 protocol gateway is needed to map these two protocols with each other. The gateway is similar with the iRTU when it comes to compatibility, because it is capable of supporting multiple protocols and interfaces and also needs user to provide the SCL-file for the IEC 61850 server interface. The commissioning work needed for each device to make them operable in the laboratory set up is presented in Table 5.6 as estimates of internal configuration parameter changes and definitions done for devices. REU615 and Unitrol 1020 require roughly the same amount of parameters to be configured, but to make the remote connection to the SAU possible for the Unitrol the HMS gateway needs to be configured too, which makes the combination more complicated than the REU615 on the commissioning point of view. The most flexible and versatile device in the laboratory set-up is the iRTU, which makes it also quite time and work consuming device to commission. It can be clearly seen from the numbers at Table 5.6 that the amount of parameters to be configured is much larger than with other devices, since the device comes with practically no preconfigured settings or interfaces.

The HMS gateway and the iRTU require the user to provide the SCL-file describing the IEC 61850 server interface, thus increasing the amount of work for commissioning notably. The HMS comes with an example SCL-file of the server interface that can be used as a template and modify it to get the SCL-file needed for the application. The iRTU does not have any template or example file provided. The interoperability of devices from different manufacturers could not be tested, since all the communication at the laboratory set-up was defined only between IEDs and SAU.

6. DISCUSSION

This chapter provides more discussion about results presented in Chapter 5 and aims to further combine and link the test results with each other. Also possibilities for future work are listed and discussed.

6.1 Summary of test results

Various test were performed to the laboratory system to validate its performance and non-functional requirements. One key feature to any automation system is reliability and along that availability. These requirements were observed with more theoretical and mathematical approach than most of the other features and a reliability block diagram was used as a basis for this assessment. In general the decentralization of the system and large amount of different measurement points in the network make the system very reliable. Different scenarios were studied including assumptions that all devices have to work in order to the whole system to operate properly and that only control devices all have to work. Calculations for different sections of the system were also conducted and effect of redundant communication devices. In reality the system is capable of operating even though some of the devices or even a SAU would be lost, but lost of monitoring devices has an effect on the accuracy of state estimation as further tests prove and loss of control devices deteriorates the controllability of the network possibly resulting the hosting capacity for DERs to decrease. The most unreliable component of the system is clearly the computer where each SAU will be operating and with failure rate acquired from a study [34] the mean time to fail (MTTF) for the whole system was eventually only 1.88 years, while for individual components other than the PC it is in the range of 50 to 150 years. Same values were calculated for the whole system with twice as long MTTF for the PC and the corresponding value for the system was increased by almost 66%. The assumption of longer MTTF for the computer was based on the fact that the study where it was originally acquired from included only consumer PCs and for substation automation use the PC would be more reliable industrial type PC.

The effect of device and communication failures along with measurement errors was tested with the laboratory set up and included low voltage network model and

SSAU, since the situation is very similar in the mid voltage network with only fewer devices but identical interfaces and features on the PSAU. Both IEC 61850 and DLMS/COSEM client interfaces were proven to be robust once properly configured and to be able to withstand and recover from the loss of connection to some or all of the server devices. The loss of connection to the field devices does not result to the failure of the state estimator, but affects the accuracy of the estimate. Different measurement loss situations and their effect on the average error of the estimate was studied and in all the cases the error for example in node voltage was below 0.004 pu. Errors in measurements and the effect of reading frequency to the error was tested with various device and this revealed also some inaccuracies on the measurement delivery to the client at SAU. Measurement error for both Kamstrup and Landis+Gyr meters turned out be very small, with around 0.28 V for voltage on both meters and current 0.186 A for Kamstrup and a lot smaller 0.074 A for the Landis+Gyr. The difference on the current measurement accuracy is probably caused by the difference on physical connections to the RTDS, since Kamstrup needs additional current transformers between the amplifier and meter terminals. Even though the three phase average of the measured quantities are very close to each other on both meters the measurement accuracy of the data transmitted to the SAU database is very different. Accuracy for current on both meters is 0.01 A, but voltage measurement accuracy is 0.01 V for Landis+Gyr and only 1 V for Kamstrup. If the voltage measurement of a smart meter would be from an important node in the network and accurate value is assumed to be available this feature should be taken in to consideration when deciding the meter type. Tests for the iRTU device revealed fairly big errors even with default 5 second reading interval and further examination showed that the reporting of measurements from the device had issues. Turned out that not all the phase measurements for one network quantity were updated at the same time, despite the simultaneous change of parameters in the simulation.

Tests conducted on the communication interfaces showed that the Ethernet based communication network is more than capable of transmitting all the necessary data for the system. On an actual network set up, on the other hand, some of the devices would be connected to the SAU with some other communication link than Ethernet and this can will have an effect on the time behaviour, accuracy and efficiency of the system. The analysis of the CPU usage of algorithms, database and communication interfaces at the SAU revealed that most of the instances running on the computer are not using more than 10% out of the available 800% of CPU capacity. Both SE and PC algorithms on the other hand reserve most of the processing capacity when they are running and PC is by far the most demanding process with average usage of half of the processing power for about 20 seconds during every run cycle and peaking momentarily close to 800%.

Time synchronization of the SAU and all the IEDs is carried out with a NTP server located on the SAU PC. It provides time with adequate accuracy for the system to operate properly, but on the demonstration purpose one simulation situation was presented to illustrate the effect of poor or complete lack of synchronization to the operation of the state estimator. The time behaviour of IEDs was studied by examining the response time for a message sent from the client. Devices turned out to have very different delays on the response time, while the REU615 relay responded in few milliseconds to all of the requests the same actions took around 70 milliseconds for the iRTU and above 500 milliseconds for the combination of HMS SG10 gateway and Unitrol 1020. Explanation for the significantly longer response time for the Unitrol is caused by the way the Modbus RTU connection operates between the gateway and the Unitrol, since it has a 500 ms operating time each time something is read or written to the registers of the Unitrol. The data mapping between IEC 61850 and Modbus protocol at the HMS gateway increases the response time too. The longer response time of the iRTU when compared to the REU615 is probably result of lower performance IEC 61850 server interface. The fact that not all of the IEDs are fully based on the IEC 61850 standard - that is used as as a main standard in this architecture - results to some constraints in the system and especially increase the work needed to integrate all the devices to the system.

The work needed to commission and integrate different devices into the system has big variation depending on the devices specifications and is an important feature to study. The range of devices integrated to the laboratory demonstration represent completely different types of IEDs when it comes to integration of them to the IEC 61850 standard based automation system. Some idea of the work needed for the commissioning of each IED were illustrated by presenting and comparing the amount of parameter changes and definitions needed to make the device operable. The REU 615 is purely based on the IEC 61850 standard and requires the least amount of work to commission when it comes to setting changes. The Unitrol 1020 requires roughly the same amount of parameter changes ad the REU 615, but to integrate it with the IEC 61850 standard the HMS SG10 protocol gateway is needed which almost doubles the amount of settings to be edited. The iRTU is the most flexible device of the set up and is capable of operating with several protocols and interfaces, but mainly because of that it is also the most labour intensive. The HMS gateway as well as the iRTU both support several communication and automation protocols and the IEC 61850 server interface needs to be specifically configured with a SCL-file, which needs to be created by the user. This requires more expertise and increases the commissioning work of the IED. As described earlier the lack of preconfigured SCL-file and IEC 61850 server interface from the manufacturer may also result to constraints on time performance or device operating accuracy when integrating the IED to IEC 61850 based automation system. Although the interoperability and ease of commission of IEDs is one of the main goals of the IEC 61850 standard it seems to leave some room for interpretations which result to devices that need very different amount of work to make them interoperable with the IEC 61850 protocol.

6.2 Recommendations for future work

All the tests conducted in this thesis apart from the reliability and availability analysis were done only for the low voltage network and SSAU, since the complete system including mid voltage network and PSAU was not available at the laboratory set up by the time the test were made. Because of the modular design of the automation architecture the functionalities and interfaces are almost identical for the SSAU and PSAU so test results presented in this thesis apply also to the PSAU, but the integration and co-operation of the two SAU units should be also tested.

Further non-functional requirement tests should also be developed and executed. Especially the scalability of the system should be tested and studied, while that is a crucial feature for a decentralized automation system that is designed to be expanded with minimal effort if needed. The challenge is to develop a method that would preferably offer results based on rather small scale laboratory tests with only couple of devices. Some possible parts of the system were listed and studied in this thesis that could be the possible bottlenecks of the system from scalability point of view, but no actual results were presented. Larger scale tests with more physical devices would also provide more information about the systems behaviour and constraints, but are quite difficult to carry out in the laboratory environment.

The behaviour of the real time monitoring and state estimation was tested in situation where some of the measurements or devices were completely missing because of communication failure. The effect of poor connection quality or partial loss of communication is something that would be good to test, but rather difficult to realize in laboratory environment where all the communication is carried out with rather short Ethernet cables and fast interfaces. This is however possible scenario in actual field installations where all of the communication may not be possible to implement with Ethernet connections especially because of the geographical distribution of the system. Further comparison to other systems and especially to legacy distribution systems with centralized architecture should be done regarding all the features tested in this thesis.

7. CONCLUSIONS

This thesis introduced a novel decentralized distribution automation system developed in IDE4L project and described the building of laboratory set up to demonstrate and test the system before field testing. The laboratory demonstration system and IEDs involved in the set up were presented and the integration of devices into the RTDS and SAU was explained. This thesis includes also various test results from the laboratory set up to study and define crucial non-functional requirements (NFR) for a decentralized automation system like the one in question.

The complete laboratory set up was introduced and the functionalities of IEDs and the SAU explained. Not all of the IEDs were involved in the actual monitoring and control simulations of the network at the time of testing, but the NFR testing for the automation system was still possible to execute since all the connections and interfaces were operational. The NFR testing of the system did not reveal any critical weaknesses or constraints in the automation system and it proved to be reliable and robust. Biggest issues were related to measurement accuracy of some devices and to IEC 61850 standard compatibility and commissioning. Measurement accuracy tests showed that one device did not send updated measurement values for all the phases at the same reading cycle and caused unexpected error to the measurements in the database. The reason for this behaviour remained unclear, but one explanation could be the IEC 61850 server interface at the IED that is not provided by the manufacturer but has to be configured when commissioning the device.

The laboratory demonstration system included devices that are fully based on the IEC 61850 standard, which is the main protocol used in this automation system, as well as devices compatible with the protocol and devices that do not support the protocol at all. This gave a chance to compare the amount of commissioning work required for each IED type to be operational by comparing the amount of parameters to be configured for each IED. Examination showed a clear impact on the amount of commissioning work when there are devices that are not fully compatible with the standard and at the worst case the work required was almost tripled when comparing to the standard based device.

Some improvements for the demonstration system and the test plan emerged. One aspect was that the automation in this thesis system is designed to be used in distribution network in mid and low voltage levels and at primary and secondary substations, but all the non-functional requirement testing of the system was conducted only for low voltage network and SSAU. This does not impair the test results gained, since the functionality and interfaces of the PSAU and SSAU are practically identical. With larger system more test cases could have been covered, such as co-operation and integration of the two SAUs which could be beneficial when defining the performance and probable constraints for the system. Methods to analyse the scalability of the system were also presented, but more work should be done on that since it is a crucial feature for a distributed system.

Some issues were raised and room for future development was found, but in general the goals for the thesis were achieved and results presented. The aim was to define critical NFRs for a decentralized automation system and present methods to tests these requirements. The laboratory set up was introduced and defined test methods demonstrated with it successfully.

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