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TAMPERE UNIVERSITY OF TECHNOLOGY

SAMPO TURUNEN

PROTECTION OF MICROGRIDS AND DISTRIBUTED ENERGY RESOURCES BASED ON IEC 61850

Master of Science thesis

Examiner: Prof. Sami Repo
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ABSTRACT

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Microgrids are a potential part of the future smart distribution grid with capability of island operation, envisioned to support the goals of increased use of renewable and distributed energy resources, active consumer participation and improved quality of electricity supply in the future power systems. This thesis examines the implementation of protection systems for microgrids and distributed energy resources using the IEC 61850 standard series. IEC 61850 is one of the core smart grid standards originally developed for substation automation, but extended in its usage to many areas including distributed energy resources.

The main objectives of this thesis are analysing the implementation of microgrid protection, usage of IEC 61850 in distribution applications, and applicability of Multipower test environment of VTT Technical Research Centre of Finland in researching these subjects. A literature review of microgrid protection issues and proposed protection schemes as well as an overview of the IEC 61850 standard series and its extensions are presented. An adaptive protection scheme is implemented in an example microgrid configuration of the Multipower environment using IEC 61850, and its correct operation verified during islanding and in the case of a communication network failure. Finally, recommendations are given on the future development and research topics of the Multipower environment, including integration of different distributed energy resource units from other VTT research areas such as fuel cells and electrical vehicles to the system, studying the usage of different networks for communication inside the environment and testing of harmonization between IEC 61850 and other smart grid standards.

TIIVISTELMÄ

SAMPO TURUNEN: Mikroverkkojen ja hajautettujen energiaratkaisujen suojaus IEC 61850 -standardiin perustuen
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Mikroverkot ovat osa tulevaisuuden älykästä sähköjakeluverkkoa, jotka tarvittaessa pystyvät itsenäiseen saarekekäyttöön jakeluverkon häiriöiden aikana. Mikroverkot tukevat tulevaisuuden energiajärjestelmän tavoitteita uusiutuvien ja hajautettujen energiaratkaisujen käytön lisäämisessä, kuluttajien aktiivisessa osallistumisessa ja sähkön toimitusvarmuuden ja laadun parantamisessa. Tämä diplomityö käsittelee mikroverkkojen ja hajautettujen energiaratkaisujen IEC 61850 -standardisarjaan pohjautuvien suojausjärjestelmien toteutusta. IEC 61850 on yksi merkittävimmistä älykkäiden sähköverkkojen tietoliikennestandardeista, jonka soveltamisaluetta on laajennettu alkuperäisestä sähköasemien sisäisestä automaatiosta ja tietoliikenteestä monille uusille alueille kuten hajautettuun energiantuotantoon.

Työssä esitetään kirjallisuusselvitys mikroverkkojen suojauksen potentiaalisista ongelmista sekä mahdollisista suojaustavoista, tiivistelmä IEC 61850 -standardisarjan rakenteesta, periaatteista, julkaistuista laajennoksista ja niiden käyttötarkoituksista, sekä analysoidaan VTT:n Multipower-testiympäristön soveltuvuutta näiden aihepiirien tutkimukseen. Multipower-ympäristön soveltuvuutta mikroverkkojen suojauksen tutkimukseen testataan toteuttamalla IEC 61850 -pohjainen adaptiivinen suojausratkaisu testiverkossa. Suojausjärjestelmän oikea toiminta todetaan saarekkeeseen siirtymisen aikana sekä tietoliikennehäiriön tapahtuessa. Multipower-ympäristön tärkeimmiksi tulevaisuuden tutkimuskohteiksi suositellaan VTT:n muiden tutkimusalueiden kuten polttokennojen ja sähköautojen tutkimuslaitteiston liittämistä ympäristöön, erilaisten tietoliikenneratkaisujen soveltuvuuden testausta tiedonsiirtoon ympäristön sisällä ja tutkimusta IEC 61850 -standardin yhteensopivuudesta muiden älykkäiden sähköverkkojen standardien kanssa.

PREFACE

This thesis was written for the Energy systems research area of VTT Technical Research Centre of Finland. I'd like to thank my supervisor Dr. Kari Mäki from VTT for this opportunity, and my examiner Prof. Sami Repo for extensive and constructive comments during the course of this work. I'd also like to thank Marja-Leena Pykälä from VTT for bringing me up to speed concerning the Multipower test environment and supervising its installations, as well as all my colleagues at VTT Energy systems for a welcoming and relaxed work environment.

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Espoo, 3.5.2016

Sampo Turunen

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LIST OF ABBREVIATIONS AND SYMBOLS

ACSI	Abstract Communication Service Interface
AL	Application Layer
AVR	Automatic Voltage Regulator
CDC	Common Data Class
CHP	Combined Heat and Power
CIGRE	Conseil International des Grands Réseaux Électriques, International Council on Large Electric Systems
CIM	Common Information Model
COSEM	Companion Specification for Energy Metering
CT	Current Transformer
DER	Distributed Energy Resources
DFT	Discrete Fourier Transform
DG	Distributed Generation
DMS	Distribution Management System
DR	Demand Response
DS	Distributed Storage
DSO	Distribution System Operator
EPRI	Electric Power Research Institute
FC	Functional Constraint
FRT	Fault ride-through
GOOSE	Generic Object Oriented Substation Event
GSE	Generic Substation Event
HIF	High Impedance Fault
IEA	International Energy Agency
IED	Intelligent Electronic Device
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IGBT	Insulated Gate Bipolar Transistor
LAN	Local Area Network
LD	Logical Device
LN	Logical Node
LoM	Loss-of-Mains
LTE	Long-Term Evolution, 4G standard for high-speed wireless communication

MMS	Manufacturing Message Specification
MGCC	Microgrid Central Controller
MPPT	Maximum Power Point Tracking
OC	Overcurrent
OSI	Open Systems Interconnection
PCC	Point of Common Coupling
PAS	Publicly Available Specification
PLL	Phase Locked Loop
PUAS	Power Utility Automation System
PV	Photovoltaics
RES	Renewable Energy Source
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SCL	Substation Configuration Language
SCR	Silicon Controlled Rectifiers
SCSM	Specific Communication Service Mapping
SGAM	Smart Grid Architecture Model
SNTP	Simple Network Time Protocol
THD	Total Harmonic Distortion
TC	Technical Committee
TR	Technical Report
TS	Technical Specification
VSC	Voltage Source Converter
VT	Voltage Transformer
VTT	VTT Technical Research Centre of Finland
XMPP	Extensible Messaging and Presence Protocol

f	frequency
H	inertia constant
P	active power
Q	reactive power
R	resistance
S	apparent power
U	voltage
X	reactance
Z	impedance
ω	angular frequency

1. INTRODUCTION

1.1 Background

Modern society is completely dependent on an uninterrupted supply of electricity. More and more attention is being paid to the security, reliability and quality of power supply while at the same time climate goals are driving investments in new, renewable energy solutions. These new elements should be integrated to the power system with minimum costs, maximum interoperability and compatibility with widely integrated internal energy markets of areas like the European Union [1]. According to the International Energy Agency (IEA), investments in renewable sources of energy increased from $60 billion in 2000 to $250 billion in 2014. Over the period to 2035, IEA estimates total investments in renewables to amount to $6 trillion and a further $7 trillion being spent on transmission and distribution. [2]

While emerging economies have to deal with hugely growing electricity demand, OECD countries are faced with aging infrastructure, wide deployment of distributed energy resources (DER) and integration of often volatile or intermittent renewable energy sources. To respond to these challenges, the existing electricity grids are being developed from passive networks to active smart grids. The European Technology Platform of Smart Grids defines smart grid as "an electricity network that can intelligently integrate the actions of all users connected to it - generators, consumers and those that do both - in order to efficiently deliver sustainable, economic and secure electricity supplies." [3] European smart grid projects launched from 2002 up to 2014 totalled $3.15 billion in investments across 459 projects [4]. The biggest changes are happening at the distribution level, where integration of distributed generation, enabling of local energy demand management and smart metering, and adoptation of technologies from transmission grids are creating a whole new set of requirements for the power system and especially the communication system associated with it. One of the promising smart grid concepts in achieving the aforementioned goals is to take a system approach which views local generation and associated loads as a sub-system or a microgrid. A microgrid can be defined as "a part of smart distribution grid with an island operation capability" [5], i.e. if needed it can operate independently without utility network connection. Microgrids are envisioned to be viewed from the outside as a single controllable entity, and be able to support the goals of future power systems in many possible ways. These include for example realizing an energy-independent area, a platform for sharing energy resources between owners, offering support for utility networks during normal operation or fault situations, or offering aggregated demand response capabilities for balancing purposes of market operators or electricity producers among others.

The protection of electricity networks is a foundational part of safe usage and operation of the power system. With these new concepts, the traditional control and protection systems face new challenges that need to be addressed in order to realize the vision of future power systems. Distributed and power electronic interfaced generation, differing characteristics of distribution and transmission networks and islanded use of microgrids all pose issues that must be considered in the protection systems of these new structures.

These developments also raise the need for standardization to manage the increasing number of interconnected systems and entities operating in the power system domain. Standardization of smart grids is a key component in achieving the goal of interoperability internally in systems with a wide variety of functions as well as between them for the large-scale integration of energy systems. The International Electrotechnical Commission (IEC), a leading international electrical standards development organization, published the IEC Smart Grid Standardization Roadmap in 2010 [6] for coordination of its standardization work. In this roadmap a number of core standards are defined, with special relevancy to nearly all smart grid applications. One of these core standards defining the smart grid communication systems is the IEC 61850 standard family "Communication Networks and Systems for Power Utility Automation". With important application areas starting from the original scope of substation automation to new application areas like hydro power and distributed energy resources, the standard is designed to adopt state-of-the-art protocols and provide also guidance in areas like engineering and maintenance. The IEC 61850 is therefore also an integral part of modern distribution grid applications, and a focus point in a lot of research related to the field.

1.2 Scope and structure of the thesis

This thesis has been written for the VTT Technical Research Centre of Finland in association with the installation of a new IEC 61850 -based control and protection system for the Multipower test environment for distributed energy resources in Espoo, Finland. The main objectives and research questions are:

- How can the protection of microgrids be implemented using IEC 61850?
- How widely can IEC 61850 be applied in distribution applications, what is the current state of the standard and what is being developed?
- How applicable is the Multipower laboratory environment in researching these subjects and what should be developed?

The new installations as well as the envisioned future state and usage of the test environment as a standard-based, multifunctional and flexible testbed are the deciding factors for the scope of this thesis. The chosen approach to the wide topic of microgrids and distributed energy resources is from a technical requirement and capability aspect, and more specifically as relevant to the widening scope of the IEC 61850 standard series. Solutions and concepts based on communication are of specific interest, since in these solutions IEC 61850 has the most relevance. The chosen point of view is also guided by the approach of the standard series: instead of examining ownerships, market participants or operators, the area of interest is in the operation and communication between devices in realizing wanted power system functions, with focus on protection systems. Business mechanisms, energy market participation models and detailed economical cost-benefit analyses of different solutions, while vitally important to real world microgrids, are not covered by IEC 61850 and therefore are not the focus of this thesis.

In the next section, the focus of this work is presented in context of the European Smart Grid Architecture Model (SGAM) framework. In Chapter 2, the general structure and properties of microgrids are examined, as well as principles for successful islanding and resynchronization to the utility grid. In Chapter 3, protection issues of microgrids as well as proposed solutions are reviewed, with a special focus on adaptive protection. Chapter 4 presents an overview of the IEC 61850 standard series, its information model and information exchange mechanisms, as well as its usage in DER applications. In Chapter 5 the Multipower test environment is introduced, and a simple test configuration is used to prove the adaptive protection capabilities of the new protection and control system installed. Finally, conclusions are presented in Chapter 6.

1.3 Relation to the Smart Grid Architecture Model (SGAM)

In March 2011, the European Commission issued the M\490 mandate for Smart Grid standardization [7]. One of the key deliverables mentioned in the mandate was "A technical reference architecture, which will represent the functional information data flows between the main domains and integrate many systems and subsystems architectures." To fulfill this requirement the Reference Architecture Working Group (SG-CG/RA) was formed under the Smart Grid Coordination Group (SG-CG) established by the European standardization organizations CEN, CENELEC and ETSI. The reference architecture is presented in the form of a technical report [8], and consists of four main components: the European Conceptual Model, the Smart Grid Architecture Model (SGAM) Framework, Architecture Viewpoints and SGAM Methodology. The European Conceptual Model is an evolution of the NIST Smart Grid Conceptual Model presented in [9] with EU specific requirements, most important being the integration of Distributed Energy Resources (DER). It acts as an overall high-level model that describes the main actors of the Smart Grid and their main interactions, while the SGAM framework along with the different viewpoints allow various levels of description of desired smart grid aspects from top-level to more detailed views. The SGAM methodology describes using the SGAM Framework in assessing smart grid use cases and how they are supported by standards, allowing standards gap analysis.

The SGAM Framework is a three dimensional model consisting of defined *interoperability layers* on top of the Smart Grid Plane divided to five *domains* and six *zones*, as seen in Figure 1.1. With these components, the SGAM framework aims to provide a mapping and design tool for smart grid use cases, architectures and entities ensuring all necessary levels of interoperability and information management hierarchy in all relevant smart grid domains are covered. The different domains describe the physical electrical energy conversion chain and include

1. Generation, including both conventional and renewable bulk generation

2. Transmission, including infrastructure for transporting electricity over long distances

3. Distribution, including infrastructure for the distribution of energy to customers

4. DER, including distributed energy resources connected directly to the public distribution grid

5. Customer Premises, including both end users and producers of electricity in industrial, commercial and home facilities.

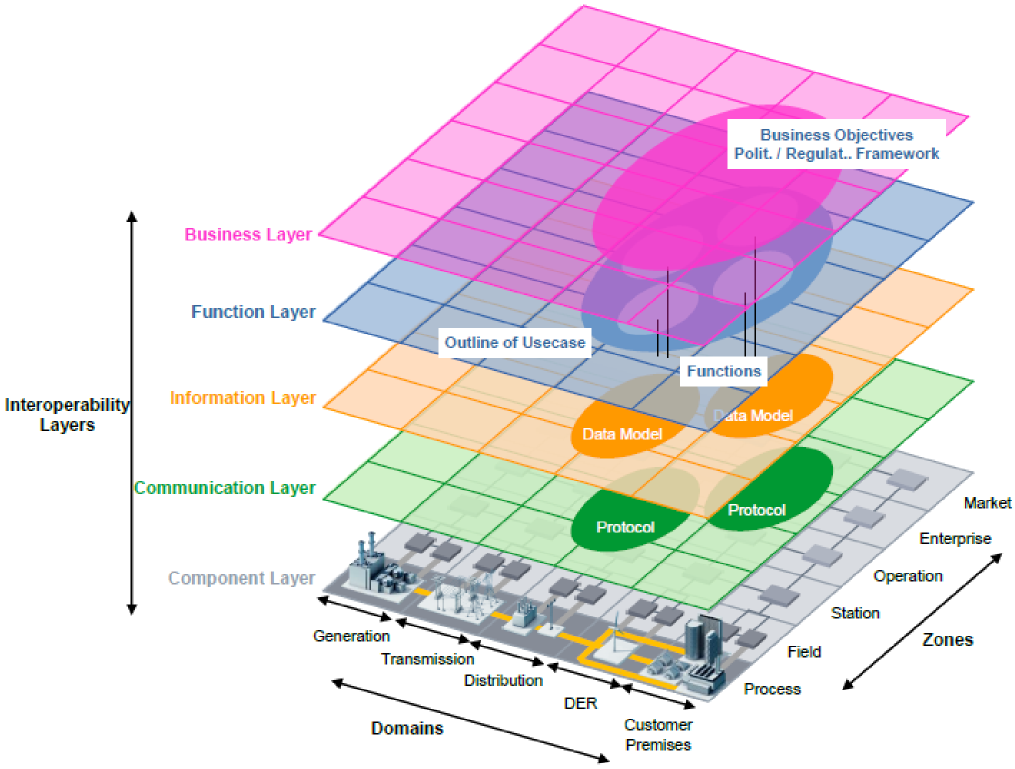

Figure 1.1 *SGAM Framework [8]*

Zones on the other hand represent the different hierarchical levels of power system management and are based on the concepts of aggregation and functional separation. Defined zones are

1. Process, consisting of transformation and movement of energy and the physical power system equipment directly involved

2. Field, consisting of the secondary process equipment used to protect, control and monitor the primary power system process
3. Station, consisting of the areal aggregation of field level data and functions
4. Operation, consisting of the overall power system control operation in the respective domain
5. Enterprise, consisting of the commercial and organizational processes, services and infrastructures of involved enterprises
6. Market, consisting of the market operations possible along the energy conversion chain spanning several organizations.

Interoperability is seen as a key enabler of smart grid. It is described in [8] as "the ability of two or more devices from the same vendor, or different vendors, to exchange information and use that information for correct cooperation". Interoperability requirements in SGAM are grouped into five layers. Inspecting and defining interoperable functionality in all layers is meant to ensure compatibility in all levels of system interactions.

1. Business Layer represents the economic and regulatory structures and policies as well as business models, capabilites and processes of the smart grid actors involved.
2. Function Layer describes functions, services and their relationships independent from actors or physical implementations.
3. Information Layer describes the information being used and exchanged between functions, services and components, as well as the underlying data models for this information.
4. Communication Layer describes the protocols and mechanisms used for the exchange of information defined in the information layer.
5. Component Layer includes the physical components, actors and applications participating in the selected functionality.

As stated in the previous section the scope of this thesis is limited to microgrid environments and distributed energy resources, with specific focus on the IEC 61850 standard series. In Figure 1.2, this scope is presented as relevant areas of the SGAM framework. Microgrids as a part of the future smart distribution system cover the domains of Distribution, DER and Customer premises, in a very interconnected way. While market participation and regulatory framework of operation are very important questions in the realization of microgrids, this thesis focuses on the technical aspects as related to the control and protection of these systems. Therefore the zones of interest include Process, Field, Station, Operation and to some extent technical systems at the Enterprise zone, but largely exclude the commercial and organizational processes at the Market zone. All of the defined interoperability layers are relevant to the chosen focus. Although the wide questions of business models, policies, and regulatory structures examined at the Business Layer fall outside the scope of this thesis, the objectives, requirements and needs for the functions at the Function layer are determined at the Business layer. Function, Information and Communication Layers are all associated with IEC 61850, and Component Layer is naturally of significance when implementing real systems such as the Multipower test environment presented in Chapter 5.

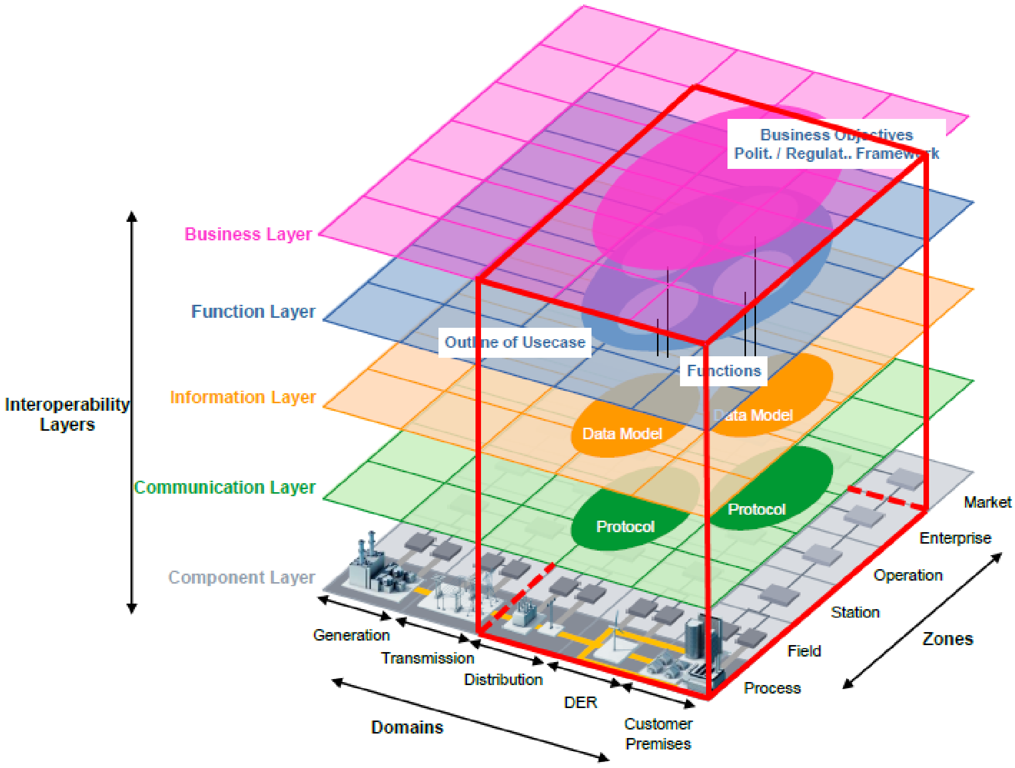

***Figure* 1.2** *Scope of the thesis in the SGAM framework.*

2. CONTROL AND MANAGEMENT OF MICROGRIDS

2.1 Microgrid structure and properties

Microgrid as a term does not have a single strict definition that is used and accepted everywhere. Lasseter described the MicroGrid concept in 2002 as "a cluster of loads and microsources operating as a single controllable system that provides both power and heat to its local area" that could be thought as a controlled cell of the power system [10]. The European Technology Platform SmartGrids defined microgrids in 2006 as low-voltage networks with distributed generation (DG) sources, local storage devices and controllable loads that have the ability to operate in islanded mode when needed in addition to while being connected to the distribution network [11]. Laaksonen raises this ability as the key property of the microgrid, with a general definition of "a part of smart distribution grid with an island operation capability" [5]. This definition has been chosen for this thesis since island operation is a unique property of microgrids compared to modern active distribution networks, which otherwise can share many of the same properties.

Microgrids aren't necessarily restricted to the low-voltage (LV) level either, but can consist of a medium-voltage (MV) feeder or even all MV feeders of a high-voltage/medium-voltage (HV/MV) substation. [5, 12] They are seen as a major building block in the distribution system of the future, with potential benefits including enhanced local reliability, improved energy efficiency and power quality, and reduced distribution network losses and capacity requirements among others [5, 13, 14]. In this section the main components and structure of microgrids is presented, along with the special properties they give to grid operation and control compared to conventional distribution systems.

2.1.1 Main components

Although microgrids can take several forms with varying sizes and locations in the electrical system, the main components forming the microgrid remain largely the same. First of all a combination of Distributed Energy Resources (DER) is integral to the functioning of a microgrid. They are small sources of energy located at or near the point of use. This can mean either distributed generation (DG) units, distributed storage (DS) systems, or a hybrid combination of both. Typical DG technologies include photovoltaics (PV), wind power, fuel cells, microturbines and reciprocating internal combustion engines with generators. Some of these technologies like microturbines or fuel cells can provide combined heat and power (CHP) which increases their overall efficiency. Most of the technologies used connect to the grid via a power electronic interface, consisting of either a DC/AC inverter or an AC/DC rectifier and a DC/AC inverter. [15] These converters can provide an additional layer of control and protection to the unit [16]. In addition to DER units, demand response (DR) technologies, also referred to as demand side integration (DSI) or demand side management (DSM), can provide additional flexibility to the microgrid by providing controllable or dispatchable loads in exchange for remuneration to the customer.

Second, the physical network connecting DER and customer loads to each other as well as to the utility grid is needed. Three basic topologies of the grid include radial, ring and mesh configurations, as shown in Figure 2.1. The structural topology of the network may differ from the topology actually used during operation, as discussed below. The connection point between the microgrid and utility network, often referred to as the *point of common coupling* (PCC), is of specific interest since it connects the microgrid to the rest of the distribution network. PCC is the boundary where a microgrid can be isolated if needed, usually located downstream of the utility transformer. It can also be seen as the limit where control responsibility moves from the utility to the microgrid owner. The technical details of measurements, control and protection needed at the PCC will be discussed in Sections 2.2.2 and 3.1.2.

Radial configuration is the simplest topology, consisting of one main line (or multiple parallel lines) with loads and DER units connected to the main line as branches. This simplifies the technical implementation of protection and control of the microgrid. It is even possible to connect the DER units close to the transformer and keep the power and current flows in one direction in all scenarios, keeping the control and protection located in the substation. Radial topology is the most common structure

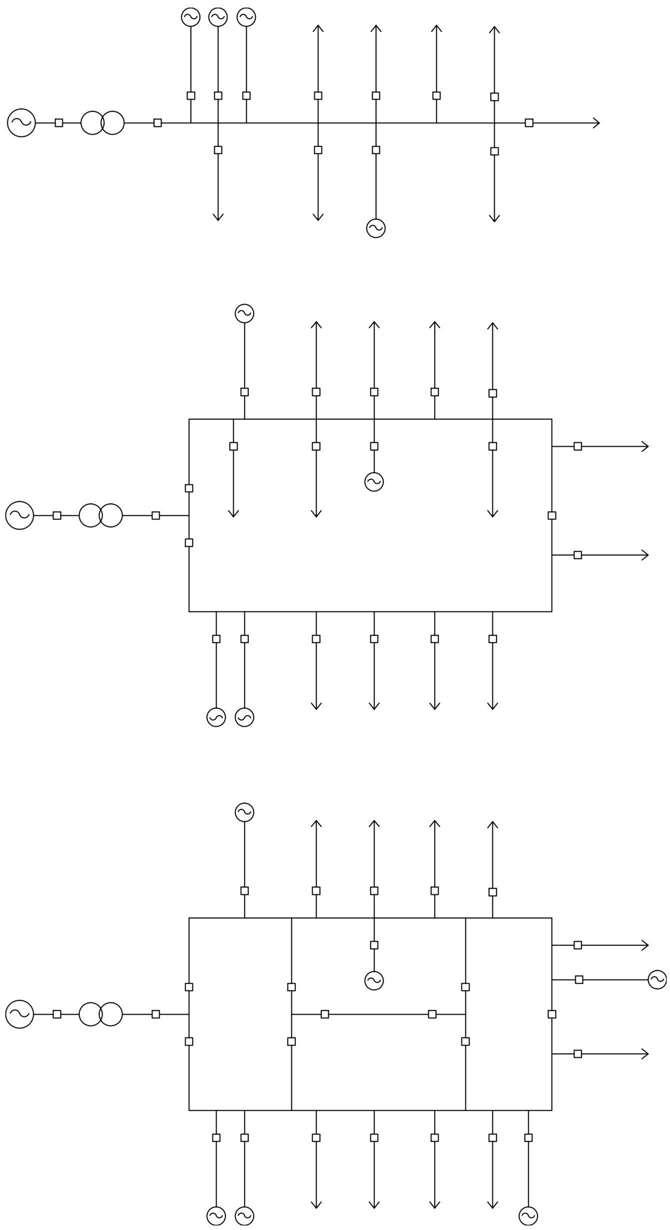

Figure 2.1 *Different grid topologies from top to bottom: radial, ring and meshed networks.*

in the current grid, especially in rural areas. Operation-wise distribution networks, with the exception of very few cases in MV networks, are operated radially, even if the actual structural topology is a ring or meshed network. It is also the only topology applicable to LV networks where fuse protection is currently the primary protection equipment, therefore not necessarily requiring new expensive components.

Ring configuration consists of lines creating a geometrical loop or ring shape, thus enabling two alternative routes for power flow to any given point of the network. This offers better voltage stability and lower power losses, but also requires a more sophisticated protection system [12]. Ring topology is currently a common network structure in residential areas, but because of the complicated protection needed, it is operated as a radial grid by keeping one disconnector of the ring always open, forming two parallel radial lines. This achieves maximum selectivity by allowing the isolation of a faulty network segment and restoration of supply to all customers behind the faulty area, while maintaining system simplicity.

Mesh configuration further increases redundancy by offering multiple alternative connections to all network nodes. It provides the most flexibility, but also makes operation and protection of the microgrid challenging. Additional power lines and breaker equipment also make mesh configurations the most expensive option. As with ring topology, only some of the possible network configurations might be used. [12]

DER penetration and its passive tolerance in the grid do not alone fulfill the characteristics of a microgrid [17]. The third main component of a microgrid is an advanced control and monitoring system that provides active supervision, control and optimization inside the grid. A microgrid operator serves multiple economic, technical and environmental aims: it is an aggregator of small generators, a network service provider, a load controller and an emission regulator at the same time. Capability of handling conflicting interests of different stakeholders and arriving at an optimal operation decision is an important characteristic of microgrid control. [13] The microgrid management system can be seen as a transition of distribution management system (DMS) functionality to the lower levels of the distribution network, and could be responsible for these lower level operations in the hierarchical management of future smart distribution networks [5]. A conceptual structure of a microgrid management system is presented in Figure 2.2. Each DER unit, in addition to having advanced electronic metering capabilities, is equipped with a microsource controller (MC). The MC is an intelligent electronic device (IED) responsible for controlling and monitoring the DER unit, and can be a separate device or a software implementation in either the DER power electronic interface or the metering unit. Additionally, demand side integration is realized by load controllers (LC) at the customer's point of connection to the grid.

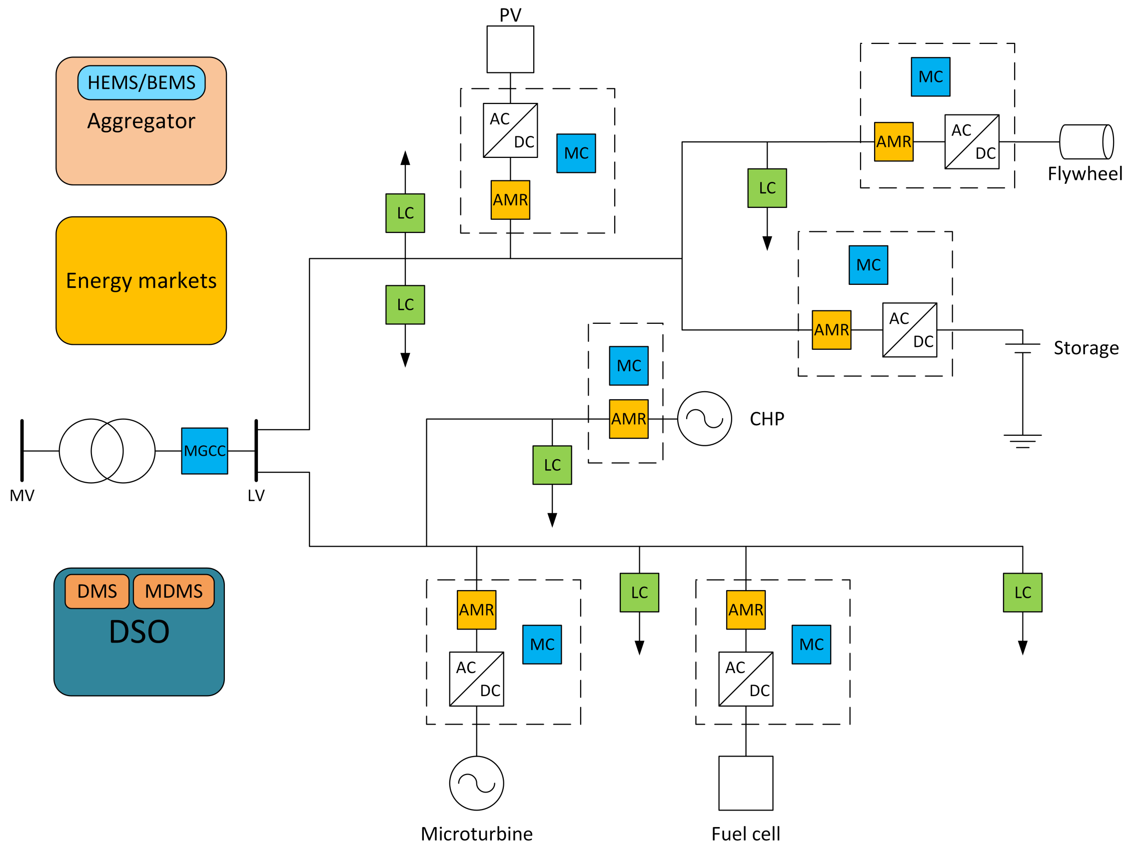

Figure 2.2 *Typical microgrid management system [13].*

The microgrid central controller (MGCC) acts as the coordinator of the microgrid as well as the main interface between the microgrid and other related actors. Among the most important are the local Distribution System Operator (DSO), possible third party aggregators and the energy markets. The DSO controls the MV side circuit breakers and disconnectors, receives measurements from the MV/LV transformer and may have IEDs communicating with the MGCC or microgrid IED at the PCC regarding protection, islanding and resynchronization between the microgrid and the utility network. The meter data management system (MDMS) of the DSO collects data from the AMR meters of the microgrid, forwards alarms and relevant measurements to the DMS and correspondingly requests from DMS to the AMR meters. Third party aggregators can act as coordinators and market operators combining the microgrid resources and offering them to energy markets or as ancillary services. These functionalities can be achieved through a home or building energy management system (HEMS/BEMS), which aggregates data of single DER units and loads, communicates with higher level systems and optimizes local energy use through resource allocation according to different microgrid stakeholders' needs.

Distribution of functions and control between the MCs and the MGCC can vary according to the selected control architecture. The main types include centralized, decentralized and distributed control. In centralized control the MGCC takes the main role in the overall optimization of the operations and value of the microgrid, taking into account market prices, grid limitations or service requests from outside the microgrid, and sending control signals to the microsources and controllable loads of the microgrid. Monitoring of the actual active and reactive power of the sources and loads is necessary in order to ensure correct operation. In fully decentralized control, the MCs are given the main responsibility of optimizing their own production according to local demand and market prices. Certain functions are still centralized, such as load and generation forecasts and security monitoring, but the DER units operate autonomously within given limits without explicit control signals from other sources. Decentralized control is visioned to need only modest communication capabilities compared to a centralized solution, at the cost of local instead of global optimization. Distributed control differs from decentralized architecture in that local controllers communicate with each other in order to form a view of the overall system state that is used on making control decisions. This can include technologies like agent-based control, in which control is achieved through independent, intelligent agents (like inverters, DGs or loads) and negotiation between them, following the multi-agent system (MAS) theory [18]. Truly distributed systems are however hard to realize in practice without some party acting as a coordinating unit, especially if network state estimation or optimal power flow calculations are needed.

In [13], Hatziargyriou recognizes centralized architecture to be applicable in a case where the microgrid is owned by a single entity with a clear goal such as an industry owner trying to minimize operating costs, while decentralized solutions are seen to work best in the case of multiple owners of DG units with diverse needs and goals, like different households in a microgrid operated in a market environment. However, in [5] Laaksonen has compiled numerous issues from the grid perspective associated with microgrid concepts without one grid-forming master unit and other grid-following units controlling their output based on reference signals, such as

- Need for additional batteries in the DC-link of the converter-connected DER units for power balance and voltage control during island operation with conventional droop control

- lack of adequate voltage control with Q/U-droops requiring a large amount of reactive power to control voltage in LV networks
- more required capacity from grid-side converters
- lack of feasible protections system compatible with normal LV networks
- synchronized reconnection procedure not possible without communication.

All in all commercial DER units are not currently compliant to the technical requirements present in decentralized microgrid operation. This is only natural because there also doesn't exist any national or international specifications that would define these requirements. In the EU project More Microgrids Schwaegerl et al. have visioned the MGCC as the responsible entity for the maximization in microgrid value, while the MCs perform local optimization in production and transient conditions [17]. In the case of multiple owners of DG units with different needs, an energy cooperative or community with centralized control could provide an alternative to decentralized control with more efficient system-wide resource optimization and system management. A 2014 review of microgrid testbeds around the world by Hossain et al. [19] shows a slight bias toward decentralized control methods, with 29 out of the 50 reviewed testbeds categorized as having either a decentralized or agent-based control system. There are locational differences: North America seems to be especially focused in decentralized systems (15 out of 20 testbeds), while in Japan all 5 testbeds that were categorized had a centralized control system. Microgrids of the European Union and the rest of the world are almost equally distributed between centralized and decentralized control. In future commercial microgrids the adopted market mechanisms, regulation and grid codes will dictate how different parties will operate their available DER resources and what kind of services they can offer [5]. These decisions also have an effect on what kind of control methods will be the most viable and efficient. In the scope of this thesis centralized solutions are of specific interest since communication and therefore related standards are inherently important to the system, though as said decentralized solutions also have some form of central coordination and communication capabilities as well.

2.1.2 Potential benefits and example market models

Microgrid offers potential benefits to the microgrid clients, the distribution system operator, possible third party operators and the public sector. The distribution system operator gets the most benefits from the grid stability, reliability and service related factors of microgrids. Local power balancing and demand side management can be used to reduce local deviations or improve stability, or be offered as a grid supporting service. Reliability can be improved inside the microgrid as well as potentially in the nearby utility network, if microgrid can provide support during disturbances by for example load shedding, resulting in lower outage costs. Distribution system upgrades due to increased peak power conditions can potentially be postponed if these peaks are reduced through active microgrid management. The development of DMS-like functionality in the microgrid management system can also make it possible for the microgrid operator to take responsibility for end distribution and quality of customer supply, with the responsibilities of the DSO ending at the PCC.

For the microgrid clients potential benefits include cost reductions, improved power quality and reliability due to smart local resource management. Microgrids can also promote the shift from consumers to prosumers, enabling clients to acquire and integrate their own production more economically. Proper user interfaces can provide more information about the effects of customer decisions, further promoting activity. Local trading or alternatively aggregation in the microgrid level can also make it possible for individuals to participate in electricity markets in an inexpensive way.

Microgids also offer opportunities for 3rd party operators in whole new roles, like providing the microgrid management and maintenance as a service to microgrid clients, backup power and disturbance workforce to the DSO or acting as an aggregator, collecting the small-scale DER units and demand response resources and offering them as an entity in the electricity markets or as technical services to the DSO, such as frequency or voltage support. Microgrids can help the public sector in achieving national or international energy goals through increased use of renewable energy sources, as well as reducing greenhouse gas emissions thorugh effective demand side management.

Some of the benefits are shared between multiple stakeholders, and naturally the investment costs as well as possible drawbacks in more complicated system usage need to be taken into account when designing a fair market model between different actors in the microgrid environment. In [17] Schwaegerl et al. have identified three typical setups for a microgrid market model: DSO Monopoly, Prosumer Consortium and Free Market. Finnish legislation effectively prevents a DSO owned and operated microgrid through the electricity market act [20], so only the prosumer consortium and free market models are shortly presented here.

In a prosumer consortium microgrid single or multiple consumers will purchase and operate DER units to minimize their electricity bill or maximize sales revenue from export, as shown in Figure 2.3. A consortium of these prosumers may take the responsibility of microgrid operation and purchase it as a service from a third party provider. Most likely motivated by high retail electricity price or DER financial support level, this type of microgrid by nature tends to minimize the import from the distribution grid and therefore reduce the revenue of the DSO [17]. Higher power based pricing might be imposed to cover the network upkeeping costs. DSO can influence the operation of the microgrid by imposing requirements and charges to the DER unit owners, but the consortium makes the operational decisions according to its own optimization goals. A local retail market must be allowed for the internal trading of the consortium.

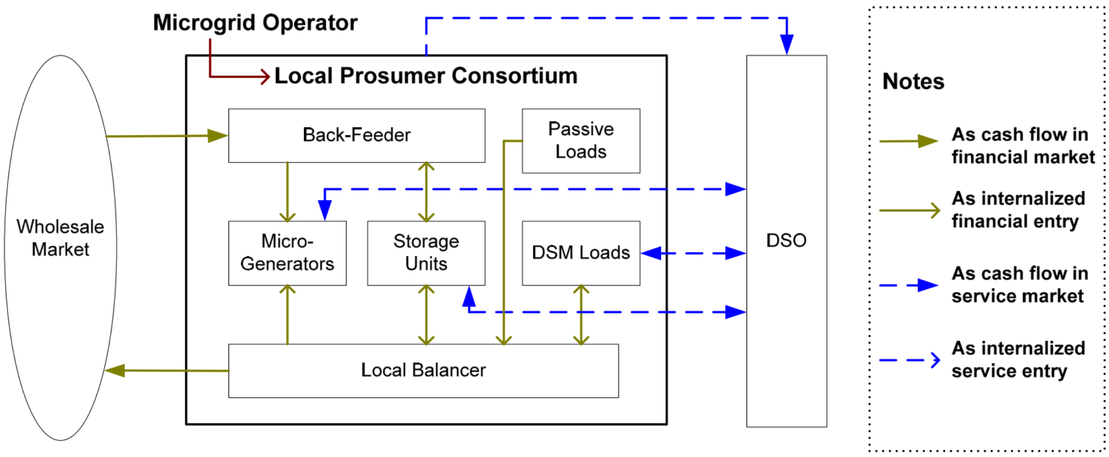

Figure *2.3 The cash flows of the prosumer consortium microgrid market model [17].*

The free market model shown in Figure 2.4 aims at flexibly optimizing various motives of different stakeholders. The daily operation decisions will be dependent on interest arbitration of all involved parties, and the microgrid central controller (MGCC) plays an important role being simultaneously responsible for local balance, import and export control, technical performance maintenance and emission level monitoring. [17] Ideally this allows the benefits of microgrid operation to be split and directed to proper recipients.

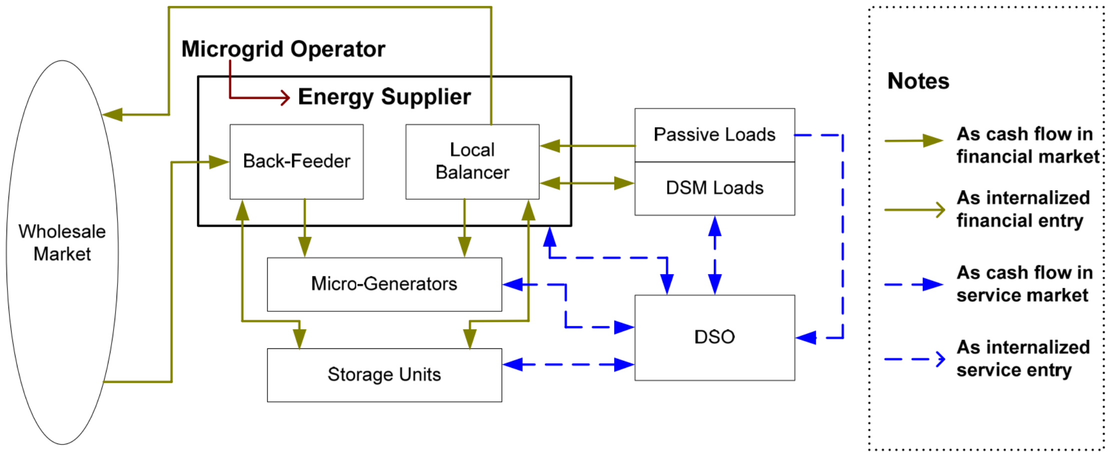

Figure 2.4 *The cash flows of the free market microgrid market model [17].*

2.1.3 Properties and testbed experiences

Traditionally, the frequency response of larger power systems is based on rotating masses of turbines and their governors, primarily found in large generation units, that provide essential natural stability to the system. In microgrids the generation is mainly converter-connected, with very few directly connected rotating masses and thus very low inertia. With the addition of possibly slow control signal response of some DG technologies, this creates power balance and voltage control challenges and makes island operation technically demanding. Because of these reasons energy storages are essential to stabilize the microgrid and permit DG units to run at a stable output despite load or primary energy source fluctuations. [5] The complete frequency control strategy should exploit cooperatively the capabilities of DG units' active power control, response of storage devices, and load shedding [15]. In addition to the technical control challenges, economical goals of different DER operators or things like required heat generation in a CHP unit can cause additional constraints for the usage of DER units.

In smaller microgrids a significant degree of unbalance may exist due to the presence of single phase loads and DER units. Also a considerable part of the supply within a microgrid can come from non-controllable sources such as wind power units or PV cells. [16] The control strategies for DER units must be designed to work in both grid-connected and islanded operation, and offer sufficient regulation of microgrid voltage and frequency during islanded use.

In [12] Soshinskaya et al. have collected experienced problems in real world microgrids, with technical issues divided in technological, dual-mode (island and grid-connected) operation, power and frequency control, and protection and safety issues. Especially fuel cells seem to cause a lot of technological problems, with Utsira Island, Santa Rita Jail and Sendai microgrids all reporting fuel cell related issues. Kythnos microgrid in Greece experienced communication problems in using Wi-fi and PLC channels due to humidity and rise of system frequency, respectively [21]. Concerning dual-mode operation the Bronsbergen microgrid in Netherlands, equipped with two parallel inverter systems, reported islanding detection to be "feasible but not as straigthforward as it would be for a single inverter", underlining the need for further research in the area. Power quality issues were also mentioned, with additional active compensation added in the inverters to reduce high 3rd, 5th and 7th harmonic voltages during islanded mode. [13] The Hachinohe microgrid in Japan reported a 2.6 Hz frequency drop and 6 % voltage drop with 50 kW AC startup, as well as too high negative sequence current caused by phase unbalance. High speed battery inverter control and a negative sequence compensator were used to solve the problems. [22] While technical issues were among the most reported, they have a multitude of potential solutions that already exist or are being researched. Soshinskaya et al. conclude that apart from the short term problem of the expensiveness of DER units, the greatest barriers to microgrid implementation are related to regulation and the market environment: issues regarding bi-directional power flow between the microgrid and utility network as well as the ability of local trading. [12]

2.2 Microgrid islanding and resynchronization principles

Previous sections have introduced typical microgrid structures and their main components, and analysed properties and challenges associated with these new structures. In this section the controllable elements of microgrids are presented, and then special attention is paid to the principles of islanding and resynchronizing procedures of microgrids, since these procedures are the ones with high relevance to the microgrid protection system and the operation of its IEDs. The issues of energy capacity and active power control during islanded operation are highly dependent on the design and implementation of inverter control and therefore not in the focus of this thesis. More on the development of appropriate control methods can be found in e.g. [23], [24] and [25].

2.2.1 Controllable elements in the microgrid

A microgrid acts inherently as a connector and service provider for a wide range of different energy resources, with varying possibilities for control. The distributed generation (DG) in a microgrid can be divided to intermittent and dispatchable units. Intermittent units, using a renewable energy source (RES) such as wind or the sun as their primary energy source, are limited by the physical nature of this source. Their control is preferably based on maximum power point tracking (MPPT), a strategy used to deliver the maximum power according to the optimal operation condition of the unit's primary energy source at each moment [16]. Furthermore, limiting the production of a RES unit is often undesirable because of the proportionally high investment and very low operating costs of these units. Therefore the desired operation strategy for intermittent RES units can be described as "priority dispatch", meaning their production will not be actively curtailed, limited or otherwise controlled by an outside source unless it leads to violation of system constraints, such as line overloads or overvoltage problems. However, the unit can have an independent reactive power interface decoupled from its active power output, in which case it can participate in the reactive power dispatch of the microgrid. [13] In islanded use it may be desirable to limit changes in the active power. Additionally, if the generation capacity is sufficient compared to the load and using the DG unit for active power dispatch allows savings like in the form of smaller energy storages in the system, controlling the output power may be economically beneficial due to the reduced investment costs.

Dispatchable DG units on the other hand allow their output power to be controlled externally, through set points provided by a supervisory control system. Typical example of a dispatchable unit is a synchronous generator driven by a reciprocating internal combustion engine, equipped with a governor for speed control and fuel in-flow adjustment, as well as an automatic voltage regulator (AVR). The governor controls the active power, while AVR controls the internal voltage of the synchronous generator, and through that the reactive power output of the unit. [16] While CHP units are often dispatchable in nature, their controllability varies according to the chosen handling of local heat demand: the unit can be heat-driven, electricity-driven, or operated in a hybrid mode [13].

Distributed Storage (DS) units in the microgrid can be operated as a balancing unit in two principally different ways. In a load-following scheme the storage acts as a balancing unit to load or RES production fluctuations, charging itself during times of low demand and high production and discharging during high demand to reduce the maximum power required. In the price-following paradigm the storage is used to maximize benefits from price differences resulting from these fluctuations over time. The timespan of the balancing operation can vary from short-term (milliseconds to minutes) to long-term (hourly or even daily scale) range. [13] Additionally energy storages may be used for power quality purposes, such as compensating for harmonic or unbalanced current components, regulating voltage, reducing voltage and frequency sags or compensating for transient disturbances in the grid [26].

Controllable loads participating in demand response can have a role similar to storage units, temporarily reducing power usage in the grid instead of increasing power output. While some loads may be deemed as critical and receive service priority in the grid, others classified as nonsensitive can be for example shifted away from the times of peak loads or scheduled according to the generation of intermittent DG units [16]. This shifting can be made attractive to the customer through various remuneration scenarios. Time-of-use (ToU) tariffs offer higher prices for peak times of electricity usage like daytime hours during the workdays and lower prices for off-peak times such as during the night or at weekends. As an example of the relative costs, the Santa Rita Jail microgrid in the USA purchases its electricity under PG&E's E-20 tariff. The tariff has 3 different prices for off-peak, part-peak and max peak times, with energy prices of 7,992, 9,807 and 14,040 c/kWh, respectively. This corresponds to a 22,7% increase for part-peak and 75,7% increase for max peak energy price compared to the off-peak price, creating a strong incentive to push electricity purchases to off-peak times. [27] Other scenarios include dynamic pricing in which the prices fluctuate according to the actual wholesale electricity prices like the hourly Nord Pool spot price in the Nordic countries [28], and critical peak prices that has the same structure as ToU, but with very high prices when wholesale electricity prices are high or the power system reliability is compromised.

The actual control of the loads can be either manual, e.g. controlled by the customer with only price information delivered by the utility, or automated, in which case a contract is made with the customer to allow automatic shifting by control or price signals. [13] While balancing inside the microgrid might be the most convenient use from the microgrid operator's point of view, several customer loads can also be aggregated by a 3rd party operator and offered as a bulk capacity to electricity markets, such as in the pilot project between Fortum and the Finnish TSO Fingrid described in [29].

2.2.2 Islanding

Capability of islanding is one of the defining properties of a microgrid. Transition to island operation can happen either intentionally or unintentionally. Unintentional islanding refers to spontaneous islanding due to a fault in the utility grid, while intentional islanding means a planned and controlled operation mode transition. The key difference is that in intentional islanding the active and reactive power flows between the microgrid and the utility grid are controlled close to zero before the transition, so that a power balance inside the microgrid can be reached. The microgrid management system monitors the transition possibility continuosly: transition is possible if the power unbalance inside the microgrid is smaller than the available control capacity. This capacity consists of the control response of locally controlled DER units, energy storages capable of rapid response, and the available controllable loads in the microgrid provided their disconnection can be executed fast enough. [5] Therefore high-speed communication between the management system and these components or directly between components can make the transition easier.

In an unintentional islanding event, the microgrid can have three operation policies depending on the requirements set by the DSO:

1. Disconnection required: the microgrid is seen as a single generation unit regarding the utility network, and therefore should be disconnected from the network to prevent energized islands in the utility grid, according to the loss-of-mains protection principles of generation units.

2. Disconnection possible: the microgrid operator can decide the action to take, and may for example let the DG unit loss-of-mains protection operate before disconnecting from the utility grid and starting coordinated energizing for island operation.

3. Disconnection prohibited: The microgrid must support the utility network during the fault like normal generation units according to predefined fault ride-through requirements. This would require a specification of power system requirements for microgrids.

If separated, the microgrid is altered to a fault in the utility network for the time before the interconnection switch or breaker at the PCC operates, disconnecting the microgrid from rest of the network. This presents the most challenging islanding scenario because the fault may easily compromise the stability of the microgrid after islanding. Some of the most sensitive components present in microgrids regarding stability issues are synchronous generators, induction motors and generators, and the converters of converter-based DG units. As such their characteristics are of significant interest in the islanding of the microgrid, and will be examined next.

The fundamental equation describing the dynamics of a synchronous generator is the swing equation

$$\frac{2H}{\omega_s}\frac{\mathrm{d}^2\delta(t)}{\mathrm{d}t^2} = p_m(t) - p_e(t) = p_a(t) \tag{2.1}$$

where ω_s is the electrical synchronous speed, H is the inertia constant, i.e. the kinetic energy of the machine at synchronous speed divided by rated power, $\delta(t)$ is the electrical angular displacement of the generator rotor, $p_m(t)$ is the mechanical power input, $p_e(t)$ is the power of the generator's electrical load and $p_a(t)$ is the accelerating power [30]. It can be seen from the equation 2.1 that a momentary unbalance in the mechanical and electrical power ($p_m(t) \neq p_e(t)$) will result in a non-zero accelerating power ($p_a(t) \neq 0$), causing the generator's rotor to accelerate ($\mathrm{d}^2\delta(t)/\,\mathrm{d}t^2 > 0$) or decelerate ($\mathrm{d}^2\delta(t)/\,\mathrm{d}t^2 < 0$). During a fault the electrical power the generator can feed in to the network drops down along with the voltage of the network while the mechanical power remains the same, causing the generator to accelerate. The lower the voltage drops during the fault, the larger the accelerating power will be, and on the other hand the longer the fault lasts the longer this power will accelerate the generator. If the fault is not cleared fast enough, the angular displacement grows too high and the generator loses synchronism with the network, causing a disconnection. It can be seen from the swing equation that a higher inertia constant H with the same accelerating power causes less acceleration or deceleration of the generator rotor, increasing stability. Synchronous generators connected to microgrids can have quite small inertia constants and therefore be sensitive to system disturbances [5].

An induction motor can react to a voltage dip in two ways: 1) stall on the occurrence of a voltage dip and not be able to reaccelerate its load when the supply voltage returns to normal, or 2) initially lose a certain amount of speed, accelerating back to normal operation after the restoration of supply voltage. The factors determining what happens in a specific scenario are largely the same as in the case of synchronous generators, like the magnitude and length of the voltage dip and the motor inertia constant. Additionally transient characteristics and the strength of the electrical system in relation to the size of the motor affect the currents fed to and drawn from the grid during and after fault situations [31]. For induction generators, phase-to-phase faults present the most difficult conditions since it leads to highest overvoltages induced by the stator fluxes [32].

As can be seen, the duration of the fault is one of the critical components in determining whether stability of these components can be maintained. Required fault clearing time depends on the microgrid dynamics, type of DG units connected and sensitivity of customer loads, and sets a minimum requirement for the operating speed of the interconnection switch or breaker at the PCC of the microgrid. Instead of a faster operating interconnection switch, another option would be to reduce the voltage dip magnitude with for example an energy storage based power quality compensator at the PCC, or even use a combination of both methods for very sensitive customers [5].

Converters of converter-based DG units may potentially experience many kinds of malfunctions during a fault. If their control is based on constant power control, a sudden decrease in grid voltage will cause an increase in the current of a voltage source converter (VSC) based DG unit. This may lead to the tripping of overcurrent protection used to protect the insulated gate bipolar transistors (IGBTs) of the VSC. Unbalanced voltage dips can produce both current harmonics and current unbalance, which may also trigger an operation of current protection. An unbalanced fault causes a negative-sequence component in the grid voltages, which gives rise to second harmonic ripple in the system. This can be seen as ripple of the DC-link voltage and output power and can lead to a trip if the maximum DC-link voltage is exceeded. Additionally the second harmonic ripple propagates into the DG unit converter controller and can cause poor power quality by producing a non-sinusoidal current reference, even potentially leading to a system trip. Technical solutions to deal with the problems mentioned above have been developed, such as VSC controllers capable of dealing with grid voltage unbalance and improved phase locked loop (PLL) algorithms to handle problems caused by second harmonic ripple. [5]

2.2.3 Resynchronization to the utility grid

The transition from island operation back to grid connected mode should also be smooth and transient free so that loads do not experience disturbances during the transition, and for this a robust grid synchronization scheme is needed [33]. Generally, before closing a circuit breaker with both sides of the connection energized, synchrocheck relays are used to ensure sufficient synchronism between the two sides. This means the voltage magnitude, voltage phase angle and frequency differences between both sides must be under set values and both voltage magnitudes over set minimums. [30] Ensuring small enough rate of change of frequencies and voltages is also commonplace. Traditionally, voltage regulation of passively managed distribution networks is based on transformer on-load-tap-changers of HV/MV substations and off-load tap changers of MV/LV substations. However, the resynchronization of a microgrid requires ability to control the voltage in the islanded microgrid, and differs in many aspects from traditional synchronization of separate HV power systems with large directly connected synchronous generators. To examine differences in the underlying control mechanisms, consider a power line in Figure 2.5.

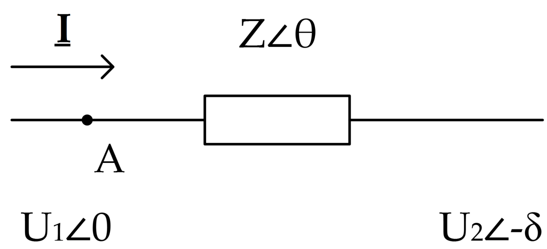

Figure 2.5 *Model of a short power line.*

The power flow at point A is

$$\underline{S} = \underline{U}_1 \underline{I}^* = \underline{U}_1 (\frac{\underline{U}_1 - \underline{U}_2}{\underline{Z}})^* = U_1 (\frac{U_1 - U_2\underline{/\delta}}{Z\underline{/-\theta}}) = \frac{U_1^2}{Z}\underline{/\theta} - \frac{U_1 U_2}{Z}\underline{/\theta + \delta} \tag{2.2}$$

where U_1 is the voltage at the beginning of the line, U_2 the voltage at the end of the line, δ the load angle and $Z\underline{/\theta}$ the line impedance. Rewriting 2.2 with $Z\underline{/\theta} = R + jX$ we get

$$\begin{aligned}\underline{S} = & \frac{U_1}{R^2 + X^2}[R \cdot (U_1 - U_2 \cos \delta) + X \cdot U_2 \sin \delta] \\ & + j\frac{U_1}{R^2 + X^2}[-R \cdot U_2 \sin \delta + X \cdot (U_1 - U_2 \cos \delta)]\end{aligned} \tag{2.3}$$

where R is the line resistance and X is the line reactance. Since $\underline{S} = P + jQ$, seperating to real and imaginary parts we get the active and reactive power:

$$P = \frac{U_1}{R^2 + X^2}[R \cdot (U_1 - U_2 \cos \delta) + X \cdot U_2 \cdot \sin \delta] \tag{2.4}$$

$$Q = \frac{U_1}{R^2 + X^2}[-R \cdot U_2 \cdot \sin \delta + X \cdot (U_1 - U_2 \cdot \cos \delta)]. \tag{2.5}$$

For typical HV overhead lines, $X >> R$. By neglecting resistance R and assuming the load angle δ to be small, it can be approximated that $\sin \delta \approx \delta$ and $\cos \delta \approx 1$ and equations 2.4 and 2.5 can be reduced to

$$P \approx \frac{U_1 U_2}{X} \delta \tag{2.6}$$

$$Q \approx \frac{U_1^2}{X} - \frac{U_1 U_2}{X} \tag{2.7}$$

From equations 2.6 and 2.7 it can be seen that with HV lines the active power P and the load angle δ and thus the frequency f are related, while the reactive power Q and the voltage difference $U_1 - U_2$ are related. By adjusting P and Q independently the frequency and voltage of the network can be controlled. This is the basis of so called conventional droop control, where linear approximations for the P/f and Q/U dependencies are used to control the active and reactive power outputs of the generators in the grid:

$$f - f_0 = -k_p(P - P_0) \tag{2.8}$$

$$U_1 - U_0 = -k_q(Q - Q_0) \tag{2.9}$$

where f_0 and U_0 are the rated frequency and grid voltage, P_0 and Q_0 are the given setpoints for active and reactive power and k_p and k_q are the droop coefficients of active and reactive power [34]. Typical LV overhead lines, on the other hand, are dominantly resistive so that $R >> X$. In this case, neglecting the reactance X and with the same assumption of the load angle being small, we get

$$P \approx \frac{U_1^2}{R} - \frac{U_1 U_2}{R} \tag{2.10}$$

$$Q \approx -\frac{U_1 U_2}{R}\delta \tag{2.11}$$

So in the case of a LV network, the dependencies are inverted: load angle δ and frequency f are associated with reactive power Q, while active power P depends mainly on the voltage difference $U_1 - U_2$. This would suggest the use of so called opposite droops, i.e. P/U- and Q/f-droops in voltage and frequency control. While P/U droop control would offer direct voltage control, Engler states in [35] that using opposite droops wouldn't make active power dispatch possible, and would lead to compatibility problems with directly connected generators and higher voltage levels. On the other hand, conventional droops are operable in the LV network DER inverters through the indirect operation of droops. The inverter power is adjusted by changing the inverter voltage with the reactive power Q, and because Q is a function of the angle δ and δ is the integral over time of the generator's frequency difference with the grid, a P/f- and Q/U-droop control can be established at the cost of needing extra reactive power [35]. However, it is questionable if adequate reactive power resources are available at LV level, and decentralized conventional droop control without communication has its own technical challenges as well, as discussed in 2.1.1.

An island operated microgrid may be in synchronism with the utility grid right after islanding, but as load and production changes in both the microgrid and utility grid, the phase angle difference across the interconnection switch at the PCC will change, and needs to be minimized before reconnection [5]. The standard IEEE 1547 "Standard for Interconnecting Distributed Resources with Electric Power Systems" requires that the phase difference across the interconnection switch must be less than 20° before the switch can close. However, Eto et al. conclude in tests conducted at the CERTS Microgrid Test Bed near Columbus, Ohio, that even stricter requirements are needed, suggesting closing "at a zero-phase difference". [36] Laaksonen and Kauhaniemi state in [37] that with only converter connected DG units phase angle differences as large as slightly over 60° can be acceptable depending on the implementation of the DG control system. This is due to the phase locked loop (PLL) component of the DG unit converter drawing the converter to phase with the utility grid frequency after reconnection [38]. However, in the case of directly connected synchronous generators even a phase difference of 22° resulted in large oscillations after reconnection, and a phase difference less than 10° was recommended. Closing at a larger phase difference can also strain the turbines and gearboxes potentially present in i.e. hydro and wind power plants.

As stated most of the DER units will be connected to the microgrid via power electronic interfaces and the resynchronization can potentially be done through the control of these units. The strategy used will depend on the chosen control concept of the microgrid: centralized control with one master unit or decentralized control of DER units through droop control. In a master unit configuration, one inverter such as a central energy storage is chosen as a master unit giving voltage reference to other active and reactive power (PQ) controlled DER units. In this case a resynchronization method such as proposed by Arulampalam et al. in [39] could be used where the PLL output angle θ is used in the energy storage controller to regulate the set reference system frequency and thus over time minimize the phase difference to acceptable limits. With P/f-droop controlled DER units all DER unit converters must be coordinated by a supervisory controller, using a method like shifting droop control presented by Qiang et al. in [40]. In order to vary the island frequency and thus the phase difference, preset droop curves are shifted to change the operating frequency and voltage without changing the active or reactive power sharing between sources. The change in actual frequency is determined by the shifting offset value provided by the central controller, and thus communication is required for the resynchronization. The Q/f-dependency of LV networks discussed earlier can also provide an alternative way to control the phase difference during resynchronization by coordinated reactive power set point changes of the DER units [38]. In [38] Laaksonen and Kauhaniemi also raise the possible issue of voltage unbalance in the microgrid due to load asymmetry and single-phase DER units, leading to phase difference deviation between each individual phase during resynchronization. In their simulations controllable 1-phase loads were used to reduce the asymmetry, and potential practical implementations of 1-phase DG units, energy storages or controllable loads coordinated by the microgrid management system were suggested.

3. MICROGRID PROTECTION

In general, power system protection is responsible for detecting and isolating occurring faults or abnormal conditions in the network, protecting humans, animals and electrical equipment from potential damage. The power system is divided into protection zones, containing devices, typically circuit breakers, capable of isolating that particular part from the rest of the grid. These devices are controlled by the protection system consisting of protection relays, instrument transformers, and all the associated wiring, communication and automation. Main requirements for the protection system can be categorized as selectivity, speed and reliability.

Selectivity means that 1) only the faulty part of the network shall be isolated, thus minimizing the harm caused by the fault, and 2) every part of the network is protected by at least one protection device. [30] Selectivity can be based on time delays coordinated between protection relays, or be implemented by defining appropriate operation curves for protection devices and their functions. Operation curves define the time delay between relay pick-up and sending of the trip command as a function of the measured quantity, enabling both selectivity in faults far away and fast fault clearance in nearby faults. For example an inverse-time over-current relay trips faster with higher fault currents. Figure 3.1 presents different operation curves for such a relay as defined in the standard IEC 60255, with I_S being the chosen pickup current. Operation speed of the protection system is very important in minimizing the negative effects caused by a fault.

Lastly, reliability of the protection system consists of two requirements. Security of protection ensures a relay does not send a tripping signal if there is no fault in its protection zone, i.e. there is no false operation. Dependability of protection means that the protection relay shall detect all the faults in its protection zone, i.e. the protection system must operate in all abnormal conditions. [30] A common practice is to also ensure redundancy of protection functions, so that a fault is isolated even if the associated main protection device fails to operate, conforming to the N-1

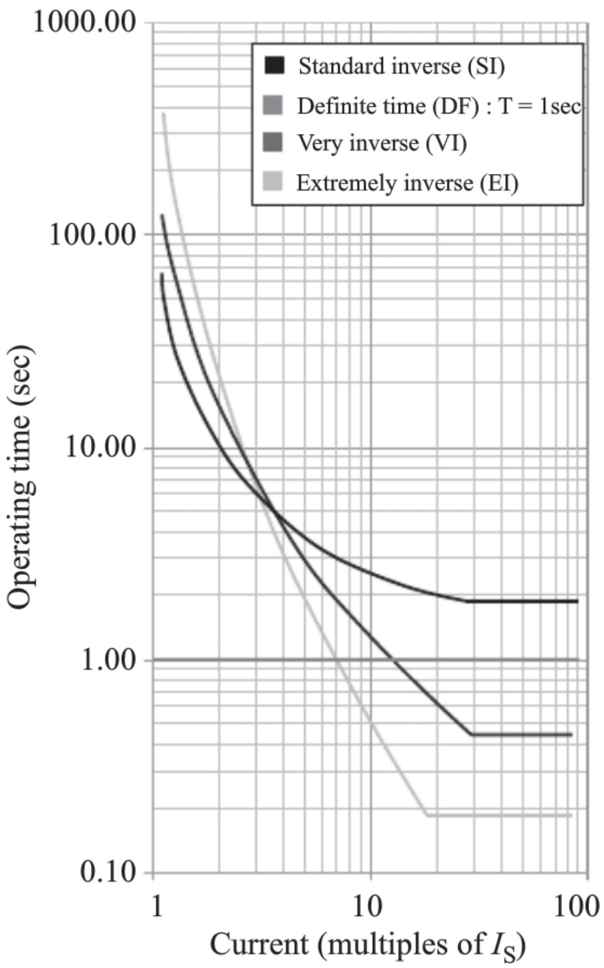

Figure 3.1 *IEC overcurrent relay operation curves according to IEC 60255 [41].*

criterion [30, 41, 42].

An example of a microgrid protection system based on [25] is shown in Figure 3.2. The microgrid central controller (MGCC) as a central entity is responsible for coordinating protection settings and communication based protection schemes between IEDs. It can also provide set points for voltage, frequency and active and reactive power outputs of DER units in the microgrid. In the case of a LV microgrid, it is questionable whether sectionalizing individual LV feeders to more than one protection zone, such as in the figure with CB6 and CB7, is justifiable with the amount of faults in the LV network and associated outage costs [37]. Otherwise the example system gives an overview of typically available control equipment and entities regarding microgrid protection.

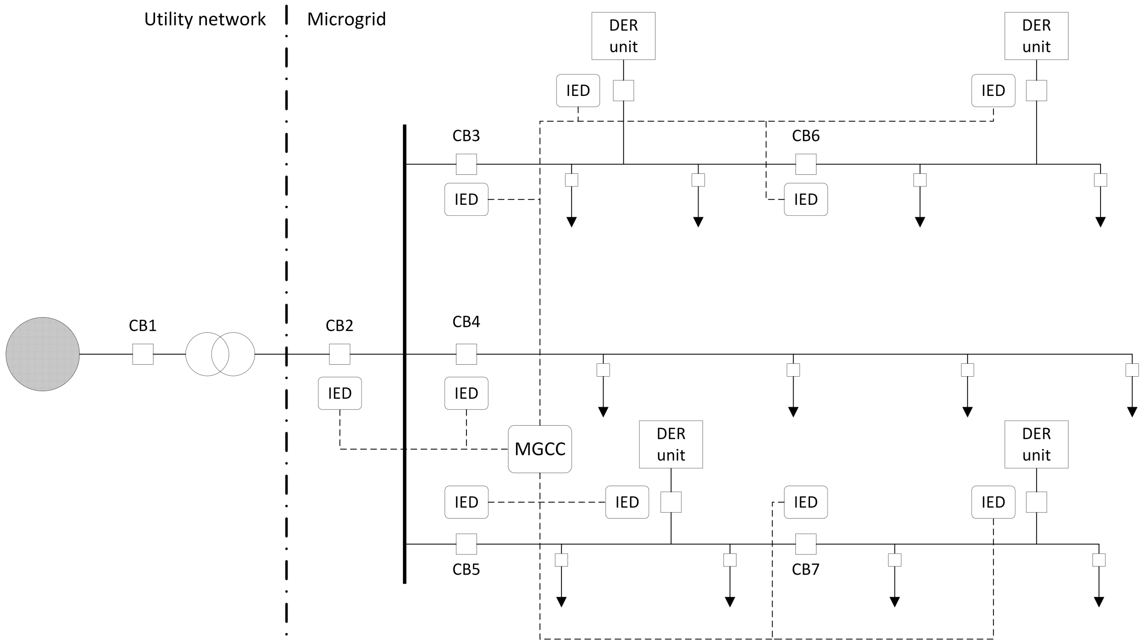

Figure 3.2 *An example of a microgrid protection system.*

The protection of microgrids has to solve two major issues in its design. Firstly, the conditions and operation times for islanding during possible faults in grid-connected mode must be examined. From operation point of view, maintaining the connection between the microgrid and the utility is highly desirable, but when islanding is mandatory, the operation speed must be sufficient to maintain stability of the microgrid after islanding as discussed in Section 2.2.2. Secondly, the stand-alone microgrid itself must be divided to protection zones with coordinated fault protection that ensures sufficient selectivity and prevents unwanted operations, such as unnecessary disconnections of DER units. [25]

The definition of "sufficient selectivity" varies largely according to the size and voltage level of a microgrid as well as chosen protection principles. It can be argued that a fault inside a microgrid after separation from the utility grid is an N-2 contingency, and the island can therefore be shut down without selectivity. If the microgrid contains enough critical loads or covers a large area, the added cost of coordinating protection zones inside the microgrid can be justifiable. In this chapter protection schemes are reviewed regarding their technical capabilities and ability to support selective operation also in internal faults of the microgrid after islanding. First, the main protection issues regarding microgrids are presented. Next, possible non-adaptive protection schemes are examined, and then special attention is paid to the principles of adaptive protection, which has been widely presented as an important or even a necessarily required part of microgrid and active distribution grid protection [42–47]. Lastly one complete protection solution for a LV microgrid is presented as an example of possible merging of different protection methods.

3.1 Protection issues of microgrids

Due to the differences discussed in chapter 2 between microgrids and conventional utility distribution networks in topologies and power system components as well as operation principles, the protection of microgrids has several issues that need to be addressed by its protection system. Some of the presented aspects such as effects of DER penetration are also present in modern distribution networks, and some such as islanding issues are unique to microgrids.

3.1.1 Effects of DER units on conventional protection

Conventional protection in distribution networks is based on over-current (OC) relays and, in LV networks, fuse protection [13]. The selectivity of the protection system is achieved by time or current coordination principles. These methods are designed for radial networks with unidirectional power flow. However, the presence of distributed generation in a network alters the magnitudes and possibly the directions of fault currents in the network and therefore the traditional coordination is either adversely affected or even completely lost. The potential problems for traditional feeder protection that can be caused by distributed generation include

- False tripping: the DG unit feeds current to a fault on a nearby feeder through a station busbar, causing false tripping of the feeder it is connected to if non-directional OC protection is used.
- Blinding of protection: the DG unit feeds current to the fault at the feeder and lowers the amount of fault current fed through the feeder protection device, preventing the operation of feeder protection. To a definite-time OC relay this corresponds to shortening the protection zone of the device, and to an inverse-time OC relay a change in the operation curve of the relay.
- Prevention of automatic reclosing: The DG unit maintains the voltage during automatic reclosing function of feeder protection, maintaining the arc at fault

location. Related to this, the reclosing function may cause the DG unit to be connected to the utility network out of synchronism if the DG unit is not disconnected during the dead time of the autoreclosing function.

The contribution of DG units to faults depend largely on the type of the unit. Synchronous generators feed larger and stable fault currents, and while this may contribute to malfunctions of protection such as mentioned above, it is clearly detectable. But as discussed in Section 2.1.1, DER units with power electronic interfaces are becoming more and more prevalent at the distribution level, and these units behave very differently from traditional generation. Different inverter designs also have different constants and there is no uniform characteristic that could represent inverters as a class of equipment [25]. One of the biggest differences is that unless specifically designed to provide a high fault current, inverter-based units have very low fault feed-in capacity that can be in the order of 2-3 times the load current or possibly even less [46]. In the case of microgrids with significant amount of power electronic interfaced DER units this may present a complete change of system behaviour between grid-connected and islanded mode considering fault situations. In grid-connected mode, large fault currents can be available from utility network, but during island operation OC protection with the same settings may operate too slowly, lose selectivity or even not operate at all [25]. If relay operation is to be ensured by setting changes, the reduced difference between the highest load current and lowest fault current can lead to nuisance tripping of protection.

3.1.2 Changing grid configurations, islanding and speed requirements

In addition to the new challenges the characteristics of DER units bring, an extra issue is that the presence of these units may vary according to several different possible optimization goals of the unit operator or due to the availability of the primary energy source. This forces the protection system to take into account all possible different configurations the microgrid can have, and for example depending on the topology as well as type and location of the DER units, may mean the direction of fault currents can change between different configurations.

The speed requirements for microgrid protection are defined by two main criteria: stability and customer sensitivity [48]. Stability has been formally defined by a joint task force of IEEE and CIGRE in 2004 as "the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact." [49] It is worth noting that the definition examines the whole system: if one generation unit disconnects after losing stability due to a disturbance, the rest of the system can still maintain stability. In the case of a microgrid the most challenging situations are the transient conditions following islanding from the utility grid and a fault occurring in the microgrid during island operation. Especially directly connected rotating machines are very sensitive to losing stability due to voltage dips caused by faults, and can further jeopardize the stability of the whole microgrid. The stability of different microgrid components was discussed in more detail in Section 2.2.2.

Due to utility side faults often presenting very challenging conditions, it is essential to ensure that especially the protection at the PCC will operate fast enough to minimize the fault and voltage-dip duration. Structural choices affecting the operation time include the chosen switch technology, communication technology and the size of distributed or central energy storages in the microgrid. [48] In addition to traditional circuit breakers (CBs) operating in the time scale of 20 to 100 ms, static switches (SSs) based on silicon controlled rectifiers (SCRs) or even insulated gate bipolar transistors (IGBTs) could be used to achieve operation times in the range of 5-20 ms or 100 µs, respectively [50]. If a protection scheme is based on communication between devices, the chosen communication technology naturally adds its own total delay to the operation time of the protection devices. The size of energy storages in the microgrid affect the needed operation speed indirectly by two ways: mainly, with larger storage it is possible to withstand larger oscillations without losing system stability during islanding, and secondly it may also increase the fault-current feeding capability of the microgrid in islanded mode, thus possibly making protection like customer fuses operate faster [48].

While the speed of protection is especially important in faults where microgrid has to be separated from utility network, it is also important to pay attention to preventing spurious separations, i.e. false trips at the PCC. Voltage and frequency protection are necessary functions at the PCC, but using only local information for them may not always be enough to determine whether the fault is on the utility feeder or within the microgrid itself [25], potentially leading to incorrect operation. Another issue is the settings of voltage unbalance protection, since a certain degree of unbalance is already present in normal operations and for more severe conditions it may again be difficult to determine if the cause is external or internal in the microgrid. Exporting microgrids have additional problems since over- and undervoltage relaying may not be enough to ensure the detection of utility faults when the microgrid itself can have enough generation capacity to maintain voltage during faults [25]. Furthermore, it is possible to have non-fault cases resulting in low voltages at the PCC such as voltage unbalances and non-fault open phases which are difficult to detect. In [46] Memon and Kauhaniemi state that currently the only reliable method in achieving both fast tripping of the PCC breaker as well as avoiding spurious separations is to have a transfer trip signal from the utility substation breaker upstream of the PCC, requiring high speed communication. The consequences of spurious separations depend on the operational capabilites of the microgrid, and a cost-benefit analysis is needed for assessing the justification of expenses on more sophisticated protection versus the increased reliability it brings.

In islanded mode, an essential issue that must be solved is the potential loss of neutral connection of the utility transformer if the PCC breaker is located downstream from the transformer. Unless another delta-wye transformer with the microgrid side directly earthed is present in the island, high earth fault currents cannot be ensured. [37] Similarly in centrally compensated MV networks earth fault current compensation can be lost, affecting the fault currents and protection requirements during earth faults.

3.1.3 FRT requirements and anti-islanding protection of DER units

The protection requirements of DER units in the microgrid are dictated by country grid codes but also the operation of other protection devices in the microgrid. The operation curves of different devices define the fault ride-through (FRT) requirements for DER units, i.e. the operation limits in which the unit should still operate normally without disconnection. For example DER units need to have the capability to cope with the voltage and frequency transients caused by islanding, since disconnection during islanding would further jeopardize the stability of the microgrid. Similarly in a microgrid consisting of several feeders the unit shouldn't disconnect on a fault on a nearby feeder before the feeder protection of the faulted feeder operates. Another issue is the anti-islanding or Loss-of-Mains (LoM) protection of DER units. Traditionally these smaller units rely on the main power system for stability, neutral earthing and reliable fault currents, so protection is fitted to detect situations where the connection to main power system is lost. However, in the case of a microgrid, islanding can happen intentionally at the PCC. This poses a possible conflict between utility requirements or grid codes and the desired microgrid operational capabilities. The anti-islanding protection may therefore be needed to be disabled along with the islanding of the microgrid if the amount of microsource generation within the microgrid is high [25]. Due to the typically high speed operation of anti-islanding protection, it might be needed to be deactivated instantly after islanding to prevent the fast tripping.

Another possible issue regarding earthing is if the DG units are connected to the microgrid via a delta-wye transformer where the generator side neutral point is directly earthed. This connection causes inability to detect an earth fault from the generator side, since the zero-sequence network is disconnected at the transformer and no earth fault current is fed from the generator. Possible solutions include either installing a residual voltage relay at the grid side of the DG unit or disconnection of the unit after feeder protection has already operated. Safety aspects require a fast disconnection of the unit, but on the other hand the installed relay can detect earth faults independent of their location in the network, creating a possibility of unnecessary separations. [51]

3.2 Available non-adaptive protection schemes

A variety of protection schemes has been proposed to be used in microgrids. Some schemes are designed for grid-connected operation, corresponding to protection of modern distribution networks with a high penetration of DER, some are designed specifically to address the issues of islanded mode, and some are applicable to both operation modes. In this section an overview of proposed schemes using principles applicable without adaptivity is presented. In this context non-adaptive means the protection response of the protection system is not modified according to power system conditions. Schemes based on adaptivity are discussed in their own Section 3.3.

It should be noted that some form of adaptivity can and is even often proposed to be added to presented methods in some form, and can possibly be used to overcome some of the disadvantages of said methods. In any case, it is very probable that a complete solution of microgrid protection incorporates and combines several different protection schemes. A summary of proposed microgrid protection schemes is presented in Table 3.1. High impedance faults (HIF) mentioned in the table do not have a strict impedance limit or definition, but they can be described as faults in which the fault impedance is high enough that detection by conventional fault current magnitude measurements is generally not possible [52]. Of the presented schemes voltage and THD based protection as well as distance and differential protection are examined in more detail in this section. While cost-benefit analysis is not in the scope of this thesis, it should be noted that sophisticated protection schemes often come with a very high implementation cost compared to current systems, especially if LV networks are considered. Currently it requires a high criticality of loads and a very specific environment, such as the protection of a data center, to be able to justify such a system.

3.2.1 Voltage based protection

A voltage based protection scheme for microgrids with converter based DGs was presented in 2006 by Al-Nasseri and Redfern in [54]. The scheme is based on measuring the DG output voltages and converting them to DC quantities in the synchronous rotating d-q frame of reference based on the dq0 or Park transformation [62]. Network faults can then be detected as a disturbance in the d-q quantities. A disturbance signal V_{DIST} is calculated and then filtered by comparing calculated and reference three-phase balanced d-q values. Under normal conditions calculated values match the reference values, and the value of V_{DIST} is zero. In case of a fault, the disturbance voltage exhibits different behaviours according to the type of the fault:

- in a three-phase fault, V_{DIST} is pure DC voltage.
- in a two-phase fault, V_{DIST} consists of a DC signal with ac ripple.
- in a single-phase fault, V_{DIST} is an oscillating signal between zero and a maximum value.

Therefore it is possible to recognize the type of fault. The scheme uses a communication link between relays for comparing the mean average values of V_{DIST} and uses this information to identify in-zone and out of zone faults and tripping the appropriate relay. The scheme has been verified by simulations of different faults

Table 3.1 Non-adaptive microgrid protection schemes

	Principle of fault detection	**Advantages/ disadvantages** [46, 53]
Voltage-based protection [54]	Disturbance in the d-q transformation of DER terminal voltages	+ applicable with low fault currents, verified with simulations for various fault types and locations − HIF and single-pole tripping not taken to account
THD-based protection [55]	Raised THD level of DER terminal voltages	+ applicable with low fault currents − possible trip failures with dynamic loads − determining THD thresholds for different fault types may prove difficult
Distance protection [56]	Impedance calculation from fault current and voltage at relay location	+ applicable to all network topologies − DG units in protection zone cause errors without adaptivity
Differential current protection [57]	Comparison of current samples on opposite ends of protected part of the system	+ detects HIF, comprehensive simulations − uneconomical, assumes very high performance of equipment, transient conditions may pose problems
Symmetrical components and residual current based protection [58]	Residual and zero sequence current measurements	+ no communication needed − need for overload and voltage backup protection − considers only two-phase short-circuit and single-phase earth faults
Inverse-time admittance-based protection [59]	Comparison of line admittance measurement to normalized admittance value	+ no communication needed, applicable with low fault currents − slow tripping for HIF and higher DG infeed, measurement errors from harmonics, transients and decaying DC components
Current traveling waves based protection [60]	Busbar residual voltage for fault detection and comparison of wavelet transform of zero-sequence current traveling waves for fault location	+ unaffected by power flow, fault current, unbalance, connection of DG units and microgrid operational mode − no simulation results
Pattern recognition based protection [61]	Differential energies from time-frequency transform of opposite bus currents used to register fault patterns and threshold values for tripping	+ better performance compared to differential current protection, immune to noise, less sensitive to synchronisation error

at different locations of a test microgrid system and is proposed to provide complimentary protection to conventional OC relaying in low fault current situations [54]. Voltage sags are taken into account by tolerating voltage magnitudes of 50 % for 200 ms, 70 % for 0,5 s and 80 % for up to 1 s. Despite this Mirsaeidi et al. argue in [53] that voltage drops within the microgrid may still lead to misoperations. In the end, FRT requirements defined for the system set the limits needed for voltage sag tolerance and define correct operation. Other shortcomings mentioned include inability to detect high impedance faults (HIF) and a strong dependency on the microgrid configuration combined with test results only for a specific microgrid. In their review of AC microgrid protection solutions, Memon and Kauhaniemi note that high impedance faults (HIF) as well as single-pole tripping haven't been taken to account [46].

3.2.2 THD based protection

Same authors have also proposed a harmonics content based protection scheme in [55]. The protection is based on computing the discrete Fourier transform (DFT) and thus monitoring the total harmonic distortion (THD) of the inverter terminal phase voltages at each DG unit, causing a disconnection if the THD exceeds the set pick-up value. In normal operation, the utility distribution network acts as a low impedance, stiff voltage source maintaining a low THD of voltage at the inverter terminal. When the microgrid transitions to islanded mode, the impedance seen at the terminal increases as only local network and loads remains connected and as a result, current harmonics at inverter output will cause increased level of voltage harmonics in the terminal voltage [55]. The proposed scheme consists of two stages. Firstly, the amplitude of the fundamental frequency of each phase is used to identify the fault type. According to simulation results presented the amplitude of the fundamental frequency will drop significantly for a faulted phase compared to healthy phases, and thus this comparison allows to identify between single phase, phase to phase and three phase faults. In the second stage the faulted phase is identified by comparing THD values of all phases, since the harmonic content of the faulted phase will be much greater than that of a healthy phase. Furthermore, a communication link is necessary to share the THD values between the relays at DGs to coordinate tripping: the relay with higher total harmonic content of all phases is recognized to be in or nearer to the fault zone and should be tripped. Simulation results presented are for two identical converter based DGs, with the authors noting that "in the case when the two DGs are different theoretically the idea should be still valid" unless one of the DGs has zero harmonics distortion, in which case another type of protection would have to be used. It is also recognized that several dynamic loads present in the microgrid may cause trip failures, and the scheme is proposed as complementary or backup for the main protection devices [55]. In [46], Memon and Kauhaniemi also mention difficulty of assessing THD threshold values for different fault types as well as sensitivity problems with varying fault impedances as possible limitations for the technique.

3.2.3 Differential protection

Sortomme et al. have described a protection scheme based on differential protection in [57]. The scheme uses digital relays including standard OC and over-/undervoltage protection. Primary protection is based on differential current protection with a minimum of 16 current samples per cycle transmitted via a communication link and then compared between relays on the opposite ends of distribution feeder. Instantaneous operation is suggested when absolute values of two samples are above the trip treshold, and a backup trip signal to be sent to adjacent relays of the same bus in the case of a switching device failure if the differential current remains for longer than an allowed time delay in the range of 0.3-0.6 s. Further backup protection for communication link or relay failures is suggested by switching to comparative voltage protection on remaining relays and tripping under 0.7 pu voltages in 0.6-0.9 s for the relay with the lowest voltage, and in 1 s for each DG source in the system. A comprehensive simulation of a test system has been conducted for all fault locations and high impedance single-phase earth-faults in addition to regular fault types. It is noted the scheme wouldn't be economically justifiable because of the amount of relays and switching devices. In literature reviews, both Memon and Kauhaniemi in [46] as well as Gopalan et al. in [63] note that in addition to being expensive the scheme assumes beyond state-of-the-art technical features of equipment such as highly sensitive and error-free current transformers (CTs). Furthermore Mirsaeidi et al. note in [53] that unbalanced systems and transients during connection and disconnection of DG units may pose problems to differential protection schemes. In [64] Sortomme et al. have presented a relay and sensor placement optimization algorithm to minimize the equipment costs and system outages, reported to result in savings of 50 % in relay and sensor costs compared to the scheme in [57] for the example microgrid.

3.2.4 Distance protection

Distance protection is based on measuring the impedance between a relay and the fault location by comparing fault current seen by the relay against the voltage at relay location. Comparing this impedance $Z_f = U/I_f$ to the known impedance of the protected line the fault can be located and tripping characteristics specified for desired reach along the line, i.e. values of Z_f. It is usual to define several time-coordinated protection zones for different reaches as percentage of line impedance to achieve backup protection and selectivity between distance relays, as demonstrated in Figure 3.3. [41]

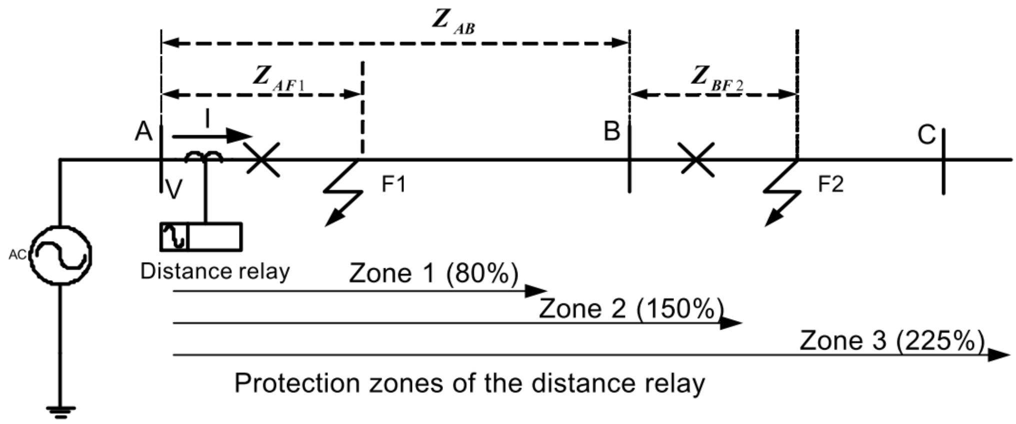

Figure 3.3 *Distance protection zones [65].*

The natural benefits of distance protection include applicability in ring and meshed configurations as well as independence from the current source impedance. The use of distance protection in MV microgrids and networks with DG penetration has been investigated by Voima et al. in [56] and [66]. In [56] the applicability of distance protection with no DG units between the relay and fault location was investigated by simulations. Under this restriction the accuracy was deemed sufficient for the test network topology, but authors noted further studies are required for different topologies and fault types. In [66], it is noted that connection of DG units in the protection zone causes an impedance measurement error proportional to the ratio of current at relay location and the in-feed current of the DG unit. The proposed solution to this problem includes telecommunications and adaptivity, and is discussed in the next section.

3.3 Adaptive protection

As discussed in 3.1.2, the protection system in microgrids has to take into account the possible configuration changes in the microgrid. These include the connection and disconnection of DER units each with their own characteristics, reconfiguration of the network after fault clearance, and transitions between islanded and grid-connected modes. To solve this problem, the methodology of *adaptive protection* has been adopted to microgrids. Adaptive protection can be defined as "an online activity that modifies the preferred protective response to a change in system conditions or requirements ... in a timely manner by means of externally generated signals or control action" [67]. In the case of a microgrid, an adaptive protection system identifies changes in microgrid configuration or DER connections and accordingly changes settings of protective relays as needed to ensure the protection requirements are fulfilled. This can mean adjusting the settings of the applied protection functions but may also include enabling or disabling different protection functions. Modern numerical relays can have several pre-configured settings groups, each corresponding to a different microgrid configuration, that can be enabled remotely. Instead of pre-calculated settings groups, it might be even possible to recalculate the protection settings in real-time, as demonstrated in [42].

This section first discusses the communication needs of an adaptive protection system, and then examines adaptive methods suggested to be incorporated to OC and distance protection as examples of possible implementations. Voima, Laaksonen and Kauhaniemi have compared the performance of directional overcurrent and distance protection in [47], noting distance protection performs better during island operation but is limited in its applicable use cases. While directional OC protection suffers from the changes in short circuit levels in islanded operation, distance protection can be adversely affected by an intermediate in-feed of DER unit in the distance protection zone, as mentioned in 3.2.4. Both of these schemes may be potentially enhanced with adaptivity. As stated earlier, adaptivity can very well be incorporated to other protection schemes as well with methodology similar to what is presented.

3.3.1 Communication requirements

A few protection schemes have been proposed where some form of adaptivity is achieved without the use of a communication network between protective devices.

In [68] Tumilty et al. propose a voltage restrained overcurrent protection scheme for inverter dominated distribution systems: a large drop in voltage causes OC protection to select a lower current threshold, moving the operation curve and reducing tripping times. The intended use is to discriminate between short-circuit and overload conditions and adjust operation speed accordingly. In [69] Dang et al. have proposed an adaptive protection scheme in a microgrid containing an energy storage connected with an isolation transformer. The scheme uses the earthings of said transformer and the utility MV/LV transformer to discriminate between grid-connected and islanded modes. The angle of measured zero sequence impedance $Z\underline{/\theta}$ at a protection device is compared to the zero sequence impedance angles θ_{T1} and θ_{T2} corresponding to configurations with the different transformers. Then a protection method is chosen based on this information, using overcurrent protection for grid-connected operation and voltage protection scheme as described in 3.2.1 for islanded mode. However, applicability of these schemes is rather marginal and the definite majority of adaptive protection schemes raise the ability for communication as a key property of the system.

In general communication with a central system such as the MGCC or between individual protection devices is seen necessary to facilitate the identification of grid configuration changes and the changing of setting groups, and using standard-based communication ensures reliable interoperability of devices. If basic backup protection exists during the reconfiguration phase (according to the N-1 principle), communication delays for setting changes are not critical and delay times in the order of 1-10 s can be tolerable [70]. It should be noted that this is far from the requirements of actual protection functions such as interlocking, which are time-critical. For example the IEC 61850 series discussed in Chapter 4 defines three performance classes for protection function messages with required transfer times in the range of 5-20 ms [71]. Naturally a communication system capable of this level of performance will be significantly more costly compared to one operating in the 1-10 s time range. One case where fast communication might still be necessary is the anti-islanding protection of DER units discussed in Section 3.1.3, in which either the islanding must be locally detected reliably and fastly or a communication signal must be used to disable the fast anti-islanding protection from tripping after intentional islanding. These fast communication based protection functions may also be necessary if selectivity is to be ensured in all microgrid faults [47, 48].

With the introduction of communication to protection systems, even if only used for status information or measurements, a new potential point of failure is also introduced to the system. Validity of data cannot be guaranteed, and therefore missing or erroneous information should not create potential hazards in the system. More importantly, supervision of the communication network needs to be ensured at a sufficient level, and valid backup protection schemes operable without communication must be prepared in the event of a network failure. An example of possible supervision might be a recurring transmission of the monitored information at regular intervals: if the information is not received at these pre-defined intervals, a communication failure can be identified within a reasonable time frame.

3.3.2 Adaptive over-current protection

The methods of adaptive protection have been proposed in for example [70], [72], [73] and [74] as a way to make overcurrent protection of microgrids feasible even with the challenges discussed in Section 3.1. Perhaps the most complete approach is presented by Oudalov and Fidigatti in [70] with an adaptive protection method for microgrids using directional over-current relays. The process consists of offline analysis and online operation. In the offline analysis an event table is generated for all meaningful microgrid configurations and feed-in states of DER units, representing positions of circuit breakers in the microgrid. Then fault analysis is carried out for different types of faults at different locations in the network, modifying repetitively a single status of a CB or DER unit after each iteration. The results, namely magnitudes and directions of fault currents seen by each relay, are then used to calculate suitable settings for each relay and each particular system state to guarantee selective operation. These settings may also include activation of protection functions like interlocking. During online operation a central controller is proposed to monitor the microgrid state by polling individual relays 1) periodically and 2) after triggered by an event like the tripping of a CB or a protection alarm. This state information is then compared to the event table, and the pre-calculated relay settings corresponding to the current system state are retrieved and uploaded to the relays. The growing complexity of the setting determination and choosing logic in wider and more complicated network configurations such as in MV microgrids may prevent the scheme's realistic applicability in all situations.

A very similar scheme is proposed by Ustun et al. in [74], though the proposed adaptivity only considers the PCC connection and DER units, monitoring their on/off-statuses, rated currents and fault current contributions. Some possible simplifications have also been proposed to promote a plug-and-play capability of DER units, such as assuming the fault contribution of a DER unit to be equal in all parts of the microgrid and approximating DG fault contributions as 1,2 times their rated current. All in all, authors of adaptive OC protection schemes conclude the need for more comprehensive testing in a variety of different test networks in the future.

3.3.3 Adaptive distance protection

In [66] Voima and Kauhaniemi expand their earlier work [56] presented in Section 3.2.4 on distance protection in MV distribution networks to cover a wider variety of cases. Namely, the possibility of an intermediate in-feed of DER units in the protection zone of the distance relay is investigated. The error in measured impedance caused by the in-feed is illustrated in Figure 3.4. The article considers converter connected DG units, and views them as constant current sources during the fault. As can be seen, multiple DG units in the protection zone of a distance relay each add a discontinuation point in the measured impedance. The magnitude of impedance error caused by the in-feed of DG is inversely proportional to the source fault current I_s [66], and therefore the effect is more severe in islanded mode where large fault currents from the utility network are not present. Since the measured impedance is larger with the intermediate in-feeds, the relay sees the fault farther away and thus the fault may fall into a further time grading zone than it actually is, meaning protection will operate slower and this may lead to selectivity problems.

The proposed solution is based on limited telecommunication capability of DG units in the system, with communication not fast enough for actual protection use but enough for the protection system to be notified of all unit connection status changes. Converter based DG units are considered as constant current sources and their fault current contribution and therefore the effect to distance relay reach can be taken into account by adjusting the impedance limits according to the connection of units, like has been presented in [75]. The requirement for applicability of the scheme is that short-circuit contributions of the DG units must be known. Microgrids with both converter based and directly connected synchronous DGs are not discussed in the proposition, and larger scale simulation studies are mentioned as necessary future work.

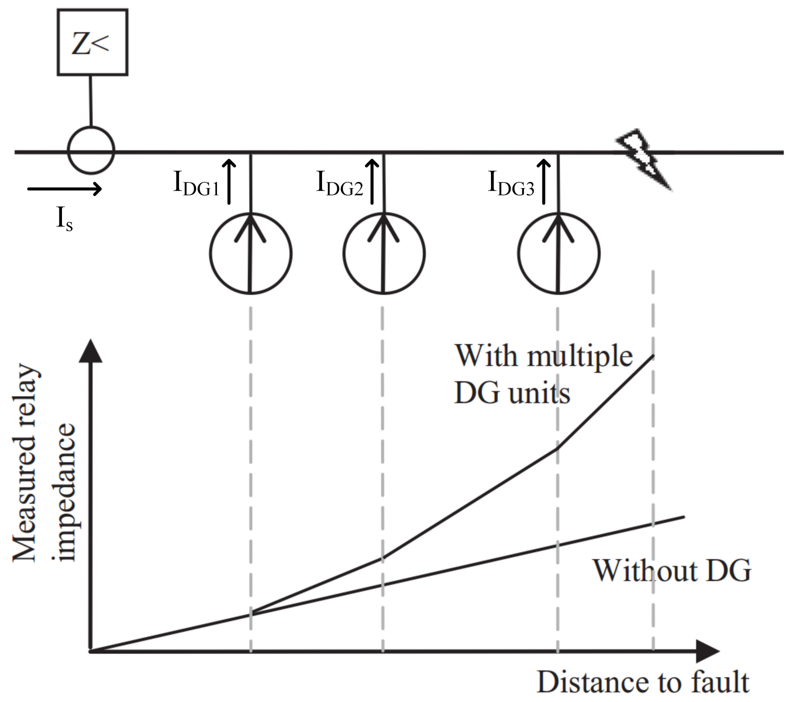

Figure *3.4 The effect of intermediate in-feeds on measured impedance of a distance relay [66].*

3.4 An example LV microgrid protection solution

Many different protection schemes can be used and combined when designing a complete solution for protection of a specific microgrid. Here a protection concept for a LV microgrid presented by Laaksonen and Kauhaniemi in [37] and Laaksonen in [48] is detailed as an example of such a solution. The concept partly relies on high speed communication used for actual protection functions, and in general assumes a high level of controllable devices and measurements for a LV network. Therefore at least currently the implementation of such a scheme would probably not be economically feasible, but the concept still provides an example of the principles in merging different types of protection, adaptivity and communication possibilities of the future. Protection zones and location of protection devices, along with possible fault locations are shown in Figure 3.5. As can be seen, four types of protection devices (PDs) with different requirements have been identified.

PD1 is responsible for the microgrid protection in the point of common coupling (PCC), equipped with a circuit breaker (CB) or a fast static switch (SS). It requires both voltage and frequency measurements. Undervoltage operation must be very

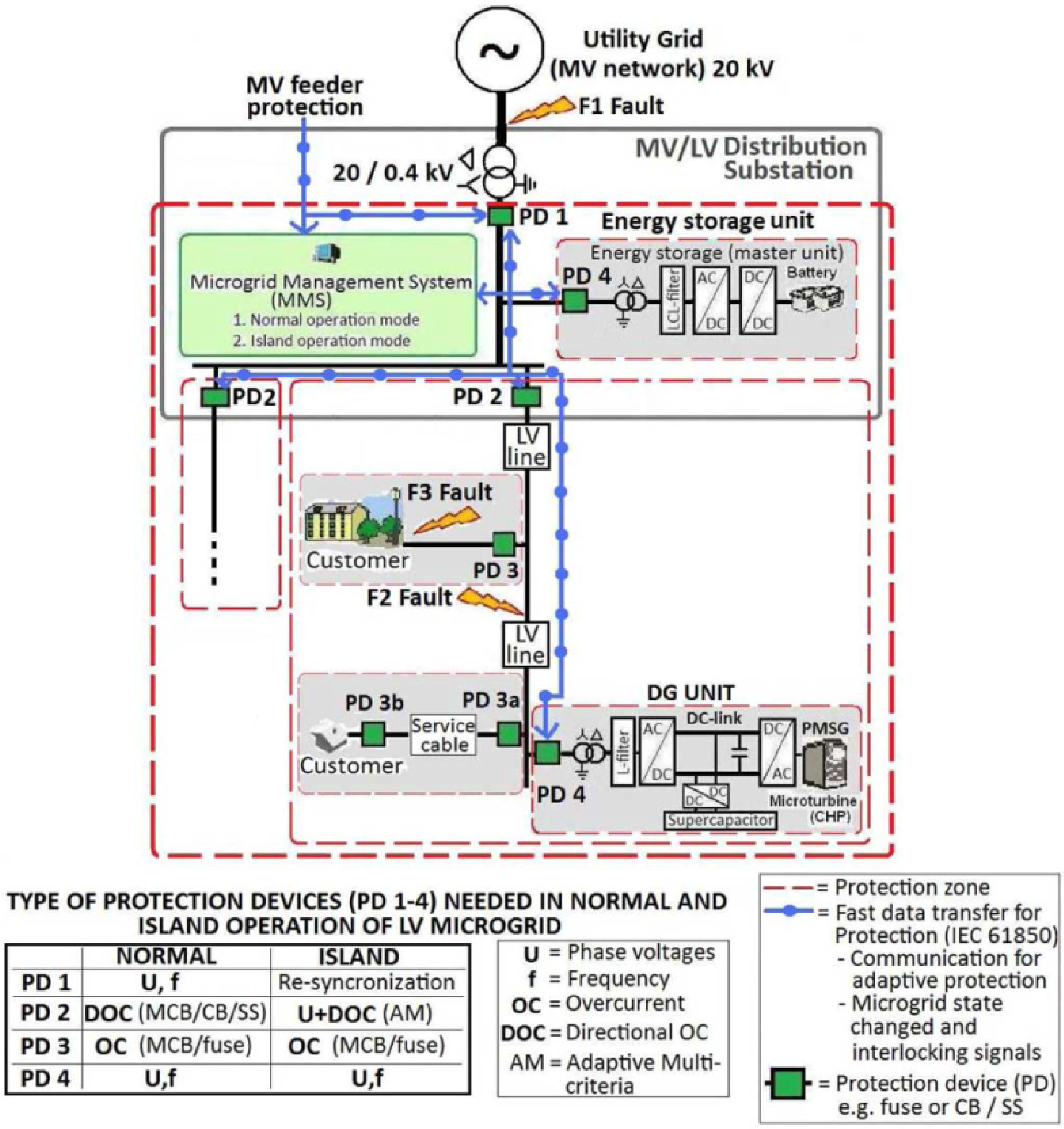

Figure 3.5 Protection zones and devices with possible fault locations in a LV microgrid. [48]

fast to clear faults at location F1 quickly, while frequency protection can be operated with a longer time-delay. Loss-of-mains (LoM) protection is proposed to be enhanced with high-speed communication via a transfer trip (disconnection signal sent after operation) from the upstream MV feeder protection, as a backup to the voltage protection. Intentional islanding operation is also handled by PD1 with a disconnection signal from the DSO. Lastly, in the case of a fault in location F2 or

F3, PD2 sends an interlocking signal to PD1 as soon as the pick-up limit of PD2 is reached to prevent unselective tripping. When transitioning back to grid-connected mode after islanding, a synchronism check function is required to ensure voltage magnitude, phase angle and frequency are within acceptable ranges of each other on both sides of the PD before closing the interconnection switch.

PD2 takes care of the individual LV feeder protection. Equipped with a directional over-current function (DOC), it operates only on F2 faults in its own feeder. The DOC is configured to have time-delay based selectivity with PD1 and PD3. As mentioned, selectivity with PD1 is further ensured with an interlocking signal sent after the current pick-up limit is reached. In island operation, an adaptive multi-criteria algorithm based on both voltage and current measurements is proposed. To operate, pick-up limits of both voltage and DOC functions have to be exceeded, and the time delay for operation depends on the magnitude of the voltage dip. Adaptivity of the algorithm means that the pick-up limit of the DOC measurement is updated by the microgrid management system to take into account the fault current feeding capability of DER units connected to the corresponding LV feeder. Furthermore, when both pick-up limits are exceeded a disconnect signal is sent to all PD4s, i.e. DER units, of the corresponding LV feeder, as well as an interlocking signal to all other PD2s to ensure selectivity. [37] Another option for LV feeder protection with only voltage relays would be the comparison of voltage measurements between PD2s some distance away from the MV/LV substation using high speed communication. This way lower voltages at the faulted feeder could be seen more clearly. [48]

PD3 is responsible for the customer protection. PD3a, located at the service connection of the customer, is equipped with a miniature circuit breaker (MCB) or a SS in case of a very sensitive customer microgrid, and contains a non-directional OC relay with time-delay based selectivity with PD 2 and PD3b. Customer protection PD3b should operate in customer faults only, and can use a traditional fuse protection with customer connections up to 3x40A, after which e.g. MCBs are required. While communication capabilities are not directly necessary from protection point of view, selectivity with PD2 may be hard to achieve in reality without interlocking signals between PD3a and PD2 [48]. Additionally, communication with the smart energy meter at customer site will be needed for advanced metering infrastructure (AMI) applications.

Finally, PD4 is used for DG unit protection, and contains both voltage and frequency measurements like PD1. To avoid unnecessary tripping and disconnection of DG units, the voltage relay has time-delay based selectivity with both PD1 and PD2. In the same manner the frequency relay has selectivity with PD 1, to ensure DG units won't disconnect in an utility grid fault when the microgrid is transitioning to islanded mode. If the DG unit consists of a directly connected rotating generator (synchronous generator), a synchronism check relay is required to connect to the microgrid during normal or island operation. As mentioned, PD4 receives a transfer trip signal from PD2 when PD2 operates. Additionally, the microgrid management system can send a disconnection signal to PD4 based on operational needs, and in a case where island operation of the microgrid is not possible, loss-of-mains protection is proposed to be achieved by a disconnection signal from the MV feeder protection [48]. The economical feasibility of communication based LoM-protection at each LV DG unit is questionable. Alternative local LoM methods include passive methods monitoring power system variables, such as rate of change of frequency (ROCOF) protection, and active methods, where a disturbance is injected and its effect on grid parameters is examined to detect islanding [76].

As discussed in Section 3.1.3, the operation curves of different protection devices also define the fault ride-through (FRT) requirements of DER units, i.e. the operation limits in which the unit should still operate normally without disconnection. They are chosen so that the stability of the microgrid or the healthy part of it can be maintained after fault clearance also with directly connected synchronous machines connected to the microgrid. As such, the operation curve for voltage relay of PD1 in normal operation and PD2 in island operation represent the voltage FRT requirements for DER units, while the frequency relay of PD4 represent the frequency FRT requirements. The technical design of DG unit converters must enable both these FRT requirements as well as the conditional loss-of-mains protection mentioned earlier.

With this, the general requirements for microgrid protection have been summarized as:

1. Adaptation capability
2. Utilization of high-speed standard-based communication (e.g. IEC 61850)
3. High-speed operation in deep voltage dips to maintain stability in the healthy part of the network as well as to fulfill the needs of very sensitive customers

4. Selective operation in all kinds of faults
5. Unnecessary operation of protection devices and disconnections of DG units must be avoided. [48]

4. IEC 61850 IN DER APPLICATIONS

With the development of microprocessor based numerical relays, a new evolution of power system secondary equipment replaced the single-function electromechanical or static devices and their hard-wired relay logic. These new intelligent electronic devices (IEDs) made it possible to fit more functions into fewer devices, the need for wiring was reduced and the communication capabilities allowed to access more information remotely. Initially proprietary communication protocols developed by each manufacturer were used, and costly protocol converters were needed if using IEDs from different vendors. These converters also introduced new problems in the form of errors and only partial functionality. Integration with the supervisory control and data acquisiton (SCADA) systems was moderately successful if the end user could lock into a solution from a single vendor, while multi-vendor systems invariably led to issues [77]. From these experiences the need for standardization to support interoperability of IEDs from different manufacturers was born. Interoperability in this context, as defined by the International Electrotechnical Commission (IEC) means "the ability of two or more IEDs from the same vendor, or from different vendors, to exchange information and use that information for correct execution of specified functions" [78].

With this goal in mind, IEC 61850 was designed as a joint effort between EPRI/IEEE and IEC TC 57 (technical committee 57) in 1997 in order to combine the earlier work of both groups and define an international standard to enable substation devices from different vendors to share data, services and functions [77]. The result of this work was a 14-part standard series IEC 61850 "Communication Networks and Systems in Substation Automation", published between 2002 and 2005. As the title suggests, these standards were exclusively designed for substation automation systems. However, the core aspects of IEC 61850 apply to automation in general and the scope of the standard family has later been extended to several other application areas as well. This was also reflected in a new name for the standard: "Communication Networks and Systems for Power Utility Automation".

Nowadays the use of IEC 61850 is widespread in new installations and it is viewed as one of the core standards in the IEC Smart Grid Standardization Roadmap, having "an enormous effect on any Smart Grid application and solution", and being seen as part of the backbone of the future smart grid [6]. Although dominant in modern installations, it is worth noting the current power system automation installed earlier is generally not retro-fitted for IEC 61850 and is still mostly using older protocols such as Modbus for field automation.

All but one of the original parts of the series (Part 2: Glossary) have been updated to edition 2 [79]. Although the original parts are sometimes referred to as IEC 61850 Edition 1 and the revised parts as IEC 61850 Edition 2, it should be noted that the edition numbering is used for individual parts, not the whole standard. For example the new extensions accepted to the standard are marked as ed1.0 [79], and as such using edition numbering for the whole standard can lead to confusions and is not advised. This chapter first presents the most important principles and concepts of the standard. Then an overview of the usage of IEC 61850 in DER applications is presented and, closely relating to this, the published extensions of the standard are examined.

4.1 IEC 61850 overview

4.1.1 Objectives

The objective of IEC 61850 in standardizing the power utility automation systems (PUAS) is to develop a communication standard that meets the necessary functional, non-functional and performance requirements, while supporting future technological developments [78]. This means the standard has to consider the operational requirements throughout the power grid, but not standardize or limit in any way the functions involved in power system operation or their allocation within the PUAS. Application functions do still need to be identified and described in order to define their interfaces and communication requirements. Other important goals for the standard include:

1. existing standards and commonly accepted principles should be used to the maximum possible extent

2. the protocols used should be open and extensible with new functionality
3. the offered communication services can be mapped to different state-of-the-art protocols
4. the complete topology of an electrical system, the generated and consumed information and the information flow between all IEDs is specified using a machine readable language. [78]

4.1.2 Approach

To achieve the goals mentioned above, three methods have been adopted to the approach of the IEC 61850 series: functional decomposition, information modelling and data flow modelling [78]. Functional decomposition means the division of a task performed by the automation system into smaller parts. The granularity of the decomposition is ruled by the communication behaviour i.e. the data exchange involved in performing the function. It is presented in the standard by logical nodes (LNs), the smallest parts of a function that exchange data. Information modelling is used to define the abstract syntax and semantics of the actual information exchanged, and consists of data object classes and types, attributes, abstract object methods (services), and their relationships. The whole data structure will be examined in detail in Section 4.2. Data flow modelling on the other hand defines the communication interfaces enabling the exchange of information between distributed functional components and the associated functional performance requirements.

The separation of the information model from data flow is an important feature of IEC 61850. Actual communication technologies evolve rapidly compared to the power system equipment with lifespans of typically tens of years. To achieve the decoupling of communication and the data model, a set of abstract services and objects are specified. This way applications can be written independent from a specific protocol, making it possible to use the current state-of-the-art protocols (goal 3 above), as well as to cope with the diversity of communication solutions in the widening scope of IEC 61850. These abstract services and their mappings to specific protocols are discussed in Section 4.3. To satisfy goal 4, a formal language named System Configuration description Language (SCL) is defined to exchange IED capability and system level descriptions.

The main functions, referred to as *application functions* in the standard [78], of a power utility automation system are control, supervision, protection and monitoring of the primary equipment and the power grid. Other functions, referred to as *system functions*, are related to the automation system itself, such as the supervision of communication. As mentioned, the standard does not specify any fixed allocation of functions to IEDs or different control levels. This is because the desired allocation can depend on many different factors like availability and performance requirements, cost constraints, state-of-the-art technology, a utility's philosophy and so on. A function that is split in modules performed by different IEDs that communicate with each other is called a *distributed function*.

4.1.3 Structure

The current IEC 61850 standard series (IEC 61850:2015 SER) contains 24 parts in total [79]. The overview of the parts and links between them are presented in Figure 4.1. Parts 1-5 describe the general requirements and system aspects. IEC 61850-1 covers a short overview and introduction to the standard. IEC 61850-2 provides a glossary of terms used in other parts. IEC 61850-3 defines the general requirements mainly regarding construction, design and environmental conditions of utility communication and automation IEDs and systems. IEC 61850-4 covers system and project management aspects like engineering requirements, system lifecycles and quality assurance. IEC 61850-5 describes communication requirements for functions and device models, including e.g. communication quality aspects like transfer time, time synchronization, data integrity, security and dependability classes, as well as the performance classes required by different message types. IEC 61850-6 defines the SCL configuration description language and provides an overview on the intended system engineering process.

IEC 61850-7-1 is an introduction to the overarching modeling paradigm for data and communication models used in other IEC 61850-7-x parts as well as their relations to other parts like 61850-5 and the concrete protocol mappings of 61850-8-x and 61850-9-x. IEC 61850-7-2 describes the abstract communication service interface (ACSI) for accessing and exchanging infromation. IEC 61850-7-3 contains the Common Data Classes (CDCs) which are the basic types of information used in modeling like a 3-phase measured value or a single point status. These CDCs make up the standardized, normative logical nodes (LNs) defined in IEC 61850-7-4 and its

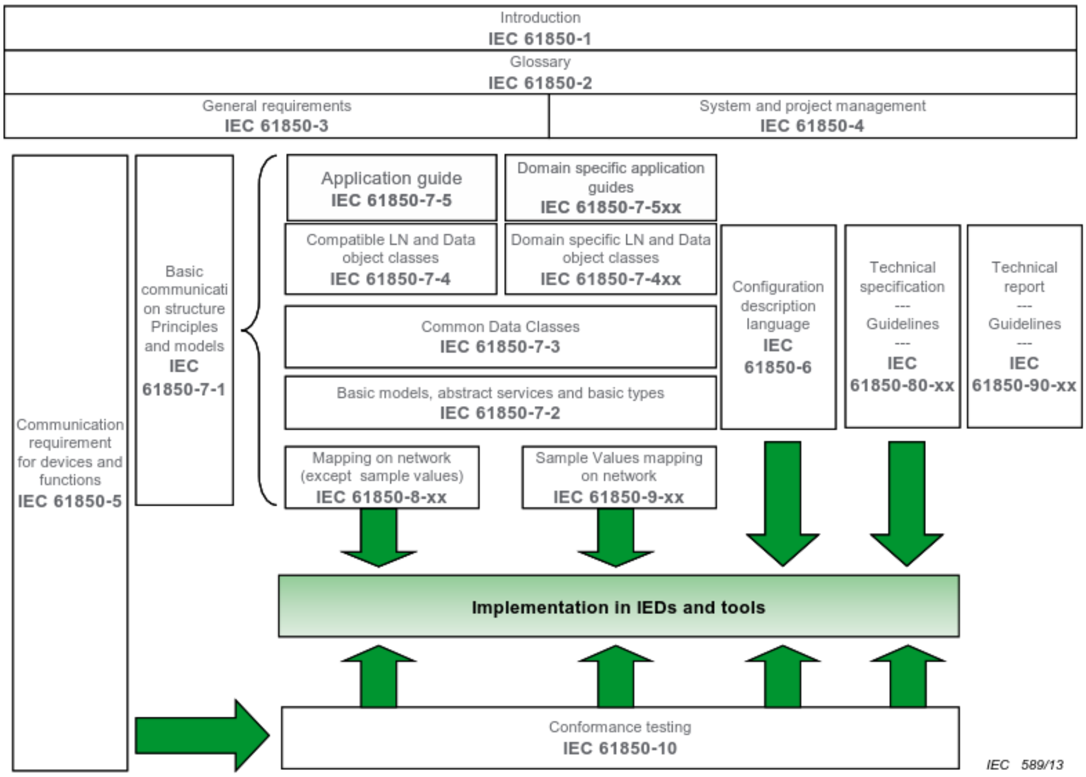

Figure 4.1 *Overview of the IEC 61850 series content [78].*

domain specific extensions 7-4xx. The 61850-7-5xx parts act as informative application guidelines for specific domains, describing how to implement the application functions using the other 7-x parts. 61850-8-x documents are normative definitions of the ACSI mapping to real protocols excluding communication related to sampled values, which have their own dedicated mappings in parts 61850-9-x. IEC 61850-10 specifies techniques for conformance testing. Finally, the IEC 61850-80-x parts are additional informative Technical Specifications (TS) related to communication mapping to other protocols like Modbus or IEC 60870-5-101/104, and the 61850-90-x are additional informative Technical Reports (TR) for further enhancements and extensions of the IEC 61850 domain like communication between substations and control centers and transmitting synchrophasor information. As can be seen, the IEC 61850 series is much more than a traditional communication protocol definition. Taking into account system aspects like project management as well as engineering guidelines, extendability and defining a common configuration language, the series aims to ensure a very high level of interoperability at application level that can adapt to a changing communication infrastructure.

4.1.4 Envisioned benefits and current experiences

Movement to IEC 61850 from legacy systems is envisioned to incur many benefits in both engineering and operation capability of power utility automation systems. Obvious benefits include reduced installation costs in moving from hardwiring to LAN-based networking, but the features of IEC 61850 are also intended to reduce engineering costs in many ways. Transducer information can be sent from one to many devices using sampled values, reducing transducer costs. Extensive manual configuration with every relay is not needed during commissioning with the SCL configuration language and object-oriented data structure, and SCL can also be used to define unambiguous user requirements in the procurement phase. Common naming conventions and defined behaviour reduce migration costs between different brands of devices and require less reconfiguration with hardware changes. Extensions to add new functionality or devices into existing systems have minimal effect on existing equipment. Integration to other utility systems is easier without the need for separate communication front-ends, remote terminal units (RTUs) or reconfiguration of devices. The interconnectedness of all devices in the same network can also open capabilities in for example new substation-wide protection schemes. [80] IEC 61850 has been designed with very much the same goals in mind as envisioned for future smart grids compared to old power systems, such as reduced costs, flexibility, extendability and interoperability. [81]

While multi-vendor interoperability is seen as an important goal for the standard, practical experiences as mentioned in for example [82], [83] and [84] have shown that some definitions of the standard are loose enough that IEDs passing the conformance test for IEC 61850 is not a guarantee of seamless interoperability. Especially with the expansion to new application areas, attention must be paid to the amount of time and effort required in engineering and configuration of wide IEC 61850 systems [85]. With the development and maturation of the standard, protocol interoperability issues are becoming less and less commonplace, but attention still needs to be paid to the data model, management, engineering and configuration process of multi-vendor environments [86].

4.2 Information model

The presentation of information in the IEC 61850 series follows the popular concepts of object-oriented data modeling, where different objects encapsulating 1) data and

2) methods are the basic units of the system. These objects are instances of classes, which group similar objects together and describe their common functionality. Objects, containing other objects, form a hierarchical data structure that describes all the system functionality at the wanted level. A more thorough introduction to object-oriented methods and programming can be found in for example [87].

In its modelling approach of real world devices, IEC 61850 creates a virtualization of a device to provide a view of those aspects that are of interest for the information exchange with other devices. Only those details that are required to achieve interoperability are defined in the standard. [88] As mentioned in the previous section, IEC 61850 uses functional decomposition to break down the application functions of an automation system to smaller parts. The chosen approach and resulting object hierarchy are presented in Figure 4.2. A physical device (IED) is divided into logical devices (LDs), virtual entities used for grouping typical automation, protection or other functions. A logical device contains the basic building blocks of the IEC 61850 information model: standardized logical nodes (LNs) defined in the IEC 61850-7-4xx parts. Finally, LNs contain a list of data representing some application-specific meaning, each with their own dedicated data attributes.

As stated, a logical device is a virtual entity that exists to enable aggregation of related logical nodes. The concept is introduced mainly for communication purposes beyond a logical node, and as such a LD is a composition of logical nodes and additional services. These services include for example defining setting groups, sampled value exchange and fast Generic Object Oriented Substation Event (GOOSE) messaging, discussed further in Section 4.3. The grouping of logical nodes in logical devices is based on common features of the LNs, such as them normally being in the same operating mode (e.g. on/off/test mode). The standard does not specify how to arrange LDs in a physical device apart from the limitation that a logical device can't be spread over many IEDs. Example of a typical logical device could be a substation bay unit, where the LNs are related by their position in the power system. As for real world IED implementations, the REF615 relays used in the case study of Chapter 5 contain up to four logical devices: CTRL for actual control equipment, DR for disturbance recorder, LD0 for protection and other functions and MU01 if a merging unit for sampled values is included [89], while for example VAMP relays use only one logical device in a single IED for all LNs [90].

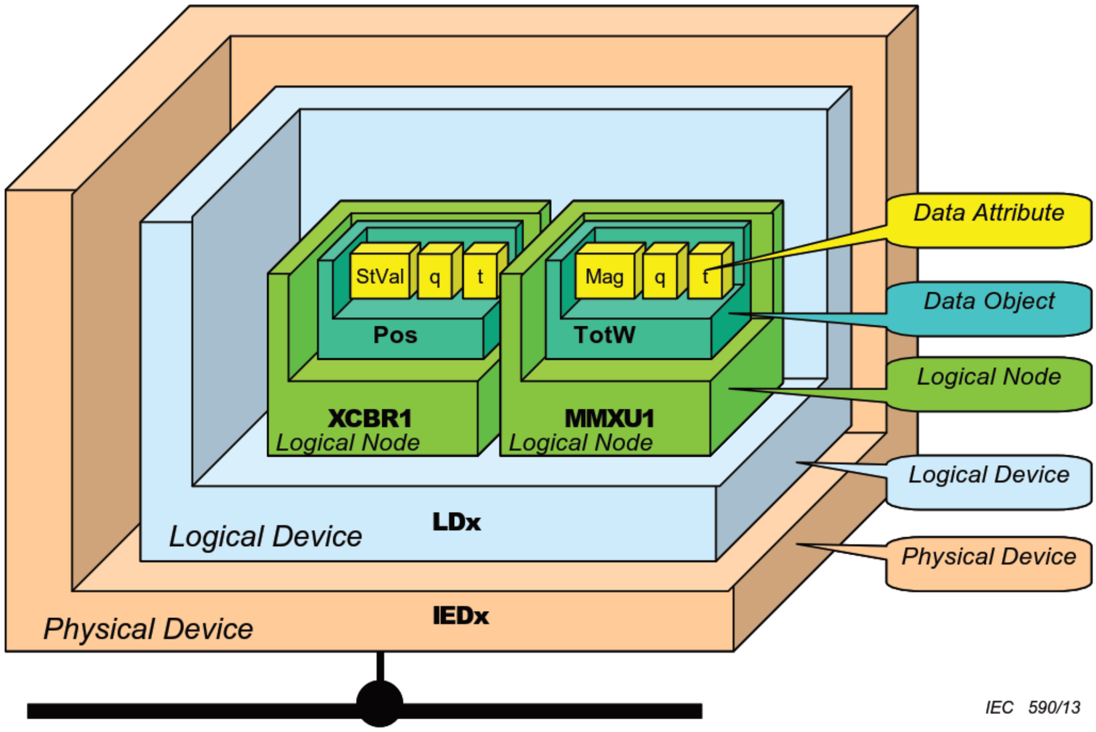

Figure 4.2 *IEC 61850 data modelling [78].*

4.2.1 Logical nodes

Logical nodes and the data contained in them are the fundamental concepts that are used in IEC 61850 to describe real systems and their functions [88]. In order to fulfill the requirements set for IEC 61850, especially aspects of interoperability and arbitrary allocation and distribution of functions between devices, the data of all functions needed to be grouped in objects with a high level semantic meaning. Logical nodes can be seen as containers for a set of data provided by a specific function for communication [71]. Said function may be constructed from multiple logical nodes, residing in one or many different physical devices. Logical nodes are grouped according to the applications they're related to, as shown in Table 4.1. They have standardized four letter names specifying exactly what part of the system the LN describes, with the group indicator always being the first letter of the name. Additionally, an application specific prefix and a numeric suffix can be added to the name for identification. Some examples of logical nodes presenting real applications include a differential protection function (PDIF), a circuit breaker (XCBR), a switch (XSWI) or a current transformer (TCTR). There are also "administrative" LNs for containing information like nameplate and self-supervision data about the physical device used as the host (LPHD), or common data for all LNs in a logical device (LLN0). IEC 61850 also has well-defined rules for defining additional logical nodes and data for new functions or application domains.

Table 4.1 *Logical node groups [88]*

Group indicator	Logical node group
A	Automatic control
C	Supervisory control
D	DER (Distributed Energy Resources)
F	Functional blocks
G	Generic function references
H	Hydro power
I	Interfacing and archiving
K	Mechanical and non-electrical primary equipment
L	System logical nodes
M	Metering and measurement
P	Protection functions
Q	Power quality events detection related
R	Protection related functions
S	Supervision and monitoring
T	Instrument transformer and sensors
W	Wind power
X	Switchgear
Y	Power transformer and related functions
Z	Further (power system) equipment

The mean number of specific data in logical nodes originally defined in IEC 61850-7-4 is approximately 20. This information provided by the logical nodes can generally be divided into 5 categories:

1. Common logical node information: information independent from the dedicated function represented by the LN, such as external equipment name plate

2. Status information: information representing the status of the process or the function represented by the LN, such as local/remote control, operation capability or operation counter

3. Settings: information needed for the function of the logical node, such as operation time, delay or pickup value of a protection function

4. Measured values: measured or calculated analogue data related to the function like total active power of a measurement or sum of switched amperes for a circuit breaker

5. Controls: data which are changed by commands, like switchgear position, block closing or resettable counters.

As an example, the structure of the mentioned XCBR logical node representing a circuit breaker according to IEC 61850-7-4 is presented in Table 4.2. The common data class column defines the structure of the data object, and is discussed later in this section. The column T would indicate a transient data object having only momentary validity for its state, while the column M/O/C defines whether the data object is mandatory (M), optional (O) or conditional (C) for an instance of the LN. The whole XCBR LN is made of a total of 16 data objects.

4.2.2 Data, data attributes and common data classes

The data in a logical node are not of simple basic types like an integer or an enumeration, but are further made up from specific data attributes. The XCBR LN has data named `Pos` belonging to the controls category that describes the position of the circuit breaker. The actual position of the breaker is stored in the data attribute `Pos.stVal`, having four possible states of on, off, intermediate-state or bad-state. In addition to the actual value, the status of the position includes other data attributes as well: quality `Pos.q` describing the validity of stVal, timestamp `Pos.t` showing the last change of it, originator `Pos.origin` having information about the originator that issued the last command to control the position and `Pos.ctlNum` storing the control number given by the originator in its request. The values of stVal and quality can also be remotely substituted, and an own set of data attributes are defined for substitution. Furthermore, several data attributes are defined for the configuration of the control behaviour of `Pos` such as control pulse configuration or control model. All in all, 24 data attributes make up the `Pos` data object of the XCBR logical node. Data attributes in a data object are classified according to their usage, for example whether they are used for description, control, measurements or configuration, by *functional constraints* (FC). The functional constraint is a two letter property and defines the services allowed for the data attribute as well as its initial values. For example the `Pos.stVal` attribute mentioned earlier has the FC of status information

Table 4.2 XCBR logical node [91]

XCBR class				
Data object name	**Common data class**	**Explanation**	**T**	**M/ O/ C**
LNNAME		The name shall be composed of the class name, the LN-Prefix and LN-Instance-ID according to IEC 61850-7-2, Clause 22.		
Data objects				
Descriptions				
EEName	DPL	External equipment name plate		O
Status information				
EEHealth	ENS	External equipment health		O
LocKey	SPS	Local or remote key (local means without substation automation communication, hardwired direct control)		O
Loc	SPS	Local control behaviour		M
OpCnt	INS	Operation counter		M
CBOpCap	ENS	Circuit breaker operating capability		O
POWCap	ENS	Point on wave switching capability		O
MaxOpCap	INS	Circuit breaker operating capability when fully charged		O
Dsc	SPS	Discrepancy		O
Measured and metered values				
SumSwARs	BCR	Sum of switched amperes, resettable		O
Controls				
LocSta	SPC	Switching authority at station level		O
Pos	DPC	Switch position		M
BlkOpn	SPC	Block opening		M
BlkCls	SPC	Block closing		M
ChaMotEna	SPC	Charger motor enabled		M
Settings				
CBTmms	ING	Closing time of breaker		O

denoted by ST, and therefore its initial value is taken from the process and it is not writable. The different services of IEC 61850 are discussed in the next section.

Across all logical nodes, data representing similar information can be found: the example of `Pos` has the prime characteristic of having four states, which is common for other switching-specific applications. The whole set of data attributes it consists of is standardized across the IEC 61850 series as a common data class (CDC). This four-state information, usually represented by two bits, is known as "double point" information, and the CDC representing it is named DPC (controllable double point).

Common data classes are defined in IEC 61850-7-3, and provide a useful means to reduce the size of data definitions and ensure the consistency of data attribute definitions by allowing data definitions to just reference the common data class. CDCs define the type, functional constraints, trigger options (conditions that may cause a report or log entry to be created), values or value ranges, and the M/O/C definitions of every data attribute included in the CDC.

4.3 Information exchange: ACSI and SCSMs

As mentioned in Section 4.1, the decoupling of communication and the data model is an important feature of IEC 61850. To establish independence from specific communication protocols, the *abstract communication service interface* (ACSI) is defined in IEC 61850-7-2. As the information models and information exchange services are necessarily interwoven to some extent, the ACSI consists of two types of models: firstly it defines the *meta models* for the utility information models contained in IEC 61850-7-3, 61850-7-4 and 61850-6, and secondly it defines the information exchange service models [92].

4.3.1 Meta models

The hierarchy created by the defined meta models is presented in Figure 4.3. The first level of definitions is the meta-meta model. This model defines the basic data types to be used like floating points, integers and different strings, but also the `CommonACSITypes` used for the attribute definitions of the classes in subsequent models, like the unique instance path-name `ObjectReference`. From these types, the meta model is constructed, defining the generic models that make up the information model presented in Section 4.2. This means formally defining the attributes and services of overall classes like `GenServerClass`, `GenLogicalDeviceClass`, `GenLogicalNodeClass` and `GenDataObjectClass`. [92] The specific LNs, CDCs and other structures in parts 7-3 and 7-4 like a XCBR logical node or a DPC common data class are instances of these generic classes, and form the domain type model. Finally, a model of an actual IED is an instance of the domain type model providing the actual data representing the virtualized view of the real world device or application.

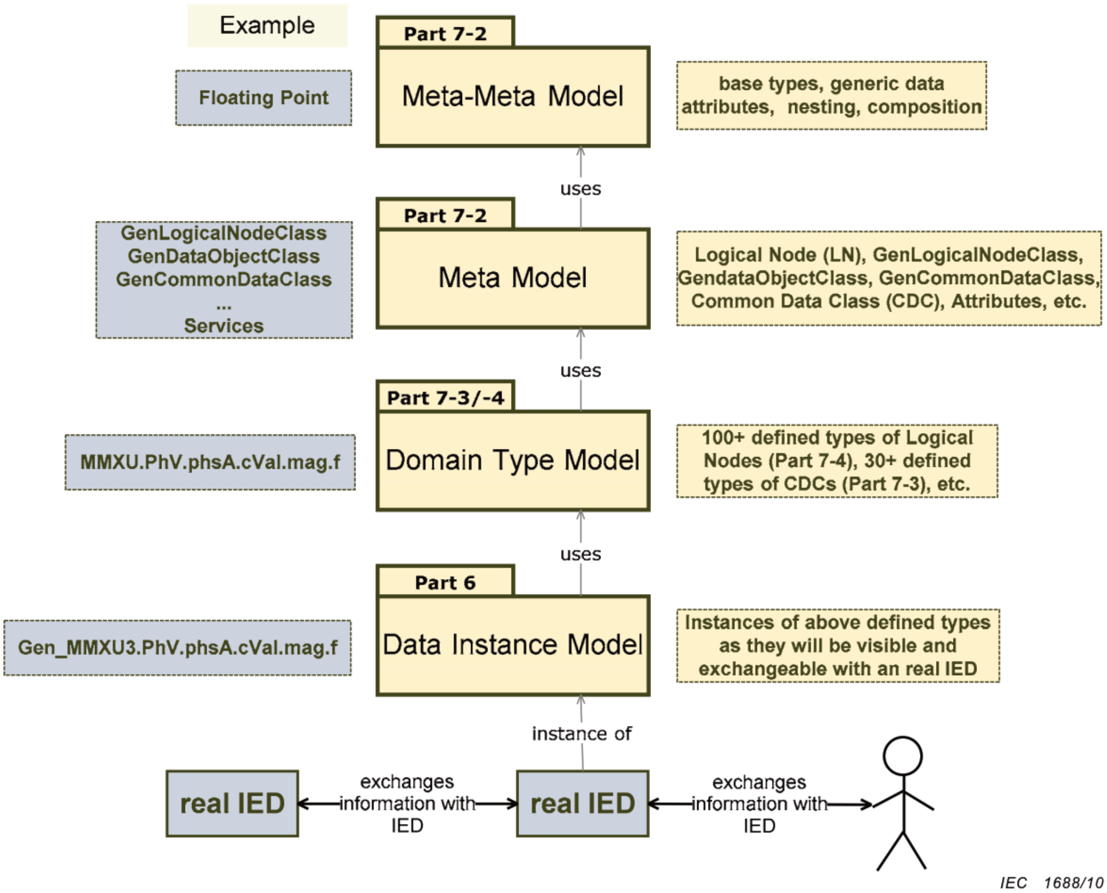

Figure 4.3 *The conceptual models of IEC 61850 [92].*

4.3.2 Information exchange modelling classes

The other part of ACSI, information exchange modelling classes, provide services operating on data objects, data attributes and data sets, and are grouped in Table 4.3 according to their usage. `DATA-SET` is a class defined in ACSI that permits the grouping of data objects and data attributes, easing their use for information exchange. Data-sets can be constructed using the functional constraints mentioned in Section 4.2. An ordered collection of data attributes having the same FC is called functional constrained data (FCD), while a reference to a single data attribute, sub data object or sub data attribute of a data object having a specific FC is called a functional constrained data attribute (FCDA). Data-sets are defined as an ordered group of FCDs and FCDAs organized as a single collection for the convenience of a client. For example, all measured values of a data object with (FC = MX) can be referenced by the measurement FCD to create a data-set for reporting to clients.

***Table 4.3** Information exchange modelling classes [92].*

Setting group control	Class defining services for switching from one set of setting values to another and editing these setting groups.
Report control	Classes controlling the procedures required for reporting values of data objects from one or more logical nodes to one client.
Logging	Classes for the storage of historical values of data objects and their retrieval over communications systems.
Control blocks for generic substation events (GSE)	Class for fast and reliable system-wide distribution of input and output values in generic object oriented substation event (GOOSE) messages.
Control block for transmission of sampled values	Classes for time-controlled and cyclic transmission of sampled values in unicast or multicast.
Control	Services to change the state of internal and external processes by a client.
Time and time synchronization	Model for providing UTC synchronized time to to applications in utility IEDs
File system	Class for transferring and management of files and file stores.
Tracking	Classes for storing the service parameters used by a service for logging or reporting of information.

The groups of Table 4.3 consist of one or more class definitions, whose attributes contain mainly IDs or references to objects or data sets, and the main focus is on the defined services. The service definitions include requests and both negative and positive responses if applicable, as well as parameters associated with them. The concept of control blocks is present in many instances like setting groups, reporting, logging, GSE and sampled values. A control block is a class defined very similarly to data object classes, but while data objects are used as an interface to application level functions, the control blocks configure the associated communication services [92]. Additionally, the `CONTROL` class used for actually manipulating the processes needs to provide different behaviours of the control object depending on the application. Therefore it defines four different state machines describing the operation in corresponding control modes: direct or select-before-operate (SBO) control with normal or enhanced security. The SBO mode first tries to select the control object to ensure multiple clients cannot operate on the same object simultaneously, while enhanced security means the control object provides additional supervision of the status value to be controlled. Models for utility functions like time and file system have a defined semantic but are limited in scope of the standard to allow specific communication service mapping (SCSM) presentation and restrictions. All the services can be tracked using the different tracking service classes, providing the necessary service parameter information for logging or reporting of the wanted information exchange services.

4.3.3 Application associations

The `GenServerClass` defined in the meta model represents the external visible behaviour of a device, and hosts all other ACSI models. The server has two possible roles regarding information exchange: communicating with a client, and sending information to peer devices [92]. Most service models in IEC 61850 use the client/server architecture, where the server provides data and services to the client upon receiving a request or spontaneously according to predefined rules. A same device can implement both server and client roles according to need. The ACSI also defines an abstract interface for fast and reliable system-wide event distribution between an application in one device and many remote applications in other devices, as well as transmission of sampled measured values in the same way. This communication happens with a unidirectional publisher/subscriber pattern, where the publisher sends its messages as a *multicast* i.e. one-to-many distribution, and all other applications interested in the information can subscribe to it to receive the messages. A multicast message differs profoundly from a broadcast message, the other form of one-to-many distribution: a broadcast message is sent to the whole network and processed by all its devices, while multicast is sent to a logical group of devices and processed only by those devices. It should be noted that many of the services and structures in the standard are optional. For a simple device, the server may comprise of just one logical device with a single control model and no other services. Furthermore, the exact relationship of the server and the underlying communication system is outside the scope of ACSI, and depends on the specific communication service mappings (SCSMs) discussed later.

The two types of information exchange are realized in ACSI by an *application association* model. It consists of 1) class definitions for associations and 2) access control concepts, providing mechanisms for establishing and maintaining connections between devices and for restricting access to instances in a server. Two application association classes are defined: the `TWO-PARTY-APPLICATION-ASSOCIATION` (TPAA) for the bidirectional client/server information exchange, and the `MULTICAST-APPLICATION-ASSOCIATION` (MCAA) for unidirectional publisher/subscriber information exchange. These application associations are part of the `GenServerClass` attributes, and each of them identifies one client or a subscriber with which the server maintains an association. The different services defined in the information modelling classes presented in Section 4.3.2 are available in the application associations.

The difference between the two classes can be seen from Figure 4.4, where the connection services used by them to initiate data transfer are compared. A TPAA is connection-oriented and initiated with the Associate-service, as well as released gracefully (completing unfinished actions) with the Release-service, or abruptly (terminating instantly) with the Abort-service. In a MCAA each exchange of information carries association parameters and data, and the "application association" ceases as soon as the service has been processed. The figure is also representative of the intended use of MCAAs in wide-scale distribution of time-critical, periodic information. These services include sending generic substation event (GSE) messages and the multicast of sampled values, and are discussed in the next section.

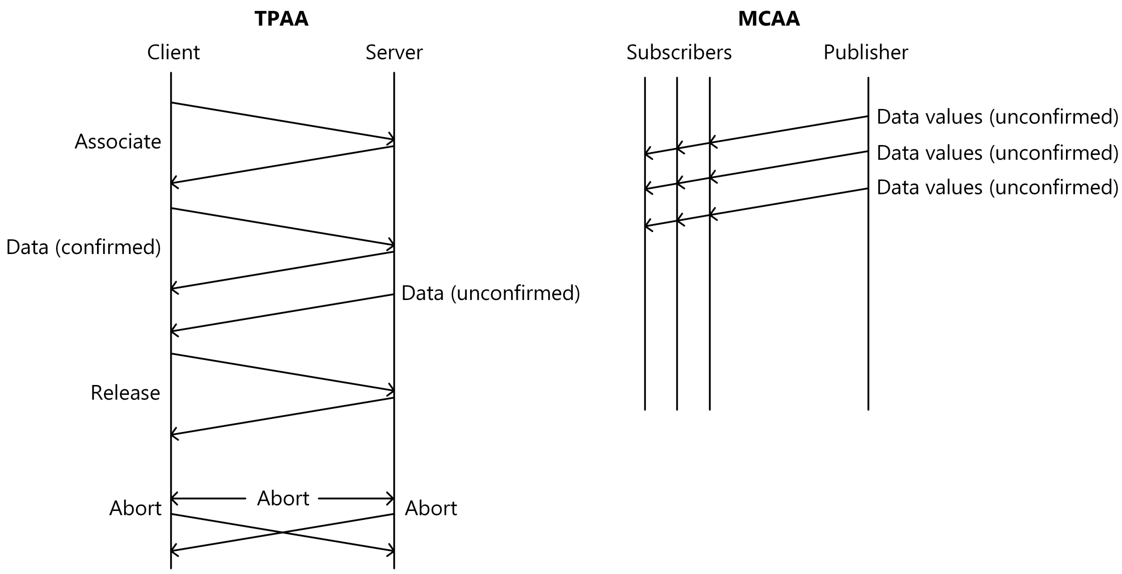

Figure 4.4 *The client/server (TPAA) and publisher/subscriber (MCAA) service models of ACSI [92].*

4.3.4 GOOSE messages and sampled values

The GSE model is based on autonomous decentralization and provides fast and reliable system-wide distribution of input and output values. It should be noted that achieving the minimal transmission delay and reliability aspects are dependent on the mapping and implementation of the communication stack. The GSE originally consisted of two different types of messages, but the generic substation state event (GSSE) used to convey state change information in bit pairs has been deprecated and is kept in the standard as an annex only for backwards compatibility. The remaining *generic object oriented substation event* (GOOSE) model supports the exchange of a wide range of possible common data organized in a data-set. GOOSE messages are used for time-critical messages especially related to protection, such as interlocks, blocks and transfer trips between protective relays.

The overview of involved classes and services is presented in Figure 4.5. In the upper part a normal ACSI service of `GetDataValues` defined in `GenDataObjectClass` is used to retrieve the values of a data object. In the lower part the GOOSE mechanism is presented. The GOOSE messages are configured by 1) defining an appropriate data-set, using FCDs and FCDAs as discussed in Section 4.2, and 2) by defining a GOOSE control block (GoCB) for setting up the GOOSE services to be used on the data-set. If the value of one or several members of the data-set changes, the transmission buffer of the publisher is updated with the local service "publish", transmitting all values with a GOOSE message. SCSM specific services will then update the reception buffer of the subscribers, and the new values received are signalled to the application locally.

In addition to the status or value changes, GOOSE messages contain also the time of the last change allowing a receiving device to set local timers related to a given event. As can be seen, the buffers and update mechanisms used are outside the scope of ACSI, and are a local issue to be implemented complying with the services defined. Finally, the `SetGoCBValues` service can be used to modify the settings of the control block. In addition to value changes, GOOSE messages are sent upon newly activating a device as an initial message, as well as continuously with a longer cycle time even if no value change has occurred to 1) be able to notice communication failures and 2) ensure that other newly activated devices will know the current status values of the publisher device.

The transmission of sampled values is based on a similar structure as presented in Figure 4.5 for GOOSE messages. Special attention for sampled values is required with regard to the time constraints, so that the combined jitter of sampling and transmission is minimized to a sufficient degree that allows an unambiguous allocation of the samples, times, and sequence [92]. As with GOOSE, a sampled value control block is defined for controlling the transmission of a specified data-set. The

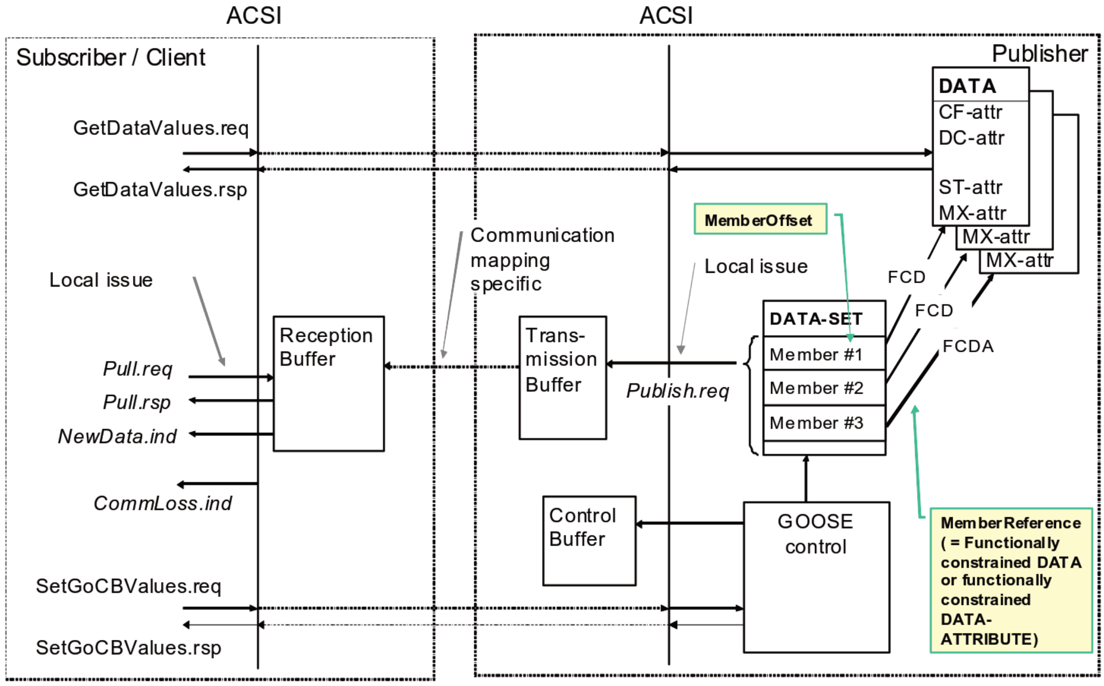

Figure 4.5 *The classes and services of the GOOSE model [92].*

transmission happens at the specified sample rate, and can be done either as multicast, using the MCAA, or as unicast, using the TPAA.

4.3.5 Specific Communication Service Mappings (SCSMs)

All in all, the IEC 61850-7-X parts define abstract information (7-3 and 7-4) and service (7-2) models for power utility automation systems. While ACSI defines services, requests, responses and parameters associated with them, it does not define concrete ACSI messages to be sent between devices. Instead, for communication purposes the ACSI services are always mapped to the Open Systems Interconnection (OSI) model for communication functions via a *specific communication service mapping* (SCSM). A thorough introduction to the OSI model defined in ISO/IEC 7498-1 can be found in for example [93]. While the fast GOOSE messages and sampled values are mapped directly to the data link layer for minimum processing and maximum speed, other communication uses the full OSI stack and maps the ACSI services to application layer messages. The application layer (AL) is the level that then uses specific protocols and produces the actual application layer protocol data units (AL PDUs) to be sent over communication media. The mapping and the application layer used define the concrete encoding and syntax for the data to be exchanged. This mapping allows ACSI to be applied to different application layers with different features. Furthermore, the lower layers of transport, network, data link and physical media protocols used are invariant to the form of the services and data offered, and vice versa: the application sending and receiving data is largely invariant to the mechanisms of information transfer used. This separation of roles makes it possible to employ many different technologies in a relatively transparent manner, and exchange the lower layers of communication as needed. The obvious benefit is that networks with different types of physical media may be used, but also the same physical network and protocols may be used by more than one application layer protocol.

The relation of ACSI, SCSMs and OSI layers is depicted in Figure 4.6. SCSMs define how the services and models presented earlier like server, logical devices, logical nodes, data, data sets, control blocks, GOOSE messages and so forth are implemented using a specific communication stack. SCSMs are defined in the IEC 61850-8-X and IEC 61850-9-X parts. The 8-X parts cover all communication except that related to sampled values, which is covered in the 9-X parts. Two widely used SCSMs include IEC 61850-8-1 for mapping to MMS (ISO/IEC 9506-1 and ISO/IEC 9506-2) and ISO/IEC 8802-3 (Ethernet), and IEC 61850-9-2 for transmission of sampled values over ISO/IEC 8802-3. A Publicly Available Specification (PAS) IEC/PAS 61850-9-3 is also issued as a pre-standard for precision time protocol profile for power utility automation [94].

The Manufacturing Message Specification (MMS) is an international standard used for transferring real time process data and supervisory control information between networked devices. Mackiewicz states in [80] that MMS was chosen for use in Utility Communication Architecture (UCA) back in 1991, an architecture later serving as foundation for IEC 61850, because "it supports complex named objects and a rich set of flexible services", providing straightforward mapping with IEC 61850. Many concepts of the standard have a straight correspondence to MMS classes, like logical nodes, data objects and data attributes being presented by MMS named variables and their structured components, or logs being presented by MMS journals. However, it is not always necessary for ACSI services to be supported directly in all application layers. For example, ACSI has the service `GetDataSetValues` returning values of multiple data, while an AL may provide a "Get"-function for single data only. In this case the mapping has to issue several "Get"-functions to implement

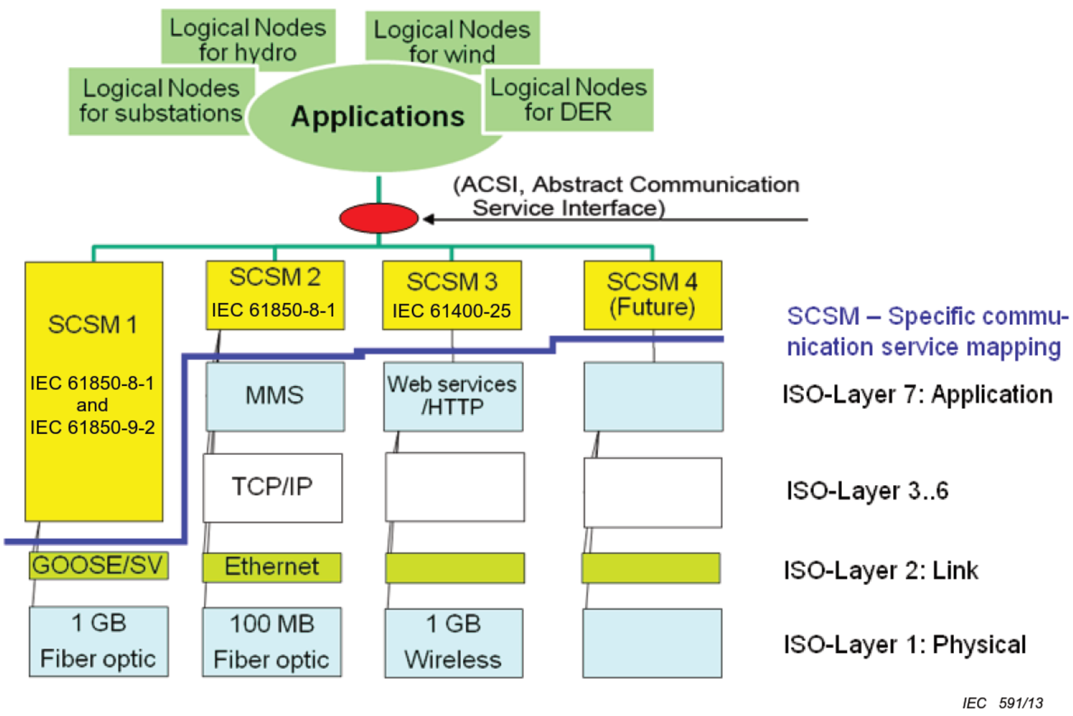

Figure 4.6 *ACSI mapping to communication stacks [78].*

the `GetDataSetValues` service, but maintains compatibility with ACSI even without direct support of the AL. [88] While MMS is run on top of a normal TCP/IP stack, GOOSE messages in IEC 61850-8-1 as well as sampled values in IEC 61850-9-2 are mapped directly to Ethernet frames (ISO/IEC 8802-3). This eliminates processing of any middle layers and improves performance.

As for other possible SCSMs, the IEC 61400-25 standard that applies IEC 61850 methodology for wind turbines includes also mappings to Web Services, OPC XML, IEC 60870-5-104 and DNP3 [95], but as of yet these mappings are not extended to be part of the IEC 61850 series. Instead, the IEC technical committee TC 57 published a technical report IEC TR 61850-80-3 in November 2015 with the title "Mapping to web protocols - Requirements and technical choices" examining the use of Web Protocols as a new communication mapping (SCSM) for the IEC 61850 standard. The need for the new SCSM was specifically to address smart grid specific challenges and use cases. The report first presents a collection of use cases for emerging smart grid architectures and applications as a new extension of the scope of IEC 61850, and charts the requirements associated with the use cases of various domains like PV, hydro, thermal, CHP and wind generation, E-Mobility, smart customers and microgrids. The report considered six different candidates for the web protocol mapping: IEC 62541 (OPC UA), IEC 61400-25-4 annex A (Web services profile for wind power), DPWS (Devices Profile for Web Services), RESTful Web Services, XML messaging over Websocket and XMPP (Extensible Messaging and Presence Protocol). Of these candidates XMPP was chosen, with key benefits listed as cyber-security, IPv6 support co-existing with IPv4, presence monitoring for use in dynamic or intermittent communications, and usage in other existing or upcoming standards. [96] The SCSM for mapping to XMPP is currently being worked on as IEC 61850-8-2, with forecasted publication date of April 2017 [97].

4.4 IEC 61850 and Distributed Energy Resources

As mentioned in the introduction of this chapter, the original scope of IEC 61850 series of substation communications has been widened to apply to other parts of power utility automation as well. This is achieved by publishing extensions based on the same concepts as the core standard, but applying those concepts on a new area of power system applications. Examples of published extensions include the aforementioned IEC 61400-25 for wind power plants as part of the IEC 61400 standard series on wind power, and IEC 61850-7-410 and 61850-7-510 for hydroelectric power plants as extensions to the original series. The extensions include additional application specific logical nodes, such as in IEC 61850-7-410, and guidelines on how to use the new defined logical nodes as well as the other parts of IEC 61850 series in order to model the respective applications, as in IEC 61850-7-510.

In 2009, the extension IEC 61850-7-420: "Basic communication structure - Distributed energy resources logical nodes" was published with the goal of establishing IEC 61850 as the common standard for the exchange of information with DER units. According to the scope of the standard, this comprises "dispersed generation devices and dispersed storage devices, including reciprocating engines, fuel cells, microturbines, photovoltaics, combined heat and power, and energy storage" [98]. The standard does not however limit its scope to the modelling of the actual DER units, but takes a more holistic approach: in addition to the internal parameters of DER units and the associated power converters, special attention is paid to the connection of the DER units to local systems as well as the utility network. An overview of the usage of new and existing logical nodes as well as potential groupings to logical devices in a DER system is presented in Figure 4.7. The DER related logical nodes have their own group indicator D.

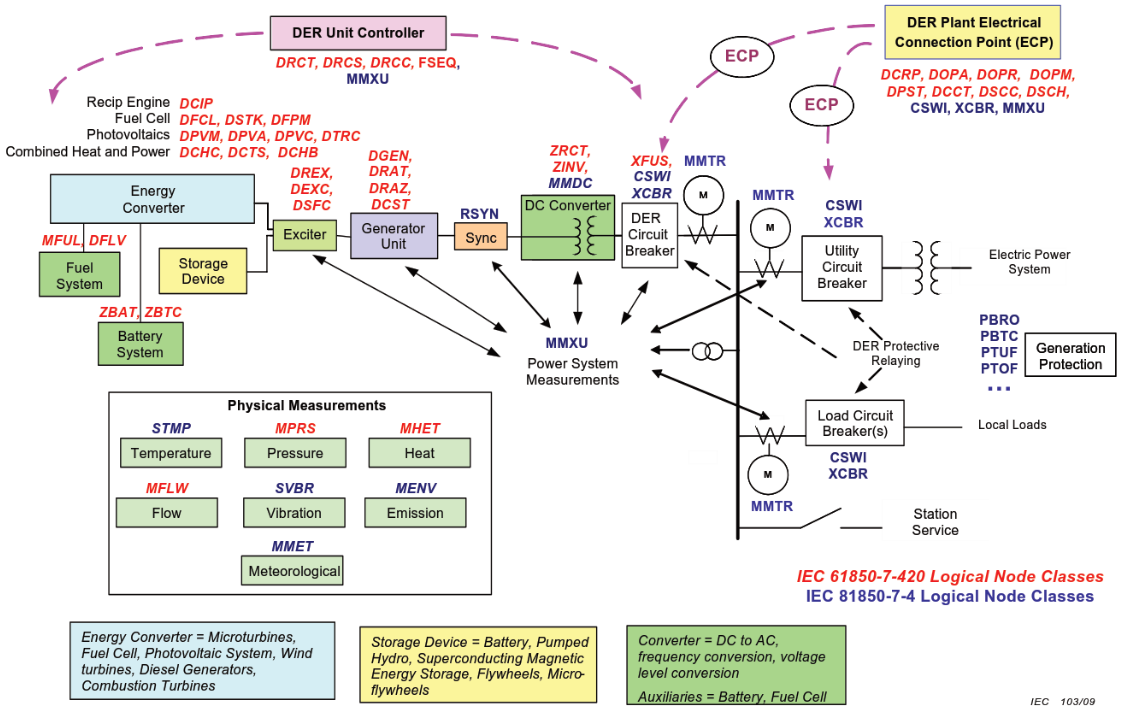

Figure 4.7 *Conceptual organization of DER logical devices and logical nodes [98].*

In its approach to modelling the connection of DER units, IEC 61850-7-420 defines two terms: *DER plant* and *electrical connection point* (ECP). DER plant is defined as "one DER unit and/or a group of DER units which are connected at an electrical connection point (ECP)" [98]. An ECP is then defined as a logical device that "defines the characteristics of the DER plant at the point of electrical connection between one or more DER units and any electric power system" [98]. Electric power systems include isolated loads, microgrids and the utility power system, and usually a switch or a circuit breaker is present at the point of an ECP. The ECPs may therefore have a hierarchical structure: a DER unit can have an ECP connecting it to a local bus with other DER units, the bus can have an ECP connecting it to the local power system with loads and the local power system can have an ECP connecting it to the utility power system. The lastly mentioned ECP between local and utility power systems is of specific interest in microgrid applications, since it is identical to the point of common coupling (PCC) of the microgrid discussed in Chapter 2. The defined ECP related logical nodes can contain information on the DER plant contractual and operational characteristics, like possible operating modes, economic dispatch parameters, schedules and operational authorities of different roles regarding the DER plant control. The ECP information assumes the "DER plant" i.e.

a single DER unit or a collection of units can be described uniformly at the ECP: for example with a single mode of operation like constant watts, or with uniform operational authorities. The defined LNs are provided to be used as necessary and may or may not be implemented in any specific ECP, so for example the PCC and all possible microgrid management regarding different units is not restricted to being described as a simple collection of mostly enumeration- and range-based LNs, but rather they should be used if appropriate. Possible legacy logical nodes of IEC 61850-7-4 to be used include an LN of the switching device at the ECP (CSWI, XCBR) as well as measurement LNs for actual power system measurements (MMXU) and interval metering information (MMTR). IEC 61850-7-420 also defines a LN for fuses (XFUS), since they may be monitored in some DER devices.

As for individual DER units, the extension recommends a DER device controller logical device that defines the operational characteristics of the single DER unit regardless of the type of generator or prime mover involved. Logical nodes defined for this include

- DRCT for DER controller characteristics like nominal output power, start and stop time delay as well as ramp load or unload rate.
- DRCS for DER controller status like ECP connection status, remote/local mode, availability and on/off status.
- DRCC for DER supervisory control like setpoints for output active/reactive powers, fixed power factor, frequency or voltages or choosing operation modes.

Likewise, for non-storage DERs a single generator model is defined regardless of the prime mover of said generator. In addition to the generator operation (DGEN), basic ratings (DRAT) and advanced features (DRAZ) describing the electrical control and characteristics of the generator at the level of detail necessary, a DCST logical node is defined for costs associated with generator operations. Regular LNs possibly needed include RSYN for synchronization, and FPID for modelling a PID regulator. For excitation systems used to start the generator, two LNs are defined: DREX for excitation ratings like voltages and currents at no load or at rated power factor, and DEXC for excitation controls and status information. For speed/frequency control of generators, a DSFC logical node is provided with settings on power droop, reference frequencies and power reserved for over- or under-frequency control.

Since many DER units connect to the grid through a power electronic interface and this has a significant impact on the control and settings needed, the modelling of these power converters is of specific interest. In IEC 61850-7-420, LNs ZRCT for rectifiers and ZINV for inverters are defined with both characteristic and current status information as well as the settings to control the output setpoints and input limits. However in 2013 IEC TC 57 released a whole technical report, IEC/TR 61850-90-7, focusing solely on the object models for power converters in DER systems. The goal of the TR is to provide means to the information exchange between "power converter-based DER systems and the utilities, energy service providers or other entities which are tasked with managing the volt, var, and watt capabilities of these power converter-based systems" [99]. This TR uses existing logical nodes of 61850-7-4 and 61850-7-420, but in some cases adds new data objects to the existing LNs, and also defines some new logical nodes. Both high level interactions, focused on the ECP of DER systems, as well as more direct interactions between local DER management systems and the DER controllers are identified as necessary. New LNs for the ECP logical device include curve-based operational mode commands, array for defining these mode curves as well as dynamic reactive current support, frequency-watt modes and feed-in watt-triggered modes of operation. The local interactions happen directly with the logical nodes of controllers, generators, power converters and other equipment as necessary, with additions of data objects to the existing LNs rather than new logical nodes.

Specific types of DER units have their own logical nodes defined in IEC 61850-7-420 for the energy converter of the primary energy source to electrical energy. A reciprocating engine is modelled by a DCIP LN, with settings on minimum and maximum speeds as well as heat rate curves of the engine, controls for speed, torque and start/stop commands as well as measured values for actual speed, torque and so forth. A fuel cell has three logical nodes: DFCL for fuel cell specific controller characteristics not found in DRCT, DSTK for fuel cell stack information and measurements like voltage and temperatures, and DFPM for the fuel cell processing module describing e.g. fuel types and measuring accumulated input and output energies as well as conversion efficiency. Photovoltaics (PV) installations vary largely in size and power, and with differing configurations the need for characteristics and status items and their number vary accordingly. Four dedicated LNs are defined: DPVM for single PV module ratings, DPVA for PV array characteristics of varying size, DPVC for the PV array controller maximizing the array power output and DTRC tracking controller for following the movement of the sun.

Combined heat and power (CHP) units are even more varied, as the term covers multiple types of generation systems involving heat in the production of electricity, with differing production priorities and restrictions, ownerships, market interactions as well as the prime movers of the system. Chosen approach is to model individiual parts of CHP systems, which can then be used as needed to construct different configurations of CHP systems. The generator and prime mover are modelled with the LNs mentioned earlier, and new LNs are defined for the CHP system controller (DCHC), thermal storage (DCTS) and the boiler system (DCHB). A wide range of different measurements may also be necessary, like pressure, temperature, flow, vibration, emission and meteorological measurements. Some are already represented in IEC 61850-7-4, but some are also suggested in the extension, though it is noted that they are not "complete" and due to their likely usage in many systems, the IEC TC57 workgroup 10 (WG10) will develop the final versions to cover all requirements and those will be then be referenced as the official LNs [98]. Logical nodes for other auxiliary systems are also defined in the standard. This includes fuel systems for covering fuel characteristics as well as the delivery system for the fuel, battery systems for modelling the battery system characteristics and the charger for the system and some miscallenous logical nodes possibly needed by DER systems, like a sequencer for startup or shutdown sequences or the aforementioned fuse device.

5. CASE STUDY: ADAPTIVE PROTECTION IN MULTIPOWER TEST ENVIRONMENT

In this chapter, the principles of adaptive microgrid protection presented in Chapter 3 are demonstrated in a simple example configuration of the Multipower test environment of VTT Technical Research Centre of Finland located in Espoo, Finland. The control and protection system of the environment is provided by ABB and is implemented using IEC 61850. Still at the early stages of development, this case study aims at proving the capabilities of implementing diverse protection schemes for future test cases.

5.1 Multipower test environment

Multipower is an empirical research infrastructure where new technical solutions and products for distributed energy systems can be tested in a multifunctional environment. The laboratory facilities have a strong interconnection with the VTT research area of efficient machines and vehicles. The switchgear and cable system of 400 V AC, 50 Hz is connected to the 20 kV distribution network via 0,5 and 1 MVA transformers. The environment is located in two separate halls inside a single building, with a cable system connecting the two busbars as needed. An example configuration of the environment is presented in Figure 5.1.

The Wärtsilä hall is largely used for motor testing and generally contains equipment with higher ratings compared to the turbine hall. These include a 1,6 MVA diesel generator unit, as well as adjustable resistive loads of 2-339 kW and 10-1700 kW. Another diesel generator rated 60 kW/200 kVA is in the process of being transformed to a movable unit. A brake dynamometer with a motor/generator rated at 570 kVA and a 755 kVA frequency converter is also available for motor test runs. At the turbine hall the environment is equipped with a modern IEC 61850 based control and protection system and is envisioned to host a wide variety of different DER

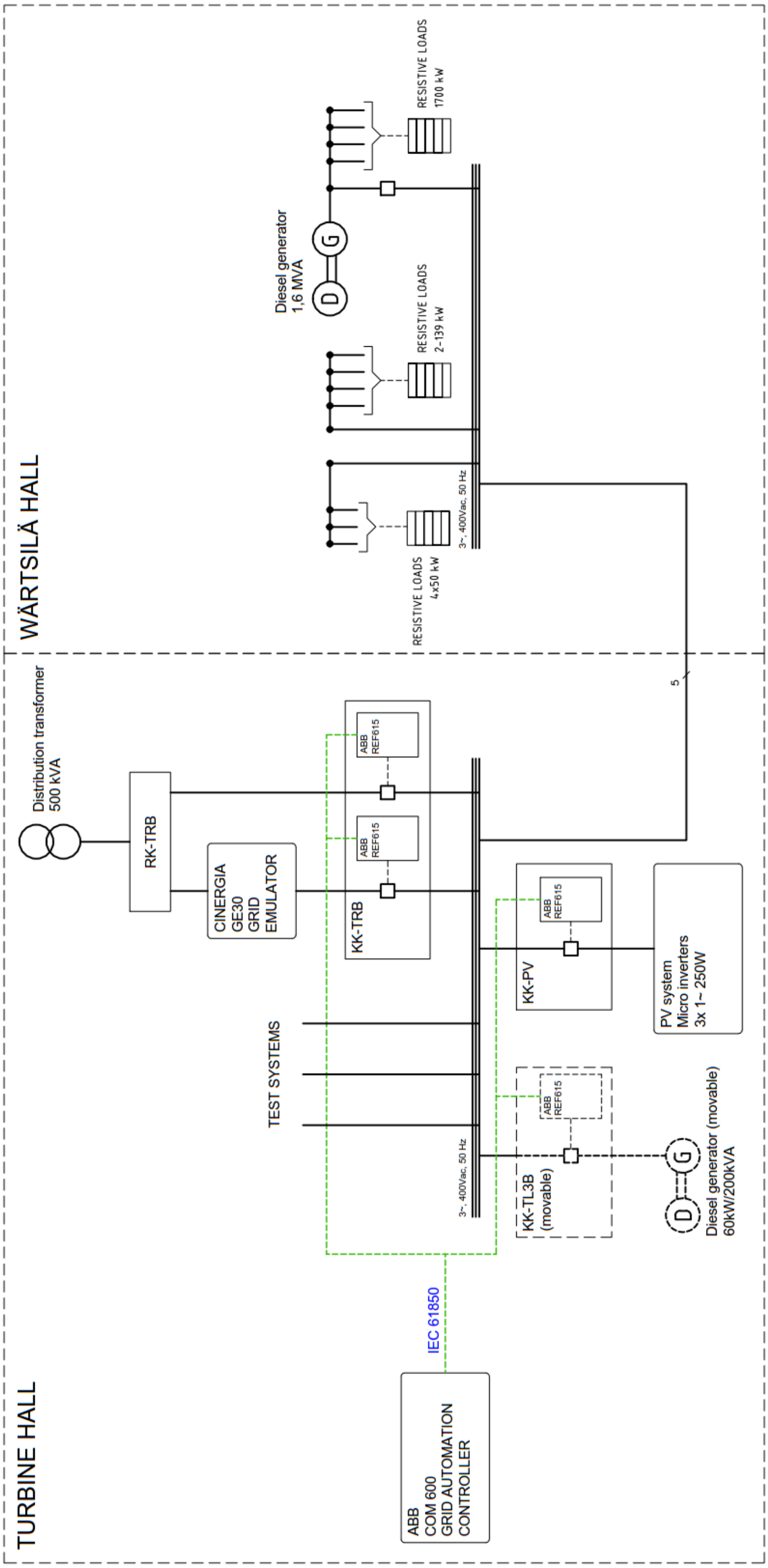

Figure 5.1 *An example configuration of the Multipower test environment.*

units as well as being capable of islanded microgrid operation. Ongoing installations include a micro-scale PV system of 750 W with environmental measurements and a grid emulator CINERGIA GE30 as an alternative feed-in source to the actual distribution network connection. Rated at 400 V and 30 kVA, the emulator is capable of generating different grid conditions as well as injecting disturbances such as balanced and unbalanced voltage dips, harmonics and frequency fluctuations to the network [100]. Test sites for energy storage of 35 kW and external units up to 100 kVA are also available. The control and protection system consists of an ABB COM600 grid automation controller and four REF615 feeder protection IEDs. Communication network based on Ethernet includes an industrial switch and a GPS time synchronization server using the Simple Network Time Protocol (SNTP).

5.2 Adaptive protection scheme and implementation

One of the most important configuration changes in a microgrid is the transition between grid-connected and islanded mode of operation, potentially presenting two very different sets of operating conditions. This may raise the need for adaptive protection discussed in Section 3.3, including adapting the protection of DER units to solve issues examined in Section 3.1.3. With communication capabilities between the IED located at the PCC of the microgrid and other microgrid IEDs, adaptive response can be realized through messaging the transition and accordingly triggering setting group changes in the relevant IEDs in the microgrid. IEC 61850 presents a very well tailored solution to this kind of communication between IEDs in the form of GOOSE messages discussed in Section 4.3.4. In the following case study these GOOSE messages are used to adapt the protection settings of a DER unit protection IED to demonstrate the implementation of adaptive protection using the new protection system in the Multipower environment.

5.2.1 Test system and desired operation

This case study considers a lightweight test microgrid system consisting of a 11 kW engine-generator set and a 9 kW resistive heating load installed in the turbine hall as shown in Figure 5.2. The goal of the study is verifying the islanding capability of the turbine hall part of the Multipower test environment, and implementing a simple adaptive protection scheme that adjusts the voltage and frequency protection settings of the IED at the generator according to the connection status of the microgrid. The protection scheme is realized using pre-defined setting groups and GOOSE messages between the IEDs at the PCC of the microgrid (Q02) and the generator circuit breaker (Q03). Because of the simplicity of this demonstration using only two IEDs, logic of setting group changes is implemented straight in the relay application configuration. In the case of more sophisticated scenarios, a logic processor engine for the whole environment could be implemented in the COM600 grid automation controller using IEC 61131-3 compatible languages as demonstrated in [45].

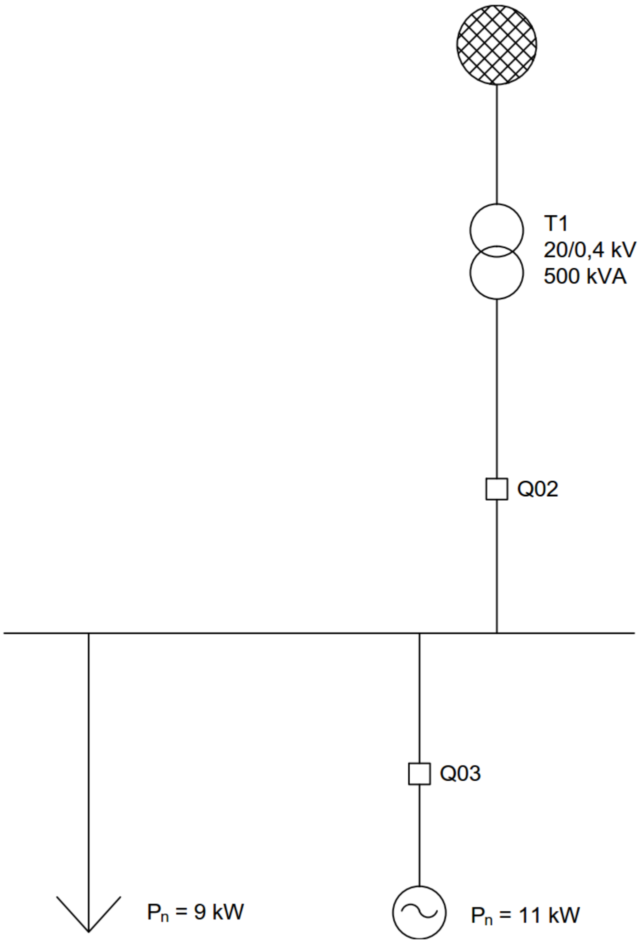

***Figure* 5.2** *Single line diagram of the system used in the case study.*

The relays have been named as REF615_verkko for the IED at Q02 and REF615_TL3B for the IED at Q03. The desired operation of the system can be summarized as follows:

- If the microgrid transitions to island operation, i.e. Q02 is opened, REF615_verkko sends information of this to REF615_TL3B

- While in islanded mode, REF615_TL3B changes its voltage and frequency protection settings to allow for larger deviations from nominal values to maintain island operation according to Table 5.1

- If communication between the relays is lost, REF615_TL3B assumes the more restricting scenario and uses the grid-connected settings.

Table 5.1 *Setting groups for voltage and frequency protection of REF615_ TL3B.*

Protection function	SG1 (grid-connected)	SG2 (islanded)
f>	51 Hz	54 Hz
	0,2 s	1,3 s
f<	48 Hz	47 Hz
	0,2 s	2,9 s
U>	110 %	110 %
	0,2 s	2,7 s
U<	85 %	85 %
	0,2 s	2,5 s

The settings for grid-connected operation are based on the recommendations of the Finnish energy industry interest group Energiateollisuus for connecting generation to the distribution network [101], while island operation parameters are based on those used in the Hailuoto island microgrid pilot as described in [45].

5.2.2 IEC 61850 model

The relevant IEC 61850 objects of the IEDs in implementing the described scheme are presented in Figure 5.3. As can be seen, many LNs use the optional prefix and numerical suffix in their name as discussed in Section 4.2.1. The REF615 feeder protection IEDs used in this study contain three logical devices: CTRL for control equipment, DR for the disturbance recorder and LD0 for protection and other functions. As said, only relevant parts are presented, and some LNs required by the standard are omitted from the figure for clarity, including the `LPHD` logical node in the CTRL logical device describing the actual physical IED, and the `LLN0`

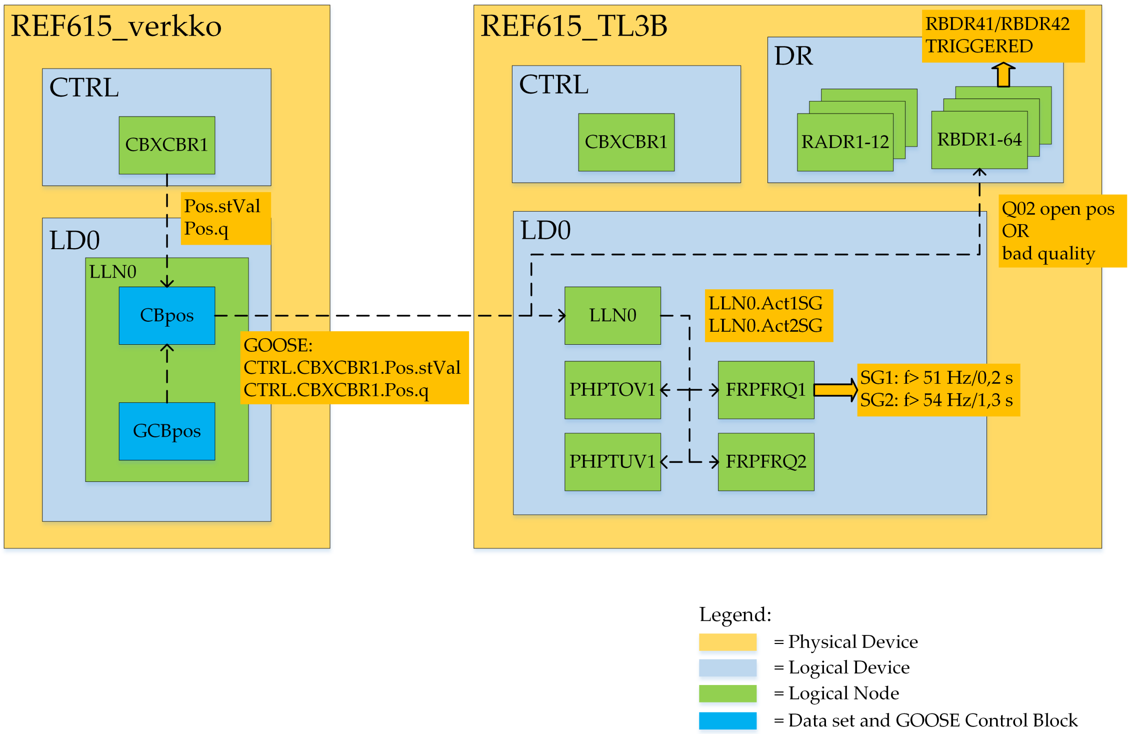

Figure 5.3 *The IEC 61850 model of the relevant objects of the case study IEDs, and the general information flow of the adaptive configuration.*

logical node required for each logical device but only shown in the LD0s. The relevant logical nodes are shortly presented in Table 5.2.

Table 5.2 *Logical nodes relevant to the implemented protection scheme.*

LN	Purpose
LLN0	Common logical device information
XCBR	Circuit breaker
PTOV	Overvoltage protection
PTUV	Undervoltage protection
PFRQ	Frequency protection
RADR	Disturbance recorder analog channel
RBDR	Disturbance recorder binary channel

In the sender IED REF615_verkko, position information of the circuit breaker is located in the `XCBR` LN for the circuit breaker. A data set, as presented in Section 4.3.2, is created containing this information. Then a GOOSE control block is created for sending the information in the defined data set to the receiving IED. Both the data set and the GOOSE control block are located in the `LLN0` logical node. In the receiving relay, the GOOSE message is used by the LN `LLN0` to manage the active setting group for all the protection functions of the LD0 logical device, as well as in the `RBDR` LNs in the disturbance recorder logical device DR to trigger recordings upon changes in received data.

5.2.3 Implementation

The relay configurations were done using the PCM600 Protection and control IED manager tool. In PCM600, the IEDs are referenced by their technical keys, `AA1N1Q02A1` for REF615_verkko and `AA1N1Q03A1` for REF615_TL3B. The IEC 61850 configuration tool of PCM600 is used to configure the information exchange. First, a data set `CBpos` is defined to LD0 of REF615_verkko containing the position information of the circuit breaker Q02, represented by the IEC 61850 object `AA1N1Q02A1.CTRL.CBXCBR1`. A general rule for the order of data arrangement in a data set is the signal to be sent first, followed by its quality. Following this the dataset, shown in Figure 5.4, consists of two entries: the actual value of the position `Pos.stVal` and the quality of said value `Pos.q`.

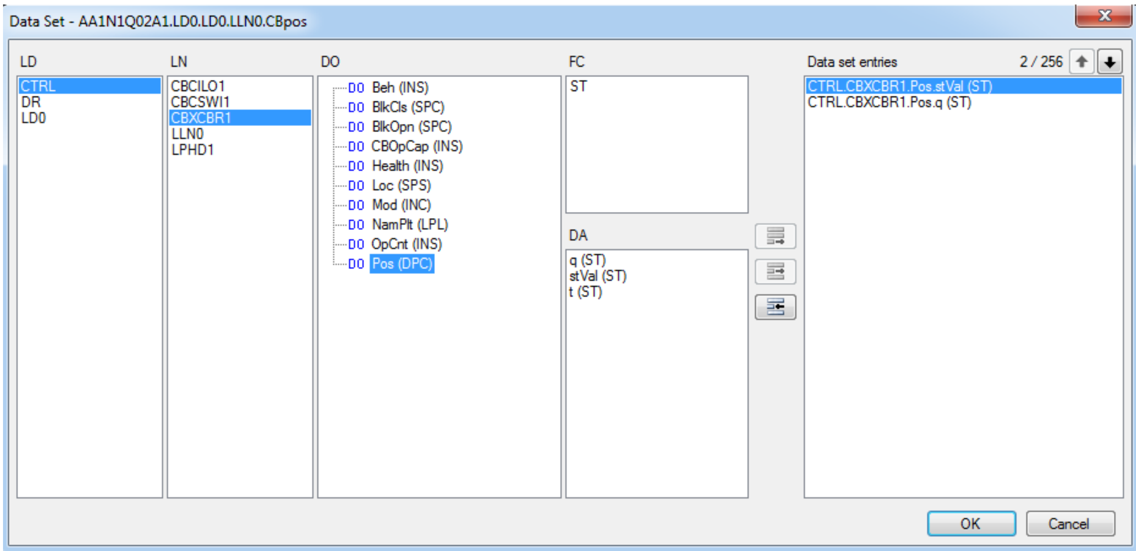

Figure 5.4 The `CBpos` data set used in GOOSE communication of the case study.

Next, a GOOSE control block `GCBpos` is created, choosing `CBpos` as its data set and the LD0 of REF615_TL3B as its subscriber. This makes the data set available to be used at the receiving IED, as shown in Figure 5.5. Finally, these inputs are then mapped to a `GOOSERCV_INTL` function block through the Signal Matrix tool, making them available in the application configuration as outputs of said function block.

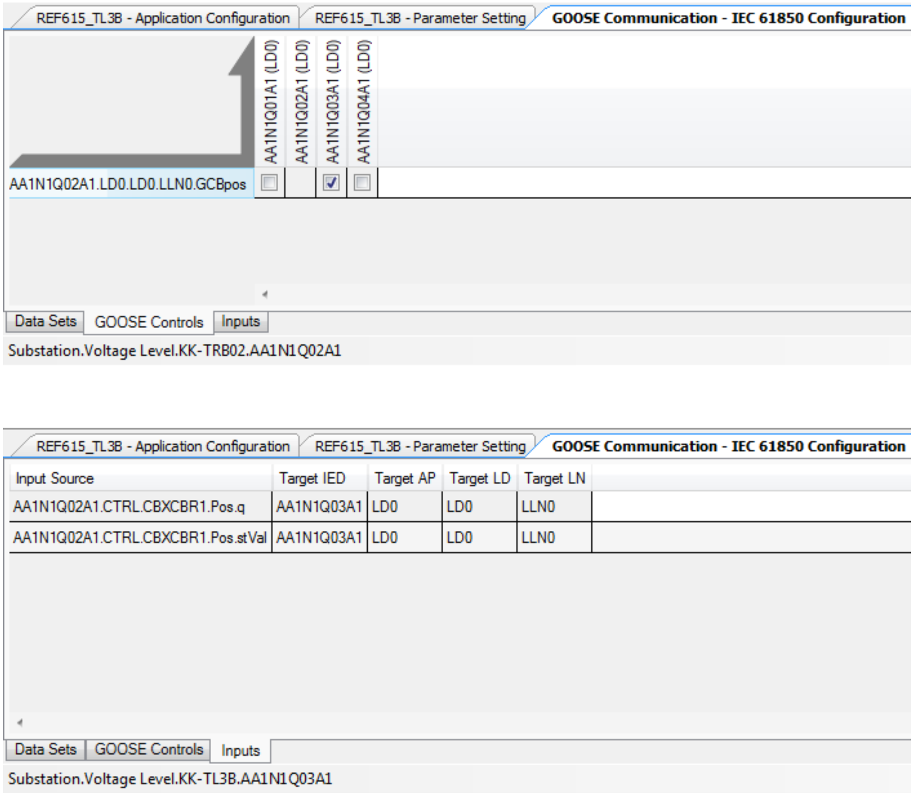

Figure 5.5 *Connection of the defined data set to the receiving IED using the GOOSE control block GCBpos (top) and received inputs at REF615_TL3B (bottom).*

To change setting groups at REF615_TL3B according to the GOOSE messages, the data object `LD0.LLN0.LgcSelSG` is set to logic mode 1 to allow controlling the setting groups via binary inputs. As the setting groups are common for all LNs of the LD0 logical device, they are activated by the `LLN0` logical node for common LD information. The data received in GOOSE messages is then used in the application configuration to determine the used setting group as shown in Figure 5.6. The GOOSE quality can be used to monitor the communication network between the IEDs: as explained in Section 4.3.4, GOOSE messages are sent periodically with a longer cycle time in addition to immediate transmission upon value changes. If a message doesn't arrive within this cycle time, the quality of the GOOSE signal changes to invalid, and the communication failure can be detected. Therefore both proper position information and validity of this information is required for activation of setting group 2. As soon as the binary input `BI_SG_2` changes back to 0, setting group 1 is reactivated.

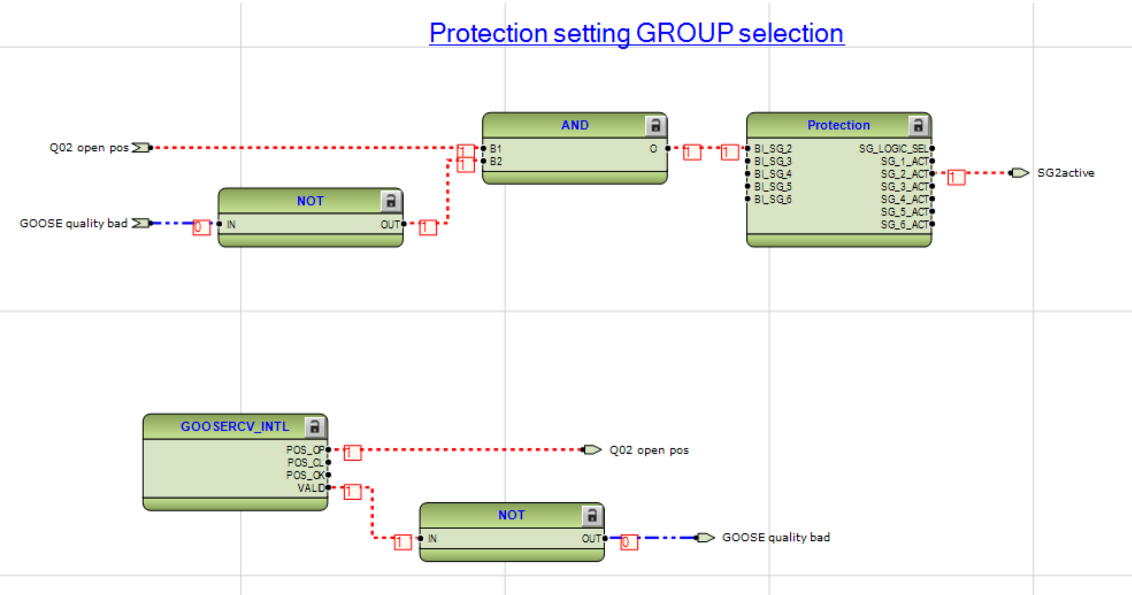

Figure 5.6 *Setting group selection using the received GOOSE messages at REF615_TL3B.*

For triggering the disturbance recorder to record GOOSE related events, the position information is also connected to the binary input 41 in the disturbance recorder of the IED (`DR.RBDR41`) as shown in Figure 5.3 to trigger a recording when Q02 opens. In the same way the quality value is connected to `DR.RBDR42` to trigger a recording if the information quality changes to invalid.

5.3 Test results

The behaviour of implemented protection scheme was tested for two cases: islanding of the microgrid and communication failure between IEDs. At the beginning of the islanding test both breakers Q02 and Q03 were closed, so the diesel-generator set was running in parallel with the distribution network. Then breaker Q02 was manually opened, corresponding to disconnection command issued to the PCC. System behaviour was monitored through the disturbance recorder of REF615_TL3B. Figure 5.7 shows the record of the setting group change during islanding in the winwave32 program. The activation of the "Q02 open" signal marks the moment the message is received through GOOSE at TL3B, and so the setting group is immediately changed. The actual delay between sending of the GOOSE message at REF615_verkko and the change of setting group at REF615_TL3B was measured over ten test runs. With the 1600 Hz sampling frequency corresponding to a time resolution of 0,625 ms, the delay varied between 2,500 and 6,875 ms with an average delay of 4,4 ms. It can also be noticed that after the CB opening the overvoltage protection function `PHPTOV1` was briefly started, but maintained the defined pick-up value for less than 50 ms. The frequency response of the system is presented in Figure 5.8. The islanding transient results in a frequency minimum of 48,4 Hz, and while the disturbance record lasts for only 5000 ms, frequency eventually stabilized at 49,4 Hz.

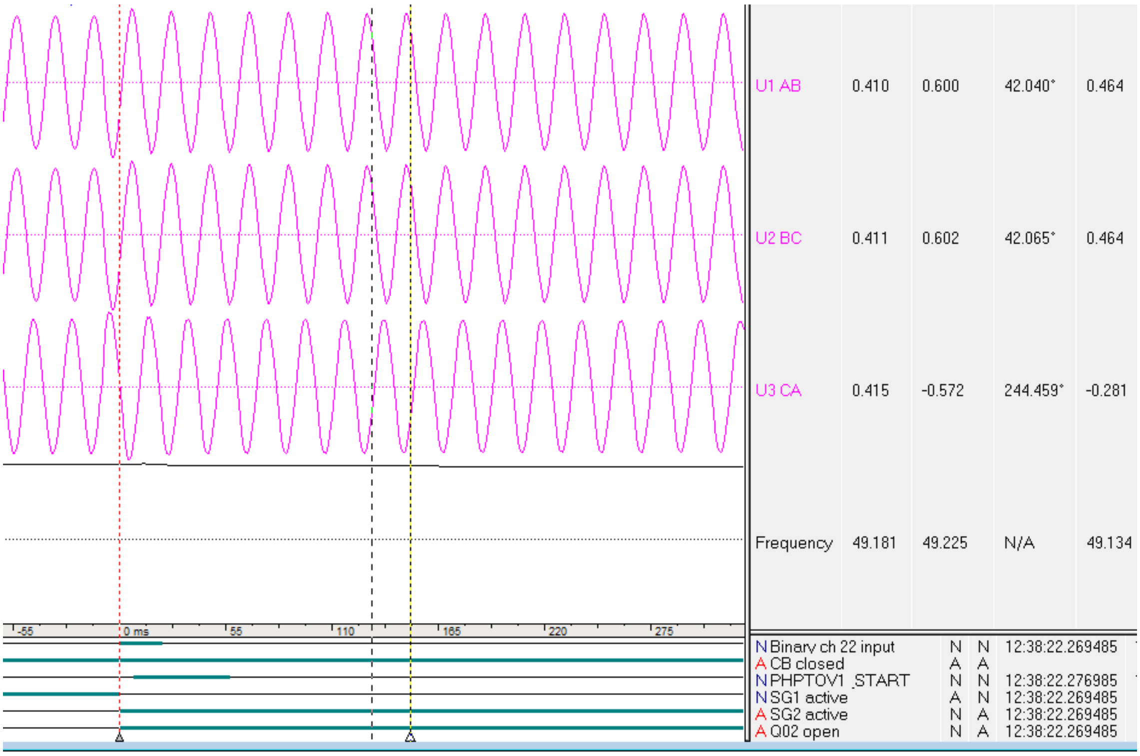

Figure 5.7 *Setting group change to SG2 during islanding.*

Communication failure was tested by disconnecting the Ethernet cable of REF615_TL3B while setting group 2 was active. As can be seen from Figure 5.9, when the IED detects the invalid GOOSE quality the active setting group is changed back to SG1. The maximum delay in detecting the loss of communication is determined by the setting `MaxTime` of the GOOSE control block in REF615_verkko,

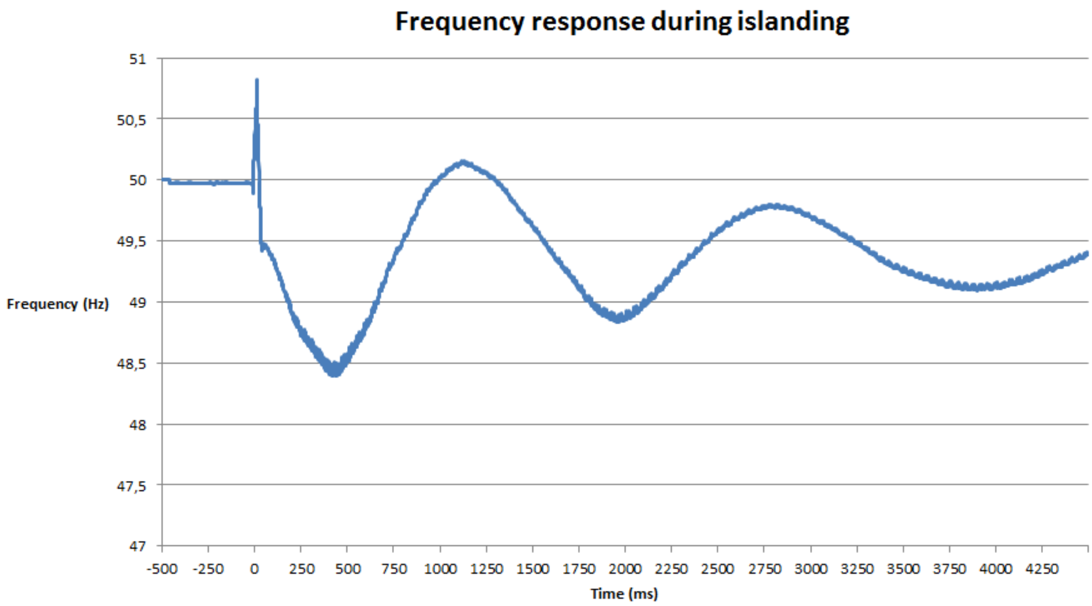

Figure 5.8 *Frequency response of the test system during islanding.*

which defines the periodic retransmission cycle time, often termed the heartbeat cycle, for its data set [102]. The value used in this configuration was 10000 ms, and represents the worst case delay for communication failure detection. Smaller values will result in faster detection, but will also increase traffic in the communication network. While definitely not limiting in this test case between just two IEDs, this is a potential problem to be considered with wide configurations of large amounts of IEDs whether inside substations or in a larger microgrid configuration.

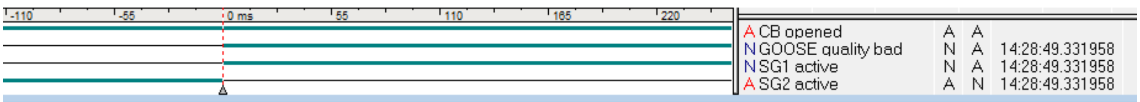

Figure 5.9 *Setting group change back to SG1 after communication failure indicated by GOOSE quality.*

5.4 Suggestions on further research

In this chapter the capability of the new IEC 61850 based protection system to implement adaptive protection was demonstrated. Potential future work with the protection system includes:

- complementing the protection scheme to a complete microgrid solution with more complex operation and coordination with multiple IEDs including possibly conflicting scenarios
- testing of the grid emulator CINERGIA GE30 in introducing actual faults to the feeding network, and islanding under these fault conditions
- protection coordination with several DER units with different characteristics such as directly connected and converter based DG units with different fault current feeding capabilities
- operation of parallel inverters with different control and protection functions
- introducing controllable loads to the network and potentially using load shedding as part of the islanding routine when islanding under heavy load
- studying the usage of other networks for communication, such as using a 4G Long-Term Evolution (LTE) network for GOOSE messaging

For additional components, the incorporation of other related VTT research areas such as fuel cells and electrical vehicle (EV) charging stations would bring major new elements to the system. As for IEC 61850 specific research, and extending the scope of usage in the environment, the environmental measurements of the micro-PV system to be installed could be converted to IEC 61850 based data such as the logical node MMET for meteorological information, and distributed further using IEC 61850. The new DER units such as a fuel cell could be interfaced with an appropriate IED and modeled using the new LNs introduced in IEC 61850-7-420, studying the completeness and suitability of the extension. A natural extension would also be introducing multi-vendor IEDs to the environment, testing the current interoperability capabilities of the standard series.

The scope of research could also be extended to cover interoperability between different smart grid standards. The COM600 grid automation controller is planned to be used for connections outside the environment network, and could serve as a testing platform for the harmonization of IEC 61850 and other used smart grid standards like the Common Information Model (CIM). Similarly, translation of the IEC 62056 Companion Specification for Energy Metering (COSEM) object model to the IEC 61850 data model is currently in Draft Technical Specification (DTS) stage, as a proposed extension IEC 61850-80-4. If a smart meter was installed to loads connected to the environment, the interoperability of these two standards could also be examined.

6. CONCLUSIONS

Increasing use of renewable energy sources, penetration of distributed energy resources in the distribution network, and stricter requirements of the security, reliability and quality of electricity supply are driving a change in existing electricity grids from passive networks to active smart grids. Microgrids, defined as part of the smart distribution grid with capability of island operation, are envisioned as one of the promising concepts in supporting the goals of future power systems. In addition to the physical network equipment and a combination of distributed energy resources (DER), an advanced control and monitoring system capable of managing the microgrid as a whole and extending DMS-like functionality to the lower levels of the distribution network is a main component in realizing the microgrid concept.

To successfully transition into island operation after an utility network fault, the separation of the microgrid must be fast enough to maintain stability inside the microgrid after islanding. The required speed is determined by the type and characteristics of DER units in the microgrid as well as sensitivity of customer loads such as induction motors. Resynchronization back to the utility grid must be done with sufficiently small voltage, frequency and phase angle deviations to prevent system oscillations after reconnection. Special attention must be paid to control methods for voltage and frequency that differ from traditional systems and vary according to the operation principles of DER units in the microgrid.

Main protection issues regarding microgrids are adverse effects of DER units on fault currents and reclosing, greatly reduced fault current feed-in capabilities of power electronic interfaced DER units compared to directly connected units, change of operation conditions between islanded and grid-connected modes, changing grid configurations, unwanted operation of DER anti-islanding protection and potential earth fault detection problems at DER units. Some form of adaptive protection, i.e. modifying the response of the protection system according to power system conditions, is deemed necessary to cope with these challenges.

The IEC 61850 series offers a wide standardization of information models and data flow in power utility automation systems as well as associated management and engineering processes, with interoperability, extendability and support for future technologies embedded in design. Originally designed for substation automation, the standard has been extended to other areas such as hydro power, power converters and distributed energy resources, and has potential to be applied widely in the distribution network. An adpative protection scheme for VTT's Multipower test environment using IEC 61850 was realized by using the freely configurable, fast GOOSE messages of the standard to initiate predefined setting group changes in protection IEDs in a simple test configuration of an islanding microgrid. Capability of islanding and the correct operation of the implemented protection scheme was demonstrated.

Potential future work includes more sophisticated scenarios with generation units and energy storages of different characteristics, studying system behaviour under utility grid faults using the grid emulator to inject disturbances, and introducing controllable loads to the system, potentially to be used as part of the islanding routine. Other research possibilities in the Multipower environment include examining the use and applicability of different networks such as LTE for protection functions, incorporation of other VTT research areas such as fuel cells and electric vehicles in to the system and extending the environment to a testing platform for the ongoing harmonization of IEC 61850 and other smart grid standards such as CIM and IEC 62056.

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