VAASAN YLIOPISTO

HANNU LAAKSONEN

Technical Solutions for Low-Voltage Microgrid Concept

ACTA WASAENSIA NO 241

ELECTRICAL ENGINEERING 1

UNIVERSITAS WASAENSIS 2011

Reviewers
Professor Matti Lehtonen
Aalto University
School of Electrical Engineering
Department of Electrical Engineering
Otakaari 5 A
FI–02150 Espoo
Finland

Professor Juha Pyrhönen
Lappeenranta University of Technology
Department of Electrical Engineering
P.O. Box 20
FI–53851 Lappeenranta
Finland

Julkaisija
Vaasan yliopisto

Julkaisupäivämäärä
Huhtikuu 2011

Tekijä
Hannu Laaksonen

Julkaisun tyyppi
Artikkelikokoelma

Julkaisusarjan nimi, osan numero
Acta Wasaensia, 241

Yhteystiedot
Vaasan yliopisto
Teknillinen tiedekunta
Sähkö- ja energiatekniikan yksikkö
PL 700
65101 Vaasa

ISBN
978–952–476–344–8 (nid.)
978–952–476–345–5 (pdf)

ISSN
0355–2667, 1799–6961

Sivumäärä
271

Kieli
Englanti

Julkaisun nimike
Pienjänniteverkon microgrid-konseptin tekniset ratkaisut

Tiivistelmä

Laajamittainen hajautetun energiantuotannon yksiköiden ja energiavarastojen liittäminen tulevaisuuden sähkönjakeluverkkoihin vaatii uuden älykkään jakeluverkkoarkkitehtuurin luomista. Microgrid-konseptin odotetaan olevan keskeisessä osassa tulevaisuuden älykkäissä sähkönjakeluverkoissa. Microgrid-konseptin erityispiirre on sen kyky tarvittaessa, esimerkiksi yleisen sähkönjakeluverkon vikatilanteissa, jatkaa automaattisesti toimintaansa omana erillisenä osakokonaisuutena ns. saarekkeena irrallaan vikaantuneesta jakeluverkosta. Saarekekäytön aikana sähkönjakelua microgrid-verkon asiakkaille voidaan siis jatkaa keskeytyksettä. Microgrid-konsepti mahdollistaa sähkönjakelun luotettavuuden sekä energiatehokkuuden parantamisen tulevaisuudessa, mikäli hajautettuja energiaresursseja hallitaan älykkäästi sekä microgrid-verkon sisällä että yleisen jakeluverkon rinnalla omana aktiivisena osakokonaisuutenaan.

Tutkimuksen tavoitteena on kehittää ja määritellä pienjännitteisille microgrid-verkoille tekninen kokonaiskonsepti, joka mahdollisimman luontevasti olisi integroitavissa tulevaisuuden älykkäisiin sähköverkkoihin. Pienjänniteverkon microgridin keskeisiä teknisiä haasteita ovat siirtyminen saarekekäyttöön, sähkön laadun hallinta ja suojauksen toteuttaminen erityisesti saarekekäytössä. Merkittävässä osassa kokonaiskonseptia kehitettäessä on ollut teknisten ratkaisujen ja toimintaperiaatteiden luominen siten, että kaikki ratkaisut olisivat keskenään yhteensopivia.

Kehitetyssä konseptissa keskitetty energiavarasto ja sen sijainti ovat tärkeitä microgridin hallinnan ja suojauksen toteutuksen kannalta. Tämän tutkimuksen teknisten ratkaisujen ja toimintaperiaatteiden kehittäminen perustuu lukuisiin PSCAD-ohjelmalla tehtyihin simulointeihin erilaisilla komponenttikonfiguraatioilla. PSCAD mahdollisti erityyppisten hajautetun energiantuotannon ja energiavarastoyksiköiden sekä kuormitusten keskinäisten vuorovaikutusten tarkastelun, joiden toteuttaminen samassa laajuudessa laboratorioympäristössä olisi vaatinut merkittäviä investointeja laitteistoihin ja henkilöresursseihin.

Tässä tutkimuksessa microgrid-konseptiin kehitettyjä teknisiä ratkaisuja voidaan hyödyntää tulevaisuuden saarekekäytön sallivia verkkoonliityntävaatimuksia määritettäessä sekä käytännön pilot-kohteita suunniteltaessa. Tutkimuksessa esitettyjä pienjänniteverkon microgrid-konseptin teknisiä valintoja sekä toiminta- ja suunnitteluperiaatteita voidaan myös käyttää hyödyksi, kun suunnitellaan uuden sukupolven microgrid-yhteensopivia suojalaitteita, hajautettujen energiantuotantoyksiköiden liityntälaitteita ja microgridin hallintajärjestelmiä sekä tulevaisuuden markkinamalleja. Tulevaisuudessa käytännön pilot-kohteita tarvitaan kehitettyjen teknisten ratkaisujen toimivuuden varmistamiseksi ja verifioimiseksi.

Asiasanat
Microgrid, hajautettu energiantuotanto, energiavarasto, suojaus, sähkön laatu, jännitteen säätö, älykäs sähköverkko

Publisher
University of Vaasa

Date of publication
April 2011

Author
Hannu Laaksonen

Type of publication
Selection of articles

Name and number of series
Acta Wasaensia, 241

Contact information
University of Vaasa
Faculty of Technology
Department of Electrical and Energy Engineering
P.O. Box 700
FI–65101 Vaasa, FINLAND

ISBN
978–952–476–344–8 (nid.)
978–952–476–345–5 (pdf)

ISSN
0355–2667, 1799–6961

Number of pages	**Language**
271	English

Title of publication
Technical Solutions for Low-Voltage Microgrid Concept

Abstract

Future electricity distribution networks with large amount of distributed energy resources will require creation of a totally new smart grid architecture. The microgrid concept is expected to play a major role in the new smart grid architecture. A special feature of microgrids is that during disturbances in the utility grid they can continue operation automatically in the island mode so that electricity supply to microgrid customers can be continued without any interruption. Thereby, the microgrid concept allows the reliability benefit of distributed energy resources to be realized while also fulfilling the future energy efficiency requirements.

In this thesis a total technical concept for low-voltage microgrid which could be integrated into the future smart grids has been developed and specified. The key technical challenges of low-voltage microgrids are the transition to island operation, the power quality management and the microgrid protection especially during island operation. Essential part of the concept development involved the development of solutions and operation principles to these key technical challenges of low-voltage microgrids so that all these solutions would be compatible with each other. The role of one central energy storage unit and the location of it are very important in the developed concept from the low-voltage microgrid management and protection point of view. The development work with the related technical challenges was carried out in this thesis with PSCAD simulation software. PSCAD enabled the examination of a simultaneous interaction of different types of distributed energy resource units and loads both in the normal utility grid connected and in the island operation mode of the microgrid. This information from simulations with multiple component configurations was essential when the technical solutions were developed and these studies could not have been undertaken to this extent in a laboratory environment without major investments in facilities and personnel.

The developed technical solutions and findings for the microgrid concept presented in this thesis can be utilized as a basis when the grid codes for future low-voltage microgrids and the plans for real-life pilot installations are carried out. The proposed technical choices as well as operation and planning principles of the developed low-voltage microgrid concept can also be taken into account in the development of low-voltage microgrid compatible protection devices, distributed energy resource units, microgrid management systems and future market structures. In the future, real-life example cases are necessary to verify and test the functionality of the developed technical solutions.

Keywords
Microgrid, distributed generation, energy storage, protection, power quality, voltage control, smart grid

PREFACE

The research work of this thesis has been carried out during the years 2007–2010 in the Department of Electrical and Energy Engineering at University of Vaasa, where I have been working at a doctoral student position of the Finnish Graduate School of Electrical Energy Engineering (GSEEE). Part of the research work behind this thesis has been conducted in "Energy storage for managing distributed generation" -project funded by Finnish Funding Agency for Technology and Innovation (TEKES) and companies. Also part of the work has been done under "Smart Grids and Energy Market" -research program (SGEM) of CLEEN Ltd, the Strategic centre for science, technology and innovation of the Finnish energy and environment cluster.

Firstly, I am grateful to my supervisor Professor Kimmo Kauhaniemi for his great guidance. I would also like to express thanks to Mr. Risto Komulainen and Mr. Lauri Kumpulainen who first introduced me to the research of microgrids and future network visions when I was working at VTT Technical Research Centre of Finland in Vaasa during years 2005–2006.

I would like to thank the pre-examiners Professor Matti Lehtonen from Aalto University School of Electrical Engineering and Professor Juha Pyrhönen from Lappeenranta University of Technology for their valuable comments on the manuscript. I also wish to thank Dr. N. Rajkumar for his assistance in improving the language of my thesis.

In addition I would like to thank my research colleagues Mr. Tuomas Karri and Mr. Sampo Voima for collaboration and relaxing off topic discussions.

The financial support of Tekniikan Edistämissäätiö and Vaasan Yliopistoseura for this work is also highly appreciated.

Especially I would like to thank my parents and relatives for all the support and encouragement. I am also grateful to my mother, Leila Laaksonen, for proof-reading and improving the English of my thesis.

Finally, my deepest gratitude is reserved to my lovely wife Hanna and our precious daughters Loviisa and Eleonoora for everything. You really are a dream come true.

Vaasa, April 2011

Hannu Laaksonen

Contents

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Nomenclature

Acronyms

AC	Alternating Current
AF	Active Filter
AM	Adaptive Multi-criteria
AMM	Automated Meter Management
CAMC	Central Autonomous Microgrid Controller
CB	Circuit Breaker
CHP	Combined Heat and Power
DC	Direct Current
DER	Distributed Energy Resources
DFIG	Doubly Fed Induction Generator
DG	Distributed Generation
DMS	Distribution Management System
DOC	Directional Over-Current
DSO	Distribution System Operator
DSOGI-FLL	Dual Second Order Generalised Integrator – Frequency-Locked Loop
DSP	Digital Signal Processor
DTC	Direct-Torque-Control
DUoS	Distribution-Use-of-System
EHV	Extra-High-Voltage
EMS	Energy Management Strategy / Energy Management System
EMTDC	Electromagnetic Transients including DC
EN	European Norms (Standards) approved by CENELEC, the European Committee for Electrotechnical Standardization (Brussels, Belgium)
EV	Electric Vehicles
FRT	Fault-Ride-Through
GOOSE	Generic Object Oriented Substation Event
HPF	High-Pass-Filter
HV	High-Voltage
IEEE	Institute of Electrical and Electronics Engineers (Inc., New Jersey, USA)
IEC	International Electrotechnical Commission (Geneva, Switzerland)
IED	Intelligent Electronic Devices
IGCT	Integrated Gate Commutated Thyristor
IM	Induction Motor
LoM	Loss-of-Mains
LV	Low-Voltage
LVCB	Low-Voltage Circuit Breaker
LVRT	Low-Voltage-Ride-Through
MB	Microgrid Breaker, microgrid interconnection switch
MCB	Miniature Circuit Breaker
MGC	Microgrid Grid Code
MGCC	Microgrid Central Controller

MMG	Multi-Microgrid
MMS	Microgrid Management System
MV	Medium-Voltage
NTP	Network Time Protocol
OC	Over-Current
OLTC	On-load Transformer Tap Changer
PCC	Point-of-Common-Coupling
PD	Protection Device
PD 1	Microgrid protection in PCC
PD 2	LV feeder protection
PD 3	Customer protection
PD 3a	Service connection protection of customer
PD 3b	Customer protection
PD 4	DER unit protection
PI	Proportional Integral
PLL	Phase-Locked-Loop
PMSG	Permanent Magnet Synchronous Generator
PQ	Active and Reactive Power
PQC	Power Quality Compensator
PR	Proportional Resonant
PSCAD	Power Systems Computer Aided Design
PU	Active Power - Voltage, control principle
PV	Photovoltaic
PWM	Pulse Width Modulation, sine-triangle based
P/f	Active Power / Frequency, droop based control principle
Q/U	Reactive Power / Voltage, droop based control principle
RES	Renewable Energy Sources
SG	Synchronous Generator
SGS	Smart Grid Switch
SiC	Silicon Carbide
SS	Static Semiconductor based Switch
SOC	State-of-Charge
SVC	Static VAR Compensator
SVM	Space Vector Modulation, same as SVPWM
SVPWM	Space Vector Pulse Width Modulation, same as SVM
TCP/IP	Transmission Control Protocol / Internet Protocol
THD	Total Harmonic Distortion
TSO	Transmission System Operator
Uf	Voltage - Frequency, master unit control principle
UPS	Uninterruptible Power Supply
VCO	Voltage Controlled Oscillator
VPP	Virtual Power Plant
VSC	Voltage Source Converter
VTT	Technical Research Centre of Finland

Greek and Roman letters

δ	Load Angle
δ_1	Angular Displacement of the Rotor [rad]
ω_s	Synchronous Speed in electrical units [rad/s]
B	Damping Coefficient
C_{delta}	Capacitance of LCL-filter with delta connected capacitors
E'	Machine Voltage
f	Frequency [Hz]
f_{LC}	Resonance Frequency of LC-filter [Hz]
f_{LCL}	Resonance Frequency of LCL-filter [Hz]
H	Inertia Constant (the stored kinetic energy in MWs at synchronous speed per machine rating in MVA)
i_{C}	Compensating Current
i_{L}	Load (i.e. microgrid) Current
i_{S}	Grid Current
t	Time [s]
I	Current
I_{act}	Active Power Reference in Master Unit Control System
I_{meas}	Measured Current for Converter Control System
$I_{\text{meas\_DGs\_ave}}$	Sum of DG units' average 1-phase current (rms) of LV feeder [A]
$I_{\text{meas LV feeder ave}}$	Measured average 1-phase current (rms) of LV feeder [A]
$I_{\text{meas load ave}}$	Average 1-phase load current (rms) of LV feeder [A]
$I_{\text{n LV feeder}}$	Nominal current of LV feeder, 1-phase rms value [A]
I_{n}	Nominal Current
I_{react}	Reactive Power Reference in Master Unit Control System
I_{ref}	Current Reference
I_{THD}	Current Total Harmonic Distortion [%]
J	Inertia Moment
L_1	Converter Side Inductance of LCL-filter
L_2	Grid Side Inductance of LCL-filter
P	Active Power [kW]
P_{e}	Electrical power crossing the air gap [pu]
P_{a}	Accelerating Power
P_{m}	Shaft Power Input [pu]
P_{PCC}	Active power flow from LV microgrid to MV network in PCC of LV microgrid [kW]
Q	Reactive Power [kVAr]
Q_{PCC}	Reactive power flow from LV microgrid to MV network in PCC of LV microgrid [kVAr]
R	Resistance [Ω],[Ω/km]
R/X	Resistance / Reactance
R_{fault}	Fault resistance [Ω]
S_{n}	Rated Power [kVA]
T_{m}	Mechanical Input Torque
U	Voltage
U_1	Voltage at the Beginning of the Feeder

U_2	Voltage at the End of the Feeder
U_{a}, U_{b}, U_{c}	Grid Voltages
$U_{\mathrm{a\ p}}, U_{\mathrm{b\ p}}, U_{\mathrm{c\ p}}$	Positive Sequence Voltages
$U_{\mathrm{a\ n}}, U_{\mathrm{b\ n}}, U_{\mathrm{c\ n}}$	Negative Sequence Voltages
U_{inf}	Infinite Bus Voltage
U_{THD}	Voltage Total Harmonic Distortion [%]
X	Reactance [Ω],[Ω/km]
X'_{d}	Machine Reactance
X_{e}	Line Reactance
X_{trans}	Includes X'_{d} and X_{e} when connected to infinite bus through it
Z	Impedance
$Z(f)$	System Harmonic Impedance

List of Publications

This thesis consists of the following publications:

1 INTRODUCTION

Future electricity distribution networks with large amount of distributed energy resources (DER), including distributed generation (DG), electricity storages, electric vehicles and customers with smart energy meters and controllable loads, require creation of a totally new smart grid architecture. This new architecture will take advantage of the properties of DER together with new intelligent management functions and hence allows the potential of DER to be realized for different interest groups such as distribution system operators (DSOs), DG producers, service providers, consumers and society. In the development of the smart grid architecture microgrids with momentary island operation possibility should be seen as basic blocks of the architecture. The term microgrid is typically used from the low-voltage (LV) network smart grid with an island operation capability. One traditional definition for microgrid is by Hatziargyriou et al. (2006):

> "Microgrids comprise low-voltage distribution systems with distributed energy sources, such as micro-turbines, fuel cells, photovoltaics, etc., together with storage devices, i.e. flywheels, energy capacitors and batteries, and controllable loads, offering considerable control capabilities over the network operation. These systems are interconnected to the medium-voltage distribution network, but they can be also operated isolated from the main grid, in case of faults in the upstream network. From the customer point of view, microgrids provide both thermal and electricity needs, and in addition enhance local reliability, reduce emissions, improve power quality by supporting voltage and reducing voltage dips, and potentially lower costs of energy supply."

However, in the future the microgrid could be defined in a more general way as a part of smart distribution grid with an island operation capability. In that case microgrid would mean a certain part of distribution network with DER that is managed as a whole with an intelligent microgrid management system (MMS). Microgrid can be one of the following as shown in Figure 1:

1. Separate island grid
2. Small household LV microgrid or LV customer microgrid
3. LV microgrid consisting of all LV feeders connected to a MV/LV distribution transformer
4. Medium-voltage (MV) network feeder microgrid or HV/MV substation microgrid consisting of all MV feeders.

In general, the role of the microgrid management system can be seen as a transition of distribution management system (DMS) intelligence also into the lower voltage levels in distribution networks (Figure 1). In other words, this means that the microgrid management system could be responsible from the lower level operations in the future hierarchical management of smart distribution networks. In addition, there are three common microgrid features (Marnay & Firestone 2007):

– Total system energy requirements are achieved efficiently, usually by combined heat and power (CHP) technology for heating and/or cooling of buildings
– Heterogeneous levels of electricity security, quality, reliability and availability, that match the requirements of different customers, can be provided and
– It appears to the utility grid as a controlled entity.

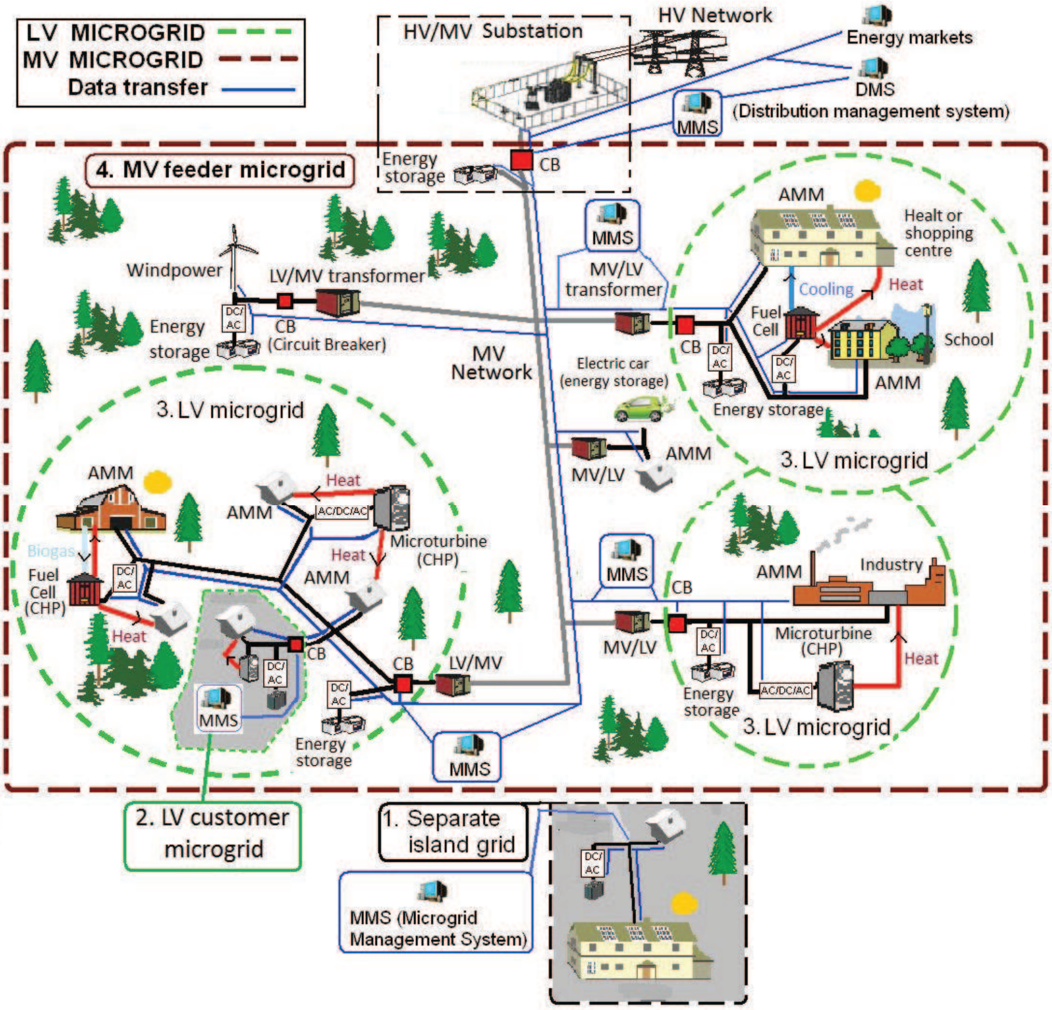


Figure 1. Different possible microgrid configurations.

The biggest impact of microgrids will be in providing higher reliability electricity distribution and better power quality to the customers. Microgrids can also provide additional benefits to the local utility by providing dispatchable power for use during peak power conditions and postponing distribution system upgrades (Kroposki et al. 2008).

Microgrids are expected to form an essential part of future smart grids with a self-healing feature. Most of the time microgrids will be operated normally parallel with utility grid. In addition to this, microgrids have a special self-healing capability, because they can continue operation also in island mode during disturbances, such as utility grid outages. Thereby, the microgrid concept can allow the reliability benefit of distributed energy resources to be realized and also fulfill the future energy efficiency requirements. In this thesis mainly technical aspects of LV microgrids are discussed. Technical choices made in the microgrid concept must be such that they can be justified by the needs of normal operation, but at the same time allowing and supporting the solutions needed for implementation of island operation.

1.1 Main objectives of the thesis

Microgrids related research has been very active for over the last five years around the world and many technical innovations have been developed, but very often the simultaneous interaction of them with each other has not been considered further. One significant distinctive feature of this thesis has been the aim to propose a total technical concept for future LV microgrids. The target has been that all the developed technical solutions will be compatible with each other so that in the end they could create a complete LV microgrid concept. However, it is not enough that the developed technical solutions only fit together. Additionally, the developed LV microgrid concept should take into account distinct features and needs of the society, DSOs, markets and customers as well as the behavior of the grid. This would ensure that LV microgrids with island operation capability could be a natural part of the future smart grids. Therefore, one of the objectives taken into consideration during the development of the LV microgrid concept has been on the capability of the concept to be integrated into the future smart grids in a justified way.

As mentioned above the development of the solutions to key technical challenges of the LV microgrid concept has been the main objective in this thesis. The detailed development of the technical solutions was carried out by multiple simulations with PSCAD power system simulation software. PSCAD has been developed by the Manitoba HVDC Research Centre and it can be used for design and verification of power quality studies, power electronic design, distributed generation, and transmission planning (Simoes et al. 2007). PSCAD is also known as PSCAD/EMTDC because EMTDC is the simulation engine, which is now the integral part of PSCAD graphical user interface. PSCAD simulation software was chosen because it is very suitable for analysis, design and verification of electrical power systems. PSCAD was also found by Simoes et al. (2007) to be the best and most suitable from different software packages tested and analyzed for microgrid modeling and simulation studies.

In general, the operation and control of island operated LV microgrid is a very complex issue because there are number of things that will have influence on the behavior of microgrid in different ways. For example the dynamic behavior of islanded microgrid is totally different when compared to the normal utility grid connected operation. Islanded microgrid is much more sensitive to disturbances and successful island operation requires fast, accurate and stable control. However, the DER unit control and configuration must be suitable for both island and normal operation.

During this Ph.D. project a number of suitable PSCAD simulation models for LV microgrid compatible DER units have been developed. The target has been to develop models which are suitable for the study of stability, power quality and protection requirements of LV microgrids as precisely as possible. Some parts from a model library created previously in a joint project between University of Vaasa and VTT have been used in the developed simulation models. However, the stable operation of converter based DER units also after transition to island operation as well as during and after disturbances required major modifications to be made to the control and configuration of the corresponding simulation models. Therefore, issues like synchronization method, current sensor location, negative sequence compensation, filter type, switching frequency, modulation method, were also examined. Component costs minimization and specification of optimal control principles for these DER units has not been the target in this thesis. To reduce the required simulation time with very accurate DER unit models, only quite large capacity three-phase DER units connected to AC low-voltage microgrids were examined in this thesis. This means that single-phase DER units as well as DC microgrids were outside the scope of this thesis. In addition, the communication between different microgrid devices has not been simulated and detailed definition of the needed communication architecture has been left for the future studies.

1.2 Scientific contribution

The main scientific contribution of this thesis has been the development and specification of the most feasible total technical low-voltage microgrid concept for future smart grids. The proposed concept can provide extremely reliable and high-quality electricity supply to the microgrid customers in the future smart grids. Previous microgrid related research has been mainly focused on the development of single device control and behavior, but the simultaneous interaction of several different microgrid connected devices has been rare. In this thesis the simultaneous interaction of several devices has been taken into account thoroughly when technical solutions have been developed. In addition, the integration of microgrids, so that they could be operated as natural part of smart grids, has not been previously considered to the same extent as in this thesis. Essential part of the total technical concept development has been in the development of solutions and operation principles to the key technical challenges of low-voltage microgrids so that all these solutions would also be compatible with each other. The key technical challenges of LV microgrids were defined in this thesis as follows:

1. Successful transition to island operation
    - Stability issues
2. Power quality management during normal and island operation
    - Power and energy balance management
    - Voltage and frequency control
    - Microgrid voltage quality management during island operation including voltage level, harmonics, unbalanced voltages
3. Microgrid protection during island operation and normal operation.

In this thesis solutions to these key technical challenges have been developed by taking into account the simultaneous interaction of several devices as well as the dependencies between the developed solutions, so that in the end they were also compatible with each other. This means that studies with multiple component configurations were required to find out for example the impact of

- Directly connected synchronous generator based DG unit when compared to case with only converter based DER units (technical challenges 1, 2 and 3)
- Filter type and switching frequency as well as modulation and synchronization method on converter based DER units (technical challenges 1 and 2)
- R/X-ratio on the LV feeders, load unbalance and different type of loads (technical challenges 1, 2 and 3)

To ensure that LV microgrids could be natural part of future smart grids the distinct features and needs of different interest groups were also taken into account in the development of the technical LV microgrid concept. Therefore, choices for the proposed LV microgrid concept were made so that they can also be justified by the needs of the normal utility grid connected operation. This means that the concept can for example support the likely future smart grid market and management structures.

The studies related to the key technical challenges were carried out with PSCAD so that the same simulation models, developed at first for the stability and power quality studies, were also utilized in the development of the new protection system. PSCAD enabled the examination of a simultaneous interaction of different types of DER units and loads during the microgrid island operation when power quality and stability were studied. This information from simulations with multiple component configurations was essential when the technical solutions were developed and these studies could not have been undertaken to this extent in a laboratory environment without major investments in facilities and personnel. The development work related to the three key technical challenges as part of the technical concept development is summarized in the following:

Technical challenge 1

- Relationships and key issues affecting the stability of an island operated LV microgrid after transition to island operation were identified and conclusions were stated.
- Summary of the possibilities to ensure stability of LV microgrid after transition to island operation due to fault in the utility grid were presented and methods to improve stability were developed through simulations.

Technical challenge 2

- Simulations revealed the possibility of power quality deterioration after transition to island operation. Reasons for the increased voltage total harmonic distortion (THD) were found and main principles to ensure low voltage THD during island operation of LV microgrid were stated.
- Alternative, power quality compensator based, central energy storage configuration for the LV microgrid was proposed. Control principles for the series and shunt converters of the power quality compensator in different operation modes were developed. The shunt converter was implemented in simulations with an adaptive configuration and control system to obtain the best possible power quality in the microgrid also during island operation.
- In addition to power quality management during island operation, the operation principles were also developed for the voltage control of smart grids as well as hierarchy of the voltage control in which active utilization of central

energy storage based master unit during normal operation parallel with utility grid will play an important role.

Technical challenge 3

- Smart protection system for LV microgrid, in which the protection adaptability and utilization of high-speed communication will be essential, was developed and also extensions to the concept were determined e.g. considering different LV microgrid configurations.
- Fault behavior of converter based DG units was studied by simulations in context of LV microgrid protection during island operation and as a conclusion recommendations about their suitable behavior during faults were stated.
- Sequence of actions for the microgrid blackstart operation as well as control principles of some DG units during blackstart were defined and developed through simulations.
- Different functions to enable synchronized re-connection were developed and successfully simulated.

The developed technical solutions and findings for the total LV microgrid concept presented in this thesis can be utilized as basis when grid codes for future low-voltage microgrids and plans for real-life pilot installations are carried out. The proposed technical choices as well as operation and planning principles of the developed LV microgrid concept can also be taken into account in the development of LV microgrid compatible protection devices (PDs), DER units, microgrid management systems and future market structures. The development of future market structures for microgrids as part of smart grids cannot be done without knowledge about the influence of the LV microgrid technical choices to the behavior of the system and to the restrictions that they can make to the corresponding market model.

1.3 Summary of publications

Figure 2 presents a summary of the main issues that have been taken into account in this thesis during development of the proposed LV microgrid concept for future smart grids. This concept has been created through multiple simulations and it includes technical solutions to the three major technical challenges of LV microgrids shown in Figure 2.

Issues related to the *fundamental structural choices A)* in Figure 2 are:

- One central energy storage based DER unit at MV/LV substation,
- Connection principles of large DER units,
- Network configuration (radially operated LV feeders),
- Microgrid management system integrated at MV/LV substation and
- High-speed communication between microgrid management system, DER units, protection devices and controllable loads (i.e. smart meters or load switches).

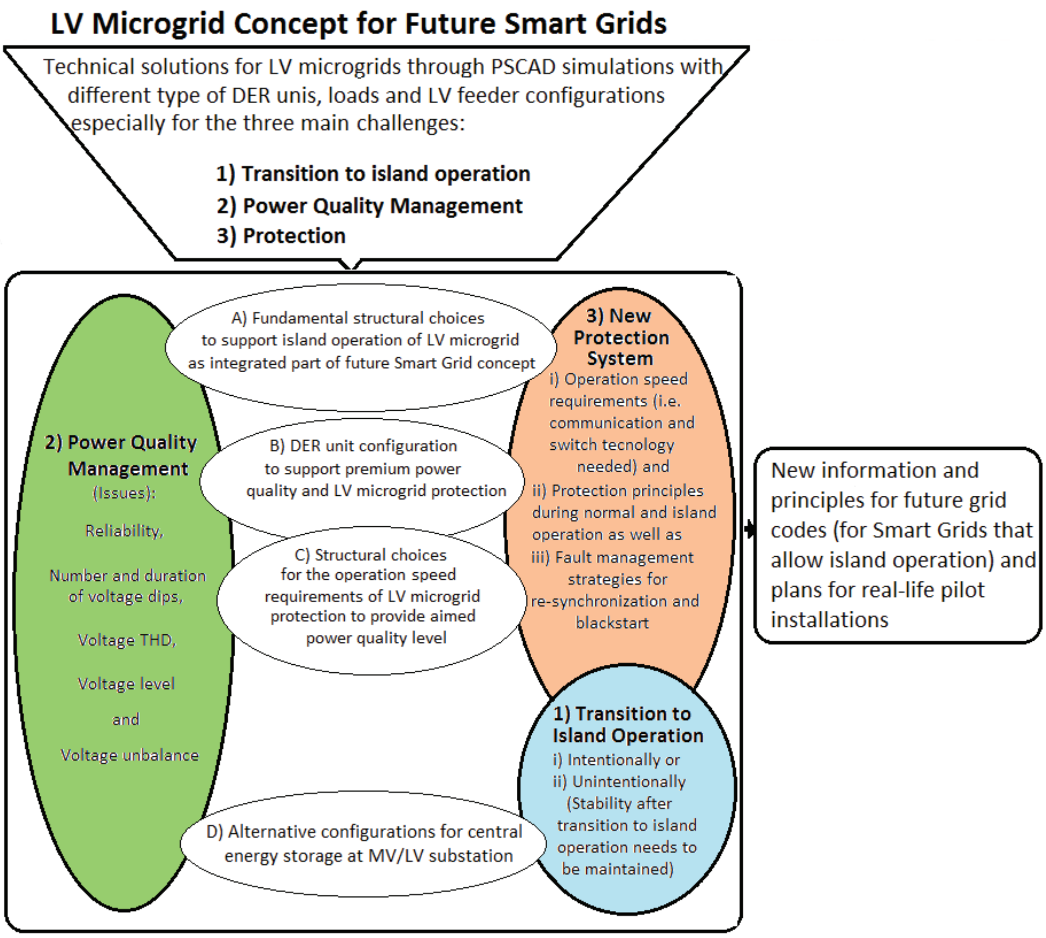


Figure 2. Summary from the main issues and their dependencies taken into account in creation of technical LV microgrid concept for the future smart grids.

Similarly, issues related to *DER unit configuration to support premium power quality and LV microgrid protection system B)* in Figure 2 consist of

- Fault or Low-Voltage Ride-Through ability,
- Fault behavior,
- Filter type and
- Control adaptability of the DER unit.

The *structural choices for the operation speed requirements of LV microgrid protection to provide aimed power quality level C)* in Figure 2 includes:

- Number of protection zones,
- Customers sensitivity to voltage dips and
- Stability after disturbances.

Finally, *alternative configurations for central energy storage at MV/LV substation D)* in Figure 2 means

- Power quality compensator concept,
- Size of the energy storage and
- Possible other configurations such as usage of two energy storages when large share of LV microgrid production is based on renewable energy sources.

This thesis consists of nine publications. Publications I and II are mainly related to the solving of technical challenge 1 (Figure 2). Issues related to the technical challenge 2 (Figure 2) has been studied and solutions have been developed in Publications III and IV. In Publications V, VI, VII, VIII and IX different aspects of technical challenge 3 have been studied and new protection system has been developed (Figure 2). The author of this thesis is the primary author of all publications.

Publication I *Voltage and Frequency Control of Low Voltage Microgrid with Converter Based DG Units*

Publication I is based on multiple PSCAD simulation studies on how different converter modulation methods, switching frequencies and filter types and sizes affected the voltage total harmonic distortion and frequency stability in islanded LV microgrid after intentional islanding during power balance or unbalance with different DG unit configurations and line impedances. When voltage total harmonic distortion increases too high during island operation, the frequency stability of LV microgrid could be lost. This is due to possible unstable operation of Phase-Locked-Loop (PLL) component and Proportional-Integral (PI)-controllers on converter based DER units. Inertia of directly connected rotating machines was found to help DER unit converter controllers to stay stable, because they reduced the speed of the oscillations after sudden changes. However, most of the problems related to high voltage THD could be avoided on converter based DER units by using appropriate switching frequency and LCL-filters instead of L-filters. Large impedance variation depending on the state of operation of LV microgrid, either normal or island operation, was also found to be a challenging task for the control of DER unit converters and grid filter design in terms of stability. Therefore, converter control parameters should be such that they work both in normal and island operation or they should be adaptive. Key relationships and issues affecting the stability of an islanded microgrid were also summarized based on literature and simulation studies done in Publication I. The most challenging issue in terms of directly connected synchronous generator (SG) and DG unit converter control stability was found to be the transfer of microgrid from normal to island operation, especially when there is a voltage dip before unintentional islanding.

Publication II *Stability of Microgrid with Different Configurations after Islanding Due to Fault in the Utility Grid*

Publication II studied the stability of LV microgrid just after transition to island operation due to a fault in the utility grid with different configurations and multiple simulations. In addition, this publication presented alternative options to maintain the stability of an islanded microgrid by reduction of voltage dip duration or magnitude. On the other hand, the stability and the fault-ride-through improvement of the converter based distributed generation units with different synchronization method modifications were also studied by simulations. In conclusion, based on the simulations, a summary of the possibilities to ensure stability of the LV microgrid after islanding due to fault in the utility grid was presented. The stability can be improved by different choices of voltage dip compensation methods in the connection point of microgrid and by different synchronization principles applied on the converters. The transition speed to island operation depends on the microgrid dynamics and the type of DG units connected as well as on the sensitivity class of the microgrid customers. For different sensitivity class of customers different features needed are defined in and also the possible operation curves for voltage dependent speed of transition to island operation for these different sensitivity class customers are shown. Depending on the sensitivity class of the microgrid customers the fault-ride-through needs of the DG units and loads can be defined respectively with sufficient margin to the voltage dependent speed of islanding curves.

Publication III *New Concept for Power Quality Management in Microgrid with Energy Storage Based Power Quality Compensator*

Publication III presents a new advanced concept to improve the power quality within the microgrid and also the quality of currents flowing between the microgrid and the utility grid. Nowadays the amount of converter based DG units and sensitive loads like computers and electronic data processing equipment which have low immunity to power quality problems such as voltage dips, is increasing in distribution networks. These devices will also be present in future LV microgrids and therefore it is important to limit power quality disturbances like harmonics coming from power electronic devices. The developed concept utilizes power quality compensator with energy storage for power quality management in microgrid. Power quality compensator consists of a shunt and a series converter. The shunt converter is implemented in PSCAD with an adaptive configuration and control system to obtain the best possible power quality in the microgrid during island operation. The main points of the developed power quality compensator control principles and power flows in different operation modes are presented in Publication III together with the results from simulations. The simulation results showed how the power quality compensator with energy storage can solve many of the power quality problems such as:

- The shunt converter of the power quality compensator can compensate the microgrid current harmonics and reactive power
- The series converter of the power quality compensator can eliminate utility grid voltage dips and utility grid voltage imbalance and
- The developed adaptive configuration and control system of the power quality compensator shunt converter enables instantaneous voltage control and power balance management with low harmonic distortion in islanded microgrid.

Simulation results confirmed that power quality in LV microgrid during normal utility grid connected operation can be easily kept within the standard limits. However, it was found that the utility grid background harmonic voltage may resonate with harmonic currents coming from DG unit converters. Therefore proper filtering of the DG unit converter currents is necessary in both normal and island operation of LV microgrid.

Publication IV *Voltage and Current THD in Microgrid with Different DG Unit and Load Configurations*

Publication IV studied the voltage and current total harmonic distortion, in LV microgrid before and after transition from normal to island operation with different DG unit and load configurations. Simulations were also made by applying negative sequence filtering in control system of converters to reduce the voltage and current total harmonic distortion in microgrid during unbalanced load. Based on the simulation results it was obvious that voltage total harmonic distortion behavior cannot be foreseen from the current total harmonic distortion contribution of the converter during normal parallel operation with utility grid. They are affected by the particular system harmonic impedance in that point and the harmonics coming from other devices, i.e. background harmonic voltages, which are dependent on the configuration, control system and parameters of these devices. When LV microgrid transfers from normal to islanded operation the grid impedances and harmonic voltages will change. Therefore, during the island operation of the microgrid there is a risk that some higher order harmonics near the switching frequency of the converter may resonate with the changed system harmonic impedance and even without resonances the harmonic currents produced by converters and possible distorting loads will generate much higher harmonic voltages during island operation. Short summary about the key issues which ensure high power quality in island operated LV microgrid is also presented in the end as follows:

- LCL-filters must be used, e.g. instead of L-filters, with converter based DG units in LV microgrid to reduce the amount of current harmonics fed to LV microgrid and to avoid possible resonance between system harmonic impedance and higher order harmonics near converter switching frequency during island operation,
- The amount of thyristor rectifier loads connected to LV microgrid should be for example 15–20 % of the total load,
- Space vector pulse width modulation (SVPWM or SVM) is preferred when compared to sine-triangle pulse width modulation (PWM) and
- Use of negative sequence filtering in the control system of DG unit converters is beneficial during unbalanced phase voltages in island operation of LV microgrid due to unbalanced loads or unbalanced faults.

Publication V *Control Principles for Blackstart and Island Operation of Microgrid*

Publication V presented strategies to handle some problematic situations, like instability after transition of LV microgrid to island operation or after fault during the island operation of the microgrid. To execute these strategies efficiently some centralized intelligence with communication capability will be needed in LV microgrid. This intelligence should be included in microgrid management system which in turn could be integrated for example into microgrid interconnection switch or central energy storage at MV/LV distribution substation. In case of instability, a blackstart operation strategy will also be needed as part of microgrid management.

The control of microgrid voltage and frequency during LV microgrid blackstart was not possible without an energy storage unit. In Publication V, sequence of actions for the microgrid blackstart operation as well as control principles of some DG units during blackstart were defined and simulated with two different microgrid configurations. The developed sequence of actions needed to execute the LV microgrid blackstart strategy was also successfully simulated. Based on these simulations, dimensioning principles for the necessary energy storage and size of simultaneously controlled loads were drawn. In addition, it was found that it is logical to connect the most oscillating and disturbing loads, i.e. rotating machines and thyristor rectifiers, at the end of the blackstart sequence. Also the connection interval between rotating machines should be long enough so that a steady state can be reached before next event. On the other hand, it was stated that it would be beneficial if all the larger rotating machines were connected to the LV microgrid through frequency converters.

Publication VI *Smart Protection Concept for LV Microgrid*

Publication VI presented a new smart protection system for LV microgrid which was developed based on extensive simulation studies. The conventional protection of distribution network is designed to operate for high fault current levels in radial networks, but during island operation of the microgrid high fault currents from the utility grid are not present. Also most of the DG units that will be connected to the LV microgrid in the future are converter interfaced and have limited fault current feeding capabilities. This means that the traditional fuse protection of LV network alone is no longer applicable and new protection methods must be developed.

In the development of the new protection scheme for LV microgrids many things must be considered including number of protection zones in LV microgrid, speed requirements for microgrid protection in different operation states and configurations and protection principles for parallel and island operation of the microgrid. In addition, the developed protection scheme for microgrid must be supported by the technical choices made in the microgrid operation and control issues. In the new LV microgrid protection system developed in Publication VI for example LV feeders are protected with protection relays that have adaptive multi-criteria algorithms and fast communication capabilities instead of traditional fuses. Adaptability means that the protection device of LV feeder takes into account the number and type of DG units at the corresponding LV feeder and also their fault current feeding capability. Fast and selective operation between different PDs is achieved by intelligent utilization of high-speed communication. One of the most important issues is to ensure that the behavior that is required from DG units, including fault-ride-through needs, during faults in microgrid during normal and island operation is compatible with the developed microgrid protection system.

Publication VII *DG Unit Fault Behavior and Protection of LV Microgrid*

Publication VII studied the effect of DG unit fault behavior to LV microgrid protection during island operation in some specific cases with PSCAD simulations. When the protection of island operated microgrid is designed one of the most important questions is how converter based DG units will contribute to the fault current feeding. In the simulation studies, different control strategies of converter connected DG units during faults were investigated with various DG unit configurations. Also the role of energy storages was examined to find out their effect to the microgrid voltages and currents that are measured by the protection devices. The increased reactive power feeding with converter based DG units was found to be beneficial for the possible over-current protection based LV microgrid protection. However, due to resistive character of LV lines, the magnitude of the voltage dip during fault was not reduced. On the other hand, it means that reactive power feeding did not significantly reduce the usability of under-voltage based protection.

Based on the simulation studies of Publication VII, it was also found out that significant reactive power feeding during fault may be challenging, e.g. for the DC-link voltage control of DG unit during fault. Also in general, the reactive power feeding of many DG units seemed to increase the possibility for angle stability problems after fault clearance. Therefore, the increased reactive power feeding of converter connected DG units during faults in island operation was not recommended. However, it is essential from the point of view of island operated LV microgrid stability and protection to take into account how the reactive power of each DG unit behaves and is controlled. Simulations also showed that the nominal power of directly connected SG, which is not located at the MV/LV distribution substation like the energy storage based master unit, should be substantially smaller than the nominal power of master unit to ensure stability after fault in island operated LV microgrid. Attention should be paid also to the excitation control of directly connected SGs so that their operation would be more stable during sudden changes in island operation. It is also important from stability perspective that the control systems of different DER units are compatible with each other. It was also pointed out that standardization of DG unit fault behavior in island operated LV microgrid is absolutely necessary for the development of future smart grids to reduce complexity and to avoid the need for too many alternative, case specific, protection solutions.

Publication VIII *Synchronized Re-Connection of Island Operated LV Microgrid Back to Utility Grid*

Publication VIII studied LV microgrid re-connection back to utility grid and different functions to enable synchronized re-connection were developed through simulations. Realization of future Smart LV Grids with island operation capability requires that possible problems related to the synchronized re-connection of island operated LV microgrid back to utility grid are solved. Island operated LV microgrid may be in synchronism with utility grid right after transition to island operation. After a while, due to LV microgrid load and production changes, the active and reactive power flows inside the microgrid will change. Thereby, also the voltage phase angle difference across microgrid interconnection switch will change.

Simulation results of Publication VIII clearly showed that synchronized re-connection is not necessarily a significant issue with small (less than 10°) phase difference across microgrid interconnection switch when there are only converter based DG units, because their control system will draw converters into phase with the utility grid frequency after re-connection. However, with directly connected synchronous generators even small phase difference across microgrid interconnection switch during re-connection is problematic. Therefore, re-synchronization functions for minimizing phase angle difference and possibly also voltage unbalance before re-connection are needed. In practice these functions should be co-ordinated by microgrid management system before LV microgrid re-connection.

Publication IX *Protection Principles for Future Microgrids*

Publication IX discussed protection issues and principles for LV microgrids and new additions to the novel protection system presented in Publication VI were developed by considering also protection of long LV feeders with section circuit breakers (CBs), connection of large DG units to LV microgrid and protection issues related to possible ring operation of LV feeders. From the simulation results of Publication IX it also became clear that selective operation of LV feeder protection at the beginning of LV feeders during normal operation of ring connected LV microgrid is not possible without utilization of high-speed communication. However, during island operation of LV microgrid the ring operation of LV feeders must be changed to radial operation of LV feeders to ensure selective operation of microgrid protection. In addition, it was stated that large DG units should be connected either directly or with own LV feeder to the MV/LV distribution substation, because connection of large DG units with high fault current feeding capability directly to LV feeders may in some cases make it challenging to achieve selective protection during island operation of LV microgrid even though adaptive protection devices developed in Publication VI at the beginning of LV feeders were used.

1.4 Structure of the thesis

Chapter 2 introduces different aspects of microgrids, such as possible benefits and applications of microgrids, properties of LV microgrids including main LV microgrid components and control principles as well as description of different functions and properties needed from microgrid management systems. Also, issues related to technical and regulatory challenges and need for new market structures are mentioned briefly in Chapter 2. In Chapter 3, the simulation models used and developed in this thesis are presented in brief. Chapters 4, 5 and 6 review the main technical solutions for the LV microgrid concept for the future smart grids that has been developed in this thesis. Chapter 4 describes the issues related to the solving of the technical challenge of transition to island operation, and in Chapter 5 the developed solutions to the power quality management during normal and island operation of LV microgrid are presented. In Chapter 6, a review of different aspects related to the protection of LV microgrid is given and the developed new protection system is presented. Chapter 7 concludes the contents of this thesis and presents proposals for possible further studies.

2 MICROGRID – ESSENTIAL COMPONENT IN FUTURE SMART GRIDS

In this chapter different aspects related to microgrids are shortly presented. These aspects include for example role of microgrids in future smart grids, potential of microgrids and properties of LV microgrids. Also issues related to technical and regulatory challenges as well as need for new market structures are shortly discussed.

2.1 Structure of future electricity distribution networks

In the future it is likely that more and more attention will be paid to the total harmfulness of different commodities for individuals, society and the globe including for example the carbon footprint, environmental friendliness and health effects of the particular commodity. This may lead to global agreements about actions, e.g. taxes and regulation, to encourage the use of climate friendly, locally produced, not harmful commodities like for example locally produced organic food. Similar approach may also be realized in the future in the electricity production and distribution. This would significantly improve the profitability of DG based on renewable energy sources and bring out the real benefits of them. DER units connected close to the customer or the end use have potential to reduce the demand for distribution and transmission network capacity, reduce losses and also increase the reliability of electricity supply to the customers. However, the increased DG based on renewable energy sources in the distribution networks together with possible large penetration of electric vehicles will cause needs for active, intelligent management of distribution networks and DER units. The active management enables the reliable electricity distribution, energy efficiently without additional investments into network capacity. Realization of this active management of future electricity distribution networks is only possible with smarter distribution networks i.e. smart grids. In Figure 3 the essential role of energy policy into the structure of future electricity distribution networks is roughly demonstrated.

The utilization of microgrid concept with island operation capability as part of future smart grid architecture allows the reliability benefit of DER to be realized as well as the energy efficiency aspects to be fulfilled. For example in the report *European SmartGrids Technology Platform – Vision and Strategy for Europe's Electricity Networks of the Future* (European Commission 2006) microgrids were viewed as one key potential technical concept to realize the active distribution networks of the future. Also in Finnish *Visionary Network 2030 – Technology* *vision for future distribution network* project report by Kumpulainen et al. (2006) the DER resources, including microgrids, were found to be major option when aging infrastructure needs to be renewed by more reliable and efficient applications which are based on renewable energy sources and sustainable practices. In addition, related to the coupling of microgrids and smart grids, it was mentioned by Schwaegerl et al. (2009) that critical signals for possible implementation of microgrids in the future are cost reduction of renewable energy sources (RES) and energy storages as well as large-scale adoption of smart grids, automated meter management (AMM) devices and plug-in electric vehicles (EVs).

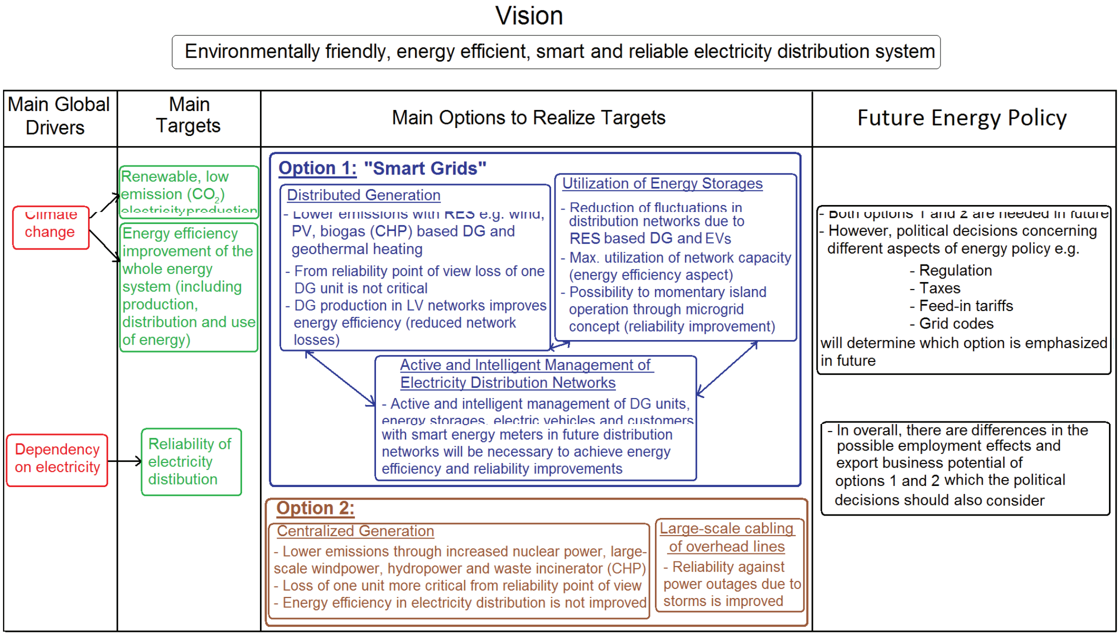


Figure 3. Role of energy policy to the structure of future electricity distribution networks.

2.2 Potential of microgrids

The potential benefits and costs of DER integration depends on factors like level of DER penetration, customer density of distribution network and correlation between DG production and customer load profiles. Actively managed DER units located near the loads will reduce losses and release the network capacity and therefore they can be used to delay future network reinforcement needs due to load growth (Marnay et al. 2008). From the point of view of reliability the active management of DER units as part of microgrid operation is most beneficial in countries with low power quality or in regions or for customer segments with comparably high outage costs (Schwaegerl et al. 2009).

2.2.1 *Possible benefits and applications*

The increased integration of DER units to the LV networks with island operation capability will bring many opportunities and benefits in the future, but also challenges. In Figure 4 the possible benefits of microgrids for different parties involved (customers, utility, society) are summarized. The challenges and barriers of today are presented later in Section 2.4.

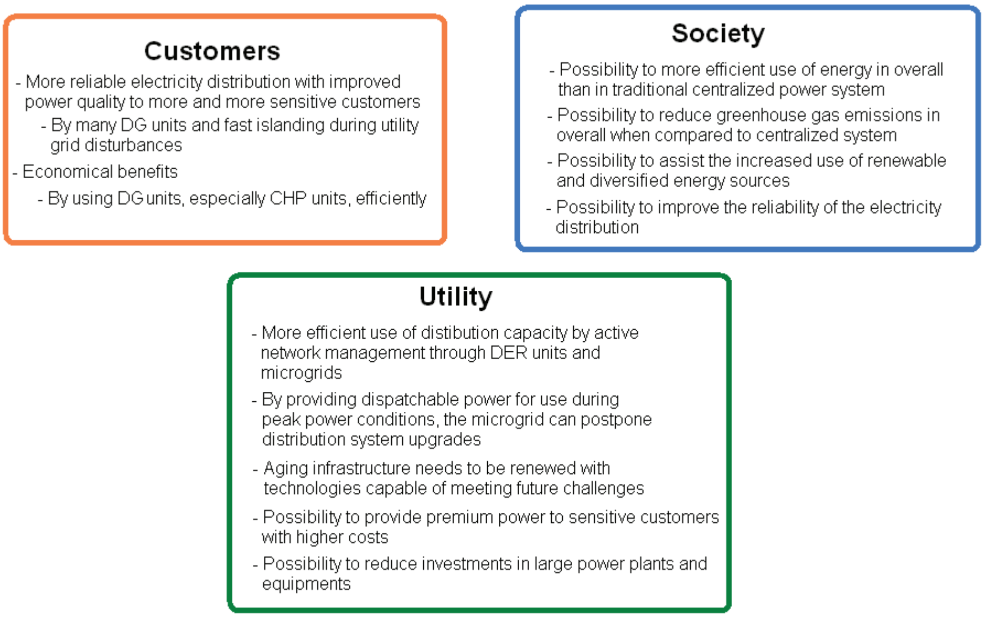


Figure 4. Possible benefits of microgrids to customers, utilities and society in the post industrial economies.

Potential applications for microgrids can be such as shopping or office centres, universities or high schools, hospitals, power for essential and critical services (police, fire, water treatment facilities), farms, remote power (islands, rural areas, villages), suburbs and blocks not connected to centralized district heating systems and military installations. From DSOs and distribution network management perspective microgrids can be designed to be corresponding to the configurations presented in Figure 1 on page 2.

Also in developing countries and rapidly industrializing economies the microgrid concept can be interesting option to meet the local challenges with electricity distribution and generation, which are quite different from those described in Figure 4 for post industrial economies. In developing economies the reach of the transmission grid is geographically limited and it is not profitable to build more transmission grid due to lack of purchasing power and low levels of average consumption among the unserved populations. Instead small remote hybrid systems based on operating diesel engine generators together with solar and/or wind power systems have been used as separate island grids. In developing economies like India electricity supply is a key enabling factor for realizing broader development targets like education, healthcare, and trade. Balijepalli, Khaparde & Dobariya (2010) have discussed different issues, enabling technologies and economics for encouraging the deployment of microgrids in India with more details. (Venkataramanan & Marnay 2008)

Schwaegerl et al. (2009) have defined expected economic and technical benefits and also roadmap for microgrid development and needed action recommendations for policy makers, regulators, DSOs. According to Schwaegerl et al. (2009) possible benefits can be achieved through

- Recognition of local energy trading within a microgrid
- Application of real-time import and export prices for microgrids
- RES support scheme and favorable tariffs
- Optimal dimensioning and allocation of DER units and
- Co-ordinated and active control of many DER units based on real-time grid conditions.

In order to optimally realize the benefits of microgrids to all interest groups through intelligent and co-ordinated operation of DER units, adequate legislative and regulatory framework should be formulated by political decisions.

2.3 Properties of LV microgrids

LV Microgrids are in many ways very different from the traditional power systems consisting of high-, medium- and low-voltage networks. The main reasons for this by Katiraei et al. (2008) are:

- Steady-state and dynamic characteristics of DER units, particularly units with converter based power electronic interfaces, are different from those of the traditional large turbine-generator units
- In a microgrid a significant degree of unbalance due to the presence of single-phase loads and/or DER units may exist
- A considerable part of supply within a microgrid can be from non-controllable sources such as wind power units or PV cells

- Short- and long-term energy storage units can play a major role in control and operation of a microgrid
- Due to economic reasons a microgrid must be ready to connect and disconnect DER units and loads while maintaining its operation
- In addition to electrical energy, a microgrid may also be responsible for generating and supplying heat to all or parts of its customers

2.3.1 Main LV microgrid components and control principles

Typically LV microgrid consists of several basic components such as converter based DER units, interconnection switches, and control systems. DG technologies typically include PV, wind, fuel cells, microturbines, and reciprocating internal combustion engines with generators. These systems may be powered by renewable or in some cases fossil fuels. Few types of DGs, for example microturbines and fuel cells, can also provide combined heat and power which will increase the overall efficiency of the corresponding DG units. Most of the DG technologies used in LV microgrids will require a power electronic interface to convert the energy into AC power. These converters may include both a AC/DC rectifier and a DC/AC converter or just the DC/AC converter. The DG unit converter also contains output filters and may contain protection functions for the DG unit and the LV microgrid. (Katiraei et al. 2008; Kroposki et al. 2008)

The frequency response of larger systems is based on rotating masses and these are regarded as essential for the natural stability of these systems. In contrast, microgrids are mainly converter dominated without or with only few directly connected rotating masses. Because some potential DG technologies, like microturbines and fuel cells, have slow response to control signals and have no inertia, island operation is technically demanding and will cause power balance and voltage control challenges. Therefore, energy storages are needed to manage these problems. Energy storage capacity can be justified in terms of medium- and long-term or in terms of short- and very short-term needs. Energy storage improves the overall performance of LV microgrid by stabilizing and permitting DG units to run at a constant and stable output despite load fluctuations. Energy storage also provides the ride-through capability when there are dynamic variations in primary energy sources like in sun, wind, or hydropower. (Kroposki et al. 2008)

There are different energy storage technologies available which could be used in LV microgrids. The most common technologies are batteries, supercapacitors and flywheels. It should be noted that a DER unit can also be a hybrid which means that it includes both a primary energy source and a storage. A hybrid DER unit is often interfaced to the microgrid through a converter system that includes bi-directional AC/DC- and DC/DC -converters. (Katiraei et al. 2008; Kroposki et al. 2008)

Battery is by far the most widely applicable storage option for DER units in a microgrid. Current research activities are mainly focused on lead acid, nickel metal hydrate, and lithium-ion batteries. Schwaegerl et al. (2009) have expected that the technology development and costs reduction of battery units to smart grid applications will be accelerated through development and introduction of battery based EVs.

The energy storage units and microgrid interconnection switches are essential during transition from utility grid connected normal mode to islanded mode. The energy storage is needed for instant voltage control due to the challenging dynamics during the islanding of the microgrid and slow controllability of some DG units. To ensure stable operation of microgrid after transition to island operation, the microgrid interconnection switch must operate very fast. The interconnection switch is located in the connection point between the microgrid and the utility grid like for example at MV/LV distribution substation. When power is restored on the utility grid, the interconnection switch or microgrid breaker (MB) must not be closed unless the utility and island are synchronized. This synchronization can be confirmed by measuring voltages on both sides of the interconnection switch. The control of the interconnection switch can be designed to be technology neutral and so it can be used with a circuit breaker as well as with faster semiconductor-based static switches like thyristors and integrated gate bipolar transistors (IGBTs). (Kroposki et al. 2008)

Control strategies for DER units are selected based on the required functions and possible operational scenarios. The main control functions for a DER unit are voltage and frequency control and active/reactive power control. The major control functions of a DER unit can be divided into the grid-following and grid-forming controls. A grid-forming master unit within a microgrid can regulate voltage at the point of connection and set the system frequency. This master unit should have relatively large capacity to be able to manage the possible power balance inside microgrid. If two or more DER units actively participate in grid stabilization and voltage regulation, then frequency- and voltage-droop control strategies can be used to share real and reactive power components. A grid-following unit controls the active and reactive power based on the reference signals from the microgrid management system. It is worth mentioning that DG units like PV cells and wind turbines are not able to control their active and reactive power without usage of a storage unit due to variable nature of their primary energy sources. (Katiraei et al. 2008)

LV microgrid concepts without one grid-forming master unit or central storage unit presented, e.g. by Engler (2005) and Piagi & Lasseter (2006), need additional batteries to be connected to the DC-link of the converter connected DER units to enable power balance and voltage control during island operation with conventional active power/frequency (P/f)- and reactive power/voltage (Q/U) -droops which are common in large directly connected SG based power plants connected in high-voltage (HV) networks. These concepts without one grid-forming central storage unit are also planned to be controlled without any communication. One challenging issue for this kind of concept is that how can it be integrated to the present grid or future smart grids in economically feasible way. This is due to the fact that the management of it seems to be developed more from the point of view of DER unit converter control than from the point of view of utility grid integration. In addition, P/f- and Q/U -droop based concepts presented by Engler (2005), Osika (2005), Guerrero et al. (2006), Piagi & Lasseter (2006), Prodanovic & Green (2006), Barklund et al. (2008), Mohamed & El-Saadany (2008) and Li & Kao (2009) for LV microgrids lack from sensible voltage control, because Q/U-droops require huge amount of reactive power to control voltage in LV network (Engler 2005; Demirok et al. 2009). This reactive power feeding or absorbing requires more capacity from DG unit grid-side converters (Demirok et al. 2009). Also additional energy storage in the DC-link of the DG unit will be needed to provide the required rapid active power control response during sudden changes. Other shortcoming that multi-master and P/f- & Q/U -droop based solutions has suffered is the lack of feasible protection system which is even to some extent compatible with present LV network or the one that will be used in normal, parallel, operation of future smart LV networks. Microgrid concepts without one grid-forming central energy storage has been planned to be controlled without communication, but for example synchronized re-connection procedure is not possible without communication (Nuñez, Gil de Muro & Oyarzabal 2010). Recently Vandoorn et al. (2011b) have also suggested a PU-droop, instead of P/f-droop, control based method for the control of LV microgrid connected converter based DER units in which proper power sharing between units has been done without communication.

Based partly on the above mentioned issues, it has been chosen, in this thesis, to examine technical LV microgrid concept that takes more into account the needs and behavior of the grid, so that island operation of LV network could be natural part of future smart grids. The role of one grid-forming energy storage based master unit and the location of it is very important from the point of view of LV microgrid management and protection. The voltage total harmonic distortion should be as low as possible to provide high quality power to microgrid customers during island operation as well. But before it is feasible to optimize the components and control of converter based DER units, specified grid codes are needed to state what kind of behavior is expected from them during normal and island operation as well as during faults.

2.3.2 Microgrid management system

Development of hierarchical smart grid concept capable in island operation requires a new hierarchical management and protection system as an essential part of the concept. Strauss (2009) has stated that effective utilization of DER units needs a management system which ensures suitable control and co-ordination between different devices and hence will speed up the development of microgrids, because reasonable co-ordination between DER units and loads even during island operation needs communication and intelligence. For example in LV microgrid the needed intelligence could be located in the microgrid management system (MMS) at the MV/LV distribution substation or directly in the intelligent microgrid interconnection switch, as suggested in Publication V, so that the interconnection switch would act as a microgrid central controller (Figure 5). Generally the microgrid management system will be responsible for the total economic and energy effective operation of microgrid taking into account the technical boundary conditions in both normal and island operation.

Microgrid management system entitled microgrid central controller (MGCC) by Schwaegerl et al. (2009) is responsible for the maximization of the microgrid value and the optimization of its operation. The optimization procedure depends on the market policy adopted in the microgrid operation. In general, the basic characteristics required from microgrid management system are the following:

- Real-time bi-directional communication with
  - Distribution management system
  - Energy storage and
  - Microgrid interconnection switch (possibly also with other protective devices)
- Information exchange with DG units and loads including
  - Measured parameters
  - Status of units and
  - Control commands to DG units
- Intelligence and adaptability
  - Built-in strategies for different possible situations.

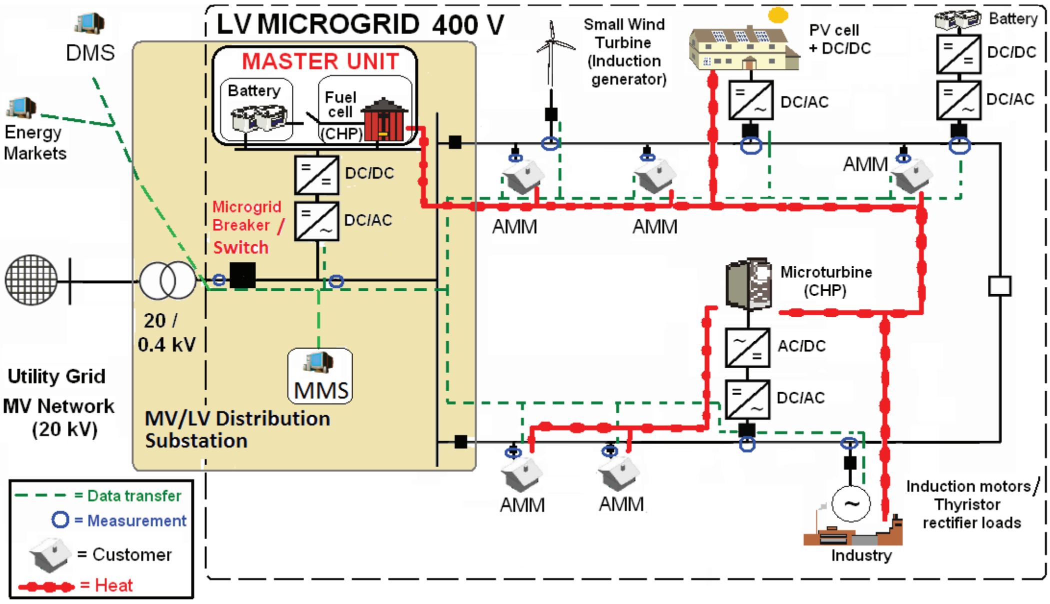


Figure 5. LV network microgrid consisting of e.g. energy storages, DG units, loads, DMS and MMS with communication capabilities.

Summary of the necessary functions of microgrid management system is presented in Figure 6.

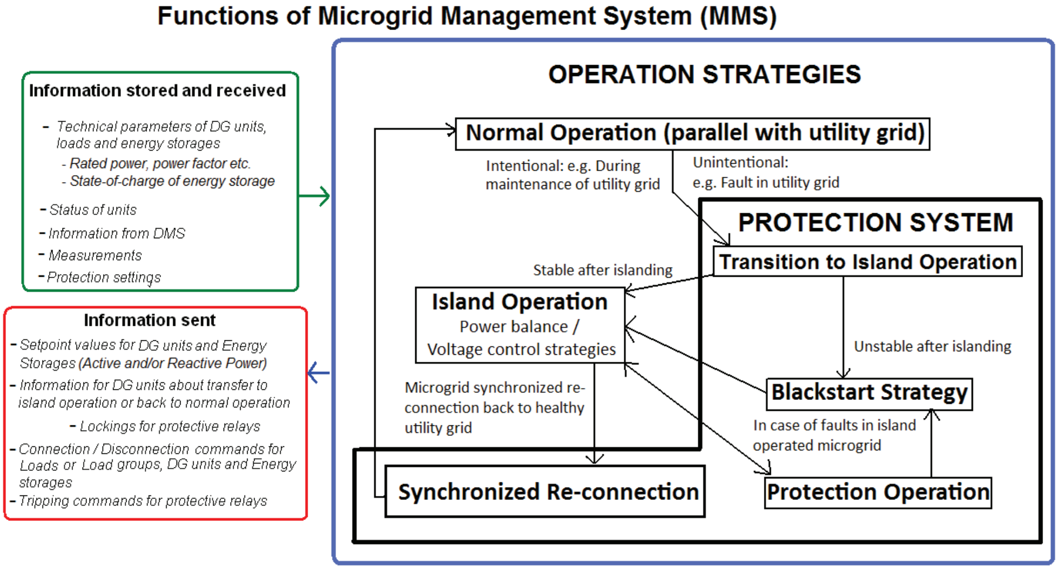


Figure 6. Summary of the necessary functions of microgrid management system.

LV microgrid operation strategies such as

- Normal operation (utility grid connected)
- Transition to island operation
- Island operation
- Blackstart
- Fault management and
- Synchronized re-connection

will be integrated into the microgrid management system (Figure 6).

The technical parameters of DG units, load groups and energy storages are stored into the database of MMS. MMS gives setpoint values for active power control capable DER units based on the stored information and present operation strategy. The transition of LV microgrid to island operation is based either on the protection settings and measurements of the microgrid interconnection switch or on the information received from the DMS (Figure 5). At the moment of transition to island operation it is necessary to have knowledge about status, present production and consumption levels of DG units and loads. Re-synchronization after island operation is based on the measurements from both sides of the microgrid interconnection switch (Figure 5).

Operation of a microgrid with more than two DER units requires also an energy management system (EMS) which could be integrated into the microgrid management system. The energy management system receives the forecasted values of load, generation and market information. Based on these forecasts appropriate control signals are sent to the utility grid, dispatchable DER units and controllable loads. The microgrid management system optimizes the power exchanged from microgrid with the utility grid by maximizing the local production depending on the market prices and security constraints (Katiraei et al. 2008). Optimal production scheduling in microgrid may be based on economic, technical, or environmental aspects as described by Schwaegerl et al. (2009) in Figure 7. Microgrid management system also determines the limits in which the successful transition to island operation is possible, in other words, the amount of active and reactive power that can be transferred between utility grid and microgrid.

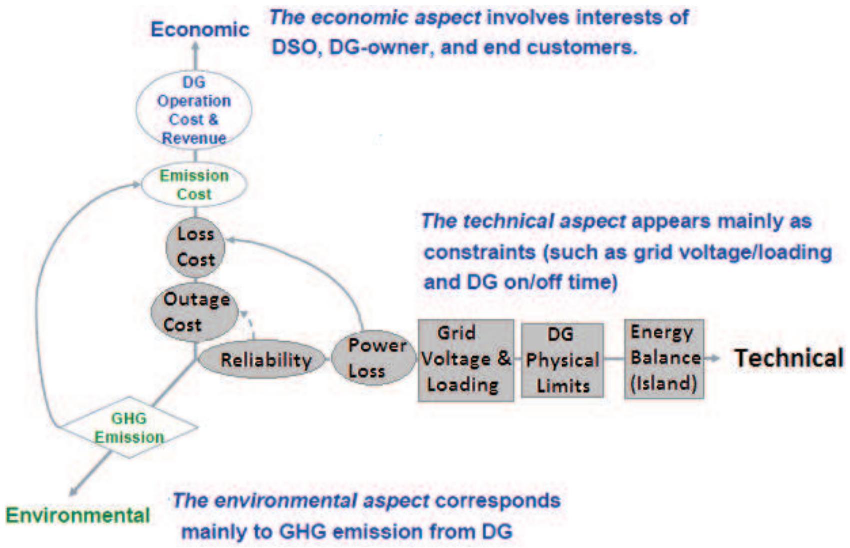


Figure 7. Microgrid operation strategies. (Schwaegerl et al. 2009)

In Figure 8 a summary about different possible functions and information flows between microgrid management system, DER units, customers, DMS and electricity markets are presented.

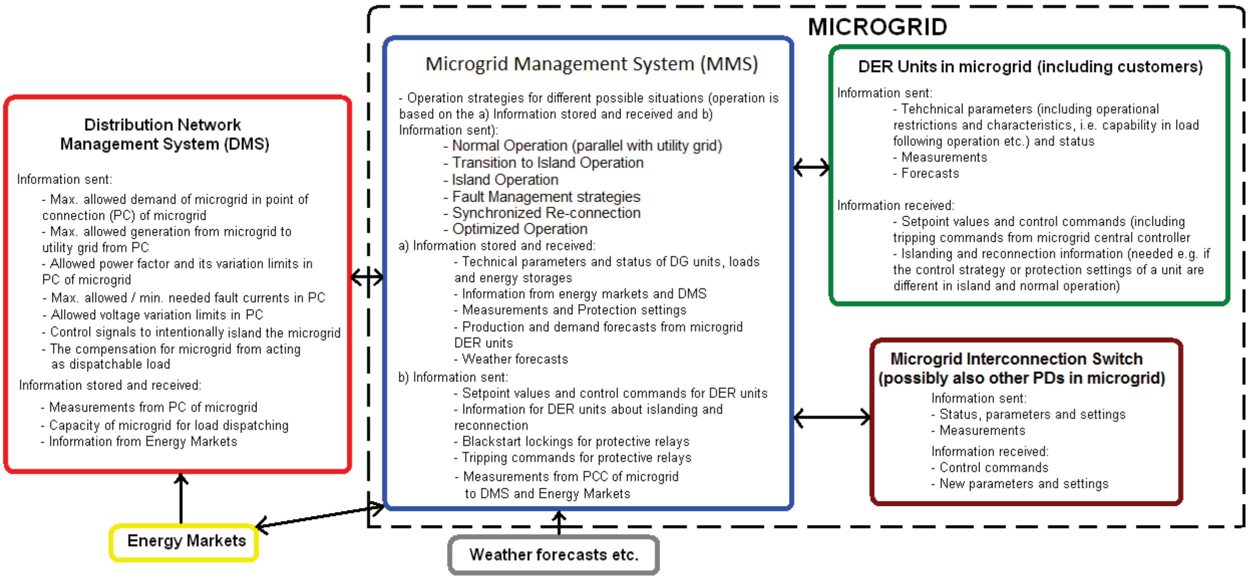


Figure 8. Summary about different possible functions of MMS and information flows between MMS, DER units (including customers with AMM), DMS and electricity markets.

An example from the implementation of a MMS in a test facility has been presented in (Borghetti et al. 2007). In case there will be several LV microgrids connected in future to distribution networks Schwaegerl et al. (2009) suggested centralized hierarchical control system for these multi-microgrids (MMGs) which is presented in Figure 9. Control level 2, central autonomous microgrid controller (CAMC) in Figure 9, can be viewed as comparable with the microgrid management system of MV feeder presented in Figure 1 (page 2).

On the contrary Issicaba, Gil & Pecas Lopes (2010) have proposed a distributed control architecture for the management of microgrids. In the proposed architecture the distribution grid is divided into management and control blocks to be able to achieve more flexible and adaptive agent-based smart grid control concept. Issicaba, Gil & Pecas Lopes (2010) also stated that standards like IEC 61850 (IEC 61850 standard 2003) and IEC 61499 (IEC 61499 standard 2005) can introduce a backbone for actual implementation of this kind of agent-based solutions in future smart grids.

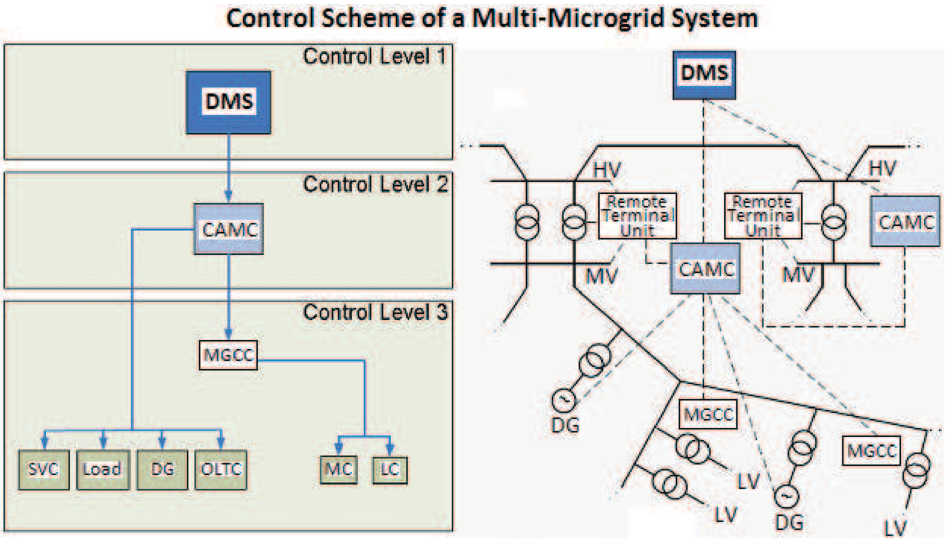


Figure 9. Control scheme of a multi-microgrid system. (Schwaegerl et al. 2009)

2.3.3 Fast real-time communication for operation and management of LV microgrids

Fast real-time communication will be needed between different LV microgrid components. This communication should be based on the same common standard. Van Overbeeke & Cobben (2010) stated that both suppliers of DER unit converters and management systems as well as DSOs require standardization of interfaces, communication protocols and converters.

Regarding the communication performance requirements for microgrids it was concluded in (Strauss 2009) that for microgrids and future smart grids communication performance requirements are quite demanding and in some cases the communication time between sending the control command and executing it is critical. In addition, the exact time synchronization of all DER units and protection devices is crucial to the operation of the microgrids. Therefore a time synchronization mechanism must also exist. (Strauss 2009)

2.3.4 Role of electric vehicles in microgrids

The fulfillment of promises about the environmental friendliness and energy efficiency of electrical vehicles, EVs, would be unquestionable if the primary energy source used in the charging is renewable, low emission and preferably local. From DSO's point of view plug-in EVs will have an effect on the voltage profile, losses and power quality i.e. current and voltage THD of the distribution network (Deilami et al. 2010), (Moses et al. 2010). It is possible that due to connection of large amount of EVs either investments in network capacities are necessary or active voltage control methods of distribution networks needs to be developed. If grid connected EVs are managed as controllable loads in future, restrictions in the charging may be included as part of the flexible distribution network voltage control.

On the other hand, active utilization of microgrids as part of smart grid management could introduce much more flexibility into the voltage control of future distribution networks. This increased flexibility could also be utilized so that it allows more flexible charging of EVs without too many restrictions. In other words this means that when voltage control principles for smart grids are being developed, the active management of microgrids and charging of EVs should be integrated as a part of the control principles.

Similarly to DER units, the standardization of the charging converters of EVs will be essential. The main reasons for this are that they must fulfill strict THD requirements, be equipped with fast communication capabilities and be capable of being controlled by MMS or DMS. From microgrid management system's point of view it is important to define the connection type (single- or three-phase), location, charging current, state-of-charging and capacity of EV, to be able to take it into account in voltage level and unbalance management during normal and island operation of LV microgrid. During island operation of LV microgrid it may be more reasonable to handle EVs by default as controllable loads instead of potential production units. This makes the total microgrid management little less complicated, e.g. from the point of view of the LV feeder protection settings.

However, in LV customer microgrids (Figure 1 on page 2) EV could act as energy storage based master unit during island operation.

2.4 Regulatory challenges and barriers

The regulatory challenges and barriers for microgrids exist because current regulation models have been created without taking the possibility of island operation into account. Traditional interconnection rules require DER units to disconnect during the occurrence of any disturbance, while the main idea of microgrid is that it will be able to island and ride through utility grid disturbances. The anti-islanding rules of existing European grid codes demand immediate disconnection of DER units to prevent potential safety threats to other network users and utility field crews, as well as to avoid operation and protection complexities. However, at the same time they allow intentional islanding of loads such as industrial plants, hospitals etc. Electricity utilities and distribution companies are natural monopolies and a common hypothesis is that utilities raise barriers to interconnection of distributed generation and also discourage energy efficiency investments due to risk of lost revenues and profits. In general, market mechanisms are still not mature enough to accommodate the participation of microgrid entities. (Marnay et al. 2008; Venkataramanan & Marnay 2008)

Possible future barriers for generalization of microgrid were found by Schwaegerl et al. (2009) to be:

- Deep connection charge applied to DER units
- Forbiddance of local energy trading
- Low electricity prices and time-invariant tariff
- Negligence of locational, environmental, and efficiency value of small DER units and
- Lack of information transparency concerning real-time network conditions.

2.4.1 Need for new market structures

Schwaegerl et al. (2009) have seen the microgrid concept as a key driver for realizing profitable operation of DG due to its capability of providing local identification and pricing of DG created values. Two potential sectors, retail and service markets, can be discussed in relation to the microgrid concept (Schwaegerl et al. 2009).

The capability of having local retail market directly between DER units and end consumers is often presented as key part of microgrid concept which makes it different when compared to other aggregator models such as virtual power plant (VPP) as shown in Figure 10. In microgrid concept technical aspects of the distribution can be considered in parallel with commercial aspects. The main challenge of location specific market may be the acceptance of it, because it goes against the common principle that energy produced from any generator in the grid should be available to any customer at any location of the grid. But local market is not necessarily a mandatory feature of microgrids, because technically a grid connected microgrid may be operated without problems even if local market is strictly banned. (Schwaegerl et al. 2009)

However, in the future market models for smart grids with island operation capability the value of improved energy efficiency and reliability should be identified with a price signal, e.g. the part of load supplied from local DG should benefit from it when compared to the part of the load supplied from utility grid source. One possibility could be for example location specific distribution-use-of-system (DUoS) charge.

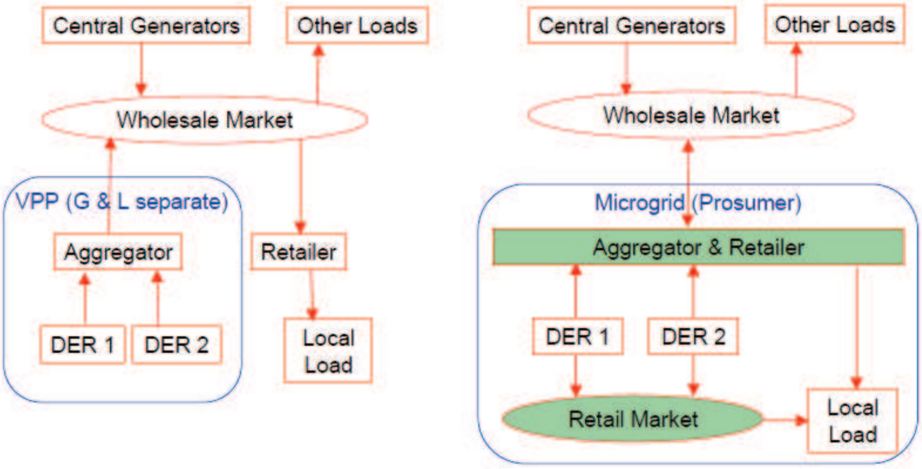


Figure 10. Illustration of differences between VPP and microgrid concept with local retail market. (Schwaegerl et al. 2009)

There is also a second possibility of local market formulation between local DER units and LV distribution network i.e. local service market. As stated by Schwaegerl et al. (2009) this kind of local service market is essential for recognition of technical contribution of DER units to the LV microgrid in which they are connected. In Figure 11 the potential formulation of technical service markets introduced by Schwaegerl et al. (2009) is illustrated for DER units located at different voltage levels. It was also stated by Schwaegerl et al. (2009) that the most convenient approach will limit the contribution of the DER unit to the voltage level to which it is connected. However, it could also be possible to allow an aggregated group of small DER units of corresponding microgrid to take part in the service market of a higher voltage level, as shown in Figure 11 with dotted lines. Schwaegerl et al. (2009) defined that in general five main types of technical services can be potentially traded between DSO and DER units in microgrid:

1. Frequency support (load following) service via control of active power
2. Voltage support service via control of reactive power
3. Peak loading and power loss compensation service
4. Islanding and blackstart support service and
5. Balancing power supply service.

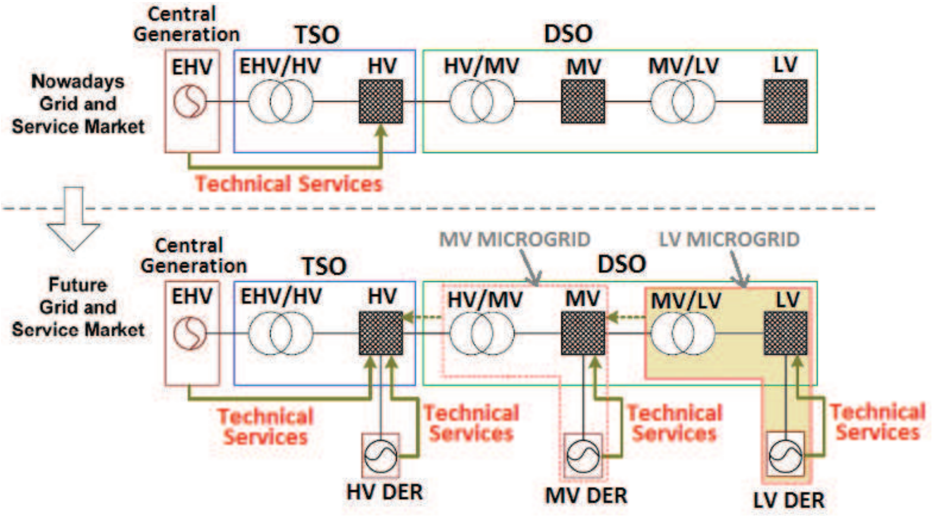


Figure 11. Provision of technical services in present and future smart grids. (Schwaegerl et al. 2009)

It is worth mentioning, that all types of DER units are not capable of providing all service types listed above. For example, PV and wind turbines are not capable of controlling their active power output. Only power curtailment i.e. active power reduction is possible due to limited availability of primary energy source. Therefore these DER units are not capable of providing any frequency, islanding, or balancing support services. (Schwaegerl et al. 2009)

Future regulation, grid codes and market structure should be based on hierarchical architecture so that the real benefit of electricity production by DG units near the consumption and the use of DER in active management of distribution networks (i.e. energy efficiency aspect and matching principle) would be realized to different parties fairly.

Schwaegerl et al. (2009) have also suggested a possible roadmap for microgrid development in Europe. This roadmap was based on the idea that the present barriers such as, cost, policy, and technology are subjected to considerable uncertainties in the future. It means that in the end they can possibly turn into key enablers, which could then lead to widespread adoption of microgrids across Europe. (Schwaegerl et al. 2009)

2.5 Smart grid standards

Several standardization efforts for smart grids in US and Europe are currently in progress, because standardization is seen as a key issue for a proper technical interoperability. Roadmaps about standardization of smart grids have been listed by Uslar et al. (2010).

For example in US available DER and smart grid related IEEE standards include IEEE 1547 series of interconnection standards and IEEE P2030 series of smart grid interoperability standards. IEEE Standard 1547 defines mainly the electrical issues related to the interconnection of DER units while IEEE P2030 concentrates on the communication and control issues. In the following communication related smart grid standardization is briefly viewed in Section 2.5.1 and DER interconnection related in Section 2.5.2. Power quality standards are discussed later in Section 5.1.1.

2.5.1 Communication

The most important aspect is that a totally new kind of ICT infrastructure is required for smart grids (Uslar et al. 2010). For example over 100 IEC Standards have been identified as relevant to the smart grids. Below is a list of the core IEC standards for smart grids defined by IEC (2011):

- IEC 62357: Service Oriented Architecture (SAO)
- IEC 61970: Common Information Model (CIM) / Energy Management
- IEC 61850: Substation Automation
- IEC 61968: Common Information Model (CIM) / Distribution Management
- IEC 62351: Security
- IEC 62056: Data exchange for meter reading, tariff and load control
- IEC 61508: Functional safety of electrical/electronic/programmable electronic safety-related systems

Standard IEEE P2030 – *Draft Guide for Smart Grid Interoperability of Energy Technology and Information Technology Operation with the Electric Power System (EPS), and End-Use Applications and Loads* consists from the following parts (IEEE SCC21 2011a):

- IEEE P2030.1: *Draft Guide for Electric-Sourced Transportation Infrastructure*
- IEEE P2030.2: *Draft Guide for Energy Storage Systems Interoperability with Electric Power Infrastructure*
- IEEE P2030.3: *Draft Standard for Tests Procedures for Electric Energy Storage Equipment and Systems for Electric Power Systems Applications*

The most promising standard for DER, microgrid and smart grid communications is IEC 61850. IEC 61850 is a part of the IEC Technical Committee 57 (TC57) reference architecture for electric power systems and originally a standard for the design of electrical substation automation (IEC 61850 standard 2003). The abstract data models defined in IEC 61850 can be mapped to a number of different protocols. Current protocol mappings in the IEC 61850 are for example for manufacturing message specification and Generic Object Oriented Substation Event (GOOSE). These protocols can run over TCP/IP (Transmission Control Protocol / Internet Protocol) -networks and/or substation local area networks using high-speed switched Ethernet to obtain the necessary response times of < 3 ms for protective relaying. (Strauss 2009)

Oyarzabal et al. (2009) have stated that communication architectures in future microgrids and smart grids should take advantage of all technologies available, like radio, Ethernet, power line carrier and services like GSM, GPRS or ISDN. This means that it will be necessary to develop new mappings of IEC 61850 to be able to make use of existing infrastructure other than Ethernet. (Oyarzabal et al. 2009)

IEC 61850 specifies for example: i) data models for DER devices and substations, ii) services for accessing the functions provided by the devices and iii) specific low level communications mapping (Oyarzabal et al. 2009). The range of devices which can be controlled includes gas turbines, diesel generators, converters, meters, load banks, switches, batteries etc. (Oyarzabal et al. 2009). More exactly IEC 61850-7-420 is the part of IEC 61850 which covers communications with DG units and also microgrids to some extent (Ringelstein & Nestle 2009). However, from the perspective of microgrids some technologies are still missing in IEC 61850-7-420 (Oyarzabal et al. 2009). Wind power has a separate standard named IEC 61400-25. Utilization of IEC 61850 based communication has also been suggested to Loss-of-Mains (LoM) protection of DG units by Rintamäki & Kauhaniemi (2009).

Usage of IEC 61850 has many advantages (Oudalov et al. 2009):

- Can be applied to every type of electrical installation,
- Guarantees interoperability between devices from different manufacturers,
- Standardizes data models and protocol,
- Provides scalability to the microgrids and
- Provides higher performance than other protocols
    - GOOSE service of IEC 61850 makes the direct information exchange between intelligent electronic devices (IEDs) possible, accepting any type of data and transmitting the data in less than 3 ms.

One of the main concerns at the time of considering IEC 61850 as a solution may be the cost of switches used for data transfer which were not necessary before. Switches allow organizing the data traffic within the network, taking into consideration several parameters like the priority of a message, or managing VLANs not to mix different traffics. Switches are necessary, but it is possible to have cheaper architectures by means of the integration of these switches within IEDs. (Oudalov et al. 2009)

Strauss (2009) stated that the combination of IEEE 1547-2003 standard with the IEC 61850-7-420 could be the basis for standardization of the non standardized concepts, such as energy management systems, demand management systems, demand side management, generation control, demand control, ancillary services, interfacing structure for smart and multi-metering, market price signals, multi agent systems, blackstart and voltage control.

In general, IEC 61850 seems to be the most sensible and economical option to meet the communication needs of future microgrids and smart grids. Also for example Ruiz-Alvarez et al. (2010) and Roman-Barri et al. (2010) have chosen to use IEC 61850 in microgrid test bed.

2.5.2 DER interconnection

Many national interconnection guidelines or grid codes for DG units are available today. In Europe CENELEC Standard EN 50438 *Requirements for the connection of micro-generators in parallel with public low-voltage distribution networks* defines protection principles for micro-generators. EN 50438 defines specific limits for each European country but also some common values are presented.

However, none of the European guidelines take into account microgrid or intentional island operation. (Oudalov et al. 2009)

Standard EN 50438 is meant for production units rated up to 16 A per phase i.e. up to 11 kVA for three-phase and 3.7 kVA in single phase. CENELEC, through its technical committee TC8X (CLC/TC8X), is also preparing a technical specification called *Requirements for the connection of generators above 16A per phase to the low voltage distribution system or to the medium voltage distribution*. This standard aims at harmonizing at European level the technical requirements for the connection of distributed energy resource (DER) to the LV and MV networks. DER-Lab which is an EU funded project formed by 11 Laboratories across Europe provides recommendations for CLC/TC8X on how to set harmonized European requirements for the connection of generators to LV and MV distribution system (see Strauss 2009). (Consortium 2009)

US interconnection standard IEEE 1547-2003 *IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems* includes at the moment the following parts (IEEE SCC21 2011b):

- 1547.1-2005: *Application Guide for IEEE Standard 1547, Interconnecting Distributed Resources with Electric Power Systems*
- 1547.2-2008: *Application Guide for IEEE 1547 Standard for Interconnection of DR with EPS*
- 1547.3-2007: *Guide For Monitoring, Information Exchange, and Control of Distributed Resources Interconnected With Electric Power Systems*

Standard IEEE 1547-2003 sets limitations and regulations for DG, disconnection times, synchronization rules, harmonics, DC injection, grounding and other protection aspects. However, the standard does not take into account intentional island operation. Guide for island operation, i.e. IEEE P1547.4 *Draft Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems*, is still under development. Also under development is a draft standard IEEE P1547.8 *Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded Use of IEEE Standard 1547* which tries to establish a common technical platform to address functionality for the interconnection of distributed resources across the power grid. In USA UL 1741 standard, *Inverters, Converters, and Controllers for Use in Independent Power Systems,* for DER units etc. has been harmonized with IEEE 1547.

In Section 6.3.1 fault behavior standardization and requirements of converter based DER units in LV microgrids will be discussed in more details after the proposed new LV microgrid protection system has been presented.

3 SIMULATION MODELS FOR LV MICROGRID STUDIES

In this thesis a number of suitable PSCAD simulation models for LV microgrid (Figure 12) compatible DER units have been developed based partly on previous studies by Laaksonen, Saari & Komulainen (2005), (2006a), (2006b) and Laaksonen & Kauhaniemi (2007a), (2007b). The target has been to develop models which are suitable for the study of stability, power quality and protection requirements of LV microgrids as precisely as possible. Simulation models for the DER units were developed in Publications I, II, III and IV to be able to study LV microgrid transition to island operation and power quality issues. These models were also used in simulation studies considering protection system development for LV microgrids in Publications V, VI, VII, VIII and IX. In this chapter, the developed PSCAD models will be presented.

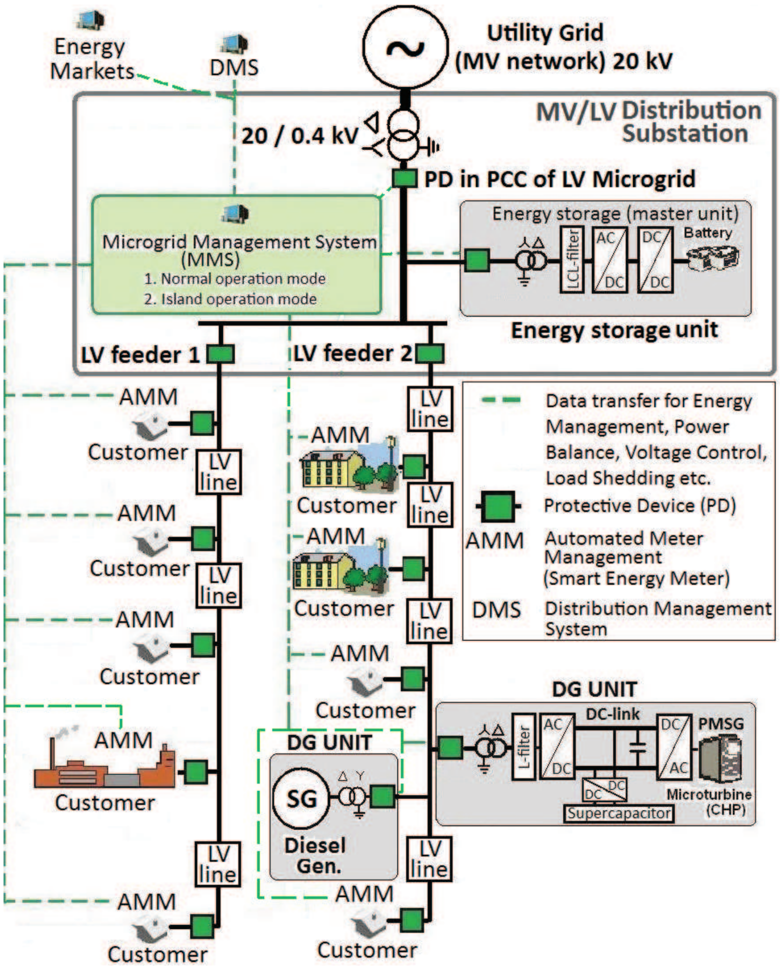


Figure 12. Example of LV microgrid with different kinds of DER units.

Stable operation of the converter based DER units in simulations after transition to island operation as well as during and after disturbances required examination and modifications to be made into the control system and configuration of the DER unit models. Therefore, issues like synchronization method, current sensor location, negative sequence compensation, filter type, switching frequency, modulation method, has been investigated. Component costs minimization and specification of optimal control principles for these DER units has not been the target in this thesis.

In all Publications I–IX the studied LV microgrid has been mainly urban microgrid (see Figure 12). This is due to the fact that the fault level and *R*/*X*-ratio (ratio of resistance to reactance in the supply) of the feeding utility grid at the 20 kV level has been 200 MVA and 0.1 respectively. This represents a strong connection to HV level during normal operation. Also the line parameters in most simulations with *R*/*X*-ratio 2.01 (AXMK 4x185S underground cable) represent strong urban LV network. However, studies have also been done with weaker LV network parameters e.g. AXMK 4x50S underground cable with *R*/*X*-ratio 7.28 or AMKA 3x35+50 overhead line with *R*/*X*-ratio 8.35. In simulation studies of Publication VI–IX also the service connections (MCMK 3x10+10 underground cable with *R*/*X*-ratio 20.80) of customer loads and smaller DER units has been included in the simulation models. In all Publications I–IX the LV feeders (Figure 12) have been operated in radial configuration, except in Publication IX in which the operation LV microgrid protection during normal operation was studied with ring connected LV feeders. The load of the LV microgrid has been modeled in Publications I–IX to be:

1. Mainly passive in all simulations
    - Balanced 3-phase and
    - Unbalanced 1-phase
2. Partly induction motor based in some simulations and also
3. Partly non-linear thyristor rectifier based in few simulations.

More details about the studied network and load configurations can be found from Publications I–IX.

3.1 Central energy storage based master unit

As mentioned and discussed previously in Section 2.4.1, in this thesis it has been chosen to examine LV microgrid concept with one central energy storage based master unit. The role of this grid-forming central energy storage and the location of it is very important from the point of view of LV microgrid management and protection if LV network island operation is planned to be natural part of future smart grids.

3.1.1 Development of central energy storage model

During islanding the central battery based energy storage unit (Figure 12) will act as the grid-forming master unit and it has the main responsibility to control the voltage and maintain frequency (Uf-control) in LV microgrid. The development of suitable converter based central energy storage model for LV microgrid was done in Publication I. In Publication I the effects of different technical issues related to the control and configuration of the energy storage unit converter were examined as part of power quality and stability studies after intentional transition to island operation with different DG unit configurations and line impedances. These issues included for example:

- Converter modulation methods (sine-triangle of space-vector PWM),
- Switching frequencies and
- Filter types (L- or LCL) and sizes.

It was shown in Publication I that, if voltage total harmonic distortion increases too high during island operation, the frequency stability of LV microgrid might be lost due to possible unstable operation of synchronization with PLL component and PI-controllers on converter based DER units. However, most of the problems related to high voltage total harmonic distortion could be avoided on converter based DER units by using appropriate switching frequency, and LCL-filters instead of L-filters.

3.1.2 Central energy storage with negative sequence filtering

The simulation model of the master unit used in Publications II–IX is based on studies done in Publications I, II and IV (Figure 13). The converter is modeled as three-phase, three-leg, space-vector modulated unit with LCL-filters. Switching frequency was chosen to be 8 kHz to achieve lower harmonic distortion during island operation. The used DC-link voltage of the converter was 0.65 kV in Publication I and 0.7 kV in Publications II–IX. The battery storage and bi-directional DC/DC-buck-boost converter models which were created previously in a joint project between University of Vaasa and VTT were connected to the DC-link of the master unit (Figure 13). More detailed description of bi-directional DC/DC-buck-boost converter model can be found in Publication II. The same DC/DC converter model has been used in the DER unit models presented in following Sections 3.2 and 3.3 which has also been utilized in studies of

Publications I–IX. The control of this DC/DC converter could have been further developed in terms of stability and losses, but this kind of optimization work was found to be out of scope of this thesis. In most of the simulations of Publications II–IX the master unit converter model included delta-wye grounded transformer enabling neutral connection (Figure 13). Direct earthing of the microgrid side of the transformer ensures path for neutral current and high earth fault currents and provides galvanic isolation.

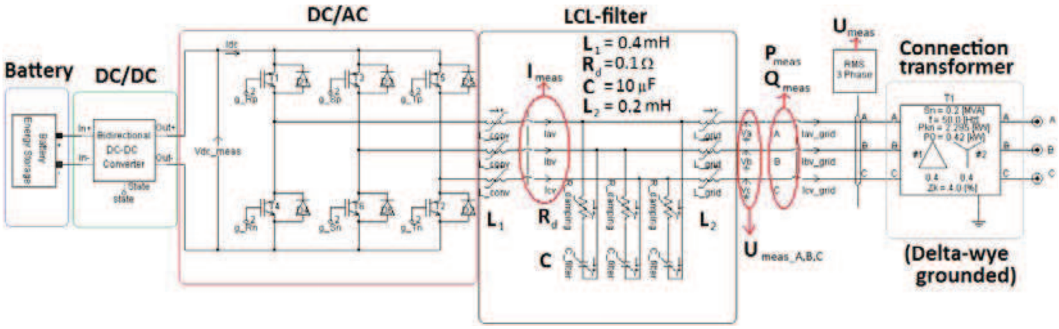
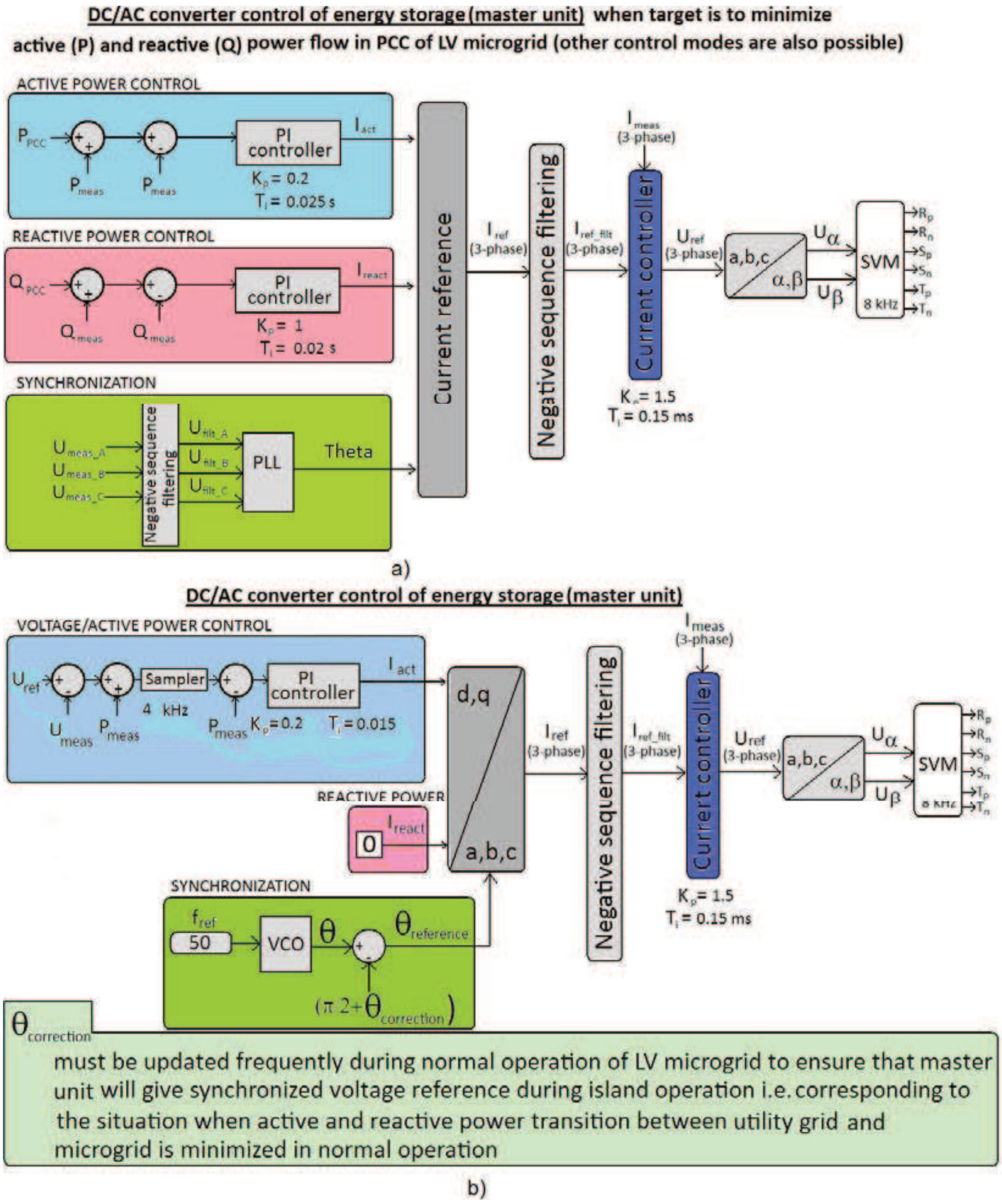


Figure 13. PSCAD model of the master unit used in Publications II–IX.

The developed control principles for the central energy storage based master unit during normal and island operation are presented in Figure 14. During normal operation the master unit control in Figure 14 a) ensures successful transition to island operation with zero active and reactive power flow from LV microgrid to MV network in Point-of-Common-Coupling (PCC) of LV microgrid , i.e. $P_{PCC} = 0$ and $Q_{PCC} = 0$. However, also other kinds of control principles during normal operation are possible.

The master unit control shown Figure 14 is based on PI-controllers which are usually used in control of three-phase converter based DER units (PERES course 2009). Specification of optimal control principles for the DER unit converters, e.g. from the point of view of practical implementation was out of scope of this thesis. However, it can be mentioned that it could have been possible to use, instead of linear PI-controller in dq-frame, linear Proportional-Resonant (PR) - controller in αβ-frame and obtain almost same kind of performance in terms of power quality during steady state operation (Timbus et al. 2006a). As stated in (Teodorescu et al. 2006) synchronous dq-frame PI-control in three-phase systems usually requires multiple frame transformations and lot of computational effort. The PR-controller can achieve the same performance as a synchronous PI-controller with less computational burden (Teodorescu et al. 2006). Another advantage of the PR-controller is the possibility of implementing selective harmonic compensation without requiring excessive computational resources when compared to PI-controller based harmonic compensation (Teodorescu et al. 2006). Also non-linear hysteresis or dead beat controllers could have been used (Timbus et al. 2006a). Non-linear dead beat controller was found by Timbus et al. (2006a) to have the best behavior during grid faults when different DG unit converter control methods were compared.



$\theta_{correction}$ must be updated frequently during normal operation of LV microgrid to ensure that master unit will give synchronized voltage reference during island operation i.e. corresponding to the situation when active and reactive power transition between utility grid and microgrid is minimized in normal operation

Figure 14. Control of master unit DC/AC-converter in a) normal utility grid connected operation and b) island operation.

Typically PI-controller parameters are tuned according to some rules in order to get the desired response and normally the tuning of the controller is dependent e.g. from the type of DER unit which is planned to be controlled (Timbus et al. 2006a). However, the PI-controller parameters presented in Figure 14 and in Publications I–IX have been chosen through multiple test simulations with different LV microgrid configurations including many DER units simultaneously to obtain the desired response in rapid changes both in normal and in island operation.

One important factor related to the stability of the master unit control is the current control stability, which is related to the point where the current (I_{meas}) is measured. In the converter simulation models used in this thesis, the current I_{meas} is sensed after the converter side inductance of the LCL-filter (Figure 13), because generally the current sensing from the grid side improves the stability margin of the system, but on the other hand the use of a LCL-filter makes the current control to be unstable if proper damping is not used (Liserre, Blaabjerg & Teodorescu 2005). LCL-filter parameter design can be made on a different basis and some principles has been presented, e.g. by Abdul-Magueed Hassan (2007) and Teodorescu & Blaabjerg (2004). Abdul-Magueed Hassan (2007) dimensioned the filter inductances so that the voltage drop across the inductances was limited to 10 % during normal operation and L_2 is $0.4 \cdot L_1$. One important issue related to LCL-filter design is also the resonant frequencies which should always be considered when LCL-filter parameters are chosen. Abdul-Magueed Hassan (2007) suggested that the resonance frequency should be in the range between ten times the fundamental frequency and one half the switching frequency. Capacitance for a star-connected capacitor of LCL-filter can be calculated from

$$C = \frac{1}{4 \cdot \pi^2 \cdot f_{\mathrm{LC}}^2 \cdot L_1} \tag{1}$$

when required values for L_1 and resonance frequency f_{LC} for $\mathrm{L_1C}$-filter are known (Wakileh 2001: 26). If filter capacitors are delta-connected, then capacitance C_{delta} of one capacitor can be calculated from capacitance of the star-connected filter, i.e. $C_{\mathrm{delta}}=C/3$. Resonance frequency f_{LCL} for LCL-filter can be calculated from (Lindgren 1998; Peltoniemi 2010).

$$f_{\mathrm{LCL}} = \frac{1}{2 \cdot \pi} \sqrt{\frac{L_1 + L_2}{L_1 \cdot L_2 \cdot C}} \tag{2}$$

In fact, the LCL-filter has three resonance frequencies, but the parallel resonance frequency of Equation (2) has the biggest influence (Peltoniemi 2010). In Publication II, LCL-filter parameters have been chosen so that L_2 is $0.5 \cdot L_1$, because in this way converter was found to produce lower current and voltage harmonics in the simulations.

It is essential for the stability of the whole LV microgrid that during disturbances the control system of the master unit converter remains stable. However, PI-controller parameters in the PU-control of master unit converter needed some modifications to ensure stability when microgrid dynamics was changed, e.g. due to addition of a directly connected synchronous generator into the LV microgrid instead of converter based DER unit. Filter and control parameters used in the simulations can be found from Publications I–IX.

In Publication II the stability of LV microgrid just after transition to island operation due to a fault in the utility grid was simulated with different configurations. The fault-ride-through improvement of the converter based DER units by different synchronization method modifications was needed to ensure stability of the LV microgrid after transition to island operation. In these models the PLL component was used for synchronization of the DER units. In Publications II–IX the PLL component was used with positive sequence detector, as described by Lee, Kang & Sul (1999), to improve fault-ride-through capability of the converter based DER units especially during unbalanced faults. The implementation of negative sequence filtering, i.e. positive sequence detector (Figure 14a)) in PSCAD is shown in Figure 15.

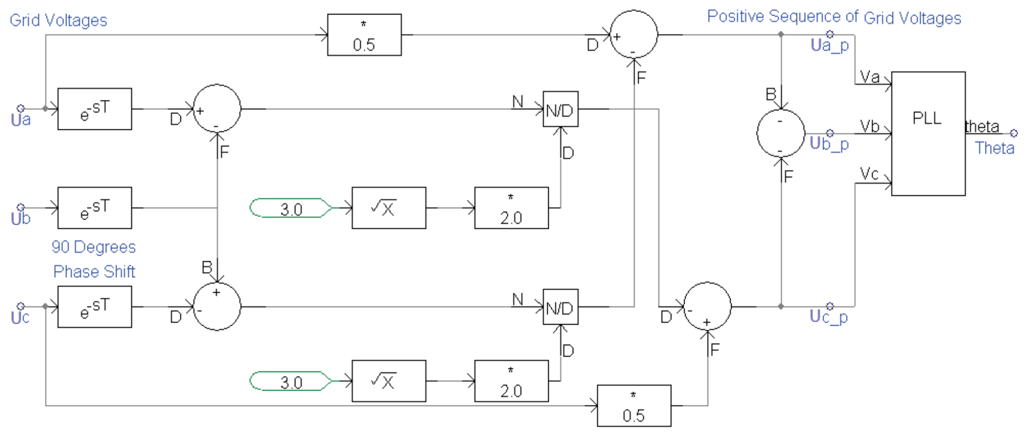


Figure 15. Implementation of positive sequence detector (negative sequence filtering) in PSCAD with the PLL component of the PSCAD master library.

Utilization of negative sequence filtering also for the current reference I_{ref} in converter control system (Figure 14) reduced the current total harmonic distortion of the corresponding DER unit during normal operation and unbalanced faults in simulations done for Publication IV. Also during island operation of LV microgrid, especially when LV microgrid load was not balanced between all three phases, the total harmonic distortion of voltage and current were found to be lower. Therefore, negative sequence filtering from the current reference has been used in simulation studies of Publications VI–IX. However, the negative sequence filtering from current reference I_{ref} does not remove the ripple from DC-link voltage during unbalanced fault.

In simulations it was found that when the master unit active power output was less than 5 % from the total load, it could not keep up the frequency stability in island operated LV microgrid. Therefore, with the used master unit control principles the master unit active power should preferably be in a steady state, e.g. more than 15 % from the total load. In this way the PU-controlled energy storage based master unit would still have possibility to reduce active power rapidly due to sudden over-voltages without losing the frequency stability. However, other voltage control actions are then needed to restore the active power feeding of master unit back to over 15 % from the total load.

The reactive power control of master unit can be viewed so that if there is a reactive power unbalance during island operation of LV microgrid and other DG units or controllable loads cannot change their reactive power production, then the master unit must produce the remaining reactive power needed. When the grid-forming master unit at the same time produces the frequency reference for microgrid then the required phase difference between current and voltage, which defines the produced reactive power, will automatically settle to the desired value if the reactive power control is by-passed after transition to island operation and reactive power reference I_{react} is changed to constant value zero (Figure 14). Regarding the fault behavior of the master unit during island operation it can be stated, that due to the selected control principles the fault current fed to microgrid by the master unit depends on the fault type and location, i.e. on the depth of the voltage dip caused by a fault in the island operated LV microgrid.

When DER unit is connected to grid with delta-wye grounded transformer, the unbalance of phase voltages as well as the phase currents is unequal at different sides of the transformer (Figure 16). Due to unbalanced phase voltages, also active and reactive power fed to microgrid by converter connected DER unit will oscillate although phase currents fed to the microgrid were balanced on the converter side of the DER unit transformer (Figure 16 and 17). Equivalent oscillations can be seen in the DC-link voltages of the DG unit converters (Figure 17). However, these oscillations could be reduced by different control principles which have been presented for example by Rodriguez et al. (2007).

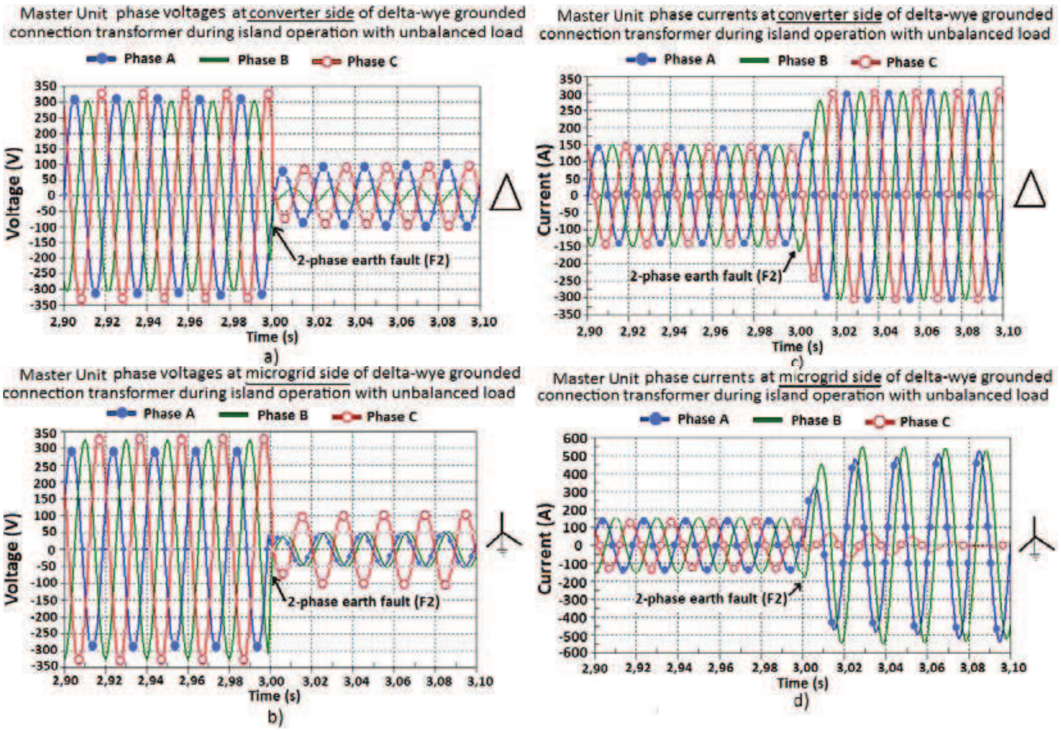


Figure 16. Phase voltages and currents at converter side (a, c) and at microgrid side (b, d) of delta-wye grounded connection transformer of master unit (energy storage based DER unit) during island operation with unbalanced load and unbalanced 2-phase earth fault (F2).

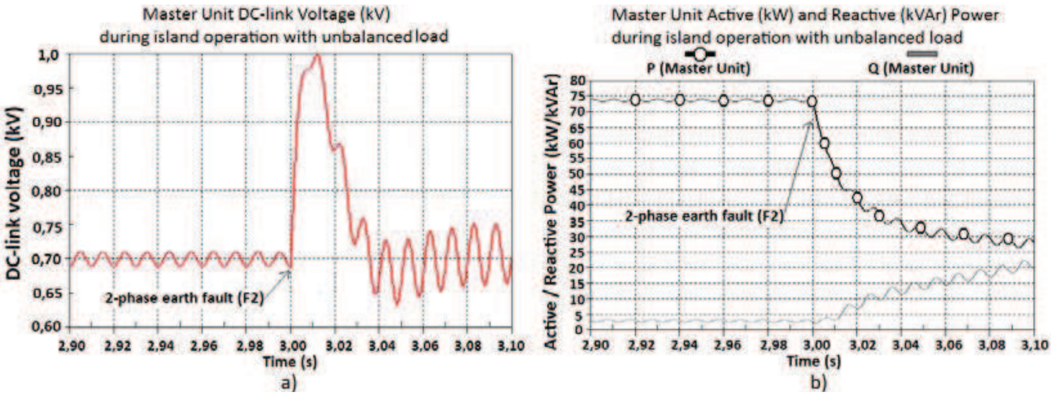
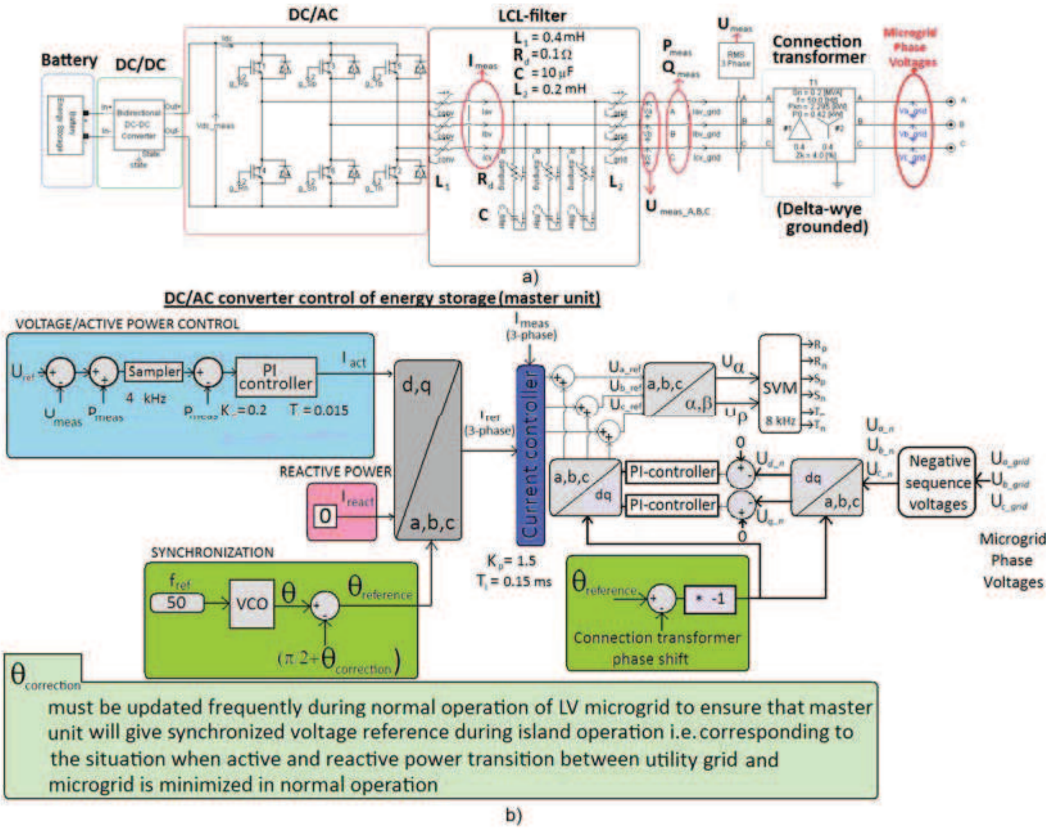


Figure 17. Master unit (energy storage based DG unit) DC-link voltage (a) and active and reactive power (b) during island operation with unbalanced load and unbalanced 2-phase earth fault (F2).

3.1.3 Central energy storage with unbalance compensation

The possibility to use central energy storage unit for voltage unbalance compensation during microgrid island operation is presented in the later part of this thesis. Microgrid voltage unbalance compensation needed modifications to be made to the control system of the master unit (Figure 18 a) presented in Figure 18 b). The voltage unbalance compensation shown in Figure 18 b) is based on presentation of Kim, Park & Hyun (2005). There are also other possible methods for voltage unbalance control like for example the one presented by Borup, Enjeti & Blaabjerg (2001).



must be updated frequently during normal operation of LV microgrid to ensure that master unit will give synchronized voltage reference during island operation i.e. corresponding to the situation when active and reactive power transition between utility grid and microgrid is minimized in normal operation

Figure 18. a) PSCAD simulation model of the master unit with the measurement of microgrid phase voltage and b) modified control of master unit converter for voltage unbalance compensation in island operation.

The PSCAD implementation of the negative sequence voltages (U_{a_n}, U_{b_n}, U_{c_n}) calculation is based on

$$\begin{bmatrix} U_{\text{a\_n}} \\ U_{\text{b\_n}} \\ U_{\text{c\_n}} \end{bmatrix} = \frac{1}{3}\cdot\begin{bmatrix} 1 & -1/2 & -1/2 \\ -1/2 & 1 & -1/2 \\ -1/2 & -1/2 & 1 \end{bmatrix}\cdot\begin{bmatrix} U_{\text{a\_grid}} \\ U_{\text{b\_grid}} \\ U_{\text{c\_grid}} \end{bmatrix} + \frac{1}{j2\sqrt{3}}\begin{bmatrix} 0 & 1 & -1 \\ -1 & 0 & 1 \\ 1 & -1 & 0 \end{bmatrix}\cdot\begin{bmatrix} U_{\text{a\_grid}} \\ U_{\text{b\_grid}} \\ U_{\text{c\_grid}} \end{bmatrix} \qquad \textbf{(3)}$$

where *j* corresponds to the 90 degrees phase shift in the model shown in Figure 19.

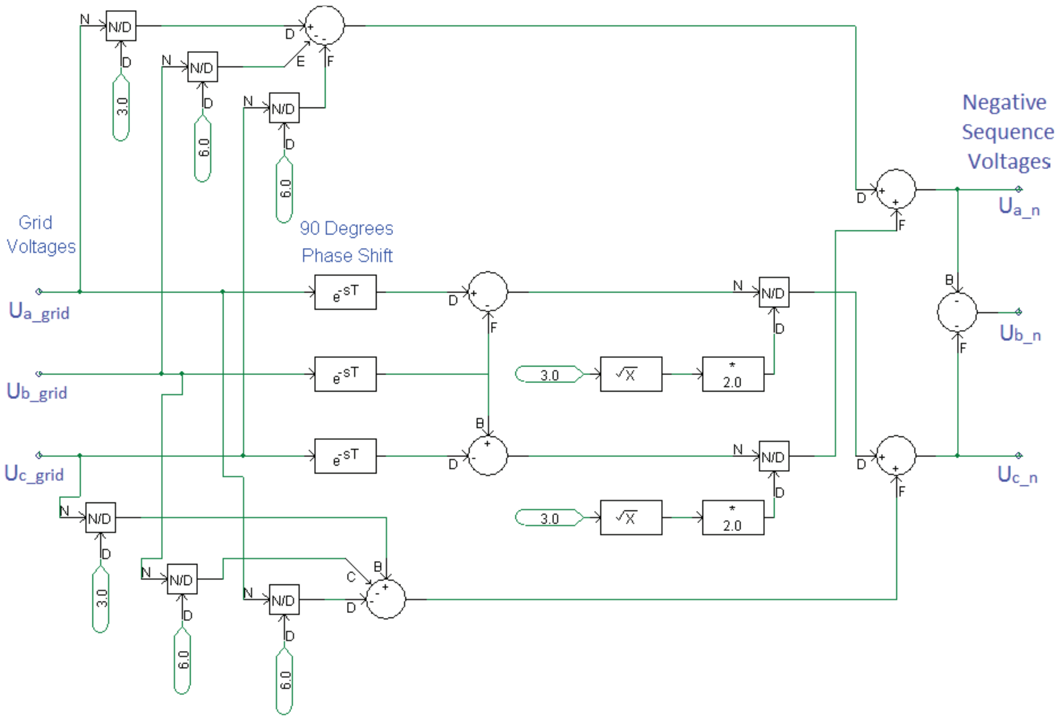


Figure 19. Implementation of negative sequence detector in PSCAD.

3.2 Central energy storage based master unit with power quality compensator

In Publication III it was presented a concept to improve the quality of power within the microgrid and also the quality of currents flowing between the microgrid and the utility grid (Figure 20). This concept was partly based on earlier preliminary studies done by Laaksonen, Saari & Komulainen (2006b) and Alanen et al. (2006) in which the basic idea of the power quality compensator in PCC of microgrid was first introduced. The developed concept utilizes the power quality compensator with energy storage for the power quality management in microgrid. The power quality compensator (PQC) consists of a shunt and a series converter (Figure 20).

With PQC, most of the power quality problems in distribution systems can be solved. The shunt converter is controlled by a PWM current control algorithm, while the series converter is controlled by a PWM voltage control algorithm similarly as in reference (Hu & Chen 2000). Due to the control scheme used, these two parts of PQC have different functions.

As stated by Hu & Chen (2000) shunt converter can
- Compensate the microgrid current harmonics,
- Compensate the reactive power of the microgrid and
- Regulate the capacitor voltage of the common DC-link.

Series converter is capable of (Hu & Chen 2000)
- Mitigating voltage dips and swells,
- Reducing harmonic voltages and
- Eliminating grid voltage unbalance.

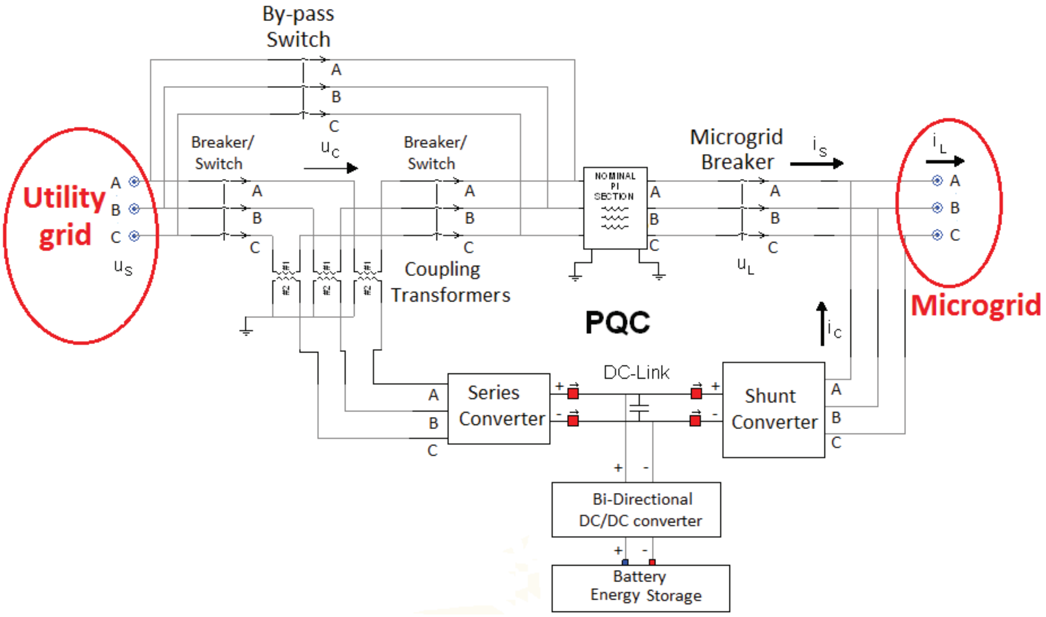


Figure 20. Energy storage (alone or parallel with some DG unit) connected to the DC-link of the power quality compensator in the PCC of microgrid.

The operation principles and active/reactive power flows of the PQC with energy storage are shown in Figure 21. These selected operation principles were developed in Publication III through multiple simulations. To avoid resonances during a normal (Figure 21 a)) and a battery charging (Figure 21 c)) operation which were detected in simulations, the coupling transformers of series converter were bypassed with bypass-switch (BS). In the normal interconnected operation (microgrid connected to utility grid) the shunt converter of the PQC produces reactive power needed by microgrid loads and compensates microgrid current harmonics with the active filtering feature of the shunt converter. At the same time the bi-directional DC/DC buck-boost converter controls the DC-link voltage. The active and reactive power flows during normal operation can be seen in Figure 21 a).

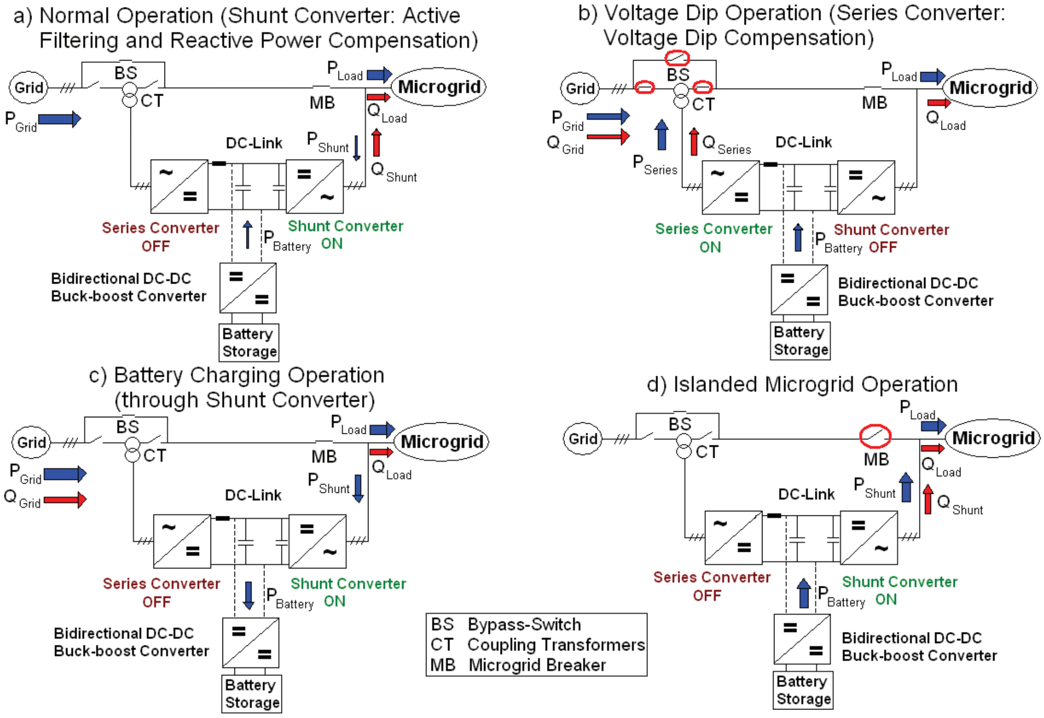


Figure 21. Operation principles and power flows of the PQC with energy storage in different cases.

The active and reactive power flows of the PQC in a voltage dip operation (voltage dip in utility grid) are shown in Figure 21 b). During the voltage dip operation the series converter of the PQC produces active and reactive power needed to compensate microgrid phase voltages. The shunt converter in active filtering mode was stopped during the voltage dip or imbalance compensation. The reason for this was that compensating currents of the series converter will increase the THD in the utility grid no matter how well the active filter compensates the microgrid current harmonics.

In Figure 21 c) the operation of the PQC with energy storage during the battery charging is presented. The battery is charged through the shunt converter and the DC/DC buck-boost converter, meanwhile the shunt converter also controls the DC-link voltage.

In the islanded microgrid operation (Figure 21 d)) the microgrid breaker is opened. During the islanded microgrid operation the active and reactive power needed for rapid the voltage control, are fed from the battery storage through the shunt converter of the PQC. During the island operation of LV microgrid the PQC with energy storage is operated in single master operation mode, which in this case means that the shunt converter with the battery storage will act as the master unit and it has the main responsibility to control the voltage and maintain the frequency in microgrid (Figure 21 d)). The control system for the shunt converter during the islanded microgrid operation is the same as the one presented in Figure 14 b).

Especially the control system and filter type of the shunt converter of the PQC with energy storage needs to adapt to requirements of each of the different possible operation modes. The control system of the shunt converter in the normal operation is based on the presentation by Hu & Chen (2000) where hysteresis modulation and L-filter (Figure 22 a)) were used for active filtering. According to Tarkiainen (2005) this is typical approach for time-domain based active filtering. The use of LCL-filter in the time-domain based active filtering method would need a more complex control system with high dynamic performance (Tarkiainen 2005) and as a result L-filter was used in the studies of Publication III. However, during the island operation of the microgrid the voltage control with hysteresis modulation was difficult to achieve and also harmonics level with L-filter increased too high. Therefore, the shunt converter needed to adapt to the island operation by changing to SVM modulation and LCL-filter configuration (Figure 22 b)). The control system of the series converter in the normal operation is also based on presentation of Hu & Chen (2000). Active filtering typically needs a higher DC-link voltage when compared to line converters (Tarkiainen 2005). However, in real LV microgrid the DC-link voltage of PQC should probably be lower than the one used in Publication III. Some examples from the dimensioning of the PQC components can be found for instance from reference (Ng, Wong & Han 2004) without DER unit in DC-link and from reference (Han et al. 2006) with DG unit in DC-link of the PQC. Also in reference (Chen, Chen & Smedley 2004) dimensioning principle for DC-link capacitor size of PQC unit has been presented when there is no DER unit connected to the DC-link.

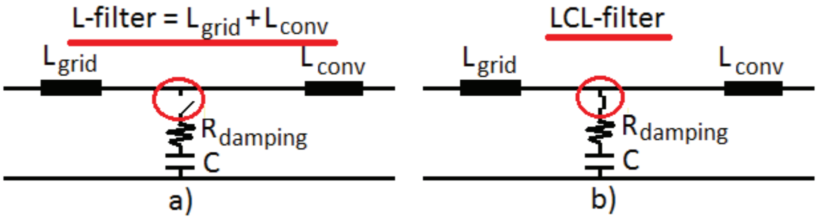


Figure 22. Filter configuration of the PQC shunt converter in the a) normal and b) island operation.

The main principles of the control algorithms for PQC shunt and series converters are presented in the following. More details about the control systems and used parameters can be found from Publication III and reference (Laaksonen, Saari & Komulainen 2006b). The control system of the shunt converter is shown in Figure 23 where measured microgrid currents are transformed from abc-frame to dq-frame. The dq-control structure as the one in Figure 23 uses the abc/dq-transformation module to transform the control variables from their natural abc-frame to a frame which synchronously rotates with the frequency of the microgrid voltage. As a consequence, the control variables will become dc-signals. The PSCAD implementation of the PQC shunt converter control system is presented in Figure 24.

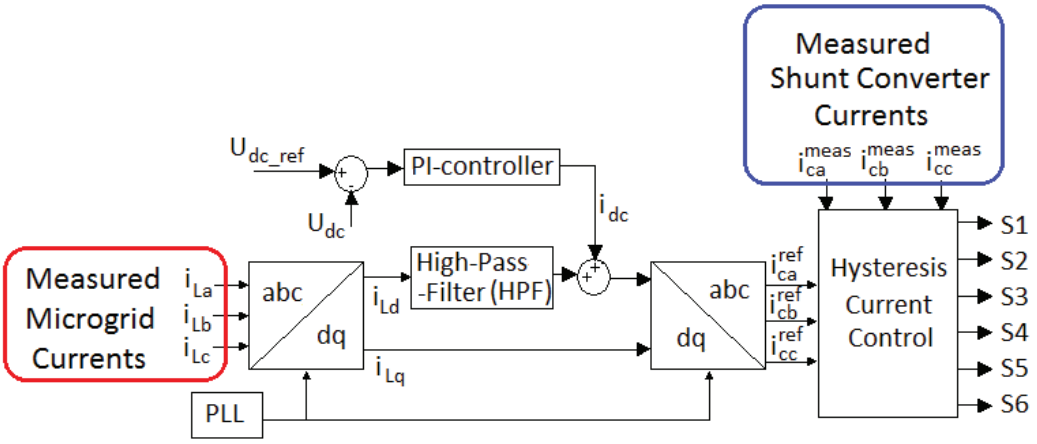


Figure 23. Control system of the PQC shunt converter (see also Figure 20). (Hu & Chen 2000)

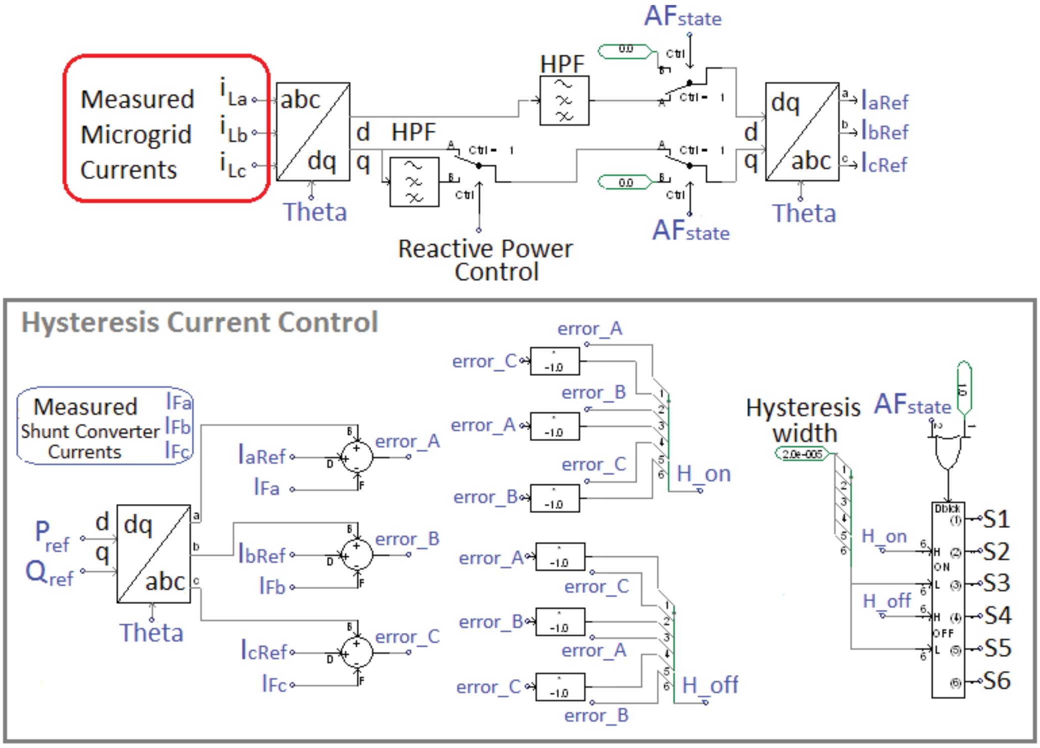


Figure 24. Implementation of the control system of the PQC shunt converter in PSCAD.

In hysteresis current control (Figure 23 and 24) the current of the shunt converter follows constantly the reference values so that, while error-signals are between hysteresis limits no switching commands for converter switches will be given. Hysteresis current control has quite rapid response and it is easy to implement, but on the other hand the switching frequency is not constant and it is mainly dependent on the width of the hysteresis (Figure 24). Due to variable switching frequency hysteresis current controlled converter may feed large amount of higher order harmonics and interharmonics to the grid, which can be difficult to filter out with traditional filters (Figure 22) and there is also a risk that some of the higher order harmonics may resonate, e.g. with grid impedances in island operation.

In some simulation studies with PQC based master unit in PCC of LV microgrid, the 3rd harmonic found in microgrid currents was not filtered from utility grid currents with the active filter function of shunt converter based on control system shown in Figure 23 and 24. Changes in the high-pass-filter (HPF) of the shunt converter control system (Figure 24) removed this problem, but on the other hand they made the operation during battery charging (see Figure 21 c)) worse and therefore some further development with the control system of shunt converter could still be done.

The series converter is connected to the network through a coupling transformer (see Figure 20). The control system of the series converter is presented in Figure 25. The PSCAD implementation of the PQC series converter control system is shown in Figure 26.

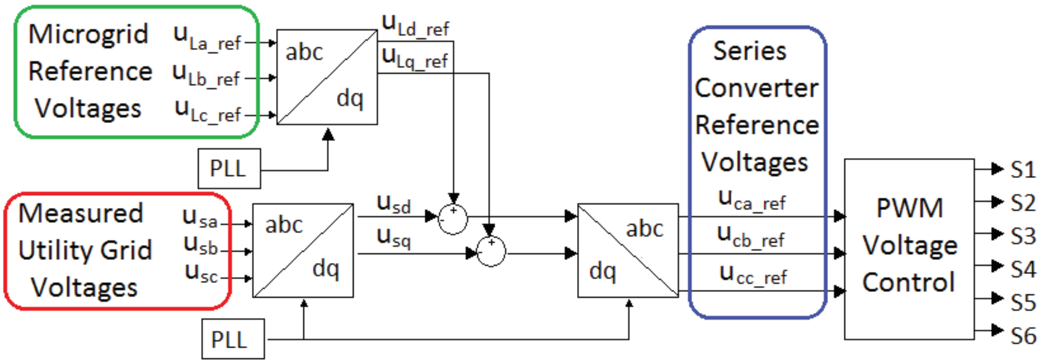


Figure 25. Control system of the PQC series converter (see also Figure 20). (Hu & Chen 2000)

In general, it was found that the control performance and choice of parameter values of the PQC shunt and series converters could be further improved. For example the control of series converter could be done with hysteresis control as stated by Khadkikar et al. (2005), but this would also require changes for example to the filter parameters of the series converter.

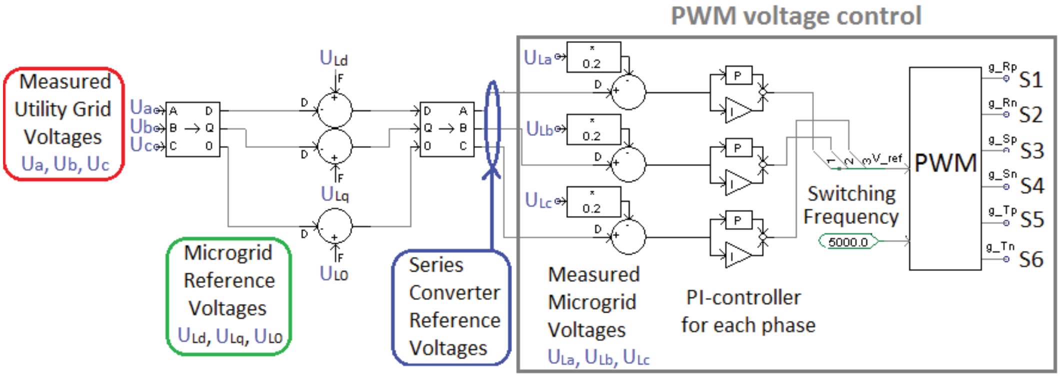


Figure 26. Implementation of the control system of the PQC series converter in PSCAD.

3.3 Simulation models for other DER units

In Figure 27 it is presented the PSCAD simulation model of directly connected SG based DG unit was also based on DG unit model developed previously in a joint project between University of Vaasa and VTT. However, many parts of the previously created model, e.g. reactive power control and speed control (Figure 27), have been modified to meet the needs of LV microgrid island operation. Details about the control and other parameters can be found for example in Publication VII.

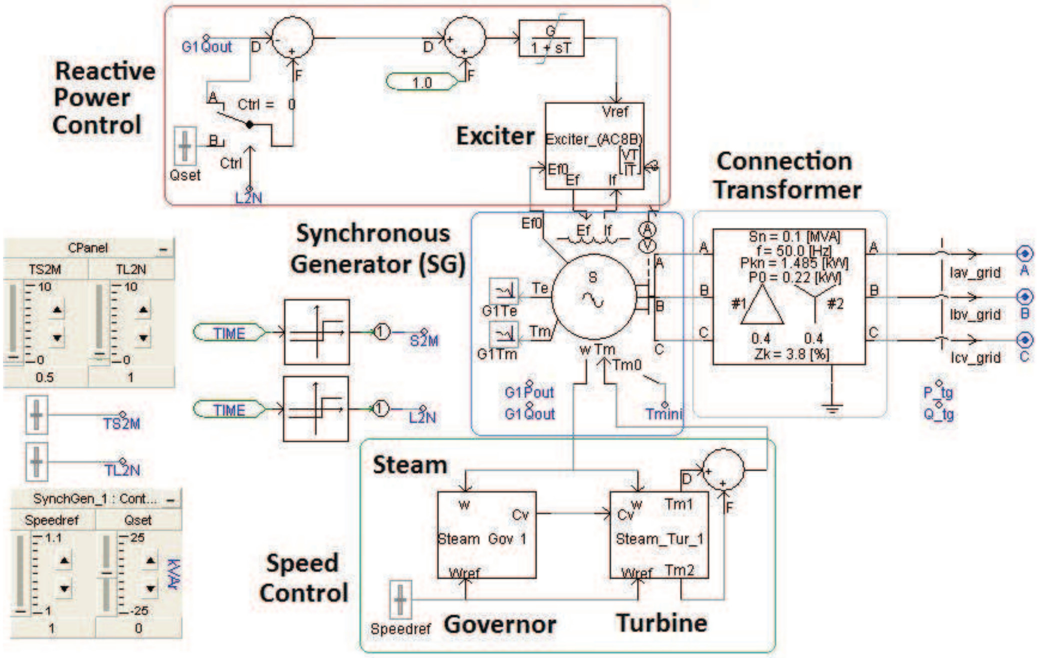


Figure 27. PSCAD simulation model for100 kVA directly connected synchronous generator (SG) based DG unit.

The main purpose of the SG based DG unit model (Figure 27) was to compare the effect of it with the cases where only converter based DER units were connected to LV microgrid. It changed the dynamic behavior of island operated LV microgrid during steady state operation and after sudden changes. The SG based DG unit was used with constant speed and reactive power control and the aim was that it did not actively participate, e.g. on LV microgrid voltage control. It was decided in this thesis not to use the multi-mass interface of PSCAD with SG based DG unit (Figure 27). However, simulations were also done with multi-mass interface. But, during island operation significant difference in fault current feeding or in stability of SG after fault was not detected when simulation results were compared. Only oscillations during island operation in the rotating speed of SG, microgrid frequency and active and reactive powers of SG were found to be higher. On the other hand, as a result of this over optimistic results from the stability of SG based DG unit will not be given.

In Figure 28 there is shown the PSCAD simulation model of the PMSG with frequency converter and supercapacitor based DG unit that has been used in Publication VII. Supercapacitor has been added to the DC-link to provide FRT ability for the DG unit.

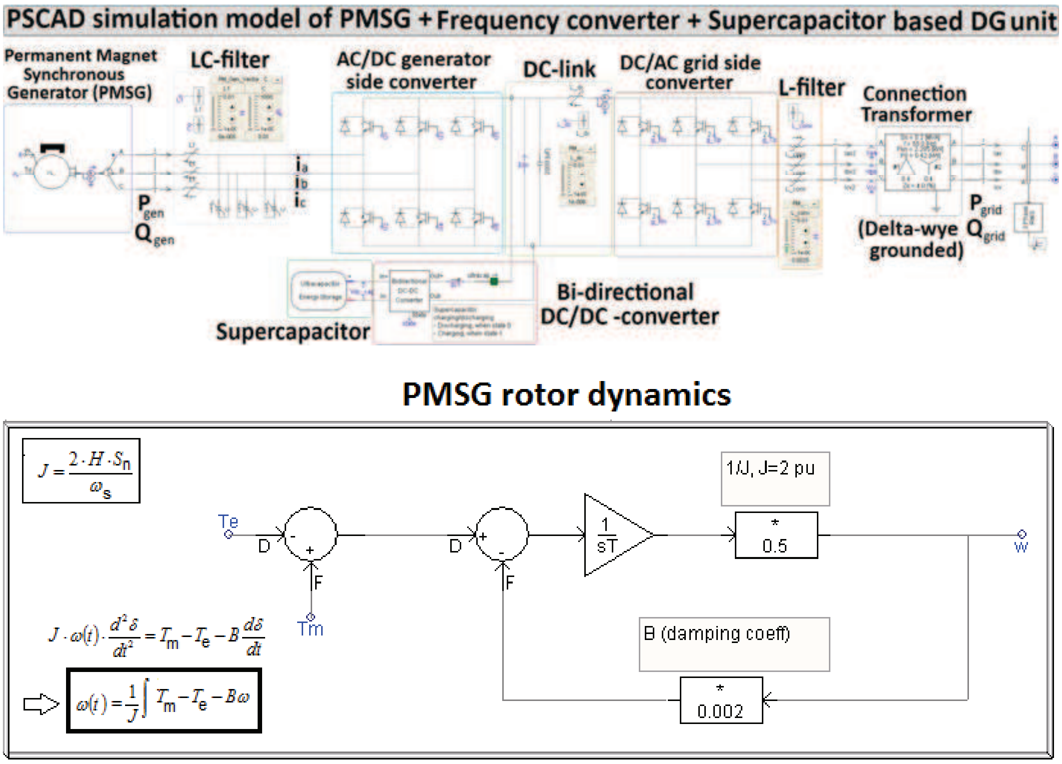


Figure 28. PSCAD simulation model of the PMSG with frequency converter and supercapacitor based DG unit.

During faults in island operation (Figure 28) the supercapacitor limits voltage rise in the DC-link by absorbing energy from the DC-link. The simulation results in Publication VII showed how the control of the voltage rise in the DC-link of the converter reduced the fault current fed by the corresponding DG unit. More details about the control parameters etc. can be found from Publication VII.

In the control system of frequency converter, PLL from the PSCAD master library has been used together with negative sequence filtering to enable the FRT ability (Figure 29).

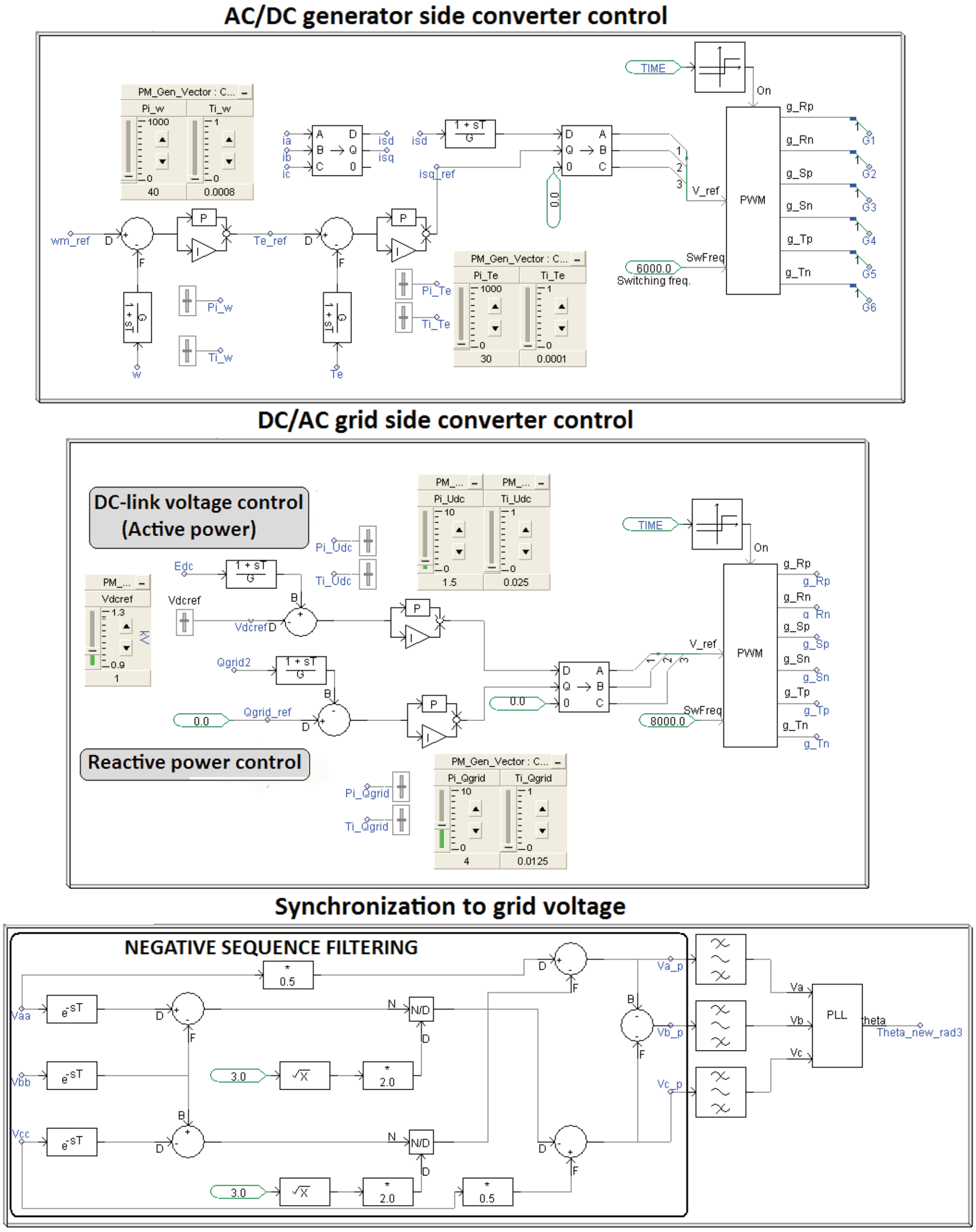


Figure 29. PSCAD simulation model of the the control system of the PMSG with frequency converter and supercapacitor based DG unit.

Instead of DC/AC- grid side converter (Figure 29) the DC/DC-converter which connects the energy storage into the DC-link could also be in charge of controlling the DC-link voltage continuously during faults. In that case the active and reactive power control of grid side converter would become more flexible both during normal and fault states if battery based energy storage is also used instead of supercapacitor.

4 TECHNICAL SOLUTIONS – SUCCESSFUL TRANSITION TO ISLAND OPERATION

In this chapter the issues related to a successful transition of LV microgrid to island operation, i.e. islanding, are reviewed. This review is mainly based on the contents and the results of Publications I and II where more details can be found. Transition to island operation may take place either intentionally or unintentionally. Unintentional islanding usually refers to transition to island operation due to a fault in the utility grid. Intentional islanding usually occurs after a power balance inside LV microgrid has been reached. It means that active and reactive power flow between LV microgrid and the utility grid is controlled to be zero before the transition. Intentional islanding in power unbalance is not sensible, but to some extent it is comparable to unintentional islanding after voltage dip in the utility grid. Microgrid management system (MMS) monitors continuously the transition possibility. Transition is possible if the power unbalance inside LV microgrid after possible islanding will not be larger than the available control capacity. This control capacity consists of the central energy storage with rapid response and amount and state of controllable loads. Also the disconnection of these controllable loads must be very rapid. Fast response can be achieved by high-speed communication signal from MMS rapidly after transition to island operation. Speed, robustness, accuracy and adaptability of other DER unit controls will also have significant effect on the stability of LV microgrid after transition. On the other hand, if the transition to island operation takes place unintentionally the operation speed of the microgrid interconnection switch or breaker will also have significant influence on stability of islanded microgrid.

The control of active and reactive power in the PCC of LV microgrid before intentional islanding can be based on different principles. The successful transition to island operation can be ensured by keeping constantly power balance inside LV microgrid during normal operation. This means that the active and reactive or only reactive power flows between LV microgrid and utility grid must be controlled to be zero. On the other hand, in the future, LV microgrid could take part on the voltage control of smart grids through technical service markets. In such case the active and reactive power in the PCC of microgrid will not be constantly zero. Therefore successful transition to island operation will require very fast and robust control from all DER units in LV microgrid. MMS will determine the limits for allowable active and reactive power flow between LV microgrid and utility grid based on technical boundaries such as voltage levels, state of central energy storage, other DER units and controllable loads etc., so that successful transition to island operation could be possible.

4.1 Frequency control principles in LV microgrid after islanding

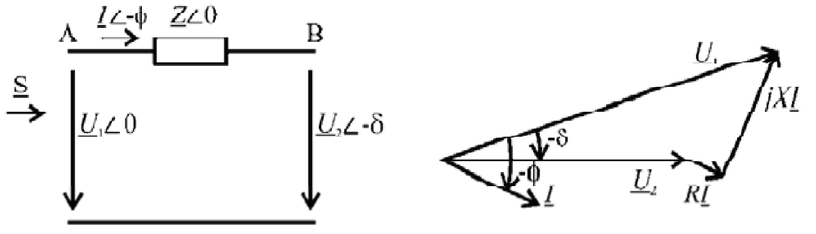
Active and reactive power flow into the line at point A (Figure 30) can be described with the following equations

$$P = \frac{U_1}{R^2 + X^2}\left[R \cdot (U_1 - U_2 \cdot \cos\delta) + X \cdot U_2 \cdot \sin\delta\right] \tag{4}$$

and

$$Q = \frac{U_1}{R^2 + X^2}\left[-R \cdot U_2 \cdot \sin\delta + X \cdot (U_1 - U_2 \cdot \cos\delta)\right] \tag{5}$$

where R is line resistance, X is line reactance, δ is load angle, U_1 is voltage at the beginning of the line and U_2 is voltage at the end of the line. (Nagrath & Kothari 1994: 148–152; De Brabandere et al. 2004a)



(a) (b)

Figure 30. a) Power flow through a line, b) phasor diagram (De Brabandere et al. 2004a)

LV microgrids will be based on mainly resistive (R>>X) LV distribution network lines. Therefore, Equations (4) and (5) can be reduced in LV network to

$$P \cong \frac{U_1^2}{R} - \frac{U_1 \cdot U_2}{R} \tag{6}$$

and

$$Q \cong -\frac{U_1 \cdot U_2}{R}\delta \tag{7}$$

by neglecting reactance X and assuming that the load angle δ is small, then $\sin(\delta)=\delta$ and $\cos(\delta)=1$. (De Brabandere et al. 2004b)

From Equations (6) and (7) it can be seen that with mainly resistive lines the active power P depends mainly on voltage difference U_1-U_2. At the same time the load angle δ and thus also the frequency f depends mainly on reactive power Q. Therefore, the traditional frequency droop control through active power and voltage droop control through reactive power will not function very well on LV network based microgrid. For that reason it can be stated that the voltage control in converter and LV network based islanded microgrid should be implemented through active power control. However, in island operated LV microgrid with converter based DER units frequency is more or less fixed. This is the case especially if there is one grid-forming master unit which generates a frequency reference for the other generators to synchronize with. For example with UPS systems this is usually done with a frequency generator (crystal oscillator) in the controller. Therefore, reactive power control in island operated LV microgrid will affect mainly on the load angle δ (see Equation (7) and Figure 30). The active power/voltage (P/U) and reactive power/frequency (Q/f) dependency of LV microgrid with converter based DER units has also been presented in literature, e.g. by Laaksonen, Saari & Komulainen (2005), Sao & Lehn (2006) and Vandoorn et al. (2010), (2011a), (2011b).

In traditional power systems large centralized synchronous generators are directly connected to the grid and there is a strong relationship between the generator rotor speed, the system frequency and the power balance in the system. The fundamental equation that governs the rotational dynamics of the synchronous generator is the swing equation

$$\frac{2\cdot H}{\omega_{\mathrm{s}}}\frac{d^2\delta_1}{dt^2} = P_{\mathrm{m}} - P_{\mathrm{e}} = P_{\mathrm{m}} - P_{\mathrm{max}}\cdot\sin\delta_1 = P_{\mathrm{a}}\,[\mathrm{pu}] \tag{8}$$

or

$$\frac{H}{\pi\cdot f}\frac{d^2\delta_1}{dt^2} = P_{\mathrm{m}} - \frac{|E'||U_{\mathrm{inf}}|}{X_{\mathrm{trans}}}\cdot\sin\delta_1 = P_{\mathrm{a}}\,[\mathrm{pu}] \tag{9}$$

where ω_{s} is the synchronous speed in electrical units in rad/s, H is the inertia constant (the stored kinetic energy in MWs at synchronous speed per machine rating in MVA), δ_1 is the angular displacement of the rotor in rad, P_{m} is the shaft power input less rotational losses in pu, P_{e} is the electrical power crossing the air gap in pu, P_{a} is the accelerating power, f is frequency, X_{trans} includes machine reactance X'_{d} and line reactance X_{e} when connected to infinite bus through it, and E' and U_{inf} are machine and infinite bus voltage values (Kundur 1994: 128–131; Nagrath & Kothari 1994: 486–495). It can be seen from Equation (8), that any unbalance in active power ($P_m \neq P_e$) will result in non-zero accelerating power ($P_a \neq 0$), i.e. the rotor of the synchronous generators will either: accelerate $\left(\frac{d^2\delta_1}{dt^2} > 0\right)$ or decelerate $\left(\frac{d^2\delta_1}{dt^2} < 0\right)$. (Reza et al. 2005)

The inertia of the synchronous machines plays a significant role in maintaining the stability of the power system in an occurrence of a power unbalance. From Equation (8) we can see that, when the value of P_e alters and P_m remains constant, a higher inertia constant (H) of the synchronous generator, causes less acceleration or deceleration of the generator rotor. With synchronous generators connected to the LV network microgrid, the inertia constant can be quite small and so they can be sensitive to system disturbances. (Kundur 1994: 128–131; Nagrath & Kothari 1994: 486–495; Reza et al. 2005)

The system frequency of a traditional power system is coupled with the rotor speed of the directly connected large synchronous generators. In these cases active power unbalance can be seen as a change in the system frequency. However, in island operated LV microgrid, all DG units can be connected to microgrid via converters. Hence, there is no inertia of rotating masses to affect the frequency. Therefore, power unbalance cannot be detected in the classical way. In such case, the active power unbalance can be detected from voltage deviations.

4.2 Stability of LV microgrid after intentional islanding

In normal utility grid connected operation DG unit converters are typically used as controlled current sources and they are synchronized to utility grid frequency with PLL component. In Figure 31 the traditional synchronous dq-frame PLL method is presented (Kaura & Blasko 1997; Blaabjerg et al. 2006).

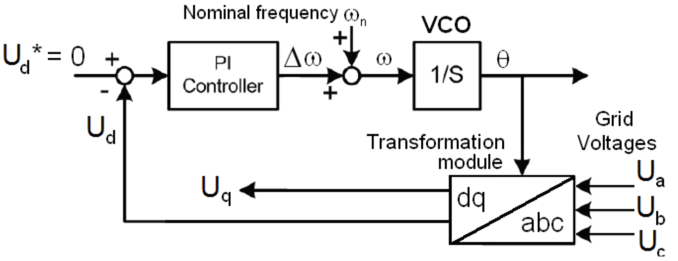


Figure 31. Control diagram of a traditional synchronous dq-frame PLL. (Blaabjerg et al. 2006)

The traditional PLL component may fail with grid synchronization due to faults, grid voltage unbalance or high harmonic distortion, if voltage negative sequence component is not filtered out from the PLL input signal (Blaabjerg et al. 2006; Rolim, Rodrigues da Costa & Aredes 2006). Also the sudden change in the network stiffness and dynamics after transition to island operation is challenging for the DER unit converter control and grid filter design from the point of view of stability. This sudden change may lead to stability problems around the current controller bandwidth frequency as well as around the LCL-filter resonance frequency (Liserre, Teodorescu & Blaabjerg 2004). Therefore, converter control parameters should be such that they work both in normal and island operation or they must be adaptive. Proper selection of converter sampling frequency is also essential for the system stability (Karlsson, Björnstedt & Ström 2005).

In this thesis it was chosen that there is one grid-forming central energy storage based master unit which had the main responsibility to control the voltage and frequency in island operated LV microgrid. Simulations done in Publication I showed how different converter modulation methods, switching frequencies and filter types affected the voltage THD and stability after intentional islanding in power balance or unbalance with different DG unit configurations and line impedances. When the voltage THD increased too much during island operation, the frequency stability of the LV microgrid was lost due to unstable operation of synchronization component, PLL, and PI-controllers on converter based DER units. However, the inertia of the directly connected rotating machines helped the DER unit converter controllers to remain stable because they decreased the speed of oscillations after sudden changes. Most of the problems related to high voltage THD could be avoided by using appropriate switching frequency and LCL-filters instead of L-filters on converter based DER units. In Figure 32 some relationships and key issues affecting the stability of an islanded microgrid are summarized based on literature and simulation studies done and presented in Publication I.

The most challenging issue in terms of DG unit stability is the transition to island operation due to fault in the utility grid. Stability after unintentional islanding depends mainly on depth and duration of the voltage dip resulting from fault as well as from the PLL configuration and DG unit control system. Particularly sensitive to voltage dips before islanding are directly and through frequency converter connected rotating machines like synchronous generators and induction motors. During transition to island operation the stability of the rotating machines should be maintained (FRT) and their own protection devices should not disconnect them from the microgrid. If rotating machines are equipped with frequency converter interfaces, they can be designed to be more flexible in terms of low-voltage-ride-through (LVRT) requirements.

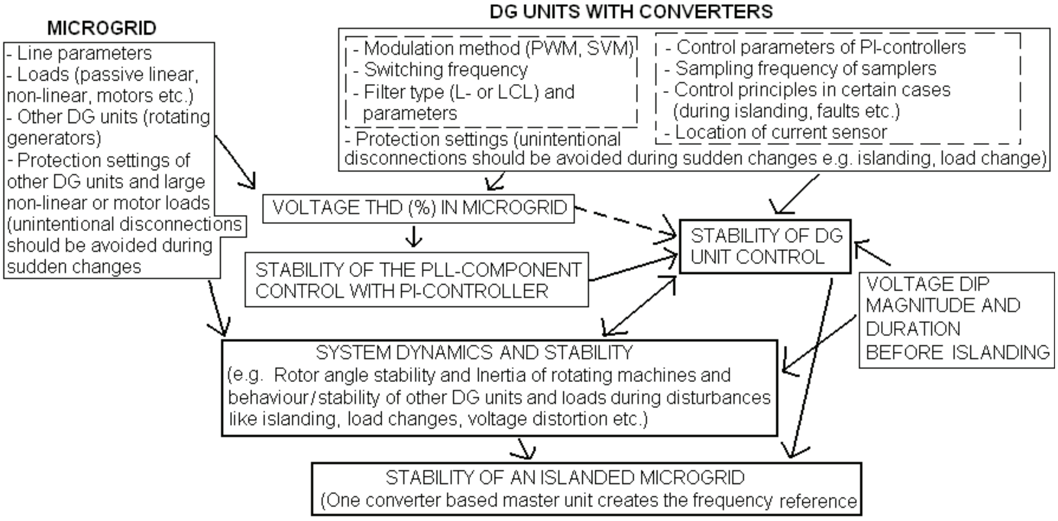


Figure 32. Relationships and key issues affecting the stability of an islanded microgrid.

4.3 Stability of LV microgrid after unintentional islanding

Unintentional islanding is the most challenging issue in terms of LV microgrid stability. In Publication II the stability of LV microgrid after transition to island operation due to a fault in the utility grid was studied with different configurations. In addition, alternative possibilities to maintain the stability by reduction of voltage dip duration or magnitude before transition to island operation were presented in Publication II. The required transition speed to island operation depends on the microgrid dynamics and type of DG units connected as well as on the sensitivity class of the microgrid customers. Successful transition to island operation due to fault in the utility grid creates simultaneously minimum requirements to the operation speed of the microgrid interconnection switch / breaker. In Publication II a summary of the possibilities to ensure stability of the LV microgrid after islanding due to fault in the utility grid was presented.

Utility grid faults may be classified into two main types: 1) balanced faults where all three grid phase voltages register the same drop in amplitude but the system remains balanced and 2) unbalanced faults where the three grid voltages register unequal drop of amplitudes. The occurrence of balanced faults is very rare in power systems. More commonly the faults are unbalanced when one or two phases will be shorted to ground or to each other, which also results into a phase shift between the phases.

4.3.1 Stability of rotating machines and converter based DG units after voltage dip

During a voltage dip with zero remaining voltage the active power of the directly connected SG cannot be fed to the grid, so P_e becomes smaller while P_m remains constant and generator accelerates (see Equation (8) on page 60). Smaller voltage dip causes less acceleration. Therefore it is important to minimize the duration and magnitude of the voltage dip.

On the other hand, an induction motor may stall during a voltage dip, and may not be able to accelerate its load when the supply voltage is restored back to normal. Loads with high-inertia and varying load torque may undergo a limited amount of retardation and may be able to reaccelerate on voltage recovery. A balanced 3-phase fault will result in the worst condition and IM contribution goes to zero within a few cycles. Unbalanced, 2-phases to earth, 2-phase, and 1-phase to earth faults will give less severe conditions of stability in the corresponding order. For unbalanced faults, IM contribution to the positive-sequence voltage can remain to be present even 300 milliseconds after fault initiation. (Das 1990; Bollen, Hager & Roxenius 2003)

Voltage dips may also lead to tripping of the frequency converter based drives. For example if control is based on constant power control, then sudden decrease in grid voltage causes an increase in the current of a voltage source converter (VSC) based DG unit. This may lead to tripping of the VSC due to operation of over-current protection which is used to protect the IGBTs. In addition, unbalanced voltage dips can produce current harmonics and current unbalance, which may also cause the current protection to trip. Characteristic to the unbalanced fault is the appearance of the negative-sequence component in the grid voltages, which gives rise to double-frequency oscillations or second harmonic ripple in the system. This can be seen as ripple in the DC-link voltage and output power and such oscillations can lead to a system trip if the maximum DC-link voltage is exceeded. The second harmonic ripple will propagate into different sections of the DG unit converter controller and can have a negative influence on the controller by producing a non-sinusoidal current reference which will make the power quality of the converter poor even leading to trip out of the system. (Sannino, Bollen & Svensson 2005; Timbus et al. 2006b; Abdul-Magueed Hassan 2007; Rodriguez et al. 2007)

To deal with above mentioned problems during unbalanced voltage dips the control of the DG unit converter plays the main role. Many controllers have already been developed and proposed for a VSC system, e.g. by Abdul-Magueed Hassan (2007), to deal with grid voltage unbalance. During unbalanced conditions, it is possible to cancel out active and reactive power oscillations only by accepting highly distorted currents. One solution proposed by Rodriguez et al. (2007) allows having sinusoidal grid currents by compensating for the oscillation in the active power only, while oscillations are present in the reactive one.

To handle the problem with second harmonic ripple, improved PLL algorithms have been developed. They are able to filter out the negative sequence and to provide a clean synchronization signal. One developed solution is presented by Timbus et al. (2006b). Along with the conventional PI controller in the PLL structure, the proposed algorithm employs a repetitive controller to deal with the second harmonic (Timbus et al. 2006b). Another possible solution to deal with the voltage unbalance is the usage of positive sequence detector as presented by Lee, Kang & Sul (1999). This detector eliminates negative sequences from the phase voltages (U_{a}, U_{b}, U_{c}) of the grid. The positive sequence voltages ($U_{\mathrm{a\_p}}$, $U_{\mathrm{b\_p}}$, $U_{\mathrm{c\_p}}$) can be calculated from

$$\begin{bmatrix} U_{\mathrm{a\_p}} \\ U_{\mathrm{b\_p}} \\ U_{\mathrm{c\_p}} \end{bmatrix} = \frac{1}{3} \cdot \begin{bmatrix} 1 & a & a^2 \\ a^2 & 1 & a \\ a & a^2 & 1 \end{bmatrix} \cdot \begin{bmatrix} U_{\mathrm{a}} \\ U_{\mathrm{b}} \\ U_{\mathrm{c}} \end{bmatrix} = \begin{bmatrix} \frac{1}{2} \cdot U_{\mathrm{a}} - j\frac{1}{2\sqrt{3}}\left(U_{\mathrm{b}} - U_{\mathrm{c}}\right) \\ -\left(U_{\mathrm{a\_p}} + U_{\mathrm{c\_p}}\right) \\ \frac{1}{2} \cdot U_{\mathrm{c}} - j\frac{1}{2\sqrt{3}}\left(U_{\mathrm{a}} - U_{\mathrm{b}}\right) \end{bmatrix} \tag{10}$$

where $a = -1/2 + j\sqrt{3}/2$ and $U_{\mathrm{a\_p}} + U_{\mathrm{b\_p}} + U_{\mathrm{c\_p}} = 0$.

Digital implementation of (10) is possible by combining all-pass 90° phase-shifter and constant gain (Lee, Kang & Sul 1999). In Publication II the PLL component with positive sequence detector, as described by Lee, Kang & Sul (1999), was implemented to improve fault-ride-through capability of the converter based DG units during unbalanced faults (see Figure 15 in Chapter 3 on page 43). The only problem with the use of the positive sequence voltages is the ripple of the DC-link voltage during unbalanced faults. This ripple also affects the active power reference and both active and reactive power will experience double-frequency oscillations over the whole fault period (Blaabjerg et al. 2006).

In Figure 33 an example from Publication II is presented to show how the usage of the positive sequence detector with the PLL on all converter based DER units improved the frequency and voltage stability when compared to case without positive sequence detector. Stability was lost without the utilization of the positive sequence detectors in the control of the DER units after 750 ms 2-phase-earth-fault before transition to island operation (Figure 33). Respectively it can be seen from Figure 33 how the usage of positive sequence detector with PLL improved the low-voltage-ride-through capability of the DER units during unbalanced 2-phase-earth-fault and the stability after islanding.

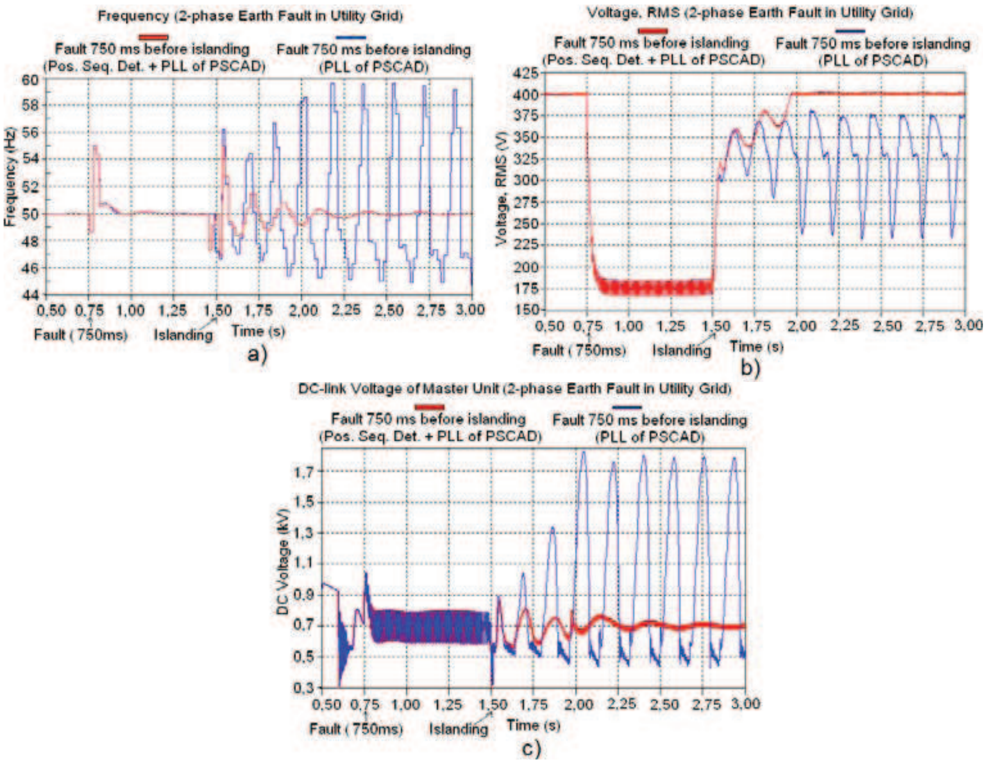


Figure 33. The effect of the use of PLL with positive sequence detector on a) frequency , b) voltage and c) master unit DC-link voltage stability in microgrid after islanding due to 2-phase earth fault in the utility grid.

Other advanced methods for grid synchronization under unbalanced and distorted conditions also exist, e.g. Dual Second Order Generalised Integrator – Frequency-Locked Loop (DSOGI-FLL) method developed by Rodriguez et al. (2006). Also a sensorless synchronization method with virtual flux approach has been suggested by Kulka (2009) to deal with unbalanced grid voltage.

4.3.2 Possibilities to reduce the effect of a voltage dip with master unit configuration

Different possible central energy storage based master unit configurations were presented in Publication II to reduce the effect of voltage dips to the stability of rotating machines. The base case was chosen to be voltage dip with 90 % magnitude and 200 ms duration before islanding. Alternatives to reduce the effect of the voltage and to maintain stability in the island operated microgrid were the following (Figure 34):

1. Significant reduction of the voltage dip duration (Case 1) or
2. Substantial reduction of the voltage dip magnitude (Case 2) or
3. Reduction of the voltage dip duration and magnitude (Case 3).

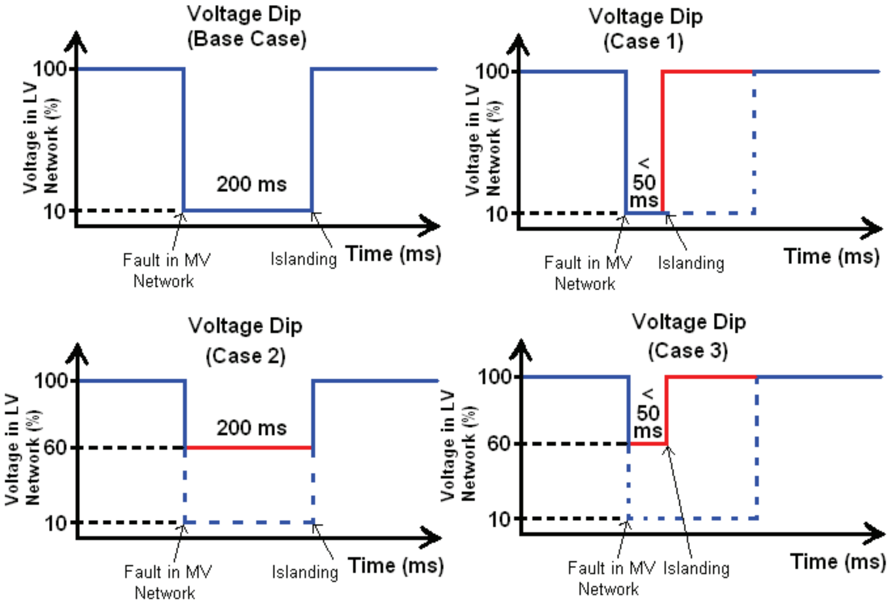


Figure 34. Alternatives (cases 1–3) to maintain stability of the microgrid after islanding by compensating/reducing the effect of the voltage dip.

These different alternatives (cases 1–3) in Figure 34 to compensate or reduce the duration of the voltage dip before islanding could be realized with different energy storage + switch -configurations. These configurations are (Figure 35):

1. Fast static switch + energy storage (Case 1) or
2. Breaker + energy storage based power quality compensator, PQC (Case2) or
3. Fast Static Switch + energy storage based PQC (Case 3).

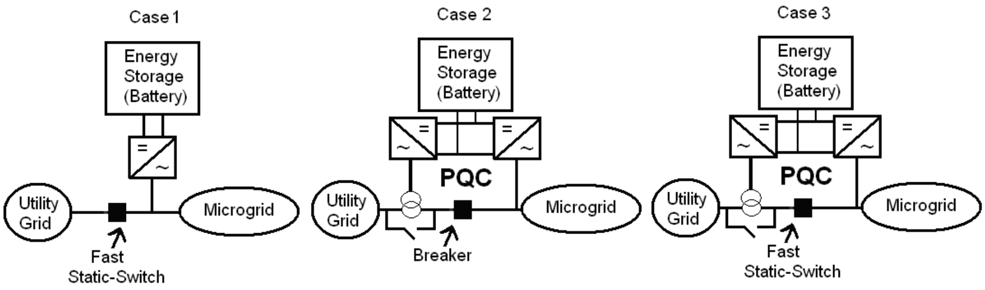


Figure 35. Possible configurations to compensate or reduce the effect of the voltage dip as illustrated in Figure 34.

Based on the simulations done in Publication II a summary of the possibilities to ensure stability of the LV microgrid after islanding due to a fault in the utility grid is presented in Figure 36. As illustrated in Figure 36 the stability can be improved by different choices of voltage dip compensation methods in the connection point of microgrid and by different PLL configurations applied on the converters. The transition speed to island operation depends on the microgrid dynamics and type of DG units connected as well as on the sensitivity class of the microgrid customers. Depending on the sensitivity class of the microgrid customers the fault-ride-through needs of the DG units and loads can be defined respectively with sufficient margin to the voltage dependent speed of transition to island operation curves.

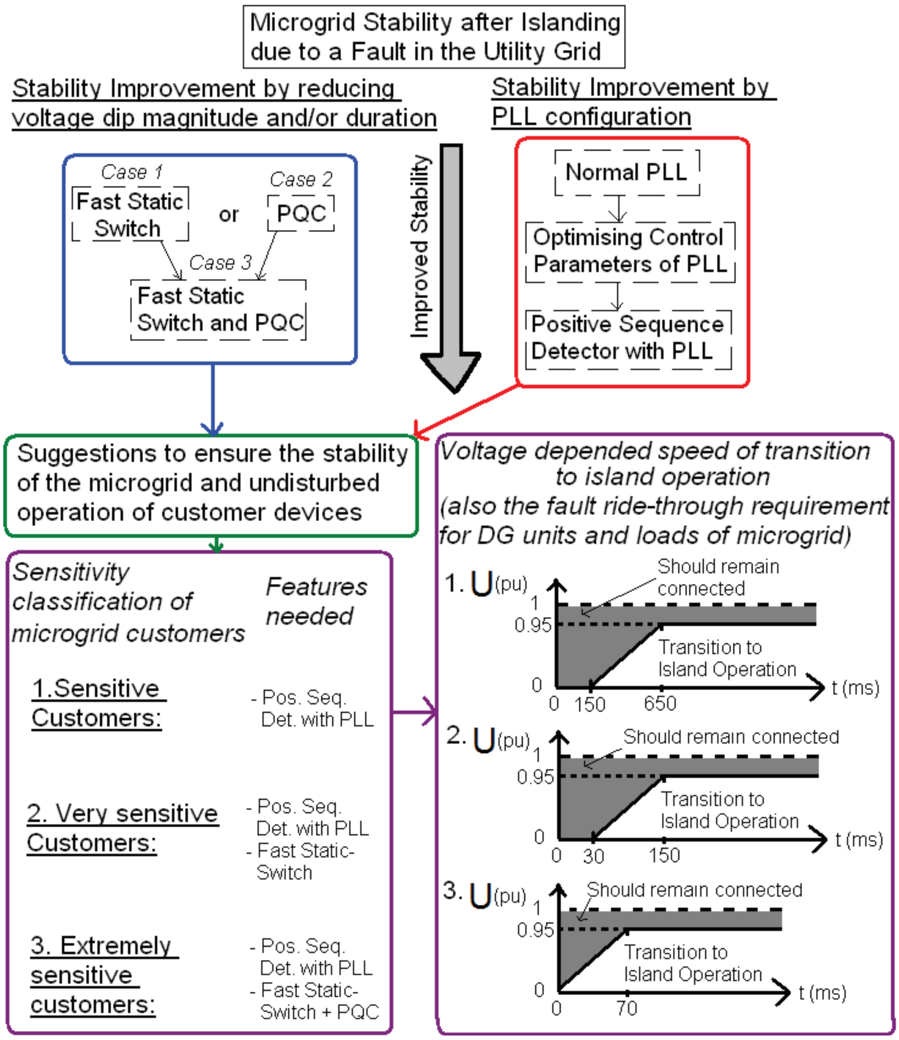


Figure 36. Summary of the possibilities to ensure stability of the LV microgrid after unintentional islanding due to a fault in the utility grid.

5 TECHNICAL SOLUTIONS – POWER QUALITY MANAGEMENT

In this chapter different aspects related to the power quality management of the LV microgrid are viewed. In following the power quality management comprises of voltage total harmonic distortion, THD (Section 5.1), power balance, voltage level and voltage unbalance management (Section 5.2). The contents of Section 5.1 is mainly based on Publications III and IV where more details can be found.

5.1 Voltage THD management in LV microgrid

High voltage THD and possible harmonics-caused resonances may damage or lead to maloperation of protection relays, metering devices, control and communication circuits as well as customer electronic equipments (Wakileh 2001: 84). Due to triplen harmonics neutral wires may need to be overrated even if the loads are balanced in LV networks (Wakileh 2001: 84). Also from the point of view of energy efficiency, the amount of harmonics in LV networks should be minimized, because voltage distortion will increase copper, iron and dielectric losses (Wakileh 2001: 81) as well as equipment loss-of-life (Wakileh 2001: 84).

Voltage harmonics are often neglected in simulations e.g. for electrical machines, transformers and converters to simplify design calculations (Wakileh 2001: 5). However, in real-life the voltage waveform is never purely sinusoidal (Wakileh 2001: 5). Therefore, it is essential that LV microgrid components are modeled as detailed as possible when proposals and principles for LV microgrid technical solutions are developed. As an example it can be mentioned that if harmonics are present, then zero and negative sequence currents exist even if the system unbalance is compensated (Wakileh 2001: 15).

Harmonic distortion in LV networks is mainly caused by nonlinear devices where the current is not proportional to the applied voltage. The response of the power system, i.e. the system impedance at each harmonic frequency, determines the impact of the nonlinear load on harmonic voltage distortion (Dugan et al. 2003: 199). In future LV microgrids it is important to minimize the impact of non-linear loads and converter based DER units to voltage THD. Cobben, Kling & Myrzik (2005) presented a real-life sample case where due to high amount of PV converters the harmonic distortion became significant in LV distribution network. Reason for the high harmonic distortion was the interaction between the harmonic currents of the PV converters and the background harmonic voltage multiplied by the resonant behavior of the grid and loads. Same kind of problem was also found by Bollen, Yang & Hassan (2008) in which resonances between 1 and 2 kHz were measured in a residential area with large amounts of PV converters. To overcome this kind of problems in island operation, the use of proper filters with DG unit converters is very important. In addition, Van Overbeeke & Cobben (2010) found that with PV converters the voltage harmonics between 650 and 750 Hz can be amplified by the control systems of the converters.

5.1.1 Standards for the current harmonic contribution of converter based DER units

Various organizations on the national and international level, like IEEE, IEC and EN (Wakileh 2001: 137), have made standards both for individual and total harmonic distortion of voltage in the LV networks. IEEE Standard 519-1992 limits the THD to be less than 5 %. Standards IEC 61000-2-2 and EN 50160 define that the supply voltage THD should be less than 8 % including all harmonics up to 40th order. Differences between the harmonic compatibility levels in standards EN 50160 and IEC 61000-2-2 are quite small (Figure 37). (Dugan et al. 2003: 282–293)

Determined voltage distortion limits are usually tighter for DG units. For example standard IEC 61000-2-4/Class 2 which applies generally to PCCs of non-public power supplies and in-plant point of coupling in industrial environments takes into account the harmonics up to 50th order and the voltage and current THD should be less than 8 %. Interharmonics are also covered. (Iov & Blaabjerg 2007) In reference (Hanzelka & Bien 2004) it was also stated that according to the IEC recommendations the voltage interharmonics are limited to 0.2 % for the frequency range from dc-component to 2 kHz.

Above mentioned standards do not take into account the possible harmonics near the converter switching frequency (e.g. 160th / 8 kHz). It is possible that these higher order harmonics may resonate with the system impedance, which in turn will cause voltage waveforms with multiple zero crossings that can disturb the timing circuits etc. (Dugan et al. 2003: 282). For example in (Strauss 2009) it is mentioned that in many DER converters, harmonic currents seem to have a significant dependency on the harmonic voltage content of the AC system voltage. In this respect, the current standard test conditions defined in the IEC standards are not sufficient, because they define that tests should be performed with an ideal grid. As a result of this, the measured currents in standard tests are often comparatively lower than the ones measured in the real system operation (Strauss 2009). Similarly, large number of converters connected on LV feeders may result in power quality problems, even if the converters individually fulfill the harmonic emission standards (Strauss 2009).

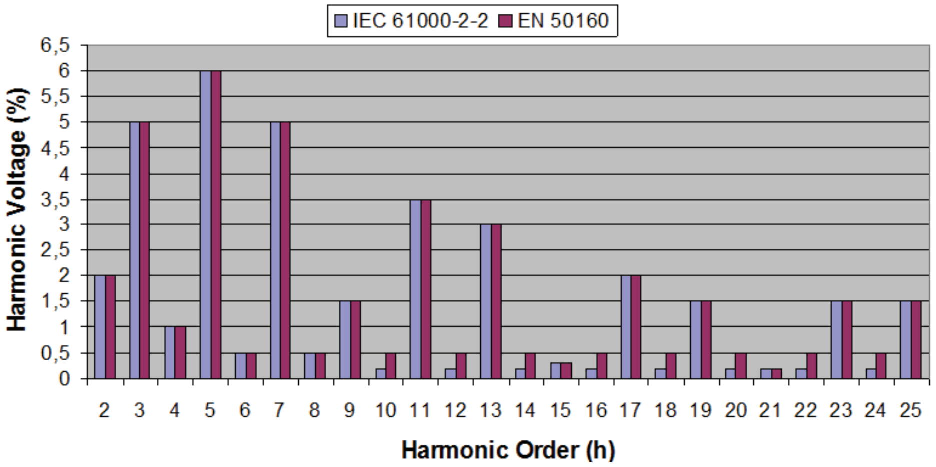


Figure 37. Voltage Harmonic compatibility levels as in EN 50160 and IEC 61000-2-2. (Dugan et al. 2003: 282–293)

Standards usually cover frequencies only up to 2–2.5 kHz. However, the frequency range from 2 to 150 kHz is not sufficiently covered in international standards. But when the number of converter based DER units will increase in distribution networks, the operating frequency band should be much more precisely defined (Bollen, Yang & Hassan 2008). The main reason for this is that usually the DER unit converters are operated at high switching frequencies. Therefore emission, compatibility and immunity levels should be defined in the future, because in the frequency range above 2 kHz, small DG units with converter connection will be a major source of distortion and as Bollen, Yang & Hassan (2008) have stated, even a very small number of DG units may cause distortion to increase over the allowable limits. In this respect, the power quality effect of the electric vehicles needs also careful consideration, because they will also have converter connection to the distribution network.

5.1.2 Power quality compensator with energy storage for power quality management in LV microgrid

In Publication III a new concept to improve the quality of power within the microgrid and also the quality of currents flowing between the microgrid and the utility grid was presented. The developed concept utilizes power quality compensator (PQC), with energy storage for power quality management in microgrid. PQC consists of a shunt and a series converter. The shunt converter was implemented in Publication III with an adaptive configuration and control system to obtain the best possible power quality in the microgrid during island operation. More detailed description about this concept can be found in Section 3.2 on page 47 and in Publication III.

Systems with low short-circuit ratios can experience high waveform distortion, because the inductance of the high system impedance may resonate with the reactive power compensating capacitors and with the harmonic filters at converter interface (Arrillaga et al. 2000: 173). These resonant frequencies can be low, possibly as low as the 2nd harmonic (Arrillaga et al. 2000: 173). In Publication III the magnitude of current and voltage THD in different points of microgrid were measured during different operation states of PQC based master unit to study interactions of different network components and to find out possible resonance problems. It was found out in Publication III that if series converter was connected during normal operation (see Section 3.2, Figure 21 a) on page 49), then the amount of lower order harmonics was increased. Reason for this was the coupling transformers of series converter which changed the system impedance and resonance frequencies. To avoid resonances during normal and battery charging operation (Section 3.2, Figure 21 on page 49) the coupling transformers of series converter were needed to be by-passed. However, the effect of different utility grid short circuit capacities and *R*/*X*-ratios (see Wakileh 2001: 33–34) to the system impedance at the connection point of PQC based energy storage was not further examined in Publication III.

5.1.3 Voltage and current THD in LV microgrid with different DER unit and load configurations

When the LV microgrid transfers from the normal operation parallel with utility grid, to island operation, the grid impedances and the harmonic voltages will change. Therefore, during the island operation LV microgrid is much weaker and more sensitive to disturbances. Especially the harmonic currents produced by the converters and loads will generate much higher harmonic voltages. High voltage distortion can cause instability and influence converter fault behavior during island operation (Laaksonen & Kauhaniemi 2007a; Laaksonen & Kauhaniemi 2007b). To overcome possible problems due to high voltage THD during island operation, the effects of different filter types, sizes and converter switching frequencies must be examined.

In Publication IV, voltage and current THD before and after islanding were studied with PSCAD simulations. In Table 1 eight studied LV microgrid configurations are presented, including the reference case 1. In reference case 1 there were converter connected energy storage based master unit, 2 converter based DG units and balanced passive load connected to the microgrid (Figure 38). In addition, all converters in case 1 were space-vector modulated (SVM) with 8 kHz switching frequency and equipped with passive LCL-filters as well as battery and DC/DC-converter connected to their DC-links to model the energy source. In case 1 the LV network lines of the microgrid were weak i.e. the *R*/*X*-ratio was high. Differences of each simulation case to the reference case 1 can be seen from Table 1. The voltage and current THD before and after islanding are also presented in Table 1. The voltage and current THD (%) results in each of the studied cases were compared with harmonics up to the order of 255 (12.75 kHz). Thus possible harmonics near the switching frequency of the DG unit converters were included in the THD values (those which are not filtered by passive filters between microgrid and DG unit converters). In this way also the possible harmonics caused by resonance between higher order harmonics coming from converters and the system impedance is included in THD values.

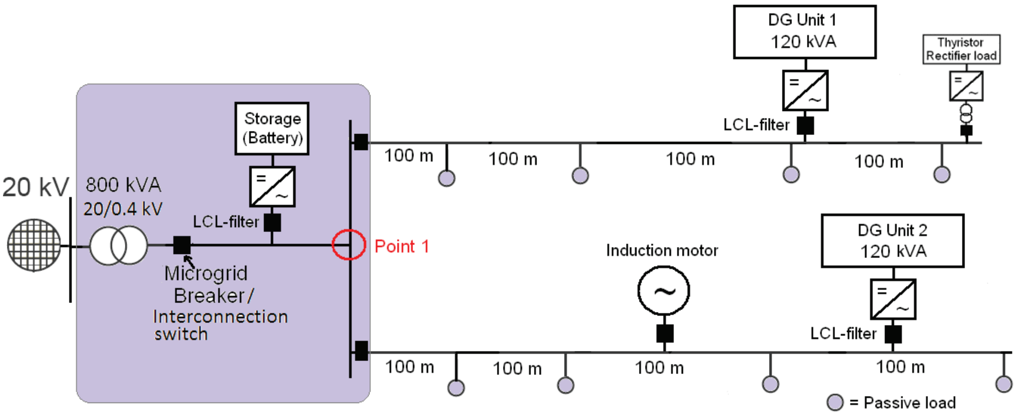


Figure 38. Studied LV network based microgrid in Publication IV.

In Figure 39 the voltage and current THD from different cases during island operation are shown as a bar graph. From Table 1 it can be seen that for example the reduction of switching frequency of converters from 8 to 4 kHz (case 2b) increases notably the voltage harmonic distortion both in normal and island operation with the used LCL-filter (see Publication IV). One can also see from Table 1 that the most significant increase in the voltage THD during normal and especially during island operation is experienced in case 6 when L-filters are used instead of LCL-filters.

Table 1. Studied microgrid configurations and voltage and current THD (255 harmonics) in microgrid with different configurations in Publication IV.

Case	Difference in microgrid configurations	Normal Operation (U_{THD}^{*}/I_{THD}^{**})	Island Operation (U_{THD}^{*}/I_{THD}^{**})
1.	*Reference case*	0.40 / 0.24	1.17 / 0.26
2a.	Lower (6 kHz) switching frequency	0.73 / 0.36	2.11 / 0.32
2b.	Lower (4kHz) switching frequency	2.00 / 1.08	5.08 / 0.61
3.	Lower *R*/*X*-ratio on LV network lines	0.42 / 0.27	1.17 / 0.26
4.	Thyristor rectifier (TR) load	0.58 / 1.23	5.39 / 3.02
5.	Induction motor (IM) load	0.41 / 0.27	1.16 / 0.29
6.	L-filters on converters	2.71 / 0.7	25.01 / 0.40
7.	PWM modulated converters	0.60 / 0.52	1.85 / 0.43
8.	Constant DC voltage source in the DC-link of converters	0.44 / 0.36	1.37 / 0.33

$^{*)}$From phase C in connection point of master unit, $^{**)}$From phase A in connection point of DG Unit 1 on feeder 1_1

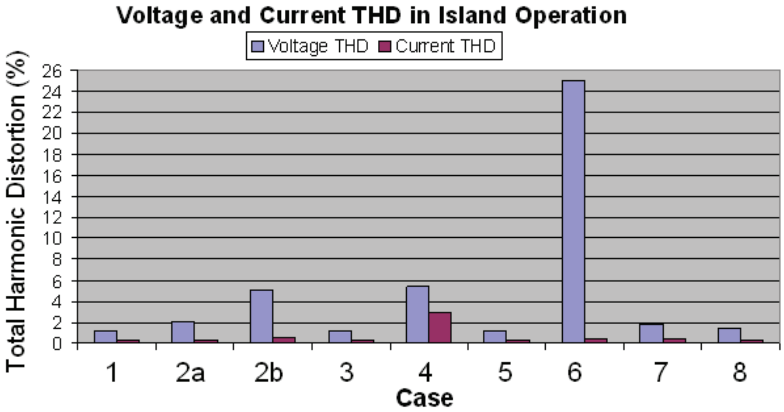


Figure 39. Voltage and current THD (%) in different cases (from Table 1) during island operation of microgrid.

With L-filter especially the higher order harmonics are not filtered out from the output current of the converters very effectively. Another reason for the high voltage THD in case 6 can be seen from Figure 40 where the system harmonic impedances in point 1 (Figure 38) from few studied cases in Publication IV during normal and island operation are presented. Especially during island operation the high resonance peak in case 6 near the switching frequency of converters will increase the voltage THD very significantly while the current THD is reasonably low (Table 1).

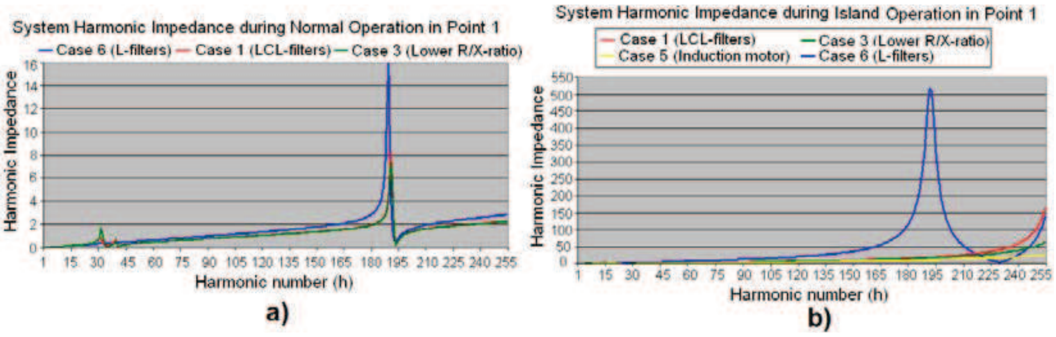
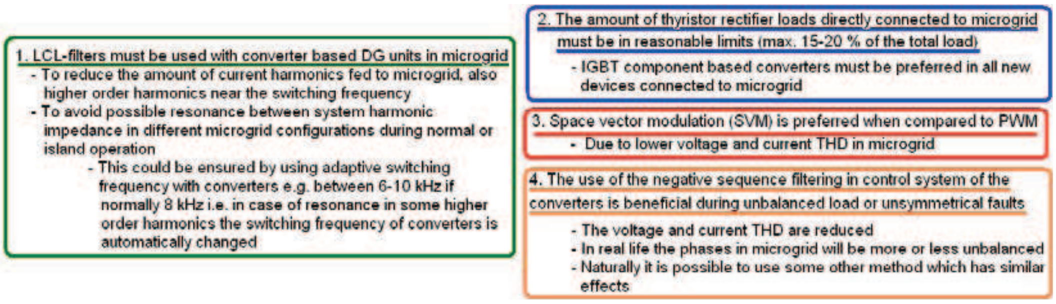


Figure 40. System harmonic impedance during a) normal and b) island operation of microgrid in cases 1, 3, 5 and 6 presented in Publication IV.

In general, the simulation results of Publication IV showed that the voltage THD behavior cannot be foreseen from the current THD contribution of the converter during normal parallel operation with utility grid. They are affected by the particular system harmonic impedance at that point and the harmonics coming from other devices (i.e. background harmonic voltages). Harmonics coming from other devices are dependent on the configuration, control system and parameters of the devices. During transition of LV microgrid from normal to island operation, the grid impedances and harmonic voltages will change. Therefore, during the island operation of microgrid there is a risk that some higher order harmonics near the converter switching frequency may resonate with the changed system harmonic impedance and even without resonances the harmonic currents produced by converters and possible distorting loads will generate much higher harmonic voltages during island operation.

Summary from the findings of Publication IV to ensure high power quality in islanded microgrid is presented in Figure 41. In addition to the recommended usage of LCL-filters (Figure 41) possibly also so called hybrid filters (Peltoniemi 2010), where L-filter is connected in parallel with LC series resonance circuit, could be an interesting option for LV microgrid connected DER units. Regarding the allowed amount of thyristor rectifier loads that can be connected to the microgrid (Figure 41) one should notice that possible compensation of lower order harmonics (e.g. 3rd, 5th and 7th) with master unit control have not been considered like in reference (Niiranen et al. 2010). In addition, the possible usage of hysteresis current control (see Section 3.2.1) or virtual direct-torque-control (DTC) principles with DER unit converters, where spread spectrum of harmonics is typical (Niiranen et al. 2010), has not been studied.



1. LCL-filters must be used with converter based DG units in microgrid
   - To reduce the amount of current harmonics fed to microgrid, also higher order harmonics near the switching frequency
   - To avoid possible resonance between system harmonic impedance in different microgrid configurations during normal or island operation
     - This could be ensured by using adaptive switching frequency with converters e.g. between 6-10 kHz if normally 8 kHz i.e. in case of resonance in some higher order harmonics the switching frequency of converters is automatically changed

2. The amount of thyristor rectifier loads directly connected to microgrid must be in reasonable limits (max. 15-20 % of the total load)
   - IGBT component based converters must be preferred in all new devices connected to microgrid

3. Space vector modulation (SVM) is preferred when compared to PWM
   - Due to lower voltage and current THD in microgrid

4. The use of the negative sequence filtering in control system of the converters is beneficial during unbalanced load or unsymmetrical faults
   - The voltage and current THD are reduced
   - In real life the phases in microgrid will be more or less unbalanced
   - Naturally it is possible to use some other method which has similar effects

Figure 41. Summary from the findings to ensure high power quality in islanded microgrid.

5.2 LV microgrid power balance management, voltage control and role in smart grid voltage control

Due to high *R*/*X*-ratio of LV network lines the voltage level in LV microgrid is mainly controlled through active power control as presented in Chapter 4 as well as by Geibel et al. (2009) and Braun & Notholt-Vergara (2008). Therefore, the voltage level and active power balance management in LV microgrids have a high correlation with each other.

5.2.1 Power balance management with distributed energy resources in LV microgrid

In the following some issues related to long-term power balance management like central energy storage unit configuration, categorization of customer loads and DER units, are shortly discussed. Microgrid management system (MMS) of the LV microgrid will be responsible for the co-ordination of the power balance management.

In addition to the central energy storage unit configurations presented in Chapter 3, the configuration can be modified for different power balance management needs as follows:

1. In case of possible long duration island operation the energy storage of the LV microgrid should have very large capacity or be capable of being charged through some primary energy source
2. If large proportion of DG units in the microgrid are based on highly varying primary energy sources like solar and wind, then there could also be another energy storage for power balancing purposes.

  - The microgrid power balance can be maintained by charging or discharging the energy storage as needed i.e. if control of the master unit cannot keep up the power balance
  - The addition of another energy storage near the interconnection point of the microgrid increases the reliability of microgrid if this energy storage based unit is also capable of acting as a master unit in case of a fault in the original master unit

Some sizing principles for microgrid battery energy storages can be found, e.g. from paper by Chen & Gooi (2010).

Also, one central energy storage unit configuration has been presented by Barnes & Binduhewa (2008) where the energy storage is integrated into the DC-link of the AC-DC-AC back-to-back converter. This has some advantages such as:

- Microgrid re-synchronization functions are not needed (see Publication VIII),
- Short voltage dips at utility network are not experienced by microgrid customers and
- Possibility to connect DC energy source directly to DC-link.

However, economical, energy efficiency and reliability issues such as system costs, system losses and reliability of power electronic converters are the main concerns in this kind of configuration presented by Barnes & Binduhewa (2008) and Niiranen et al. (2010), because all power between utility grid and microgrid is transferred through the converters. Although at least system losses could be reduced by the use of modular multilevel converters presented by Lesnicar & Marquardt (2003) and Peftitsis et al. (2010). Majumder et al. (2010) have also proposed methods for power flow control between utility and microgrid when microgrid is connected to utility grid through back-to-back converter. On the other hand, Shah et al. (2010) have proposed a dynamic power limiter, which consists of a high-frequency step-down transformer and three-phase to single-phase matrix converters, to be used for the power flow control at the PCC of the microgrid.

Utilization of demand side management as part of LV microgrid power balance management requires full adoption of smart metering and smart control of household, commercial, and agricultural loads within the microgrid. In addition, household MMSs or AMM devices should be able to directly control all dispatchable loads in the household. Fast load disconnection during island operation of LV microgrid requires utilization of high-speed communication. Depending on criticality of target load, dispatchable load can be (Schwaegerl et al. 2009):

- Shiftable, which means that a predefined task that can be completed with flexible time schedule in the course of a day (water pumps, electric water heating devices etc.) or
- Interruptible, which refers to unessential or constant loads that can be reduced or switched off during supply constraints or emergency situations (standby devices with no near-term use plan and day-time lighting etc.).

In the future, if existing dispatchable household loads are updated to be smart grid compatible, they could be connected to the LV network with new kind of load switches with standard IEC 61850 based object models (see Section 2.5.1 on page 33) with different priorities included. However, these features should be integrated into new dispatchable devices in the future. It would then be possible to disconnect very rapidly loads of certain priority based on commands directly from LV microgrid MMS.

DER units can also be categorized by their active power controllability, i.e. capability to take part in the power balance management of LV microgrid. DER unit can be able to:

1. Control active power instantly (energy storage units),
2. Control active power slowly (usually thermal driven CHP units with fuels such as natural gas, bio-fuels or hydrogen) or
3. Not to control active power, i.e. is non-controllable (intermittent renewable energy sources like wind and solar power).

In the future the controllability of the load or the DER unit will determine its capability to take part in the power balance management of LV microgrid which may be realized through local technical service markets (see Section 2.4.1 on page 30).

5.2.2 Voltage control in LV microgrid

Traditionally, voltage regulation on passively managed distribution networks has been done with transformer on-load-tap-changers (OLTC) at HV/MV substations and with fixed off-load transformer tap changers at MV/LV distribution substations. The expected increase in the connection of DG units and electric vehicles into LV networks will increase the voltage variations in the future. Active management of increased voltage variations in LV networks will require more intelligent methods than active power curtailment of DG units or huge amount of reactive power absorbing/feeding by DG unit to be used for better utilization of the LV network (Demirok et al. 2009).

It has been suggested by Oates, Barlow & Levi (2007) and Awad, Shafiu & Jenkins (2008) that current fixed off-load tap-changers at MV/LV distribution transformers should be changed to OLTCs to control LV network voltage level as part of active distribution network management due to increased production and consumption changes in future distribution networks. On the other hand, from LV microgrid concept's point of view, where one central energy storage based master unit is included, the central energy storage at MV/LV distribution substation should also have some functions during normal operation of LV network to be economically feasible. This means that it should not only enable possible momentary island operation or to provide enough fault current during island operation for protection purposes as presented by Van Overbeeke (2009).

One solution to the above mentioned could be that instead of adding controllable OLTCs to distribution transformers, the central energy storage at MV/LV distribution substation would actively manage the voltage level of LV microgrid during normal grid connected operation. In addition, the LV microgrid could also take part in the MV feeder voltage control through co-ordinated management of the central energy storage, controllable DER units and dispatchable loads by MMS. The use of central energy storage unit in normal operation to active voltage control would make distribution networks more flexible and enable more DG capacity to be connected in LV networks. It will also enable better capacity utilization of existing LV network lines and thus improves the energy efficiency of the LV distribution networks. In the future smart grids, the local technical service markets are one possibility to implement these functions (see Figure 11 in Section 2.4.1) in reality. During the normal operation of LV microgrid operation modes of central energy storage unit could be for example:

- Voltage level control in LV network – For example during high generation and low loading the rise of voltage level would be controlled by charging energy storage or during low voltage levels energy storage could be discharged so that it would increase the LV network voltage level
- Power flow management from LV microgrid to MV network in PCC of LV microgrid, e.g. so that P_{PCC}=0, Q_{PCC}=0 or based on control command from DMS of DSO about the allowable power flow limits for active and reactive power in PCC of LV microgrid etc.

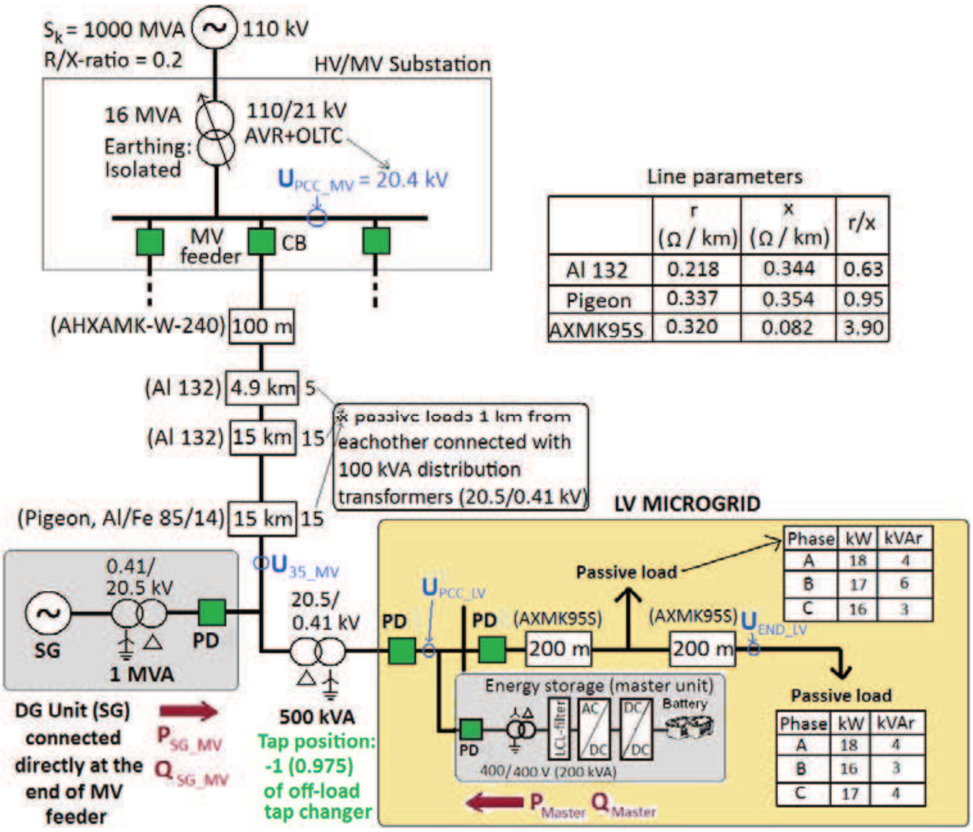
However, participation of LV microgrid in active management of MV feeder voltage control will be restricted by the technical boundaries and limits discussed in Chapter 4 which will ensure that successful transition to island operation is possible. This means that there is a reasonable limit which determines how much active and reactive power is allowed to flow in PCC of LV microgrid between utility grid and microgrid without losing the possibility to island operation.

During island operation the voltage level control of LV microgrid can be affected by changing the master unit reference voltage to deal with large voltage level differences between LV feeders, e.g. if one LV feeder is heavily loaded and another LV feeder is very lightly loaded with high amount of DG units.

Active participation of LV microgrid to smart grid voltage control – Simulations

Some PSCAD simulations were carried out to estimate the participation capability of the central energy storage unit to LV network voltage level management as well as the capability of LV microgrid to take part in the active voltage control of MV feeder. Therefore, the MV feeder was also modeled with more details and the LV microgrid was located 35 km away from the HV/MV substation (Figure 42).

In the following simulations it has been studied mainly the ability of LV microgrid (Figure 42), especially the capability of the central energy storage unit connected directly to MV/LV distribution substation, to participate into the voltage control of MV feeder.



Line parameters

	r (Ω / km)	x (Ω / km)	r/x
Al 132	0.218	0.344	0.63
Pigeon	0.337	0.354	0.95
AXMK95S	0.320	0.082	3.90

Phase	kW	kVAr
A	18	4
B	17	6
C	16	3

Phase	kW	kVAr
A	18	4
B	16	3
C	17	4

Figure 42. Study system used in PSCAD simulation studies about active participation of LV microgrid to smart grid voltage control.

The studied two cases during normal grid connected operation of LV microgrid were:

- **A) HIGH LOAD – LOW PRODUCTION -CASE (NO SG):** MV network load is high, 95 % from HV/MV transformer nominal load and central battery based energy storage unit in the PCC of LV microgrid is controlled to support the voltage at the PCC of LV microgrid through active (*P*) and reactive power (*Q*) changes.
- **B) LOW LOAD – HIGH PRODUCTION -CASE (WITH SG):** MV network load is low, 35 % from HV/MV transformer nominal load, SG based DG unit connected to MV feeder near PCC of LV microgrid (*P*=1 MW, *Q*=0 MVAr which means that it does not take part in voltage control of MV feeder through reactive power control) and the central battery based energy storage unit in the PCC of LV microgrid is controlled to decrease the voltage at the PCC of LV microgrid through active (*P*) and reactive power (*Q*) changes.

In Figure 43 a) the sequence of actions considering the behavior of the battery energy storage based central unit in the simulation of case A) is shown. In Figure 43 b) the state-of-charge (SOC) and current of the battery energy storage in case A) are presented. Simultaneous effect of energy storage active and reactive power changes presented in Figure 43 a) on voltage level behavior in different locations at MV feeder in case A) can be seen from Figure 44 a) and correspondingly at LV microgrid side from Figure 44 b).

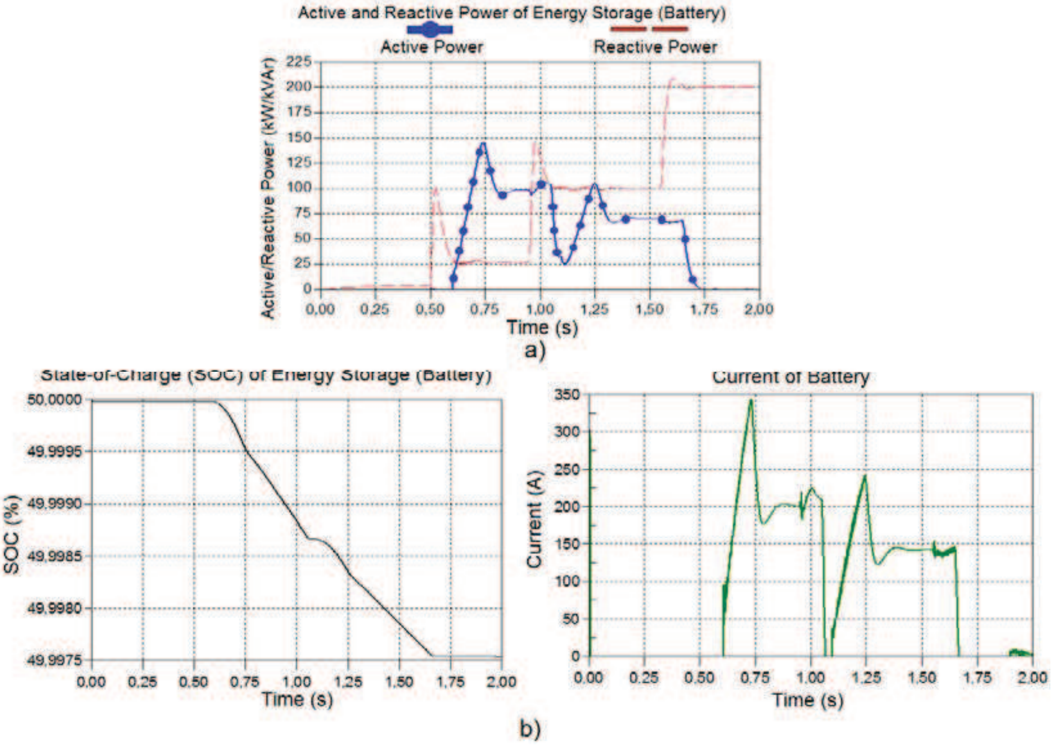


Figure 43. a) Sequence of actions from active and reactive power changes and b) SOC and current of central battery energy storage unit in case A).

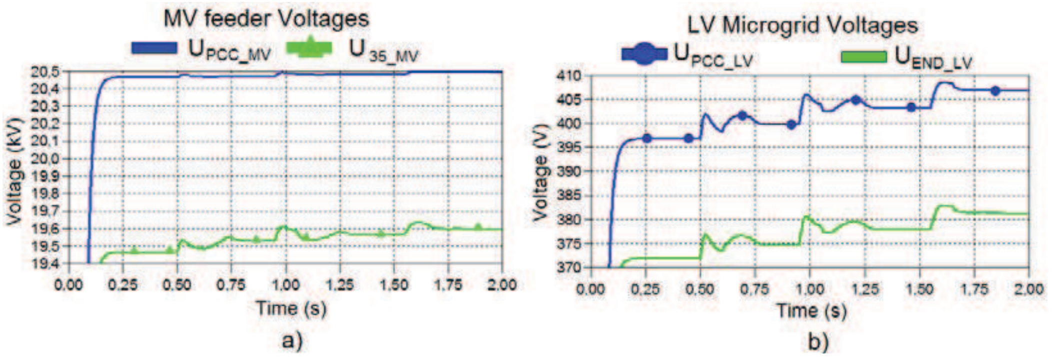


Figure 44. Voltage level changes on different locations at a) MV feeder simulation and b) simultaneously at LV microgrid side in case A) (see Figure 42).

Correspondingly to case A), the Figure 45 a) shows the sequence of actions considering the active and reactive power changes of the battery energy storage unit in the simulation of case B).

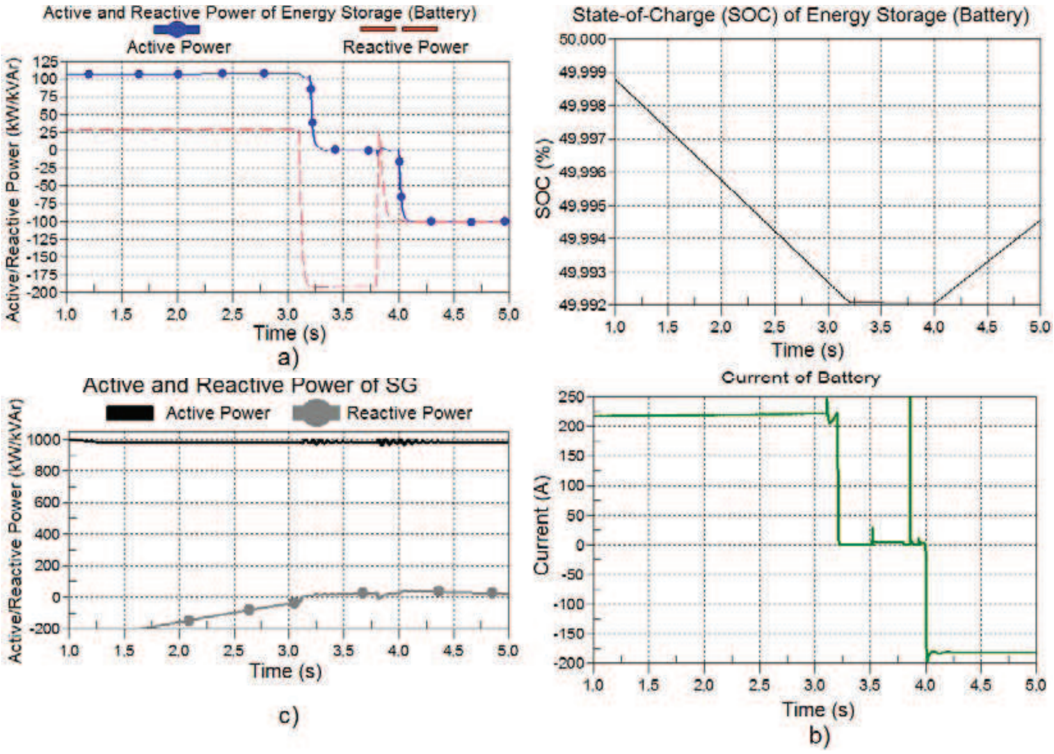


Figure 45. a) Sequence of actions from active and reactive power changes, b) SOC and current of central battery energy storage unit and c) active and reactive power behavior of SG based DG unit connected to MV feeder (see Figure 42) in case B).

In Figure 45 b) the SOC and current of the battery energy storage unit in case B) are shown. In addition, in Figure 45 c) the active and reactive power behavior of SG based DG unit which is connected to MV feeder (see Figure 42) is presented. Simultaneous effect of energy storage active and reactive power changes on voltage level behavior in different locations at MV feeder in case B) can be seen from Figure 46 a) and at LV microgrid side from Figure 46 b).

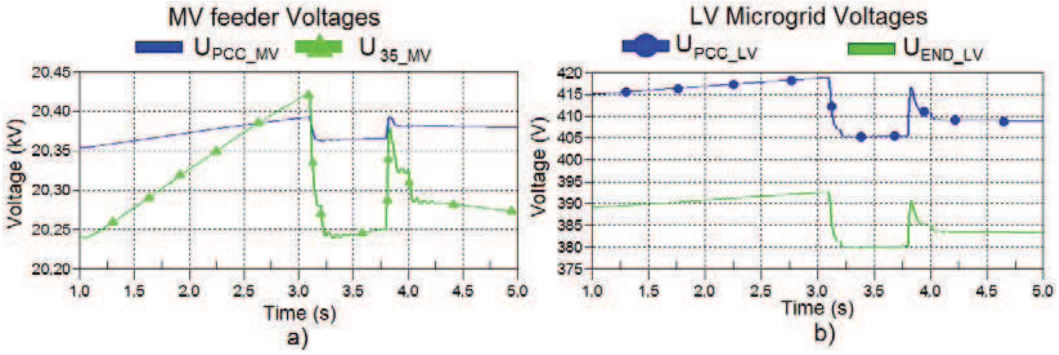


Figure 46. Voltage level changes on different locations at a) MV feeder simulation and b) simultaneously at LV microgrid side in case B) (see Figure 42).

The purpose of the PSCAD simulations was to estimate the participation capability of the central energy storage unit to LV network voltage level management as well as capability of LV microgrid to take part in active voltage control of MV feeder. Simulation results of case A) and B) (Figure 44 and 46) show how the voltage level can be affected both in MV and in LV network by active and reactive power changes of battery based energy storage unit which is connected directly to MV/LV distribution substation. One important fact in relation to the operation of the central energy storage unit is that when the active power of energy storage is zero (P=0 kW) and only reactive power is absorbed or fed to grid, the energy storage (battery) is neither charged or discharged (see Figure 43 and 45). Based on the previous simulations it can be concluded that the usage of central energy storage unit located at MV/LV distribution substation can be an effective and more precise way to control the voltage level when compared to the use of OLTC at MV/LV distribution substation.

5.2.3 Voltage unbalance management in microgrid

Due to single-phase loads or single-phase PV cells there will always be some voltage unbalance in island operated microgrid. Depending on the connection and control type of the converter based DG unit, unbalanced voltages in island operation may also cause oscillations in the active and reactive powers of the DG unit as well as in the DC-link voltages. The voltage unbalance may also cause overheating of induction and synchronous machines (Baggini 2008: 526). Therefore excessive voltage unbalance should be compensated through the control of single-phase DG units, energy storages, charging of electrical vehicles (EVs) or controllable loads. All these should be co-ordinated by MMS. On the other hand, voltage unbalance will be present to some extent in the island operated LV microgrid, because it is not necessarily feasible to try to constantly compensate it totally. In that case LV microgrid customer loads should have at least some tolerance against voltage unbalance. However, it must be ensured that voltage unbalance is not too high and does not overheat for example the connected three-phase rotating machines such as SGs and IMs.

In general, from the LV microgrid concept's point of view it is essential that the chosen method for the compensation of excessive voltage unbalance in island operated LV microgrid is compatible with other chosen technical solutions of LV microgrid concept. These are for instance protection principles and settings, voltage level and voltage THD management as well as re-synchronization functions. In the next section the possibility to use the central energy storage unit for voltage unbalance compensation during microgrid island operation is studied with PSCAD simulations.

Voltage unbalance compensation in LV microgrid – Simulations

In the following simulation results are compared between two cases, so that during the simulated island operation the control of the central energy storage unit at MV/LV distribution substation is changed from the one presented in Figure 14 b) (see Chapter 3, page 41) to another presented in Figure 18 b) (see Chapter 3, page 46) in which voltage unbalance compensation is included. The LV network that was used in the simulations of this section is presented in Figure 47.

The study system shown in Figure 47 consists of one 800 kVA MV/LV-transformer which normally feeds LV feeders 1 and 2. In the simulation studies the islanded LV microgrid is disconnected from MV network by the microgrid breaker. At the connection point of the microgrid, before the feeders 1 and 2, there is a converter connected central energy storage based master unit (battery, S_n=150 kVA). At the end of feeder 1 there is a converter connected DG Unit 1 (S_n=120 kVA, in simulation P=100 kW, Q=30 kVAr and about I=150 A/phase). At the end of the feeder 2 there is also a converter connected DG Unit 2 (S_n=120 kVA, in simulation P=100 kW, Q=0 kVAr). The load in the microgrid consists of four three-phase passive loads on each feeder and few single-phase passive loads

(Figure 47) on both feeders which means that the load between phases is unbalanced. Filter and control parameters of the converter based DG units used in the simulations can be found from Publication VIII.

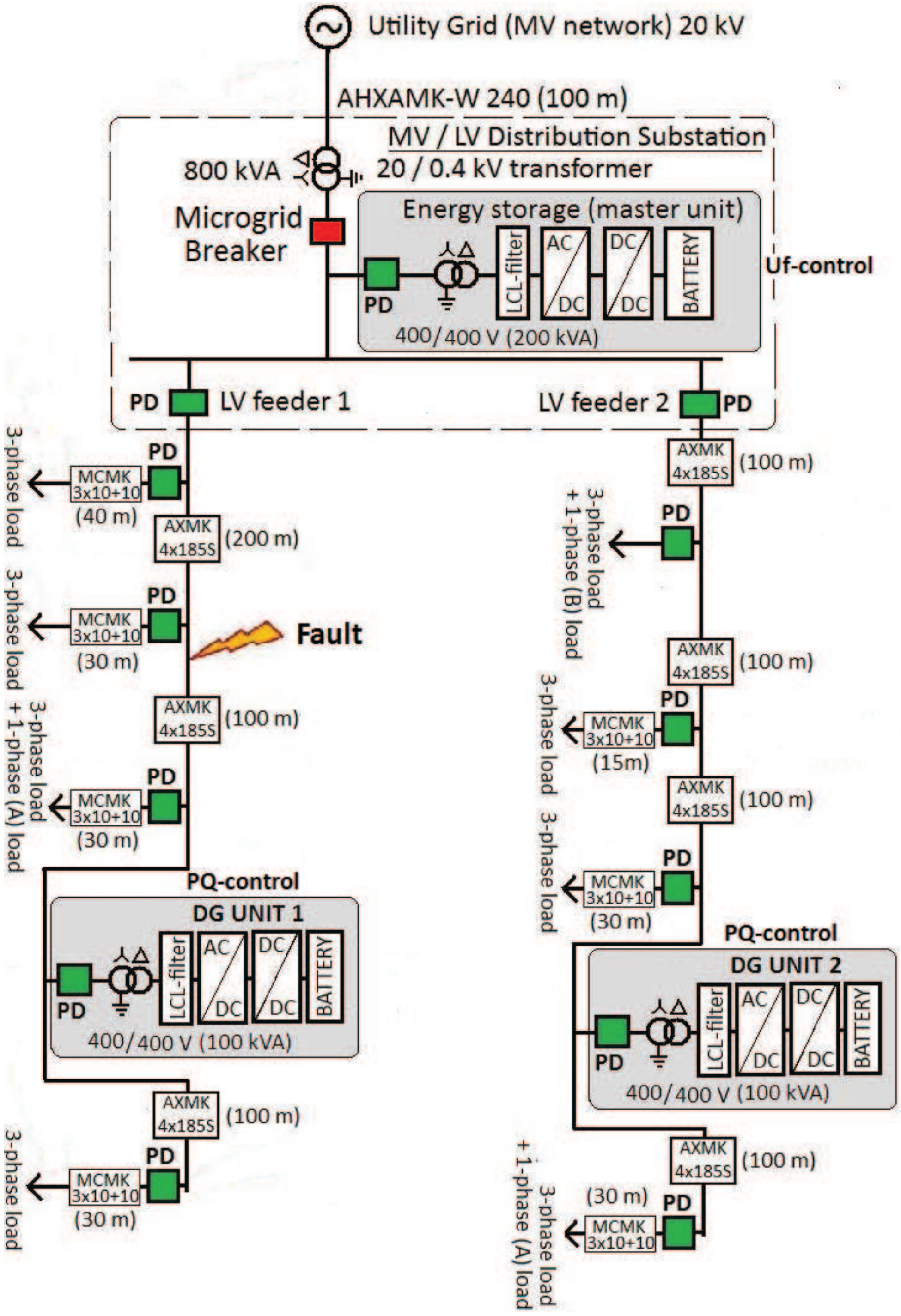


Figure 47. Studied LV microgrid.

In Figure 48 simulation results from microgrid phase voltages in PCC of master unit, voltage THD and phase difference between microgrid and utility grid voltages across microgrid breaker during island operation are presented. Transition to island operation takes place at time 1.5 s and the control of central energy storage based master unit is changed at time 2.0 s from the one presented in Figure 14 b) on page 41 to the voltage unbalance compensation control presented in Figure 18 b) on page 46.

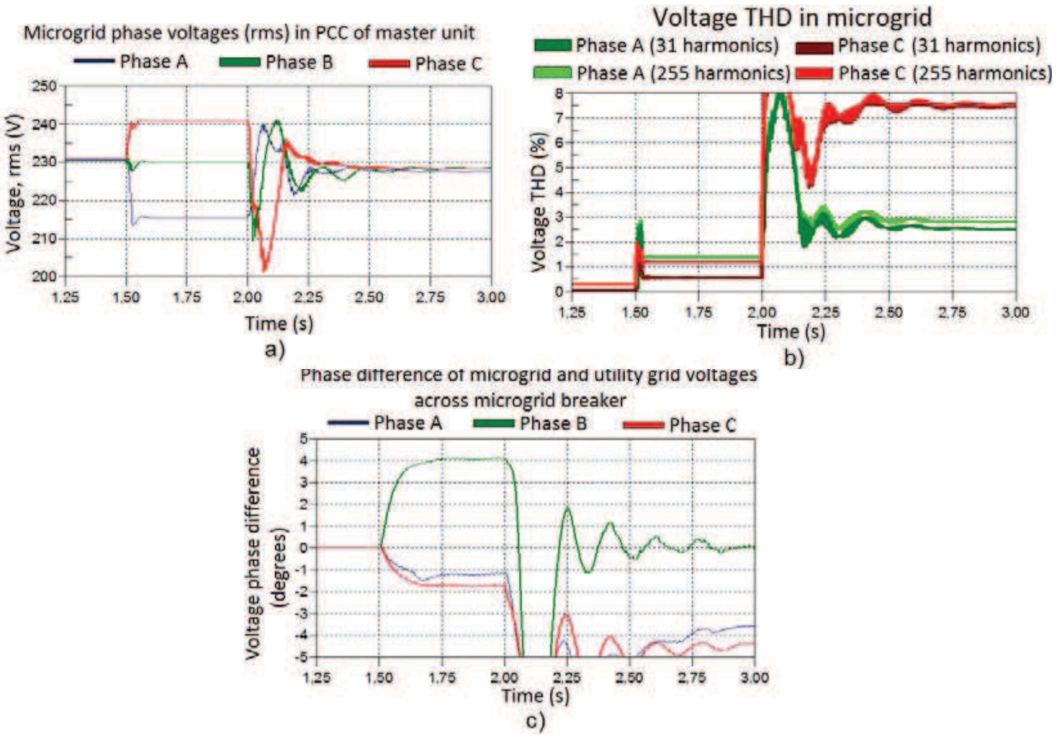


Figure 48. a) Microgrid voltage level (phase voltages in PCC of master unit), b) microgrid voltage THD and c) phase difference between microgrid and utility grid voltages across microgrid breaker (see Figure 47) during island operation.

From simulation results of Figure 48 it can be seen that voltage unbalance compensation by master unit control compensates voltage magnitude asymmetry well (Figure 48 a)), but the voltage phase difference asymmetry across microgrid breaker or interconnection switch before re-connection of island operated LV microgrid back to utility grid is not totally removed (Figure 48 c)) with the master unit control used (see also Section 6.5 and Publication VIII). To be able to compensate the phase difference asymmetry as well, each phase should be controlled separately. From Figure 48 b) it can be seen that the voltage unbalance compensation with central energy storage unit increases microgrid voltage THD level significantly, especially the amount of lower order (less than 31) harmonics in phase C, during island operation. However, in phase A the voltage THD is still under 3 % even with higher order (less than 255) harmonics included (Figure 48 b)). This indicates that there may be some kind of resonance or saturation problem in phase C which could possibly be corrected by improved control of the master unit.

In Figure 49 simulation results from active and reactive powers, phase currents and DC-link voltages of master unit and DG unit 2 during island operation are shown (transition to island operation takes place at time 1.5 s and the control of central energy storage based master unit is changed at time 2.0 s).

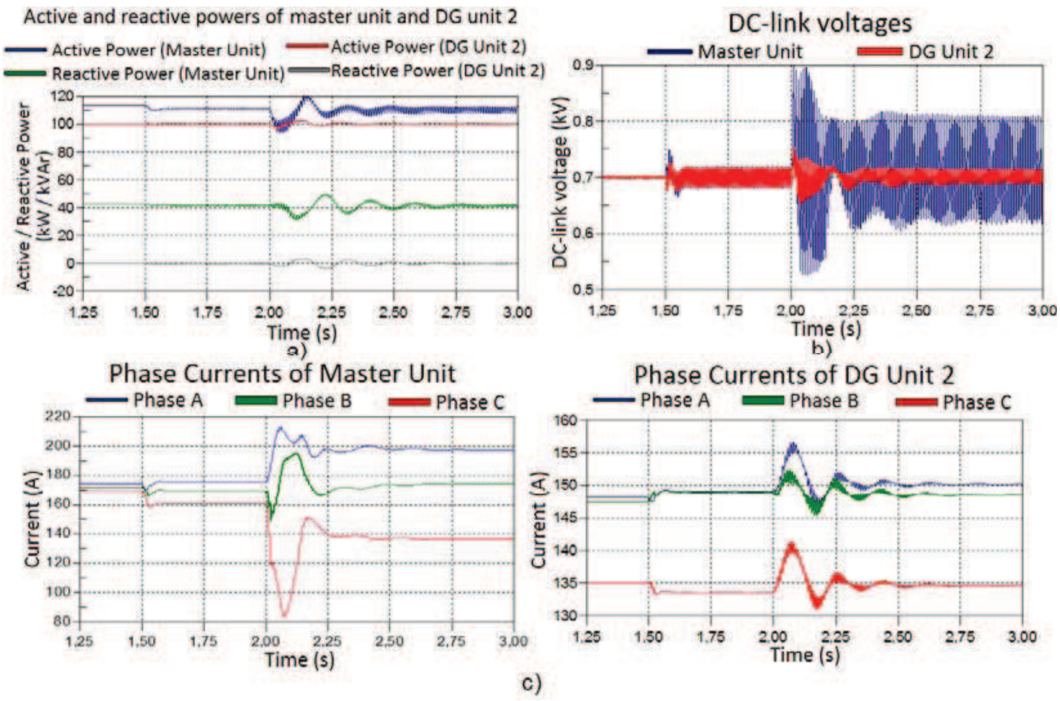


Figure 49. a) Active and reactive powers, b) DC-link voltages and c) phase currents and of master unit and DG unit 2 during island operation.

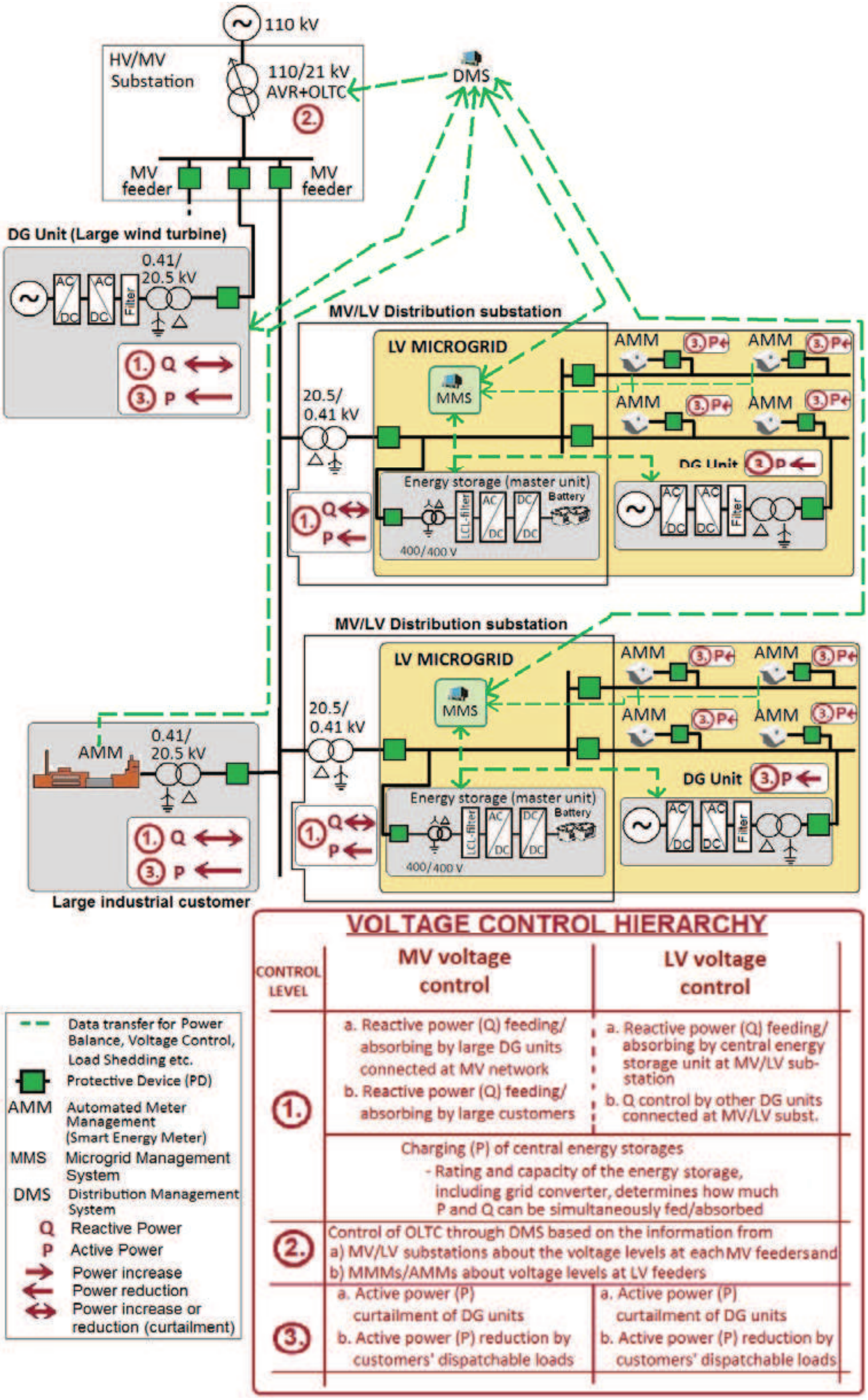
From simulation results of Figure 49 it can be seen that after the control change of master unit to voltage unbalance compensation control at *t*=2.0 s, there is a significant increase in oscillations of the active and reactive powers (Figure 49 a)) as well as in the DC-link voltage (Figure 49 b)) of the master unit. Simultaneously slightly reduced oscillations in the active / reactive powers and the DC-link voltage of the DG unit 2 can be seen in Figure 49. The deviation in the phase current magnitudes of the master unit (Figure 49 c)) naturally increases after *t*=2.0 s, but no significant changes in the phase current magnitudes of the DG unit 2 will occur after *t*=2.0 s.

Also, a two-phase-to-earth fault in the middle of LV feeder 1 was simulated. The fault occured during island operation and the PD of LV feeder 1 disconnected the feeder 1 (Figure 47). The possible effect of master unit voltage unbalance compensation control during the fault to microgrid protection behavior was also studied by comparing the microgrid voltages and master unit currents in two different cases. These two cases were a) without and b) with master unit voltage unbalance compensation. The simulation results showed that there was not notable difference in microgrid voltages and master unit phase currents between cases two-phase-to-earth fault in island operation. This means that the settings or operation principles of microgrid protection, which could be based on voltage and/or current measurements, are not affected by the control method of central energy storage in these cases.

5.2.4 Future hierarchical smart grid voltage control scheme with LV microgrids

Proposal for future hierarchical smart grid voltage control scheme, which can make distribution networks much more flexible, and where active utilization of the central energy storage unit plays major role, is presented in Figure 50. Reactive power feeding or absorbing and active power absorbing of energy storage (charging) is primarily used to distribution network voltage control.

Both active and reactive power control of the central energy storage unit at MV/LV distribution substation will simultaneously influence the MV feeder and LV microgrid voltage levels (Figure 50) which could be seen from simulation results of Section 5.2.2. However, the distance between the PCC of LV microgrid and HV/MV substation as well as the impedance of the MV feeder will have considerable effect on the magnitude of the voltage level change. In other words, this means that in weak or less stiff connection points at distribution networks the potential need for active voltage control will be more significant. It can be concluded that from the point of view of the central energy storage control, during parallel operation with utility grid, the reactive power control alone should always be preferred as first option if SOC level is sufficient, because it does not affect the battery SOC level as presented in Section 5.2.2. On the other hand, it is economically feasible to use active power absorbing to voltage control if SOC level is low especially if owner of the energy storage unit receives compensation from the local technical service markets so that it will make the charging price of the battery lower.



VOLTAGE CONTROL HIERARCHY

CONTROL LEVEL	MV voltage control	LV voltage control
1.	a. Reactive power (Q) feeding/ absorbing by large DG units connected at MV network b. Reactive power (Q) feeding/ absorbing by large customers	a. Reactive power (Q) feeding/ absorbing by central energy storage unit at MV/LV sub-station b. Q control by other DG units connected at MV/LV subst.
	Charging (P) of central energy storages - Rating and capacity of the energy storage, including grid converter, determines how much P and Q can be simultaneously fed/absorbed	
2.	Control of OLTC through DMS based on the information from a) MV/LV substations about the voltage levels at each MV feeders and b) MMMs/AMMs about voltage levels at LV feeders	
3.	a. Active power (P) curtailment of DG units b. Active power (P) reduction by customers' dispatchable loads	a. Active power (P) curtailment of DG units b. Active power (P) reduction by customers' dispatchable loads

Figure 50. The future hierarchical smart grid voltage control scheme in which active utilization of the central energy storages at LV microgrids will play major role.

Different co-ordinated MV network voltage control schemes, in which the active management of OLTC plays a major role together with reactive power control of DG units connected to the MV network, have been studied over the last years and most recent studies e.g. by Kulmala et al. (2010) and Leisse, Samuelsson & Svensson (2010), has been done in the smart grid context. Regarding the voltage control hierarchy of Figure 50, the level 2 with control of OLTC could also be the first option before reactive power control. The main difference in the use of OLTC for MV network voltage control is that it affects all the MV feeders simultaneously, while with other voltage control methods the voltage level of the corresponding MV feeder can be more locally controlled. In principle, the overall voltage control scheme should be such that the needed control actions are performed as close as possible to the section of distribution network with voltage level problems.

Simultaneous operation of LV microgrid central energy storage units, DER units and loads as part of smart grid voltage control (local technical service markets) as well as part of future energy markets seems to be quite difficult task to be realized, because these two markets have so large impact on each other due to technical characteristics of LV networks. Because of the strong active power (P) and voltage (U) dependency in LV networks, the active power increase of DG units or discharging of energy storages unit should be included only in energy markets, not on the local technical service markets (Figure 50).

One possibility in future market structure could be that energy storages are owned by third party, other than DSOs, and they will participate in future energy markets by active power production (discharging) and in the active voltage control of distribution networks through possible local technical service markets. In such case the voltage control functions shown in Figure 50 which will participate in the local technical service markets are from hierarchy levels 1 and 3. DSOs will pay compensation through technical service markets to DER units from their reactive and/or active power control to active voltage level management of distribution network. However, the price of the compensation in the technical service markets for active power curtailment of DG units needs to be higher than the value of the produced power sold to the energy markets. Otherwise, there will be no benefit for DG unit owners to decrease their power production. In addition, by allowing disconnection or control of dispatchable loads (mainly active power consuming), e.g. electric water heaters, charging control of EVs or electric heating, LV network customers at voltage control hierarchy level 3 in Figure 50 can also take part in the future technical service markets.

New market structures should take into account the benefit of electricity production by DG units near the consumption and the use of DER in active management of distribution networks. The customers should benefit from using energy produced by the local DG when compared to the customers supplied from the utility grid source.

6 TECHNICAL SOLUTIONS – PROTECTION OF LV MICROGRID

Realization of future smart LV networks with island operation capability requires that the protection of LV microgrids during normal and island operation could also be solved. The conventional protection system in radial distribution networks is designed to operate for high fault current levels. However, during island operation of the LV microgrid high fault currents from the utility grid are not present. Also, most of the DER units that will be connected to LV microgrids will be converter interfaced and have limited fault current feeding capabilities. Traditional fuse based over-current protection with a single setting group will not be able to guarantee selective tripping for all type of faults that can occur. This means that the traditional protection of LV network will not be applicable for LV microgrids and therefore new adaptive protection system must be developed. However, the adaptive LV microgrid protection system must be economically feasible and therefore cannot be too complex (Oudalov et al. 2009). In (Oudalov et al. 2009) it was stated that the technical requirements to implement an adaptive protection system are the following:

- Utilization of numerical relays (IEDs, Intelligent Electronic Devices) as protection devices instead of traditional fuses. At least a directional over-current function will be needed to deal with bi-directional power flows, because simple over-current function will not be adequate.
- Availability of more than one setting group which can be activated or deactivated locally or remotely, manually or automatically.
- Communication between protection devices. Communication system can be centralized or de-centralized in which each IED takes its own decisions.

As mentioned in (Chowdhury, Chowdhury & Crossley 2009: 95) the high-speed of operation of the protection devices is very crucial for reliable operation of the microgrid protection system. Utilization of high-speed telecommunication will be an essential part of future smart grid protection system to achieve fast and selective protection both in grid connected and islanded modes of operation. The same communication protocols and standards used in HV/MV network can be applied directly to the LV microgrids. However, due to the smaller scale of LV microgrid‘s, the costs of protection devices must also be lower than the cost of devices used in the HV/MV network. Protection and control functions of IEDs in LV microgrid will need real-time information about network topology, status of DER units (on or off), state of charge of storage systems, and also number and size of loads connected to the microgrid. These conditions have to be updated and checked continuously in order to guarantee that protection settings are suitable for current configuration. (Oudalov et al. 2009)

6.1 Grounding of LV microgrid and DER units

International standard IEC 60364 specifies three types of grounding arrangements in the distribution network using two letter codes TN, TT and IT. The first letter indicates the connections between ground and the generator or transformer. T means a direct connection between a point and the earth and I means no point of connection between the point and the earth. The second letter defines the connection between ground and the electrical device, where T means direct connection with earth and N means the connection with earth is via supply system. Most of the European distribution systems use TN-S or TN-C-S system for reliable grounding (Norrga 2009). Jayawarna et al. (2005) have concluded that TN-C-S or TT grounding systems are the most suitable for neutral grounding of a LV microgrid. In TN-C-S grounding system part of the system uses combined PEN conductor while at some points PE and N conductors are separated like inside house wiring. The combined PEN conductor can be grounded at different points providing multiple grounds. This reduces the risk of broken neutral or ground conductors.

One essential issue from the point of view of protection is the loss of neutral connection of MV/LV transformer during island operation when microgrid interconnection switch is located downstream from MV/LV transformer. When DER unit connection transformers are used, it is necessary to consider the connection type, i.e. delta-delta, delta-wye, of these transformers from microgrid protection's point of view particularly during earth faults in island operation. In many countries DG units are also required to be connected to the network through transformers for galvanic isolation. But because transformers decrease the overall efficiency of the DER unit, DER unit topologies especially for three-phase PV converters has been developed without transformers. With transformer-less DER units it is important to simultaneously take into account that ground leakage current through parasitic capacitances is kept low enough (Kerekes et al. 2007).

Norrga (2009) compared three suitable converter topologies for DER unit connection to four-wire three-phase grids. The main outcome from the comparison of the topologies by Norrga (2009) was that the solution for handling the neutral connection will affect the cost and complexity of the converter in the following different ways, in:

1. Transformer-less DER unit, the DC capacitor of the midpoint connected converter will need to be large if unbalanced loads are to be handled,
2. Transformer-less DER unit, the cost of the additional phase leg with the four-leg converter will have to be considered which is needed to smoothen the ground-mode ripple and

3. Transformer connected converter, the cost of the transformer will make up a significant portion of the overall system cost.

It has also been stated in (Strauss 2009) that there is a concern that transformer-less converter based DER units may inject sufficient DC current into LV networks which may cause distribution transformer saturation. However, the transformer offers several benefits in addition to providing the neutral connection and galvanic isolation which may be even necessary in many countries and applications (Norrga 2009). For example lower voltage at DG unit side of the transformer may reduce the component costs because they can be dimensioned to be smaller.

In this thesis it was chosen that all DER units should be connected to LV microgrid with delta-wye grounded connection transformers. It means that microgrid side of the transformer is directly earthed which ensures a path for neutral current and high earth fault currents.

6.2 Smart protection system for LV microgrid

As stated by Chowdhury, Chowdhury & Crossley (2009: 79), the protection issues for microgrids cannot be properly resolved without a thorough understanding of microgrid dynamics before, during and after islanding. Therefore, utilization of simulation tools such as PSCAD provides great basis for protection system development before proceeding to real-life pilot and test installations. In Publication VI new smart protection system for LV microgrid was proposed based on extensive PSCAD simulations.

6.2.1 Framework for microgrid protection

In the development of the new protection scheme for LV microgrids several issues must be considered like for example

- The number of protection zones in LV microgrid,
- Speed requirements for microgrid protection in different operation states and configurations and
- Protection principles for parallel and island operation of the microgrid.

In addition, the developed protection scheme for microgrid must be supported by the technical choices made in the microgrid operation and control issues. In this section the key issues related to the LV microgrid protection are briefly reviewed based on Publication VI from which more detailed information can be found.

The size and number of LV microgrid protection zones will define the needed amount of PDs for microgrid protection. The size of microgrid protection zone must be such that it fulfills the customer requirements and is economically feasible. The protection zones used in this thesis are presented in Figure 51. Also the necessary protection devices (PD 1–4) for these protection zones are shown in Figure 51. Three basic fault types, F1, F2 and F3 can also be seen in Figure 51. Protection devices shown in Figure 51 are:

- **PD 1:** Microgrid interconnection switch including relay and circuit-breaker or fast static-semiconductor-switch (SS)
- **PD 2:** LV feeder protection including relay and circuit-breaker or static-switch (SS)
- **PD 3:** Customer protection including fuse or low-voltage-/miniature- circuit-breaker (LVCB/MCB) or in case of very sensitive customers LV customer microgrid (DC or AC) with SS may be needed
- **PD 4:** DER unit protection

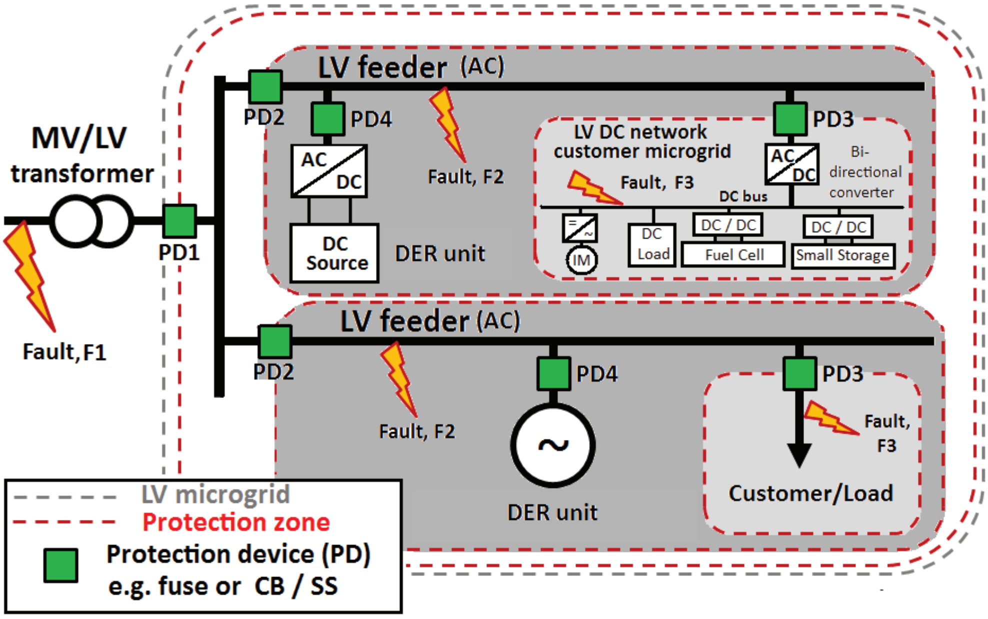


Figure 51. Number of protection zones and devices in LV microgrid.

Few fundamental structural choices will determine the speed requirements and operation principles of LV microgrid protection. On the other hand, these speed requirements will define certain structural choices needed to fulfill them. The two main reasons for the speed requirements are stability and customer sensitivity. Stability has to be maintained after sudden changes. The most challenging changes are transition to island operation due to fault in MV or fault in LV microgrid during island operation. One essential issue related to the operation principles of LV microgrid protection is the control of converter based DER units during faults. It should be compatible with the proposed microgrid protection system.

Especially directly connected rotating machines are very sensitive to lose stability in voltage dips caused by faults in island operated microgrid. Therefore, they may jeopardize the stability of the whole microgrid. Therefore, LV microgrid protection should operate rapidly for all types of faults. For example, if microgrid customers have fuse protection there is a risk that customer protection may operate too slowly in island operation due to low fault currents, which in turn may cause instability in island operated microgrid after fault clearance.

Structural choices needed to fulfill the speed requirements may be divided into
- Switch technology needed,
- Communication technology needed, and
- Capacity of the central energy storage based master unit.

Naturally the speed requirements will create a demand to microgrid interconnection switch (PD 1) to operate very rapidly, which means that the traditional circuit cannot be used and instead PD 1 possibly needs to include fast static semiconductor based switch (Kroposki et al. 2007; Chowdhury, Chowdhury & Crossley 2009: 95). On the other hand, Degner & Valov (2009) reported that the total breaking time of some commercial low-voltage-circuit-breakers (LVCBs) was measured to be less than 15 ms after receiving switching-off command from an intelligent controller. It means that LVCBs could also be one possible option for PD 1. Silicon carbide (SiC) based power electronic components presented by Zhang et al. (2010) could also be possible solution in the future to be used in microgrid protection devices as well as in DER unit converters, due to potential improvements in power density, cooling requirements, system response times, overload capability, and reliability. In addition, PD 1 could be some of the combinations described in Publication II, e.g. LVCB/SS + PQC where power quality compensator compensates the depth of the voltage dip and that way allows longer operation time to PD 1.

With larger capacity central energy storage unit it could be possible to survive from larger oscillations without losing stability. In addition, fault current feeding capability during island operation could be increased with larger energy storage to make customer fuses operate faster. DG unit converter control principle during fault has a major impact on fault detection in island operated microgrids (Brucoli & Green 2007) and standards and other regulations are needed to be set for converters fault behavior in the very beginning of the design process (Laaksonen

& Kauhaniemi 2007b). To ensure that protection operates as fast as possible the fault current fed by DG unit converter must be at least the rated current and the DG unit cannot be disconnected before microgrid protection has operated. Stability is also affected by many other things related to converter control which have been discussed in more detail in Publications I and II.

6.2.2 Proposed LV microgrid protection system

Due to lack of high fault currents, it has been proposed by Laaksonen & Kauhaniemi (2007b) and Al-Nasseri & Redfern (2007) that voltages could be used for protection of an islanded microgrid. However, it is difficult to realize selective microgrid protection during island operation with voltage or current relays alone (Oudalov & Fidigatti 2008). Nikkhajoei & Lasseter (2007) designed detection of unbalanced faults in LV microgrid based on current zero and negative sequence components. But, unbalanced load also produces zero and negative sequence components. Therefore, the determination of the detection limits may become difficult. It is also worth mentioning that structural choices made in the microgrid concept of Nikkhajoei & Lasseter (2007) were different when compared to the technical choices made in this thesis. In this thesis, one central energy storage unit located at MV/LV distribution substation was chosen instead of integrating energy storages in each of the DER units. On the other hand, some of the proposed microgrid protection schemes are only applicable for MV feeder or HV/MV substation microgrids, as the one suggested by Sortomme, Venkata & Mitra (2010) for MV microgrid protection which was primarily based on differential protection.

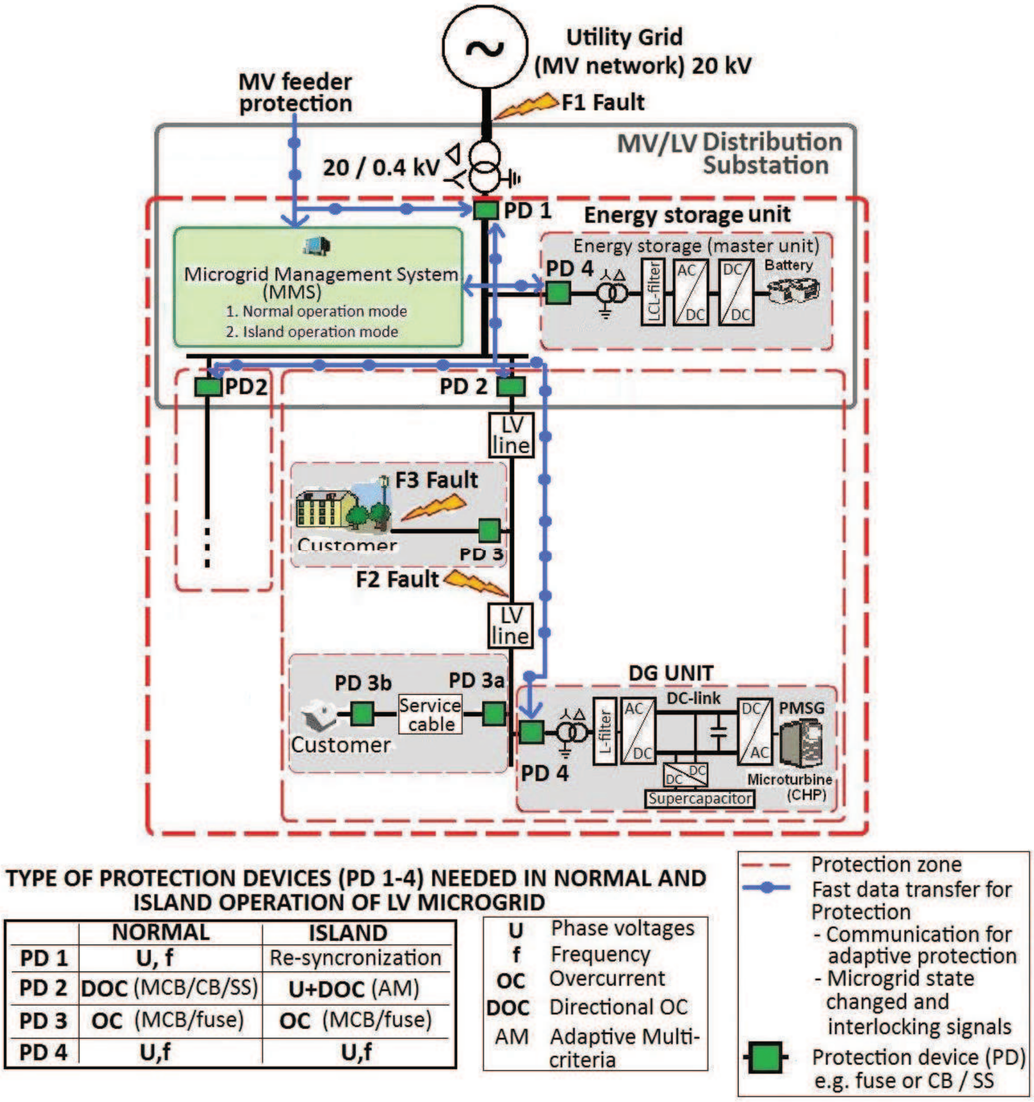
The main structural choices and functions of the proposed LV microgrid protection system are summarized in Figures 52 and 53. The chosen types of protection devices (PD 1–4) are shown in Figure 52. In Figure 53, functions needed from these PDs in normal and island operation are then summarized. Because active and reactive power measurements between utility grid and LV microgrid are required during normal operation (see Section 5.2.2 on page 78), phase current measurements are also needed from PD 1 and PD 4 (Figure 52). However, from the proposed protection system's point of view the current measurements at PD 1 and PD 4 are not necessarily needed. To be able to achieve selective protection for PD 2s during island operation, the protection algorithm of the devices was chosen to be multi-criteria based where both voltage and current measurements were utilized (Figure 52). In addition, the protection algorithm of PD 2s should be able to adapt to the current network configuration as well as to states of the DER units during island operation (Figure 52). In practice microgrid management system (MMS) could be used to change settings and pick-up limits of PD 2s when microgrid configuration changes (Figure 53).

After LV microgrid transition from normal to island operation MMS will send state-changed signal to different PDs so that they can adapt to the changed microgrid configuration (Figure 52). Microgrid interconnection switch, PD 1, is changed to be ready for LV microgrid synchronized re-connection back to utility grid. The re-synchronization requires that phase voltages are measured from both sides of the PD 1. Protection settings of PD 2s will adapt to the needs of island operation. To avoid malfunction of PD 2s, the protection settings of PD 2s are not changed from normal to island operation settings before all possible transients and oscillations due to islanding are stabilized. MMS will also send state-changed signals to PD 2s and PD 4s after successful LV microgrid re-connection back to utility grid (Figure 52).

Role of MMS is also important in power balance management of island operated microgrid. For example after fault F2 at LV feeder, MMS must send after operation of PD 2, new set point values for those DER units which are still connected at the healthy part of the microgrid or alternatively a disconnection signal to less critical customer loads.

To achieve selective protection and avoid unnecessary tripping of protection, possible oscillations due to sudden changes in microgrid configuration needs to be taken into account. This can be done by using communication based interlocking signals. In Figure 53 functions of the developed LV microgrid protection system during normal and island operation are illustrated.

Fast real-time communication is needed for microgrid protection purposes between protection devices (PD 1 and 2) and also between master unit and DER units. In addition, MMS needs to be able to communicate in real-time with all these microgrid components including customer loads. In this thesis it is proposed that this communication should be based on common standard like IEC 61850 (Figure 52) as discussed also in Sections 2.3.3 and 2.5.1. Utilization of phasor measurement units (PMUs) for time synchronized measurements with PDs inside LV microgrid is not needed, because according to Sortomme, Venkata & Mitra (2010) they may be only required with lines longer than 29 kilometers.



TYPE OF PROTECTION DEVICES (PD 1-4) NEEDED IN NORMAL AND ISLAND OPERATION OF LV MICROGRID

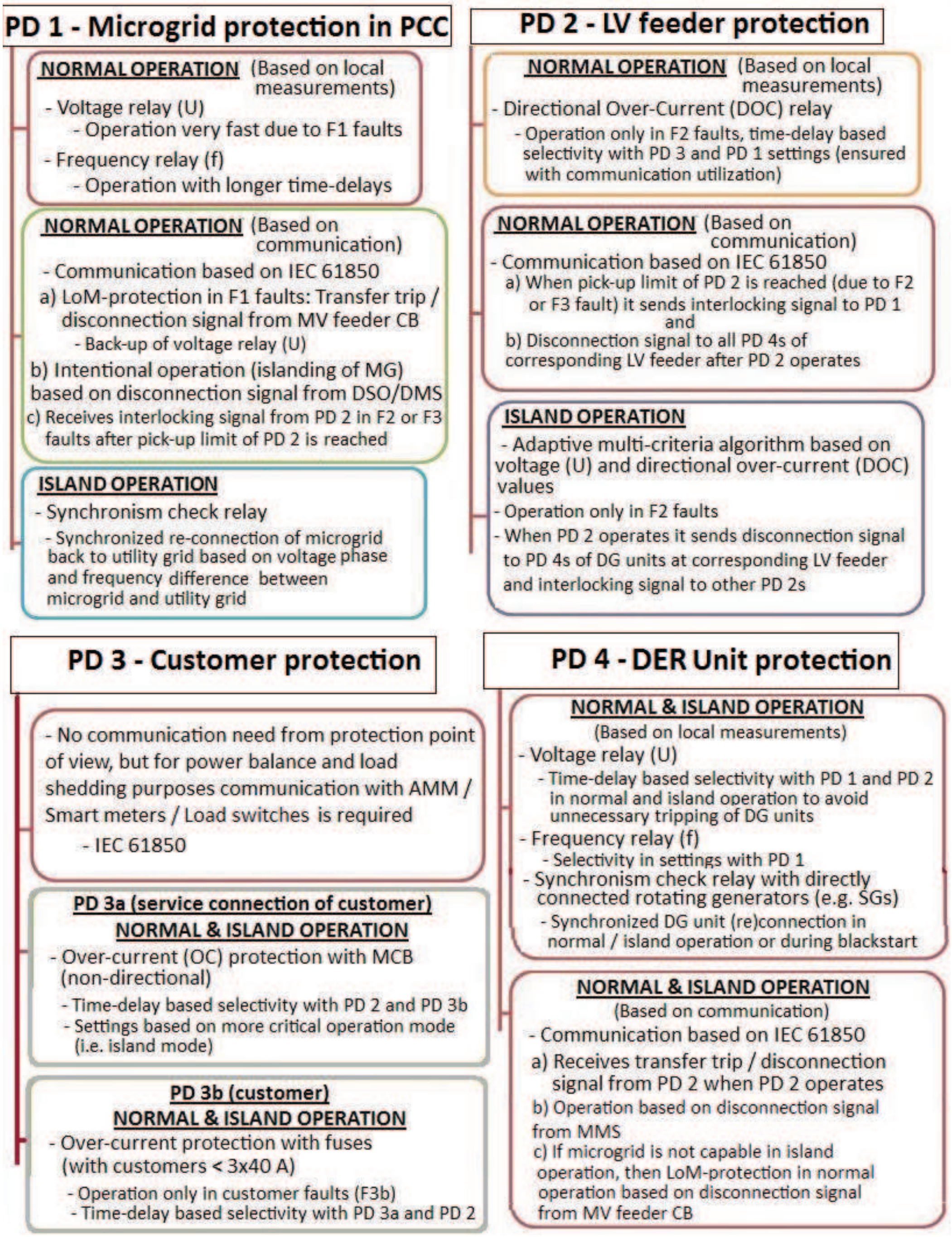
	NORMAL	ISLAND
PD 1	U, f	Re-syncronization
PD 2	DOC (MCB/CB/SS)	U+DOC (AM)
PD 3	OC (MCB/fuse)	OC (MCB/fuse)
PD 4	U,f	U,f

U	Phase voltages
f	Frequency
OC	Overcurrent
DOC	Directional OC
AM	Adaptive Multi-criteria

— —	Protection zone
●—●	Fast data transfer for Protection - Communication for adaptive protection - Microgrid state changed and interlocking signals
🟩	Protection device (PD) e.g. fuse or CB / SS

Figure 52. Type of protection devices (PD 1–4) needed in normal and island operation of LV microgrid for chosen number of protection zones.

Active microgrid components in the PCC of LV microgrid, microgrid interconnection switch, central energy storage unit and MMS, are also responsible for synchronized re-connection of microgrid back to utility grid (Figure 52). To achieve cost efficient solutions integration should be done with the protection functions of new DER units (PD 4). Functions of PD 4 should be part of the control system so that separate protection relays would not be needed. However, with the already existing DER units it could be easier to install the IEC 61850 DER object models to the new protection devices with direct link to the DER units instead of installing these models into the DER units themselves (Oudalov et al. 2009).



PD 1 - Microgrid protection in PCC

NORMAL OPERATION (Based on local measurements)
- Voltage relay (U)
  - Operation very fast due to F1 faults
- Frequency relay (f)
  - Operation with longer time-delays

NORMAL OPERATION (Based on communication)
- Communication based on IEC 61850
a) LoM-protection in F1 faults: Transfer trip / disconnection signal from MV feeder CB
  - Back-up of voltage relay (U)
b) Intentional operation (islanding of MG) based on disconnection signal from DSO/DMS
c) Receives interlocking signal from PD 2 in F2 or F3 faults after pick-up limit of PD 2 is reached

ISLAND OPERATION
- Synchronism check relay
  - Synchronized re-connection of microgrid back to utility grid based on voltage phase and frequency difference between microgrid and utility grid

PD 2 - LV feeder protection

NORMAL OPERATION (Based on local measurements)
- Directional Over-Current (DOC) relay
  - Operation only in F2 faults, time-delay based selectivity with PD 3 and PD 1 settings (ensured with communication utilization)

NORMAL OPERATION (Based on communication)
- Communication based on IEC 61850
a) When pick-up limit of PD 2 is reached (due to F2 or F3 fault) it sends interlocking signal to PD 1 and
b) Disconnection signal to all PD 4s of corresponding LV feeder after PD 2 operates

ISLAND OPERATION
- Adaptive multi-criteria algorithm based on voltage (U) and directional over-current (DOC) values
- Operation only in F2 faults
- When PD 2 operates it sends disconnection signal to PD 4s of DG units at corresponding LV feeder and interlocking signal to other PD 2s

PD 3 - Customer protection

- No communication need from protection point of view, but for power balance and load shedding purposes communication with AMM / Smart meters / Load switches is required
  - IEC 61850

PD 3a (service connection of customer)
NORMAL & ISLAND OPERATION
- Over-current (OC) protection with MCB (non-directional)
  - Time-delay based selectivity with PD 2 and PD 3b
  - Settings based on more critical operation mode (i.e. island mode)

PD 3b (customer)
NORMAL & ISLAND OPERATION
- Over-current protection with fuses (with customers < 3x40 A)
  - Operation only in customer faults (F3b)
  - Time-delay based selectivity with PD 3a and PD 2

PD 4 - DER Unit protection

NORMAL & ISLAND OPERATION
(Based on local measurements)
- Voltage relay (U)
  - Time-delay based selectivity with PD 1 and PD 2 in normal and island operation to avoid unnecessary tripping of DG units
- Frequency relay (f)
  - Selectivity in settings with PD 1
- Synchronism check relay with directly connected rotating generators (e.g. SGs)
  - Synchronized DG unit (re)connection in normal / island operation or during blackstart

NORMAL & ISLAND OPERATION
(Based on communication)
- Communication based on IEC 61850
a) Receives transfer trip / disconnection signal from PD 2 when PD 2 operates
b) Operation based on disconnection signal from MMS
c) If microgrid is not capable in island operation, then LoM-protection in normal operation based on disconnection signal from MV feeder CB

Figure 53. Functions needed from LV microgrid protection in normal and island operation based on local measurements and communication (see Figure 52).

Operation curves of PDs in the proposed LV microgrid protection system

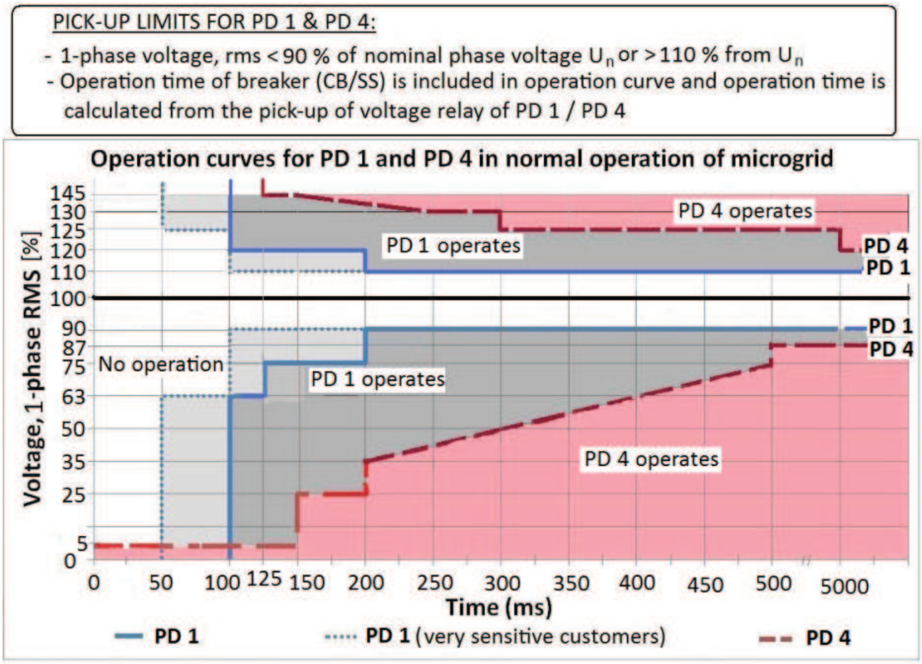
Different kinds of protection methods and principles for microgrids have been proposed previously by Feero, Dawson & Stevens (2002), Jenkins et al. (2005), Al-Nasseri & Redfern (2007), Brucoli & Green (2007), Driesen, Vermeyen & Belmans (2007), Nikkhajoei & Lasseter (2007), Tumilty et al. (2007), Al-Nasseri & Redfern (2008), Oudalov & Fidigatti (2008), Degner & Valov (2009) and Loix, Wijnhoven & Deconinck (2009). One problem in some of the proposed solutions for LV microgrid protection, e.g. by Al-Nasseri & Redfern (2008) and Loix, Wijnhoven & Deconinck (2009), is that their applicability is limited to microgrids with only converter connected DG units. Therefore, these solutions may for example overlook the protection operation speed requirements needed to maintain stability in LV microgrid equipped with directly connected rotating machines.

Key fundamental properties required from the future LV microgrid protection systems include

1. Adaptability,
2. Utilization of fast standard based communication,
3. Fast operation in deep voltage dips due to faults to maintain stability in healthy part of LV microgrid,
4. Fast operation to fulfill needs of very sensitive customers,
5. Selective operation in every kind of faults and
6. Unnecessary operation of PDs and disconnection of DG units must be avoided.

In following the operation curves for the PDs during LV microgrid normal and island operation are described. These operation curves were developed in Publication VI. Operation curves for PD 1 in normal and for PD 2 in island operation were created so that stability of LV microgrid or healthy part of LV microgrid could be maintained after fault clearance in every studied configuration. Therefore, these operation curves also represent FRT requirements for the DER units connected in LV microgrid. Voltage relay operation curve for PD 4 ensures selectivity with PD 1 in normal operation and with PD 2 in island operation to avoid unnecessary tripping of DER units. Frequency relay of PD 1 and PD 4 is only used to protect microgrid customers from possible long-term frequency deviations, caused by disturbances due to power imbalance in HV network, which cannot be seen from phase voltage measurements. Operation curves for frequency relay of PD 4 will also represent frequency based FRT required from DG and energy storage units. Pick-up and operation limits for PD 3s OC settings should be quite low, because their operation speed should be same also in island operation, where fault current level will be much lower than in normal operation.

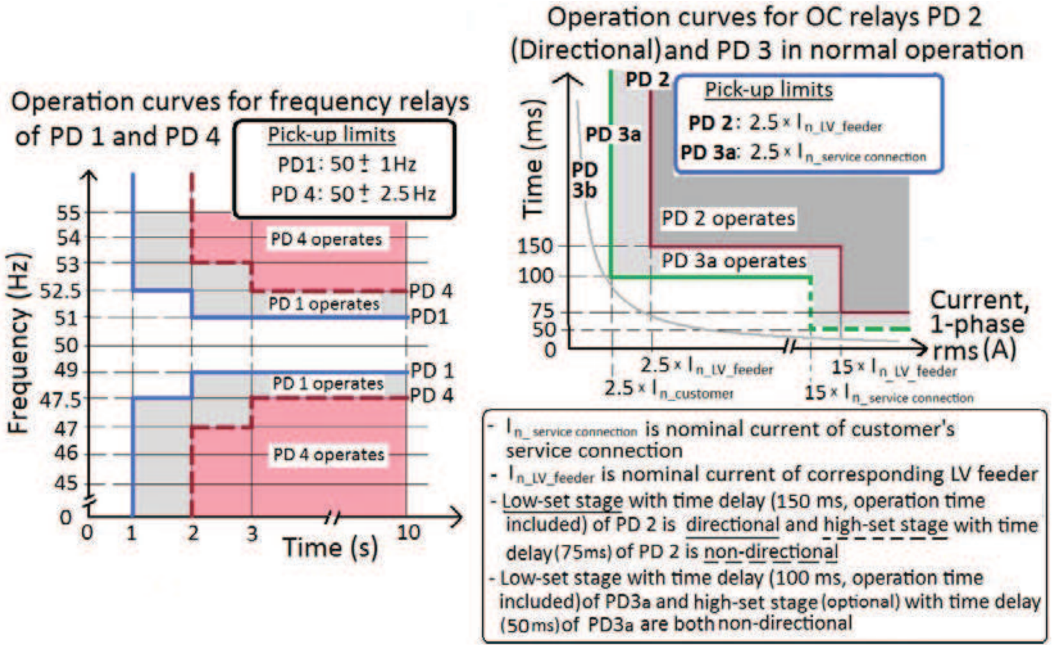
In Figure 54 and 55, requirements for the operation of microgrid protection devices during normal operation of microgrid are presented.



PICK-UP LIMITS FOR PD 1 & PD 4:

- 1-phase voltage, rms < 90 % of nominal phase voltage U_n or > 110 % from U_n
- Operation time of breaker (CB/SS) is included in operation curve and operation time is calculated from the pick-up of voltage relay of PD 1 / PD 4

Figure 54. Operation curves for voltage relays (PD 1 in normal operation and PD 4 in normal and island operation).



- $I_{n\_service\ connection}$ is nominal current of customer's service connection
- $I_{n\_LV\_feeder}$ is nominal current of corresponding LV feeder
- Low-set stage with time delay (150 ms, operation time included) of PD 2 is directional and high-set stage with time delay (75ms) of PD 2 is non-directional
- Low-set stage with time delay (100 ms, operation time included) of PD3a and high-set stage (optional) with time delay (50ms) of PD3a are both non-directional

Figure 55. Operation curves frequency relays of PD 1 and PD 4 in normal and island operation of microgrid and operation curves for OC relays of PD 2 (directional low-set stage and non-directional high-set stage) in normal operation and PD 3 in normal and island operation.

The operation limits for low-set and high-set stages of PD 2 and PD 3a in Figure 55 are instructional, based on simulation studies done in Publication VI. The protection of LV feeders with PD 2s in normal operation is based on directional OC relays (Figure 55). The direction of the current must be to corresponding LV feeder with such time delay that all possible F3 type of customer faults will be cleared with PD 3s before possible operation of PD 2. The chosen time delays in Figure 55 between PD 2 and PD 3a are quite small and selectivity between them may be hard to achieve in reality, without communication based interlocking signals from PD 3a.

The operation curve for PD 4 must be time selective with other PDs so that it will never unnecessarily disconnect DER unit due to any type of fault. In Publication VI also an extra definition for PD 4 was specified. It stated that disconnection of DER unit with PD 4 based on under-voltage should only take place in less than 150 ms after pick-up limit is reached if voltage in all three phases (A, B, C) is less than 5 % from nominal (see Figure 54) when voltages are measured from microgrid side of delta-wye grounded transformer. Fulfillment of the LV microgrid protection requires FRT ability from the DER units. In practice this means that converter based DER units require PLL with negative sequence filtering as discussed in Publications II and IV or alternatively some other stable and reliable synchronization method with FRT capability. Some examples have been presented by Blaabjerg et al. (2006) and Rodriguez et al. (2007). The main difference in the protection of LV microgrid during island operation is the required change in the protection algorithm of PD 2s. Based on the simulations adaptive multi-criteria algorithm for PD 2 (Figure 56) was developed in Publication VI.

Adaptability of PD 2 (Figure 56) means that during island operation it takes into account the number and type of DG units at corresponding LV feeder and also their fault current feeding capability. In addition, multi-criteria algorithm of PD 2 is based on both phase-to-earth voltage and current measurements. Fast and selective operation between different PD 2s during island operation is achieved by intelligent utilization of high-speed communication. The protection of PD 3s and PD 4s remains unchanged during island operation of microgrid (see Figure 54 and 55).The time delay in the multi-criteria algorithm of PD 2 (Figure 56) is dependent on the voltage dip which at the same time

- Ensures stability after fault clearance,
- Minimizes the effect of the voltage dip to other microgrid customers and
- Prevents unnecessary operation due to connection of certain type of loads, e.g. induction motors.

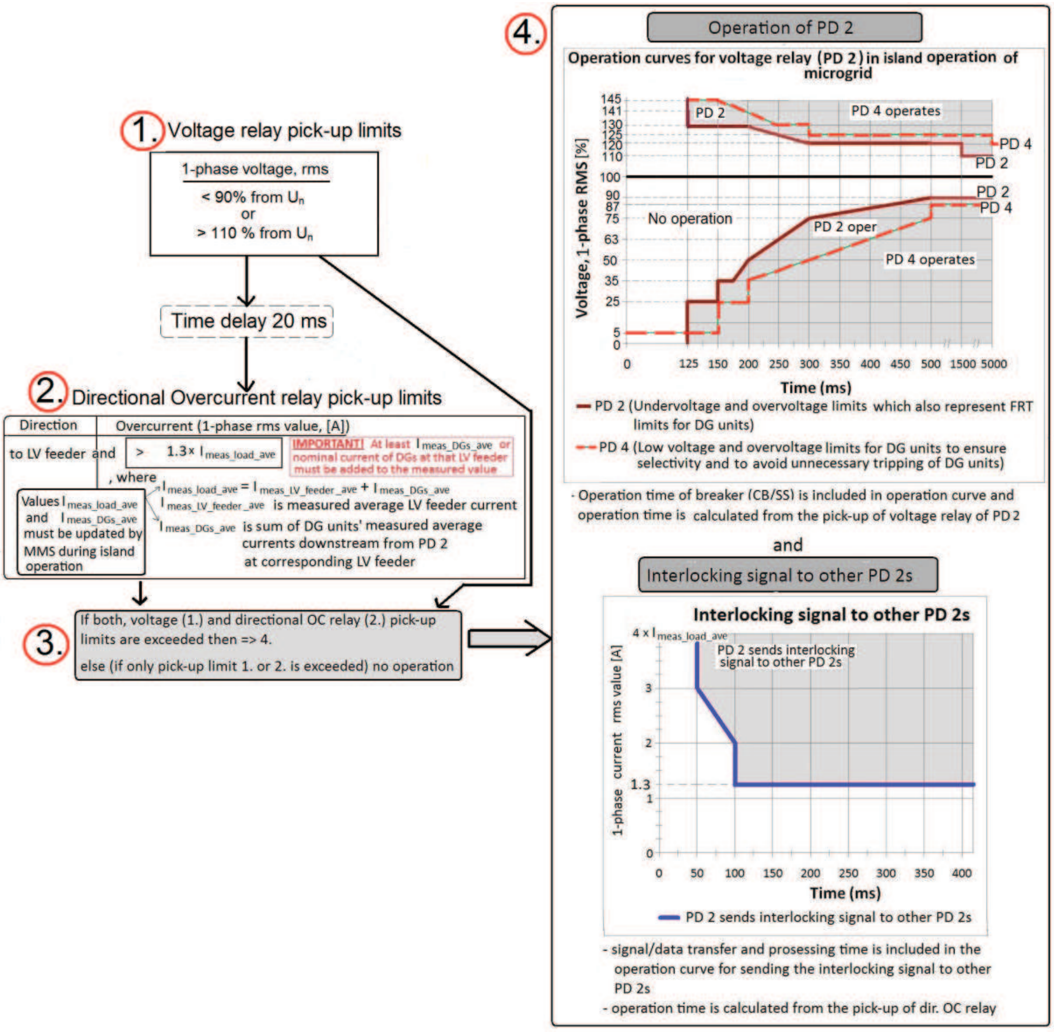


Figure 56. Adaptive multi-criteria algorithm for PD 2 to achieve selective operation between PD 3a and PD 2 in customer faults (F3) and LV feeder faults (F2) during island operation of LV microgrid.

Pick-up limit of the directional over-current (OC) measurement as part of the multi-criteria algorithm of PD 2 is adaptive so that it takes into account the number and type of DG units at corresponding LV feeder and also their fault current feeding capability. To ensure selectivity between PD 2s of LV feeders during island operation of microgrid, PD 2 should send an interlocking signal to other PD 2s after pick-up limits for voltage and directional OC values of it have been exceeded. Also short time delay could be used in the sending of the interlocking signal so that with higher currents the time delay of sending the interlocking signal would be shorter (see Figure 56). In this way the selectivity between PD 2s could be ensured even further.

To maintain stability during island operation at the remaining healthy part of LV microgrid after operation of PD 2 in 125 ms after a large voltage dip (Figure 56), the rated power of the central energy storage unit must be higher than the rating of the largest directly connected rotating DG. Shorter operation time, e.g. less than 60 ms could be beneficial from the DG unit's and customers' point of view, because then FRT requirements for DER units would be easier and voltage dips experienced by customers would be shorter. However, in that case the selectivity between PD 2 and PD 3a and PD 3b would be quite challenging to be realized, because then the devices would be required to operate in few tens of milliseconds. But if for example IEC 61850 based communication were also utilized on PD3a and PD 3b then the realization could be possible. The performance criteria specified by IEC 61850-5, *Communication requirements for functions and device models*, for the GOOSE messaging defines the transfer time to be less than 3 ms for a TRIP GOOSE command and 20 ms for a BLOCK GOOSE command 61850 (IEC 61850 standard 2003). The BLOCK command means that it will block the other PDs from tripping by sending an interlocking signal. Hakala-Ranta, Rintamäki & Starck (2009) has also presented how the GOOSE commands of the IEC 61850 standard can be used with the blocking-based busbar protection schemes at MV level.

Another option during island operation for only voltage relay based protection at PD 2s in radial LV feeders could be comparison of voltage measurements between PD 2s. This requires that PD 2 voltages are measured some distance away from MV/LV distribution substation at corresponding LV feeders with high speed communication to PD 2s. In this way lower phase voltages at the faulted LV feeder could be seen more clearly.

The effect of higher R/X-ratio on LV feeders and the influence of it on protection settings of PD 2s and PD 3s were also simulated in Publication VI. Simulations showed that higher R/X-ratio reduces slightly both the fault currents measured by PD 2s and PD 3s and the magnitude of the voltage dip during fault.

In all simulations of Publication VI fault resistance R_{fault} has been 0.005 Ω. In addition, it was simulated in Publication VI that how much larger can the fault resistance be in order to be cleared with the multi-criteria algorithm of PD 2 (Figure 56). For example separation between connection of larger single-phase load and single-phase earth fault with R_{fault}=5 Ω at LV feeder during island operation could not be made. The simulation showed that during 1-phase earth fault with R_{fault}=1 Ω at the end of LV feeder 1 the multi-criteria algoritm of PD 2 detects the fault. The simulations in Publication VI gave also reasons to determine the maximum size of single-phase load or DG unit that can be connected to microgrid with island operation capability. This could be done for example in percents from capacity of master unit, so that the risk of unnecessary operation of PD 2 can be avoided during island operation. Regarding to this it should be mentioned here that the simulation studies in Publication VI were done without microgrid voltage unbalance compensation by central energy storage (see Section 5.2.3).

The under- or over-voltage-ride-through ability of customers is also determined by the protection settings and operation curves of microgrid protection described above. For example the same FRT requirements are valid for frequency converter connected induction motors. In cases where customer equipments are very sensitive to voltage dips or momentary overvoltages, customer specific solutions like UPS, LV customer DC microgrid, overvoltage protection etc. will be required.

Additions to the proposed LV microgrid protection system

In Publication IX few additions to the proposed LV microgrid system presented in Publication VI were further developed. In studies of Publication IX the protection of long LV feeders with section PDs, connection of large DG units to LV microgrid and protection issues related to possible ring operation of LV feeders were examined.

With long radial LV feeders it may in some cases be beneficial to divide feeders into two protection zones (Figure 57). In addition, by adding PD 2_{ring} (Figure 57), which is normally open, between LV feeders, the self-healing capability of LV microgrid could be increased. By closing PD 2_{ring} instantaneously when PD 2a is opened (Figure 57), due to a fault at LV feeder section between PD 2a and PD 2b, the number of customers affected by the fault could be reduced. When PD 2a opens due to fault between PD 2a and PD 2b (Figure 57) it will send closing signal to PD 2_{ring} and interlocking signal to other PD 2s. On the other hand, if fault occurs after PD 2b at corresponding LV feeder (Figure 57) PD 2a and PD 2b will detect the fault simultaneously. In this case, to ensure selectivity between PD 2a and PD 2b, PD 2b must send interlocking signal immediately to PD 2a of the same LV feeder before PD 2a operates. In other words this means that when fault occurs after PD 2b, the time delay of PD 2a at the corresponding LV feeder must be such that interlocking signal from PD 2b can reach PD 2a before it will operate (Figure 57). In addition, to confirm selective operation of LV microgrid protection also during island operation, PD 2b could send measured phase voltage values with timestamp as an attachment of interlocking signal to PD 2a. If phase voltages measured by PD 2a at the same time are lower than the ones received from PD 2b, then PD 2a will be opened despite the interlocking signal received.

During normal and island operation also the selective operation of PD 2a and PD 2b with PD 3 must always be ensured.

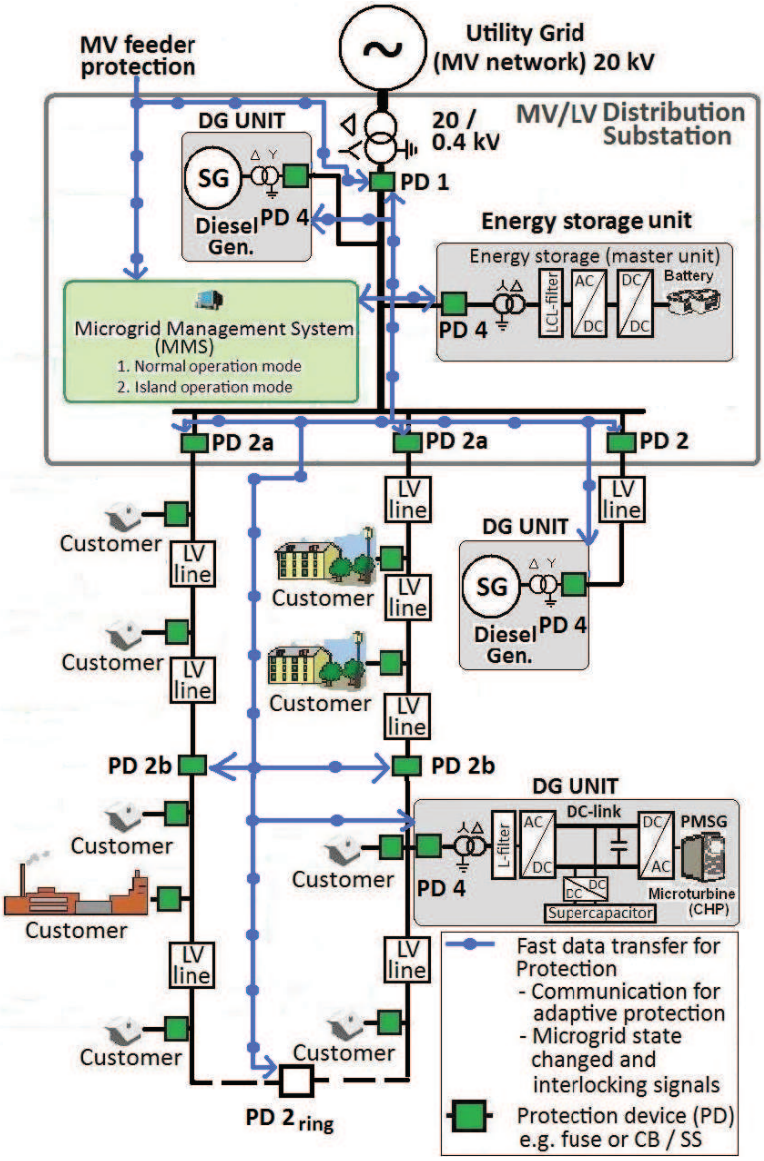


Figure 57. Long LV feeders with section PDs, e.g. CBs, (PD 2b, PD2$_{ring}$) and connection principles of large DG units.

Connection of large DER units with relatively high fault current feeding capability, say greater than 50 kVA directly connected SGs, is discussed briefly in the following. Fault current feeding capability of directly connected SGs may be circa six times the nominal current (I_n) for a short duration. It could also be possible that in the future the fault current of converter connected DG units can be even four times I_n under specific circumstances (Braun & Notholt-Vergara 2008). This converter overloading capability depends on several factors such as the pre-fault steady state power, the duration of the fault and the design of the heat sink (Braun & Notholt-Vergara 2008). The most relevant factor found by Braun & Notholt-Vergara (2008) was the thermal loading of the power electronics components. A higher overload capability is possible but at the cost of a lower performance under part-load conditions, or in other cases, higher volumes, weights and costs (Braun & Notholt-Vergara 2008). The connection of large DG units with high fault current feeding capability directly into the LV feeders may in some cases make it challenging to achieve selective protection during island operation even if adaptive PDs were used. Therefore, large DG units should be connected either directly or with own LV feeder to the MV/LV distribution substation (Figure 57). Such a DG unit connection is also beneficial if this unit is heat producing CHP unit, because it will always remain connected regardless of possible faults at other LV feeders (Figure 57).

In normal operation of LV microgrid it can be beneficial from the point of view of the voltage level control to operate the LV feeders with ring configuration (Figure 57). This means that PD 2_{ring} is needed and it will be closed during normal operation. Section PDs in the middle of LV feeders (PD 2b in Figure 57) are not necessarily needed. From the simulation results of Publication IX it became clear that with ring connected LV feeders during microgrid normal operation, selective operation of PD 2as was not possible without utilization of high-speed communication. However, in order to ensure selective operation of microgrid protection also during island operation, it would be beneficial to open the PD 2_{ring} (Figure 57) during island operation.

Further studies needed in the development of the LV microgrid protection system

First of all, the proposed new LV microgrid protection system revealed the need for fast operating, accurate, low-cost, programmable PDs with high-speed communication capability in future smart LV networks. Fuses cannot be parametrized and contactor or load switch alone is not able to disconnect high fault currents. Therefore, this kind of new PD or LV network Smart Grid Switch (SGS) could be based on breaker or semiconductor technology to achieve rapid response. Most sensible option would be that the same LV network SGS with standard (IEC 61850) based communication capabilities could be utilized as PD 1, PD 2 or PD 4 in the proposed new LV microgrid protection system just by programming the operation curves of the PD as needed. PD 1 and PD 2 should also be able to break high fault currents during normal operation. Basic measurements of LV network SGSs could include measurement of phase currents (directional), phase voltages (at least in PD 1 from both sides) as well as active and reactive powers. Also some add-on features could be included into the LV network SGSs, like for example frequency, voltage and/or current THD and unbalance measurements in PD 1 and PD 4. Especially power quality measurements from distribution networks will increase in the future and this information for different possible future applications of MMS and DMS could also be provided by these SGSs. For example knowledge from measurements of microgrid interconnection switch (PD 1) about voltage level and transformer loading at MV/LV distribution substation could be useful for distribution network planning and operation purposes for DSOs. On the other hand, power quality measurements could also be made more extensively in future smart grids with separate devices as presented by McEachern & Eberhard (2010) or with AMM devices. Also the communication compatibility of the LV network SGS devices, especially PD 1, with MV feeder IEDs in future smart grids may be useful if for example zero voltage or zero current measurements at MV/LV distribution substations from MV side of the transformer are communicated between PD 1 devices and MV feeder IEDs for earth fault locating purposes in certain type of MV networks.

In Publication VI in which the proposed LV microgrid protection system was developed, the fault level and R/X-ratio of the utility grid at the 20 kV level were 200 MVA and 0.1 respectively, which means that there was quite strong connection to HV level during normal operation. Due to this it could be useful to study further the possible influence of fault level at LV microgrid connection point, e.g. to the pick-up limits and low-/high-set stage settings of PD 2 and PD3a (see Figure 55) to ensure selectivity between different PDs in all possible cases. In the future, also the effect of DER unit operation state to the fault current feeding capability of it could be further studied from the new LV microgrid protection system's point of view. For example, what possibly is the difference in the fault current fed during different type of faults, if production of the DER unit is 25 or 100 % from nominal power. In further studies, the dynamics of the DER unit primary energy source could be modeled with more details to find out possible effects on the fault current feeding capability of the DER units in different operating states. In the future the flexibility and applicability of the proposed LV microgrid system to different kinds of microgrids could also be further studied. Real example cases are also important in the future to verify, test and develop the proposed LV microgrid protection system.

6.3 DER unit fault behavior and protection of LV microgrid

One of the most important issues is to ensure that the behavior required from DER units during faults is compatible with the developed LV microgrid protection system. This means that when protection of island operated microgrid is designed, one of the most important questions is how converter based DER units will contribute to the fault current. Loix, Wijnhoven & Deconinck (2009) have stated that low thermal overload capability of converters limits their maximum output current to about 2–3 times the rated current. To avoid converter disconnection due to high fault current during a fault converter output current limitation algorithm is used for the period needed by the protection system to locate and isolate the fault (Loix, Wijnhoven & Deconinck 2009). On the other hand in references (Van Overbeeke 2009) and (Van Overbeeke & Cobben 2010) more fault current to island operated microgrid is provided by fault current source to ensure that the over-current based protection operates correctly. As mentioned before in Braun & Notholt-Vergara (2008) investigation it was found that under specific circumstances the converter was able to provide up to four times its nominal current during a fault.

In general, the behavior of converter based DER units during faults including allowable voltage and frequency fluctuations is determined by national interconnection requirements or grid codes which differ from country to country. Therefore, standardization is needed to determine the operation of converter based DER units during faults to ensure efficient operation of smart grids with high penetration levels of DER units (Strauss et al. 2009). Strauss et al. (2009) also suggested few general requirements about converters fault behavior. For example, converter should not disconnect in case of faults and converter should support the grid voltage in case of faults by injection of reactive power during the fault (Strauss et al. 2009). However, it has been pointed out by Strauss et al. (2009) that at different network levels (MV/LV) grid-support during faults by DER unit converters may require different solutions.

The fault-ride-through (FRT) capability of converter based DER unit will not always be just a control issue. This means that also the hardware layout of the DER unit converter may need to be adjusted to provide FRT capability. For example Abbey & Joos (2007) have used supercapacitor based energy storage in doubly fed induction generator (DFIG) wind turbine to smooth the output power and to provide FRT ability. Supercapacitors have also been proposed by Tao, Duarte & Hendrix (2008), to be used with fuel cell based UPS systems to improve their control response which is otherwise quite moderate due to the slow dynamics of the fuel processor. Also other types of modifications to provide FRT capability for converter connected DER units have been suggested. In the work by Wanik & Erlich (2009), DC chopper was added to the DC-link of microturbine converter instead of larger capacitance to limit voltage rise in DC-link during faults. This DC chopper dissipates the excessive power during faults through its resistor. Also in some simulations done in Publication VII it has been examined the effect of supercapacitor in the DC-link of DG unit converter to provide FRT ability, i.e. to limit voltage rise in DC-link during faults. The simulation results in Publication VII showed how the control of voltage rise in the DC-link of the converter reduced the fault current fed by the corresponding DER unit.

In Publication VII the effect of DG unit fault behavior to LV microgrid protection during island operation was studied in some specific cases with PSCAD simulations. In the simulations of Publication VII different control strategies of converter connected DG units during faults were investigated with various DG unit configurations. In addition, the role of energy storages was examined to find out their effect to the microgrid voltages and currents measured by the protection devices.

Based on the simulations done in Publication VII the increased reactive power feeding with converter based DG units was found to be beneficial for the possible over-current protection based protection in LV microgrid. On the other hand, it did not significantly reduce the usability of under-voltage based protection due to resistive character of LV lines. However, the reactive power feeding during fault did not significantly reduce the magnitude of the voltage dip, i.e. support microgrid voltage during fault. It was also found in Publication VII that significant reactive power feeding during fault may be challenging for the DC-link voltage control of DG unit during fault. In addition, the reactive power feeding by many DG units seemed to increase the possibility of angle stability problems after fault clearance.

The capability to feed or absorb large reactive powers with converter connected DG unit will require more capacity from the grid side DC/AC- converter of the DG unit. Demirok et al. (2009) stated that 17.64-% overrating extends the operation range of converter between 0.85 lagging and 0.85 leading power factor. In the end, the excessive reactive power feeding by converter connected DG units during fault in island operated LV microgrid was not justified based on the simulations done in Publication VII. However, it is essential from the point of view of the island operated LV microgrid stability and protection to take into account how the reactive power of each DG unit behaves and is controlled.

Simulations of Publication VII also showed that the nominal power of directly connected SG, which is not located at the MV/LV distribution substation like the energy storage based master unit, should be, e.g. 25–50 % smaller than the nominal power of master unit to ensure stability after fault in island operated LV microgrid. Excitation control of directly connected SGs should also be tuned so that their stable operation would be ensured during and after sudden changes in island operation. It is also important from stability perspective that the control systems of different DER units are compatible with each other.

6.3.1 Fault behavior standardization of converter based DER units in LV microgrids

Standardization plays a key role in the future development and realization of the smart grids with converter based DER units (Strauss 2009). FRT capabilities are a state-of-the-art for the connection of wind parks to the transmission network. But FRT has not yet been required from smaller generators until the beginning of 2009 when the new German code for the connection of generators in MV networks came into effect in Germany. However, this regulation does not apply to DER units which are connected to the LV networks. The capability of some commercial photovoltaic converters to ride-through voltage dips has been earlier studied, e.g. by Bletterie, Bründlinger & Fechner (2005). Anyhow, the FRT ability is nowadays not required from DER units in LV networks in many countries. Therefore, any drop in the voltage below certain limits will lead to disconnection of the LV network connected DER units.

Figure 58 shows the requirements for the fault behavior of converter based DER units connected to MV network in Germany as presented by Laukamp (2008) and Notholt (2009). From Figure 58 it can be seen that the DER unit must remain connected to the grid and inject reactive power during the first 150 ms of any fault and for longer faults, the DER unit must remain connected for fault over the limit line 2 and must inject reactive power for faults over the limit line 1 (Notholt 2009).

However, it has been pointed out by Strauss (2009) that at different network levels (MV/LV) grid support by DER inverters requires adapted solutions. Requirements and capabilities which are appropriate for generators connected to MV network might on the other hand not be practical for LV connections.

Grid codes and standards for smart grids with island operation capability, microgrid grid codes (MGCs), are absolutely necessary for the development of future smart grids. MGCs will reduce complexity and avoid the need for too many alternative, case specific, protection solutions. Nowadays there are many different national grid codes, interconnection guidelines and national standards. Some overview of the existing regulations in mostly used European standards has been given, for instance in (Norrga 2009).

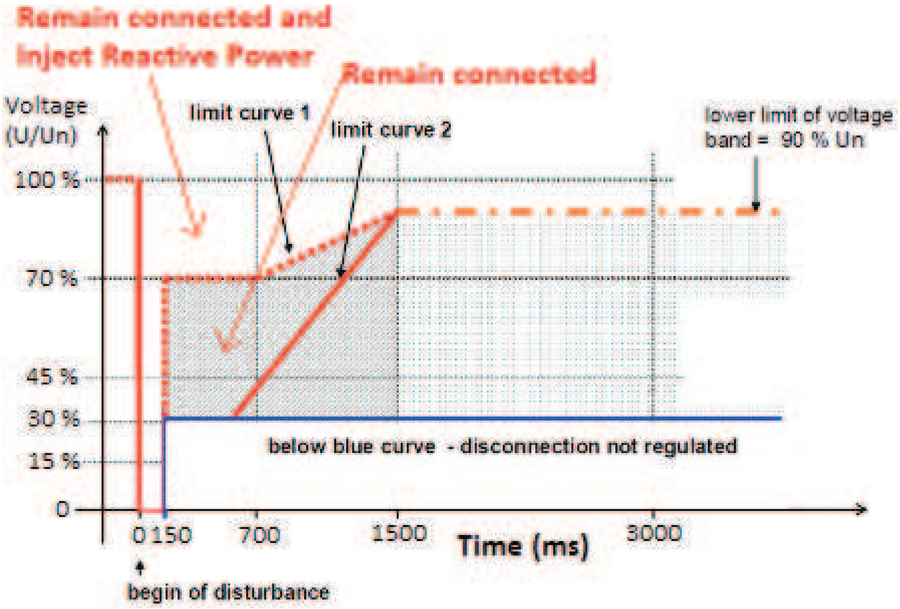
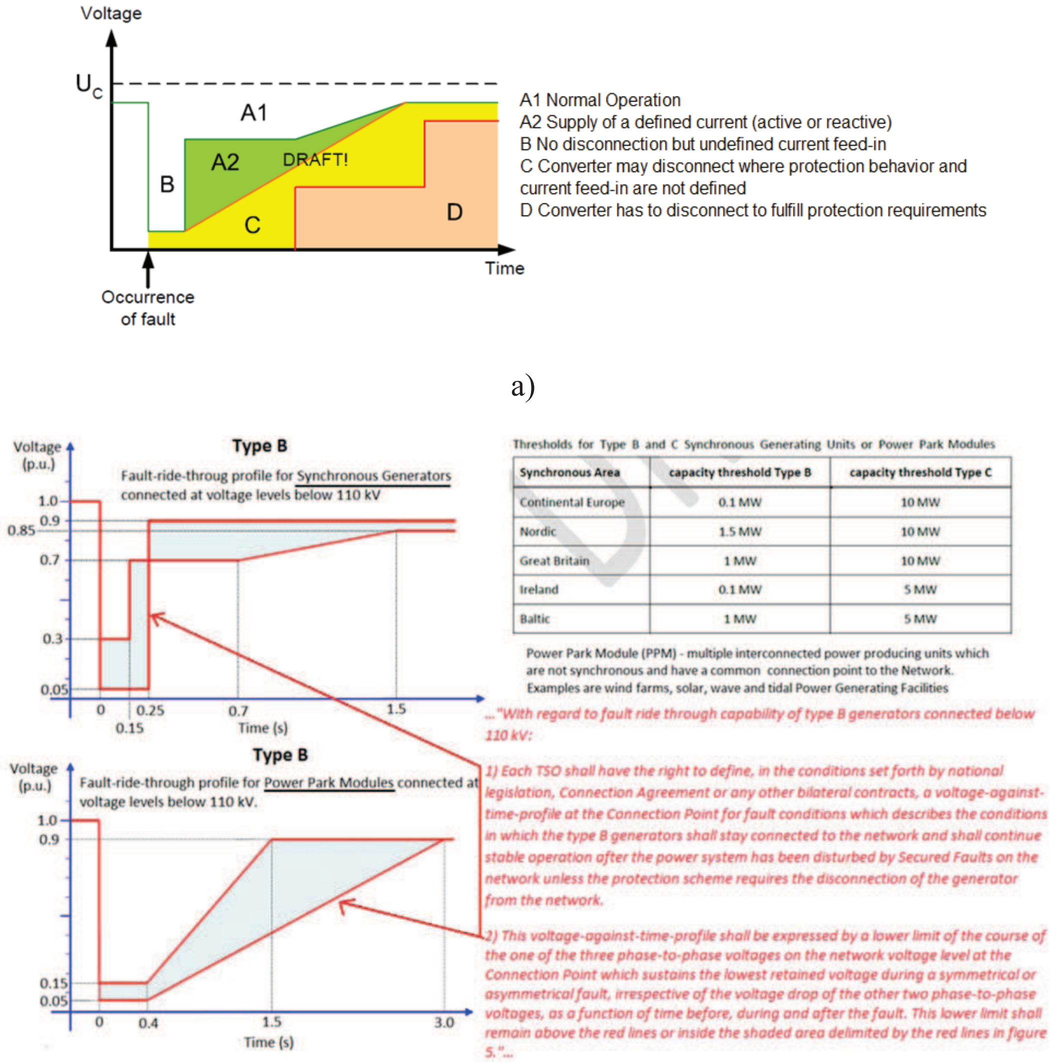


Figure 58. FRT requirements for DER units which are not based on directly connected SGs. The DER unit must remain connected to the grid and inject reactive power during the first 150 ms of any fault and for longer faults, the DER unit must remain connected for fault over the limit line 2 and must inject reactive power for faults over the limit line 1 (Laukamp 2008), (Notholt 2009).

MGC should determine the fundamental structural choices of corresponding LV microgrid concept, including harmonic emission limits, protection and power balance management issues, and the required DER unit behavior and control principles during normal operation and faults in that concept. Strauss (2009) proposed DER unit fault behavior in *DER inverter white book* as shown in Figure 59 a). Also ENTSO-E (2011) has recently proposed in *Draft Requirements for Grid Connection Applicable to all Generators* FRT requirements for type B generators connected at voltage levels below 110 kV as shown Figure 59 b).



Thresholds for Type B and C Synchronous Generating Units or Power Park Modules

Synchronous Area	capacity threshold Type B	capacity threshold Type C
Continental Europe	0.1 MW	10 MW
Nordic	1.5 MW	10 MW
Great Britain	1 MW	10 MW
Ireland	0.1 MW	5 MW
Baltic	1 MW	5 MW

Power Park Module (PPM) - multiple interconnected power producing units which are not synchronous and have a common connection point to the Network. Examples are wind farms, solar, wave and tidal Power Generating Facilities

..."With regard to fault ride through capability of type B generators connected below 110 kV:

1) Each TSO shall have the right to define, in the conditions set forth by national legislation, Connection Agreement or any other bilateral contracts, a voltage-against-time-profile at the Connection Point for fault conditions which describes the conditions in which the type B generators shall stay connected to the network and shall continue stable operation after the power system has been disturbed by Secured Faults on the network unless the protection scheme requires the disconnection of the generator from the network.

2) This voltage-against-time-profile shall be expressed by a lower limit of the course of the one of the three phase-to-phase voltages on the network voltage level at the Connection Point which sustains the lowest retained voltage during a symmetrical or asymmetrical fault, irrespective of the voltage drop of the other two phase-to-phase voltages, as a function of time before, during and after the fault. This lower limit shall remain above the red lines or inside the shaded area delimited by the red lines in figure 5."...

a)

b)

Figure 59. a) Proposal for the specification of FRT and protection requirements for DER converters in *DER inverter white book* (Strauss 2009) and b) Proposal for type B generators FRT requirements connected at voltage levels below 110 kV (ENTSO-E 2011).

In Figures 54–56 the exact voltage and time values for the protection curves of different PDs were also presented and from these curves the needed FRT capability for LV microgrid compatible DER units could be derived. But for example supply of active or reactive current was not defined in detail. However, based on the simulations done in Publication VII the reactive current feeding with converter based DER units during faults in island operated LV microgrid was not recommended.

As a conclusion it can be suggested that during faults in island operation the fault current fed by converter based DER units is recommended to be active instead of reactive if possible. And the control of the converters during possible faults is not recommended to be changed due to increased possibility to instabilities after fault clearance. This means that if DER unit is PQ-controlled and produces for example 100 kW active and 20 kVAr reactive power, there is no need to change this control principle during fault to produce only active current. Also from the proposed LV microgrid protection system's point of view (Section 6.2) it is not advisable during possible faults in island operated LV microgrid to feed four times the nominal current I_n from the converter based DER units which was stated to be possible under specific circumstances by Braun & Notholt-Vergara (2008), because it could in some cases lead to instability regardless of the nature of the fault current, whether active or reactive. This means that even if the increased fault current ($4 \cdot I_n$) of converter based DER unit is mainly active, it will compensate the voltage dip, for example due to fault in one LV feeder, and slow down the operation of PD2s based on multi-criteria algorithms (see Figure 56). Therefore the possibility for instabilities after fault clearance may be increased. On the other hand, it was stated in Publication IX that connection of large DG units, especially SGs, with high fault current feeding capability directly to LV feeders may in some cases make it challenging to achieve selective protection during island operation of LV microgrid even though adaptive PDs were used. It is enough from the proposed LV microgrid protection system's point of view that converter based DER units will feed $2 \cdot I_n$ current during faults in LV microgrid for the required FRT time defined by the operation curves of different PDs (Figures 54–56).

6.4 Blackstart strategy as part of LV microgrid protection and fault management system

In Publication V blackstart operation strategy as part of protection and fault management strategies was presented. It is needed to handle problematic situations like instability after transition of LV microgrid to island operation or after fault during the island operation. In case of instability all DG units must be first disconnected before the blackstart strategy will be executed by MMS. The central energy storage unit will play the main role in maintaining the power balance and acceptable voltage level in microgrid during the blackstart as well. The load connection could be done in groups with communication between MMS and advanced AMM systems. Co-ordination between DG units and loads during blackstart operation is also managed with MMS. In Publication V, sequence of actions for the microgrid blackstart operation (Figure 60) and control principles for some DG units during blackstart were defined and simulated.

The main difference between blackstart operation principles presented in Publication V when compared to references (Moreira, Resende & Pecas Lopes 2007) and (Pecas Lopes, Moreira & Resende 2005) is the lack of sectionalizing which means that the microgrid is divided into smaller islands around DER units and these islands are synchronized with each other during the blackstart.

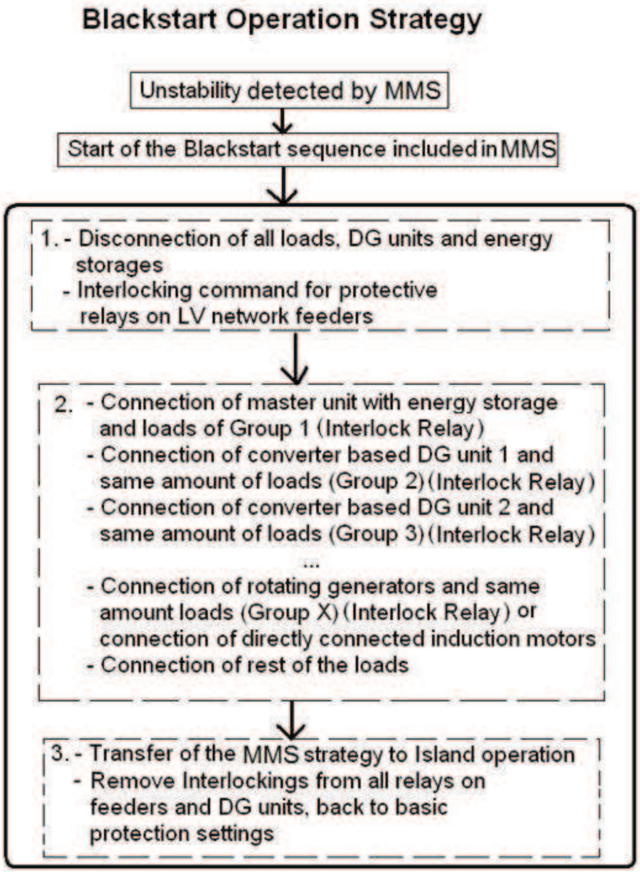


Figure 60. Basic principles for blackstart operation strategy from Publication V.

Because isolated distribution systems are not as stiff as utility grids, large starting currents and voltage drop during starting of directly connected induction motor could be critical for the entire microgrid (Laaksonen & Kauhaniemi 2007a). Based on the simulations of Publication V, some dimensioning principles for the needed central energy storage and size of simultaneously controlled loads were given which are presented in the following:

1. Rated capacity of the master unit with energy storage should be at least equal to the largest converter based DG units or motor drives and also 1.5–2 times larger than any of the rotating machines connected directly to the microgrid,
2. Load groups which are connected sequentially should not be larger than the capacity of the master unit and
3. Large directly connected rotating machines must be connected separately from other loads.

It was also found out in simulations of Publication V that during blackstart it is logical to connect the most disturbing loads, like rotating machines and thyristor rectifiers, at the end of the blackstart sequence. Also the connection interval between rotating machines should be long enough so that the steady state can be reached before the next event. On the other hand, it was suggested from the point of view of blackstart in Publication V that all the larger rotating machines should be preferably connected to the microgrid through frequency converters.

6.5 Synchronized re-connection of island operated LV microgrid back to utility grid

Synchronized re-connection of island operated LV microgrid back to utility grid was studied in Publication VIII. Although the island operated LV microgrid may be in synchronism with utility grid right after transfer to island operation, later due to load and production changes, i.e. changes in active and reactive power flows both in utility and microgrid, the voltage phase angle difference across microgrid interconnection switch (PD 1) will change. Synchronized re-connection of island operated LV microgrid back to utility grid means that the voltage angle difference between utility grid and LV microgrid should be minimized before re-connection.

In the HV transmission lines where $X>>R$ the active power P depends mainly on load angle δ and reactive power Q depends mainly on voltage difference. Therefore, the control of active power P transmission directly controls the load angle δ and frequency f. Generation units connected to HV network are usually equipped with directly connected SGs. Phase angle difference over open CB between two separate large HV power systems can be controlled before closing CB with traditional steam turbine based power plants, by controlling the mechanical input torque T_m in similar manner that is done in frequency control of HV power system. In HV network synchronism check relays are configured e.g. so that frequency difference over open CB should be under 55 mHz and phase difference 20°–45° before connection (AREVA 2002).

In LV microgrids most of the DER units will be connected through power electronic interfaces and re-synchronization of LV microgrid could be possibly done through the control of these DER units. With LV distribution lines $R>>X$ and therefore, in contrast to HV transmission lines, the active power P depends mainly on voltage difference, while the load angle δ and depends mainly on reactive power Q because. Therefore, one way to control the phase difference across microgrid interconnection switch could be through co-ordinated reactive power set point changes of the DER units.

The chosen strategy is dependent on the chosen microgrid concept. Arulampalam et al. (2004) have proposed that during resynchronization the control of energy storage unit slowly shifts the microgrid system frequency reference value to the main network frequency value. On the other hand, for example with P/f -droop controlled DER units synchronized re-connection of microgrid requires that all DER unit converter controls must be co-ordinated. This co-ordination must be done by an external central controller that guides all the converters in the synchronization process. To vary the island frequency and to control the angle an action is required over the P/f -droop curve which needs communication from a central controller. (Nuñez, Gil de Muro & Oyarzabal 2010; Van Overbeeke & Cobben 2010)

Voltage unbalance due to load asymmetry and single-phase DER units affects the voltage phase difference across open microgrid interconnection switch so that the phase difference deviation may be different in every phase A, B and C. In some cases this asymmetry between phases may also be required to be reduced before re-connection of island operated microgrid.

Active microgrid components in the PCC of microgrid, such as microgrid interconnection switch, central energy storage unit and microgrid management system, are responsible for synchronized re-connection of LV microgrid back to utility grid. Oyarzabal et al. (2009) have proposed that synchronous island operation could be done by a reference signal containing phase and frequency information to the master unit of the microgrid. The phase difference should be within acceptable levels, e.g. less than 60°, during re-connection to utility grid (Oyarzabal et al. 2009). Based on (Eto et al. 2009), microgrid re-synchronizing function has to meet a more stringent requirement than the one defined by IEEE 1547 which requires that the phase difference between a microgrid and the utility grid should be less than 20° before the interconnection switch can close.

In Publication VIII issues related to the re-connection were studied and different functions to enable synchronized re-connection were developed and simulated. The LV network simulated in Publication VIII is presented in Figure 61.

In the simulations of Publication VIII either

1. Master unit voltage phase angle or
2. Reactive power output of DG units was modified to enable synchronized re-connection (Figure 61) and in addition also
3. Controllable single-phase loads were used in for asymmetry compensation before re-connection at MV/LV distribution substation (Figure 61).

The simulation results in Publication VIII showed that both re-synchronization functions 1) voltage phase angle adjustment with master unit control and 2) reactive power feeding of DG unit could be utilized to enable successful synchronized re-connection of island operated LV microgrid back to utility grid. However, the voltage phase difference deviation or asymmetry between phases A, B and C across microgrid interconnection switch (Figure 61) still existed with these re-synchronization functions. If this phase difference deviation is too large, it must be compensated before re-connection of island operated LV microgrid. In simulations of Publication VIII this phase difference deviation was well corrected by connection of resistive or capacitive single-phase loads at MV/LV distribution substation (Figure 61). However, quite large frequency and voltage oscillations after connection of single-phase capacitive loads were detected when compared to the connection of purely resistive loads.

In general, the simulation results of Publication VIII clearly showed that synchronized re-connection is not necessarily a significant issue with small, e.g. less than 10°, phase difference across microgrid interconnection switch when there are only converter based DER units. Reason for this was that PLL will draw converters into phase with the utility grid frequency after re-connection. However, with directly connected synchronous generators even small phase difference across interconnection switch during re-connection was found to be problematic. Therefore, re-synchronization functions for minimizing phase angle difference and possibly also voltage unbalance before LV microgrid re-connection will be needed and in practice these functions should be co-ordinated by microgrid management system.

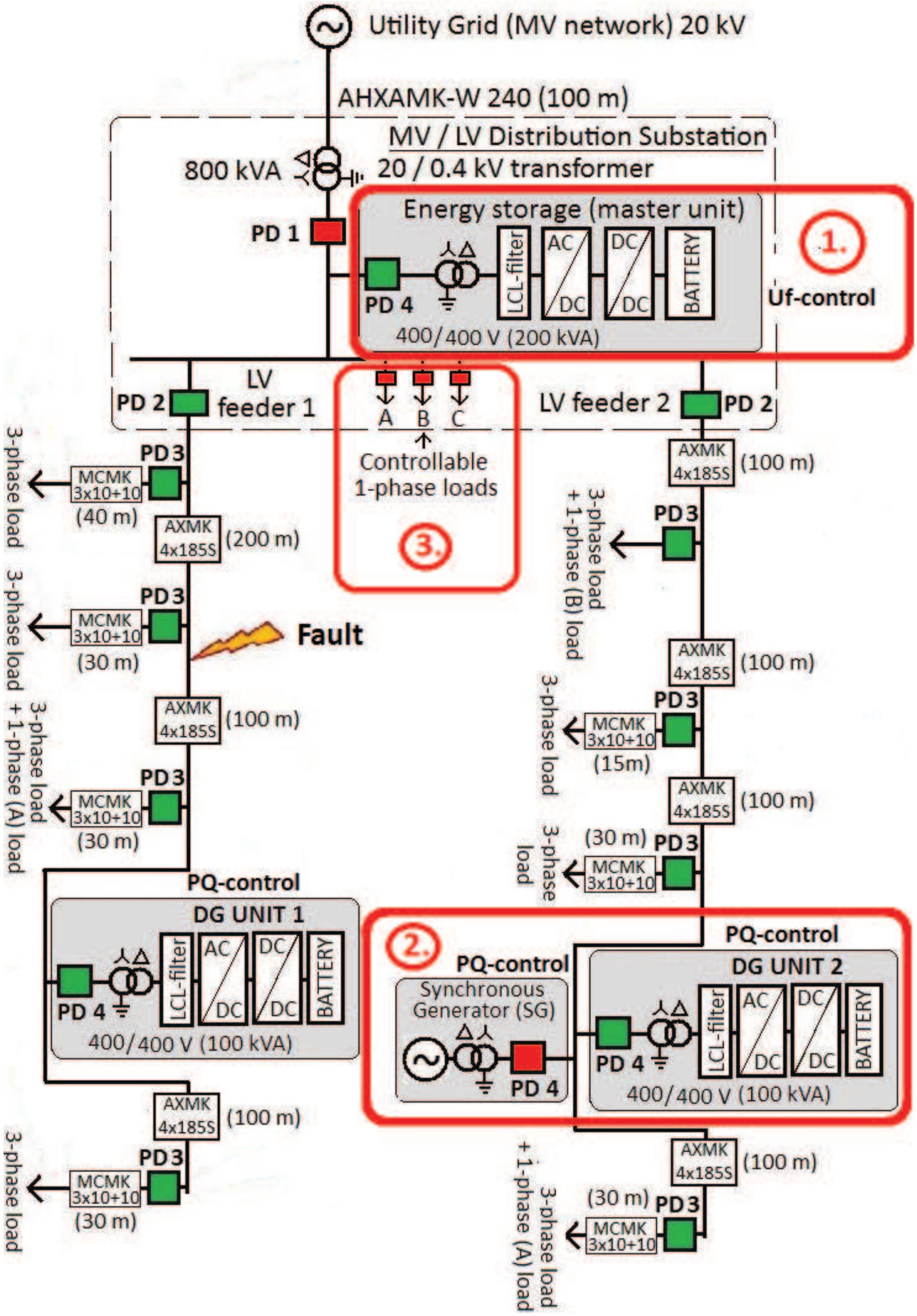


Figure 61. Studied LV microgrid in Publication VIII.

7 CONCLUSIONS AND DISCUSSION

Low-voltage microgrid concepts without one grid-forming central storage unit have been extensively studied and proposed in the literature. Most common have been the P/f- and Q/U -droop control based concepts. However, they have some drawbacks related to their capability to be integrated into the present grid or future smart grids in a feasible way. This is due to the fact that the management of these concepts seems to be developed more from the point of view of DER unit converter control than from the point of view of utility grid integration. Major problems with P/f- and Q/U -droop based LV microgrid concepts are

- The lack of sensible voltage control, because Q/U -droops require huge amount of reactive power to control the voltage in LV network,
- The lack of feasible protection system which is to some extent compatible with the present LV network or the one that will be used in normal parallel operation of future smart LV networks and
- The fact that these concepts are planned to be controlled without any communication, although most of the smart grid features will be based on extensive utilization of high-speed communication.

In addition, one problem in many of the proposed solutions for new LV microgrid protection system has been that their applicability is limited to microgrids with only converter connected DER units. The proposed solutions may therefore overlook the protection operation speed requirements required to maintain stability in LV microgrid equipped with directly connected rotating machines.

In this thesis, total technical LV microgrid concept was developed which takes more into account the needs and behavior of the grid, so that island operation of LV network could be natural part of future smart grids. Essential in the development of the total technical concept was the development of solutions and operation principles to the key technical challenges of low-voltage microgrids so that all these solutions were compatible with each other. The key technical challenges of low-voltage microgrids were defined in this thesis to be successful transition to island operation and power quality management as well as microgrid protection during normal and island operation.

The main scientific contribution in this thesis was the development of technical solutions to the key technical challenges by taking into account the simultaneous interaction of several devices as well as the dependencies between the developed solutions. This required simulation studies with multiple component configurations. In Chapters 4, 5 and 6, the developed technical solutions to the key technical challenges were presented.

For example the impact of directly connected synchronous generator based DG unit when compared to case with only converter based DER units was taken into account in the development of all the proposed solutions. It was found that fault-ride-through (FRT) capability of directly connected synchronous generator based DG unit was not as good as with converter based DER units. However, it was also found that FRT capability of converter based DER units required low total-harmonic-distortion (THD) of voltage during island operation and synchronization method which was able to survive from unbalanced faults. During island operation the voltage THD of LV microgrid should also be as low as possible to provide high quality power for customers during island operation as well. The characteristic behavior of these different types of DER units affected to the proposed operation curves of the developed new LV microgrid protection concept. The proposed LV microgrid concept is capable of adapting to the needs of different kind of DER units and is suitable also for LV microgrids with directly connected synchronous generators. The studies performed and presented in this thesis were mainly done in relatively strong urban LV network based microgrid. However, the effect of the R/X-ratio value of LV network feeder lines was also considered in most of the simulations. Therefore, the proposed technical solutions can be generalized also to weaker LV networks with overhead lines. The main difference in weaker networks with higher R/X -ratio feeders was that they were found to be more sensitive for voltage fluctuations and the requirements for the DER unit control system stability and accuracy were also higher.

Before it is feasible to optimize the components and control of converter based DER units, specified grid codes are needed to state what kind of behavior is expected from them. This behavior must also be compatible with the LV microgrid management and protection system. In the developed protection system for LV microgrids in this thesis, exact voltage and time values for the protection curve of DER units (PD 4) with FRT capability were defined as part of the protection system and it was stated that the fault current fed by converter based DER units during faults in island operated LV microgrids is recommended to be active instead of reactive, if possible. In addition, it was stated that from the new LV microgrid protection system's point of view it is enough if converter based DER units can feed two times their nominal current during faults in LV microgrid for the required time. It was also found in Publication VI that DER units with very high fault current feeding capability at household customer may require directional OC protection and high-speed communication to be used as part of customer protection (PD 3a) to always ensure the selectivity of protection during island operation. Otherwise the DER unit should be connected directly to the corresponding LV feeder. Due to above mentioned issues it is absolutely necessary to predefine the expected fault behavior and connection type of future

LV microgrid compatible DER units together with the proposed protection system.

To ensure that LV microgrids could be a natural part of future smart grids choices for the proposed total technical LV microgrid concept were made so that they can also be justified by the needs of the normal utility grid connected operation. The role of one central, grid-forming, energy storage unit and the location of it is very important from the point of view of the LV microgrid management and protection. For example the connection of the central energy storage unit at MV/LV distribution substation enables the LV microgrid participation into the MV feeder voltage control during normal utility grid connected operation as well as the utilization of the power quality compensator based energy storage concept. In addition, during island operation it is important from the point of view of the protection selectivity that large share of the fault current is coming from determined direction i.e. from the central storage unit. To further ensure the correct operation of the protection during island operation, large DG units should be connected either directly or with own LV feeders to the MV/LV distribution substation. Such a DG unit connection is also beneficial for microgrid customers when the DG unit is heat producing CHP unit, because it will always remain connected regardless of possible faults on other LV feeders.

It has been proposed in this thesis that instead of adding on-load-tap-changers to MV/LV distribution transformers, the central energy storage at MV/LV distribution substation could actively manage the voltage level of LV microgrid during normal operation. Also through co-ordinated management by microgrid management system, the central energy storage could take part in the MV feeder voltage control together with controllable DER units and dispatchable loads. The usage of central energy storage unit for active voltage control enables more DG capacity to be connected in LV networks as well as better capacity utilization of existing LV network lines. This means that energy efficiency of electricity distribution in LV networks could also be improved. In future smart grids, the local service markets are one possibility to implement these functions in reality. However, participation of LV microgrid to active management of MV feeder voltage control can be restricted by the limits which ensure that successful transition to island operation is possible.

The developed technical solutions and findings for the total LV microgrid concept presented in this thesis can be utilized as basis when grid codes for future low-voltage microgrids and plans for real-life pilot installations are carried out. The proposed technical choices as well as operation and planning principles of the developed LV microgrid concept can also be taken into account in the development of LV microgrid compatible protection devices (PDs), DER units, microgrid management systems and future market structures. The protection principles and operation strategies developed in this thesis for LV microgrids were based on a hierarchical centralized architecture. In the future possible utilization of multi-agent based, adaptive, distributed architectures for LV microgrid protection and management could also be studied.

The work done in this thesis with the developed PSCAD models provides a very good basis for the further LV microgrid protection and power quality studies. In the future some details of these models could be further developed, but it is not likely that this development would have any effect on the validity of the technical solutions proposed in this thesis. In power quality studies, very accurate DER unit models including all the converter switching actions were necessary. But in the future it could be more feasible to use more generalized models in protection analysis to reduce the required simulation time. Some comparative studies with other simulation tools could also be done in the future when the control systems of the DER units are further developed and verified with real-life measurements. In addition, for example the further development and simulation of different possible voltage control strategies is more sensible to carry out with other type of simulation tools.

In the future it is absolutely necessary to develop regulations, standards and grid codes for microgrids and island operation. It is also important to further determine and develop market structures and business models for future smart grids parallel with the development of technical solutions. In this thesis it has been proposed that the future smart grid concept needs to be operated hierarchically with microgrids as building-blocks to achieve the main targets of different stakeholders i.e. society, DSOs and customers that can be defined as:

1. Improved energy efficiency through full exploitation of existing network capacity with co-ordinated and intelligent control of active resources (mainly controllable DER units) by DMS and MMS and
2. Improved power quality including reliability and voltage quality.

To fulfill these targets smart grid concept should

- Always fulfill technical boundaries (e.g. related to protection and voltage level and quality) in energy efficient and sustainable way,
- Have local retail market participation possibility for DER units which however may in some cases be limited by technical boundaries, and
- Have local technical service markets, mainly for voltage control purposes, to stay between technical boundaries.

Realization of targets to improve energy efficiency and reliability will require new market structures and business models for smart grids to be developed which can take into account the properties of DER and possible island operation as well as enable or support the operation of microgrids as part of active management of smart grids. New market structures should take into account the benefit of electricity production with DG units near the consumption and the use of DER in active management of distribution networks (i.e. energy efficiency aspect and matching principle). The customers should benefit from using energy produced by the local DG when compared to the customers supplied from the utility grid source.

Simultaneous operation of LV microgrid central energy storage units, DER units and loads as part of smart grid voltage control (local technical service markets) as well as part of future energy markets seems to be a difficult task to be realized, because these two markets have so large impact on each other due to technical characteristics of LV networks. Because of the strong active power and voltage dependency in LV networks, the active power increase of DG units or discharging of energy storages units should be included only in energy markets, not on the local technical service markets.

One possibility in future market structure could be that energy storages are owned by third party, other than DSOs, and they will participate in future energy markets by active power production (discharging) and in the active voltage control of distribution networks through local technical service markets. DSOs will pay compensation through technical service markets for DER units from their reactive and/or active power control as part of distribution network active voltage level management. It is also important that compensation paid in the local technical service markets from voltage control through active or reactive power feeding or absorbing of some market player needs to be based on the realized effect on local voltage level, not just on the amount of active or reactive power produced or absorbed.

Simultaneously, as part of new market structures, new business models for DSOs needs to be developed. Required future regulation could allow for example service level differentiation based DUoS charging. Service level could be differentiated in terms of power and voltage quality e.g. into A, B, C classes to sell different power quality for different prices. In the service level differentiation of customers also the penalty structure considering compensations from poor power quality (presently usually based on supply interruption times) should be differentiated. At least, all the second generation smart energy meters or AMM devices will be capable of measuring and keeping record of the deviations in the power quality of all customers and therefore the service level realization can be verified.

In Figure 62 some framework for future smart grid market model is presented based on above mentioned issues. The presented framework model takes fairly into account the benefits of DER. Therefore, the need for other financial support structures such as feed-in-tariffs for renewable energy sources could possibly be reduced.

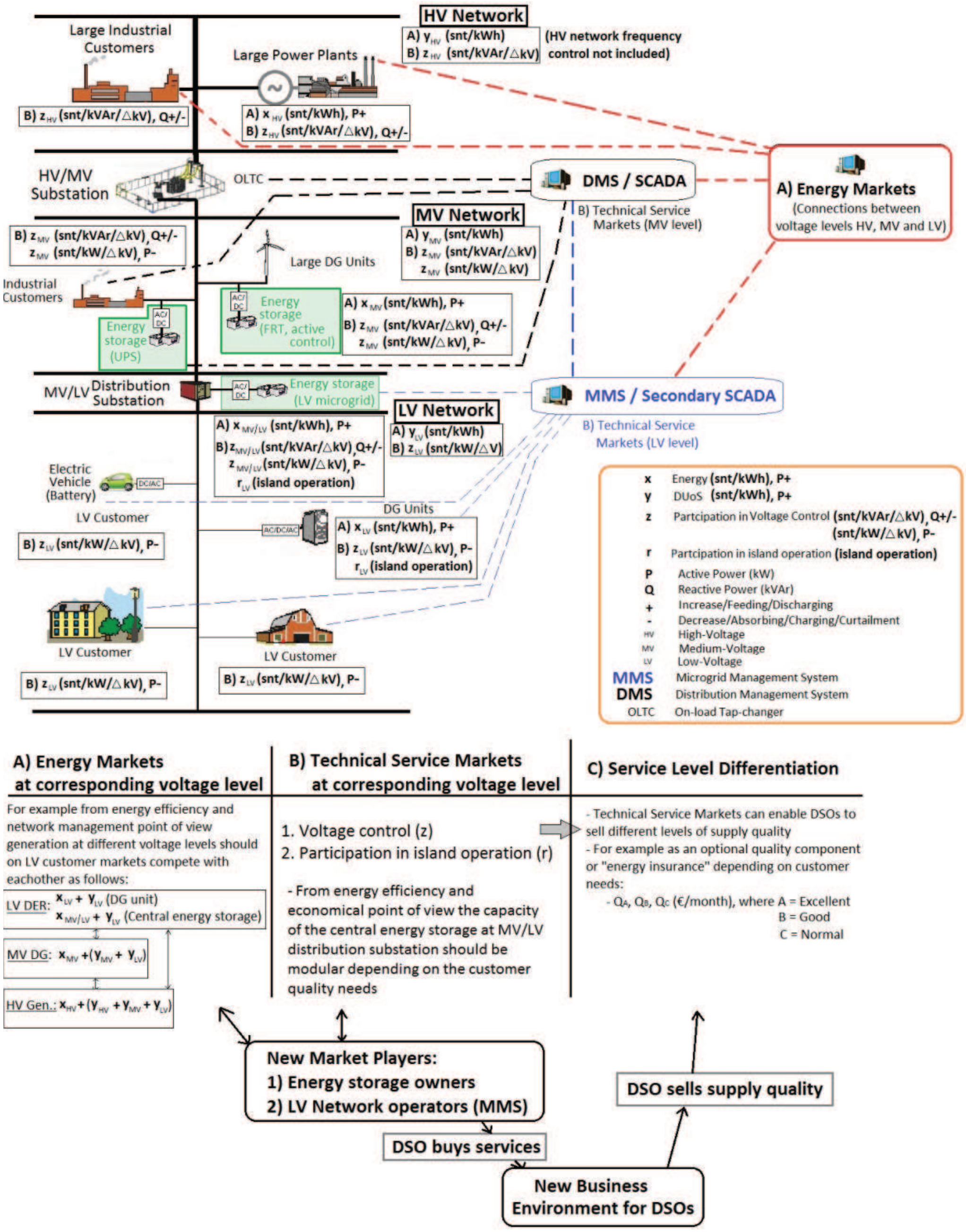


Figure 62. Framework for the future new smart grid market model studies.

In the development of future market and business models for smart grids it is essential to always keep in mind the influence of the technical choices to the restrictions that they can make to the corresponding market model. Therefore, real example cases are also important in the future to verify and test the functionality of the developed technical solutions for LV microgrids and smart grids.

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Published by International Science Press

VOLTAGE AND FREQUENCY CONTROL OF LOW VOLTAGE MICROGRID WITH CONVERTER BASED DG UNITS

Hannu Laaksonen & Kimmo Kauhaniemi
University of Vaasa, P. O. Box 700, FI-65101 Vaasa, Finland

This paper studies voltage and frequency control of an islanded low voltage (LV) microgrid after islanding in power balance or unbalance with different DG unit configurations and line impedances. In conventional power systems the system frequency is related with the rotor speed of the directly grid connected large synchronous generators and power unbalance can be seen as changing system frequency. But in an islanded microgrid it is possible that all generation units are connected to grid via converters and there is no inertia of rotating masses to affect the frequency. In this case the frequency has to be produced by a power electronic device and the frequency is more of less fixed and power unbalance cannot be detected in the traditional way. The studied low voltage (LV) network based microgrid consists of three converters and one synchronous generator based distributed generation (DG) units. In this case the battery converter with rapid response is considered to act as a master and it has the main responsibility to control the voltage and frequency in microgrid when islanded from the utility grid. Simulation studies show the voltage - active power and frequency - reactive power dependency in LV network, master unit control strategy for different cases and factors affecting the stability of an islanded microgrid. The studies are made with PSCAD simulation software.

1. INTRODUCTION

Microgrids can be defined as distribution systems with DG units, energy storages and controllable loads, which can be operated either in interconnected mode, which means that the microgrid operates in parallel with the distribution grid, or in islanded mode, where the connection to the utility grid is switched off. Transition to islanded mode may take place due to faults or intentional switching events. The advantage for the grid is that microgrid can be seen as a single dispatchable load and from the customer point of view, microgrid meets local needs for power and improves local reliability and power quality. Transition between the interconnected and the islanding mode is crucial for uninterrupted continuity of supply, but also during reconnection the issue of out-of phase reclosing needs careful examination. [1], [2], [3]

The following technical issues has to be solved for realizing the future microgrid [3]: 1) Power and energy balance in the microgrid, 2) Power quality improvement (limitation of harmonic distortion), 3) All protection devices in the grid should remain working or a new protection system has to be introduced.

In this paper the control of voltage and frequency of an islanded microgrid is studied. The studied low voltage (LV) network based microgrid consists of three converters and one synchronous generator (SG) based distributed generation (DG) units. In this case a battery converter with rapid response is considered to act as a master and it has the main responsibility to control the voltage and frequency in the microgrid when islanded from the utility grid. The load in the microgrid consists of eight passive loads.

In CERTS Microgrid [4] different kind of concept is used where each microsource can seamlessly balance the power on the islanded microgrid using a power (P) vs. frequency droop and a voltage vs. reactive power (Q) droop controller. There are no components in CERTS microgrid, such as a master controller or central storage unit that is critical for operation of the microgrid [4]. CERTS kind of concept is also used during parallel operation of DG unit converters with selfsync^{TM} control which is based on P/f- and Q/V-droops [5], [6].

To conduct the studies, a test system is defined and the corresponding PSCAD based digital computer simulation model is developed. Some parts from a model library created previously in a joint

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project between University of Vaasa and VTT are used in the studied simulation model. Simulations are made to find out suitable converter control strategy and configuration, especially for master unit, which ensures microgrid stability in different cases. Also the factors affecting the stability of an islanded microgrid are studied more extensively than in our previous studies [7]. In this paper the stability margins of converter controllers are not considered, which requires modelling and simulation in frequency domain using MATLAB.

Section II of the paper discusses briefly about (a) voltage and frequency control in high voltage (HV) and low voltage (LV) network with active and reactive power and (b) power system stability both in traditional case with rotating machines and in microgrid case with converter connected units. Section III introduces the test system. Simulation results of the study and discussions are reported in Section IV. Conclusions are stated in Section V.

2. VOLTAGE AND FREQUENCY CONTROL

2.1 Active and Reactive Power Flow in Network - Theory

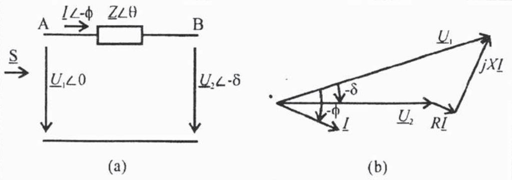
Active and reactive power flowing into the line at point A as represented in Fig. 1 can be described with following equations (1) and (2). [8], [9]

$$P = \frac{U_1}{R^2 + X^2}\left[R \cdot (U_1 - U_2 \cdot \cos\delta) + X \cdot U_2 \cdot \sin\delta\right] \quad (1)$$

$$Q = \frac{U_1}{R^2 + X^2}\left[-R \cdot U_2 \cdot \sin\delta + X \cdot (U_1 - U_2 \cdot \cos\delta)\right] \quad (2)$$

HV Transmission Lines

With HV transmission lines where X>>R, the resistance R may be neglected. If the power angle δ is also small, then *sin*(δ) = δ and *cos*(δ) = 1. Hence equations (1) and (2) are reduced to equations (3) and (4):



(a) (b)

Figure 1: (a) Power Flow Through a Line, (b) Phasor Diagram [8]

$$P \cong \frac{U_1 \cdot U_2}{X}\delta \quad (3)$$

$$Q \cong \frac{U_1^2}{X} - \frac{U_1 \cdot U_2}{X} \quad (4)$$

From equations (3) and (4) it can be seen that for lines where X>>R with small power angle δ and small voltage difference U_1-U_2, the active power *P* depends mainly on power angle δ and reactive power *Q* depends mainly on voltage difference U_1-U_2. The control of frequency *f* dynamically controls the power angle δ and consequently also the active power *P* or, in other words, the control of active power *P* directly controls the power angle δ and thus the frequency *f*. While the control of reactive power *Q* directly controls the voltage *U* (e.g. terminal voltage of a DG unit U_1). [8], [9]

LV Distribution Lines

The microgrid can be based just on mainly resistive (R>>X) LV distribution network lines. Therefore the above mentioned control principles of frequency and voltage in HV network are not functional in LV network based microgrid. Table 1 shows typical line parameters for LV, MV and HV lines.

Table 1
Typical Line Parameters [5]

Type of Line	*R (Ω/km)*	*X (Ω/km)*	*R/X*
Low voltage line	0.642	0.083	7.7
Medium voltage line	0.161	0.190	0.85
High voltage line	0.060	0.191	0.31

Simplifications made in forming equations (3) and (4) from (1) and (2) are therefore not valid in LV networks. Instead equations (1) and (2) are reduced in LV network where *R*>>*X* to (5) and (6) by neglecting reactance X and assuming that the power angle δ is small, then *sin*(δ)=δ and *cos*(δ)=*1*. [10]

$$P \cong \frac{U_1^2}{R} - \frac{U_1 \cdot U_2}{R} \quad (5)$$

$$Q \cong -\frac{U_1 \cdot U_2}{R}\delta \quad (6)$$

From equations (5) and (6) it can be seen that for lines where R>>X with small power angle δ and small voltage difference U_1-U_2, the active power *P* depends mainly on voltage difference U_1-U_2, while the power angle δ and thus also the frequency *f* depends mainly on reactive power *Q*. Because of this the traditional frequency droop control through active power and voltage droop control through reactive power, used in higher voltage levels, will not function very well on *LV* network based microgrid. Instead, the voltage control should be implemented through active power and frequency control through reactive power production/consumption in a converter and *LV* network based islanded microgrid. The control in *LV* network could be executed with linear *PU*- and *Qf*-droops. This kind of droops (partially non-linear) has also been presented in reference [10].

2.2 Stability of Traditional Power Systems with Rotating Machines vs. Microgrid with Converter Based DG Units

This section is devoted to the discussion of some differences between different kind of generators (synchronous machines and converter connected units) and their characteristics in terms of frequency and control stability.

Traditional Power Systems with Rotating Machines

Large centralized synchronous generators are directly connected to the grid in traditional power systems and so there is a strong relationship between the generator rotor speed, the system frequency, and the power balance in the system. The fundamental equation that governs the rotational dynamics of the synchronous generator is the swing equation [9], [11]:

$$\frac{2\cdot H}{\omega_s}\frac{d^2\delta}{dt^2} = P_m - P_e = P_m - P_{\max}\cdot\sin\delta = P_a[pu] \quad (7)$$

or

$$\frac{H}{\pi\cdot f}\frac{d^2\delta}{dt^2} = P_m - \frac{|E'||V|}{X_{trans}}\cdot\sin\delta = P_a[pu] \quad (8)$$

where, w_s is the synchronous speed in electrical units in rad/s, H is the inertia constant (the stored kinetic energy in MW at synchronous speed per machine rating in MVA), d is the angular displacement of the rotor in rad, P_m is the shaft power input less rotational losses in pu, P_e is the electrical power crossing the air gap in pu, P_a is the accelerating power, f is frequency, X_{trans} includes machine reactance X'_d and line reactance X_e when connected to infinite bus through it, and E′ and V are machine and infinite bus voltage values. It can be seen from equation (7), that any unbalance in active power ($P_m \neq P_e$) will result in non-zero accelerating power ($P_a \neq 0$), i.e. the rotor of the synchronous generators will either: accelerate $\left(\frac{d^2\delta}{dt^2} > 0\right)$ or decelerate $\left(\frac{d^2\delta}{dt^2} < 0\right)$. [12]

The inertia (H) of the synchronous machines plays a significant role in maintaining the stability of the power system during an occurrence of a power unbalance. From equation (7) we can see that, when the value of P_e alters (and P_m remains constant), a higher inertia constant (H) of the synchronous generator, causes less acceleration or deceleration of the generator rotor. [12]

Microgrid with Converter Based DG Units

The system frequency of a traditional power system is coupled with the rotor speed of the directly grid connected large synchronous generators. In these cases the power unbalance can be seen as a change in the system frequency. However, in an islanded microgrid it is possible that all generation units are connected to grid via converters and there is no inertia of rotating masses to affect the frequency. In this case the frequency has to be created by a power electronic device so that at least one unit creates a frequency reference for the other generators to synchronize with. Therefore the frequency control in a stand-alone power system with converter based units can be seen as an open-loop system [13]. The frequency is more of less fixed and power unbalance cannot be detected in the classical way. Power unbalance can be detected in this case from voltage changes.

Grid Synchronization

In normal grid connected operation DG unit converters are used as controlled current sources and they are synchronized with utility grid phase angle/frequency normally with Phase-Locked Loop (PLL) component. In this paper the PLL component of PSCAD is used to examine possible problems. In Figure 2 the traditional synchronous dq-frame PLL method is presented [14], [27].

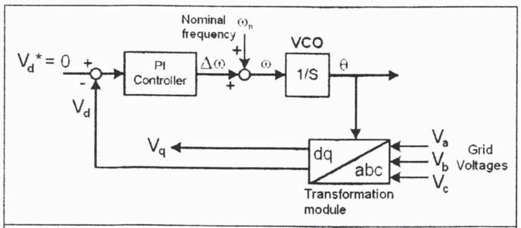


Figure 2: Control Diagram of a Traditional Synchronous *dq*-frame PLL [14]

Especially during faults, grid voltage unbalance or high harmonic distortion the traditional PLL component may fail with grid synchronization, if voltage negative sequence component is not filtered out from the PLL input signal. [14], [15] Paper [16] presents improved version of the synchronous d-q frame PLL by using positive and negative sequence decomposition method and paper [17] also proposes a multirate PLL to overcome synchronization problems related to very distorted utility network signals.

In an islanded microgrid where the voltage and frequency can not be set by the utility grid, at least one of the converters must control these quantities. This is usually in uninterruptible power supply (UPS) systems done with a frequency generator (crystal oscillator) in the controller to produce the 50 Hz frequency to microgrid. But also combined voltage and frequency control methods without this frequency generator have been proposed [4], [5], [6], [8], [18], because according to [5] fixed frequency and fixed voltage controlled converters cannot operate parallel due to possible differences between phase angles of converter crystals and tolerances of sensors. This has been taken into account in the concept studied in this paper, so that there is only one master unit (battery storage with converter) which determines the frequency in islanded microgrid and other converters synchronize their output to this frequency with their PLL-component. Thus no communication between master unit and other converters is needed for voltage and frequency control. However, if islanded, the microgrid is divided into protection zones and the communication between master unit and other DG unit converters may be necessary for protection purposes or for blackstart capability in case of serious stability problems in microgrid during islanding.

Converter Control Stability

Connection of converter interfaced DG units to distribution network can lead to grid instability if these converters are not properly controlled. Different control behavior needed under sudden changes, e.g. faults, and stricter standards have increased the interest in DG unit converter control issues. In overall power quality, grid synchronization and current controller are the main focus. [14]

Also large impedance variation depending on the grid, whether strong urban cable network or weak rural network, is a challenging task in normal operation for the control of DG unit converters and grid filter design in terms of stability. Impedance variation can lead to stability problems around the current controller bandwidth frequency as well as around the LCL-filter resonance frequency. [19] In addition, converter control parameters should be such that they work both in normal and island operation, were grid impedances also differ largely from each other, or they must be adaptive. Proper selection of converter sampling frequency is also essential for system stability [20].

If DG unit converters are connected in a modular way to a common bus before connection to the utility grid or microgrid, the converter control can be done by distributing the control between a central controller and local controllers of each converter through a low-bandwidth communication link instead of typical master-slave control. With this kind of control method circulating currents flowing between converter units can be avoided and higher power quality in a microgrid can be provided [21]. Wireless-control strategies for parallel operation of DG unit converters have also been proposed in [22], where the active and reactive power control through the analysis of the output impedance of the converters and the impact of it to power sharing between converters are explored.

Syncronized Reconnection

Microgrid synchronized reconnection to utility grid means that the voltage angle difference between utility grid and microgrid should be minimized before reconnection. This is not a significant issue when converter based DG units with PLL-component are considered, because PLL will "draw" converters into phase with the utility grid frequency after reconnection. However DG units with traditional synchronous generator interface cannot deal with major phase difference during microgrid reconnection without losing rotor angle stability. Therefore master unit of microgrid should create the frequency reference in microgrid so that it is as close as possible to utility grid phase. Otherwise, the SG based DG units must be first disconnected from the grid during microgrid reconnection and after that they can be connected back to grid in synchronism with utility grid frequency. One way to help resynchronization of microgrid to utility grid frequency during reconnection is presented in paper [23].

3. STUDY SYSTEM

3.1 Studied LV Network Based Microgrid

The LV network used in this work is shown in Figure 3. The system consists of one 800 kVA MV/

LV-transformer which normally feeds LV feeders 1_1 and 1_2. In the simulation studies the islanded microgrid is disconnected from main network by the breaker so that the microgrid consists of feeders 1_1 and 1_2 (Figure 3). At the beginning of the feeder 1_1 there is a storage unit (battery 120 kVA) equipped with converter 1 and L-/LCL-filter. At the end of feeder 1_1 there is a DG Unit 1 (120 kVA) equipped with converter 3 and L-/LCL-filter. In front-end of the feeder 1_2 there is a synchronous generator (100 kVA) and at the end of the feeder there is also DG Unit 2 (120 kVA) equipped with converter 2 and L-/LCL-filter.

The load in the microgrid consists of four passive loads on each feeder. The passive loads can be adjusted so that the loading of the transformer (which feeds LV feeders 1_1 and 1_2) gets some desired value between 0...150% of the transformer ratings. For comparison purposes the simulations are done with and without SG. Initially loading of the transformer was set to 33% without SG (power factor 0.97_{ind}) and to 45% with SG (power factor 0.98_{ind}). During islanding load is increased suddenly from 33% to 38% without SG and from 45% to 50% with SG to study converter control and microgrid stability. Simulations are made with different LV network line parameters. Line parameters with lower (strong LV network, AXMK 4x185S) and higher (weak LV network, AMKA 3x35+50) R/X -ratio of the line used in LV network under study (Figure 3) are shown in Table 2. The fault level and R/X-ratio of the feeding utility network (20 kV, 50 Hz) are 200 MVA and 0.1 respectively.

Two different converter modulation methods, pulse width modulation (PWM) and space vector modulation (SVM) of DG units are simulated and compared with different size of L-/LCL-filter parameters and switching frequencies. Converter control system and strategy used especially for the master unit are explained in Section III.B in more detail. The dc-link voltage V_{DC} of converters is chosen to be 0.65 kV and dc-link is modeled as a) constant dc-voltage source or b) battery storage + DC/DC-buck-boost converter. The converters are modeled as three-phase, three-leg units with L-/LCL-filters. Converters are also modeled without neutral connection, i.e. Delta/Wye grounded transformer, because loads are by default symmetrical in all phases and safety issues are not considered in this paper. Further details about the study system components (L- or LCL-filters) are listed in Appendix.

Table 2
Resistance, Reactance and R/X Ratio of LV Network in Figure 3

	R (Ω/km)	X (Ω/km)	R/X
AXMK 4x185S	0.164	0.0817	2.01
AMKA 3x35+50	0.868	0.104	8.35

3.2 Converter Control System

During islanding, microgrid is operated in single master operation mode, which in this case means that the converter 1 with battery storage will act as the master unit and it has the main responsibility to control the voltage and frequency in microgrid when

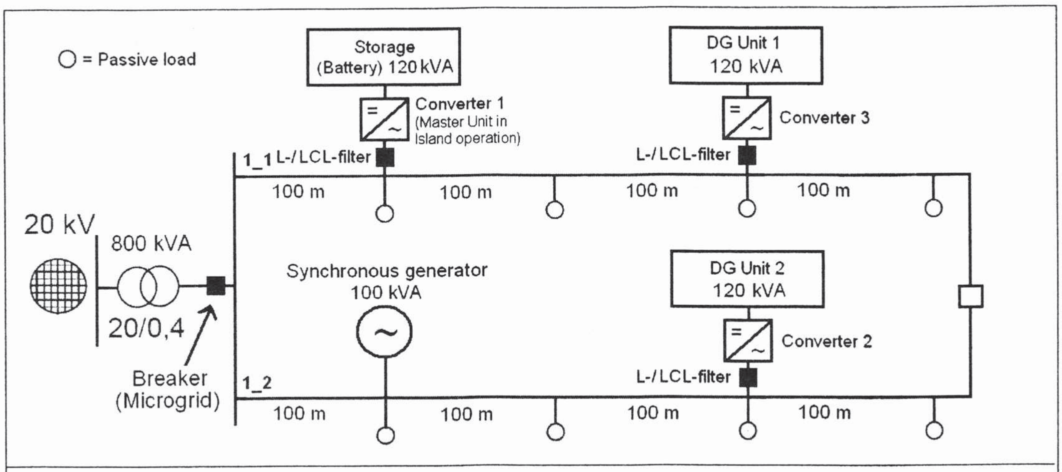
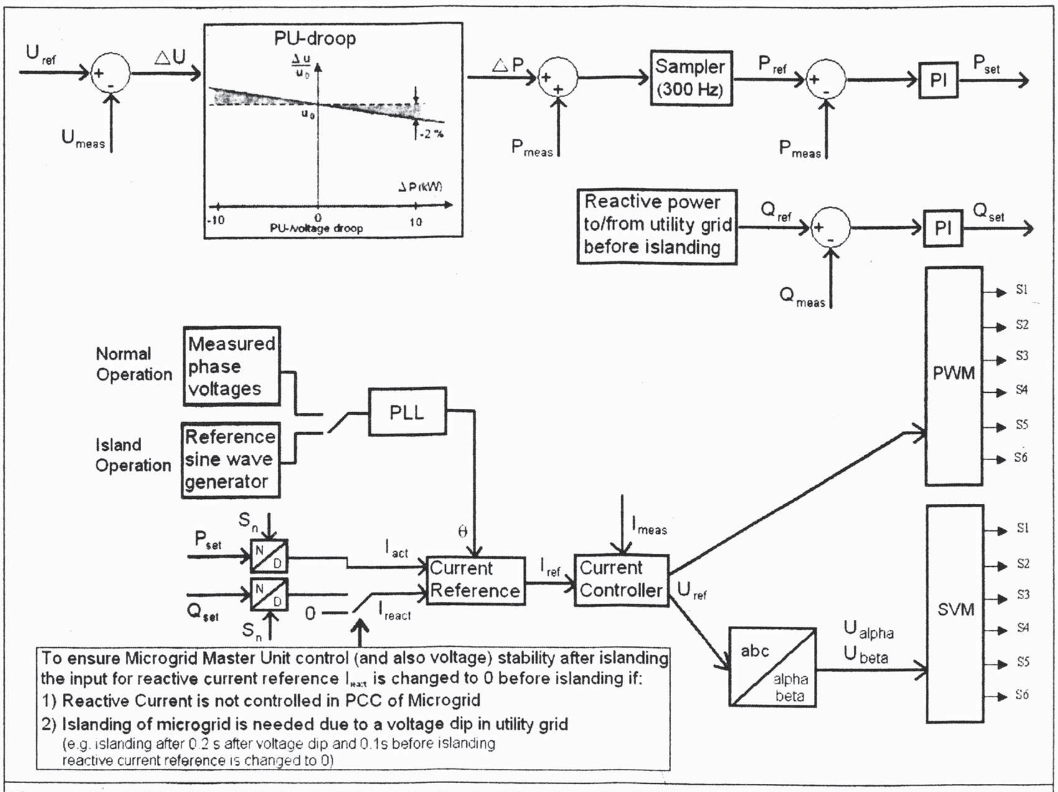


Figure 3: Studied LV Network Based Microgrid

islanded. All the other DG units can then be operated in conventional PQ mode i.e. they do neither take part in frequency nor voltage control. The control system for master unit (Battery storage) converter 1 in island operation is shown in Figure 4. The application of PU-droop for voltage control during islanding used in the simulation studies is also presented in this Figure. Converter 1 (master unit) also controls the frequency of microgrid by having the input for Phase-Locked Loop, PLL, during islanding from the 50 Hz 3-phase reference sine wave generator (Figure 4) i.e. the master unit determines the synchronism of the microgrid.

The reactive power control of master unit means that if there is a reactive power unbalance during islanding of microgrid and other DG units will not change their reactive power production after islanding, then the master unit must produce the reactive power needed. Therefore, from the stability point of view it may be convenient to pass the reactive power control of master unit and change reactive power reference to constant value zero. Because when the master unit at the same time produces the frequency reference for microgrid then the required phase difference between current and voltage for reactive power production will settle to the desired value. When reactive power reference input is zero, the required amount of reactive power for microgrid loads will be automatically produced by master unit.

Simulations also confirmed that in case of a voltage dip in the utility grid before islanding (Figure 4), the reactive power reference of the master unit converter must be changed to zero just before or during islanding. Otherwise voltage dip can cause a momentary power unbalance in microgrid if active power decreases at the same time and it will lead to instability of converter active and reactive power control (overvoltage). To avoid this, the master unit active power reference should always be kept zero before islanding as well.



To ensure Microgrid Master Unit control (and also voltage) stability after islanding the input for reactive current reference I_{react} is changed to 0 before islanding if:

1) Reactive Current is not controlled in PCC of Microgrid
2) Islanding of microgrid is needed due to a voltage dip in utility grid (e.g. islanding after 0.2 s after voltage dip and 0.1s before islanding reactive current reference is changed to 0)

Figure 4: Control System of Master Unit Converter During Islanding with PWM or SVM Modulation

The current PI-controller parameters are similar between converters depending on the modulation method (PWM/SVM). Active and reactive power controller parameters are also similar between converters 2 and 3, but different with master unit converter 1 which was discussed above (Figure 4). Details about the PI-controller parameters of the converter control system can be found in Appendix.

An important fact in considering the stability of the current control loop is related to the point where the current (I_{meas}) is measured. In the converter simulation models used in this study, the current (I_{meas}) is sensed after the converter side inductance of the L- and LCL-filter (Figure 5), because generally the current sensing from the grid side improves the stability margin of the system, but on the other hand the use of an LCL-filter makes the current control to be unstable if a proper damping is not used [24]. From Figure 5 it can be seen that phase voltages (V_{meas}) are measured for the PLL- component from the grid side of the LCL-filter which is also the case with L-filter. With converters 2 and 3, the input signals for PLL-component are filtered with band-pass filters.

LCL-filter parameter design can be made on a different basis and some principles can be found from references [25] and [26]. In this paper LCL-filter parameters for PWM modulated converters have been chosen so that grid side inductance L_2 is $0.5 \times L_1$ (converter side inductance). But for comparison purposes the LCL-filter parameters for SVM modulated converters have been chosen differently to study possible effects on voltage THD and stability. One important issue related to LCL-filter design is also the resonant frequencies which should be always considered when LCL-filter parameters are chosen. In addition it is worth mentioning that in the simulations of this paper the same LCL-filters have been used with different converter switching frequencies (8 or 4 kHz).

The simulation model of the converter based DG unit with battery storage + DC/DC-buck-boost converter modelled as a dc source in dc-link is shown in Figure 6. PI-controller parameters of the dc-dc converter control system are presented in Appendix.

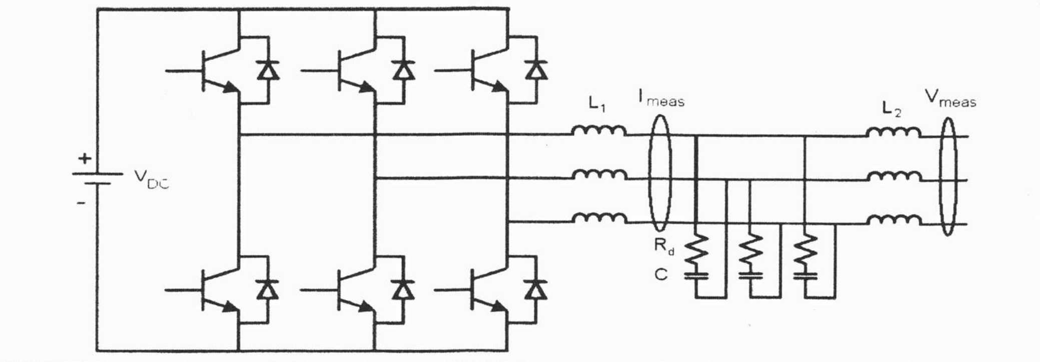


Figure 5: Current and Voltage Measurement Points for LCL-filter Equipped Converter Control System

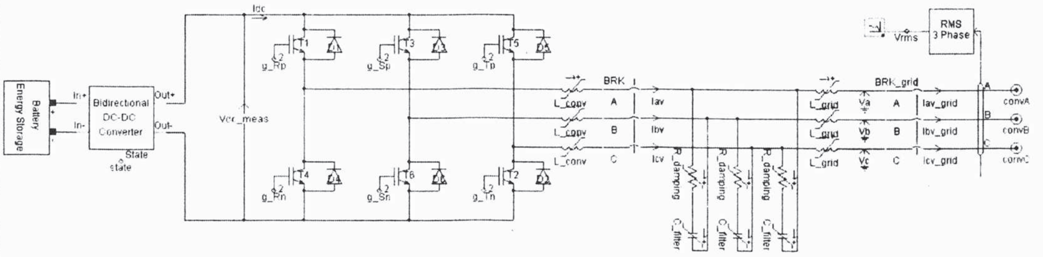


Figure 6: PSCAD Simulation Model of the Converter based DG unit with Battery Storage + DC/DC-buck-boost Converter Modelled as a dc source in dc-link.

4. SIMULATION RESULTS

Simulation studies in this paper are made to examine the voltage and frequency control stability of an islanded low voltage (LV) microgrid after islanding in power balance or unbalance with different DG unit configurations and line impedances. In Section III.B the master unit control system which is developed based on simulations was presented. Eight different cases simulated in Section IV.A of this paper are presented in Table 3. All these cases were also simulated with eight different variants shown in Table 4. So the total number of simulations done was 72. In Section IV.B simulation results about islanding after 30 % voltage dip and 3-phase fault at MV network are presented. In all simulations islanding occurs at the time of 5s, load increase at 10s and microgrid reconnection to utility grid at 15 s. The number of considered harmonics to calculate the voltage THD (%) is 255. Channel plot step is 300 μs in all the other figures than in Figure 9 where the plot step is 150 μs.

Table 3
Simulated Cases

Case	*Filter Type of Converters*	*Switching Frequency of Converters*	*DC-link of Converters*	*Freq. reference*
1.*	L	8 kHz	A	NM
2.*	L	8 kHz	A	SM
3.*	LCL	8 kHz	A	NM
4.*	LCL	8 kHz	A	SM
5.*	L	4 kHz	A	SM
6.*	LCL	4 kHz	A	SM
7.**	LCL	8 kHz	A	SM
8.***	LCL	8 kHz	A	SM
9.**	LCL	8 kHz	B	SM
10.***	LCL	8 kHz	B	SM

* Islanding in Active and Reactive Power Balance,
** Islanding in Active Power Unbalance and Reactive Power Balance,
*** Islanding in Active and Reactive Power Unbalance, NM = No Master / Frequency reference, SM = Single Master/ Frequency reference, A = Constant DCsource, B = Battery storage + DC/DC-buck-boost converter

Table 4
Case Variants

Case Variant	*Modulation Method of Converters*	*R/X -ratio of LV Network*	*Synchronous Generator (SG)*
a	PWM	Low	Yes
b	PWM	Low	No
c	PWM	High	Yes
d	PWM	High	No
e	SVM	Low	Yes
f	SVM	Low	No
g	SVM	High	Yes
h	SVM	High	No

4.1 Microgrid Stability After Islanding in Different Cases

Frequency Stability

In all cases without frequency reference created by master unit (i.e. No Master cases) frequency differs from 50 Hz, but from Figure 7 it can be seen that in different cases the frequency settles down to different values. The deviation can be very large or quite small from nominal 50 Hz and load increase can again result in a new value for frequency. This is a result from the different behaviour of the PI-controller inside the PLL component. The upper and lower limits of the integrator in the PLL component are chosen so that they are ±10 Hz from the nominal 50 Hz frequency. Also the settings of the PI-controller of PLL (Appendix) determines the rate of change of frequency after islanding.

In Figure 8 microgrid frequency damping is shown in four different cases after islanding with

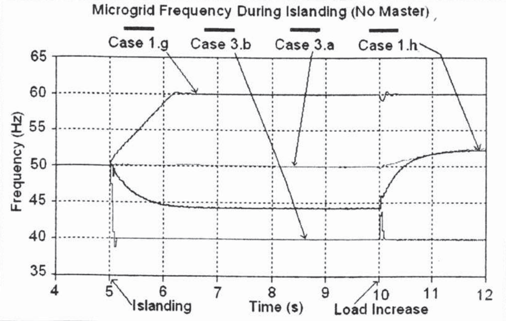


Figure 7: **Microgrid Frequency During Islanding and Load Increase Without Frequency Reference Created by Master Unit in Four Different Cases**

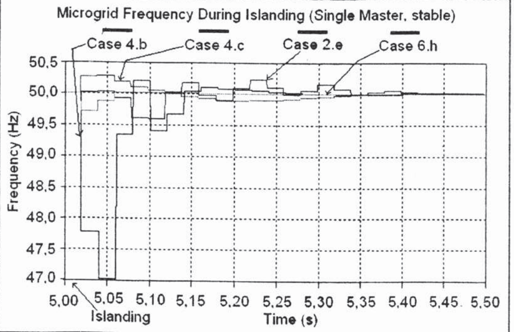


Figure 8: **Microgrid Frequency During Islanding with Frequency Reference Created by Master Unit (i.e Single Master) in Four Stable Cases**

frequency reference created by master unit. In general the damping times are a bit longer with SG, but the magnitude of first frequency oscillations after islanding can be quite high in some cases without SG. Total frequency damping times are a bit longer with higher R/X-ratio when compared to cases with SG. Without SG the frequency stabilization time was not affected by LV network R/X-ratio.

In case 4.d the frequency was marginally stable before load increase during islanding and stable after load increase, but when sampler frequency (Figure4) was changed from 300 to 500 Hz then it was stable before and after load increase. This indicates that the sampling rate of sampler in converter controls system can also have an impact on stability.

In Figure 9 cases 5.b, 5.d, 5.f and 5.h with frequency instability problems (in addition to cases 1 and 3 without frequency reference i.e no master unit) are shown. All these cases are without SG and switching frequency of converters with L-filters is 4 kHz. PLL fails with synchronization even though input signals for PLL are filtered with converters 2 and 3. The same instability problems were found also without filtering the PLL input voltages. But the possible reason for this can be high voltage THD in microgrid which is shown in Table 5 (cases x.b/f), even though the difference in voltage THD during normal operation is not very different between cases 5.b/f and 2.b/f. In case 5.h with SVM modulation, high R/X-ratio and no SG the frequency stability is maintained until load is increased in microgrid. In cases with SG the resistive loading of microgrid is also higher and so voltage THD (cases x.a/e in Table 5) is lower in all cases (especially in cases were converters are equipped with L-filters) which together with the presence of SG affects in case 5.a/e so that it remains stable after islanding. When line R/X-ratio is increased from 2 to 8.35 the voltage THD increases in all cases x.d/h in Table 5. The effect of SG to voltage THD in cases x.c/g (not shown in Table 5) is similar as in cases x.a/e.

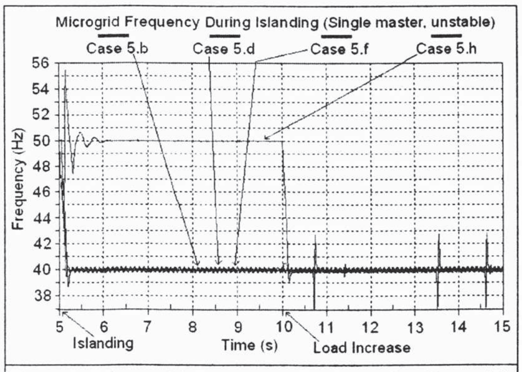


Figure 9: Microgrid Frequency During Islanding with Frequency Reference Created by Master Unit in Unstable Cases 5.b, 5.d, 5.f and 5.h

The phase voltages before and after islanding are presented in Figure 10 from cases 2.f, 5.f, 4.b and 9.b. In cases 2.f and 5.f the DG unit are equipped with L-filters which leads to high voltage THD after islanding (see also Table 5) and in case 5.f with lower switching frequency on converters the frequency stability is lost due to PLL failing with synchronization when the voltage THD is even higher than in case 2.f. In cases 4.b and 9.b the LCL-filters are used and the only difference between these cases is the dc-link modelling method (Figure 10). From Figure 10 and Table 5 can be seen that the voltage THD is very small with LCL-filter and even smaller when in case 9.b where DC-link is modelled with battery storage + DC/DC-buck-boost converter.

From Table 5 can be seen that the voltage THD is lower in all cases (9a., b., e. and f.) with DC-link modelled with battery storage + DC/DC-buck-boost converter than in similar cases (4a., b., e. and f.) where DC-link is modelled as constant DC source. One should also notice that the modelling method of DC-link does not affect the stability if DC-DC converter is controlled appropriately. In future stability studies also DG units with frequency converter interface should be examined especially through the DC-link behaviour under sudden events.

Table 5
Voltage THD (%) in PCC of Master Unit

	PWM			*SVM*	
	Before Islanding	*After Islanding*		*Before Islanding*	*After Islanding*
2.b	4.3	38.5	2.f	3.8	31.8
4.b	0.8	2.8	4.f	1.1	3.8
5.b	4.9	≈ 120	5.f	4.6	≈ 65
6.b	3.7	7.1	6.f	9.9	21.8
9.b	0.73	1.82	9.f	1.05	3.41
2.a	3.9	16.0	2.e	3.4	14.2
4.a	0.7	1.8	4.e	1.0	2.8
5.a	4.4	17.2	5.e	4.1	16.0
6.a	3.5	6.2	6.e	9.4	18.0
9.a	0.70	1.54	9.e	0.99	2.66
2.d	4.6	42.3	2.h	4.2	35.2
4.d	0.8	3.2	4.h	1.2	3.9
5.d	5.2	≈ 100	5.h	4.8	62.0
6.d	3.7	7.1	6.h	10.3	21.9

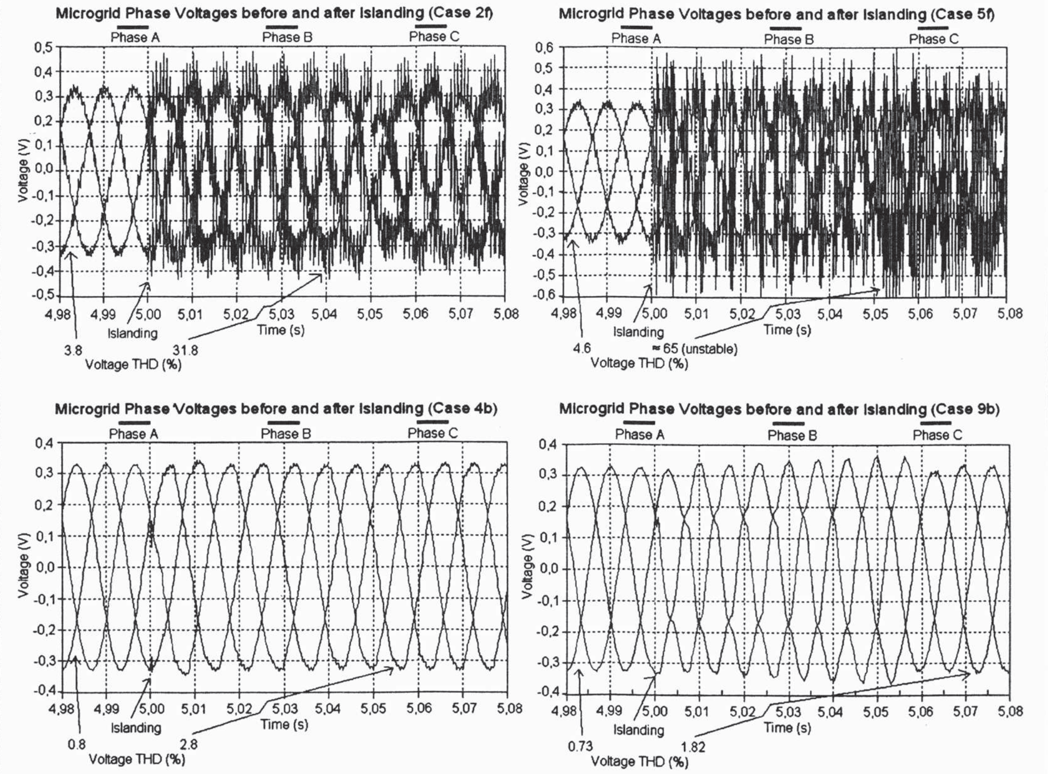


Figure 10: Microgrid Phase Voltages Before and After Islanding in Cases 2.f, 5.f, 4.b and 9.b

The relationship between frequency and rotor speed oscillations after sudden changes is presented in Figure 11 from case 8.a.

Voltage Control and Stability

The functionality of master unit converter control principles presented in Section III.B during islanding e.g. for voltage control in terms of real and reactive power production is shown in Figure 12 from case 8.a where islanding takes place under real and reactive power unbalance. Frequency behaviour of the same case was shown in Figure 11. The real power of master unit increases after load increase so that voltage remains at the reference value of 400 V and at the same time reactive power of it settles down to a new value, while there is no change in real and reactive power of other units.

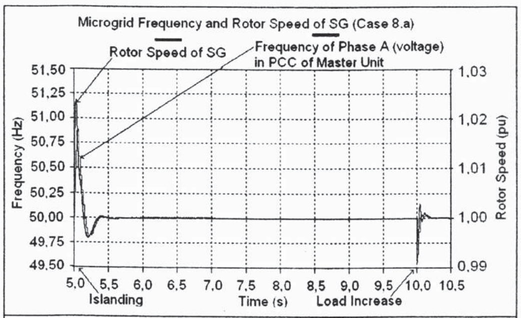


Figure 11: Islanded Microgrid Frequency and Rotor Speed of SG in Case 8.a

In cases with no master unit which are unstable in terms of frequency (cases 1 and 3), this instability is only seen from voltage rms values in cases 3.b and

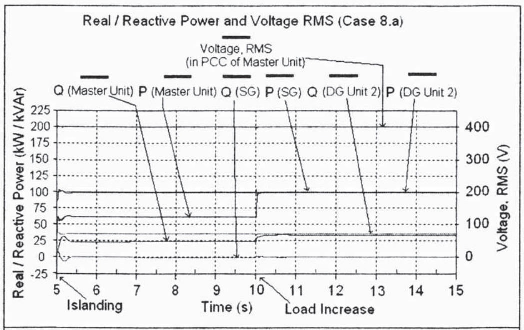


Figure 12: Real and Reactive Powers of DG Units and Voltage RMS Value of Master Unit during Islanding in Case 8.a

3.d. But cases 5.b, 5.d, 5.f and 5.h (Figure 13) where frequency was unstable are also unstable in voltage rms values (reference voltage rms value is 400 V). In general the voltage rms value damping times are also a bit longer with SG and with higher R/X-ratio when compared to cases with and without SG. The oscillation in the Figure 13 voltages is a result from the instability of the converter controllers during frequency instability (see also Figure 9).

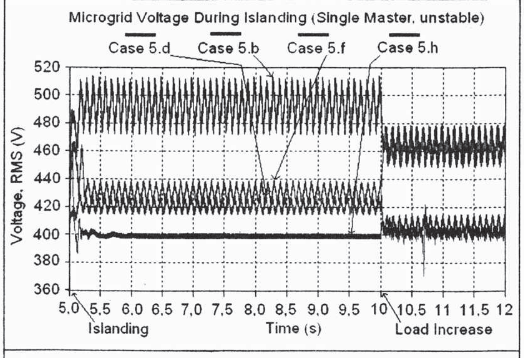


Figure 13: Microgrid Voltage During Islanding with Frequency Reference Created by Master Unit (i.e Single Master) in Unstable Cases 5.b, 5.d, 5.f and 5.h

4.2 Voltage Dip or 3-phase Fault Before Islanding

Simulation results in Figure 14 show how 30% symmetrical voltage dip at 0.2s or 3-phase fault in MV network at 0.1s before islanding affects the voltage and frequency stability in case 4.a. Voltage and frequency after 30% voltage dip will become stable in islanded microgrid, although the damping times are longer due to oscillations of SG. But due to 3-phase fault in MV network 0.1s before islanding, voltage dip is so deep that voltage and frequency will become unstable in islanded microgrid. Future studies need to examine whether the stability can be maintained if islanding occurs faster than 0.1s in case of serious voltage dips.

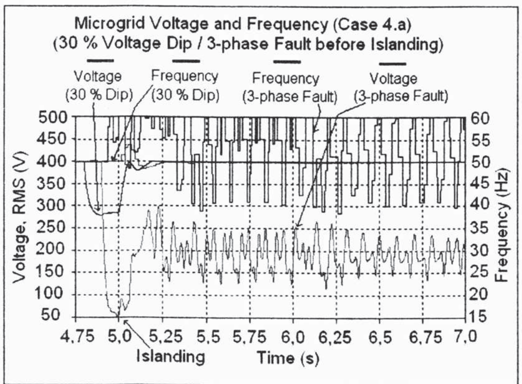


Figure 14: Microgrid Voltage and Frequency During Islanding with 30% Symmetrical Voltage Dip 0.2s or 3-phase Fault in MV Network 0.1s before Islanding in Case 4.a

Stable operation of SG requires stable operation of the converter control during sudden changes such as load increase. Furthermore, stable operation of the converter in islanded microgrid depends on the control circuits of it (e.g. PI-controller parameters) ability to stay stable during sudden changes in much weaker grid (than normally) with more harmonic distortion in voltage. If voltage THD increases too high in microgrid the frequency stability might be lost, although inertia of rotating machines can help converter controllers to stay stable because they will slow down the dynamics of different changes. And added to that, the harmonic distortion under stable operation depends upon the modulation method and switching frequency of the converter and also from the passive filter type and its sizing.

In Figure 15 some relationships and key issues affecting the stability of an islanded microgrid are summarized based on literature and simulation studies presented in this paper with PSCAD. The most challenging issue in terms of SG and DG unit converter control stability is the transfer of microgrid from normal to island operation (voltage dip magnitude and duration before islanding) and this subject needs further examinations.

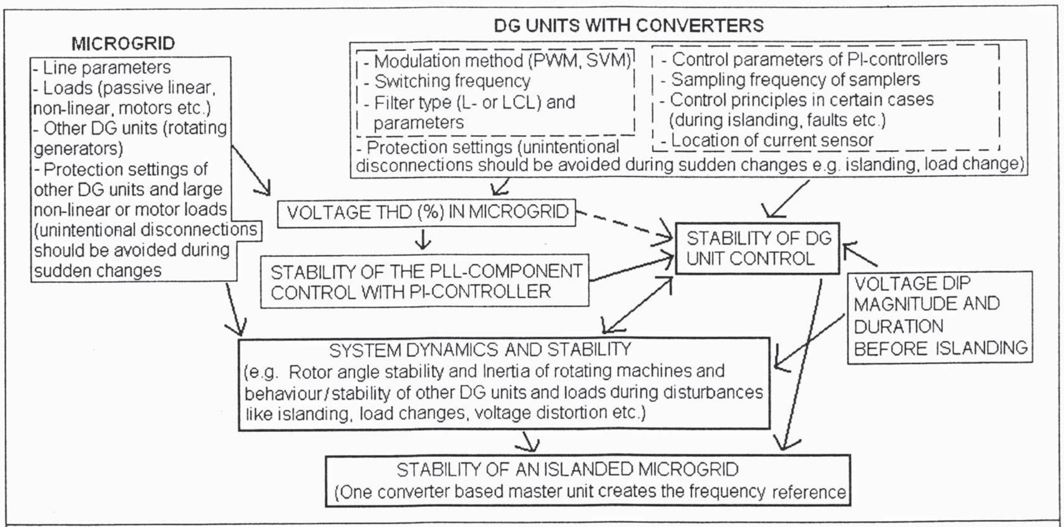


Figure 15:Relationships and Key Issues Affecting the Stability of An Islanded Microgrid

5. CONCLUSIONS

When studying the frequency stability of an islanded microgrid with converter connected DG units one have to be sure which stability problems are due to the converter controller instability and how these situations can be avoided, because in some cases highly distorted microgrid voltage leads to converter control problems which in turn can lead to frequency stability problems in microgrid. In the studies of this paper, normal DG unit converters do not have adaptive PI-controller settings between normal and island operation, but they should be able to ride-through the faults to stay connected to microgrid during the voltage dip before islanding.

Simulations showed how different converter modulation methods, switching frequencies and filter sizes affected the voltage quality (THD) and frequency stability in islanded microgrid after islanding during power balance or unbalance with different DG unit configurations and line impedances. The studies also confirmed the functionality of the developed master unit converter control principles to ensure frequency and voltage stability under different conditions before and during island operation. Based on simulations it can be concluded that the single master mode is enough to maintain the frequency and voltage stability in an islanded microgrid with traditional PLL if voltage THD can be kept small enough. It was also found that, if the voltage THD in the islanded microgrid is very high, the presence of a rotating machine can improve the stability of DG unit converter controllers and PLL components. In the end, most of the problems related to high voltage THD could be avoided on converter based DG units by using appropriate switching frequency and LCL-filters instead of L-filters. Future work regarding the microgrid frequency and voltage stability after islanding must consider the allowable voltage dip magnitude and duration before islanding and also other types of loads like motors and thyristor rectifiers.

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APPENDIX

System parameters of the test system with different DG unit converter filter and controller parameters are presented in Table 6. The solution time step in simulations was 5μs.

Table 6
Study System Parameters

	Parameter	*Value*
DG Unit Converters(DC/AC)	Modulation method	PWM / SVM
	Switching frequency	8 kHz / 4 kHz
	Filter L (PWM / SVM)	1.2 mH (Conv 1),1.7 mH (Conv 2 & 3)
	Filter L_1, R_d, C, L_2 (PWM)	0.4 mH, 0.1 Ω, 10 μF, 0.2 mH
	Filter L_1, R_d, C, L_2 (SVM)	0.35 mH, 1 Ω, 4 μF, 0.4 mH
PLL(of PSCAD)	Proportional gain	50
	Integral gain	900
	Base Volts / Base Frequency	400 V / 50 Hz
	Offset angle to PLL	90 degrees
Current PI-controller	Gain $K_{current}$ (PWM)	5
	Integrator time constant T_{c_i} (PWM)	0.5 ms
	Gain $K_{current}$ (SVM)	1.5
	Integrator time constant T_{c_i} (SVM)	0.15 ms
Active Power PI-controller	Gain K_p (PWM / SVM)	$1 / 2^{**)}$
	Integrator time constant T_{p_i} (PWM / SVM)	0.015 s / 0.0015 $s^{*)}$ / 0.00075 $s^{**)}$
	Sampling rate	4 kHz
Reactive Power PI-controller	Gain K_Q (PWM / SVM)	5
	Integrator time constant T_{q_i} (PWM / SVM)	0.015 s
	Sampling rate	4 kHz
DC-DCBuck-boost Converter	Gain $K_{dc/dc}$	0.3
	Integrator time constant T_{dc/dc_i}	0.06 s
	Sampling rate_dc/dc	1 kHz
	DC-link capacitor	5000 μF
Synchr. Generator(SG)	Inertia constant	0.1049 MW/MVA
	R_a / X_p / Air gap f.	0.012 pu / 0.087 pu / 0.8
	X_d / X_d' / X_d''	3.5 pu / 0.128 pu / 0.077 pu
	X_q / X_q' / X_q''	2.1 pu / 0.128 pu / 0.098 pu
	T_{do}' / T_{do}''	2.71 s / 0.02 s
	T_{qo}' / T_{qo}''	2.71 s / 0.02 s
Reactive Power Control of SG (Input to Exciter)	Gain	1.0
	Time constant	1.0 s

* With master unit during island operation with constant dc-link (Fig. 4),

** With master unit during island operation with battery storage + dc/dc-converter based dc-link

International Review of Electrical Engineering (I.R.E.E.), Vol. 3, N. 3
May – June 2008

Stability of Microgrid with Different Configurations after Islanding Due to Fault in the Utility Grid

H. Laaksonen, K. Kauhaniemi

Abstract – *The most challenging issue in terms of microgrid stability is the transfer from normal parallel operation to islanded operation. The stability after transition to island operation due to a fault in the utility grid depends mainly on the depth and duration of the voltage dip caused by the fault. Particularly sensitive to voltage dips before islanding are directly and through frequency converter connected rotating machines. During transition to island operation fault ride-through capability is also required from these machines. In this paper the stability of the microgrid after fault in the utility grid is studied with different configurations and multiple simulations, which are made with PSCAD simulation software. This paper presents alternative options to maintain the stability of an islanded microgrid by reduction of voltage dip duration or magnitude. On the other hand, the stability effect and the fault ride-through improvement of the converter based distributed generation units with different phase-locked loop component modifications are studied by simulations. Finally summary of the possibilities to ensure stability of the microgrid after islanding due to fault in the utility grid is presented.* ***Copyright © 2008 Praise Worthy Prize S.r.l. - All rights reserved.***

***Keywords**: Microgrid, Stability, Distributed Generation, Energy Storage, Voltage Dip Compensation, Low Voltage Network*

Nomenclature

DG	Distributed Generation
IGBT	Insulated Gate Bipolar Transistor
IM	Induction Motor
LV	Low Voltage
MV	Medium Voltage
PLL	Phase-Locked Loop
PM	Permanent Magnet
PQC	Power Quality Compensator
PWM	Pulse Width Modulation
SG	Synchronous Generator
SVM	Space Vector Modulation
THD	Total Harmonic Distortion
VSC	Voltage Source Converter
VTT	Technical Research Centre of Finland
δ	Angular displacement of the rotor [rad]
ω_s	Synchronous speed [rad/s]
f	Frequency
E'	Machine voltage
H	Inertia constant [MW/MVA]
I_{meas}	Current measured after L_1 of converter LCL-filter
L_1	Converter side inductance of LCL-filter
L_2	Grid side inductance of LCL-filter
P_m	Shaft power input power [pu]
P_e	Electrical power crossing the air gap [pu]
P_a	Accelerating power
X_{trans}	is machine reactance X'_d+line reactance X_e when connected to infinite bus
V	Infinite bus voltage
V_{DC}	DC-link voltage
V_a, V_b, Vc	Grid phase voltages
$V_{a\_p}, V_{b\_p}, V_{c\_p}$	Positive sequence voltages

I. Introduction

Microgrid can be defined as a LV distribution system with DG units, energy storage and controllable loads, which can be operated either parallel with utility grid or islanded from the utility grid (Fig. 1). Transition to islanded mode will take place due to faults or intentional switching events. Transition between the interconnected and the islanding mode is crucial for uninterrupted continuity of supply, but also during reconnection the issue of out-of phase reclosing needs careful examination. [1]

Based on previous studies [2] the most challenging issue in terms of microgrid stability is the transfer from normal parallel operation to islanded operation. The stability after transition to island operation due to fault in the utility grid depends mainly on the depth and duration of the voltage dip. In overall it would be very beneficial from stability point of view if the voltage dip depth and duration could be compensated before transition to island operation of microgrid.

Manuscript received and revised May 2008, accepted June 2008

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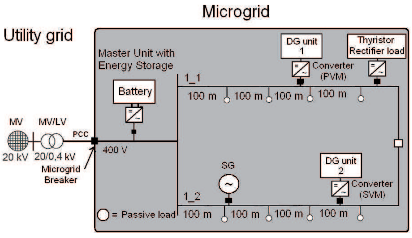

Fig. 1. Example from LV network based microgrid

Particularly sensitive to voltage dips before islanding are directly connected rotating machines like synchronous generators and induction motors. During transition to island operation the stability of the rotating machines should be maintained and their own protections should not disconnect them from the microgrid. This means that some time-delay in their protections will be needed.

Simultaneously the stability of the microgrid depends also from the stability of the control systems of converter connected DG units during voltage dips and from the fault ride-through capabilities of these converter based units. To avoid disconnection of DG units with converter interface the control system should be designed so that fault ride-through of voltage dips before islanding is possible. DG unit converters could also have adaptive control system settings between normal and island operation to ensure stable operation also during island operation.

Stability is also affected by the voltage THD during islanding, because if voltage waveform is too distorted the control system of converters may become unstable. The contribution of converter based DG units to harmonic distortion in islanded microgrid depends from the type of their passive filter (e.g. L- or LCL) and from their switching frequencies.

In this paper the stability of microgrid with different configurations after islanding due to fault in the utility grid is studied. The studied LV network based microgrid depending on the simulated case consists of three converter based DG units with different configurations and one SG unit or permanent magnet generator with frequency converter. In this paper a battery converter with rapid response acts as a master and it has the main responsibility to control the voltage and frequency in the microgrid when islanded from the utility grid. The load in the microgrid depending on the case consists of eight passive loads, thyristor rectifier load and IM load.

To conduct the studies, test systems are defined and the corresponding PSCAD based digital computer simulation models are developed. Some parts from a model library created previously in a joint project between University of Vaasa and VTT are used in the studied simulation model. Simulations are made to find out the effect of voltage dip depth and magnitude before islanding to the stability of the microgrid after islanding with different DG unit and load configurations. In addition different PLL component settings and configurations with positive sequence detector are studied to find out their effect on stability as well as the effect of a DG unit converter connection through a Delta/Wye grounded transformer.

Section II of the paper discusses briefly about the stability of rotating machines and converter based DG units after voltage dip. In section III possibilities to reduce the depth and duration of a voltage dip with different master unit configurations are discussed. Section IV introduces the test system. Simulation results of the study and discussions are presented in Section V. Conclusions are stated in Section VI.

II. Stability of Rotating Machines and Converter Based DG Units after Voltage Dip

This section is devoted to the discussion of the stability of rotating machines and converter connected units during and after voltage dips caused by grid faults. The grid faults can be classified in two main types:

1) Balanced fault: All three grid phase voltages register the same drop amplitude but the system remains balanced. The occurrence of this type of fault is very rare in power systems.
2) Unbalanced fault: The three grid voltages register unequal drop of amplitudes. Usually, phase shift between the phases also appears in this situation. This type of faults, where one or two phases that are shorted to ground or to each other, are more common in power systems.

II.1. Stability of Synchronous Machines

Transient stability refers to ability of synchronous machines to remain in synchronism with respect to major changes such as different types of faults. The fundamental equation that governs the rotational dynamics of the synchronous generator is the swing equation [3], [4]:

$$\frac{2H}{\omega_s}\frac{d^2\delta}{dt^2} = P_m - P_e = P_m - P_{max}\sin\delta = P_a \quad [\text{pu}] \quad (1)$$

or:

$$\frac{H}{\pi f}\frac{d^2\delta}{dt^2} = P_m - \frac{|E'||V|}{X_{trans}}\sin\delta = P_a \quad [\text{pu}] \quad (2)$$

Difference between active power P_m and P_e will result in non-zero accelerating power ($P_a \neq 0$), i.e. the rotor of the synchronous generator will either:

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accelerate $\left(\frac{d^2\delta}{dt^2} > 0\right)$ or decelerate $\left(\frac{d^2\delta}{dt^2} < 0\right)$. During the voltage dip the active power of the generator cannot be fed to the grid, so P_e becomes smaller while P_m remains constant and generator accelerates. Smaller voltage dip causes less acceleration and therefore it is from the stability point of view important to minimize the duration and magnitude of the voltage dip.

The inertia H of the synchronous machines plays also a significant role in maintaining the stability of the power system during an occurrence of a power unbalance. From equation (1) can be seen, that when the value of P_e alters (and P_m remains constant), a higher inertia constant (H) of the synchronous generator, causes less acceleration or deceleration of the generator rotor. With synchronous generators connected to LV network microgrid, the inertia constant can be quite small and so they can be sensitive to system disturbances [3], [4].

II.2. Stability of Induction Motors

Because the induction and synchronous motors may be stable only for a finite duration on a certain depth of voltage dip, it would be desirable to delay their tripping to maintain continuity of operations. The stability of the motors on voltage dips is dependent on the motor and load characteristics, as well as on power and control system parameters [5].

During a voltage dip, an induction motor may stall, and may not be able to accelerate its load when the supply voltage is restored back to normal. On the other hand, it may initially lose speed and reaccelerate on the restoration of voltage. This behaviour is determined by many interrelated factors. For example depending on the initial speed loss and the magnitude of the recovery voltage after fault clearance, the motors may accelerate, taking a current depending on their speed and starting current characteristics. A three-phase fault will result in the worst condition of stability and the motor contribution decays to zero within a few cycles. Two-phase-to-ground, phase-to-phase, and phase-to-ground faults will give less severe conditions of stability in the order stated. For non-symmetrical faults, the motor contribution to the positive-sequence voltage can remain present even 300 milliseconds after fault initiation [6], [5].

During speed loss the slip of the induction motor will increase with an increase in the line current. Constant torque loads with low-inertia will rapidly decelerate, and the output continuity may be lost. Loads with high-inertia and varying load torque may undergo a limited amount of retardation and may be able to reaccelerate on voltage recovery [5].

During island or blackstart operation of microgrid it must be notified that isolated distribution systems are not as stiff as utility grids. Therefore large starting currents and voltage drop during starting of an induction motor could be critical for the entire microgrid [7].

II.3. Stability of Converter Connected DG Units

Short duration voltage disturbances like voltage dips typically will lead to tripping of the frequency converter based drives. For many years uncontrolled diode rectifiers and line-commutated thyristor rectifiers have been used in grid side of the frequency converters. Nowadays, self-commutated converters with fully controllable devices like IGBTs are used in a number of applications because of their higher controllability and better power quality. Self-commutated VSCs equipped in the grid side with LCL-filters instead of L-filters, have also the potential of improved grid current harmonics. For a VSC based DG unit, a sudden decrease in grid voltage normally causes an increase in the current, as the control attempts to maintain the power at the DC link constant. This can lead to tripping of the VSC because of overcurrent, in order to protect the IGBTs. Unbalanced voltage dips will also produce current harmonics and unbalance, which can cause current protection to trip. Characteristic to the unbalanced fault is the appearance of the negative-sequence component in the grid voltages, which gives rise to double-frequency oscillations in the system. This can be seen as ripple in the dc-link voltage and output power and such oscillations can lead to a system trip if the maximum dc-link voltage is exceeded. It can also have a negative influence on the control of the grid converter by producing a non-sinusoidal current reference which will make the power quality of the VSC worse [8], [9], [10].

A) Converter Control During Unbalanced Voltage Dips:

To deal with above mentioned problems during unbalanced voltage dips the control of the converter plays the main role. Already many controllers have been developed and proposed to deal with grid voltage unbalance for a VSC system connected to the grid through L-filter or LCL-filter. Because of the negative-sequence current flowing through the grid-connected power converter during unbalanced voltage dips, the implementation of a dual current controller has been proposed and improved results are noticed when the negative-sequence current is also controlled. In dual current controller there is one controller for the positive-sequence current and one for the negative-sequence current. Also control system with one controller in the positive sequence frame with feed forward for the negative sequence has been developed to reduce current imbalance of LCL-filter equipped converters during unbalanced voltage dips [8].

It is also worth mentioning that during unbalance conditions, it is possible to cancel out active and reactive power oscillations only by accepting highly

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distorted currents. One solution proposed in [10] allows having sinusoidal grid currents by compensating for the oscillation in the active power only, while oscillations are present in the reactive one [10].

B) Synchronization in Unbalanced Voltage Dips:

In normal grid connected operation DG unit converters are used as controlled current sources and they are synchronized with utility grid phase angle/frequency normally with PLL component. In Fig. 2 the traditional synchronous dq-frame PLL method is presented [11], [12]. In ideal grid conditions this method performs quite well. Although if voltage waveform is distorted the bandwidth of the PLL must be reduced. This slows down the dynamics of the system [12].

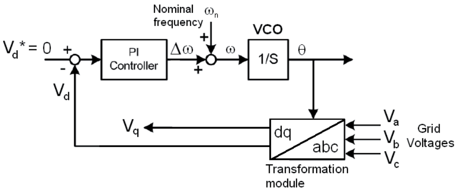

Fig. 2. Control diagram of a traditional synchronous dq-frame PLL [12]

The second harmonic ripple, which is a consequence from the voltage phase unbalance caused by the fault, will propagate into different sections of the DG unit converter controller and can have a negative influence on the controller even leading to trip out of the system. To deal with this problem improved PLL algorithms have been developed. They are able to filter out the negative sequence and to provide a clean synchronization signal. One developed solution is presented in [12]. Along with the conventional PI controller in the PLL structure, the proposed algorithm employs a repetitive controller to deal with the second harmonic. [12]

Another possible solution to deal with the voltage unbalance by using positive sequence detector is presented in [13]. This detector eliminates negative sequences from the phase voltages (V_a, V_b, V_c) of the grid. The positive sequence voltages (V_{a_p}, V_{b_p}, V_{c_p}) can be calculated from (3):

$$\begin{aligned}\begin{bmatrix} V_{a\_p} \\ V_{b\_p} \\ V_{c\_p} \end{bmatrix} &= \frac{1}{3}\begin{bmatrix} 1 & a & a^2 \\ a^2 & 1 & a \\ a & a^2 & 1 \end{bmatrix}\begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} \\ &= \begin{bmatrix} \frac{1}{2}V_a - j\frac{1}{2\sqrt{3}}\left(V_b - V_c\right) \\ -\left(V_{a\_p} + V_{c\_p}\right) \\ \frac{1}{2}V_c - j\frac{1}{2\sqrt{3}}\left(V_a - V_b\right) \end{bmatrix} \end{aligned} \tag{3}$$

where $a = -1/2 + j\sqrt{3}/2$ and $V_{a\_p}+V_{b\_p}+V_{c\_p}=0$.

Digital implementation of (3) is possible by combining all-pass 90° phase-shifter and constant gain [13].

In this paper the PLL component of the PSCAD master library is used in all simulations except in Section V.2. In Section V.2 different PLL component configurations also with positive sequence detector, as described in [13], are simulated to improve fault ride-through capability of the converter based DG units especially during unsymmetrical faults and to examine their effect on stability during islanding.

II.4. Stability of DG Units During Microgrid Islanding and Reconnection

Microgrid synchronized reconnection to utility grid means that the voltage angle difference between utility grid and microgrid should be minimized before reconnection. This is not a significant issue when converter based DG units with PLL component are considered, because PLL will ”draw” converters into phase with the utility grid frequency after reconnection. However DG units with traditional synchronous generator interface cannot deal with major phase difference during microgrid reconnection without losing rotor angle stability. Therefore master unit of microgrid should create the frequency reference in microgrid so that it is as close as possible to utility grid phase. Otherwise, the SG based DG units must be first disconnected from the grid during microgrid reconnection and after that they can be connected back to grid in synchronism with utility grid frequency.

Synchronized islanding is also needed not only because of the above mentioned needs of the synchronous generators during the reconnection of the microgrid, but also due to stability reasons. This means that the phase angle difference between utility grid and microgrid cannot be too high, otherwise the frequency stability of the islanded microgrid will be lost. This can be ensured e.g. by changing the input of the master unit PLL to come sufficient time before microgrid reconnection from the healthy utility grid phase voltages.

III. Possibilities to Reduce the Effect of a Voltage Dip with Master Unit Configuration

The stability of induction and synchronous generators can be maintained after three-phase fault for 150 ms before the DG units protections will operate when fault ride-through requirements are taken into account. But this time is considerably shorter for machines with low inertia [14]. In this section different possible master unit configurations to reduce the effect

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of voltage dips to e.g. rotating machines are shortly presented.

If the base case is chosen to be voltage dip with 90 % magnitude and 200 ms duration before islanding of the microgrid, then the alternatives to maintain stability in the islanded microgrid are (Fig. 3):

1) Significant reduction of the voltage dip duration (Case 1) or
2) Substantial reduction of the voltage dip magnitude (Case 2) or
3) Reduction of the voltage dip duration and magnitude (Case 3)

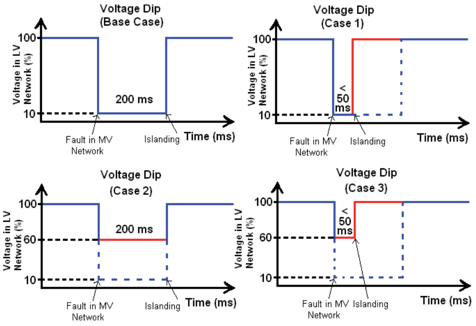

Fig. 3. Alternatives (cases 1-3) to maintain stability of the microgrid after islanding by compensating/reducing the effect of the voltage dip

These different alternatives (cases 1-3) in Fig. 3 to compensate or reduce the duration of the voltage dip before islanding can be realized with different energy storage + switch -configurations. These possible configurations are (Fig. 4):

1) Fast static switch + energy storage (Case 1) or
2) Breaker + energy storage based PQC (Case2) or
3) Fast Static Switch + energy storage based PQC (Case 3)

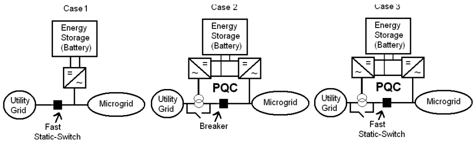

Fig. 4. Possible configurations to compensate or reduce the effect of the voltage dip as illustrated in Fig. 3

In the simulations configuration Case 2 (Fig. 4) was selected for cases where stability after islanding was not maintained by reducing the voltage dip duration before islanding from 200 to 100 ms. Energy storage based PQC, which is described and studied much more in detail in [15], has also other good features when it is operating parallel to the utility grid e.g. current active filtering and voltage unbalance compensation capability. More details about the studied system can be found from the next section IV.

IV. Study System

IV.1. Studied LV Network Microgrid

The LV network used in this work is shown in Fig. 5. The system consists of one 800 kVA MV/LV-transformer which normally feeds LV feeders 1_1 and 1_2. In the simulation studies the islanded microgrid is disconnected from main network by the breaker so that the microgrid consists of feeders 1_1 and 1_2 (Fig. 5). At the connection point of the microgrid there is a storage unit (battery 120 or 200 or 400 kVA) equipped with converter 1 and LCL-filter. At the end of feeder 1_1 there is a DG Unit 1 (120 kVA) equipped with converter 3 and LCL-filter. In front-end of the feeder 1_2 there is a synchronous generator (100 kVA) and at the end of the feeder there is also DG Unit 2 (120 kVA) equipped with converter 2 and LCL-filter. On the feeder 1_2 there is also a PM generator equipped with frequency converter (100 kVA) and L-filter. For comparison purposes the simulations are done with and without SG or in some cases with PM generator equipped with frequency converter. Also in some simulations where the effect of voltage dip compensation before islanding was studied the master unit consisted of energy storage based PQC (Case 2 in Fig. 4).

The load in the microgrid depending on the case consists of four passive loads on each feeder and also thyristor rectifier load (36 kW, 9 kVAr) and IM load (51 kW, 34 kVAr) in some cases on feeder 1_2 (Fig. 5). The passive loads can be adjusted so that the loading of the transformer (which feeds LV feeders 1_1 and 1_2) gets some desired value between 0…150 % of the transformer ratings. Initially loading of the transformer was set to 33 % without SG (power factor 0.97_{ind}) and to 45 % with SG (power factor 0.98_{ind}). Simulations were made with different LV network line parameters. Line parameters with lower (strong LV network, AXMK 4x185S) and higher (weak LV network, AMKA 3x35+50) R/X -ratio of the line used in LV network under study (Fig. 5) are shown in Table I. The fault level and R/X-ratio of the feeding utility network (20 kV, 50 Hz) are 200 MVA and 0.1 respectively.

For DG unit converters space vector modulation and for PM generator + frequency converter pulse width modulation was used. Converter control system and strategy used especially for the master unit are explained in Section IV.2 in more detail. The dc-link voltage V_{DC} of converters is chosen to be 0.65 kV and dc-link is modeled as a constant dc-voltage source or in cases with PQC master unit the dc-link of all converter based DG units consists of a storage + dc-dc buck-boost converter. The converters are modeled as three-phase, three-leg units with LCL-filters. In few simulations the converters were modeled with neutral connection, i.e. delta/wye grounded transformer.

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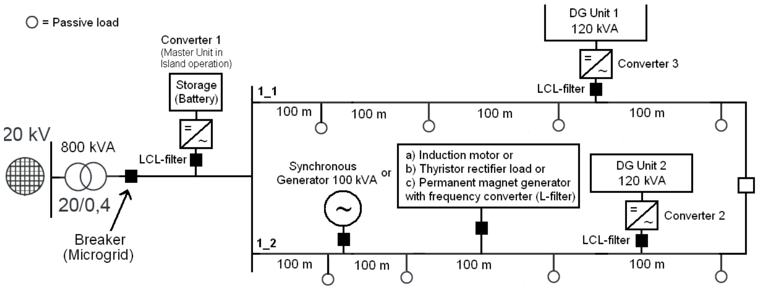
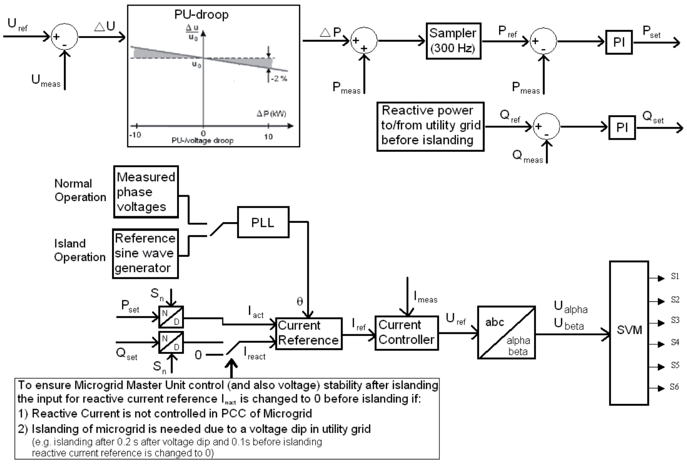


Fig. 5. Studied LV network based microgrid



To ensure Microgrid Master Unit control (and also voltage) stability after islanding the input for reactive current reference I_{react} is changed to 0 before islanding if:
1) Reactive Current is not controlled in PCC of Microgrid
2) Islanding of microgrid is needed due to a voltage dip in utility grid
(e.g. islanding after 0.2 s after voltage dip and 0.1s before islanding reactive current reference is changed to 0)

Fig. 6. Control system of master unit converter during islanding with SVM modulation

TABLE I
RESISTANCE, REACTANCE AND R/X RATIO OF LV NETWORK IN FIG. 5

	R (Ω/km)	X (Ω/km)	R/X
AXMK 4x185S	0.164	0.0817	2.01
AMKA 3x35+50	0.868	0.104	8.35

Further details about the study system components (LCL-filters) are listed in Appendix.

IV.2. Control of Converters

Distributed generation units based on storage devices or regulated prime movers are responsible for frequency and voltage regulation during islanded operation of a microgrid and they are often described as grid-forming units [16]. In this paper microgrid is operated in single master operation mode during islanding, which in this case means that the converter 1 with battery storage will act as the master unit and it has the main responsibility to control the voltage and frequency in microgrid when islanded. The control system for master unit (Battery storage) converter 1 in island operation is shown in Fig. 6. The application of PU-droop for voltage control during islanding used in the simulation studies is also presented in Fig. 6. Converter 1 (master unit) also controls the frequency of microgrid by having the input for PLL during islanding from the 50 Hz 3-phase reference sine wave generator i.e. the master unit determines the synchronism of the microgrid. One important notification considering the master unit is that to be able to give the frequency reference for other DG units to synchronize with, the master unit active power output should be at least some 5 % of the total load. This must be taken into account in the control system of the master unit. The master unit control during the synchronized reconnection of the microgrid to the utility grid voltages should be done so that I_{act} in master unit control system (Fig. 6) should be given as 0 after the reconnection of microgrid. Also a sufficient time before reconnection the input of PLL in the master unit control system should be changed to come from the utility grid voltages. In addition the duration of the possible automatic reclosing operations in the utility grid should be remembered when the microgrid reconnection possibility is evaluated.

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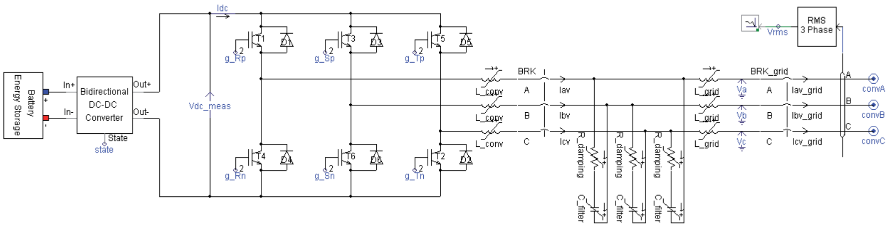

Fig. 7. PSCAD simulation model of the converter based DG unit with battery storage + dc-dc buck-boost converter modelled as a dc source in dc-link

On the other hand, DG units intended for energy production (such as photovoltaics or wind turbines) lack the capability of producing controlled active power on demand, if no storages are used, and so they are normally operated under active/reactive power i.e. PQ control [16]. The control of these units remains same regardless of the operation mode, normal or island operation. In the simulations of this paper all the other DG units than the master units is operated in conventional PQ mode i.e. they do neither take part in frequency nor voltage control.

In principle it is also possible with PLL component modifications (see Section V.2) to implement the control system of all converter based units, including master unit, so that the input voltages of the PLL remain the same after islanding. Then the allowed frequency range (e.g. 49-51 Hz) in microgrid would be defined by the PI-controller limits of the converters' PLL components. This frequency range should be taken into account by protective devices i.e. possible frequency relays.

Active and reactive power controller parameters are similar between converters 2 and 3, but different with master unit converter 1 (Fig. 6). Details about the PI-controller parameters of the converter control system can be found in Appendix. It is essential for the stability of the whole microgrid that during disturbances the control system of the master unit converter remains stable. One important thing related to the stability of the master unit control is the current control stability, which is related to the point where the current (I_{meas}) is measured. In the converter simulation models used in this study, the current I_{meas} is sensed after the converter side inductance of the LCL-filter (Fig. 7), because generally the current sensing from the grid side improves the stability margin of the system, but on the other hand the use of an LCL-filter makes the current control to be unstable if a proper damping is not used [17]. With converters 2 and 3, the input signals for PLL component are filtered with band-pass filters. LCL-filter parameter design can be made on a different basis and some principles can be found from [8] and [18]. In [8] the filter inductances are dimensioned so that the voltage drop across the inductances is limited to 10 % during normal operation and L_2 is 0.4xL_1. In this paper LCL-filter parameters for have been chosen so that L_2 is 0.5xL_1, because this way converter was found to produce lower current and voltage harmonics in simulations with PSCAD. One important issue related to LCL-filter design is also the resonant frequencies which should be always considered when LCL-filter parameters are chosen. [8] suggests that the resonance frequency should be in the range between ten times the fundamental frequency and one half the switching frequency.

The master unit configuration (energy storage+dc-dc converter with PQC) used in cases where the voltage dip magnitude before islanding was compensated with series converter of PQC is shown in Fig. 8. In a normal interconnected operation (microgrid connected to utility grid) the shunt converter of the PQC produces reactive power needed by microgrid loads and compensates microgrid current harmonics with the active filtering feature of the shunt converter. At the same time the bidirectional dc-dc buck-boost converter controls the dc-link voltage. During the voltage dip operation the series converter of the PQC produces active and reactive power needed to compensate microgrid phase voltages. The shunt converter in active filtering mode is stopped during the voltage dip or imbalance compensation. The battery is charged through the shunt converter and the dc-dc converter, meanwhile the shunt converter also controls the dc-link voltage. In the islanded microgrid operation (Fig. 8) the microgrid breaker is opened.

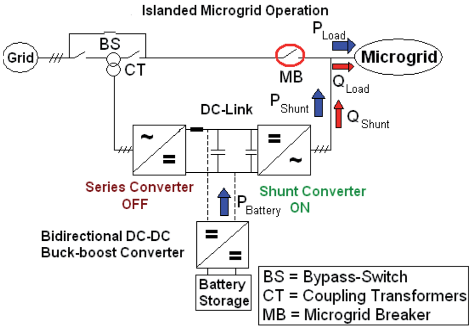

Fig. 8. Operation principles and power flows of the PQC with energy storage during island operation [15]

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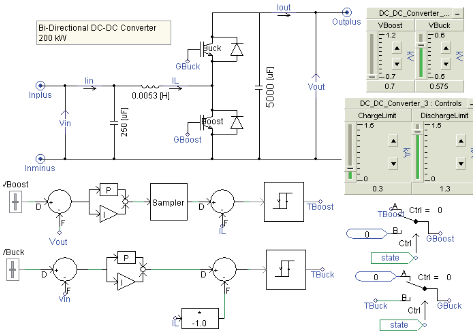


Fig. 9. PSCAD simulation model of the dc-dc buck-boost converter

During the islanded microgrid operation the active and reactive power, needed for rapid the voltage control, are fed from the battery storage through the shunt converter of the PQC and the control of the shunt converter is changed to the one shown in Fig. 6. In Fig. 9 also the simulation model of the dc-dc converter is presented. Details about the parameters of the PQC with energy storage and dc-dc converter is presented in Appendix [15].

V. Simulations

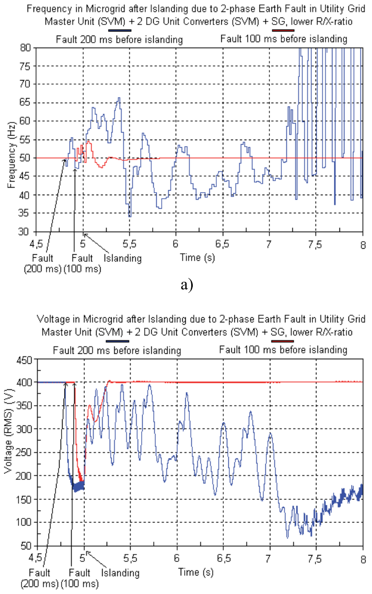
Simulation studies for this paper were made first with master unit configuration Case 1 (Fig. 4) with different fault types (3-phase fault, 2-phase fault, 2-phase earth fault and earth fault), DG unit configurations and line impedances. From these simulations the most problematic cases were found to be fault types 3-phase fault and 2-phase earth fault in which to the voltage dip magnitude is higher.

In Section V.1 the simulation results considering islanding after voltage dip due to fault in the utility grid are presented. At first results from different cases where stability of microgrid after islanding can be maintained by faster disconnection from utility grid are shown. After that simulation results from certain cases where stability can be maintained after islanding with voltage dip compensation by PQC of master unit before islanding are given. Also the simulation results from the effect of DG unit converter connection through delta/wye grounded transformer to the stability of microgrid are presented. In Section V.2 different PLL component configurations, also with positive sequence detector, are examined to find out their effect on stability during islanding.

V.1. Improvement of Microgrid Stability after Islanding Due to Fault in the Utility Grid

A) <u>With Faster Islanding – Reducing the Voltage Dip Duration:</u>

In following the simulation results from different cases where stability of the microgrid after islanding can be maintained by faster disconnection are presented. In the first case there is master unit (120 kVA), 2 converter based DG units and SG connected to LV network microgrid with lower R/X-ratio lines. From Fig. 10 one can see that the frequency and voltage stability is lost in case of 200 ms voltage dip produced by 2-phase earth fault in utility grid before islanding. But if islanding of microgrid is performed faster, in 100 ms, then the frequency and voltage stability can be maintained after islanding (Fig. 10).



a)

b)

Fig. 10. a) Frequency and b) voltage stability in microgrid after islanding due to 2-phase earth fault in the utility grid with faster islanding (200->100 ms) i.e. reduced voltage dip duration

In the second case there is master unit (200 or 400 kVA), 2 converter based DG units and PM generator with frequency converter connected to LV network microgrid with lower R/X-ratio. From Fig. 11 it can be seen that the frequency and voltage stability is lost in case of 200 ms voltage dip produced by 2-phase earth fault in utility grid before islanding when 200 kVA master unit with energy storage is used. However, if larger energy storage (400 kVA) is used or islanding of microgrid is conducted in 100 ms, then the frequency and voltage stability can be maintained after islanding (Fig. 10). But when the behaviour of the dc-link voltage of the frequency converter of PM generator is examined, one can notice that the faster islanding in 100 ms with 200 kVA master unit the dc-link voltage is more stable. Possibly the oscillation in the case with

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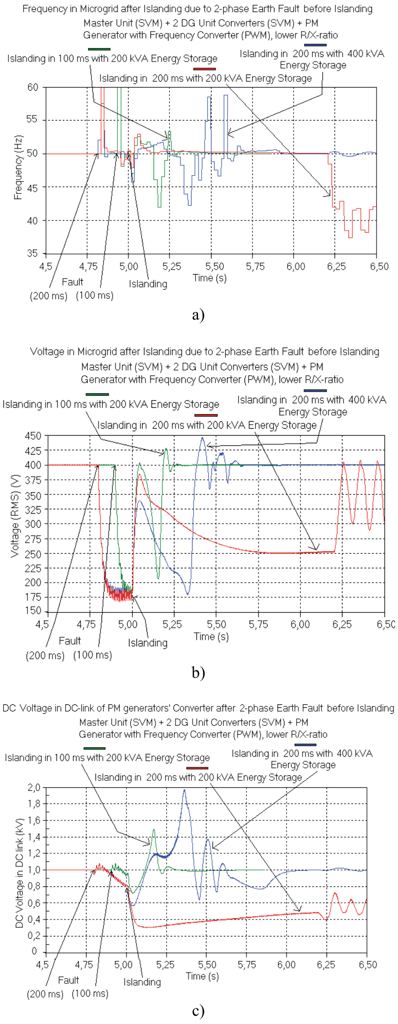
larger 400 kVA master unit and 200 ms voltage dip duration could be controlled with addition of a supercapacitor or battery into dc-link of frequency converter, but it is not necessarily the cheapest solution. Naturally also the master unit with larger capacity causes more expenses. Anyhow, these questions are not that straightforward because the microgrid concept should be reviewed as a whole and take into account also many other things e.g. fault management in islanded microgrid.



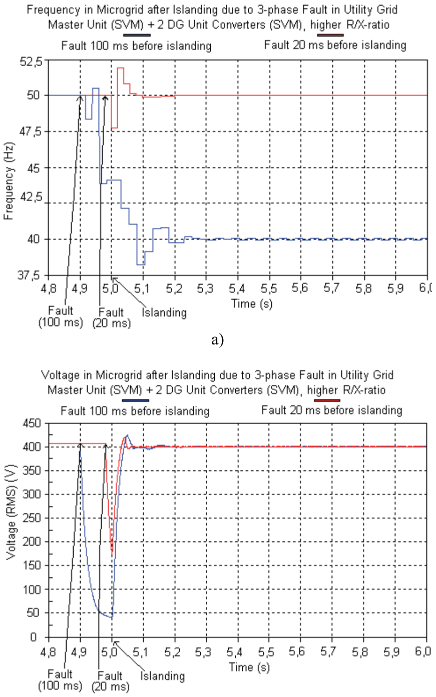
a)

b)

c)

Fig. 11. a) Frequency , b) voltage stability in microgrid and c) dc voltage behaviour in dc-link of PM generator's frequency converter after islanding due to 2-phase earth fault in the utility grid with faster islanding (200->100 ms) i.e. reduced voltage dip duration or larger capacity of master unit with energy storage

In the third case there is master unit (120 kVA) and 2 converter based DG units connected to LV network microgrid with higher R/X-ratio. From Fig. 12 it can be seen that only the frequency stability is lost in case of 100 ms voltage dip produced by 3-phase fault in utility grid before islanding. However, if islanding of microgrid is conducted faster in 20 ms, then the frequency and voltage stability can be maintained after islanding (Fig. 12). In this case also the meaning of R/X-ratio can noted, because the same case simulated with lower R/X-ratio and 100 ms voltage dip was stable.



a)

b)

Fig. 12. a) Frequency and b) voltage stability in microgrid after islanding due to 3-phase fault in the utility grid with faster islanding (100->20 ms) i.e. reduced voltage dip duration

In the fourth case there is master unit (120 kVA), 2 converter based DG units and SG connected to LV network microgrid with higher R/X-ratio i.e. the only difference to third simulation (Fig. 12) is the presence of SG. From Fig. 13 one can see that the frequency and voltage stability is lost in case of 100 ms voltage dip caused by 3-phase fault in utility grid before islanding. But if islanding of microgrid is done in 20 ms, then the frequency and voltage stability can be maintained after islanding (Fig. 13).

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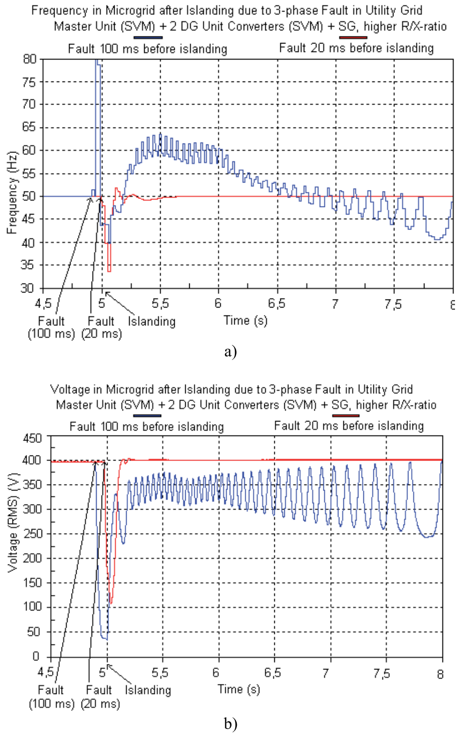

Fig. 13. a) Frequency and b) voltage stability in microgrid after islanding due to 3-phase fault in the utility grid with faster islanding (100->20 ms) i.e. reduced voltage dip duration (difference to Fig. 12 is the presence of SG)

In some cases the DG unit converters may be connected to microgrid through delta/wye grounded 400/400V transformers for grounding purposes. In one simulated case with master unit (120 kVA), 2 converter based DG units, SG and lower R/X-ratio LV network it was found out that, the frequency and voltage stability is lost in case of 100 ms voltage dip caused by 2-phase earth fault in utility grid before islanding. But when these transformers are not used, then the frequency and voltage stability can be maintained. This stability problem could be solved by faster islanding after fault utility grid, compensation of voltage dip before islanding or by changing e.g. the PI-controller parameters in the converter control system.

B) With Voltage Dip Compensation by PQC – Reducing Voltage Dip Magnitude:

In this section the simulation results are presented from certain cases where stability of the microgrid after islanding can be maintained with voltage dip compensation by PQC of the master unit before islanding. In the first case (Fig. 14) there is master unit (120 kVA), 2 converter based DG units and SG connected to LV network microgrid with higher R/X-ratio. The only difference to the simulation of Fig. 13 is addition of PQC based master unit i.e. this case in Fig. 14 is alternative to the one presented in Fig. 13. From Fig. 14 it can be seen that the frequency and voltage stability is lost in case of 100 ms voltage dip caused by 3-phase fault in utility grid before islanding. However, when voltage dip before islanding is compensated (from 80 % to 40 %) by the use of series converter in PQC based master unit, then the frequency and voltage stability can be maintained after islanding (Fig. 14). From the simulation results of Fig. 14 it can also be seen that the PLL of the series converter cannot maintain the 50 Hz frequency before islanding, which possibly may become problematic in certain cases. However, by the modification of the PLL these problems can be handled.

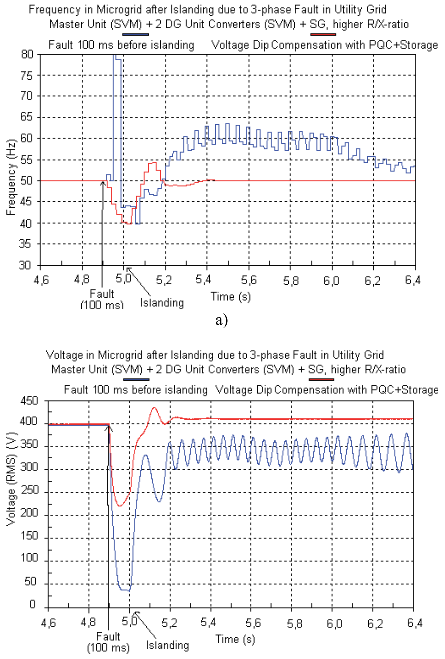

Fig. 14. a) Frequency and b) voltage stability in microgrid after islanding due to 3-phase fault in the utility grid with voltage dip compensation by PQC of master unit (80->40 %)

In the second case (Fig. 15) there is master unit (120 kVA), 2 converter based DG units and SG connected to LV network microgrid with higher R/X-ratio. The only difference to the simulation of Fig. 14 is the fault type i.e. the voltage dip magnitude before islanding. From Fig. 15 it can be seen that also in this case the frequency and voltage stability is lost in 100 ms voltage dip caused by 2-phase earth fault in the utility grid before

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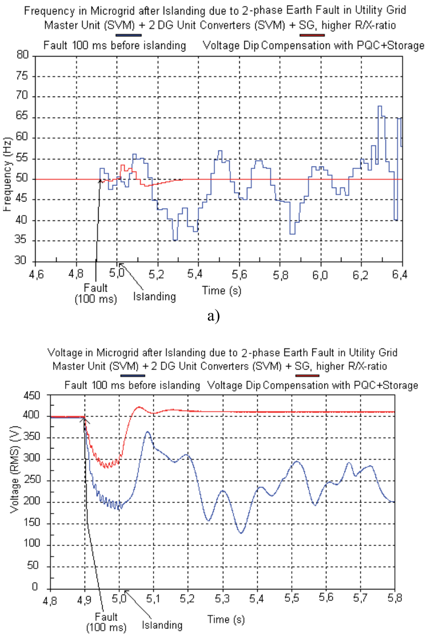
islanding. But when voltage dip before islanding is compensated (from 50 % to 25 %) by the use of POC based master unit, then the frequency and voltage stability can be maintained after islanding (Fig. 15).

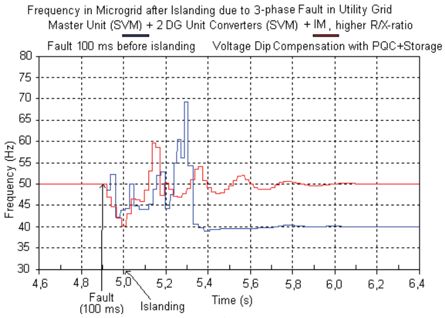


a)

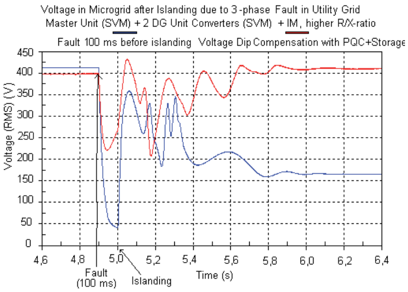
b)

Fig. 15. a) Frequency and b) voltage stability in microgrid after islanding due to 2-phase earth fault in the utility grid with voltage dip compensation by PQC of master unit (50->25 %)

In the third case (Fig. 16) there is master unit (120 kVA), 2 converter based DG units and induction motor (IM) connected to LV network microgrid with higher R/X-ratio. The only difference to the simulation of Fig. 14 is the presence of IM instead of SG.



a)



b)

Fig. 16. a) Frequency and b) voltage stability in microgrid after islanding due to 3-phase fault in the utility grid with voltage dip compensation by PQC of master unit (80->40 %) (difference to Fig. 14 is the presence of IM instead of SG)

From Fig. 16 one can see that the frequency and voltage stability is lost in case of 100 ms voltage dip caused by 3-phase fault in utility grid before islanding. However, when voltage dip before islanding is compensated (from 80 % to 40 %) by the use of POC, then the frequency and voltage stability can be maintained (Fig. 16).

V.2. The Fault Ride-through and Stability Improvement of Converter Based DG Units by PLL Modifications

In all previous simulation studies the used PLL component was the one which can be found from the master library of PSCAD with parameters of Table II and the phase voltages of the grid were used as the input for it. On the contrary, in this Section V.2 simulations are done for comparison purposes with new PLL setting and with positive sequence detector to improve fault ride-through capability of the converter based DG units. The studied case in Section V.2 consists of the master unit (120 kVA), 2 converter based DG units, IM and unbalanced passive load connected to LV network microgrid with higher R/X-ratio. In Fig. 17 the voltage unbalance of the simulations in Section V.2 during island operation is shown. In all simulations done for Section V.2 the dc-link of all converter based DG units consisted of a storage + dc-dc buck-boost converter (see Fig. 9).

TABLE II
PLL OF PSCAD MASTER LIBRARY - PARAMETERS

Parameter	Value
Proportional gain	50
Integral gain	900
Base Volts, Frequency	400 V, 50 Hz
Offset angle to PLL	90 degrees

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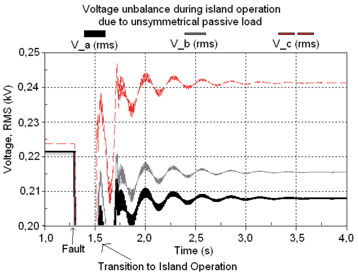


Fig. 17. Voltage unbalance in simulations of Section V.2 during island operation due to unsymmetrical passive load

In following subsections A) and B) the simulations are done with different PLL configurations. In the simulations of subsection A) the stability effect of the new PLL with different parameters is studied and in subsection B) the impact of positive sequence detector is examined.

A) Comparison of PLL of PSCAD and new PLL with different parameters:

The simulations in the following are done for a comparison with the PLL of the PSCAD (Table II) and with a new PLL component (Fig. 18) with parameters of Table III to study the effect of their parameters on stability after islanding.

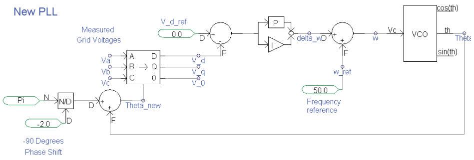
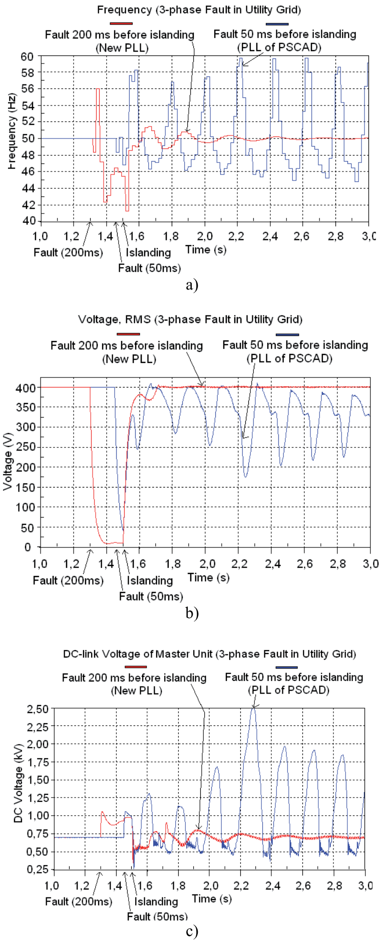


Fig. 18. Control system of the new PLL component used in simulations

TABLE III
THE NEW PLL COMPONENT - PARAMETERS

Parameter	Value
Proportional gain (PI)	15
Integral time constant (PI)	0.0009 s
Maximum limit (PI)	5 Hz
Minimum limit (PI)	-5 Hz
Nominal Frequency	50 Hz
Phase Shift to abc/dq0 Transformation	-π/2 rad

From Fig. 19 it can be seen that with the use of PLL of PSCAD (Table II) on all converters, the frequency and voltage stability is lost in case of 50 ms 3-phase fault in utility grid before islanding. However, when the new PLL (Fig. 18, Table III) is used with all converters, then the frequency and voltage stability can be maintained even in case of 200 ms 3-phase fault in utility grid before islanding (Fig. 19). During the 200 ms 3-phase fault, the speed of the IM decreases from 0.98 pu to 0.92 pu. Also the DC-link voltage of the master unit is stabilized quite well after islanding, with the new PLL (Fig. 19c).



a)

b)

c)

Fig. 19. The effect of the new PLL with different parameters on a) frequency , b) voltage and c) master unit dc-link voltage stability in microgrid after islanding due to 3-phase fault in the utility grid

B) Comparison of PLL of PSCAD with and without of Positive Sequence Detector:

The simulations in the following are done with and without the positive sequence detector together with the PLL component of the PSCAD master library with parameters of Table II. The positive sequence detector presented in [13] was implemented in PSCAD as shown in Fig. 20.

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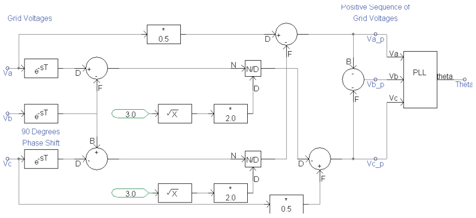

Fig. 20. Implementation of positive sequence detector in PSCAD with the PLL component of the PSCAD master library

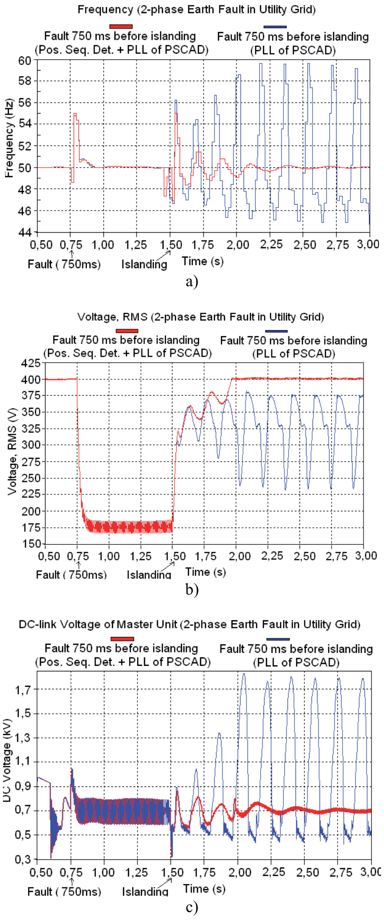

Fig. 21. The effect of the use of PLL with positive sequence detector on a) frequency , b) voltage and c) master unit dc-link voltage stability in microgrid after islanding due to 2-phase earth fault in the utility grid

The only problem with the use of the positive sequence voltages is the ripple of the dc-link voltage during unsymmetrical faults. This ripple affects also the active power reference and both active and reactive power will experience double-frequency oscillations over the whole fault period. [19]

From Fig. 21 one can be see that with the use of PLL of PSCAD (Table II) on all converters, the frequency and voltage stability is lost in case of 750 ms 2-phase earth fault in utility grid before islanding. On the other hand, when the positive sequence detector is used with the PLL (Fig. 20, Table II) on all converters, then the frequency and voltage stability can be maintained even in case of 750 ms 2-phase earth fault (Fig. 21). Although in this case during the 750 ms 2-phase earth fault, the speed of the IM decreases from 0.98 pu to 0.855 pu, but is still able to recover back to 0.98 pu after islanding. In reality the transition to islanding should be faster, so that the speed loss of the IM due to voltage dip would be smaller. In the DC-link voltage of the master unit, the ripple during unsymmetrical 2-phase earth fault can be seen with both PLL components used in simulations of Fig. 21c).

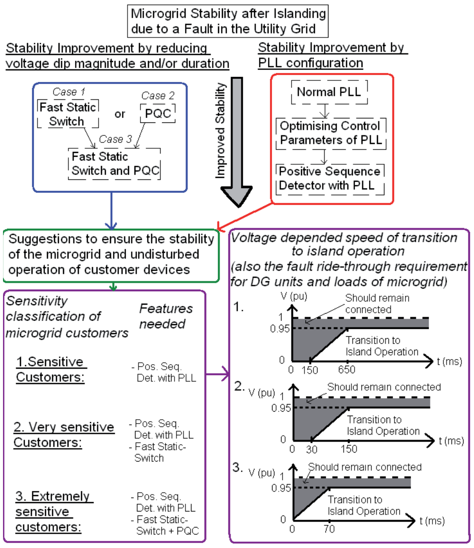

Fig. 22. Summary of the possibilities to ensure stability of the microgrid after islanding due to a fault in the utility grid

VI. Conclusion

The transfer from normal parallel operation to islanded operation is the most challenging issue in terms of microgrid stability. The stability depends mainly on the depth and duration of the voltage dip caused by a fault in the utility grid and from the PLL configuration and control system of the converter based DG units in microgrid. Particularly sensitive to voltage dips before islanding are directly and through frequency converter connected rotating machines. Based on the simulations a summary of the possibilities to ensure stability of

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microgrid after islanding due to a fault is presented in Fig. 22. As illustrated in the Fig. 22 the stability can be improved by different choices of voltage dip compensation methods in the connection point of microgrid and by different PLL configurations applied on the converters. The transition speed to island operation depends from the microgrid dynamics and control (to ensure stability) as well as on the sensitivity class of the microgrid customers (Fig. 22). For different sensitivity class of customers different features needed are defined in Fig. 22 and also the possible operation curves for voltage dependent speed of islanding for these different sensitivity class customers are shown. Depending on the sensitivity class of the microgrid customers the fault ride-through needs of the DG units and loads can be defined respectively with sufficient margin to the voltage dependent speed of islanding curves (Fig. 22).

VII. Further Studies

The limits to ensure stability and high quality power for sensitive microgrid customers are the main factors to decide the operation speed of the microgrid breaker or switches in the fault situation. But, if still DG units or load in the microgrid are disconnected for some reason and the stability is lost during transition to island operation, the microgrid should have strategy for blackstart operation and load management. In future studies these blackstart and other, e.g. fault management, strategies as well as master unit sizing needs to be defined to have in the end one suggestion to completely functional microgrid concept.

Appendix

System parameters of the test system with different DG units, loads and controller parameters are presented in Tables IV and V. The solution time step in simulations was 5 µs.

TABLE IV
STUDY SYSTEM PARAMETERS – PART ONE

	Parameter	Value
DG Unit Converters (DC/AC)	Modulation method	SVM
	Switching frequency	8 kHz
	Filter L_1, R_d, C, L_2	0.4 mH, 0.1 Ω, 10 µF, 0.2 mH
Current PI-controller	Gain $K_{current}$	1.5
	Integrator time constant T_{c_i}	0.15 ms
Active Power PI-controller	Gain K_p	1* / 2**
	Integrator time constant T_{p_i}	0.015* / 0.00075** s
	Sampling rate	4* / 0.3** kHz
Reactive Power PI-controller	Gain K_Q	5
	Integrator time constant T_{q_i}	0.015 s
	Sampling rate	4 kHz
DC-DC Buck-boost Converter	Reference dc voltage V_{DC}	0.7 kV
	Gain $K_{dc/dc}$	0.3
	Integrator time constant T_{dc/dc_i}	0.06 s
	Sampling rate_dc/dc	1 kHz
	DC-link capacitor	5000 µF
Synchr. Generator (SG)	Inertia constant	0.1049 MW/MVA
	R_a / X_p / Air gap f.	0.012 pu / 0.087 pu / 0.8
	X_d / X_d'/ X_d''	3.5 pu / 0.128 pu / 0.077 pu
	X_q / X_q'/ X_q''	2.1 pu / 0.128 pu / 0.098 pu
	T_{do}' / T_{do}''	2.71 s / 0.02 s
	T_{qo}' / T_{qo}''	2.71 s / 0.02 s
Reactive Power Control of SG (Input to Exciter)	Gain	1.0
	Time constant	1.0 s
Permanent Magnet (PM) Generator with Frequency Converter	Modulation method	PWM
	Switching Frequency	6^{***} / 8 kHz^{****}
	Filter L	2.5 mH
	DC-link capacitor	12000 µF

*) In normal operation, **) In island operation, ***) Generator side converter, ****) Grid side converter

TABLE V
STUDY SYSTEM PARAMETERS – PART TWO

	Parameter	Value
Series Converter of PQC	Filter L, C	0.2 mH, 100 µF
	Modulation method	PWM
	Switching Frequency	8 kHz
	Coupling transformer rated voltage	230/46 V
Shunt Converter of PQC	Filter L_1, C, L_2 (In normal operation $L=L_1+L_2$ and in island operation LCL)	0.4 mH, 4 µF, 0.35 mH
	Modulation method	$Hysteresis^{*}$ SVM^{**}
	Switching Frequency	Not $constant^{*}$ 8 kHz^{**}
DC-link (DC-DC Buck-boost Conv.) of PQC ↓	Gain $K_{dc/dc}$	1.25
	Integrator time constant T_{dc/dc_i}	0.0125 s
	Sampling rate_dc/dc	500 Hz
	Capacitor C_1 (DC-DC converter), C_2 (on shunt converter side)	10 000 µF, 5 000 µF

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	Inductance L_{dc} (on series converter side)	0.3 mH
	Reference dc voltage V_{DC}	1.05 kV
Battery Storage of PQC	Capacity	2 000 Ah
	DC-DC Buck-boost Converter	0.575/1.05 kV
	Max. Charging Current	300 A
Induction motor (IM)	P_n	75 kW
	cosφ	0.93
	Inertia	6.47 kgm^2

*) In normal operation, **) In island operation

Acknowledgements

The authors want to express their thanks to Tekes, the Finnish Funding Agency for Technology and Innovation, and companies for their financial support in *Energy storage for managing distributed generation* -project which is part of Tekes Distributed energy systems technology programme (DENSY) 2003-2007.

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Authors' information

University of Vaasa,
Finland.

H. Laaksonen was born in Vaasa, Finland, on November 22, 1977. He received his Master's degree (2004) in Electrical Power Engineering from Tampere University of Technology.
His employment experience includes working as a research scientist in VTT Technical Research Centre of Finland in Vaasa and before that in Institute of Power Engineering department at Tampere University of Technology. Currently he works as a research scientist and PhD student with Department of Electrical Engineering and Automation at University of Vaasa. His field of interests are planning + integration of DG in distribution networks, power electronics in distribution networks and future network concepts (e.g. microgrids).

K. Kauhaniemi was born in in Kankaanpää, Finland, in 1963. He received his M.Sc degree (1987) and Dr. Tech. degree (1993) in electrical engineering from Tampere University of Technology, Finland. He was previously employed by VTT Technical Research Centre of Finland. Currently he is Professor in electrical engineering at the University of Vaasa, Finland. His special interest areas include the modeling and simulation of power systems.

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International Journal of Distributed Energy Resources
Volume 4 Number 2(2007) Pages 123 - 142
Manuscript received: 15. August 2007

NEW CONCEPT FOR POWER QUALITY MANAGEMENT IN MICROGRID WITH ENERGY STORAGE BASED POWER QUALITY COMPENSATOR

Hannu Laaksonen, Kimmo Kauhaniemi
Department of Electrical Engineering and Automation
University of Vaasa
P.O.Box 700, FI-65101 Vaasa, Finland
Phone (358) 63248688, Fax (358) 63248344
E-mail: hannu.laaksonen@uwasa.fi

Keywords: distributed generation; energy storage; islanded operation; low voltage network; microgrids; power quality

ABSTRACT

Power quality, stability and energy balance issues of the microgrid are essential for realizing future microgrids. This paper presents a new advanced concept to improve the quality of power within the microgrid and also the quality of currents flowing between the microgrid and the utility grid. The developed concept utilizes power quality compensator (PQC) with energy storage for power quality management in microgrid. PQC consists of a shunt and a series converter. The shunt converter is implemented in PSCAD with an adaptive configuration and control system to obtain the best possible power quality in the microgrid during island operation. First the main points of the developed PQC control principles and power flows in different operation modes are presented. Then the studied PSCAD simulation model and simulation results are shown. The simulation results confirmed that the PQC with energy storage can solve many of the power quality problems: i) The shunt converter of the PQC can compensate the microgrid current harmonics and reactive power, ii) The series converter of the PQC can eliminate the utility grid voltage dips and voltage imbalance and iii) Islanding and island operation is possible due to faults in the utility grid or intentionally using the instantaneous voltage control and power balance management of the PQC shunt converter.

International Journal of Distributed Energy Resources, ISSN 1614-7138, Volume 4 Number 2

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1 INTRODUCTION

1.1 Microgrids

Microgrids are distribution systems with DG units, energy storages and controllable loads, which can be operated either interconnected to the utility distribution grid or in an island mode. Microgrid can be disconnected from the utility grid as a consequence of disturbances in the utility grid or due to planned switching events (e.g. part of active network control or during maintenance operation). The microgrid remains operational in an autonomous mode after islanding and meets the corresponding load requirements. Seamless transition between the interconnected and the island mode is crucial for the stability and the continuity of supply. Also during reconnection the issue of out-of phase reclosing needs to be carefully considered. From the utility grid microgrid can be seen as a single dispatchable load and from the customers' point of view microgrid meets their local needs for power (and heat) and enhances local reliability and power quality. [1], [2], [3] In overall, to realize the future microgrid following technical issues have to be solved [3]:

- Power and energy balance in the microgrid
- Power quality improvement (Harmonic distortion)
- All protection devices in the grid should remain working or introduce a new protection system

An increasing demand for the reliable, high quality power and an increasing number of distorting loads have led to an increased awareness of power quality both by customers and utilities. For example critical loads such as computers and electronic data processing equipment are sensitive to power quality disturbances, e.g., voltage dips.

One important issue also related to the microgrid interconnection to utility grid is also to study the impact of imbalanced utility grid voltages and utility voltage dips on the overall system performance. Normally it is thought that if the utility grid voltages are seriously imbalanced a separation device (connected between the microgrid and the utility grid) will open and isolate the microgrid. However, when the utility grid voltages are not too seriously imbalanced or the voltage dip is under certain percentage and limits, the separation device could remain closed, so that the microgrid would not transfer to island mode too frequently. [4], [5], [6], [7]

Paper [3] presents a real-life sample case where due to the high amount of installed PV-converters the harmonic distortion became significant. Reason for the high harmonic distortion was the interaction between converters harmonic currents and background harmonic voltage multiplied by the resonant behaviour of the grid and loads. To overcome this kind of problems in the microgrid situation, e.g., the use of proper filters with DG unit converters is important.

1.2 Power Quality Compensator

Power quality compensator consists of a series converter and a shunt converter connecting together by a dc-link with capacitor (Fig.1.1). With the PQC, most of the possible power quality problems in the distribution systems can be solved. The shunt converter is controlled by a current control algorithm, while the series converter is controlled by a PWM voltage control algorithm. Because of the used control scheme, these two parts of PQC have different functions [8]:

Shunt Converter

- Compensates the load / microgrid current harmonics
- Compensates the reactive power of the load / microgrid

Series Converter

- Mitigates voltage dips
- Eliminates grid voltage imbalance

1.3 Energy Storage with Power Quality Compensator in Microgrid

In any case the use of some kind of energy storage for voltage control in microgrid during island operation and sudden load changes will be required. Therefore, it would be very useful in many ways to connect this energy storage, e.g., battery or supercapacitor (up to 100 kW) with power quality compensator to the microgrid point of common coupling (PCC) (Fig.1.1).

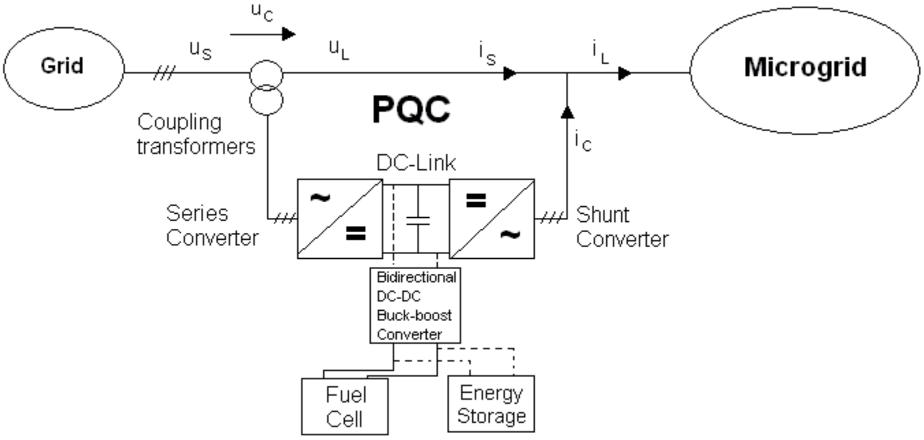


Figure 1.1: *Energy storage (or parallel with DG unit) connected to the DC-link of the power quality compensator in the PCC of microgrid.*

A concept where the energy storage is connected to the DC-link of the PQC was first introduced in the previous project by VTT [12]. Also a DG unit could be connected to DC-link of the PQC unit parallel with the energy storage (Fig. 1.1). In that case the energy storage will take care of the rapid control until the slower control of the DG unit (e.g. fuel cell) is able to response to the current demand. So at the same time when control participation of DG unit increases the participation of energy storage decreases.

Functions of the power quality compensator (listed in section 1.2) together with the energy storage would in normal operation (connected to utility grid) help to protect the sensitive microgrid customers or loads against the voltage dips and voltage imbalance coming from the utility grid. It will also enable the compensation of microgrid current harmonics and reactive power. Thereby current harmonics from microgrid would not flow to utility grid and reactive power would not be taken from utility grid to microgrid loads. However, if also the current waveform inside the microgrid is needed to get filtered then the DG unit converters in the microgrid, e.g., near distorted non-linear loads, should be equipped with active filtering possibility. It is also important to stress that the extent to which active filtering is feasible is limited by the apparent power rating of the converter [9].

During interconnected operation of the microgrid the series converter of the PQC is needed to compensate voltage dips (e.g. due to fault in the utility grid). Because otherwise voltage dips will also occur to microgrid customers due to the control delay of the microgrid circuit breaker relay, e.g., 100-200 ms (Fig. 1.2).

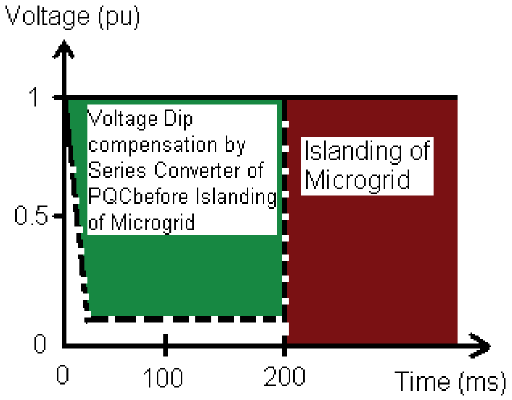


Figure 1.2: *Voltage dip compensation by the series converter of the PQC before the microgrid island operation.*

Our previous simulation studies [10] showed that to maintain the frequency balance in the islanded converter based microgrid, there should be one master unit which determines the synchronism of the microgrid. In this paper, the energy storage with the shunt converter of the PQC acts as this master unit and it has also the main responsibility to control the voltage of the islanded microgrid. In the long-term, depending on the type of other DG units in microgrid, the active power production is shared among DG units with slower control response (e.g. fuel cells, microturbines) than the master unit with energy storage and also possibly with controllable loads.

To conduct the studies, a study system was defined and the corresponding PSCAD simulation model was developed based on the previous studies [11, 12]. Also parts from a model library created previously in a joint project between University of Vaasa and VTT were applied in the studied simulation model. In section 2 the developed operation principles and the control system of the PQC are discussed briefly. In section 3 the study system is introduced and the simulation results of the study and discussions are reported. Conclusions are stated in section 4.

2 OPERATION PRINCIPLES AND CONTROL SYSTEM OF THE PQC WITH ENERGY STORAGE IN MICROGRID

2.1 Operation Principles

The operation principles and active/reactive power flows of the PQC with energy storage are shown in Fig.2.1a)-d).

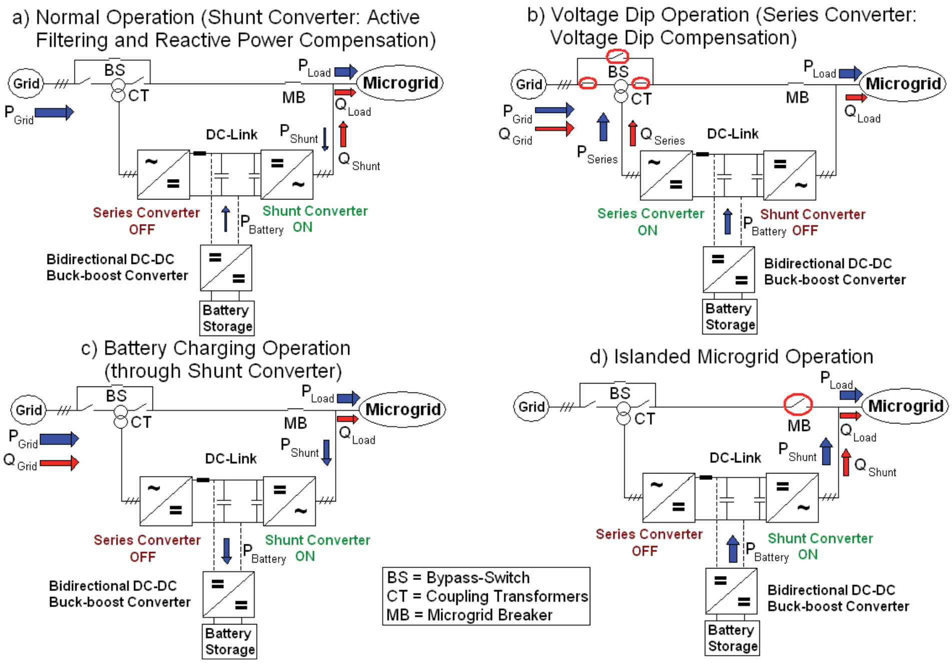


Figure 2.1: *Operation principles and power flows of the PQC with energy storage in different cases.*

These selected operation principles were developed through multiple PSCAD simulations. In a normal interconnected operation (microgrid connected to utility grid) the shunt converter of the PQC produces reactive power needed by microgrid loads and compensates microgrid current harmonics with the active filtering feature of the shunt converter. At the same time the bidirectional DC-DC buck-boost converter controls the dc-link voltage. The active and reactive power flows during normal operation can be seen from Fig.2.1a). The active and reactive power flows of the PQC in a voltage dip operation (voltage dip in utility grid) are shown Fig.2.1b). During the voltage dip operation the series converter of the PQC produces active and reactive power needed to compensate microgrid phase voltages. The shunt converter in active filtering mode is stopped during the voltage dip or imbalance compensation. The reason for this is that compensating currents of the series converter will increase the total harmonic distortion (THD) in the utility grid no matter how well the active filter compensates the microgrid current harmonics. In Fig.2.1c) operation principle of the PQC with energy storage is presented during the battery charging operation. The battery is charged through the shunt converter and the DC-DC buck-boost converter, meanwhile the shunt converter also controls the dc-link voltage. In the islanded microgrid operation (Fig.2.1d)) the microgrid breaker is opened. During the islanded microgrid operation the active and reactive power, needed for rapid the voltage control, are fed from the battery storage through the shunt converter of the PQC.

In all other cases than in the voltage dip or imbalance operation (Fig. 2.1b)) the modulation of series converter is stopped and the coupling transformers of the series converter are passed with a bypass-switch. In this way possible problems with the active filtering of the shunt converter during the normal operation and possible resonance problems during the battery charging operation are avoided. These problems should be solved at least during the normal operation. Otherwise the need of the series converter in the PQC can become questionable (see Fig.1.2), because in real life some delay will occur in the compensation of the voltage dips due to switching of the bypass-switch. On the other hand lower voltage distortion in the microgrid can be achieved during the normal operation with operation configuration used in Fig.2.1, where the series converter is off and the coupling transformers are bypassed.

2.2 Adaptive Configuration and Control System

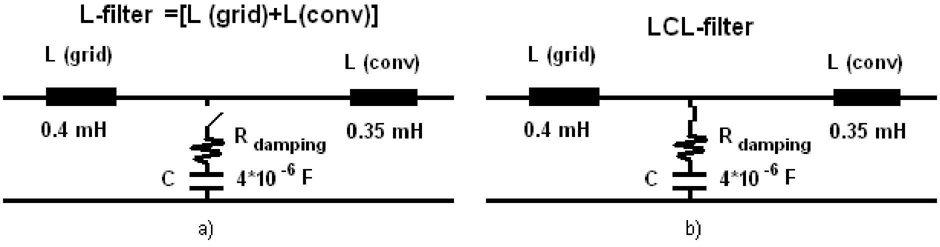


Figure 2.2: *Filter configuration of the shunt converter a) in the normal operation and b) in the islanded operation.*

Especially the control system and filter type of the shunt converter of the PQC with energy storage needs to adapt to requirements of each of the above mentioned different possible operation modes. The control system of the shunt converter in the normal operation is based on reference [8] where hysteresis modulation and L-filter (Fig.2.2a)) are used for time-domain based active filtering as usual [13]. The use of LCL-filter in the time-domain based active filtering method would need a more complex control system with high dynamic performance [13] and so L-filter is used in the studies of this paper. However, during the islanded microgrid operation the voltage control with hysteresis modulation is difficult and also harmonics level with L-filter will increase too high. Therefore, the shunt converter must adapt to island operation by changing to Space Vector Modulation (SVM) (Fig.2.3 and 2.4) and LCL-filter configuration (Fig.2.2b)). Anyhow, it is worth mentioning that the active filter control of the shunt converter in the normal operation is also possible to make by the control system based on SVM, but hysteresis modulation is used in simulations of this paper. The control system of the series converter in the normal operation is also based on reference [8].

The control system for the shunt converter during the islanded microgrid operation is shown in Fig.2.3. and Fig.2.4. During islanding the microgrid is operated in single master operation mode, which in this case means that the shunt converter with the battery storage will act as the master unit and it has the main responsibility to control the voltage and frequency in microgrid. All the other DG units can then be operated in a conventional PQ mode i.e. they do neither take part in frequency nor voltage control during the microgrid island operation. In Fig.2.3 the application of a PU-droop, used in the simulation studies of this paper, for the voltage control with master unit is presented.

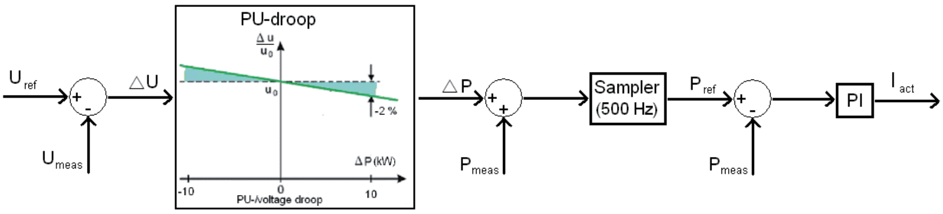


Figure 2.3: *Application of the PU-droop for the voltage control during microgrid island operation in the studied PSCAD simulation model.*

The shunt converter (master unit) also controls the frequency of the microgrid by having the input for Phase-Locked Loop (PLL) during islanding from the 50 Hz 3-phase reference sine wave generator (Fig.2.4) i.e. the master unit determines the synchronism of the microgrid. [10]

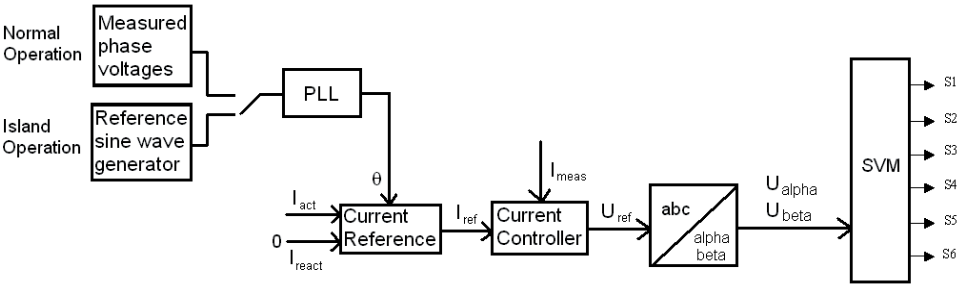


Figure 2.4: *The shunt converter control system during the microgrid island operation. Input for the shunt converter PLL comes from 50 Hz 3-phase reference sine wave generator during islanding.*

3 SIMULATION RESULTS OF THE STUDIED SYSTEM

In this section the PSCAD simulation results of the studied system are presented and discussed. First in section 3.1 the studied system is described. Then in following section 3.2 the simulation results are presented about the behaviour of the PQC and voltage and current THD changes in different network and production/loading configurations.

3.1 The Study System Simulated with PSCAD

The studied urban cable LV network based microgrid is shown in Fig. 3.1, where 800 kVA transformer feeds two radially operated LV feeders 1_1 and 1_2 which have eight loading points consisting of linear passive loads. The passive loads can be adjusted so that the loading of the transformer (which feeds LV feeders 1_1 and 1_2) gets some desired value between 0…150 % of the transformer ratings. Line parameters of the line (AXMKx185S) used in the studied LV network (Fig. 3.1) are R= 0.164 Ω/km, X= 0.0817 Ω/km and R/X -ratio is 2. The fault level and R/X-ratio of feeding power system at the 20 kV level (50 Hz) are 200 MVA and 0.1 respectively, which means that there is a strong connection to HV level.

The feeders 1_1 and 1_2 are connected to LV bus which is fed by distribution transformer through PQC unit with series and shunt converter and also battery storage connected to the dc-link between converters through bi-directional DC-DC buck-boost converter (Fig. 3.1). The dc-link voltage is chosen to be 1.05 kV, because active filtering typically needs a higher dc-link voltage when compared to line converters [13]. In following simulations the islanded microgrid is disconnected from main network with breaker so that the microgrid will consist of feeders 1_1 and 1_2 (Fig. 3.1). At the end of feeder 1_1, there is also a non-linear thyristor rectifier load (35 kW and 9 kVar).

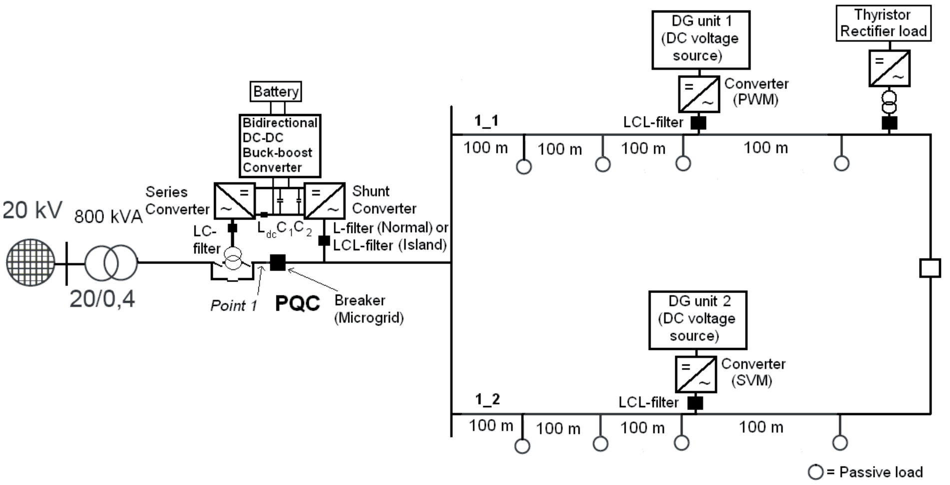


Figure 3.1: *The studied urban LV network based microgrid with battery storage+PQC in the connection point of microgrid.*

There are also two converter connected DG units in microgrid. One is in feeder 1_1 (DG unit 1, PWM) and the other in feeder 1_2 (DG unit 2, SVM) as shown in Fig. 3.1. Initially with two DG units in microgrid the total passive load of the microgrid is 256 kVA with power factor 0.97_{ind} and 68 kVA and 0.97_{ind} without the DG units. Some details about the study system components (PQC and DG units) and their parameters are listed in table 3.1.

Table 3.1: Study system parameters used in the PSCAD simulations

	Parameter	*Value*
Simulation	Solution time step	5 µs
Series Converter	Filter L, C	0.2 mH, 100 µF
	Modulation method	PWM
	Switching Frequency	8 kHz
	Coupling transformer rated voltage	230/46 V
Shunt Converter	Filter L_1, C, L_2	0.4 mH, 4 µF, 0.35 mH
	(In normal operation $L=L_1+L_2$ and in island operation LCL)	
	Modulation method	Hysteresis*
	(* normal, **island)	SVM**
	Switching Frequency	Not constant*
	(* normal, **island)	8 kHz**
DC-link	Capacitor C_1 (DC-DC converter), C_2 (on shunt converter side)	10 000 µF, 5 000 µF
	Inductance L_{dc} (on series converter side)	0.3 mH
	Reference dc voltage V_{DC}	1.05 kV
Battery Storage	Capacity	2 000 Ah
	DC-DC Buck-boost Converter	0.575/1.05 kV
	Max. Charging Current	300 A
DG unit 1 120 kVA	Filter L_1, C, L_2	0.2 mH, 10 µF, 0.4 mH
	Modulation method	PWM
	Switching Frequency	8 kHz
DG unit 2 120 kVA	Filter L_1, C, L_2	0.4 mH, 4 µF, 0.35 mH
	Modulation method	SVM
	Switching Frequency	8 kHz

3.2 Simulation Results

In following the simulation results from utility voltage dip compensation (3.2.1), microgrid current harmonics compensation (3.2.2) and voltage and current THD

(%) with different network and load configurations (3.2.3) are presented and discussed.

3.2.1 Series Converter of PQC for Balanced and Imbalanced Voltage Dip Compensation

In the simulation there is first 20 % imbalanced 2-phase (0.5-0.7 s) and then 30 % balanced 3-phase (1.2-1.4 s) voltage dip in the utility grid. These voltage dips are compensated (Fig. 3.2a) and c)) by series converter active and reactive power as shown in Fig. 3.2b). Simulation results show that the voltage dips can be well compensated with the developed model of the PQC.

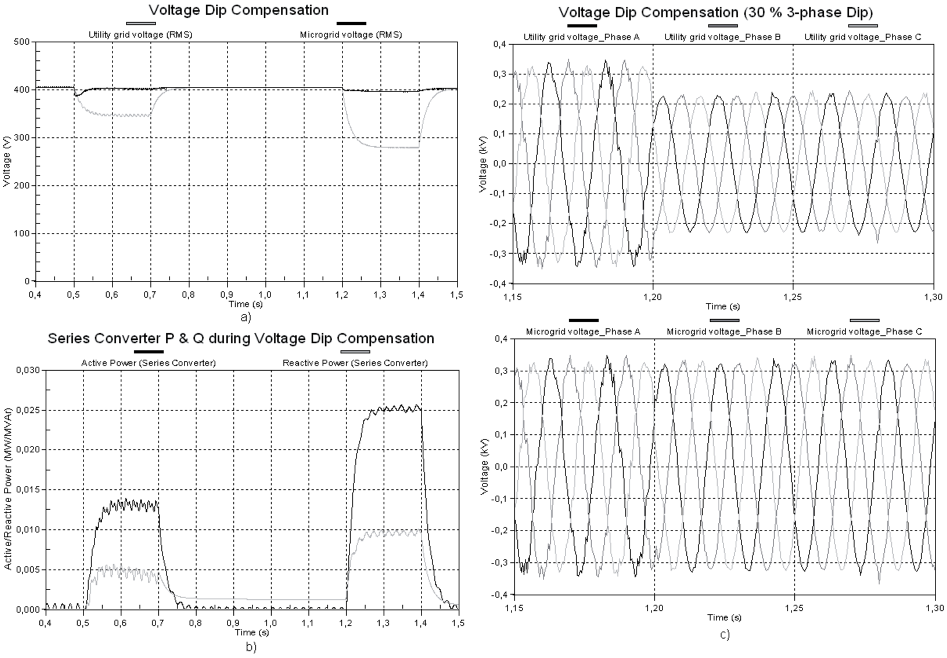


Figure 3.2: *a) Voltage (rms) values in utility grid and microgrid during 2- and 3-phase voltage dips, b) Series converter active and reactive power during 2- and 3-phase voltage dips and c) Utility grid and microgrid phase voltages during 3-phase voltage dip. (These results are from simulation with two DG units in microgrid.)*

3.2.2 Shunt Converter of PQC for Microgrid Current Harmonics Compensation

In Fig. 3.3 the simulation results from the microgrid reactive power and current harmonics compensation with the shunt converter of the PQC are shown. In Fig. 3.3a)-c) phase A currents for PQC, microgrid and utility grid are presented when shunt converter of PQC compensates microgrid current distortion. In Fig. 3.3d) the phase A current of PQC is shown when it also compensates microgrid reactive power. The microgrid and utility grid current harmonic spectrums (harmonics between 2 and 25) at the same time are shown in Fig. 3.3e) and f). From simulation results one can see that the PQC is able to compensate reactive power and microgrid current harmonics quite well. Although 2nd harmonic is significantly increased in the utility grid side current.

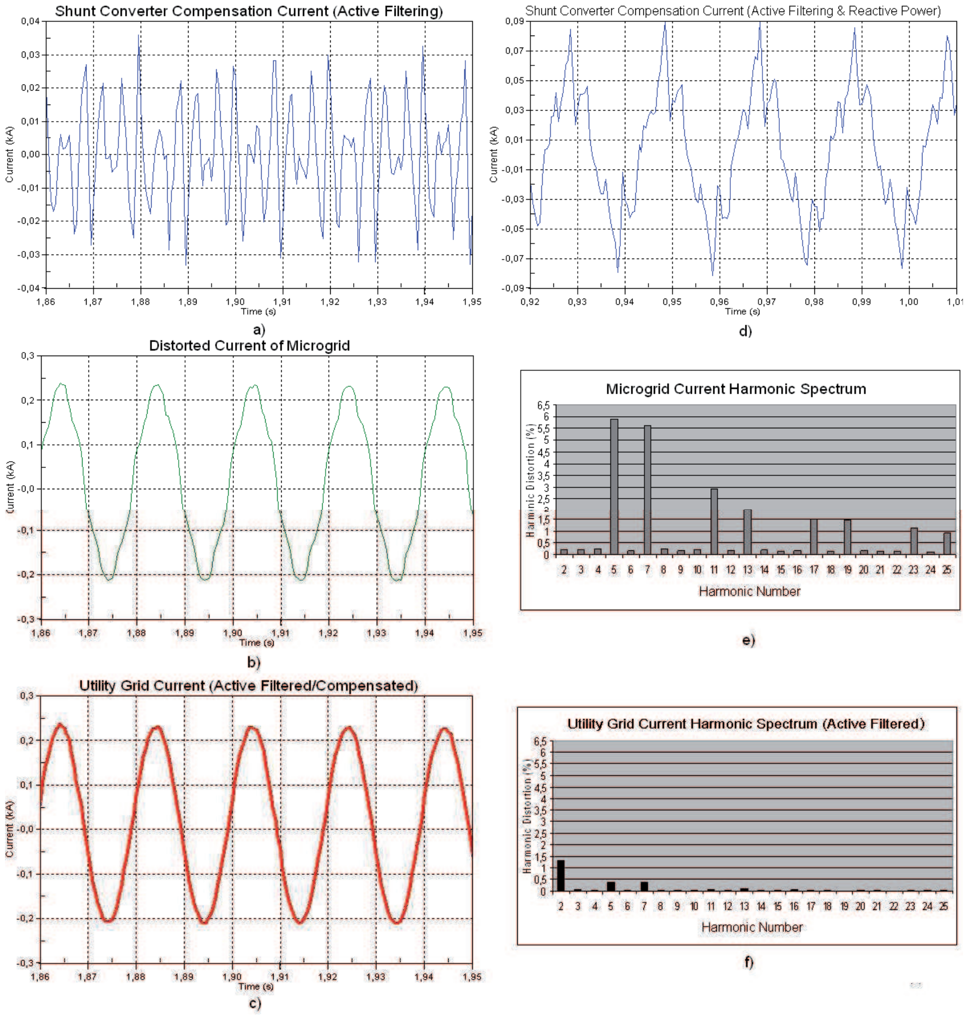


Figure 3.3: *a)-c) Phase A currents for PQC, microgrid and utility grid when the shunt converter of the PQC compensates microgrid current distortion. d) Phase A current of the PQC, e) Microgrid current harmonic spectrum between 2 and 25 and f) Active filtered utility grid current harmonic spectrum when the shunt converter of the PQC compensates also microgrid reactive power in addition to microgrid current distortion. (These results are from simulation with two DG units in microgrid.)*

3.2.3 Voltage and Current THD (%) with Different Network and Load Configurations

Various organizations on the national and international level have made standards both for individual and total harmonic distortion of voltage in the LV networks. IEEE Standard 519-1992 limits the THD to be less than 5 %. Standards IEC 61000-2-2 and EN 50160 define that the THD of the supply voltage including all harmonics up to 40th order shall be less than 8 %. Differences between the harmonic compatibility levels in standards EN 50160 and IEC 61000-2-2 are quite small (Fig. 3.4). [14]

For distributed generation units usually more tight limits for voltage individual and total harmonic distortion are defined. For example standard IEC 61000-2-4 /Class 2 which applies generally to PCCs for non-public power supplies and in-plant point of coupling (IPC) in industrial environments takes into account the harmonics up to 50th order and THD of voltage and current should be less than 8%. Also interharmonics are covered. [15]

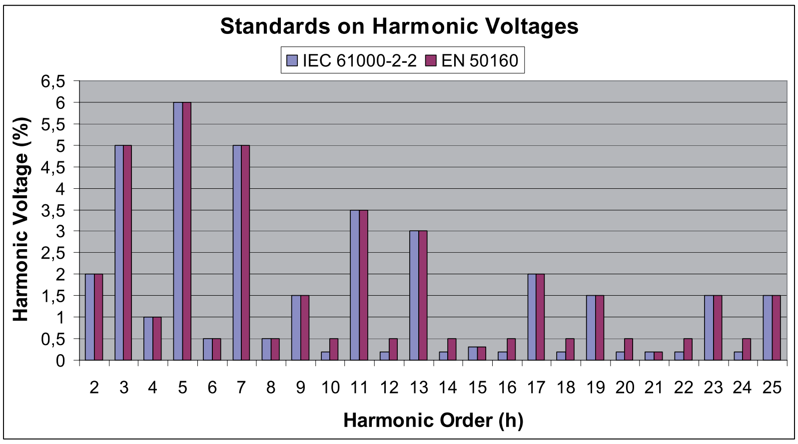


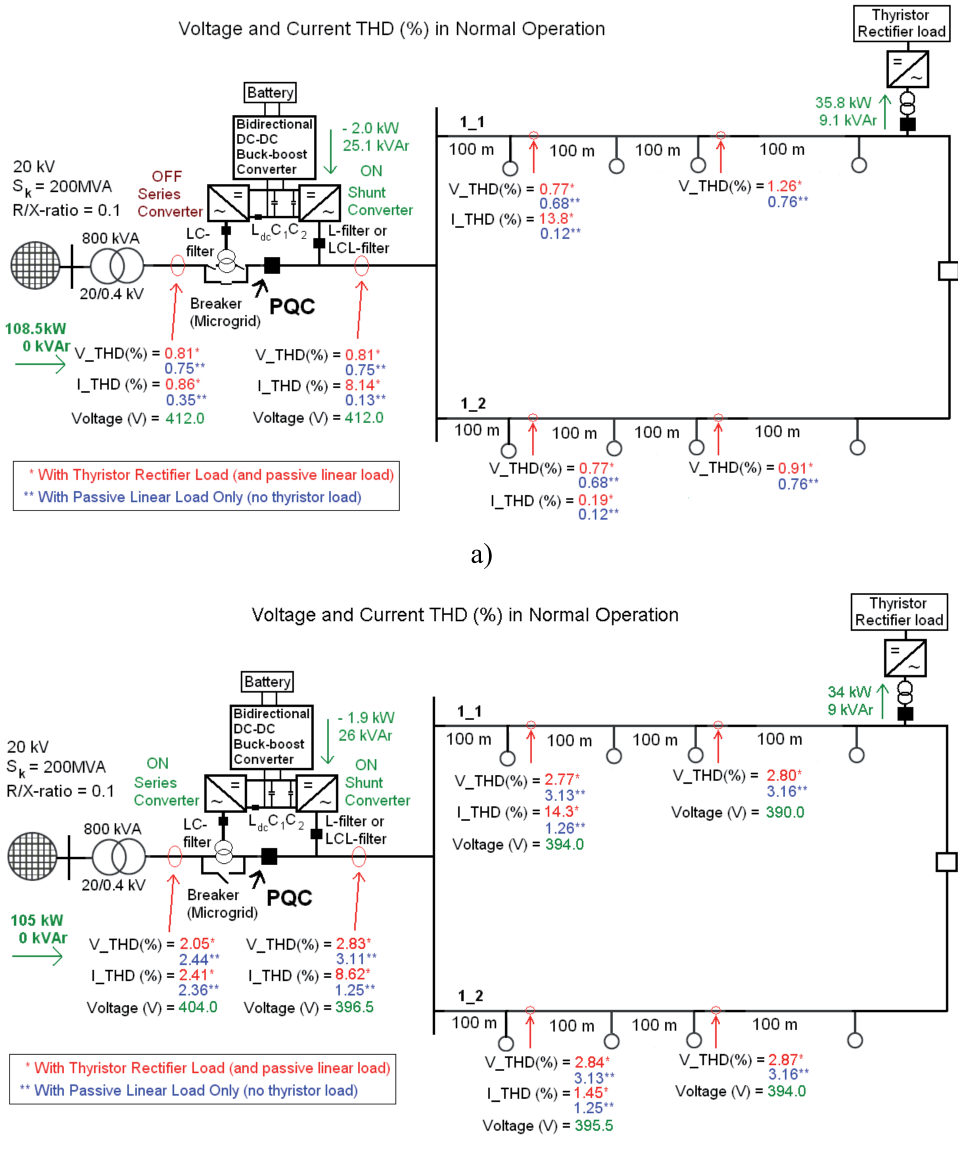
Figure 3.4: *Voltage Harmonic compatibility levels as in EN 50160 and IEC 61000-2-2. [14]*

In sections 3.2.3.1 (without two DG units) and 3.2.3.2 (with two DG units) the simulation results from voltage and current THD (%) in different points of the microgrid with different load configurations in normal and island operation are presented. The voltage and current THD (%) results are presented in studied cases for each microgrid point with harmonics up to 255 (12.75 kHz), so also possible harmonics near the switching frequency of the DG unit converters are included in THD values (those which are not filtered by passive filters between microgrid and DG unit converters).

3.2.3.1 Voltage and Current THD (%) without other DG units in microgrid

From the simulation results in the normal operation (Fig. 3.5) it can be seen that when the thyristor rectifier load is connected to feeder 1_1, the voltage THD (%) is naturally notably higher at the end of that feeder than at the end of feeder 1_2.

Simulation results also show how PQC reduces current THD from 8.14 % to 0.86 % when the thyristor rectifier load is connected to the microgrid (Fig. 3.5a)). While the series converter is on (Fig. 3.5b)) the microgrid voltage distortion becomes higher than in Fig. 3.5a) and if there is only passive linear load in microgrid (the non-linear thyristor load is replaced with same amount of passive linear load), the voltage THD in microgrid is even higher.



a)

b)

Figure 3.5: *Voltage and current total harmonic distortion, THD (%) with different load configurations in normal operation without other DG units in microgrid, a) Series converter off and coupling transformers bypassed, b) Series converter on.*

In the island operation of microgrid (Fig. 3.6) the voltage THD becomes very high (about 17 %) because very large share of the total load is non-linear (thyristor load). And even without the thyristor load, the voltage THD stays quite high (about 6 %) because the microgrid is so lightly loaded in overall, although the current THD (%) at the same time is very small (about 0.35 %).

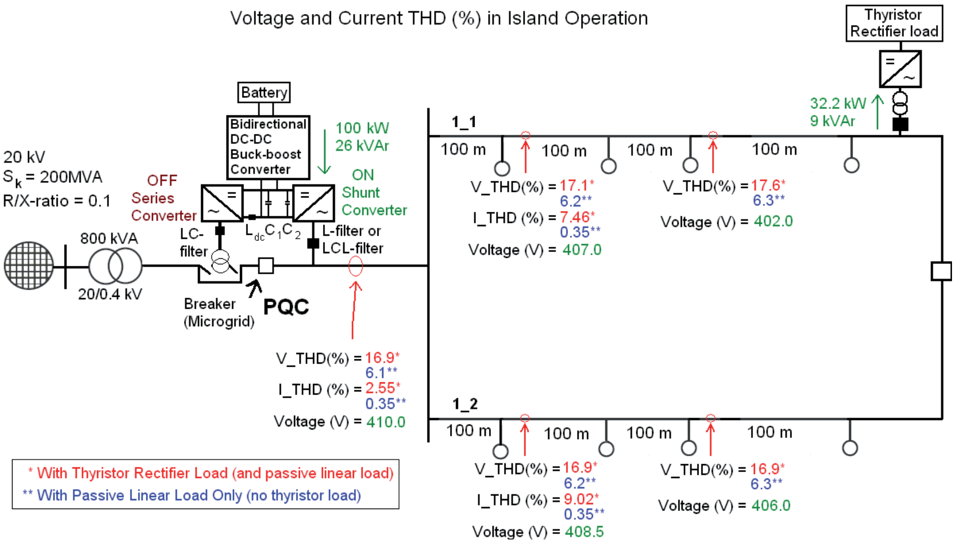
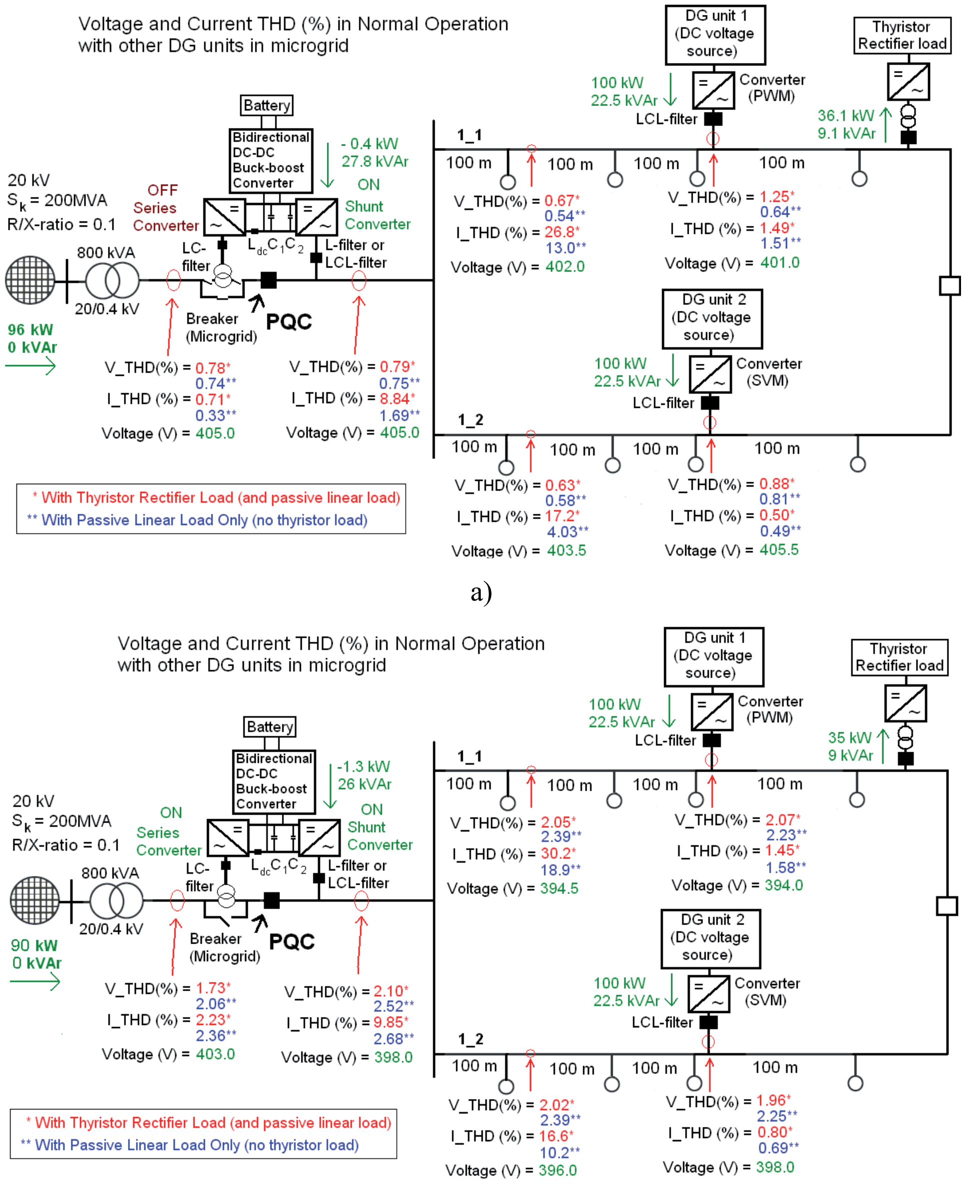


Figure 3.6: *Voltage and current total harmonic distortion, THD (%) with different load configurations in island operation without other DG units in microgrid (Voltage target value in PCC of PQC is 410 V).*

3.2.3.2 Voltage and Current THD (%) with two DG units in microgrid

The simulation results with two DG units in microgrid which are presented in Fig. 3.7 and 3.8 are in principle similar to previous results without DG units in Fig. 3.5 and 3.6. However, in this case with two DG units the replacement of the non-linear thyristor load with the linear passive load does not reduce current THD in the PCC of the PQC as much as without these DG units. Because of this one can conclude that the increase in the current THD without the non-linear load is due to the converter based DG units. When series converter is on (Fig. 3.7b)) the voltage distortion in microgrid is higher than in Fig. 3.7a), but also in this case with two DG units the change of non-linear thyristor load to linear passive load even increases the voltage THD in microgrid. If only 31 instead of 255 harmonics were taken account in the voltage THD, it would reduce on the utility grid side of the PQC from 0.78 % to 0.26 % in Fig. 3.7a) and from 1.73 % to 0.26 % in Fig. 3.7.b). This indicates that there are considerable amount of higher order harmonics (> 31) in voltage THD.

During the island operation (Fig. 3.8) voltage THD is much lower than in Fig. 3.6. The reason for the lower voltage THD in the island operation, with two DG units in microgrid, is the lower share of non-linear load from total load than in the case without DG units. In overall it can also be seen that smaller thyristor rectifier load increases much more voltage and current THD than DG units with proper (LCL) filters.



a)

b)

Figure 3.7: *Voltage and current total harmonic distortion, THD (%) with different load configurations in normal operation with two DG units in microgrid, a) Series converter off and coupling transformers bypassed, b) Series converter on.*

In Fig. 3.9 the microgrid current and voltage harmonic spectrum during the normal and the island operation are presented. In Fig. 3.9 only harmonics between 2 and 25 are shown and so the possible harmonics near the PQC switching frequency are not covered. The simulation results from the microgrid current harmonic spectrum during the normal operation show that 5th, 7th, 11th, 13th, 17th, 19th, 23th, and 25th harmonics are quite high with the thyristor load and the series converter off (Fig. 3.10a)) as well as with the series converter on (Fig. 3.10b)). From the active filtered utility grid current spectrum (Fig. 3.10a)) can be seen that the 2nd harmonic becomes higher there than in the microgrid. But when the series converter is on (Fig. 3.10 b)) the 2nd harmonic is quite high also in the microgrid and the 3rd and 4th harmonics are increased as well. In Fig. 3.10c) and d) during the island operation the same harmonics (Fig. 3.10d)) are present in the voltage as in current (Fig. 3.10c)), but also the 3rd harmonic can be found from the current spectrum.

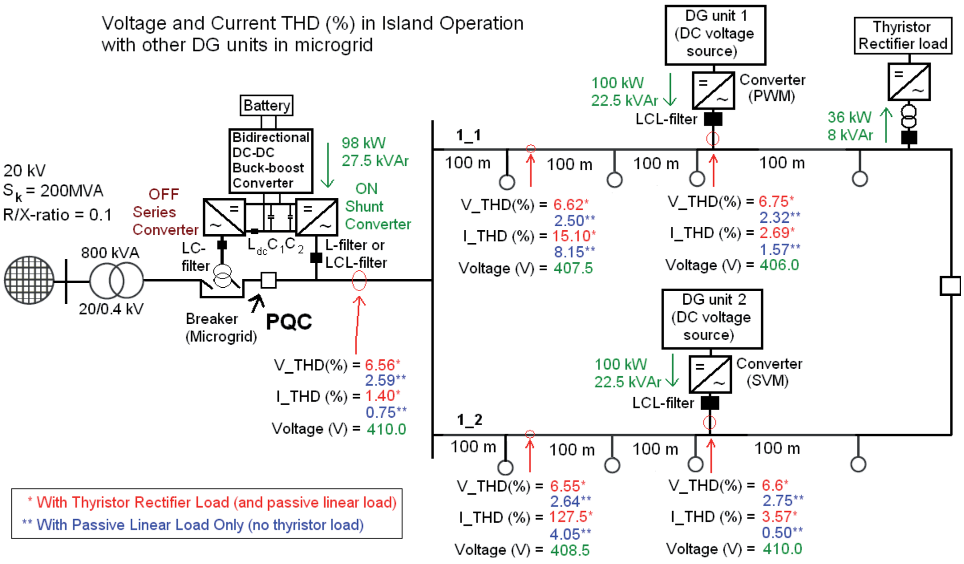


Figure 3.8: *Voltage and current total harmonic distortion, THD (%) with different load configurations in island operation with two DG units in microgrid (Target value for voltage in PCC of PQC is 410 V).*

The reason for the current 2nd (and also 3rd and 4th) harmonic increase and higher voltage distortion in the microgrid during the normal operation when the series converter is on could be that, e.g., the coupling transformers change the system impendance and resonance frequencies. Because systems with low short circuit ratios can experience high waveform distortion therefore that the inductance of high ac system impedance may resonate with reactive power compensating capacitors and with harmonic filters at converter terminals [16]. These resonant frequencies can be low, possibly as low as the 2nd harmonic [16]. Some confirmation for this assumption can be found from Fig. 3.10, where the system harmonic impedance Z(f) (with two DG units in microgrid) is drawn from point 1 of PQC (see Fig. 3.1) for frequecies up to 2500 Hz. The system harmonic impedance is quite high for frequencies under 200 Hz. If this problem can be solved, then the series converter could be on during the normal operation.

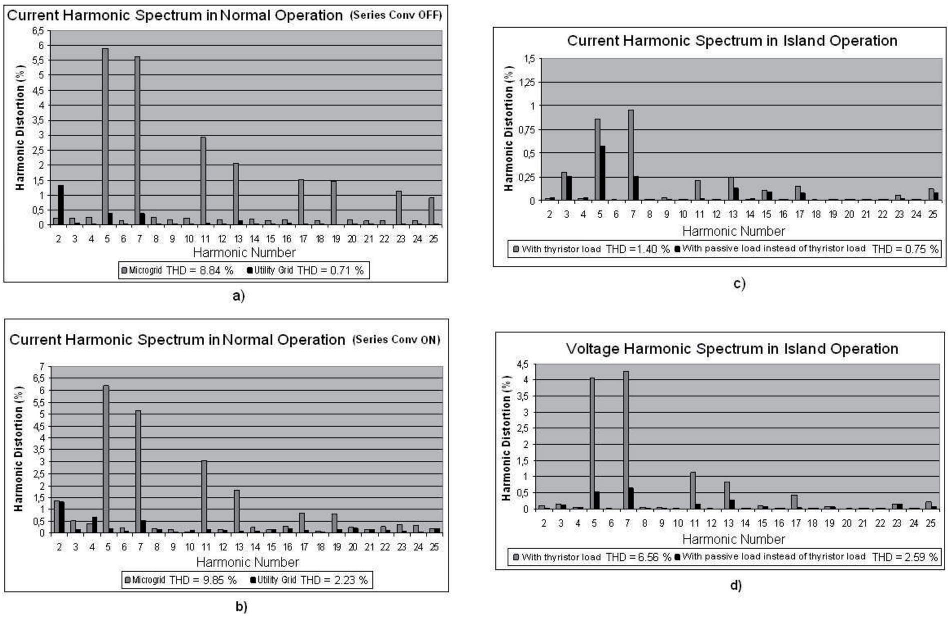


Figure 3.9: *Microgrid current harmonic spectrum during normal operation a) Series converter off, b) Series converter on and during island operation c) current and d) voltage harmonic spectrum in PCC of PQC.*

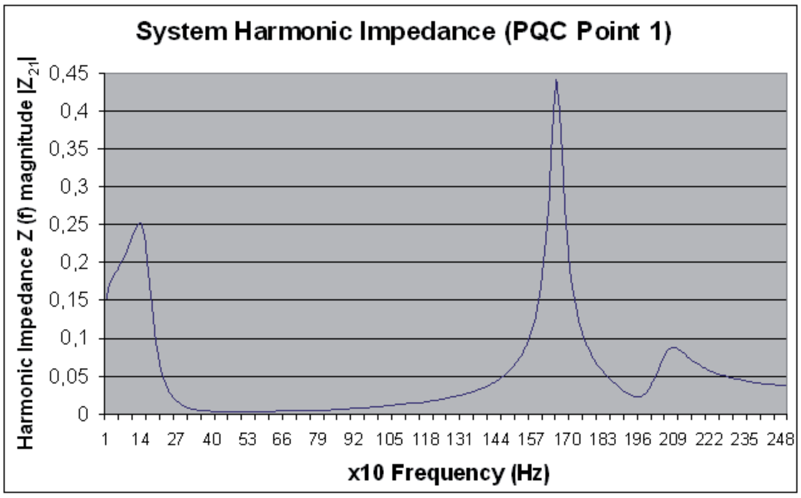


Figure 3.10: *System harmonic Impedance Z(f) in Point 1 of PQC (Fig. 3.1) for frequecies up to 2500 Hz.*

4 CONCLUSIONS

Power quality, power balance and protection issues of the microgrid are crucial for future microgrids. This paper presented a new advanced concept to improve the quality of power within the microgrid and also the quality of currents flowing between the microgrid and the utility grid by means of the power quality compensator (PQC) with energy storage.

The PSCAD simulation results showed how the PQC with energy storage can solve many of the power quality problems: 1) The shunt converter of the PQC can compensate the microgrid current harmonics and reactive power, 2) The series converter of the PQC can eliminate utility grid voltage dips and utility grid voltage imbalance and 3) Islanding and the island operation is possible unintentionally or intentionally by the developed adaptive configuration and control system of the PQC shunt converter which makes possible the instantaneous voltage control and power balance management with low harmonic distortion in islanded microgrid.

From the simulation results it can also be seen that power quality during the island operation, from the current and voltage THD point of view, can very well be kept in the standard limits a) with reasonable share of non-linear thyristor based load of the total microgrid load and b) when the DG units in microgrid are equipped with good LCL-filters. LCL-filters are needed in island operation, because short circuit power is very low in weak island network and so the harmonic currents will have a greater effect on generating harmonic voltages than in normal operation. But also in the normal operation when the microgrid is connected to utility grid, the utility grid background harmonic voltage can resonate with harmonic currents coming from DG unit converters. Therefore proper filtering of the DG unit converter currents is necessary in both island and normal operation.

Nowadays the amount of converter based DG units and sensitive loads, which have low immunity to power quality problems (e.g. voltage dips), is increasing in distribution networks. Therefore it is important to limit power quality disturbances (harmonics) coming from power electronic devices (loads and DG units) and possibly also increase the immunity of sensitive loads. However, in some distribution networks the problems are already emerging and also there the concept of the PQC with energy storage introduced in this paper could be a functional way to deal with the power quality problems.

5 ACKNOWLEDGEMENTS

The authors want to express their thanks to Tekes, the Finnish Funding Agency for Technology and Innovation, and companies for their financial support in *Energy storage for managing distributed generation* -project which is part of Tekes Distributed energy systems technology programme (DENSY) 2003-2007.

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VOLTAGE AND CURRENT THD IN MICROGRID WITH DIFFERENT DG UNIT AND LOAD CONFIGURATIONS

Hannu LAAKSONEN
University of Vaasa – Finland
hannu.laaksonen@uwasa.fi

Kimmo KAUHANIEMI
University of Vaasa – Finland
kimmo.kauhaniemi@uwasa.fi

ABSTRACT

After microgrid transition from the normal operation to the islanded operation the system impedance changes considerably and it affects on the harmonic voltages of the microgrid. In this paper the voltage and current THD before and after islanding are studied with different microgrid configurations. Simulations are also made by applying negative sequence filtering in control system of converters to reduce the voltage and current THD in microgrid during unsymmetrical load. Based on the studies recommendations for technical solutions which ensure high power quality in islanded microgrid are given.

INTRODUCTION

Microgrids are distribution systems with DG units, energy storages and controllable loads, which can be operated parallel with utility grid or in an island mode (Fig. 1). Microgrid can be disconnected from the utility grid as a consequence of disturbances in the utility grid or due to planned switching events.

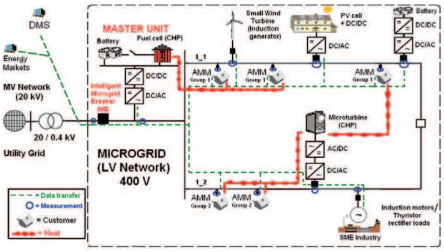

Figure 1. Example of a LV network microgrid.

An increasing demand for the reliable, high quality power and an increasing number of distorting loads have led to an increased awareness of power quality both by customers and utilities. In addition, most of the distributed generation (DG) units connected in future to low voltage (LV) network microgrids will be converter based. These DG unit converters together with possibly existing nonlinear loads have potential to distort the voltage waveform even more.
This paper studies the voltage and current THD before and after islanding in the microgrid with different microgrid configurations (Fig. 1). In table 1 eight studied microgrid configurations are listed, including the reference case 1. In reference case 1 there are converter based master unit, 2 converter based DG units and balanced passive load in microgrid. All converters are SVM (Space vector modulation) modulated with 8 kHz switching frequency and equipped with passive LCL-filters as well as battery and dc-dc converter connected to their dc-links to model the energy source. In case 1 the LV network lines of the microgrid are weak i.e. the R/X-ratio is high. Differences of each simulated cases to the reference case 1 can be seen from table 1. The studies are made with PSCAD simulation software package.

Table1. Studied microgrid configurations

Case	Difference in microgrid configurations
1.	*Reference case*
2a.	Lower (6 kHz) switching frequency on converters
2b.	Lower (4kHz) switching frequency on converters
3.	Lower R/X-ratio on LV network lines
4.	Thyristor rectifier (TR) load
5a.	Induction motor (IM) load
5b.	Induction motor (IM) load and unbalanced passive load
6.	L-filters on converters
7.	PWM (Pulse width modulation) modulated converters
8.	Constant DC voltage source in the dc-link of converters

HARMONIC DISTORTION IN MICROGRID

Harmonic distortion in power systems is caused by nonlinear devices in which the current is not proportional to the applied voltage. The response of the power system i.e. the system impedance at each harmonic frequency determines the impact of the nonlinear load on harmonic voltage distortion. Various organizations on the national and international level have made standards both for individual and total harmonic distortion of voltage in the LV networks. For example standards IEC 61000-2-2 and EN 50160 define that the THD of the supply voltage including all harmonics up to 40th order shall be less than 8 %. For distributed generation units usually more tight limits for voltage individual and total harmonic distortion are defined. These standards do not take into account the possible harmonics near the converter switching frequency (e.g. 160th / 8 kHz). It is possible that these higher order harmonics caused by converters may resonate with the system impedance, which in turn will cause voltage waveforms with multiple zero crossings that can disturb the timing circuits etc. [1]
When the microgrid transfers from the normal operation, parallel with utility grid, to the islanded operation the grid impedances and the harmonic voltages will change. Therefore, during the island operation the microgrid is much weaker and more sensitive to disturbances and especially the harmonic currents produced by converters and possible distorting loads will generate much higher harmonic voltages. To overcome possible problems during islanding

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Paper was presented at the CIRED Workshop and published at the *Proceedings of CIRED 2008 Seminar: SmartGrids for Distribution*, Frankfurt, Germany.

due to high voltage and current total harmonic distortion (THD), the effect of different filter types, sizes and switching frequencies of the converters must be carefully examined. High voltage distortion can cause instability during the island operation of the microgrid and it may also interact on the converters fault-behaviour during island operation [2], [3].

The voltage and current THD (%) results are presented in each of the studied cases with harmonics up to 255 (12.75 kHz). Thus possible harmonics near the switching frequency of the DG unit converters are included in the THD values (those which are not filtered by passive filters between microgrid and DG unit converters). In this way also the possible harmonics caused by resonance between higher order harmonics coming from converters and the system impedance will be included in THD values.

STUDIED SYSTEM AND SIMULATION RESULTS

Studied LV Network Based Microgrid

The LV network used in this work is shown in Fig. 2. The system consists of one 800 kVA MV/LV-transformer which normally feeds LV feeders 1_1 and 1_2. In the simulation studies the islanded microgrid is disconnected from main network by the breaker so that the microgrid consists of feeders 1_1 and 1_2. At the connection point of the microgrid, before the feeders 1_1 and 1_2, there is a storage unit (battery 120 kVA) equipped with converter 1. At the end of feeder 1_1 there is a DG Unit 1 (100 kW, 30 kVAr) equipped with converter 3 and also thyristor rectifier load (31 kW, 7 kVAr). In the middle of the feeder 1_2 there is an induction motor (51 kW, 34 kVAr) as well as DG Unit 2 (100 kW, 30 kVAr) equipped with converter 2 at the end of the feeder.

The load in the microgrid consists of four passive loads on each feeder. The passive loads can be adjusted so that the loading of the transformer (which feeds LV feeders 1_1 and 1_2) gets some desired value between 0…150 % of the transformer ratings. In reference case 1 (table 1) loading of the transformer was set to 35 % (power factor 0.98_{ind}) and in different cases it was changed according to the size of the possible additional load (IM or TR).

Simulations are made in reference case 1 with higher R/X-ratio LV network line parameters shown in table 2. The fault level and R/X-ratio of the feeding utility network (20 kV, 50 Hz) are 200 MVA and 0.1 respectively. The converters are modeled in reference case as three-phase, three-leg, SVM modulated units with LCL-filters and the dc-link of the master unit is modeled with battery storage + DC/DC-buck-boost converter. The dc-link voltage V_{DC} of converter is chosen to be 0.7 kV. With all converters the PSCAD's own PLL component was used. Filter parameters used in simulations on converter based DG units are presented in table 3.

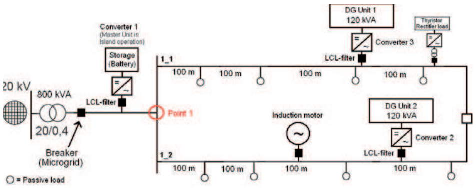


Figure 2. Studied LV network based microgrid.

Table 2. Resistance, Reactance and R/X ratio of LV network in Fig. 2.

	R (Ω/km)	X (Ω/km)	R/X
AMKA 3x35+50	0.868	0.104	8.35
AXMK 4x185S	0.164	0.0817	2.01

Table 3. Filter parameters used in simulations on converter based DG units.

	Parameter	Value
LCL-filter	L_1, R_d, C, L_2	0.4 mH, 0.1 Ω, 10 μF, 0.2 mH
L-filter	L_1	1.6 mH

Single Master Operation

During islanding, microgrid is operated in single master operation mode, which in this case means that the converter 1 with battery storage (Fig. 3) will act as the master unit and it has the main responsibility to control the voltage and frequency in microgrid when islanded. The control system for master unit (Battery storage) converter 1 in island operation is shown in Fig. 4. All the other DG units can then be operated in conventional PQ mode i.e. they do neither take part in frequency nor voltage control.

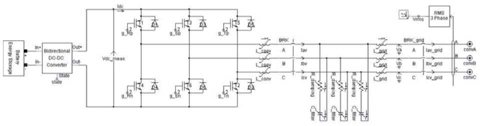
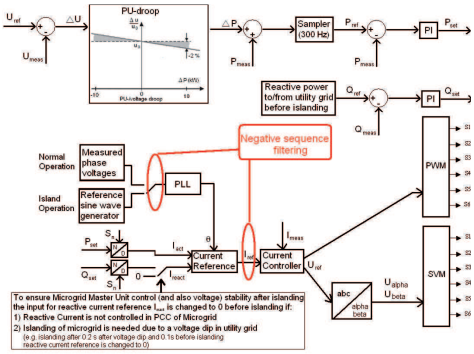


Figure 3. PSCAD simulation model of the master unit with battery storage + dc-dc buck-boost converter.



To ensure Microgrid Master Unit control (and also voltage) stability after islanding the input for reactive current reference I_{react} is changed to 0 before islanding if:
1) Reactive Current is not controlled in PCC of Microgrid
2) Islanding of microgrid is needed due to a voltage dip in utility grid
(e.g. islanding after 0.2 s after voltage dip and 0.1s before islanding reactive current reference is changed to 0)

Figure 4. Control system of master unit converter during islanding.

By using power quality compensator (PQC) with energy storage as the master unit of microgrid it could also be possible to improve the quality of currents flowing between the microgrid and the utility grid [4].

Simulation results

In this section the simulation results from studies about voltage and current THD during normal and island operation of microgrid with different configurations are presented as well as the effect of negative sequence filtering on THD.

Voltage and current THD with different configurations

In table 4 the voltage and current THD before and after islanding in the microgrid with different microgrid configurations (table 1). In Fig. 5 the voltage and current THD from different cases during island operation are shown as a bar graph. From table 4 can be seen that the reduction of switching frequency of converters from 8 to 4 kHz (case 2b) increases notably the voltage harmonic distortion both in normal and island operation with the used LCL-filter parameters on converters (table 3). Also the effect of thyristor load (case 4) to the harmonic voltage distortion and the current THD of the DG unit converter next to it is obvious especially during island operation (Fig. 5). With PWM modulation (case 7) and with modeling the energy source as constant dc source (case 8) the voltage and current THD are slightly higher than in reference case 1. The most significant increase in voltage THD during normal and especially during island operation is experienced in case 6 when L-filters are used on converters instead of LCL-filters.

Table 4. Voltage and current THD (255 harmonics) in microgrid with different configurations

Case	Before Islanding $(U_{THD}^{*}/I_{THD}^{**})$	During Islanding $(U_{THD}^{*}/I_{THD}^{**})$
1.	0.40 / 0.24	1.17 / 0.26
2a.	0.73 / 0.36	2.11 / 0.32
2b.	2.00 / 1.08	5.08 / 0.61
3.	0.42 / 0.27	1.17 / 0.26
4.	0.58 / 1.23	5.39 / 3.02
5a.	0.41 / 0.27	1.16 / 0.29
6.	2.71 / 0.7	25.01 / 0.40
7.	0.60 / 0.52	1.85 / 0.43
8.	0.44 / 0.36	1.37 / 0.33

$^{*)}$From phase C in connection point of master unit, $^{**)}$From phase A in connection point of DG Unit 1 on feeder 1_1

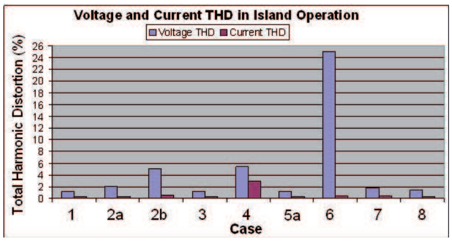
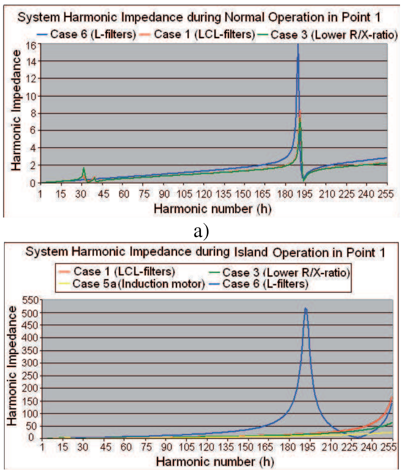


Figure 5. Voltage and current THD (%) in different cases (from table 4) during island operation of microgrid.

With L-filter especially the higher order harmonics are not filtered out from the output current of the converters very effectively. Another reason for the high voltage THD in case 6 can be seen from Fig. 6 where the system harmonic impedance from point 1 (Fig. 2) in some cases during normal and island operation are presented. Especially during island operation the high resonance peak in case 6 near the switching frequency of converters will increase the voltage THD very significantly while the current THD is reasonably low (table 4).



a)

b)

Figure 6. System harmonic impedance during a) normal and b) island operation of microgrid in cases 1, 3, 5a and 6.

The effect of negative sequence filtering on THD

In addition to the previous simulation results with different microgrid configurations (table 4), the simulation results with cases 5a and 5b (table 1) are presented in table 5. The simulations are done to show the possibility to reduce the microgrid voltage and current THD during unsymmetrical faults and/or unbalanced load by using negative sequence filtering [5] in control system of converters (see Fig. 4). From Fig. 7 the effect of unbalanced load on phase voltages during normal and island operation can be seen.

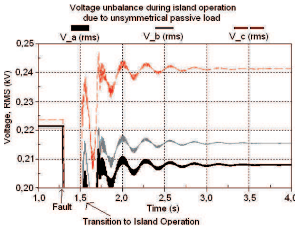


Figure 7. Voltage unbalance in simulations during island operation due to unsymmetrical passive load.

Table 5. The effect of negative sequence filtering in control system of converters to voltage and current THD (255 harmonics) of microgrid in cases 5a and 5b.

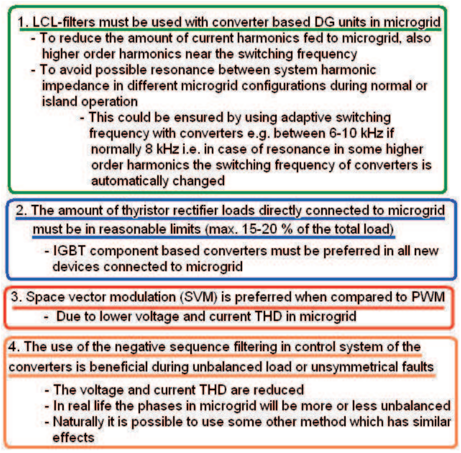
Neg. Seq. filtering	**Before Islanding (U_{THD}^{*}/I_{THD}^{**})**	**During Fault*** Before Islanding (U_{THD}^{*}/I_{THD}^{**})**	**During Islanding (U_{THD}^{*}/I_{THD}^{**})**
5a. No	0.41 / 0.27	0.75 / 8.70	1.16 / 0.29
5b. No	0.42 / 0.44	1.01 / 8.90	1.70 / 1.11
5a. With PLL	0.41 / 0.27	0.54 / 6.1	1.16 / 0.29
5b. With PLL	0.42 / 0.41	0.81 / 6.23	1.70 / 1.12
5a. With PLL & I_{ref}	0.41 / 0.27	0.19 / 0.20	1.14 / 0.25
5b. With PLL & I_{ref}	0.41 / 0.28	0.25 / 0.21	1.15 / 0.31

*)From phase C in connection point of master unit, **)From phase A in connection point of DG Unit 1 on feeder 1_1, ***)Unsymmetrical 2-phase earth fault (A-B-ground) in utility grid

From the simulation results of table 5 it can be seen that the unsymmetrical passive load in case 5b increases the voltage and current THD in microgrid especially during islanding when the difference between phase voltage magnitudes (Fig. 7) is larger when compared to case 5a. The negative sequence filtering with PLL can be done to improve the stability of the converter based unit especially during unsymmetrical faults. From simulation results of table 5 one can see that by using negative sequence filtering with PLL the voltage and current THD is slightly reduced in cases 5a and 5b. However, when negative sequence is filtered from the current reference I_{ref} in converter control system (Fig. 4) the current THD is reduced in case 5b during normal operation and also during unsymmetrical fault before islanding the voltage and current THD in cases 5a and 5b is significantly reduced (table 5). In addition, after islanding the distortions in voltage and current are notably lower. However, the negative sequence filtering from current reference I_{ref} does not remove the ripple from dc-link voltage during unsymmetrical fault.

CONCLUSIONS

Based on the simulation results it is obvious that voltage THD behaviour cannot be foreseen from the current THD contribution of the converter when operating normally parallel with utility grid. They are affected by the particular system harmonic impedance in that point and the harmonics coming from other devices (i.e. backround harmonic voltages) which are dependent on the configuration, control system and parameters of these devices. When the microgrid transfers from normal to islanded operation the grid impedances and the harmonic voltages will change. Therefore, during the island operation of the microgrid there is a risk that some higher order harmonics near the switching frequency of the converter may resonate with the changed system harmonic impedance and even without resonances the harmonic currents produced by converters and possible distorting loads will generate much higher harmonic voltages during island operation. Summary about the findings to ensure high power quality in islanded microgrid is presented in Fig. 8.



1. LCL-filters must be used with converter based DG units in microgrid
  - To reduce the amount of current harmonics fed to microgrid, also higher order harmonics near the switching frequency
  - To avoid possible resonance between system harmonic impedance in different microgrid configurations during normal or island operation
    - This could be ensured by using adaptive switching frequency with converters e.g. between 6-10 kHz if normally 8 kHz i.e. in case of resonance in some higher order harmonics the switching frequency of converters is automatically changed

2. The amount of thyristor rectifier loads directly connected to microgrid must be in reasonable limits (max. 15-20 % of the total load)
  - IGBT component based converters must be preferred in all new devices connected to microgrid

3. Space vector modulation (SVM) is preferred when compared to PWM
  - Due to lower voltage and current THD in microgrid

4. The use of the negative sequence filtering in control system of the converters is beneficial during unbalanced load or unsymmetrical faults
  - The voltage and current THD are reduced
  - In real life the phases in microgrid will be more or less unbalanced
  - Naturally it is possible to use some other method which has similar effects

Figure 8. Summary from the findings to ensure high power quality in islanded microgrid.

Acknowledgments

The authors want to express their thanks to Tekes, the Finnish Funding Agency for Technology and Innovation, and companies for their financial support in *Energy storage for managing distributed generation* -project which is part of Tekes Distributed energy systems technology programme (DENSY) 2003-2007.

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Control Principles for Blackstart and Island Operation of Microgrid

H. Laaksonen, and K.Kauhaniemi

***Abstract*--In some unexpected situations a microgrid may become unstable after transition to islanded mode and all DG units must be disconnected from microgrid. In case of these events a restoration strategy for microgrid blackstart is needed. Also if the islanded microgrid is divided into different protection zones in case of a fault, fault management strategy with capability of very fast operation is needed to maintain stability in the healthy section of the islanded microgrid. The control of microgrid voltage and frequency during the microgrid blackstart is not possible without energy storage unit. In this paper sequence of actions for the microgrid blackstart operation as well as control principles of some DG units during blackstart are defined and simulated with two different microgrid configurations. Also one simulation case considering fault management strategy and control principles during fault in islanded microgrid is presented. Based on the simulations dimensioning principles for the needed energy storage and size of simultaneously controlled loads can be drawn.**

***Index Terms*—Blackstart, distributed generation, energy storage, frequency control, islanding, low voltage network, microgrid, stability, voltage control.**

I. INTRODUCTION

MICROGRIDS can be defined as low voltage (LV) distribution systems with distributed generation (DG) units, energy storages and controllable loads, which can be operated either in interconnected mode, which means that the microgrid operates in parallel with the distribution grid, or in islanded mode, where the connection to the utility grid is switched off. Transition to the islanded mode may take place due to faults or intentional switching events. [1], [2] The storage units are essential during transition from interconnected to islanded mode of operation as well as during the microgrid island operation in long term. In some cases the microgrid may need to be shut down by disconnecting all DG units after transition to islanded mode e.g. due to very deep voltage dip before islanding which may result in unstable operation of the microgrid in terms of voltage and frequency. In case of these situations the microgrid blackstart operation strategy including the load management strategy is needed. At the same time if an islanded microgrid is divided into different protection zones in case of a fault, the protection must operate very rapidly to maintain stability in the healthy section of the islanded microgrid. Also for these cases the blackstart operation strategy is needed as a backup. Due to possible oscillations during blackstart, the settings of the protective devices cannot probably be as tight as during the normal island operation.

The control of microgrid voltage and frequency during the microgrid blackstart is not possible without energy storage unit. In this paper sequence of actions for the microgrid blackstart operation as well as control principles of few type of DG units during blackstart are defined and simulated with two different microgrid configurations. The studied LV network based microgrid will consist of three converter and one synchronous generator based DG units with passive loads or three converter based DG units and one induction motor load together with passive loads. Also one simulation considering fault management strategy and control principles during fault in islanded microgrid is simulated with three converter based DG units, permanent magnet generator (PMG) equipped with frequency converter and passive loads. In all configurations the energy storage (battery) converter with rapid response acts as a master unit [3], which has the main responsibility to control the voltage and frequency in the microgrid during microgrid blackstart and island operation.

Based on the simulations sizing principles for the needed energy storage and size of simultaneously controlled loads can be drawn. If the island operation will last for a long time, a strategy to reduce power continuously taken from energy storage must also be defined. Simulations are done with PSCAD simulation software package.

Section II of the paper discusses briefly about blackstart and island operation and Section III about fault management operation. Section IV introduces the test system and blackstart as well as fault management strategies used in the simulations. Simulation results of the study and discussions are presented in Section V. Conclusions are stated in Section VI.

II. BLACKSTART AND ISLAND OPERATION

A. Island Operation

The whole idea of microgrid is to provide uninterruptible, high-quality power to the customers energy efficiently by local DG units. In addition, some DG units can also produce heat to the microgrid customers. The local production of electricity may be based on renewable energy sources e.g. solar, wind

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This work was supported by Tekes, the Finnish Funding Agency for Technology and Innovation, and companies as part of 'Energy storage for managing distributed generation' -project which was part of Tekes Distributed energy systems technology programme (DENSY) 2003-2007.

The authors are with the University of Vaasa, P.O.Box 700, FI-65101 Vaasa, FINLAND (e-mail: hannu.laaksonen@uwasa.fi, kimmo.kauhaniemi@uwasa.fi

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Paper was presented and published at the *Proceedings of Nordic Workshop on Power and Industrial Electronics (NORPIE 2008)*, Espoo, Finland.

energy or biogas, which should be exploited as well as possible i.e. disconnection of these unit for voltage control purposes is not preferred. Instead energy storages should be used within the DG units or as one larger storage in microgrid. Also the principle of using loads with different order of importance for voltage control purposes does not support the basic idea of providing premium power to all microgrid customers. Therefore, the usage of energy storages within microgrid would be practical. In addition to above mentioned reasons, the energy storage is needed for instant voltage control because of the challenging dynamic properties of an islanded microgrid and slow controllability of some DG units.

In this paper the master unit with energy storage controls the voltage of microgrid during sudden changes and creates the frequency reference for other DG units in microgrid (Fig. 1). Therefore the active power output of master unit should never go under certain percent e.g. 5 % of the total load. The configuration of the master unit could also be as the one presented in [4]. In case of long duration island operation of microgrid the energy storage of the microgrid should be capable of being charged through some primary energy source e.g. fuel cell (Fig. 1). If large proportion of generating units in the microgrid are based on highly varying output power (solar or wind energy), then there could also be one other energy storage, in addition to the master unit, for power balancing purposes (Fig. 1). The microgrid power balance can be maintained by charging or discharging the energy storage as needed i.e. if control of the master unit can not keep up the power balance.

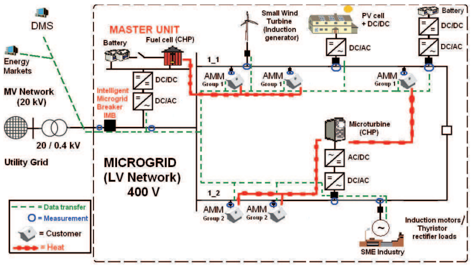


Fig. 1. LV network microgrid consisting of e.g. energy storages, DG units, loads, DMS and IMB with communication capabilities.

Reasonable co-ordination between DG units and loads during island operation needs communication and intelligence. The needed intelligence could be located to the breaker of microgrid (IMB) with communication capability, so that no additional microgrid central controller would not be required (Fig.1).

The islanding decision and re-synchronization after island operation is based on the measurements from both sides of the IMB. At the moment of islanding IMB has knowledge about status, present production or consumption levels of DG units and loads. In addition the technical parameters of DG units (e.g. rated power, power factor), load groups and energy storages (e.g. state of charge) are stored into the database of IMB. Based on the stored information, current measurements and chosen island operation strategy the IMB gives e.g. setpoint values for units capable of active power control during island operation. In addition to the island operation strategy, the islanding, blackstart, fault management, reconnection strategy of microgrid are included into the IMB. The transfer to island operation is based either on the protective settings and measurements of the IMB or on the information received from the distribution management system (DMS) (Fig. 1). In conclusion, the basic characteristics required from IMB are 1) real-time bi-directional communication with DMS and with energy storages, 2) information change with DG units and loads e.g. measured parameters, status of units and control instructions to units as well as 3) intelligence and adaptivity, which means built-in strategies for different possible situations. The summary from the IMB functions needed is presented in Fig. 2.

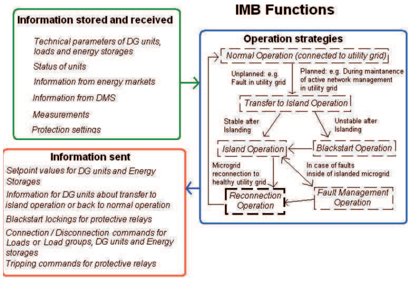


Fig. 2. Summary about the IMB functions.

B. *Blackstart Operation*

If an unplanned event occurs in microgrid during transition to island operation, the stability of microgrid may possibly be lost and all DG units must be disconnected from the microgrid. The service restoration is done with the microgrid blackstart strategy, which controls the power balance and voltage during blackstart. The energy storage based master unit of microgrid plays the main role in maintaining the power balance and acceptable voltage level in microgrid also during blackstart. The load management could be done in groups with advanced automated meter management (AMM) systems (Fig. 1). Co-ordination between DG units and loads during blackstart operation is done by using the IMB. In Fig. 3 basic principles for blackstart operation strategy used in the simulations of this paper are presented.

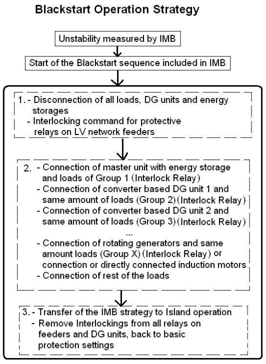


Fig. 3. Basic principles for blackstart operation strategy.

During blackstart one must remember that the calculation of the PLL components in the converter based DG units needs to be reset back to initial state before the DG unit is reconnected. Also the fact that the active power output of the master unit should be at least some 5 % percent of the microgrid total load must be taken into account, because otherwise the master unit is not able to give the frequency reference for other DG units to synchronize with. Duration of the blackstart sequence is dependent on the load and DG unit types in the microgrid. DG units with slow dynamic response as well as rotating machines need longer time to reach stable operation after their connection and after sudden voltage changes. This is one reason why they should be connected at the end of the blackstart sequence (Fig. 3).

Some dimensioning principles for the successful blackstart operation can be concluded based on the simulations: 1) Rated capacity of the master unit with energy storage should be at least equal with largest converter based DG units or motor drives and also 1,5-2 times larger than any of the rotating machines connected directly to the microgrid, 2) Load groups which are connected sequentially should not be larger than the capacity of the master unit and large directly connected rotating machines must be connected separately from other loads.

The main difference between blackstart operation principles presented in this paper when compared to references [5] and [6] is the lack of sectionalizing the microgrid into smaller islands around microsources, which are then during the blackstart synchronized with each other.

III. FAULT MANAGEMENT PRINCIPLES

Fault management operation during islanding of microgrid is also important with larger microgrids which are divided into protection zones i.e. faulted zone will be disconnected from the remaining healthy zones of the microgrid (Fig. 4). Due to limited fault current available during islanding, there are relays at the LV feeders instead of conventional fuses.

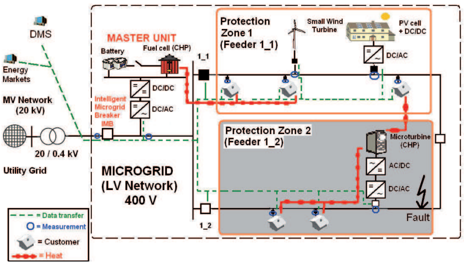


Fig. 4. Protection zones of an islanded microgrid.

The fault detection may be based on voltage rms values and fault type detection on measured phase voltages. Fault location detection could be done with current measurements from feeder relays which are in case of a fault sent to IMB. IMB detects the faulted protection zone based on these measurements and then sends disconnection command to relay and DG units of the faulted zone i.e. feeder 1_2 in Fig.4. However, in case of faults the DG units should always also have their own protection settings as a backup for IMB functions which will take into account the fault ride-through needs of successful microgrid operation. In Fig. 5 fault management operation strategy during islanding of microgrid which is used in this paper is shown. Duration of the fault management operation is dependent on the fault clearance time. In some cases the healthy part of the microgrid may be connected back to utility grid before the fault is cleared (Fig. 5). But if the microgrid remains islanded, then also in the fault management operation equally to blackstart operation, the rotating machines will be connected last back to microgrid. The same dimensioning principles presented in Section II for blackstart operation about the capacity of the master unit with energy storage apply also for the fault management operation.

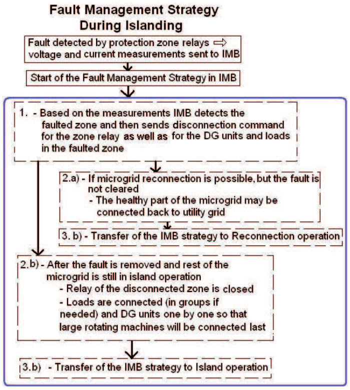


Fig.5. Fault management operation strategy during islanding of microgrid.

Attention should be paid on the disconnection speed of the faulted zone to ensure stability in the rest of the islanded microgrid. For this reason the relays of the protection zones could have different operation characteristics during normal and island operation, which are changed when IMB sends islanding notification for microgrid relays, DG units and loads.

IV. STUDY SYSTEM

A. Studied LV Network Based Microgrid

The LV network used in this work is shown in Fig. 6. The system consists of one 800 kVA MV/LV-transformer which normally feeds LV feeders 1_1 and 1_2. In the simulation studies the islanded microgrid is disconnected from main network by the breaker so that the microgrid consists of feeders 1_1 and 1_2 (Fig. 6). At the PCC of the microgrid, before the feeders 1_1 and 1_2, there is a storage unit (battery 120 kVA) equipped with converter 1. At the end of feeder 1_1 there is a DG Unit 1 (120 kVA) equipped with converter 3. In blackstart simulation there at the front-end of the feeder 1_2 is a synchronous generator (100 kVA) or induction motor (51 kW, 34 kVAr). In fault management simulations there is at the feeder 1_2 a permanent magnet generator equipped with frequency converter (100 kVA). In all simulations there is also at the end of the feeder DG Unit 2 (120 kVA) equipped with converter 2.

The load in the microgrid consists of four passive loads on each feeder. The passive loads can be adjusted so that the loading of the transformer (which feeds LV feeders 1_1 and 1_2) gets some desired value between 0…150 % of the transformer ratings. For comparison purposes the blackstart simulations are done with SG or with IM. Initially loading of the transformer was set to 45 % with SG (power factor 0.98_{ind}) and to 30 % with IM (power factor 0.98_{ind}). During blackstart load is increased in steps from 0 % to 45 % with SG and from 0 % to 30 % with IM. In fault management simulations with PMG + frequency converter the loading is 60 % (power factor 0.98_{ind}).

Simulations are made with LV network line parameters shown in Table 1. The fault level and R/X-ratio of the feeding utility network (20 kV, 50 Hz) are 200 MVA and 0.1 respectively. Converter based DG units are space vector modulated (SVM) and frequency converter of PMG is pulse width modulated (PWM). The dc-link voltage V_{DC} of converter is chosen to be 0.65 kV and dc-link is modeled as constant dc-voltage source in all converter based DG units, except in blackstart simulations the dc-link of the master unit is modeled with battery storage + DC/DC-buck-boost converter. The converters are modeled as three-phase, three-leg units with LCL-filters. With all converters the PSCAD's own PLL component was used. Further details and parameters about the study system components are listed in Appendix.

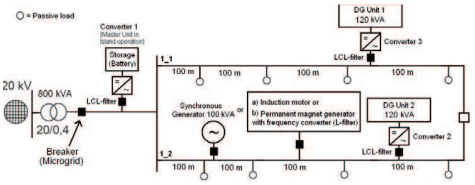


Fig. 6. Studied LV network based microgrid.

TABLE 1
RESISTANCE, REACTANCE AND R/X RATIO OF LV NETWORK CABLES IN FIG. 6

	R (Ω/km)	X (Ω/km)	R/X
AXMK 4x185S	0.164	0.0817	2.01

B. Single Master Operation

During islanding, microgrid is operated in single master operation mode, which in this case means that the converter 1 with battery storage (Fig. 7) will act as the master unit and it has the main responsibility to control the voltage and frequency in microgrid when islanded. The control system for master unit (Battery storage) converter 1 in island operation is shown in Fig. 8. All the other DG units can then be operated in conventional PQ mode i.e. they do neither take part in frequency nor voltage control.

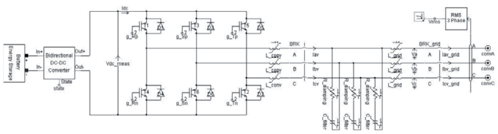


Fig. 7. PSCAD simulation model of the master unit with battery storage + dc-dc buck-boost converter.

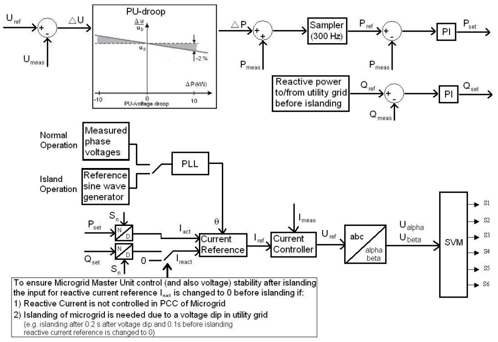


Fig. 8. Control system of master unit converter during islanding.

C. Blackstart Simulations

In this section the sequence of actions from two different blackstart cases with different configurations are shown. Simulation results are presented in Section V. First, sequence of actions from blackstart strategy with three converter based DG units and SG is shown in Table 2.

TABLE 2
BLACKSTART STRATEGY WITH THREE CONVERTER BASED DG UNITS AND SG

Time (s)	Sequence of actions
0	Islanded operation of microgrid (All DG units and loads are disconnected)
0.15	Connection of Master Unit (PQC) with Energy Storage and connection of passive load (56 kW, 11.5 kVAr)
1.5	Connection of DG unit converter 2 on feeder 1_2 (100 kW, 30 kVAr) and connection of passive load (91 kW, 19 kVAr)
3.0	Connection of DG unit converter 3 on feeder 1_1 (100 kW, 30 kVAr) and connection of passive load (190 kW, 38.5 kVAr)
6.0 ->	Connection of Synchronous generator (SG) on feeder 1_2 (96 kW, 0 kVAr) and connection of passive load (91 kW, 19 kVAr)
6.075	Synchronized connection of SG when Voltage angle (theta) difference is smaller than the chosen limit e.g. 15 degrees
7.0	Connection of passive load (25 kW, 5 kVAr)
20	Reconnection of microgrid to utility grid

This sequence of actions begins from the island operation with DG units and loads disconnected from microgrid. Otherwise the principles presented in Fig. 3 are followed. Although, it is worth mentioning that in this case the connection of the SG in synchronism is very important for the stability of the microgrid. In this case it was also found out that improvement of power quality and stability during blackstart operation was needed and achieved with adaptive parameters in the master unit controller (Fig. 8). Chosen parameters are also presented in Appendix.

The sequence of actions from the another blackstart simulation with three converter based DG units and IM is presented in Table 3. In this case islanding takes place after 3-phase fault in utility grid. Due to frequency instability detected in microgrid, the blackstart sequence shown in Table 3 is started. Also this sequence of actions is based on the priciples described in Fig. 3.

TABLE 3
BLACKSTART STRATEGY WITH THREE CONVERTER BASED DG UNITS AND IM

Time (s)	Sequence of actions
4.85	3-phase fault in utility grid
5	Islanding of microgrid
5.5	Disconnection of all DG units and loads due to voltage and frequency instability
7	Reconnection of Master Unit (PQC) with Energy Storage and connection of passive load (56 kW, 11.5 kVAr)
8.5	Reconnection of DG unit converter on feeder 1_2 (100 kW, 30 kVAr) and connection of passive load (91 kW, 19 kVAr)
10.0	Reconnection of DG unit converter on feeder 1_1 (100 kW, 30 kVAr) and connection of passive load (82 kW, 16 kVAr)
12.0	Connection of induction motor load (51 kW, 34 kVAr)
15.0	Torque (and load) increase of induction motor (12 kW, 4.5 kVAr)
16.0	Connection of passive load (15 kW, 3 kVAr)
20	Reconnection of microgrid to utility grid

D. Fault Management During Island Operation

In Table 4 the sequence of actions from the simulated fault management operation strategy is presented. Simulation results from this case are shown in Section V. This sequence of actions is based on the principles described in Fig. 5, so that the fault will be cleared during the simulation. In this case the relay operating time of the faulted protection zone was 200 ms.

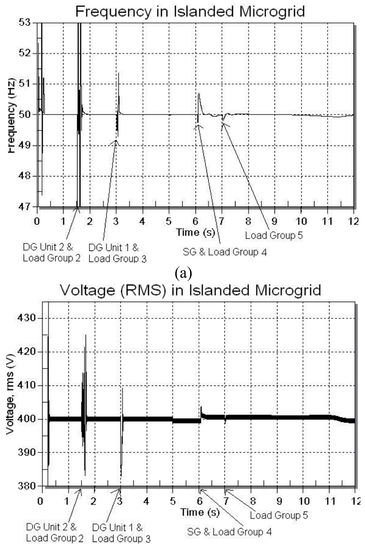
TABLE 4
FAULT MANAGEMENT STRATEGY WITH THREE CONVERTER BASED DG UNITS AND PM GENERATOR WITH FREQUENCY CONVERTER

Time (s)	Sequence of actions
2	Islanding of microgrid
3	2-phase fault in microgrid (at the end of feeder 1_1)
3.2	Relay of the feeder 1_1 disconnects the feeder 1_1
3.5	DG Unit 1 on faulted feeder 1_1 is disconnected and because of the master unit minimum power requirements the output power of DG Unit 2 is reduced to 30 kW and 10 kVAr from 100 kW and 30 kVAr
4	The fault is cleared
6.5	Relay of the feeder 1_1 is closed when fault is removed and rest of the microgrid is stable
6.7	DG Unit 1 is connected back to microgrid after successful connection of feeder 1_1 and it's loads
10	End of the simulation

V. SIMULATION RESULTS

A. Blackstart with Three Converter Based DG Units and SG

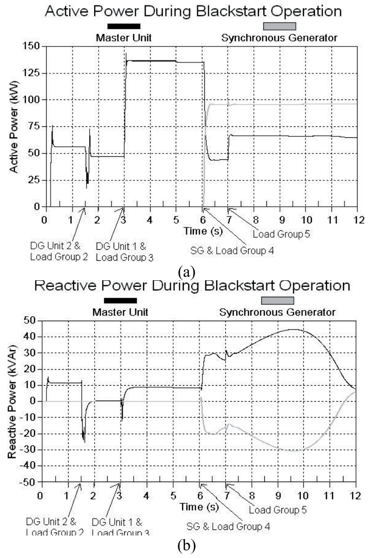
In the following Fig. 9-11 the simulation results from blackstart simulation case with master unit with energy storage, two converter based DG units and one synchronous generator are shown. At the beginning of the blackstart (0-3s), the microgrid is very sensitive for frequency and voltage variations (Fig. 9). But in overall the strategy of connecting simultaneously generation and load seems to work reasonably well.



(b)

Fig. 9. Simulation results from the blackstart simulation with the SG: a) Frequency and b) Voltage (rms).

In Fig. 10 the active and reactive power of the master unit and SG are shown for a comparison. It can be seen that the well synchronized connection of the SG does not cause notable oscillations in output power of the SG. From Fig.10b) one can also see that after the SG reconnection, the slow reactive power control of the SG is well compensated with the reactive power output of the master unit.



(b)

Fig. 10. Simulation results from the blackstart simulation with the SG: a) Active and b) Reactive Powers of the master unit and SG.

The DC-link voltage behaviour of the master unit during the blackstart with SG is presented in Fig. 11. It can be seen that the connection of other units and load causes transient in the DC-link voltage, but the voltage settles very quickly to the reference value.

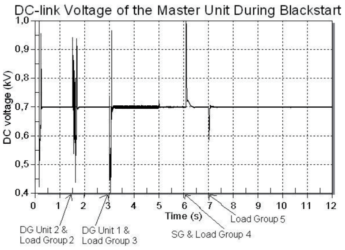
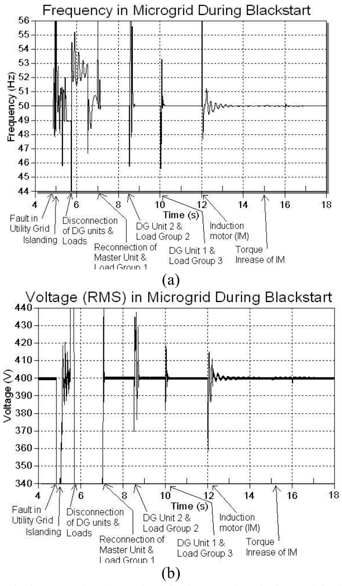


Fig. 11. DC-link voltage from the blackstart simulation with the SG.

B. Blackstart with Three Converter Based DG Units and IM

In Fig. 12-14 the simulation results from blackstart simulation case with master unit with energy storage, two converter based DG units and induction motor are presented. Similarly to the previous simulation (Fig. 9) from Fig. 12 it can be seen that at the beginning of the blackstart, the microgrid is more sensitive to frequency and voltage disturbances i.e. load changes.

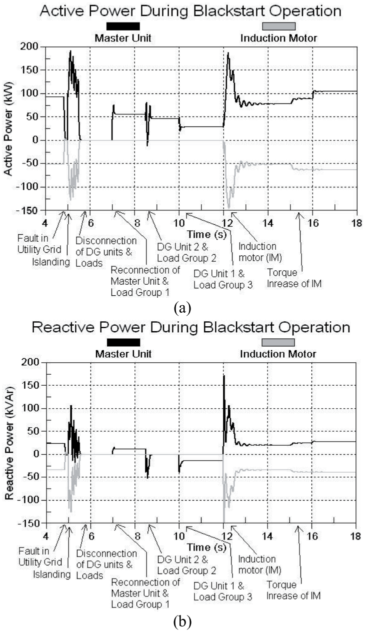


(a)

(b)

Fig. 12. Simulation results from the blackstart simulation with the IM: a) Frequency and b) Voltage (rms).

For comparison purposes, the active and reactive power of the master unit and IM are presented in Fig. 13. From these results one can be see that the connection of the IM directly to the islanded microgrid is very challenging in terms of power balance and stability. Although in this case the rapid voltage control of the master unit helps to stabilize the voltage quite rapidly (Fig. 12).



(a)

(b)

Fig. 13. Simulation results from the blackstart simulation with the IM: a) Active and b) Reactive Powers of the master unit and IM.

In Fig. 14 the DC-link voltage behaviour of the master unit during the blackstart with IM is shown. The longest oscillations in the DC voltage are caused by the connection of IM. In other changes the following transients are stabilized very rapidly.

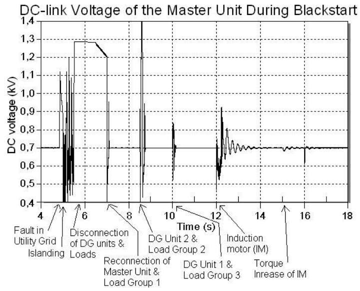
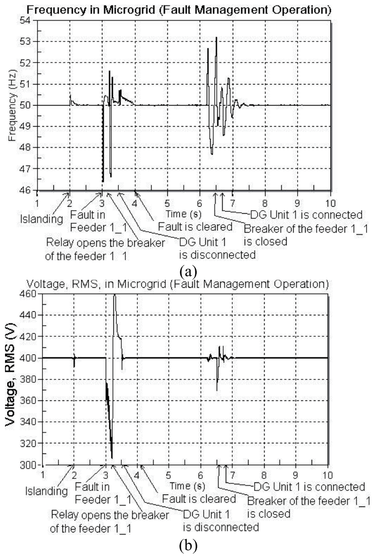


Fig.14. DC-link voltage from the blackstart simulation with the IM.

From both blackstart simulation cases (Section V.A and B) it can be seen that the beginning of the blackstart is the most challenging in terms of frequency and voltage stability. For this reason it is logical to connect the most disturbing loads i.e. rotating machines and thyristor rectifiers at the end of the blackstart sequence.

C. Fault Management Strategy with Three Converter Based DG Units and PMG with Frequency Converter

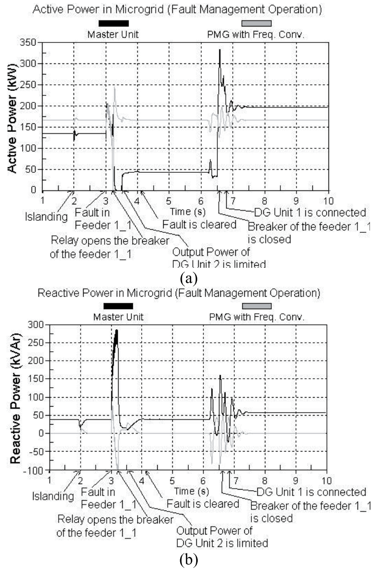
In Fig. 15-17 the simulation results from fault management simulation case with master unit, two converter based DG units and PMG with frequency converter are shown.



(a)

(b)

Fig. 15. Simulation results from the fault management simulation: a) Frequency and b) Voltage (rms).



(a)

(b)

Fig. 16. Simulation results from the fault management simulation: a) Active and b) Reactive Powers of the master unit and PMG with freq. converter.

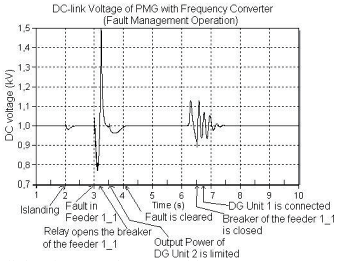


Fig.17. DC-link voltages of the PMG with frequency converter during the fault management operation.

From the simulation results in Fig. 15-17 it can be seen how the fault affects the dc-link voltage of the PMG and also to the microgrid voltage. Also the reconnection of the faulted zone after fault clearance creates oscillations to to dc-link voltage and frequency of the microgrid. For these reasons attention should be paid on the control of the dc-link by the the grid-side converter, because it also plays important role when stability of the microgrid is considered.

VI. CONCLUSIONS

This paper presents strategies to handle some problematic situations, like unstability after islanding and fault situations, which may occur during the island operation of the microgrid. To execute these strategies efficiently some centralized intelligence with communication capability will be needed. For this purpose new kind of intelligent microgrid breaker, IMB, is presented and the function needed for the operation of it are derived. in this paper. this responsibility is given for new kind of microgrid breaker (IMB). In case of unstability, the blackstart operation strategy will be needed and the basic principles for the possible implementation of it has been shown in Section II. If fault occurs in the islanded microgrid, only the faulted protection zone may be disconnected with pre-defined fault management strategy presented in Section II and the stability of the healthy section of the microgrid can be maintained.

In this paper the developed sequence of actions' needed to execute these strategies were also successfully simulated. Based on these simulations, dimensioning principles for the needed energy storage and size of simultaneously controlled loads can were drawn. In addition, during blackstart simulations it was found out that it is logical to connect the most disturbing loads i.e. rotating machines and thyristor rectifiers at the end of the blackstart sequence. Also the connection interval between rotating machines should be long enough so that the steady state can be reached before next event. On the other hand it could be recommended that all the larger rotating machines are connected to the microgrid through frequency converters. However, during fault management simulations it was found out that also when rotating machines are connected through frequency converters, the oscillations during faults and switching events may be considerable due to oscillations in the dc-link of the frequency converter. Because of that it should be noted that the disconnection speed of the faulted zone is short enough to ensure stability in the rest of the microgrid. From the simulations it can also be concluded that the relays of the possible protection zones as well as the protections of the DG units should probably have different operation characteristics during normal and island operation, which are changed when IMB sends islanding notification for microgrid relays, DG units and loads. In future studies, the operation criteria of the microgrid still needs to be studied in overall and also more detailly with different fault scenarios to achieve practical and fast protection for microgrid in every situation.

APPENDIX

System parameters of the test system with different DG units, loads and controller parameters are presented in Table 5. The solution time step in simulations was 5 µs.

TABLE 5
STUDY SYSTEM PARAMETERS

	Parameter	Value
DG Unit Converters (DC/AC)	Modulation method	SVM
	Switching frequency	8 kHz
	Filter L_1, R_d, C, L_2	0.4 mH, 0.1 Ω, 10 µF, 0.2 mH
Current PI-controller	Gain $K_{current}$	1.5
	Integrator time constant T_{c_i}	0.15 ms
Active Power PI-controller	Gain K_p	1* / 2**
	Integrator time constant T_{p_i}	0.015* / 0.00075** s
	Sampling rate	4 * / 0.3** kHz
Active Power PI-controller (Blackstart)	Gain K_p	0.25 -> 2
	Integrator time constant T_{p_i}	0.005 -> 0.00075 s
	Sampling rate	2 -> 0.3 kHz
Reactive Power PI-controller	Gain K_Q	5
	Integrator time constant T_{q_i}	0.015 s
	Sampling rate	4 kHz
DC-DC Buck-boost Converter	Reference dc voltage V_{DC}	0.7 kV
	Gain $K_{dc/dc}$	0.3
	Integrator time constant T_{dc/dc_i}	0.06 s
	Sampling rate_dc/dc	1 kHz
	DC-link capacitor	5000 µF
Synchr. Generator (SG)	Inertia constant	0.1049 MW/MVA
	R_a / X_p / Air gap f.	0.012 pu / 0.087 pu / 0.8
	X_d / X_d'/ X_d''	3.5 pu / 0.128 pu / 0.077 pu
	X_q / X_q'/ X_q''	2.1 pu / 0.128 pu / 0.098 pu
	T_{do}' / T_{do}''	2.71 s / 0.02 s
	T_{qo}' / T_{qo}''	2.71 s / 0.02 s
Reactive Power Control of SG (Input to Exc.)	Gain	1.0
	Time constant	1.0 s
Permanent Magnet (PM) Generator with Frequency Converter	Modulation method	PWM
	Switching Frequency	6^{***} / 8 kHz^{****}
	Filter L	2.5 mH
	DC-link capacitor	12000 µF
Induction motor (IM)	P_n	75 kW
	cosφ	0.93
	Inertia	6.47 kgm^2

*) In normal operation, **) In island operation

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BIOGRAPHIES

Hannu Laaksonen was born in Vaasa, Finland, on November 22, 1977. He received his Master's degree (2004) in Electrical Power Engineering from Tampere University of Technology.

His employment experience includes working as a research scientist in VTT Technical Research Centre of Finland in Vaasa and before that in Institute of Power Engineering department at Tampere University of Technology. Currently he works as a research scientist and PhD student with Department of Electrical Engineering and Automation at University of Vaasa. His field of interests are planning + integration of DG in distribution networks, power electronics in distribution networks and future network concepts (e.g. microgrids).

Kimmo Kauhaniemi was born in in Kankaanpää, Finland, in 1963. He received his M.Sc degree (1987) and Dr. Tech. degree (1993) in electrical engineering from Tampere University of Technology, Finland. He was previously employed by VTT Technical Research Centre of Finland. Currently he is Professor in electrical engineering at the University of Vaasa, Finland. His special interest areas include the modeling and simulation of power systems.

Praise Worthy Prize

International Review of Electrical Engineering (I.R.E.E.), Vol. 5, N. 2
March-April 2010

Smart Protection Concept for LV Microgrid

H. Laaksonen[1], K. Kauhaniemi[2]

Abstract – *The conventional protection in distribution networks is designed to operate for high fault current levels in radial networks, but during island operation of the microgrid high fault currents from the utility grid are not present. Also most of the distributed generation (DG) units that will be connected to the low voltage (LV) microgrid in the future are converter interfaced and have limited fault current feeding capabilities. This means that the traditional fuse protection of LV network alone is no longer applicable and new protection methods must be developed. In this paper new smart protection concept for LV microgrid is proposed in which for example LV feeders are protected in addition of traditional fuses with protective relays that have adaptive multi-criteria algorithms and fast standard IEC 61850 based communication capabilities. One of the most important issues is to ensure that the behavior that is required from DG units, including fault-ride-through (FRT) needs, during faults in microgrid during normal and island operation is compatible with the developed microgrid protection concept. The simulation studies done in the development of new protection concept were made with PSCAD simulation software.* **Copyright © 2010 Praise Worthy Prize S.r.l. - All rights reserved.**

***Keywords**: Microgrid, Protection, Distributed Generation, Energy Storage, Smart Grids*

Nomenclature

AC	Alternating Current
AMM	Automated Meter Management
CB	Circuit Breaker
DC	Direct Current
DER	Distributed Energy Resources
DG	Distributed Generation
DMS	Distribution Management System
DOC	Directional Over-Current
DSO	Distribution System Operator
DSP	Digital Signal Processor
FRT	Fault Ride Through
HV	High Voltage
IGBT	Insulated Gate Bipolar Transistor
IGCT	Integrated Gate Commutated Thyristor
IM	Induction Motor
LoM	Loss of Mains
LV	Low Voltage
LVCB	Low Voltage Circuit Breaker
MCB	Miniature Circuit Breaker
MGC	Microgrid Grid Code
MMS	Microgrid Management System
MV	Medium Voltage
OC	Over-Current
PCC	Point of Common Coupling
PD	Protection Device
PLL	Phase Locked Loop
PQC	Power Quality Compensator
PU	Active Power - Voltage
PV	Photovoltaic
PQ	Active and Reactive Power
SCR	Silicon Controlled Rectifier
SG	Synchronous Generator
SS	Static Semiconductor based Switch
SVM	Space Vector Modulation
THD	Total Harmonic Distortion
Uf	Voltage and frequency
UPS	Uninterruptible Power Supply
f	Frequency [Hz]
$I_{meas\_DGs\_ave}$	Sum of DG units' average 1-phase current (rms) of LV feeder [A]
$I_{meas\_LV\_feeder\_ave}$	Measured average 1-phase current (rms) of LV feeder [A]
$I_{meas\_load\_ave}$	Average 1-phase load current (rms) of LV feeder [A]
$I_{n\_LV\_feeder}$	Nominal current of LV feeder, 1-phase rms value [A]
R_{fault}	Fault resistance [Ω]
U	Voltage [V]
V_{DC}	DC-link voltage

I. Introduction

Large scale integration of DER, including DG, electricity storages, electric vehicles and customers with smart energy meters and controllable loads, to distribution network in future requires creation of a totally new Smart Grid concept which will take advantage of the properties of DER. Advanced Smart Grid concept allows the use of DER in a coordinated way through intelligent management system and hence allows the potential of DER to be realized for different

Manuscript received and revised March 2010, accepted April 2010

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interest groups (DSOs, DG producers, service providers, consumers and society). Simultaneously with the development of the Smart Grid concept the future island operation possibility should be integrated so that it requires only minimal changes to the concept.

Typically the term microgrid is used from the LV network Smart Grid with island operation capability. However, microgrid concept should be defined in a more general way as a smart distribution grid part with island operation capability. In that case microgrid would mean certain part of distribution network with DER (1. Separate island grid, 2. Small household LV microgrid or LV customer microgrid, 3. LV microgrid consisting of all LV feeders connected downstream from MV/LV distribution transformer, 4. MV network feeder microgrid or MV substation microgrid with all MV feeders, see figure below) that is managed as a whole with intelligent MMS. In overall the role of MMS can be seen as distributed intelligence of DMS to lower voltage levels in distribution networks (Fig. 1).

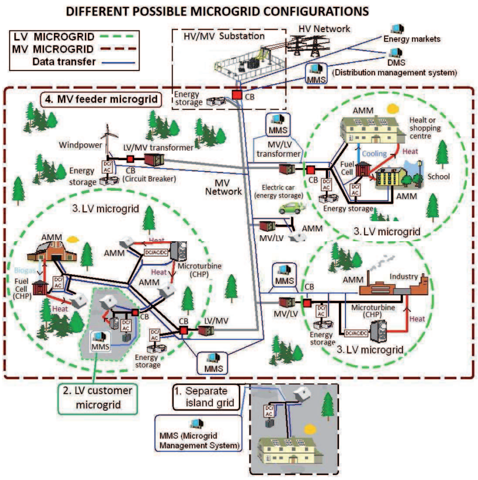

Fig. 1. Different possible microgrid configurations.

Microgrid is normally operated parallel with utility grid and e.g. during faults in upstream network it can be separated quickly from utility grid and operated independently as an island grid. MMS will be responsible from the overall economic and energy effective operation of microgrid taking account the technical boundary conditions in both normal and island operation. In this paper only technical aspects related to LV microgrids are discussed. Technical choices made in the microgrid concept must be such that they can be justified by the needs of normal operation, but at the same time allowing and supporting the solutions needed for implementation of island operation.

In overall the operation and control of LV microgrid is a very complex issue because there are number of things that will have influence to the behavior of microgrid in different ways. For example the dynamics of islanded microgrid, e.g. lack of inertia, is totally different when compared to the normal operation of the microgrid parallel with utility grid. Islanded microgrid is much more sensitive to disturbances and successful island operation requires fast, accurate and stable control.

In addition the protection of the future microgrid is a challenging issue and very strongly connected to the control and operation issues of a microgrid. The conventional protection in distribution networks is designed to operate for high fault current levels in radial networks, but during island operation of the microgrid high fault currents from the utility grid are not present. Also most of the DG units that will be connected to the LV microgrid in the future are converter interfaced and have limited fault current feeding capabilities. This means that the traditional fuse protection of LV network is no longer applicable and new protection methods must be developed. The developed protection scheme for microgrid must be supported by the technical choices made in the microgrid operation and control issues.

In the development of the new protection scheme for LV microgrids many things must be considered including amount of protection zones in LV microgrid, speed requirements for microgrid protection in different operation states and configurations and protection principles for parallel and island operation of the microgrid. In this paper new protection concept for LV microgrid is proposed based on previous studies [1]-[5] and protection simulations of LV microgrid done for this paper. In section II the framework for the new protection concept of LV microgrid is created. In section III the study system is introduced and some remarks from the fault simulations done to develop the LV microgrid protection concept shown in section IV are presented. Then, based on simulations done in this paper, in section V the operation curves of different protective devices needed in the developed LV microgrid protection concept are presented. Some simulation results from few example cases are presented and discussed in section VI and conclusions are stated in section VII.

II. Framework for Microgrid Protection

This section is devoted to the discussion of the size and needed amount of protection zones in LV microgrid and also to consideration of speed requirements and operation principles of LV microgrid protection.

II.1. Number of Protection Zones in LV Microgrid

The size and number of LV microgrid protection zones will define the needed amount of PDs for microgrid protection. The size of microgrid protection zone must be such that it fulfills the requirements of customers and at the same time is economically feasible.

Based on references [6], [7] failure rate in LV network

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is approximately 20-40 faults (overhead lines) and <5 (underground cables) per 100 km annually in typical European LV networks. Therefore splitting the LV feeders in more than one protection zones would not be justified in most of the cases [8] (see Fig. 2). Naturally customers connected to LV feeders will create the smallest protection zones at the bottom of the microgrid protection hierarchy (Fig. 2). Very disturbance sensitive customers can have their own protection and energy storage (e.g. electric car) or UPS system so that they can continue operation also during all possible faults at the corresponding LV feeder (Fig. 2) i.e. they create small LV customer microgrid. In these small household LV microgrids the use of DC distribution may increase in future (Fig. 2).

The amount and degree of protection zones used in this paper is presented in Fig. 2. Also the needed protection devices (PD 1-4) for these protection zones to clear three type of basic faults (F1, F2, F3) are shown in Fig. 2.

PD 1: Microgrid protection (in PCC) including relay and CB or fast SS

PD 2: LV feeder protection including fuses, relays and CB or SS

PD 3: Customer protection including fuse or MCB or in case of LV customer microgrid (DC or AC) with very sensitive customers SS may be needed

PD 4: Production / DG unit protection

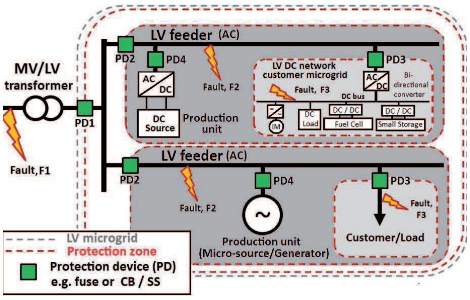

Fig. 2. Amount of protection zones and devices in LV microgrid

II.2. Speed Requirements and Operation Principles of LV Microgrid Protection

There are some fundamental structural choices that will determine the speed requirements and operation principles of LV microgrid protection and conversely these speed requirements will define certain structural choices needed to fulfill the speed requirements. There are two main reasons for speed requirements of LV microgrid protection: stability and customer sensitivity. Stability needs to be maintained after sudden changes i.e. after islanding due to fault in MV network during parallel operation with utility grid or after fault in LV microgrid during island operation. One essential issue related to operation principles of LV microgrid protection is control of converter based DG units during faults. It should be compatible with the proposed microgrid protection concept.

In principle OC protection of customers can be retained or renewed completely but total renewing would be quite hard to justify from economical perspective just because of possible momentary island operation. However, if second generation smart energy meters could be used also to protection purposes together with very fast communication capabilities the case would be different. In references [6], [9] it is stated that customer OC protection with fuses does not need to be renewed due to possible island operation and instead of renewing the protection it is just allowed to operate slower during island operation as a consequence of smaller fault currents. But especially if there are directly connected rotating machines in island operated microgrid it is essential to ensure that the customer protection will operate fast enough to minimize fault and voltage dip duration and especially to ensure that stability can be maintained in islanded microgrid after fault clearance / operation of customer protection. Directly connected rotating machines are very sensitive to lose stability in voltage dips caused by faults in island operated microgrid and so they may jeopardize the stability of the whole microgrid. For that reason protection should operate in islanded microgrid rapidly in every kind of faults and e.g. if microgrid customers have fuses with high rated currents on larger customers there is a risk that customer protection may operate too slowly in island operation due to low fault currents, which in turn may cause instability in island operated microgrid after fault clearance.

Structural choices that are needed to fulfill the speed requirements may be divided to i) switch technology needed, ii) communication technology needed and iii) size of energy storage on master unit. Naturally the speed requirements will create a demand to PD 1 to operate very rapidly which means that probably traditional CB cannot be used and instead of that PD 1 needs to include fast static semiconductor based switch [3], [10]. According to reference [10] operation speed of PD 1 can be improved if functions of traditional CB concept such as switch hardware, voltage and current sensing devices, protective relays, a controller with diagnostic and monitoring functions, a communications processor, power supplies, and other components, are integrated to the control functions in a DSP. This kind of integrated concept can be based on CBs or solid-state switches. Based on tests in [10], the CB cannot be disconnected faster than 90 ms after the most severe voltage dips even with this new integrated, DER Switch, technology. However, SCR-based solid-state switches are able to disconnect in 8-17 ms and IGBT- or more probably IGCT based switches even faster [10]. On the other hand, in reference [11] the total breaking time of some commercial LVCBs was measured to be less than 15 ms after receiving switching-off command from an

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intelligent controller. PD 1 could also be some of the combinations described in reference [3] e.g. CB/SS+ PQC where PQC compensates the depth of the voltage dip and that way allows longer operation time to PD 1.

With larger energy storage on master unit it could be possible to survive from larger oscillations without losing stability and also to increase fault current feeding capability in island operated microgrid to e.g. make customer fuses operate faster. DG unit converter control principle during fault has a major impact on fault detection in island operated microgrids [12] and standards and other regulations are needed to be set for converters fault behavior in the very beginning of the design process [13]. To ensure that protection operates as fast as possible e.g. in customer faults (F3) the fault current fed by DG unit converter must be at least rated and DG unit cannot be disconnected before microgrid protection has operated (FRT).

Stability is also affected by many other things which are related to converter control and has been discussed on previous studies [1], [3]. To improve stability and reduce voltage and current THD in islanded microgrid it has been chosen in this paper as in references [3], [4] to use negative sequence filtering principle with PLL component and current control of DG unit converters. Therefore, instead of analyzing converter control stability more deeply, chosen control principles in this paper are leaning on results from previous studies [1], [3], [4] and only in certain cases PI controller parameters are adjusted if microgrid configuration required it from stability point of view. Howerever, it should be highlighted here that other possible stable synchronization methods exists and control methods and PLL components used in this paper are still not optimized and most robust e.g. during faults, but control development is more sensible to carry out in future when it is more clear that how converters are wanted to operate in different situations. One should also remember that in reality due to the nonlinearities of different network components (e.g. in inductance of LCL-filter) e.g. THD of converters and behavior of controllers may differ from reality if these nonlinearities are not taken into account in simulation models. For this reason developed control methods and protection concepts in simulations should naturally be tested thoroughly in future with real world pilot installations.

One essential issue from island operated microgrid protection point of view is loss of neutral connection of MV/LV transformer during island operation when PD 1 is located downstream from MV/LV transformer. For this reason it has been chosen in this paper that master unit needs to be connected to microgrid through delta-wye transformer (i.e. microgrid side of this transformer is directly earthed) to ensure path for neutral current and high earth fault currents. On the other hand still in many countries DG units are required to be connected to network through transformers for galvanic isolation. But because transformers decrease overall efficiency of the DG unit, DG unit topologies especially for three-phase PV converters has been developed without transformers taken simultaneously into account that leakage current must be kept low enough [14]. When DG unit connection transformers are used, it is necessary to consider the connection type (e.g. delta-delta, delta-wye) of these transformers from microgrid protection point of view particularly during earth faults in island operation. In reference [15] it has been concluded that TN-C-S or TT earthing systems are the most suitable for neutral earthing of a LV microgrid and DG units could be operated safely without earthing their neutral points locally, both in grid-connected operation and islanded operation. However, in the simulations of this paper DG units have been connected to LV microgrid with delta-wye grounded connection transformers.

Realization of the microgrid concept or smart grid with island operation capability needs development of grid codes that allow island operation i.e. MGC. When MGCs are defined it is important to recognize that protection requirements and settings are dependent from control principles and technical implementation of converter based DG units and vice versa. In MGC it should be determined the fundamental structural choices with corresponding microgrid concept so that e.g. converter manufacturers could be able manufacture their products compatible with that concept during both normal and fault operation. MGC should also define power balance control principles including use of load control through second generation smart energy meters (AMM) and issues related to possible blackstart. Separate island grids and DC microgrids should have their own specifications in MGC or completely own grid codes.

III. Simulations for LV Microgrid Protection Concept Development

The LV network studied in this work is presented in Fig. 3. The system consists of one 800 kVA MV/LV-transformer which normally feeds LV feeders 1 and 2. In the simulation studies the islanded microgrid is disconnected from main network by the microgrid breaker PD 1. At the connection point of the microgrid, before the feeders 1 and 2, there is a converter connected energy storage unit (battery, S_n=150 kVA). At the end of feeder 1 there is a converter connected DG Unit 1 (S_n = 120 kVA, in simulations usually P = 100 kW, Q = 30 kVAr and about I = 150 A/phase). In the beginning of the feeder 2 there is a synchronous generator, SG, (S_n = 100 kVA, in simulations usually P = 100 kW, Q = 0 kVAr) and in the middle of the feeder 2 there is an induction motor, IM, (51 kW, 34 kVAr) as well as converter connected DG Unit 2 (S_n = 120 kVA, in simulations usually P = 100 kW, Q = 30 kVAr and about I = 150 A/phase) at the end of the feeder 2.

The load in the microgrid consists of four 3-phase passive loads on each feeder and few 1-phase passive

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loads (Fig. 3) on both feeders which means that the load between phases is asymmetrical. The passive loads can be adjusted so that the loading of the transformer (which feeds LV feeders 1 and 2) gets some desired value between 0…150 % of the transformer ratings and in different cases size of passive loads is changed according to the existence of IM load.

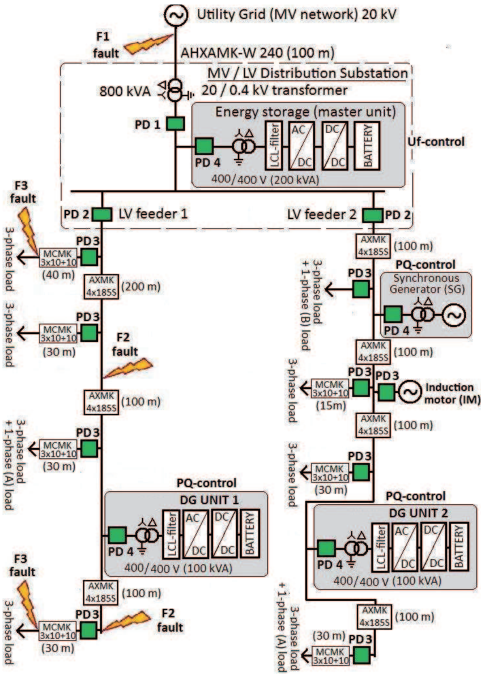

Fig. 3. Studied LV microgrid

Simulations are made with LV network line parameters shown in table I. Service connections of customer loads and DG units are also included in the simulation model (Fig. 3). The fault level and R/X-ratio of the feeding utility network (20 kV, 50 Hz) are 200 MVA and 0.1 respectively.

TABLE I
RESISTANCE, REACTANCE AND R/X RATIO OF MV AND LV NETWORK IN FIG. 3

	R (Ω/km)	X (Ω/km)	R/X
AHXAMK-W 240	0.13	0.116	1.12
AXMK 4x185S	0.164	0.0817	2.01
MCMK 3x10 +10	1.83	0.088	20.8

The converters are modeled as three-phase, three-leg, SVM modulated units with LCL-filters and the dc-link of the master unit is modeled with battery storage + DC/DC-buck-boost converter. In all simulations the master unit converter and DG unit converters were modeled with neutral connection, i.e. delta-wye grounded transformer (Fig. 3). The dc-link voltage V_{DC} of converter is chosen to be 0.7 kV. With all converters modified PLL component was used instead of the PSCAD's own PLL component to improve stability in deep voltage dips e.g. during transition to island operation due to F1 fault in utility grid [3]. Active and reactive power controller parameters are similar between DG units 1 and 2, but different with master unit converter. It is essential for the stability of the whole microgrid that during disturbances the control system of the master unit converter remains stable. However, it is worth noticing that PI-controller parameters of master unit converter PU-control needed some modification to ensure stability when microgrid dynamics is changed due to configuration change e.g. addition of an induction motor load to microgrid. Filter and control parameters used in simulations on converter based DG units are presented in Appendix.

During islanding, microgrid is operated in single master operation mode, which in this case means that the converter 1 with battery storage (Fig. 3) will act as the master unit and it has the main responsibility to control the voltage and frequency (Uf-control) in microgrid when islanded. Description of the control system for master unit can be found from [3] and [4]. Due to the selected control principle for master unit, the fault current fed to microgrid by this master unit depends on the fault type and location i.e. on the depth of the voltage dip caused by a fault in island operated microgrid.

DG units intended for energy production (such as PV cells or wind turbines) lack the capability of producing controlled active power on demand, if no storages are used, and so they are normally operated under PQ control. The control of these units remains same regardless of the operation mode, normal or island operation. In the simulations of this paper all the other DG units than the master units is operated in conventional PQ mode i.e. they do neither take part in frequency nor voltage control.

With delta-wye grounded transformers, the asymmetry of phase voltages is unequal at different sides of the transformers and due to that the symmetry of the phase currents is different at the microgrid side of the DG unit transformers. Due to asymmetrical phase voltages, also active and reactive power fed to microgrid by converter connected DG unit will oscillate although phase currents fed to the microgrid were symmetrical. Equivalent oscillations can be seen in the dc-link voltages of the DG unit converters and partly due to reactive power control during faults these oscillations in the dc-link voltage will increase significantly during faults. However, this oscillation could be reduced by using different control principles than in this paper e.g. some that is presented in reference [16].

To develop new concept for the LV microgrid protection multiple simulations were done with faults F1, F2 and F3 (3- / 2-phase short circuit faults and 2- / 1-

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phase earth faults) during normal and island operation of LV microgrid in different locations (Fig. 3). The configuration and combinations of the DG units and loads was changed during fault simulations to take into account their effect on the developed LV microgrid protection concept. Special focus was in island operation fault simulations of the LV microgrid.

Traditionally selective protection of PD 2s and PD 3s (Fig. 3) is based on non-directional over-current protection with fuses. The measurements done in simulations from different locations of LV microgrid (Fig. 3) for selection of appropriate type of PDs for the LV microgrid protection concept under development were such that for example in PCC of microgrid (PD 1) rms-values from 1-phase voltages and 1-phase currents were measured. In addition at the beginning of LV feeder (PD 2) rms-values from 1-phase voltages and 1-phase currents together with residual currents and negative sequence voltages were measured. Residual voltage was not measured, because during faults it stays the same in every point of islanded microgrid. During simulations from F3 faults rms-values from 1-phase currents were measured at customer PCC (PD 3) and operation times of fuses with different ratings were determined. In following some remarks from the simulations are presented.

III.1. Faults in Normal Operation of LV Microgrid

The simulation results from customer faults (F3) during normal operation of LV microgrid showed that voltages at the beginning of the LV feeder will remain in normal limits, between 210-250 V, regardless of the fault type. This means that although high fault currents will flow in customer faults (F3) through PD 1 it would not operate if the operation of it is based on voltage values.

Utility grid fault F1 during normal operation of LV microgrid will cause a voltage dip for microgrid customers and the duration of the voltage dip can be minimized with fast operation of PD 1 based on voltage level. Fast operation of PD 1 is also needed to maintain stability in microgrid after transition to island operation. Based on reference [6] sensitive customers may require that PD 1 operates in less than 70 ms. The operation of PD 1 can be only depended on the depth of the voltage dip, because e.g. during F1 faults LV feeder protection (PD 2) will not operate because the current direction is from LV microgrid to utility grid. This also means that directional overcurrent relay is not necessarily needed in PD 1. In overall, based on the simulation results from F1 faults, the most critical component from the stability point of view is directly connected synchronous generator which requires very fast operation from PD 1 during transition to island operation of microgrid. The operation speed of PD 1 may be a bit slower if capacity of the energy storage based master unit is increased in relation to the capacity of SG [3]. It is noteworthy that in cases with only converter connected DG units minimum fault clearance times could be slower and still the stability could be maintained. But in those cases the duration of voltage dip may become too long for the most sensitive customers in LV microgrid. It should be also noted here that to prevent unnecessary disconnection of DG units, the operation curve for voltage relay of PD 4s of DG units must always have longer time delays than the operation curve for voltage relay of PD 1.

It is important from stability point of view that phase angle reference given by master unit after islanding, e.g. due to F1 fault, is as near as possible to the original utility grid voltage phase angle. One interesting issue related to the simulations with SG was that although the voltage and frequency stability could be maintained even with quite long operation times of PD 1 (200-400 ms) in other type of F1 faults than 3-phase fault and 2-phase earth fault, the long fault clearance time created a large phase angle difference between SG and reference voltage phase angle given by master unit. This caused the synchronous generator to take large reactive power after islanding which is supplied by the master unit and the capacity of master unit was not large enough to supply the reactive power needed in all cases and that again caused dc-link voltage of master unit to rise to quite high values momentarily.

III.2. Faults in Island Operation of LV Microgrid

In customer fault (F3) simulations during island operation of LV microgrid, especially in cases with only converter connected DG units, it was noticed that during 2-phase short circuit the voltage of the healthy phase may rise considerably. In fault simulations during island operation of LV microgrid, also the effect of loss of one DG unit to LV microgrid protection behavior was studied in customer faults (F3). Possible loss of one DG unit during island operation of LV microgrid requires not only new PQ set points given for remaining DG units or disconnection of less critical loads but also adaptation from protection of LV feeders (PD 2s). Adaptation is needed to ensure selectivity of protection and stability after possible faults or loss of some DG unit during island operation. In simulations with SG the most significant consequence due to loss of one DG unit was the deterioration of marginal stability i.e. increase in oscillations of SG after fault clearance. Probably oscillations in the reactive power of SG could be reduced by improving the control of excitation during island operation. But to ensure stability in island operated microgrid after F3 fault clearance the rated capacity of the master unit with energy storage should be at least e.g. 1.5-2 times larger than the largest directly connected SG in microgrid, which was also suggested in [5] where blackstart of microgrid was simulated.

The selection of pick-up and operation limits for PD 2s may become challenging for example if in case with directly connected SG the fault occurs during island operation at the same LV feeder 2 where SG is located

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(Fig. 3). Reason for this is the large fault current fed to fault by directly connected SG which reduces the fault current seen by PD 2 of LV feeder 2. Adaptation to present microgrid DG unit configuration will be needed from PD 2s. When islanded microgrid protection settings and principles are developed attention should be paid also to the effects resulting from the connection of certain type of loads e.g. induction motors. Connection of a relatively large load may cause temporary voltage dip in island operated LV microgrid which should be distinguished e.g. from 3-phase faults. It is important that protection settings of PD 2s and PD 4s are such that they will not operate incorrectly when for example relatively large induction motor is connected to island operated microgrid. Selectivity could not be realized based only on values of measured currents, because for example currents seen by PD 2 during F2 faults are not necessarily notably larger than in some F3 faults if F2 fault occurs at the end of LV feeder. In addition the currents seen by PD 2s during F2 or F3 faults may in some microgrid configurations be only a little bit larger than nominal or average load currents at LV feeders. Instead, change in the voltage values indicates more clearly about possible F2 or F3 fault during island operation of microgrid. Therefore time based selectivity between PD 3s and PD 2s should be done so that operation of PD 2s is based on some kind of algorithm which takes into account both direction and value of LV feeder currents and also voltage value.

One interesting issue seen from the F2 fault simulation results during island operation of LV microgrid in cases with SG, was the growth in the phase difference between original utility grid voltage and microgrid voltage depending on the operation speed of PD 2 after F2 fault in island operated microgrid. This drifting of voltage phase angle is mainly caused by the dynamics of SG. For example when 3-phase F2 fault was cleared in 100 ms the voltage phase difference increased 4° during the fault, but when F2 was cleared in 150 ms phase difference had increased to 22°. Although stability of island operated microgrid was maintained in both cases the problem appeared during re-connection of microgrid to utility grid, because in the simulations it was assumed that phase of the utility grid is the same as before transition to island operation. When phase difference during re-connection of microgrid was 22° SG started to oscillate largely after re-connection and therefore it is important if there are directly connected SGs in microgrid the phase difference between utility grid and microgrid voltages should be less than 10°.

IV. Proposed LV Microgrid Protection Concept

Due to lack of high fault currents it has been proposed in [13] and [17] that voltages could be used for protection of an islanded microgrid instead of currents. Alone with voltage relays or current relays [6] it is difficult to realize selective microgrid protection during island operation. In reference [18] detection of asymmetrical faults (1-phase earth faults or 2-phase short circuit and earth faults) is designed to be based on zero and negative sequence components of the current. However, asymmetrical load produces also zero and negative sequence components to the current and therefore detection (pick up) limits for them may be difficult to determine. It is also worth mentioning here that structural choices made in the microgrid concept of reference [18] are different when compared to the technical choices made in this paper such as central energy storage (master unit) located at MV/LV distribution substation. The main structural choices and functions of the developed LV microgrid protection concept are summarized in Fig. 4 and 5 which are based on extensive simulation studies done with PSCAD (see chapter III). In Fig. 4 type of protective devices (PD 1-4) chosen and in Fig. 5 functions needed from them in normal and island operation are presented. Properties of the examined LV microgrid e.g. type, number and location of fault current feeding DG units made it difficult to realize selective protection for PD 2s during island operation which is only based on current or voltage relays. Therefore protection algorithm of PD 2s during island operation of LV microgrid is chosen to be adaptive multi-criteria based where both voltage and current measurements are utilized (Fig. 4). MMS is used to change settings and pick up limits of protective devices (PD 2s) when microgrid configuration changes (Fig. 4).

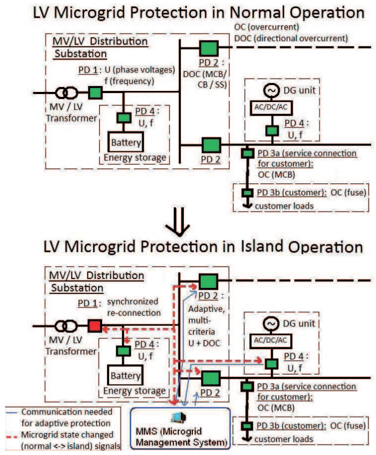

Fig. 4. Type of protection devices (PD 1-4) needed in normal and island operation of LV microgrid (see Fig. 5)

MMS will send state changed signal from normal to island operation to different PDs of microgrid to adapt to the changed microgrid configuration (Fig. 4). PD 1 is changed to be ready for future synchronized re-connection back to utility grid. Protection settings of PD

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2s are changed to those needed in island operation. To avoid malfunction of PD 2s, the protection settings of PD 2s are not changed from normal to island operation settings before all possible transients and oscillations in voltages, currents and frequency are stabilized after transition to island operation. MMS will also send state changed from island to normal operation signals to PD 2s and PD 4s after successful re-connection back to utility grid (Fig. 4). Also the role of MMS is important in power balance management and stability in island operated microgrid e.g. after fault F2 at LV feeder, MMS must send immediately after operation of LV feeder protection (PD 2) new set point values for those DG units that are still connected at the healthy part of the microgrid or disconnection signal to some less critical customer loads. In protection of island operated microgrid possible oscillations due to sudden changes in microgrid configuration needs to be taken into account to achieve selective protection and to avoid unnecessary tripping of protection. This could be done by using communication based interlocking signals. In Fig. 5 functions of the developed LV microgrid protection concept during normal and island operation are illustrated.

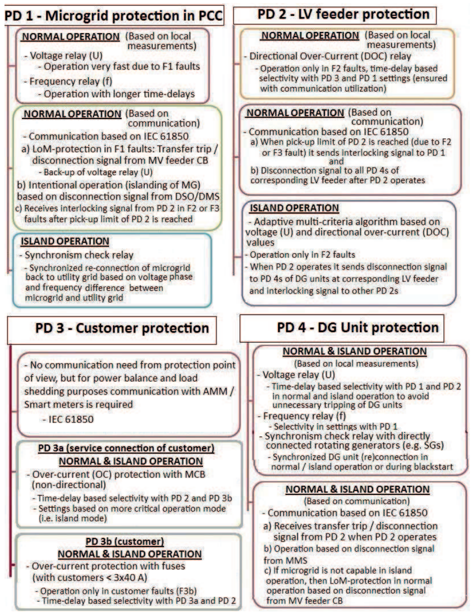

Fig. 5. Functions needed from LV microgrid protection in normal and island operation based on local measurements and communication (see Fig. 4)

Fast real-time communication is needed for microgrid protection purposes between protective devices (PD 1 and 2) and also with master unit and DG units during microgrid island operation. In addition MMS needs to be able to communicate in real-time with all these microgrid components as well as with customer loads. In this paper (Fig. 5) it has been decided that this communication should be based on some common standard such as IEC 61850 which has been also suggested to LoM protection of DG units in normal operation [19]. Communication based on the same common standard e.g. IEC 61850 between different network components and MMS is the most sensible and economical option in overall. For example in reference [20] with BEMI system, which is an energy management system designed for installation at LV grid connection points, it also has been planned that communication between different active network components is based on standard IEC 61850. More exactly IEC 61850-7-420 is the part of IEC 61850 which covers communication with DG units and also microgrids to some extent [20]. In IEC 61850-7-420 data models for different DG units are defined, but from perspective of microgrids some technologies are still missing [21]. Wind power has a separate standard named IEC 61400-25. To achieve cost efficient solutions integration should be done also e.g. with protection functions of DG units (PD 4) which should be part of the control system of it so that separate protection relays are not needed. Active microgrid components in the PCC of microgrid (PD 1, master unit and MMS) are also responsible for synchronized re-connection of microgrid back to utility grid (Fig. 4). Based on reference [22] synchronous islanded operation is proposed as a means to keep the island in synchronism with the main system while not being electrically connected i.e. during island operation. This could be done by a reference signal containing phase and frequency information to the master unit of the microgrid [21]. The phase difference should by within acceptable levels (under 60°) during reconnection to utility grid [21]. Based on previous simulation studies the phase angle difference may be even slightly larger with converter connected DG units depending on the implementation of the control system and PLL. However with SGs the phase difference should be preferably significantly smaller than 60° to avoid large oscillations and electrical stresses. Based on [23] microgrid resynchronizing function have to meet a more stringent requirement than the one defined by IEEE 1547 which requires that the phase difference between microgrid and utility grid should less than 20° before the PD 1 can close. In comparison for example in HV network synchronism check relays are configured in some cases so that frequency difference should be under 55 mHz and phase difference 20°-45° [24].

V. Operation Curves of PDs in LV Protection Concept

One problem in some of the proposed solutions for LV microgrid protection, e.g [25] or [26], is that their applicability is limited to microgrids with only converter connected DG units. Therefore, these solutions may

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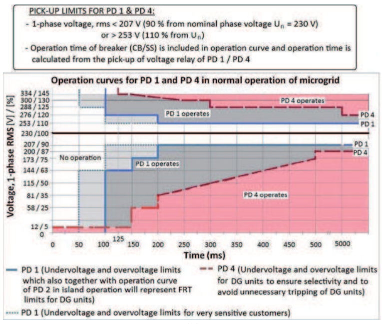
overlook e.g. operation speed requirements of protection to maintain stability of LV microgrid with directly connected rotating machines after fault clearance.

Key fundamental properties required from the future LV microgrid protection concepts include, i) adaption capability, ii) utilization of fast standard based communication, IEC 61850, iiia) fast operation in deep voltage dips due to faults to maintain stability in healthy part of LV microgrid, iiib) fast operation to fulfill needs of very sensitive customers, iv) selective operation in every kind of faults and v) unnecessary operation of PDs and disconnection of DG units must be avoided. In following exact specifications and operation curves for developed LV microgrid protection concept (chapter IV) during normal and island operation are presented.

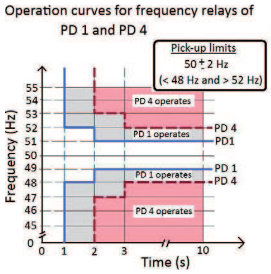
One important issue is that operation curves for PD 1 in normal and PD 2 in island operation also represent FRT requirements for DG units connected to the LV microgrid, because they are created so that stability of LV microgrid or healthy part of LV microgrid could be maintained after fault clearance also in cases where directly connected SG was connected in LV microgrid. Voltage relay operation curve of PD 4 ensures selectivity with settings of PD 1 in normal operation and PD 2 in island operation to avoid unnecessary tripping of DG units. Frequency relay of PD 1 and PD 4 is only used to protect microgrid customers from possible long-term frequency deviations from nominal 50 Hz e.g. caused by disturbances due to power imbalance in high voltage network which cannot be seen from phase voltage measurements. Operation curves for frequency relay of PD 4 will also represent FRT required from DG and energy storage units based on frequency. Pick-up and operation limits for PD 3s OC settings should be quite low, because their operation speed should be same also in island operation, where fault current level will be much lower than in normal operation.

V.1. Operation Curves for LV Microgrid Protection in Normal Operation

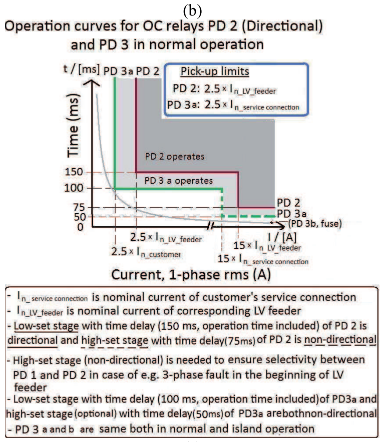
In Fig. 6 requirements for the operation of microgrid protective devices (PD 1, PD 2, PD 3 and PD 4) during normal operation of microgrid are presented.


PICK-UP LIMITS FOR PD 1 & PD 4:
- 1-phase voltage, rms < 207 V (90 % from nominal phase voltage U_n = 230 V) or > 253 V (110 % from U_n)
- Operation time of breaker (CB/SS) is included in operation curve and operation time is calculated from the pick-up of voltage relay of PD 1 / PD 4

(a)



(b)



- $I_{n\_service\ connection}$ is nominal current of customer's service connection
- $I_{n\_LV\_feeder}$ is nominal current of corresponding LV feeder
- Low-set stage with time delay (150 ms, operation time included) of PD 2 is directional and high-set stage with time delay(75ms) of PD 2 is non-directional
- High-set stage (non-directional) is needed to ensure selectivity between PD 1 and PD 2 in case of e.g. 3-phase fault in the beginning of LV feeder
- Low-set stage with time delay (100 ms, operation time included)of PD3a and high-set stage (optional) with time delay(50ms)of PD3a arebothnon-directional
- PD 3 a and b are same both in normal and island operation

(c)

Figs. 6. (a) Operation curves for voltage relays (PD 1 in normal operation and PD 4 in normal and island operation), (b) Operation curves frequency relays of PD 1 and PD 4 in normal and island operation of microgrid and (c) Operation curves for OC relays of PD 2 (directional) in normal operation and PD 3 in normal and island operation

The operation of PD 1 during normal operation of microgrid is based on the operation curve of voltage relay described in Fig. 6 a). If there are many customers in microgrid that are very sensitive to voltage dips, then operation of PD 1 should be faster (Fig. 6 a)) and breaker type of PD 1 must be SS based instead of CB. PD 1 operates depending only on the depth of the voltage dip.

The operation limits for low-set and high-set stages of PD 2 and PD 3a in Fig. 6 c) are instructional, based on simulation studies done for this paper. The protection of LV feeders with PD 2s in normal operation is based on directional over-current relays (Fig. 6 c)). The direction of the current must be to corresponding LV feeder with such time delay that all possible F3 type of customer faults will be cleared with PD 3s before possible operation of PD 2. The chosen time delays in Fig. 6 c) between PD 2 and PD 3a are quite small and selectivity may be hard to achieve between them in reality without communication based interlocking signals from PD 3a. It is also worth noticing that different network configurations or lay-outs will require different settings from PD 3a which means that operation limits of it must

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be adjustable. Especially in pick-up limit for directional OC of PD 2 one needs to take into account the effect of fault current fed by DG units (e.g. at least nominal current with converter connected DG units) connected downstream from PD 2. Pick-up limit of PD 2 in Fig. 6 c) has been chosen to be quite low, current > 2.5*$I_{n\_LV\ feeder}$, which also takes into account the effect of possible DG unit at that LV feeder. After pick-up limit of PD 2 is reached interlocking signal must be sent immediately from PD 2 (< 100 ms) to PD 1 and tripping signal from PD 2 to PD 4s of DG units at corresponding LV feeder.

When 3-phase F2 fault at the very beginning of the LV feeder without any DG units at that feeder was simulated during normal operation of microgrid it was found out that fault currents may be up to 17.5 kA (> 50*$I_{n\_LV\ feeder}$, if $I_{n\_LV\ feeder}$ = 315 A) and voltage drops < 150 V in 20 ms i.e. selectivity between PD 1 and PD 2 cannot be maintained in this case without high-set stage of PD 2 (Fig. 6 c)) . In case of fault is between PD 1 and PD 2s, PD 1 will operate in 100 ms based on the operation curve of Fig. 6 a) if it has not received interlocking signal from some of the PD 2s.

In protection of customer service connection with PD 3a and in protection of customers with PD 3b it was decided that the same PD 3 protection must be functional in both normal and island operation without any changes needed. Based on the simulations the largest applicable fuse that can be used as PD 3b is < 3*40 A in the size range of LV microgrid that was studied in this paper. Protection of larger customers ≥ 3*40 A with PD 3b must be done e.g. with MCBs that are capable of selective operation between PD 3a (Fig. 6 c).

The operation curve for PD 4 must be such that it will never unnecessarily disconnected DG unit due to F1, F2 or F3 fault i.e. PD 4 needs to be time selective with PD 1, PD 2 and PD 3 both in normal and in island operation of microgrid. Fulfillment of the FRT curve for DG units (PD 1) in Fig. 6 a) may be challenging especially for the directly connected rotating generators during island operation. In relation to the FRT requirements, if converter connected DG unit is expected to feed any fault current at all during the fault then voltage cannot be zero (see Fig. 6 a)). For this reason it has been chosen in the operation curve for PD 4 in Fig. 6 a) that minimum voltage requirement is e.g. 5 % from nominal voltage. Although, for example if 1-phase earth fault occurs near PCC of some DG unit, voltage at the faulted phase may drop < 12 V at that phase and DG unit may be unnecessarily disconnected. Therefore operation curve of voltage relay at PD 4 needs an extra definition presented in chapter VI.

V.2. Operation Curves for LV Microgrid Protection in Island Operation

In following requirements for the operation of microgrid protection during island operation are presented focusing on the changes that are necessary in microgrid protection when compared to the normal operation. Main difference is the needed change in the protection algorithm of PD 2. Based on the simulations adaptive multi-criteria algorithm for PD 2 shown in Fig. 7 was created.

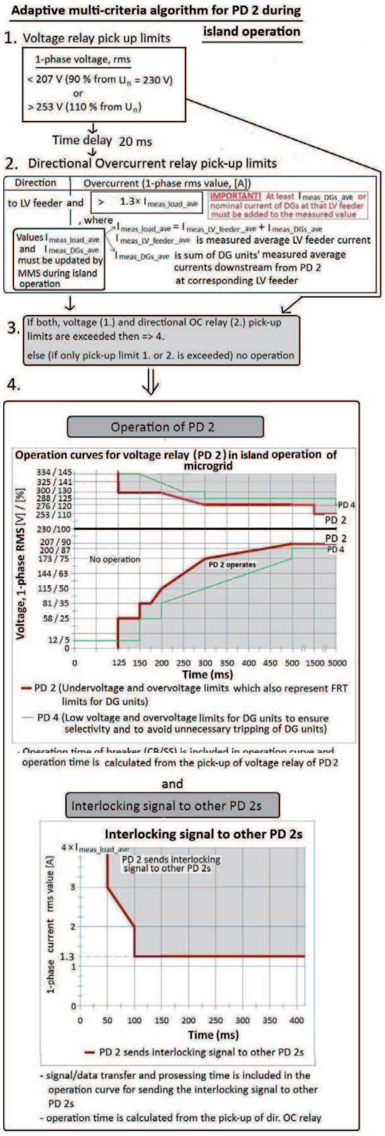

Fig. 7. Adaptive multi-criteria algorithm for PD 2 to achieve selective operation between PD 3a and PD 2 in customer faults (F3) and LV feeder faults (F2) during island operation of LV microgrid.

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The time delay in the multi-criteria algorithm of PD 2 (Fig. 7) is dependent on the voltage dip which at the same time ensures stability after fault clearance, minimizes the effect of the voltage dip to other customers of the microgrid and prevents unnecessary operation due to connection of certain type of loads (e.g. IM). Pick-up limit of the directional OC measurement as part of the multi-criteria algorithm of PD 2 is adaptive so that it takes into account the number and type of DG units at corresponding LV feeder and also their fault current feeding capability. To ensure selectivity between PD 2s of LV feeders during island operation of microgrid PD 2 should send an interlocking signal to other PD 2s after pick-up limits for voltage and directional OC values of it have been exceeded. Possibly some very short time delay could be used in interlocking signal sending so that with higher current measurement values the time delay of sending the interlocking signal would be shorter (see Fig. 7).

To maintain stability in island operation after large voltage dip due to 3-phase short circuit or 2-phase earth fault also in those cases where directly connected rotating DGs (e.g. SGs) are connected to remaining healthy part of LV microgrid after operation of PD 2 in 125 ms (Fig. 7) the size or nominal power of master unit needs to be larger than that directly connected SG. Shorter operation time e.g. less than 50 ms could be beneficial from the DG unit's point of view due to easier FRT requirements and from microgrid customers perspective due to shorter voltage dips experienced after faults. But in that case selectivity of PD 2 with PD 3a and PD 3b may become challenging to realize because then they would be required to operate in few tens of millisecons if communication is not used with PD 3a.

Another option for protection of radially operated LV feeders during island operation with only voltage relays at PD 2s could be comparison of voltage measurements between PD 2s which are measured some distance away from MV/LV distribution substation at corresponding LV feeders with high speed communication to PD 2s. This way lower phase voltage / voltages at the faulted LV feeder could be seen more clearly.

The protection of PD 3s and PD 4s remains unchanged during island operation of microgrid (see Fig. 6). One important issue related to the re-connection of island operated microgrid to utility grid was that if there are directly connected SGs in microgrid the phase difference between utility and microgrid voltages should be < 10°.

The effect of higher R/X-ratio on LV feeders and the influence of it on protection settings of PD 2s and PD 3s was also studied through simulations. Simulations showed that higher R/X-ratio reduces slightly both the fault currents measured by PD 2s and PD 3s and the magnitude of the voltage dip during fault.

In all simulations fault resistance R_{fault} has been 0.005 Ω. In addition it was simulated that how much larger the fault resistance can be in order to be cleared with the multi-criteria algorithm of PD 2 (Fig. 7). For example separation between connection of larger 1-phase load and 1-phase F2 earth fault with R_{fault} = 5 Ω could not be made. The simulation showed that during 1-phase F2 earth fault with R_{fault} = 1 Ω at the end of LV feeder 1 the multi-criteria algoritm of PD 2 detects the fault. The simulations gave also reasons to determine the maximum size of 1-phase load or DG unit that can be connected to microgrid with island operation capability, e.g. in percents from capacity of master unit, so that the risk of unnecessary operation of PD 2 can be avoided during island operation. The under- or overvoltage ride-through ability of customers is also determined by the protection settings and operation curves of microgrid protection described above. For example the same FRT requirements are valid for frequency converter connected induction motors. In case that customer has more equipments that are more sensitive to voltage dips or momentary overvoltages, then customer specific solutions e.g. UPS, LV customer DC microgrid, overvoltage protection etc. are required.

VI. Example Cases from LV Microgrid Protection During Island Operation

In this chapter some protection issues of island operated LV microgrid are highlighted through fault simulations with simulation model shown in Fig. 8 which is based on the simulation model presented previously in Fig. 3. Specific interest in simulations (Fig. 8) is on effect of DG unit to LV microgrid protection during island operation. But also the functionality of developed protection concept for LV microgrid is examined.

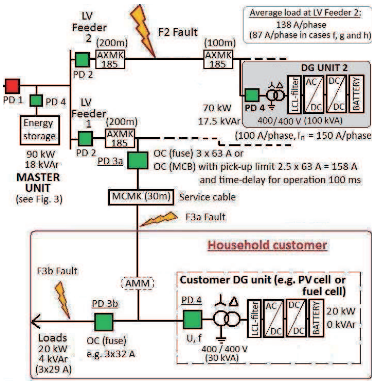

Fig. 8. Simulation model for simulation of 1-phase earth fault in three different locations (F2, F3a, F3b) with variable amount of DG units connected during island operation of LV microgrid.

Next simulation results from eight different cases a-h are presented. Simulations are done so that 1-phase earth fault (cases a-g) or 2-phase short circuit fault (case h) occurs in different locations (F2, F3a, F3b) with variable

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amount of DG units connected during island operation of LV microgrid (Fig. 8). These eight simulated cases a-h are (Fig. 8):

a) F3a fault – With DG unit 2 and without DG unit at household customer – PD 3a non-direct. OC protection with 3 x 63 A fuse
b) F3a fault – With DG unit 2 and DG unit at household customer – PD 3a non-direct. OC protection with 3 x 63 A fuse
c) F3b fault – With DG unit 2 and without DG unit at household customer – PD 3a non-direct. OC protection with MCB
d) F3b fault – With DG unit 2 and DG unit at household customer – PD 3a non-direct. OC protection with MCB
e) F2 fault at LV feeder 2 – With DG unit 2 and DG unit at household customer – PD 3a non-direct. OC protection with MCB
f) F2 fault at LV feeder 2 – Without DG unit 2 and with DG unit at household customer – PD 3a non-direct. OC protection with MCB
g) F2 fault ($R_{fault} = 1\ \Omega$) at LV feeder 2 – Without DG unit 2 and with DG unit at household customer – PD 3a non-direct. OC protection with MCB
h) F2 fault at LV feeder 2 – Without DG unit 2 and with DG unit at household customer – PD 3a non-direct. OC protection with MCB

In Table II simulation results from cases a and b are presented in which 1-phase earth fault (F3a, see Fig. 8) occurs. From simulation results (table II) it can be seen that the operation time of OC protection at PD 3a with 3 x 63 A fuse is too long. In case b the fault current fed by DG unit of household customer reduces the fault current going through fuse (PD 3a) and increases the operation time of fuse from 330 ms to 400 ms when compared to case a (table II). As a conclusion from cases a and b can be stated that time selective protection during island operation of LV microgrid cannot be achieved with fuses (3 x 63 A) at PD 3a. Instead of fuses at PD 3a there should be MCB e.g. with low-set pick-up limit 2.5 x 63 A = 158 A and 100 ms time-delay (see Fig. 6c)).

TABLE II
F3A FAULT[*)] (FIG. 8)

Case	Operation time of PD 3a fuse (ms)	1-Phase Currents, rms, at PD 3a / PD 2 of LV feeder 1 (A)	1-Phase Voltages, rms, at PD 3a / PD 2 of LV feeder 1 (V)
a	330	445, 35, 35 / 455, 110, 105	26, 285, 278 / 43, 289, 282
b	400	412, 55, 55 / 425, 83, 155	25, 285, 273 / 40, 288, 278

*) Measured current and voltage values at the operation time of PD 3a

But is it sufficient that OC protection at PD 3a with MCB is non-directional or should it be directional, adaptive and equipped with fast communication? In following (table III) the simulation results from cases c and d are presented in which F3b fault occurs (Fig. 8). The simulation results of table III show that time selectivity between PD 3a (MCB) and PD 3b (3 x 32 A fuse) can be maintained in this type of fault regardless of the presence of household customer DG unit.

From simulation results shown in Table III it can be seen that in case d with F3b fault at customer PCC voltage at faulted phase A decreases < 12 V which means that PD 4 of customer DG unit will disconnect it immediately (see Fig. 6a)) if phase voltages are measured from grid side of the delta-wye grounded connection transformer of DG unit. This is unnecessary because voltage is only too low in one phase (A). Therefore operation curve of voltage relay at PD 4 needs an extra definition, i.e. disconnection of DG unit with PD 4 based on undervoltage should only take place < 150 ms after pick-up limit is reached if voltage in all three phases (A, B, C) is < 12 V (see Fig. 6a)). This case becomes different if phase voltages for PD 4 are measured from DG unit side of delta-wye grounded transformer, then above mentioned extra definition is not necessarily needed.

TABLE III
F3B FAULT[*)] (FIG. 8)

Case	Operation time of PD 3b fuse (ms)	1-Phase Currents, rms, at PD 3b / PD 3a (A)	1-Phase Voltages, rms, at PD 3b / PD 3a (V)
c	38	420, 32, 32 / 430, 33, 31	2, 249, 242 / 26, 252, 247
d	35	460, 33, 31 / 375, 53, 55	2, 260, 247 / 23, 259, 250

*) Measured current and voltage values at the operation time of PD 3b

Next the correct operation of LV microgrid protection and measurements of PD 3a and PD 2 during 1-phase earth fault F2 at LV feeder 2 (Fig. 8) in simulation cases e and f are examined. Simulation results from cases e and f are presented in table IV. Here it is worth mentioning that due to absence of DG unit 2 in case f, the total load of LV microgrid is also lower and the size of customer load is changed from 29 A to 19 A/phase (Fig. 8).

TABLE IV
F2 FAULT[*)] AT LV FEEDER 2 (FIG. 8)

Case	Operation time of PD 2 of LV feeder 2 (ms)	1-Phase Currents, rms, at PD 3a / PD 2of LV feeder 2 (A)	1-Phase Voltages, rms, at PD 3a / PD 2 of LV feeder 2 (V)
e[**)]	125	51, 10, 11 / 347, 47, 55	16, 291, 279 / 14, 295, 283
f	125	54, 16, 13 / 366, 118, 91	16, 292, 280 / 15, 295, 282

*) Measured current and voltage values at the operation time of PD 2,
**) $I_{meas\_DGs\_ave}$ or nominal current of DG unit 2 has not been added to the measured currents of PD 2 in case e (Fig. 7)

Firstly, it can be seen from simulation results of Table IV that non-directional OC protection at PD 3a will not operate during F2 fault in cases e) and f) due to fault current fed by DG unit of household customer (Fig. 8). Although the current direction at PD 3a (Table IV) is to LV microgrid, the OC current pick-up limit of non-directional PD 3a (158 A) is not exceeded. However, if there were e.g. a directly connected 20 kW SG based DG unit at household customer instead of converter connected PV cell then OC protection at PD 3a should be directional. Secondly, the operation of multi-criteria algorithm of PD 2 (Fig. 7) at LV feeder 2 in F2 faults can be viewed. The pick-up limit of directional OC relay of PD 2 in multi-criteria algorithm (Fig. 7) is in case e is about $1.3\ x\ I_{meas\_load\_ave} = 1.3\ x\ \{[(46+32+29)/3] + (107+$

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$104+96)/3]\} = 179\ A$ and in case f about $1.3\ x\ I_{meas\_load\_ave} = 1.3\ x\ 87A = 113\ A$. When these pick-up limits are compared to the measured current and voltage values of PD 2 during F2 fault it can be seen from table IV that multi-criteria algorithm of PD 2 (Fig. 7) operates correctly. Here it should be noted that in case e DG unit 2 current $I_{meas\_DGs\_ave}$ (104 A/phase) has not been added to the measured currents of PD 2 in table IV (see Fig. 7). With addition of $I_{meas\_DGs\_ave}$ to the measured currents of PD 2 in case e (table 4) the measurement result which is compared to the pick-up limit of PD 2 (179 A in case e) becomes 451, 151 and 159 A for A, B and C phases respectively. Losses are not taken into account. However, if there were e.g. a directly connected SG based DG unit at LV feeder 2 instead of converter connected DG unit then the higher fault current feeding capability of it should be taken into account in the directional OC current pick-up limit ($I_{meas\_load\_ave}$) of PD 2, because the initial fault current of SG is multiple of the nominal current of SG. This may be challenging and it could be reasonable to connect larger (e.g. > 20 kW) directly connected SGs to the MV/LV distribution substation before PD 2s of LV feeders' to ensure their correct operation. In overall, it is important to determine from LV microgrid protection point of how DG units behave and feed fault current during possible faults during island operation.

Finally, in cases g and h previously simulated case f (table IV) is simulated again with few changes. In case g the correct operation of PD 2 during 1-phase earth fault with higher fault resistance ($R_{fault} = 1\ \Omega$) than in case f ($R_{fault} = 0.005\ \Omega$) is studied and in case h fault type is different (2-phase short circuit) than in case f. Simulation results from cases g and h are presented in Table V.

TABLE V
F2 FAULT*) AT LV FEEDER 2 (FIG. 8)

Case	Operation time of PD 2 of LV feeder 2 (ms)	1-Phase Currents, rms, at PD 3a / PD 2of LV feeder 2 (A)	1-Phase Voltages, rms, at PD 3a / PD 2 of LV feeder 2 (V)
g	260	24, 8, 6 / 200, 104, 87	149, 257, 269 / 150, 259, 271
h	125	47, 51, 20 / 237, 248, 105	159, 166, 324 / 161, 166, 327

*) Measured current and voltage values at the operation time of PD 2

The pick-up limit ($1.3\ x\ I_{meas\_load\_ave}$) of directional OC relay of PD 2 in cases g and h the same as in case f i.e. circa 113 A. In both cases g and h OC pick-up limit of PD 2 is reached (Table V). However, the operation time of multi-criteria algorithm at PD 2 increases in case g to 260 ms. In case h PD 2 operates still in 125 ms, but instead of undervoltage the operation is now based on overvoltage of phase C (Fig.7).

Based on the simulation results presented above from cases a-h it can be concluded that OC protection at PD 3a with MCB can be non-directional and real-time adaptability with high-speed communication is not necessarily needed. But very large size or some type (e.g. directly connected SG) of DG unit at household customer may require directional OC protection at PD 3a. If household customer with DG unit is intended to form LV customer microgrid in case of F2 type of faults, the protection of PD 3a should be voltage and fast communication based which isolates LV customer microgrid in less than 100 ms (Fig. 9).

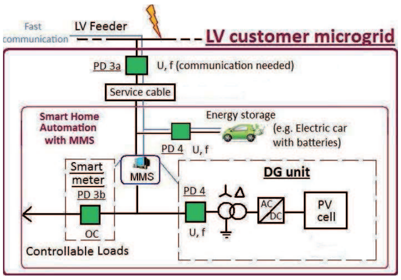

Fig. 9. Example from possible LV customer microgrid configuration

VII. Conclusion

The conventional protection in distribution networks is designed to operate for high fault current levels in radial networks, but during island operation of the microgrid high fault currents from the utility grid are not present. Also most of the DG units that will be connected to the LV microgrid in the future are converter interfaced and have limited fault current feeding capabilities. This means that the traditional fuse protection of LV network alone is no longer applicable and new protection methods must be developed. In this paper new smart protection concept for LV microgrid is developed through simulation studies with PSCAD in which for example LV feeders are protected (PD 2) in addition of traditional fuses with protective relays that have adaptive multi-criteria algorithms and fast standard IEC 61850 based communication capabilities. Adaptivity means that protection of PD 2 takes into account the number and type of DG units at corresponding LV feeder and also their fault current feeding capability. Fast and selective operation between different PDs is achieved by intelligent utilization of high-speed communication.

In further studies also the dynamics of the primary energy source e.g. fuel cell, photovoltaic cell or microturbine should modeled more detailed to verify the functionality of the developed LV microgrid concept. It is also important to ensure that the behavior that is required from DG units during faults in microgrid during normal and island operation is compatible with the developed microgrid protection concept. The developed smart LV microgrid protection concept revealed the urgent need for fast operating, accurate, low-cost, programmable PDs with high-speed communication capability in future smart LV networks. In future studies

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the developed LV microgrid protection concept could be widened to cover also cases where e.g. long LV feeders are divided into smaller protection zones. Naturally in future real example cases are important to verify and test developed LV microgrid protection concept in practice.

Appendix

System parameters of the test system with different DG unit converter filter and controller parameters are presented in Table VI. The solution time step in simulations was 5 µs.

TABLE A. I
STUDY SYSTEM PARAMETERS

	Parameter	**Value**
DG Unit Converters (DC/AC)	Modulation method	SVM
	Switching frequency	8 kHz
	Filter L_1, R_d, C, L_2	0.4 mH, 0.1 Ω, 10 µF, 0.2 mH
Current PI-controllers	Gain $K_{current}$	1.5
	Integrator time constant T_{c_i}	0.15 ms
Active Power PI-controller (Master Unit)	Gain K_p	$0.2^{*)}$, $1.5^{**)}$
	Integrator time constant T_{p_i}	$0.015^{*)}$, $0.001^{**)}$ s
	Sampling rate	$4^{*)}$, $1^{**)}$ kHz
Active Power PI-controller (Other DG Units)	Gain K_p	0.2
	Integrator time constant T_{p_i}	0.025 s
	Sampling rate	4 kHz
Reactive Power PI-controller (Other DG Units)	Gain K_Q	1
	Integrator time constant T_{q_i}	0.03 s
	Sampling rate	4 kHz
Synchr. Generator (SG)	Inertia constant	0.1049 MW/MVA
	R_a / X_p / Air gap f.	0.012 pu / 0.087 pu / 0.8
	X_d / X_d'/ X_d''	3.5 pu / 0.128 pu / 0.077 pu
	X_q / X_q'/ X_q''	2.1 pu / 0.128 pu / 0.098 pu
	T_{do}' / T_{do}''	2.71 s / 0.02 s
	T_{qo}' / T_{qo}''	2.71 s / 0.02 s
Reactive Power Control of SG (Input to Exciter)	Gain	1.0
	Time constant	1.0 s
DC-DC Buck-boost Converters	Gain $K_{dc/dc}$	0.3
	Integrator time constant T_{dc/dc_i}	0.06 s
	Sampling rate_dc/dc	1 kHz
	DC-link capacitor	5000 µF

Setting $A^{*)}$ is for simulation cases with only converter connected DG units and setting $B^{**)}$ is for simulation cases with also rotating machines e.g. SG connected to LV microgrid. Settings $A^{*)}$ and $B^{**)}$ with own PLL component and modified current control during fault current feeding, with transformers on all DG unit converters. Master Unit controller before islanding i.e. in normal operation with settings $A^{*)}$ and $B^{**)}$, Active power control, Kp_P = 0.2, Ti_P = 0.025, Reactive power control, Kp_Q = 1, Ti_Q = 0.02. Reactive power control of master unit in all simulations after islanding is changed so that zero input is given as current reference i_q.

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Authors' information

[1]University of Vaasa.

[2]University of Vaasa.

H. Laaksonen was born in Vaasa, Finland, on November 22, 1977. He received his Master's degree (2004) in Electrical Power Engineering from Tampere University of Technology.
His employment experience includes working as a research scientist in VTT Technical Research Centre of Finland in Vaasa and before that in Institute of Power Engineering department at Tampere University of Technology. Currently he works as a research scientist and PhD student with Department of Electrical Engineering and Automation at University of Vaasa. His field of interests are planning + integration of DG in distribution networks, power electronics in distribution networks and future network concepts (e.g. microgrids).

K. Kauhaniemi was born in Kankaanpää, Finland, in 1963. He received his M.Sc degree (1987) and Dr. Tech. degree (1993) in electrical engineering from Tampere University of Technology, Finland. He was previously employed by VTT Technical Research Centre of Finland. Currently he is Professor in electrical engineering at the University of Vaasa, Finland. His special interest areas include the modeling and simulation of power systems.

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International Review on Modelling and Simulations (I.RE.MO.S.), Vol. 3, N. 3
June 2010

DG Unit Fault Behavior and Protection of LV Microgrid

H. Laaksonen, K. Kauhaniemi, S. Voima

Abstract – *Microgrids can be defined as distribution systems with DG units, energy storages and controllable loads i.e. Smart Grids. Most of the time microgrids will be operated normally connected to utility grid with the same management principles as other parts of the Smart Grids. In addition to this microgrids have a special capability of working in islanded mode, e.g., during the utility grid outages. In this paper effect of distributed generation (DG) unit converter's fault behavior to low voltage (LV) microgrid protection during island operation is studied in some specific cases through simulation studies with PSCAD simulation software. When protection of islanded microgrid is designed one of the most important questions is how converter based DG units will contribute to the fault current feeding. In the simulations different control strategies of converter connected DG units during faults are investigated with various DG unit configurations and also the role of energy storages is examined to find out their effect to microgrid voltages and currents that are measured by the protective devices. In overall the protection of LV microgrid needs to be very fast to both minimize duration of voltage dips to customers and maintain stability in island operated microgrid.* ***Copyright © 2010 Praise Worthy Prize S.r.l. - All rights reserved.***

***Keywords**: Microgrid, Distributed Generation, Energy Storage, Protection, Islanding, Low Voltage Network, Fault Behavior, Stability*

Nomenclature

AC	Alternating Current
AMM	Automated Meter Management
CB	Circuit Breaker
DC	Direct Current
DER	Distributed Energy Resources
DFIG	Doubly Fed Induction Generator
DG	Distributed Generation
DMS	Distribution Management System
DSO	Distribution System Operator
FCS	Fault Current Source
FRT	Fault Ride Through
LoM	Loss of Mains
LV	Low Voltage
MMS	Microgrid Management System
MV	Medium Voltage
PCC	Point of Common Coupling
PD	Protection Device
PLL	Phase Locked Loop
PMSG	Permanent Magnet Synchronous Generator
PU	Active Power - Voltage
PV	Photovoltaic
PQ	Active and Reactive Power
SG	Synchronous Generator
SS	Static Semiconductor based Switch
SVM	Space Vector Modulation
Uf	Voltage and frequency
UPS	Uninterruptible Power Supply

I. Introduction

Large scale integration of DER (including DG, electricity storages, electric vehicles and customers with smart energy meters and controllable loads) to distribution network in future requires creation of a totally new Smart Grid concept which will take advantage of the properties of DER.

Advanced Smart Grid concept allows the use of DER in a coordinated way through intelligent management system and hence allows the potential of DER to be realized for different interest groups (DSOs, DG producers, service providers, consumers and society). Simultaneously with the development of choices made in the Smart Grid concept the future island operation (microgrid) possibility should be integrated and supported by minimal changes to the concept.

Typically the term microgrid is used from the LV network Smart Grid with island operation capability. However, microgrid concept should be defined in a more general way as a smart distribution grid part with island operation capability.

In that case microgrid would mean certain part of distribution network with DER which is managed as a whole with intelligent MMS. Microgrid can be for example (see Fig. 1):

1. Separate island grid,
2. Small household LV microgrid or LV customer microgrid,

Manuscript received and revised May 2010, accepted June 2010

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3. LV microgrid consisting of all LV feeders connected downstream from MV/LV distribution transformer or

4. MV network feeder microgrid or MV substation microgrid with all MV feeders.

In overall the role of MMS can be seen as distributed intelligence of DMS to lower voltage levels in distribution networks (Fig. 1).

Microgrid is normally operated parallel with utility grid and, e.g., during faults in upstream network it can be separated quickly from utility grid and operated independently as an island grid. MMS will be responsible from the overall economic and energy effective operation of microgrid taking into account the technical boundary conditions both in normal and island operation.

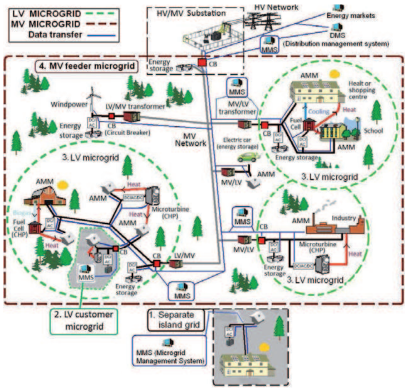

Fig. 1. Different possible microgrid configurations

Technical choices made in the microgrid concept must be such that they can be justified by the needs of normal operation, but at the same time allowing and supporting the solutions needed for implementation of island operation.

When technical decisions considering, e.g., LV microgrid concept are drawn one must take into account in all phases the possibilities and development steps of LV network automation, communication standards (especially IEC 61850), AMM devices of LV customers, LV network connected DG units, energy storages, electric vehicles and legislation/regulation. Grid codes and standards that allow also the island operation possibility are needed to speed up the transition from present passive and inefficient distribution grids to active Smart Grids.

In this paper only technical aspects related to LV microgrids are discussed. The operation and control of LV microgrid is a very challenging issue because there are number of things that will have influence to the behavior of microgrid in different ways.

In overall the dynamics of islanded microgrid, e.g., lack of inertia, is totally different when compared to the normal operation of the microgrid parallel with utility grid. Islanded microgrid is much more sensitive to disturbances and successful island operation requires fast, accurate and stable control.

Also the protection of the future microgrid is a challenging issue and very strongly connected to the control and operation issues of a microgrid. The conventional protection in distribution networks is designed to operate for high fault current levels in radial networks, but during island operation of the microgrid high fault currents from the utility grid are not present. Also most of the DG units that will be connected to the LV microgrid in the future are converter interfaced and have limited fault current feeding capabilities. This means that the traditional fuse protection of LV network is no longer applicable and new protection methods must be developed. In addition, the developed protection scheme for microgrid must be naturally supported by the technical choices made in the microgrid operation and control.

In the development of the new protection scheme for LV microgrids many things must be considered including amount of protection zones in LV microgrid, speed requirements for microgrid protection in different operation states and configurations and protection principles for parallel and island operation of the microgrid.

Taking into account the possibility of island operation in the future means, e.g., from the point of view of converter connected DG unit manufacturers that technical design of the converter must enable both present LoM protection requirements and future FRT requirements.

Fulfillment of the FRT requirement may require, e.g., to use energy storages like supercapacitors in the DC-links of DG unit converters to control the DC-link voltage rise during faults. In addition Smart Grid compatible DG unit converter must be equipped with fast standard based communication capabilities.

In the simulations of this paper different control strategies of converter connected DG units during faults in microgrid island operation are investigated with various DG unit configurations to find out their effect to microgrid voltages and currents which are measured by the protective devices.

Section II of the paper discusses briefly about issues related to protection of LV microgrid and section III about DG unit converter control during faults. Section IV introduces the studied system and simulation results of the study and discussions are presented in Sections V and VI. Conclusions are stated in Section VII.

II. Issues Related to Protection of LV Microgrid

The number of microgrid protection zones will define the needed amount of protection devices for microgrid protection. The size of microgrid protection zone must be

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such that it fulfills the requirements of customers and at the same time is economically feasible.

Based on references [1], [2] failure rate in LV network is approximately 20-40 faults (overhead lines) and <5 (underground cables) per 100 km annually in typical European LV networks.

Therefore splitting the LV feeders in more than one protection zones would not be justified in most of the cases [3] (see Fig. 2).

Naturally customers connected to LV feeders will create the smallest protection zones at the bottom of the microgrid protection hierarchy (Fig. 2).

Very disturbance sensitive customers can have their own protection and energy storage or UPS system so that they can continue operation also during all possible faults at the corresponding LV feeder (Fig. 2), i.e. they create small household LV microgrid. In these small household LV microgrids the use of DC distribution may increase in future (Fig. 2).

The amount and degree of protection zones used in this paper is presented in Fig. 2. Also the needed protection devices (PD 1-4) for these protection zones to clear three type of basic faults (F1, F2, F3) are shown in Fig. 2.

PD 1: Microgrid protection (in the PCC) including relay and CB or fast SS

PD 2: LV feeder protection including fuses, relays and CB or SS

PD 3: Customer protection including fuse or mini-circuit breaker or in case of LV customer microgrid (DC or AC) SS is needed

PD 4: DG/DER unit protection

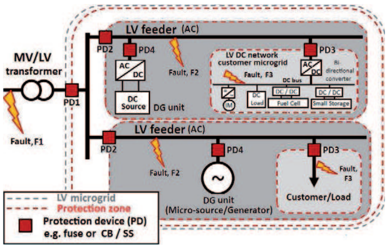

Fig. 2. Protection zones and devices in the studied LV microgrid

Traditionally selective protection of PD 2s and PD 3s (Fig. 2) is based on non-directional over-current protection with fuses.

Due to lack of short-circuit power and high fault currents it has been proposed in [4] and [5] that voltages could be used for protection of an islanded microgrid instead of currents. Alone with voltage relays or current relays it is difficult to realize selective microgrid protection during island operation [1].

In reference [6] the detection of asymmetrical faults (1-phase earth faults or 2-phase short circuit and earth faults) is designed to be based on zero and negative sequence components of the current. However, asymmetrical load produces also zero and negative sequence components to the current and therefore detection/pick up limits for the protection devices may be difficult to determine. It is also worth mentioning here that structural choices made in the microgrid concept of reference [6] are different in many ways when compared to the technical choices made in this paper.

In this paper the protection concept of island operated LV microgrid is not developed. However, it is assumed that for the protection of LV feeders in island operated LV microgrid (PD 2s in Fig. 2) voltage and/or current measurements could be used.

Therefore in the simulations of this paper the effect of different control strategies of converter connected DG units during faults in island operated LV microgrid to operation time of fuse based PD 3s and rms-values of voltages and currents measured by the PD 2s are investigated with various DG unit configurations.

III. DG Unit Converter Control during Faults in LV Microgrid

From the island operated LV microgrid protection point of view it is essential to know how converter based DG units will contribute to the fault current.

In reference [7] it is stated that converters low thermal overload capability limits their maximum output current to about 2-3 times the rated current and to avoid converter disconnection due to high fault current during a fault, i.e. to improve converter FRT ability, converter output current limitation algorithm is used for the period needed by the protective system to locate and isolate the fault. On the other hand in reference [8] more fault current to island operated microgrid is provided by FCS to ensure that the over-current based protection operates correctly.

In overall the behavior of converter based DG units during faults including allowable voltage and frequency fluctuations is determined by national interconnection requirements or grid codes which differ from country to country.

Therefore, standardization is needed to determine the operation of converter based DG units during faults to ensure efficient operation of smart grids with high penetration levels of DG units [9]. In reference [9] some general requirements about converters behavior during faults which have to be fulfilled are stated, e.g. converters should not disconnect in case of faults, converters should support the grid voltage in case of faults by injection of reactive power during the fault. However, it has been pointed out in [9] that at different network levels (MV/LV) grid-support during faults by DG unit converters may require different solutions.

The increased reactive power feeding of converter connected DG units during faults in island operated LV microgrid has been studied in the simulations of this paper to find out its effect on stability after fault and voltage level during faults.

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In Fig. 3 the control of converter based DG units during fault is presented with increased reactive power feeding. To improve stability of converter based DG unit and to avoid disconnection during faults due to loss of synchronism negative sequence filtering has been used with PLL component and current control of DG unit converters (Fig. 3) [10], [11]. The used LV microgrid simulation model is described with more details in chapter IV. In the simulations of this paper the control of DG unit converters during faults in island operation of LV microgrid was carried out so that when a phase-to-earth voltage decreased below 180 V (normal reference value is 230 V) in PCC of DG unit then if the voltage remains below 180 V during the 20 ms time delay the reactive power reference I_{react} of converter was increased to 0.7^*I_n until all phase-to-earth voltages are above 220 V, i.e. fault is cleared (Fig. 3).

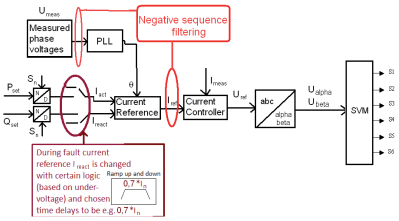

Fig. 3. Control of converter based DG units during fault with increased reactive power feeding

It is also important to keep in mind that sudden change of DG unit control system or parameters during faults may be a bit risky from the stability point of view in a fault during island operation. Partly for that reason the fault current reference I_{react} is increased and decreased as a ramp in the simulations of this paper (Fig. 3).

This is also the reason why control system of the master unit is kept constant also during faults throughout the operation in island mode.

In every case the FRT capability of converter based DG unit will not be only a control issue.

This means that also the hardware layout of the DG unit converter may need to be adjusted to provide FRT capability.

For example in [12] supercapacitor based energy storage is used in DFIG wind turbine to smooth the output power and to provide FRT ability. Supercapacitors are also proposed, for example in [13], to be used with fuel cell based UPS systems to, e.g., improve their control response which is otherwise quite moderate due to the slow dynamics of the fuel processor.

Also other kind of modifications to provide FRT capability for converter connected DG units has been suggested. For example in [14] DC chopper is added to the DC-link of microturbine converter instead of larger capacitance to limit voltage rise in DC-link during faults. This DC chopper dissipates the excessive power during faults through its resistor. Also in some simulations done in this paper the effect of supercapacitor in the DC-link of DG unit converter to provide FRT ability, i.e. limit voltage rise in DC-link during faults, has been examined.

IV. Simulation Model of the Study System

The LV network studied in this work is presented in Fig. 4. The system consists of one 800 kVA MV/LV-transformer which normally feeds LV feeders 1 and 2. In the simulation studies the islanded microgrid is disconnected from main network by the microgrid breaker PD 1. At the connection point of the microgrid, before the feeders 1 and 2, there is a converter connected energy storage unit (battery, S_n=150 kVA).

At the end of feeder 1 there is a converter connected DG Unit 1 (S_n = 120 kVA, in simulations usually P = 100 kW, Q = 30 kVAr and about I = 150 A/phase). In the beginning of the feeder 2 there is a synchronous generator, SG, (S_n = 100 kVA, in simulations usually P = 100 kW, Q = 0 kVAr) and at the end of the feeder 2 there is also converter connected DG Unit 2 (S_n = 120 kVA, in simulations usually P = 100 kW, Q = 30 kVAr and about I = 150 A/phase). The load in the microgrid consists of four three-phase passive loads on each feeder and few single-phase passive loads (Fig. 4) on both feeders which mean that the load between phases is asymmetrical. The passive loads can be adjusted so that the loading of the transformer (which feeds LV feeders 1 and 2) gets some desired value between 0…150 % of the transformer ratings. Simulations are made with cable parameters shown in Table I. Service connections of customer loads and DG units are also included in the simulation model (Fig. 4). The fault level and R/X-ratio of the feeding utility network (20 kV, 50 Hz) are 200 MVA and 0.1 respectively.

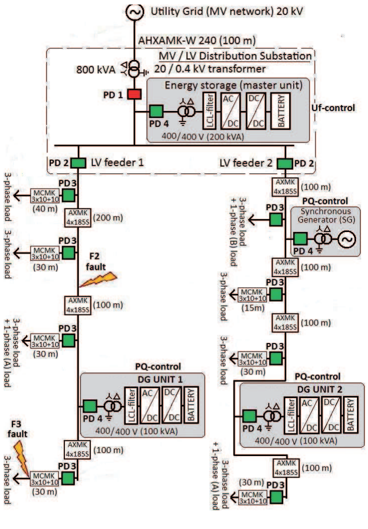

Fig. 4. Studied LV microgrid

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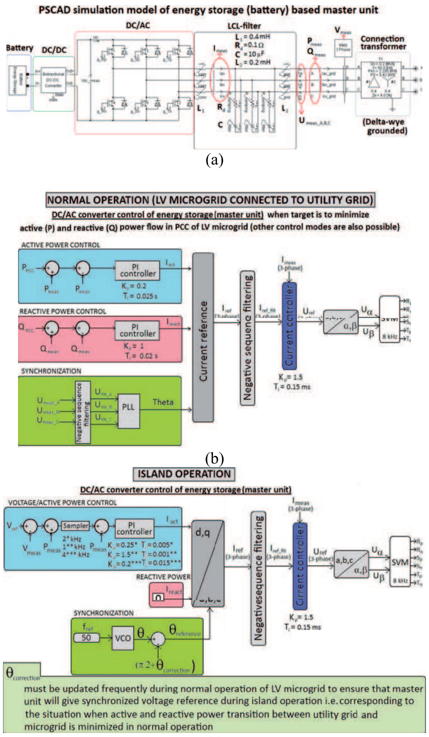
TABLE I
RESISTANCE, REACTANCE AND R/X RATIO OF THE CABLES IN FIG. 4

	R (Ω/km)	X (Ω/km)	R/X
AHXAMK-W 240	0.13	0.116	1.12
AXMK 4x185S	0.164	0.0817	2.01
MCMK 3x10 +10	1.83	0.088	20.8

The converters are modeled as three-phase, three-leg, SVM modulated units with LCL-filters and the DC-link of the master unit is modeled with battery storage + DC/DC-buck-boost converter. In all simulations the master unit converter and DG unit converters were modeled with neutral connection, i.e. delta-wye grounded transformer (Figs. 4 and 5). The DC-link voltage of converter is chosen to be 0.7 kV. With all converters modified PLL component was used instead of the PSCAD's own PLL component to improve stability in deep voltage dips, e.g., during transition to island operation due to fault F1 in utility grid [10]. Active and reactive power controller parameters are similar between DG units 1 and 2, but different with master unit converter (Figs. 5).



(a)

(b)

$\theta_{correction}$ must be updated frequently during normal operation of LV microgrid to ensure that master unit will give synchronized voltage reference during island operation i.e. corresponding to the situation when active and reactive power transition between utility grid and microgrid is minimized in normal operation

(c)

Figs. 5. (a) PSCAD simulation model of energy storage (battery) based master unit. Control of master unit DC/AC- converter; (b) in normal operation and (c) in island operation

It is essential for the stability of the whole microgrid that during disturbances the control system of the master unit converter remains stable.

However, it is worth noticing that PI-controller parameters of master unit converter PU-control needed some modification to ensure stability when microgrid dynamics is changed due to configuration change.

Filter and control parameters used in simulations on converter based DG units are presented in Appendix. During islanding, microgrid is operated in single master operation mode, which in this case means that the battery storage based DER unit (Fig. 4) will act as the master unit and it has the main responsibility to control the voltage and frequency (Uf-control) in microgrid when islanded (Fig. 5 (c)).

Due to the selected control principle for master unit, the fault current fed to microgrid by this master unit depends on the fault type and location, i.e. on the depth of the voltage dip caused by a fault in island operated microgrid.

DG units intended for energy production (such as PV cells or wind turbines) lack the capability of producing controlled active power on demand, if no storages are used, and so they are normally operated under PQ control.

The control of these units remains same regardless of the operation mode, normal or island operation.

In the simulations of this paper all the other DG units except the master unit are operated in conventional PQ mode i.e. they do neither take part in frequency nor voltage control.

However, in the simulation the reactive power control of these units is modified during faults in island operated microgrid.

It needs thorough considerations to decide that is it worthwhile to add energy storage to the DC-link of this type of DG units (e.g. PV cells) and also increase DC/AC- converter capacity of the DG unit just to be capable of feeding or absorbing large amount of reactive power.

For example based on references [15], [16] reactive power feeding or absorbing by DG units in mainly resistive LV networks is an inefficient way to control voltage.

When DG unit is connected to grid with delta-wye grounded transformers, the asymmetry of phase voltages is unequal at different sides of the transformers and therefore the symmetry of the phase currents is different at the microgrid side of the DG unit connection transformers (Figs. 6).

Due to asymmetrical phase voltages, also active and reactive power fed to microgrid by converter connected DG unit will oscillate although phase currents fed to the microgrid were symmetrical on the converter side of the DG unit transformer (Fig. 4).

Equivalent oscillations can be seen in the DC-link voltages of the DG unit converters and partly due to reactive power control during faults these oscillations in

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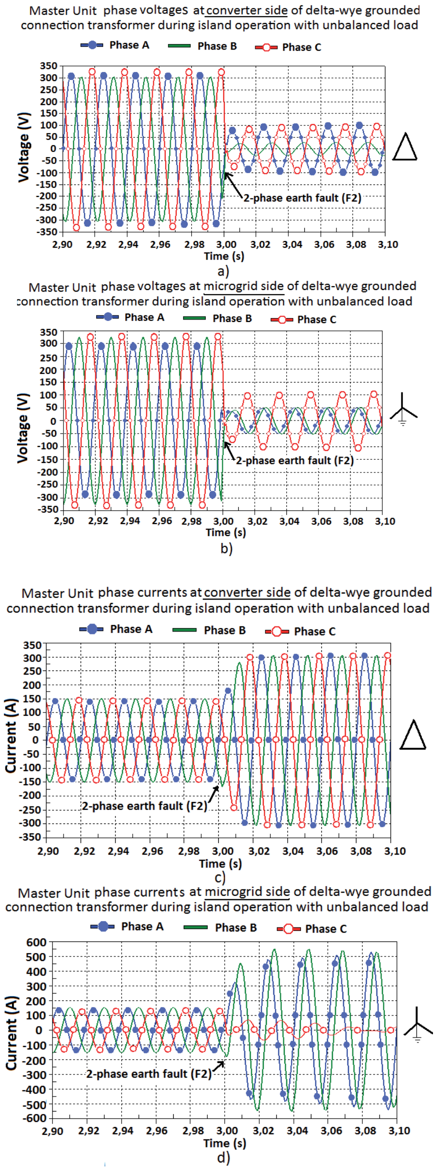
the DC-link voltage will increase significantly during faults (Figs. 7).

However, these oscillations could be reduced by using different control principles, e.g., those one presented in reference [17].


Master Unit phase voltages at converter side of delta-wye grounded connection transformer during island operation with unbalanced load

a)

Master Unit phase voltages at microgrid side of delta-wye grounded connection transformer during island operation with unbalanced load

b)

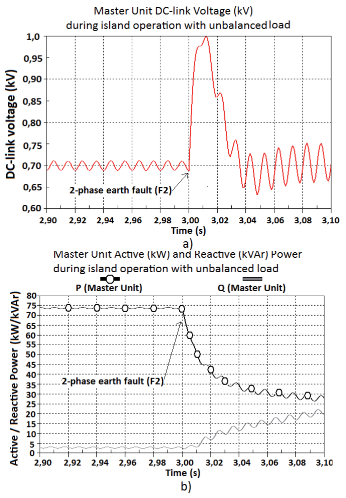
Master Unit phase currents at converter side of delta-wye grounded connection transformer during island operation with unbalanced load

c)

Master Unit phase currents at microgrid side of delta-wye grounded connection transformer during island operation with unbalanced load

d)

Figs. 6. Phase voltages and currents at converter side (a, c) and at microgrid side (b, d) of delta-wye grounded connection transformer of master unit (energy storage based DG unit) during island operation with unbalanced load and unbalanced 2-phase earth fault (F2)


Master Unit DC-link Voltage (kV) during island operation with unbalanced load

a)

Master Unit Active (kW) and Reactive (kVAr) Power during island operation with unbalanced load

b)

Figs. 7. Master unit (energy storage based DG unit) DC-link voltage (a) and active and reactive power (b) during island operation with unbalanced load and unbalanced 2-phase earth fault (F2)

V. Simulations of the Fault Behavior of Different Type of DG Units during Faults in Island Operation

In this chapter the fault behavior of different type of DG units and the effect of reactive power feeding of the converter connected DG units during fault in island operation of LV microgrid is examined. In section V.1 effect of DG unit reactive power feeding during F3 fault and in V.2 during F2 fault has been simulated. In the simulations of V.1 and V.2 there are only converter connected DER units in LV microgrid i.e. all other DER units of the studied system presented in Fig. 4 except the directly connected SG. In the simulation studies presented in section V.3 DG unit 2 at the LV feeder 2 is disconnected and SG is connected (Fig. 4) to find out effect of SG and to compare the fault behavior of directly connected SG to simulations in V.2 without SG. Studied cases A and B in chapter V are:

Case A: Unbalanced load, DG unit control of DG is not changed during fault

Case B: Unbalanced load, control of converter based DG is changed to feed reactive power during fault (see chapter III and Fig. 3)

V.1. Fault F3 (2-Phase Earth Fault) at the End of LV Feeder 1 – Effect of Reactive Power Feeding during Fault

In Table II and in Figs. 8 and 9 simulation results from 2-phase earth fault (F3) which occurs at the end of LV feeder 1 in cases A and B during island operation are presented.

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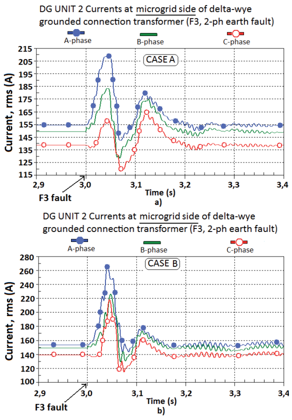
From Table II it can be seen that the operation time of PD 3 (3*40 A fuse) is only 2 ms shorter in case B due to reactive power feeding of DG units.

TABLE II
OPERATION TIME AND CURRENTS SEEN BY PD 3 (3*40 A FUSE) DUE TO F3 FAULT AT THE END OF LV FEEDER 1 (FIG. 4)

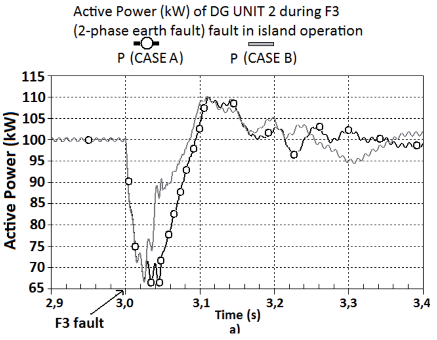
	Operation time of PD 3, 3*40 A fuse (ms)	Currents flowing through PD 3 at the time of operation of PD 3 / 20 ms after beginning of fault (A)
*Case A**)	49	570, 590, 25 / 500, 500, 25
*Case B**)	47	650, 650, 50 / 500, 500, 40

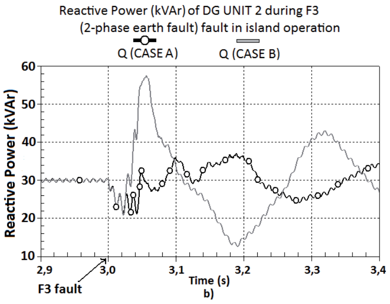
*) PI controller parameters of Master Unit, config. A, (Appendix)



Figs. 8. Fault currents of DG unit 2 (Fig. 4) after 2-phase earth fault (F3) at the end of LV feeder 1 a) in case A and b) in case B during island operation

Figs. 9 illustrates how PQ-control of DG unit 2 takes more time to stabilize in case B than in case A. This arouses question that is it worthwhile to change the converter control mode during fault if the benefit in the operation time fuse based protection is minor when compared to the increased risk of instability after the fault due to the converter control mode change during fault.





Figs. 9. a) Active and b) Reactive power of DG unit 2 (Fig. 4) after 2-phase earth fault (F3) at the end of LV feeder 1 in cases A and B during island operation

V.2. Fault F2 (2-Phase Earth or Short Circuit Fault) in the Middle of LV Feeder 1 – Effect of Reactive Power Feeding during Fault

In simulations presented in this section V.2 the operation time of PD 2 at LV feeder 1 due to fault F2 is in case A 100 ms and in case B 150 ms. In case B converter based DG unit 2 at LV feeder 2 ends increased reactive power feeding 20 ms after the operation of PD 2. In following Table III and in Figs. 10-12 simulation results from 2-phase earth fault (F2) which occurs in the middle of LV feeder 1 in cases A and B during island operation are presented.

TABLE III
VOLTAGES AND CURRENTS SEEN BY PD 2 DUE TO 2-PHASE EARTH FAULT (F2) IN THE MIDDLE OF LV FEEDER 1 (FIG. 4)

	Voltages seen by PD 2 before fault / when PD 2 operates (V)	Currents through PD 2 before fault / at the time of operation of PD 2 (A)
*Case A**)	215, 230, 240 / 35, 35, 80	54, 34, 49 / 555, 555, 80
*Case B**)	215, 230, 240 / 40, 40, 93	54, 34, 49 / 620, 620, 70

*) PI controller parameters of Master Unit, config. C, (Appendix)

From Table III it can be seen that the increased reactive power feeding in case B does not rise microgrid voltages substantially even though the currents seen by PD 2 are increased in case B. This means that if operation time of PD 2 depends from magnitude of the voltage dip, reactive power feeding will not jeopardize the operation of it. On the other hand, voltage dip sensitive customers in LV microgrid will have only a little benefit from increased reactive power feeding in case B.

The increased reactive power feeding with converter based DG units is beneficial for the possible overcurrent protection at PD 2 and it does not significantly reduce the usability of possible under-voltage based protection at PD 2 by increasing microgrid voltage level during fault in island operation.

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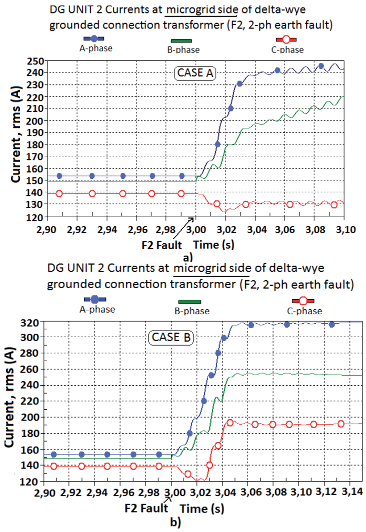
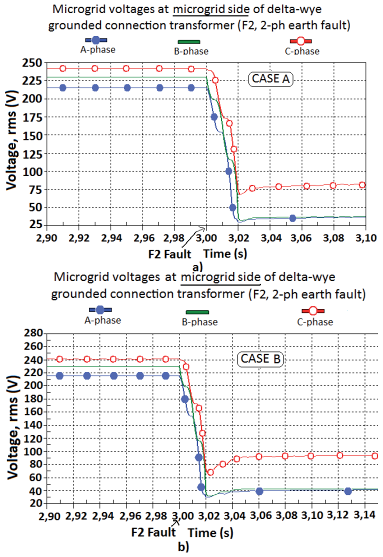
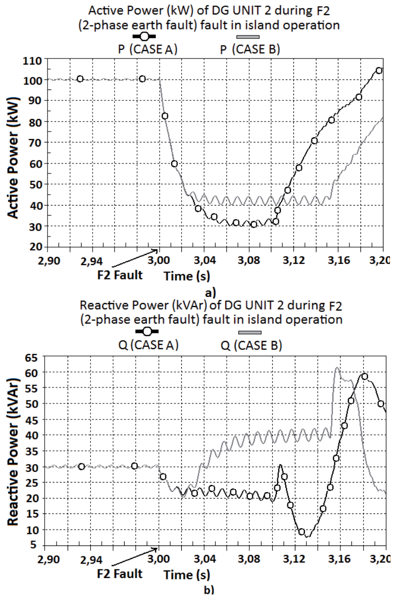


Figs. 10. Fault currents of DG unit 2 after 2-phase earth fault (F2) in the middle of LV feeder 1 a) in case A and b) in case B during island operation



Figs. 11. Microgrid voltages after 2-phase earth fault (F2) in the middle of LV feeder 1 a) in case A and b) in case B during island operation

In following Table IV and in Figs. 13-16 simulation results from 2-phase short-circuit fault (F2) which occurs in the middle of LV feeder 1 in cases A and B during island operation are presented.



Figs. 12. a) Active and b) Reactive power of DG unit 2 after 2-phase earth fault (F2) in the middle of LV feeder 1 in cases A and B during island operation

TABLE IV
VOLTAGES AND CURRENTS SEEN BY PD 2 DUE TO 2-PHASE SHORT-CIRCUIT FAULT (F2) IN THE MIDDLE OF LV FEEDER 1 (FIG. 4)

	Voltages seen by PD 2 before fault / when PD 2 operates (V)	Currents through PD 2 before fault / at the time of operation of PD 2 (A)
Case A$^{*)}$	215, 230, 240 / 155, 165, 320	54, 34, 49 / 340, 325, 80
Case B$^{*)}$	215, 230, 240 / 122, 132, 255	54, 34, 49 / 236, 140, 107

$^{*)}$ PI controller parameters of Master Unit, config. C, (Appendix)

An interesting behavior appeared in case B due to increased reactive power feeding of DG unit 1 and 2. Even though the reactive power feeding does not substantially increase microgrid voltages during fault in islanded LV microgrid it can make microgrid unstable after fault clearance if master unit is controlled to keep microgrid voltage level constant all the time.

In case B this behavior can be seen (Figs. 14 and 16) when master unit decreases it's active power output to compensate the voltage rise caused by reactive power feeding of DG unit 1 and 2 which leads to microgrid unstability after the operation of PD 2.

In case of LV microgrid with even higher R/X-ratio LV feeders than the ones used in the simulations of this paper (see Table I and Fig. 4) problems due to increased reactive power feeding of DG units during fault are even more probable.

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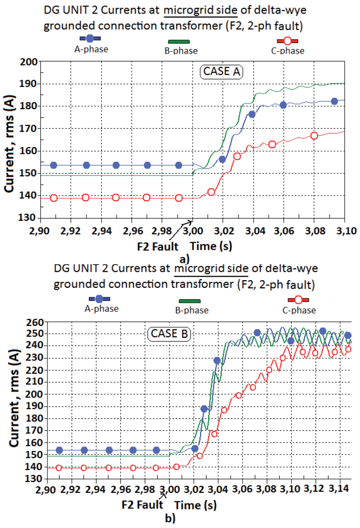
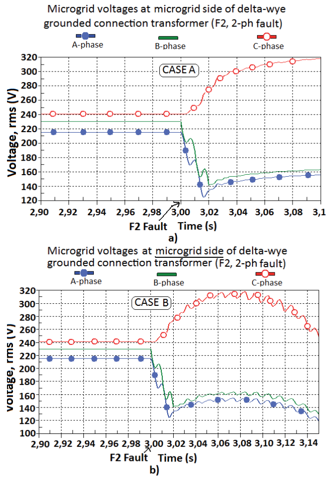
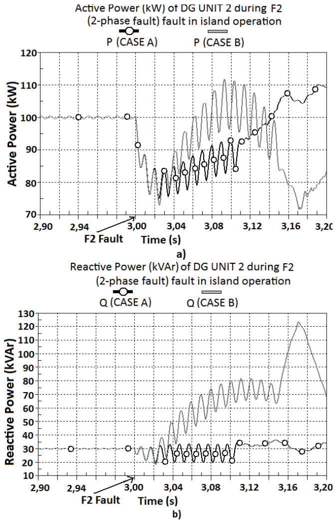


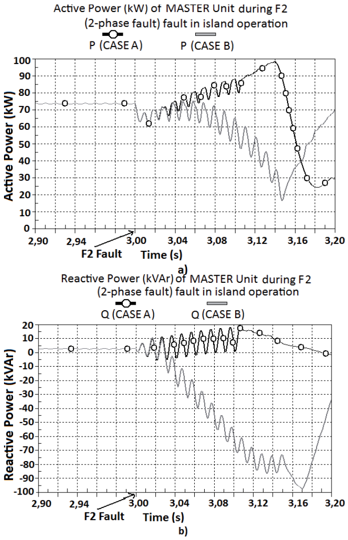
Figs. 13. Fault currents of DG unit 2 after 2-phase short-circuit fault (F2) in the middle of LV feeder 1 a) in case A and b) in case B during island operation



Figs. 14. Microgrid voltages after 2-phase short-circuit fault (F2) in the middle of LV feeder 1 a) in case A and b) in case B during island operation



Figs. 15. a) Active and b) Reactive power of DG unit 2 after 2-phase short-circuit fault (F2) in the middle of LV feeder 1 in cases A and B during island operation



Figs. 16. a) Active and b) reactive power of master unit after 2-phase short-circuit fault (F2) in the middle of LV feeder 1 in cases A and B during island operation

V.3. Fault F2 in the middle of LV feeder 1 - Effect of directly connected SG

In following simulations with 2-phase earth and short-circuit fault (F2) during LV microgrid island operation the DG unit 2 at the LV feeder 2 is replaced with SG (Fig. 4 and 17) to find out effect of directly connected SG and to compare the fault behavior of SG to simulations done in section V.2 without SG. Only case A without increased reactive power feeding of DG unit 1 is examined.

In Table V and in Figs. 18 and 19 results from simulations where there is 2-phase short-circuit fault (F2) in the middle of LV feeder 1 during island operation are presented. PD 2 of LV feeder 1 operates in 100 ms after beginning of F2 fault.

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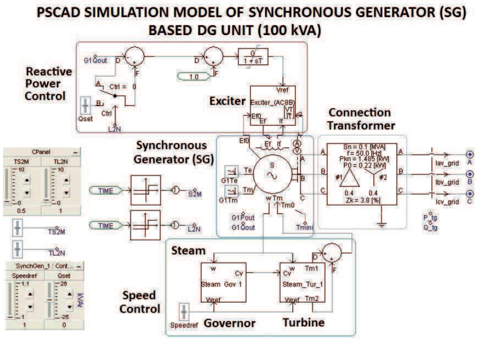
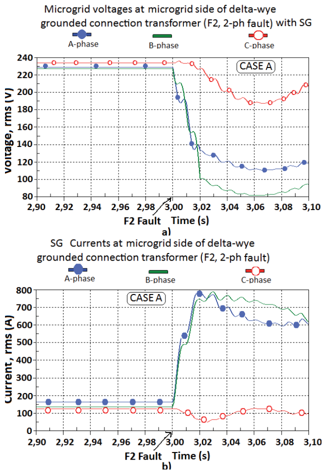


Fig. 17. PSCAD simulation model of SG based DG unit

TABLE V
VOLTAGES AND CURRENTS SEEN BY PD 2 DUE TO 2-PHASE SHORT-CIRCUIT FAULT (F2) IN THE MIDDLE OF LV FEEDER 1 (FIG. 4)

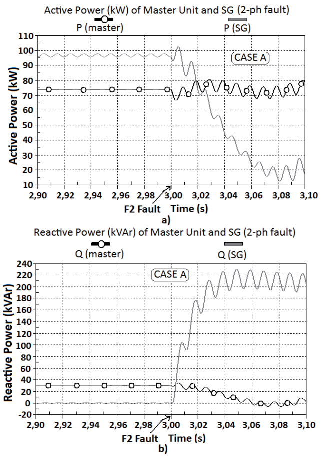
	Voltages seen by PD 2 before fault / when PD 2 operates (V)	**Currents through PD 2 before fault / at the time of operation of PD 2 (A)**
Case A[*)]	229, 227, 234 / 119, 95, 210	65, 31, 46 / 708, 663, 76

[*)] PI controller parameters of Master Unit, config. B, (Appendix)



Figs. 18. a) Microgrid voltages and b) fault currents of SG after 2-phase short-circuit fault (F2) in the middle of LV feeder 1 in case A during island operation

First of all, when behavior of microgrid voltages after 2-phase short-circuit F2 fault with SG (Fig. 18 a)) is compared with the previous simulation results without SG (Fig. 14), one can see that now the voltage in the healthy phase C will not rise over the nominal 230 V. Reason for this can be found by comparing the phase C fault currents fed by SG (Fig. 18 c)) and DG unit 2 (Fig. 13) to the healthy phase C.



Figs. 19. a) Active and b) reactive power of SG and master unit after 2-phase short-circuit fault (F2) in the middle of LV feeder 1 in case A during island operation.

The current fed by SG to phase C does not increase during 2-phase short-circuit fault (Fig. 18 b)) and therefore voltage in phase C will not rise over nominal value. Secondly, the fault current of SG is by nature much more reactive than the fault current fed by DG unit 2 in case A. This can be seen by comparing the active and reactive power behavior of SG and DG unit 2 during F2 fault from case A in Fig. 19 and 15. Due to the resistive nature of LV network lines (table I) the voltage phase angle difference in island operated LV microgrid is more dependent from reactive power transfer than from active power transfer. Therefore, significant reactive power feeding of SG during fault combined with exciter control of SG that is not optimized for island operation seems to increase the possibility of angle stability problems after fault clearance.

When corresponding simulation in case A with SG was done with 2-phase earth fault (F2), stability of healthy part of LV microgrid could not be maintained after operation of PD 2. The reason for this appeared to be the active and reactive power sharing between master unit and SG, because when the same simulation was done with larger passive load then stability could be maintained after 2-phase earth fault. Based on the simulations it may be concluded that the nominal power of directly connected SG, which is not located at the MV/LV distribution substation like the energy storage based master unit, should be substantially smaller than the nominal power of master unit and the operation time of PD 2 in very deep voltage dips due to faults must be very fast e.g. less than 150 ms.

In following table VI and in Fig. 20 and 21 simulation results where there is 2-phase earth fault (F2) in the middle of LV feeder 1 during island operation are presented. PD 2 of LV feeder 1 operates in 125 ms after beginning of F2 fault.

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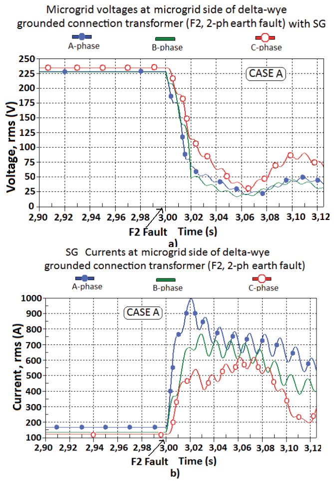
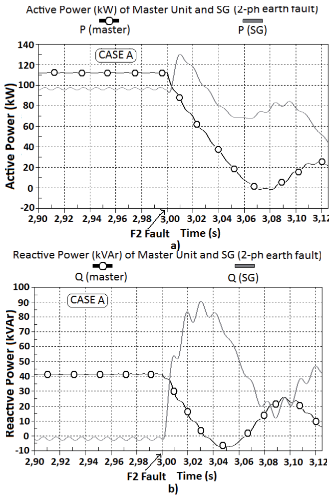
TABLE VI
VOLTAGES AND CURRENTS SEEN BY PD 2 DUE TO 2-PHASE EARTH FAULT (F2) IN THE MIDDLE OF LV FEEDER 1 (FIG. 4)

	Voltages seen by PD 2 before fault / when PD 2 operates (V)	**Currents through PD 2 before fault / at the time of operation of PD 2 (A)**
Case A$^{*)}$	229, 227, 234 / 38, 32, 68	65, 31, 46 / 714, 507, 146

$^{*)}$ PI controller parameters of Master Unit, config. B, (Appendix)



Figs. 20. a) Microgrid voltages and b) fault currents of SG after 2-phase earth fault (F2) in the middle of LV feeder 1 in case A during island operation



Figs. 21. a) Active and b) Reactive power of SG and master unit after 2-phase earth fault (F2) in the middle of LV feeder 1 in case A during island operation

It is also worth mentioning here that PI-controller parameters of master unit needed to be adjusted in the simulation cases with SG (configuration B, Appendix) to avoid unstable oscillation after transition to island operation. These oscillations resulted from the changed dynamics of island operated LV microgrid and incompatibility of previous master unit PI-controller parameters of configuration C (Appendix) with dynamic behavior of SG.

VI. Simulations from the Fault Behavior of Frequency Converter Connected PMSG Based DG Unit with Supercapacitor in DC-link

In following the effect of supercapacitor, which prevents excessive voltage rise in converter DC-link during fault, to the fault current contribution of frequency converter connected PMSG based DG unit has been simulated in three different cases I-III. In all cases 3-phase short-circuit fault (F2) in the middle of LV feeder occurs during island operation (Fig. 22) and PD 2 of LV feeder 1 operates 100 ms after beginning of the fault. In all simulated cases PI controller parameters of master unit are the same as in configuration A (Appendix). The three simulated cases are:

I) No supercapacitor in DC-link
II) Supercapacitor in DC-link limits the DC-link voltage rise to 1.03 kV
III) Supercapacitor in DC-link limits the DC-link voltage rise to 1.05 kV

The simulation model used in the simulations of this chapter VI is presented in Fig. 22 and it is modified from the simulation model presented in Fig. 4. The main difference is that frequency converter connected PMSG based DG unit has been added to LV feeder 2.

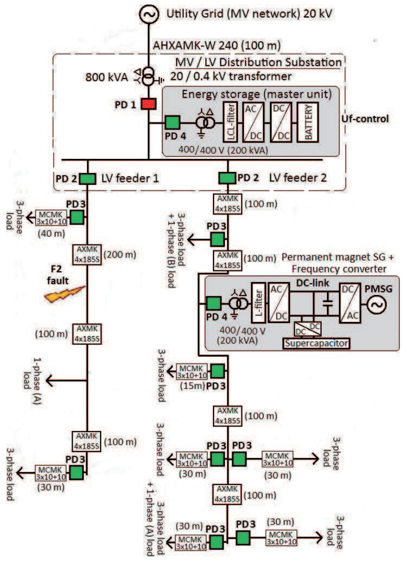


Fig. 22. Modified simulation model (from the one presented in Fig. 4) used in chapter VI simulation

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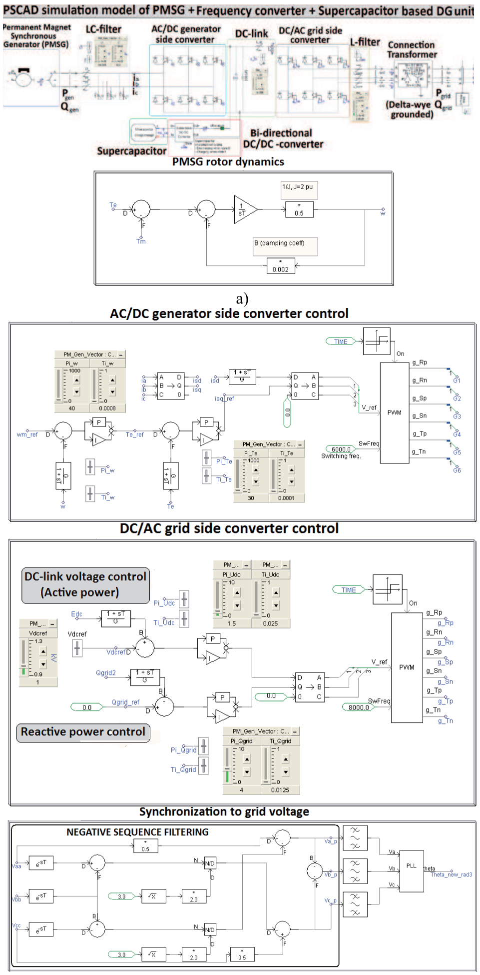
In the control system of frequency converter PLL of PSCAD has been used together with negative sequence filtering to enable FRT ability (Fig. 23 b)) and supercapacitor has been added to the DC-link to provide FRT during fault in island operation (Fig. 23 a)). Here it is worth mentioning that instead of DC/AC- grid side converter (Fig. 23 b)) the DC/DC- converter which connects the energy storage into the DC-link could be in charge of controlling the DC-link voltage continuously also during faults. In that case the active and reactive power control of grid side converter would become more flexible both in normal and fault operation of the DG unit if also battery based energy storage is used instead of supercapacitor.



a)

b)

Figs. 23. a) PSCAD simulation model of the PMSG with frequency converter and supercapacitor based DG unit and b) the control system of the DG unit

In Fig. 24 simulation results from the microgrid voltage behavior after the fault is illustrated in different cases. It can be seen from these results that in case I the microgrid voltage is quite unstable after PD 2 operation of faulted LV feeder 1. Voltage is most stable in case II after the F2 fault (Fig. 24).

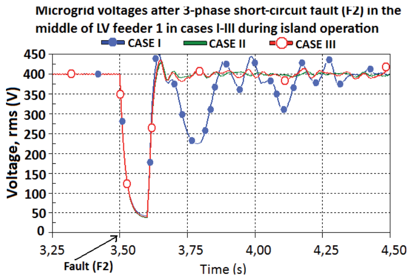
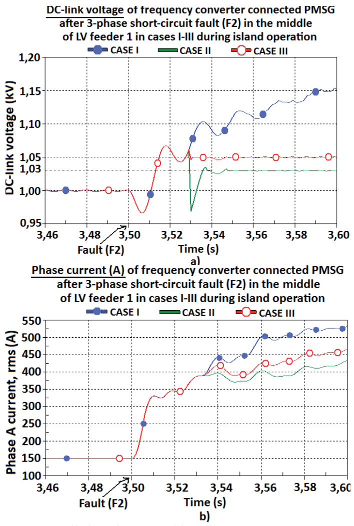


Fig. 24. Microgrid voltages after 3-phase short-circuit fault (F2) in the middle of LV feeder 1 in cases I-III during island operation.

In Fig. 25a) DC-link voltage and in Fig. 25b) phase A current of frequency converter connected PMSG after 3-phase F2 fault in three different cases I-III is presented. From the simulation results it can be seen how the control of voltage rise in the DC-link of the converter reduces the fault current fed by the DG unit.



Figs. 25. a) DC-link voltage and b) Phase A current of frequency converter connected PMSG after 3-phase short-circuit fault (F2) in the middle of LV feeder 1 in cases I-III during island operation.

In Figs. 26 active and reactive power of frequency converter connected PMSG after 3-phase F2 fault in three different cases I-III is illustrated. From the simulation results one can also see how supercapacitor control in DC-link of DG unit converter reduces the active and reactive power fed to microgrid during fault.

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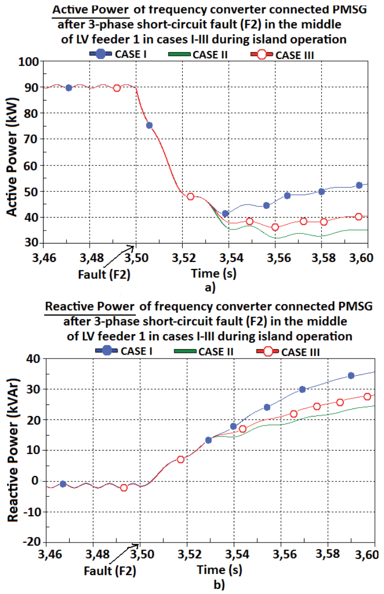

Figs. 26. a) Active and b) Reactive power of frequency converter connected PMSG after 3-phase short-circuit fault (F2) in the middle of LV feeder 1 in cases I-III during island operation.

VII. Conclusion

In this paper the effect of DG unit fault behavior to LV microgrid protection during island operation is studied in some specific cases with PSCAD simulations. When protection of island operated microgrid is designed one of the most important questions is how converter based DG units will contribute to the fault current feeding. In the simulations different control strategies of converter connected DG units during faults were investigated with various DG unit configurations and also the role of energy storages was examined to find out their effect to the microgrid voltages and currents that are measured by the protective devices.

The increased reactive power feeding with converter based DG units was found to be beneficial for the possible overcurrent protection based protection in LV microgrid and it did not significantly reduce the usability of undervoltage based protection either. On the other hand, the reactive power feeding during fault did not significantly reduce the magnitude of the voltage dip, i.e. support microgrid voltage during fault. In addition, significant reactive power feeding during fault may be challenging, e.g., for the DC-link voltage control of DG unit during fault and in overall the reactive power feeding of many DG units seems to increase the possibility of angle stability problems after fault clearance.

It should also be taken into account that the capability of feeding or absorbing large reactive power with converter connected DG unit requires more capacity from the grid side DC/AC- converter of the DG unit. To be able to feed or absorb significant amount of reactive power or control active power with DG units intended for energy production (e.g. PV cells or wind turbines), additional energy storage will be needed in this type of DG units.

Based on the simulations of this paper excessive reactive power feeding of converter connected DG units during fault in island operated LV microgrid is not justified. However, it is essential from the island operated LV microgrid stability and protection point of view to take into account how the reactive power of each DG unit behaves and is controlled. In addition, reactive power feeding or absorbing during normal operation of LV microgrid is inefficient way to control LV network voltage.

Voltage control of LV microgrid must be done through active power control and energy storages will be essential part of this control scheme. In overall, the increased reactive power feeding from converter based DG units may not be recommended during island or normal operation of LV microgrid, but especially during island operation the reactive power needed by LV customer loads must be delivered by DG units.

Simulations also showed that the nominal power of directly connected SG, which is not located at the MV/LV distribution substation like the energy storage based master unit, should be substantially smaller than the nominal power of master unit to ensure stability after fault in island operated LV microgrid. Attention should be paid also to the excitation control of directly connected SGs so that their operation would be more stable during sudden changes in island operation. It is also important from stability perspective that the control systems of different DER units are compatible with each other.

Simulations were also made to examine the effect of supercapacitor to the fault current contribution of frequency converter connected PMSG based DG unit and the results showed how the use of supercapacitor in the converter DC-link reduced the fault current contribution of corresponding DG unit.

Finally, it can be stressed that standardization of DG unit fault behavior in island operated LV microgrid is absolutely necessary for the development of future Smart Grids to reduce complexity and to avoid the need for too many alternative, case specific, protection solutions.

Appendix

System parameters of the test system with different DG unit converter filter and controller parameters are presented in Tables VII and VIII. The solution time step in simulations was 5 µs.

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TABLE VII
STUDY SYSTEM PARAMETERS

	Parameter	Value
DG Unit Converters (DC/AC)	Modulation method	SVM
	Switching frequency	8 kHz
	Filter L_1, R_d, C, L_2	0.4 mH, 0.1 Ω, 10 μF, 0.2 mH
Current PI-controllers	Gain $K_{current}$	1.5
	Integrator time constant T_{c_i}	0.15 ms
Active Power PI-controller (Master Unit)	Gain K_p	$0.25^{*)}$, $1.5^{**)}$, $0.2^{***)}$
	Integrator time constant T_{p_i} [s]	$0.005^{*)}$, $0.001^{**)}$, $0.015^{***)}$
	Sampling rate	$2^{*)}$, $1^{**)}$, $4^{***)}$ kHz
Active Power PI-controller *),**), ***) *(Other DG Units)*	Gain K_p	0.2
	Integrator time constant T_{p_i}	0.025 s
	Sampling rate	4 kHz
Reactive Power PI-controller *),**), ***) *(Other DG Units)*	Gain K_Q	1
	Integrator time constant T_{q_i}	0.03 s
	Sampling rate	4 kHz

Configurations $A^{*)}$, $B^{**)}$ and $C^{***)}$ with own PLL component and modified current control during fault current feeding, with transformers on all DG unit converters. Master Unit controller before islanding i.e. in normal operation with configurations $A^{*)}$, $B^{**)}$ and $C^{***)}$, Active power control, Kp_P = 0.2, Ti_P = 0.025, Reactive power control, Kp_Q = 1, Ti_Q = 0.02. Reactive power control of master unit in all simulations after islanding is changed so that zero input is given as current reference i_q.

TABLE VIII
STUDY SYSTEM PARAMETERS

	Parameter	Value
Synchr. Generator (SG)	Inertia constant	0.1049 MW/MVA
	R_a / X_p / Air gap f.	0.012 pu / 0.087 pu / 0.8
	X_d / X_d'/ X_d''	3.5 pu / 0.128 pu / 0.077 pu
	X_q / X_q'/ X_q''	2.1 pu / 0.128 pu / 0.098 pu
	T_{do}' / T_{do}''	2.71 s / 0.02 s
	T_{qo}' / T_{qo}''	2.71 s / 0.02 s
Permanent Magnet (PM) Generator with Frequency Converter	Modulation method (Grid side converter)	PWM
	Switching Frequency (Grid side converter)	8 kHz
	Filter L	2.5 mH
	DC-link capacitor	12000 μF
Super-capacitor	Capacitance / cell	3000 F
	Number of cells	213
	Cell max. voltage	2.7 V
Reactive Power Control of SG (Input to Exciter)	Gain	1.0
	Time constant	0.675 s
DC-DC Buck-boost Converter	Reference dc voltage V_{DC}	0.7 kV
	Gain $K_{dc/dc}$	0.3
	Integrator time constant T_{dc/dc_i}	0.06 s
	Sampling rate_dc/dc	1 kHz
	DC-link capacitor	5000 μF

Acknowledgements

This work was supported by *Smart Grids and Energy Market (SGEM)* research program of CLEEN Ltd, the Strategic centre for science, technology and innovation of the Finnish energy and environment cluster.

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Authors' information

University of Vaasa

H. Laaksonen was born in Vaasa, Finland, on November 22, 1977. He received his Master's degree (2004) in Electrical Power Engineering from Tampere University of Technology.

His employment experience includes working as a research scientist in VTT Technical Research Centre of Finland in Vaasa and before that in Institute of Power Engineering department at Tampere University of Technology. Currently he works as a research scientist and PhD student with Department of Electrical Engineering and Automation at University of Vaasa. His field of interests are planning + integration of DG in distribution networks, power electronics in distribution networks and future network concepts (e.g. microgrids).

K. Kauhaniemi was born in Kankaanpää, Finland, in 1963. He received his M.Sc degree (1987) and Dr. Tech. degree (1993) in electrical engineering from Tampere University of Technology, Finland. He was previously employed by VTT Technical Research Centre of Finland. Currently he is Professor in electrical engineering at the University of Vaasa, Finland. His special interest areas include the modeling and simulation of power systems.

Sampo Voima was born in Vaasa, Finland, in 1981. He received his M.Sc degree (2009) in electrical engineering from University of Vaasa, Finland. Currently he works as a research scientist and PhD student in electrical engineering at University of Vaasa. His special interest areas include protection of Smart Grids.

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Synchronized Re-Connection of Island Operated LV Microgrid Back to Utility Grid

H. Laaksonen, and K. Kauhaniemi

***Abstract*--Microgrids can be defined as distribution systems with distributed generation (DG) units, energy storages and controllable loads. Microgrids are expected to form an essential part of future Smart Grids with self-healing feature. Most of the time microgrids will be operated normally parallel with utility grid. In addition to this microgrids have a special self-healing capability, because they can continue operation also in island mode during disturbances, e.g., utility grid outages. One important issue which needs to be solved is the synchronized re-connection of island operated microgrid back to utility grid. In this paper issues related to the re-connection of low voltage (LV) microgrid are studied and different functions to enable synchronized re-connection are presented with various DG unit configurations through simulation studies with PSCAD simulation software.**

***Index Terms*--Distributed Generation, Energy Storage, Islanding, Microgrid, Protection, Smart Grids, Synchronization**

I. INTRODUCTION

LARGE scale integration of distributed energy resources (DER), including DG, electricity storages, electric vehicles and customers with smart energy meters and controllable loads, to distribution network in future requires creation of a totally new Smart Grid concept which will take advantage of the properties of DER. Advanced Smart Grid concept allows the use of DER in a coordinated way through intelligent management system and hence allows the potential of DER to be realized for different interest groups such as distribution system operators (DSOs), DG producers, service providers, consumers and society. Simultaneously with the development of choices made in the Smart Grid concept the future island operation (microgrid) possibility should be integrated and supported by minimal changes to the concept.

Typically the term microgrid is used from the LV network Smart Grid with island operation capability. However, microgrid concept should be defined in a more general way as a smart distribution grid part with island operation capability. In that case microgrid would mean certain part of distribution network with DER which is managed as a whole with intelligent microgrid management system (MMS). Microgrid can be for example (see Fig. 1): 1. Separate island grid, 2. Small household LV microgrid or LV customer microgrid, 3. LV microgrid consisting of all LV feeders connected downstream from MV/LV distribution transformer or 4. Medium voltage (MV) network feeder microgrid or MV substation microgrid with all MV feeders. In overall the role of MMS can be seen as distributed intelligence of distribution management system (DMS) to lower voltage levels in distribution networks (Fig. 1). Microgrid is normally operated parallel with utility grid and, e.g., during faults in upstream network it can be separated quickly from utility grid and operated independently as an island grid. MMS will be responsible from the overall economic and energy effective operation of microgrid taking into account the technical boundary conditions both in normal and island operation.

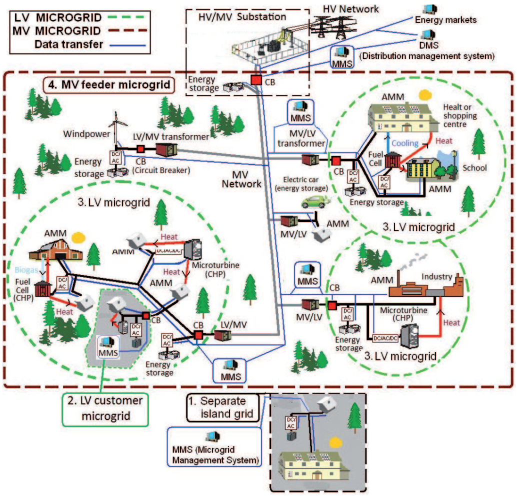


Fig. 1. Different possible microgrid configurations.

Realization of future Smart Grids with island operation capability requires that all technical issues, such as power and energy balance, power quality and protection during island operation, are solved. One important issue is also synchronized re-connection of island operated LV microgrid back to utility grid, which has been studied in this paper. In the PSCAD simulations of this paper issues related to the re-connection of island operated LV microgrid are studied and different functions to enable synchronized re-connection are presented with various DG unit configurations.

This work was supported by *Smart Grids and Energy Market (SGEM)* research program of CLEEN Ltd, the Strategic centre for science, technology and innovation of the Finnish energy and environment cluster.

The authors are with the University of Vaasa, P.O.Box 700, FI-65101 Vaasa, FINLAND (e-mail: hannu.laaksonen@uwasa.fi, kimmo.kauhaniemi@uwasa.fi)

Section II of the paper discusses briefly about issues related to synchronized re-connection of island operated LV microgrid and section III about synchronized re-connection as part of microgrid protection and management concept. Section IV introduces the studied system and simulation results of the study and discussions are presented in section V. Conclusions are stated in Section VI.

II. ISSUES RELATED TO SYNCHRONIZED RE-CONNECTION OF ISLAND OPERATED LV MICROGRID

First of all, the ability to maintain synchronism after transition to island operation is crucial from stability point of view [1]. Secondly, synchronized re-connection of island operated LV microgrid back to utility grid means that the voltage angle difference between utility grid and LV microgrid should be minimized before re-connection. This is not a significant issue when converter based DG units with phase locked loop (PLL) component are considered, because PLL will draw converters into phase with the utility grid frequency after re-connection. However, DG units with traditional synchronous generator interface cannot deal with major phase difference during LV microgrid re-connection without losing rotor angle stability. Therefore, some kind of principles for minimizing phase angle difference before re-connection are needed.

A. Synchronized Connection of Separate HV Power Systems with directly connected SGs

In the high voltage (HV) transmission lines (X>>R) the active power P depends mainly on power angle δ and reactive power Q depends mainly on voltage difference. Therefore, control of active power P transmission directly controls the power angle δ and frequency f. [2]

Generation units connected to HV network are usually equipped with directly connected synchronous generators (SGs). Phase angle difference over open circuit breaker (CB) between two separate large HV power systems can be controlled before closing CB, e.g. with traditional steam turbine based power plants, by controlling the mechanical input torque T_m in similar manner that is done in frequency control of HV power system. For example if steam valve of steam turbine is opened then mechanical input power P_m to SG rotor is increased and therefore also rotor angle is increased. After reaching steady state again the electrical output power P_e of SG is also increased and phase difference over open CB between two separate power systems has been reduced small enough so that synchronized connection of these two power systems may be performed if frequency difference is also small enough. In HV network synchronism check relays are configured in some cases so that frequency difference should be under 55 mHz and phase difference 20° - 45° [3].

B. Synchronized Re-connection of LV Microgrid back to Utility Network

In LV microgrids most of the DER units will be connected through power electronic interfaces and re-synchronization of LV microgrid can be possibly done through the control of these DER units. However, the chosen strategy is dependent on the chosen microgrid concept i.e. active and reactive power (PQ) controlled DER units with one central master unit or active power/frequency (P/f) -droop controlled DER units without central master unit. In [4] it has been proposed that during resynchronization the control of energy storage unit slowly shifts the microgrid system frequency reference value to the main network frequency value.

On the other hand, with P/f-droop controlled DER units synchronized re-connection of microgrid requires that all DER unit converter controls must be coordinated. This coordination must be done by an external central controller that guides all the converters in the synchronization process. To vary the island frequency and to control the angle an action is required over the P/f droop curve which needs communication from a central controller. [5]

With LV distribution lines (R>>X) the active power P depends mainly on voltage difference, while the power angle δ and depends mainly on reactive power Q. [2] Therefore, one way to control the phase difference in PCC of LV microgrid could be through coordinated reactive power set point changes of DER units by MMS.

C. Synchronized Re-connection and Voltage Unbalance of Islanded LV Microgrid

Voltage unbalance due to load asymmetry and single-phase DER units affects the voltage phase difference across open microgrid breaker so that the phase difference deviation may be different in every phase A, B and C. In some cases this asymmetry between phases may also be needed to be reduced before other possible re-synchronization functions coordinated by MMS related to the synchronized re-connection of island operated microgrid.

III. SYNCHRONIZED RE-CONNECTION AS PART OF MICROGRID PROTECTION AND MANAGEMENT CONCEPT

In this paper, like in previous studies [1], [2], [6], [7], it has been chosen to study microgrid concept with one central, energy storage based, master unit located at MV/LV distribution substation. In [7] protection concept for LV microgrid was developed. In Fig. 2 type of protective devices (PD 1-4) chosen for this protection concept are presented. The needed protection devices (PD 1-4) are

PD 1: Microgrid protection (in PCC) including relay and CB or fast static switch (SS)

PD 2: LV feeder protection including fuses, relays and CB or SS

PD 3: Customer protection including fuse or miniature CB (MCB) or in case of LV customer microgrid (DC or AC) with very sensitive customers SS may be needed

PD 4: Production / DG unit protection

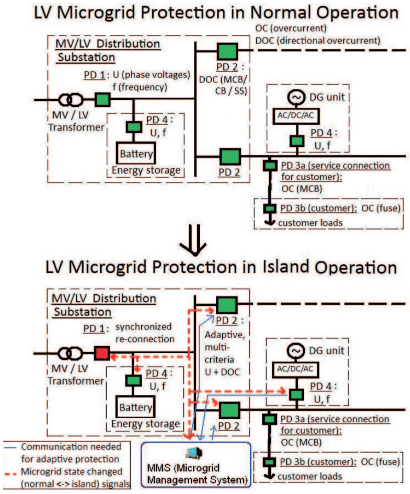


Fig. 2. Type of protection devices (PD 1-4) needed in normal and island operation of LV microgrid. [7]

MMS is used to change settings and pick up limits of protective devices (PD 2s) when microgrid configuration changes (Fig. 2). MMS will send state changed signal from normal to island operation to different PDs of microgrid to adapt to the changed microgrid configuration (Fig. 2). PD 1 is changed to be ready for future synchronized re-connection back to utility grid. Fast real-time communication is needed for microgrid protection purposes between protective devices and also with master unit and DG units during microgrid island operation. In addition MMS needs to be able to communicate in real-time with all these microgrid components as well as with customer loads. Therefore, communication between different network components and MMS based on common standard like IEC 61850 is the most sensible and economical option in overall. [7]

Active microgrid components in the point of common coupling (PCC) of microgrid (PD 1, master unit and MMS) are also responsible for synchronized re-connection of LV microgrid back to utility grid (Fig. 2). In reference [8] synchronous islanded operation is proposed to be done by a reference signal containing phase and frequency information to the master unit of the microgrid [8]. The phase difference should be within acceptable levels (under 60°) during re-connection to utility grid [8]. Based on previous simulation studies the phase angle difference may be even slightly larger with converter connected DG units depending on the implementation of the control system and PLL. However with SGs the phase difference should be preferably significantly smaller than 60° to avoid large oscillations and electrical and mechanical stresses. Based on [9] microgrid re-synchronizing function have to meet a more stringent requirement than the one defined by IEEE 1547 which requires that the phase difference between microgrid and utility grid should less than 20° before the PD 1 can close. It was also observed during the simulations for [7] that when phase difference during re-connection of LV microgrid was 22° large oscillations in the powers of SG occured after re-connection and therefore it is important if there are directly connected SGs in LV microgrid the phase difference between utility grid and LV microgrid voltages should be even less than 10°. [7]

IV. SIMULATION MODEL OF THE STUDY SYSTEM

The LV network studied in this work is presented in Fig. 3. The system consists of one 800 kVA MV/LV-transformer which normally feeds LV feeders 1 and 2. In the simulation studies the islanded LV microgrid is disconnected from MV network by the microgrid breaker PD 1. At the connection point of the microgrid, before the feeders 1 and 2, there is a converter connected energy storage unit (battery, $S_n=150\ kVA$). At the end of feeder 1 there is a converter connected DG Unit 1 ($S_n = 120\ kVA$, in simulations usually $P = 100\ kW$, $Q = 30\ kVAr$ and about $I = 150\ A/phase$). At the end of the feeder 2 there is a converter connected DG Unit 2 ($S_n = 120\ kVA$, in simulations usually $P = 100\ kW$, $Q = 0\ kVAr$) or a synchronous generator, SG, ($S_n = 100\ kVA$, in simulations usually $P = 100\ kW$, $Q = 0\ kVAr$).

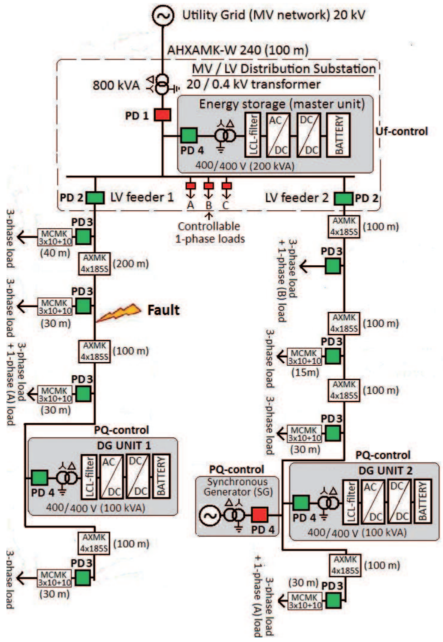


Fig.3. Studied LV microgrid.

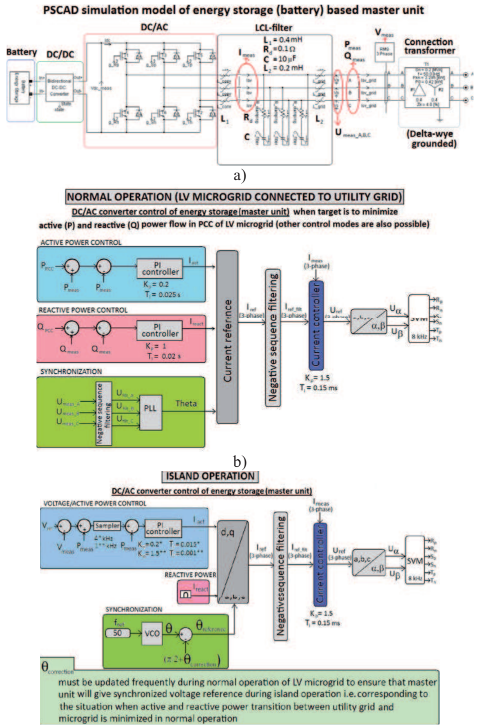
The load in the microgrid consists of four three-phase passive loads on each feeder and few single-phase passive loads (Fig. 3) on both feeders which means that the load between phases is asymmetrical. The passive loads can be adjusted so that the loading of the transformer (which feeds LV feeders 1 and 2) gets some desired value between 0…150 % of the transformer ratings. Controllable 1-phase loads that are used in the simulations for asymmetry compensation before re-connection of island operated LV microgrid at MV/LV distribution substation are also shown in Fig. 3.

Simulations are made with cable parameters shown in table 1. Service connections of customer loads and DG units are also included in the simulation model (Fig. 3). The fault level and R/X-ratio of the feeding utility network (20 kV, 50 Hz) are 200 MVA and 0.1 respectively.

TABLE 1
RESISTANCE, REACTANCE AND R/X RATIO OF THE CABLES IN FIG. 3

	R (Ω/km)	X (Ω/km)	R/X
AHXAMK-W 240	0.13	0.116	1.12
AXMK 4x185S	0.164	0.0817	2.01
MCMK 3x10 +10	1.83	0.088	20.8

The converters are modeled as three-phase, three-leg, SVM modulated units with LCL-filters and the DC-link of the master unit is modeled with battery storage + DC/DC-buck-boost converter. In all simulations the master unit converter and DG unit converters were modeled with neutral connection, i.e. delta-wye grounded transformer (Fig. 3 and 4). The DC-link voltage of converter is chosen to be 0.7 kV. With all converters modified PLL component was used instead of the PSCAD's own PLL component to improve stability in deep voltage dips [1].



a)

b)

c)

$θ_{correction}$ must be updated frequently during normal operation of LV microgrid to ensure that master unit will give synchronized voltage reference during island operation i.e. corresponding to the situation when active and reactive power transition between utility grid and microgrid is minimized in normal operation

Fig. 4. a) PSCAD simulation model of master unit. Control of master unit DC/AC- converter b) in normal operation and c) in island operation.

Active and reactive power controller parameters are similar between DG units 1 and 2, but different with master unit converter (Fig. 4). It is essential for the stability of the whole microgrid that during disturbances the control system of the master unit converter remains stable. However, it is worth noticing that PI-controller parameters of master unit converter active power-voltage (PU)-control needed some modification to ensure stability when microgrid dynamics is changed due to configuration change e.g SG or DG unit 2 connected during island operation. Filter and control parameters used in simulations on converter based DG units are presented in Appendix.

During islanding, microgrid is operated in single master operation mode, which in this case means that the battery storage based DER unit (Fig. 3) will act as the master unit and it has the main responsibility to control the voltage and frequency (Uf-control) in microgrid when islanded (Fig. 4 c)).

DG units intended for energy production (such as PV cells or wind turbines) lack the capability of producing controlled active power on demand, if no storages are used, and so they are normally operated under PQ control. The control of these units remains same regardless of the operation mode, normal or island operation. In the simulations of this paper all the other DG units except the master unit are operated in conventional PQ mode i.e. they do neither take part in frequency nor voltage control. However, in the simulation the reactive power control of these units is modified during synchronized re-connection. In Fig. 5 the PSCAD simulation model of SG based DG unit is presented.

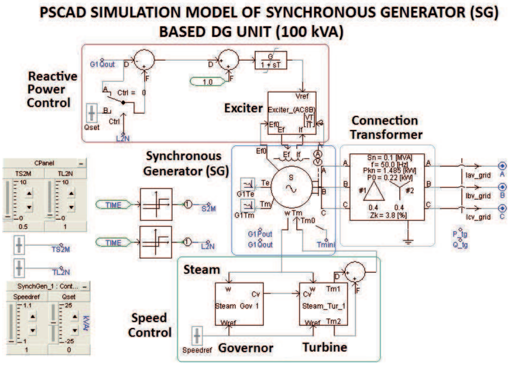


Fig. 5. PSCAD simulation model of SG based DG unit.

V. SIMULATION OF THE SYNCHRONIZED RE-CONNECTION OF ISLAND OPERATED LV MICROGRID

In following sections A, B and C simulation results from synchronized re-connection of island operated LV microgrid are presented. In section A simulations are done with SG based DG unit connected and DG Unit 2 disconnected (see Fig. 3). In section B simulations SG based DG unit is disconnected and converter interfaced DG Unit 2 is connected. Finally, in section C compensation of unsymmetrical load before re-connection is simulated.

In all simulations 2-phase earth fault in the middle of LV feeder 1 occurs during island operation. Due to the fault PD 2 of LV feeder 1 operates in 125 ms [7] and disconnects the feeder (Fig. 3). As a result of feeder 1 disconnection the active and reactive power flows and therefore also voltage phase angle difference across PD 1 at PCC of LV microgrid will change. Therefore, re-synchronization functions will be needed and in practice these functions should be coordinated by MMS before LV microgrid re-connection.

A. Simulations with directly connected SG based DG unit

Simulations of this section are done with directly connected SG (Fig. 3). However, it is worth mentioning here that the connection of this size of directly connected SG at the end of radial LV feeder is not sensible from the protection point of view during island operation of LV microgrid. Therefore, especially larger SG based DG units should be connected directly to the PCC of LV microgrid at MV/LV distribution substation either physically or with own LV connection feeder. In addition of securing the proctection of island operated LV microgrid, this also enables the availability of corresponding large DG unit after possible fault at some other LV feeder.

Simulated cases of this section were:

A0) No re-synchronization functions before re-connection

A1) Re-synchronization with voltage phase angle adjustment (phase A) by master unit control i.e. adjustment of $\theta_{correction}$ (see Fig. 4c)) before re-connection

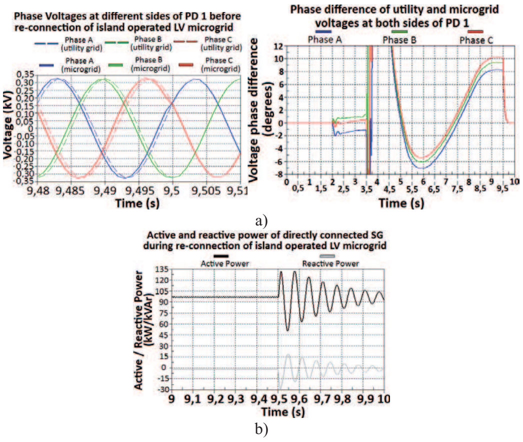
A2) Re-synchronization with voltage phase angle adjustment (phase A) by reactive power feeding of SG before re-connection

Sequence of actions occurring in the simulations are presented in table 2 and master unit control system parameters used in the simulations of this section (configuration B) can be found from Appendix. Simulation results from case A0) are shown in Fig. 6.

TABLE 2
SEQUENCE OF ACTIONS IN THE SIMULATIONS OF SECTION V.A

Time (s)	Case	Action
2.0	A0), A1), A2)	Transition to island operation
3.5	A0), A1), A2)	2-phase earth fault in the middle of LV feeder 1 => PD 2 of LV feeder 1 operates at 3.625 s
5.0	A2)	Reactive power feeding of SG (from 0 to 9.5 kVAr) for voltage phase angle adjustment so that phase angle difference across PD 1 in PCC of LV microgrid is almost zero in phase A
7.5-9.0	A1)	Voltage phase angle adjustment by master unit control in phase A for re-synchronization with a ramp (see Fig. 4c))
9.5	A0), A1), A2)	Re-connection of island operated LV microgrid back to utility grid

Simulations were also done with directly connected induction motor (IM) load and significant problems were not detected with less than 10 degrees out-of-phase re-connection of LV microgrid. But as from the simulation results of Fig. 6 can be seen, the case with SG was different with the same circa 10 degrees phase difference. Large oscillation in active and reactive power of SG can be seen after re-connection (Fig. 6b)).

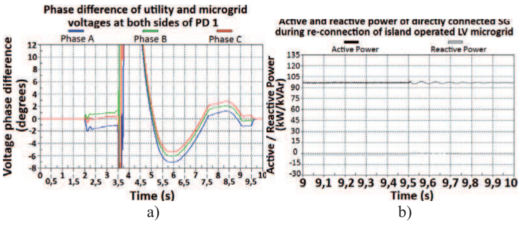


a)

b)

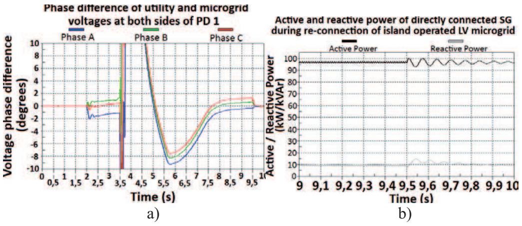
Fig. 6. a) Voltage phase difference across PD 1 and b) active and reactive power of SG in case A0)

Simulation results from cases A1) and A2) are presented in Fig. 7 and 8 respectively. From the simulation results of Fig. 7 and 8 it can be seen how oscillations in active and reactive powers of SG after re-connection are reduced with both re-synchronization functions, voltage phase angle adjustment (phase A) by master unit control (case A1)) and by reactive power feeding of SG (case A2)), before re-connection of island operated LV microgrid.



a) b)

Fig. 7. a) Voltage phase difference across PD 1 and b) active and reactive power of SG in case A1)



a) b)

Fig. 8. a) Voltage phase difference across PD 1 and b) active and reactive power of SG in case A2)

The effect of R/X-ratio was also examined in the simulations and it was found out that for example the needed amount of reactive power feeding of SG for voltage phase angle adjustment before re-connection was determined by the reactance (X/km) between PD 1 and SG, not the R/X-ratio.

However, larger R/X-ratio e.g. 7.28 affects to the operation time of PD 2 due to fault during the simulation so that it operates in 150 ms instead of 125 ms [7]. This is due to the fact that larger R/X-ratio represents also higher short circuit impedance which reduces the voltage dip and fault current magnitude during fault.

B. Simulations with only Converter Based DG units

In this section simulation of three different cases was done with only converter based DG units (Fig. 3). Simulated cases of section B were:

B0) No re-synchronization functions before re-connection

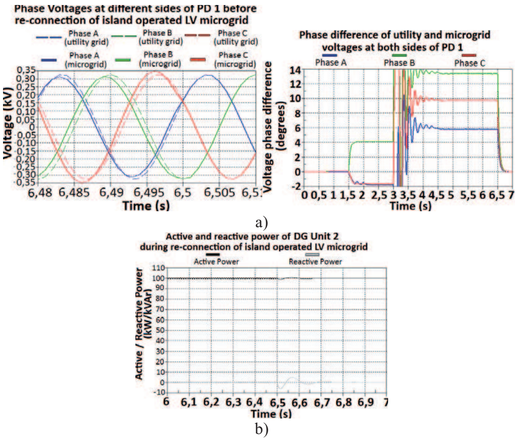
B1) Re-synchronization with voltage phase angle adjustment (phase A) by master unit control i.e. adjustment of $\theta_{correction}$ (see Fig. 4c)) before re-connection

B2) Re-synchronization with voltage phase angle adjustment (phase A) by reactive power feeding of DG unit 2 before re-connection

Sequence of actions occurring in the simulations are shown in table 3 and master unit control system parameters used in the simulations of this sections B and C (configuration A) are presented in Appendix. Simulation results from case B0) are shown in Fig. 9.

TABLE 3
SEQUENCE OF ACTIONS IN THE SIMULATIONS OF SECTION V.B

Time (s)	Case	Action
1.5	B0), B1), B2)	Transition to island operation
3.0	B0), B1), B2)	2-phase earth fault in the middle of LV feeder 1 => PD 2 of LV feeder 1 operates at 3.125 s
5.0	B2)	Reactive power feeding of converter based DG unit 2 (from 0 to 9 kVAr) for voltage phase angle adjustment so that phase angle difference across PD 1 in PCC of LV microgrid is almost zero in phase A
5.5-6.0	B1)	Voltage phase angle adjustment by master unit control in phase A for re-synchronization with a ramp (see Fig. 4c))
6.5	B0), B1), B2)	Re-connection of island operated LV microgrid back to utility grid



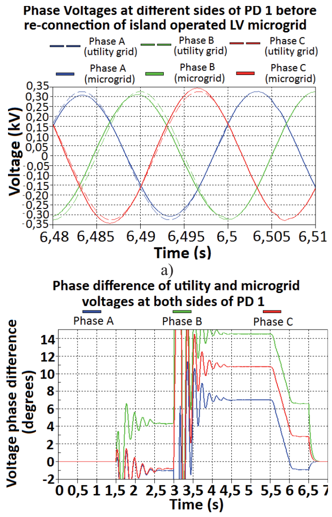
a)

b)

Fig. 9. a) Voltage phase difference across PD 1 and b) active and reactive power of converter based DG unit 2 in case B0)

From the simulation results of Fig. 9 one can see, that with converter based DG unit 2 the phase difference before re-connection does not create large oscillations in active and reactive power of DG unit 2 (Fig. 9b)) when compared to case with SG in Fig. 6b).

Simulation results from cases B1) and B2) are presented in Fig. 10 and 11 respectively. From the simulation results of Fig. 10 and 11 it can be seen that the same functions for re-synchronization before re-connection of island operated LV microgrid, that were simulated in section A cases A1) and A2), are also applicable in section B simulations with only converter based DG units.



a)

b)

Fig. 10. a) Phase voltages across PD 1 before re-connection and b) Voltage phase difference across PD 1 from case B1)

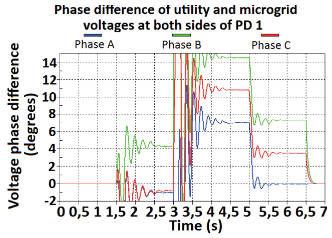


Fig. 11. Voltage phase difference across PD 1 from case B2)

When simulation results of section A and B about voltage phase difference across PD 1 are compared, one can see that phase difference deviation between phases A, B and C is much larger in section B. Therefore, in following section C compensation of unsymmetrical load i.e. phase difference deviation before re-connection of island operated LV microgrid is studied.

C. Compensation of Unsymmetrical Load Before Re-connection

Controllable 1-phase loads that were used in the simulations of this section for asymmetry compensation before re-connection of island operated LV microgrid at MV/LV distribution substation are presented in Fig. 3. In practice this asymmetry compensation could be also done e.g. through reactive power control of 1-phase DG units, energy storages or controllable loads coordinated by MMS.

In this section simulation of two cases was also done with only converter based DG units (Fig. 3). Simulated cases of this section were:

B3) Re-synchronization and asymmetry compensation with voltage phase angle adjustment by connection of 1-phase capacitive reactive power feeding loads before re-connection

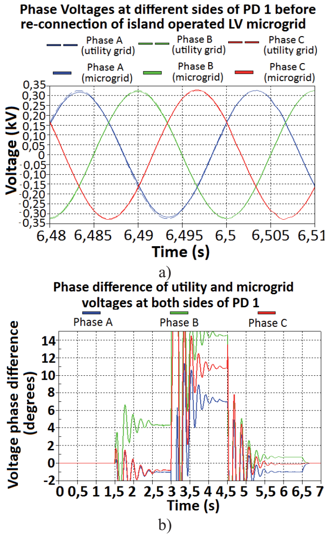
B4) Asymmetry compensation by connection of 1-phase resistive active power consuming load and re-synchronization with voltage phase angle adjustment (phase A) by reactive power feeding of DG unit 2 before re-connection

Sequence of actions during the simulations are presented in table 4. Simulation results from cases B3) and B4) are shown in Fig. 12 and 13.

TABLE 4
SEQUENCE OF ACTIONS IN THE SIMULATIONS OF SECTION V.C

Time (s)	Case	Action
1.5	B3), B4)	Transition to island operation
3.0	B3), B4)	2-phase earth fault in the middle of LV feeder 1 => PD 2 of LV feeder 1 operates at 3.125 s
4.25	B4)	Active consumption of 1-phase resistive load connected in phase C (12,5 kW) at MV/LV distribution substation to reduce voltage magnitude unsymmetry between phases
4.5	B3)	Reactive power feeding of 1-phase capacitive loads connected in phases B (9,5 kVAr) and C (3,4 kVAr) at MV/LV distribution substation
5.0	B4)	Reactive power feeding of converter based DG unit 2 (from 0 to 9 kVAr) for voltage phase angle adjustment so that phase angle difference across PD 1 in PCC of LV microgrid is almost zero in all phases A, B and C
6.5	B3), B4)	Re-connection of island operated LV microgrid back to utility grid

In case B3) there were quite large frequency and voltage oscillations after connection of 1-phase capacitive reactive power feeding loads at 4.5 s. But in case B4) frequency and voltage oscillations were much smaller than in case B3) after connection of 1-phase resistive active power consuming load at 4.25 s and reactive power feeding increase of DG unit 2 at 5.0 s. From Fig. 12 and 13 it can be seen that, like voltage magnitude asymmetry, also voltage phase difference asymmetry across PD 1 before re-connection was a bit smaller in case B4) than in case B3).



a)

b)

Fig. 12. a) Phase voltages across PD 1 before re-connection and b) Voltage phase difference across PD 1 from case B3)

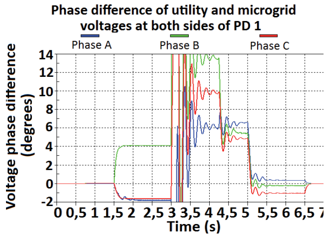


Fig. 13. Voltage phase difference across PD 1 from case B4)

VI. CONCLUSIONS

Realization of future Smart LV Grids with island operation capability requires that all technical issues, such as power and energy balance, power quality and protection during island operation, are solved. One important issue that has been investigated in this paper is the synchronized re-connection of island operated LV microgrid back to utility grid.

Although the island operated LV microgrid may be in synchronism with utility grid right after transfer to island operation, later due to load and production changes i.e. changes in active and reactive power flows the voltage phase angle difference across PD 1 at PCC of LV microgrid will change. Therefore, re-synchronization functions will be needed and in practice these functions should be coordinated by MMS before LV microgrid re-connection.

In this paper issues related to the re-connection were studied and different functions to enable synchronized re-connection were developed and successfully simulated with PSCAD simulation software. Simulation results clearly showed that synchronized re-connection is not necessarily a significant issue with small (less than 10°) phase difference across PD 1 when there are only converter based DG units, because PLL will draw converters into phase with the utility grid frequency after re-connection. However, with directly connected SGs even small phase difference across PD 1 during re-connection is problematic. Therefore, re-synchronization functions for minimizing phase angle difference and possibly also voltage unbalance before re-connection are needed.

VII. APPENDIX

System parameters of the test system with different DG unit converter filter and controller parameters are presented in table 5. The solution time step in simulations was 5 µs.

TABLE 5
STUDY SYSTEM PARAMETERS

	Parameter	**Value**
DG Unit Converters (DC/AC)	Modulation method	SVM
	Switching frequency	8 kHz
	Filter L_1, R_d, C, L_2	0.4 mH, 0.1 Ω, 10 µF, 0.2 mH
Current PI-controllers	Gain $K_{current}$	1.5
	Integrator time constant T_{c_i}	0.15 ms
Active Power PI-controller (Master Unit)	Gain K_p	0.2$^{*)}$, 1.5$^{**)}$
	Integrator time constant T_{p_i} [s]	0.015$^{*)}$, 0.001$^{**)}$
	Sampling rate	4$^{*)}$, 1$^{**)}$ kHz
Active Power PI-controller $^{*),**)}$ (Other DG Units)	Gain K_p	0.2
	Integrator time constant T_{p_i}	0.025 s
	Sampling rate	4 kHz
Reactive Power PI-controller $^{*),**)}$(Other DG Units)	Gain K_Q	1
	Integrator time constant T_{q_i}	0.03 s
	Sampling rate	4 kHz
Synchronous Generator (SG)	Inertia constant	0.1049 MW/MVA
	R_a / X_p / Air gap f.	0.012 pu / 0.087 pu / 0.8
	X_d / X_d'/ X_d''	3.5 pu / 0.128 pu / 0.077 pu
	X_q / X_q'/ X_q''	2.1 pu / 0.128 pu / 0.098 pu
	T_{do}' / T_{do}''	2.71 s / 0.02 s
	T_{qo}' / T_{qo}''	2.71 s / 0.02 s
Reactive Power Control of SG (Input to Exciter)	Gain	1.0
	Time constant	0.675 s
DC-DC Buck-boost Converter	Reference dc voltage V_{DC}	0.7 kV
	Gain $K_{dc/dc}$	0.3
	Integrator time constant T_{dc/dc_i}	0.06 s
	Sampling rate_dc/dc	1 kHz
	DC-link capacitor	5000 µF

Configurations A$^{*)}$ and B$^{**)}$ with own PLL component and modified current control during fault current feeding, with transformers on all DG unit converters. Master Unit controller before islanding i.e. in normal operation with configurations A$^{*)}$ and B$^{**)}$, active power control, Kp_P = 0.2, Ti_P = 0.025, reactive power control, Kp_Q = 1, Ti_Q = 0.02. Reactive power control of master unit in all simulations after islanding is changed so that zero input is given as current reference i_q.

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IX. BIOGRAPHIES

H. Laaksonen was born in Vaasa, Finland, on November 22, 1977. He received his Master's degree (2004) in Electrical Power Engineering from Tampere University of Technology.

His employment experience includes working as a research scientist in VTT Technical Research Centre of Finland in Vaasa and before that in Institute of Power Engineering department at Tampere University of Technology. Currently he works as a research scientist and PhD student with Department of Electrical Engineering and Automation at University of Vaasa. His field of interests are integration and active management of distributed energy resources in smart distribution networks and development of Smart Grid concepts (e.g. microgrids).

K. Kauhaniemi was born in Kankaanpää, Finland, in 1963. He received his M.Sc degree (1987) and Dr. Tech. degree (1993) in electrical engineering from Tampere University of Technology, Finland. He was previously employed by VTT Technical Research Centre of Finland. Currently he is Professor in electrical engineering at the University of Vaasa, Finland. His special interest areas include the modeling and simulation of power systems.

2910 IEEE TRANSACTIONS ON POWER ELECTRONICS, VOL. 25, NO. 12, DECEMBER 2010

Protection Principles for Future Microgrids

Hannu Jaakko Laaksonen

***Abstract*—Realization of future low-voltage (LV) microgrids requires that all technical issues, such as power and energy balance, power quality and protection, are solved. One of the most crucial one is the protection of LV microgrid during normal and island operation. In this paper, protection issues of LV microgrids are presented and extensions to the novel LV-microgrid-protection concept has been developed based on simulations with PSCAD simulation software. Essential in the future-protection concept for LV microgrids will be the utilization of high speed, standard, e.g., IEC-61850-based communication to achieve fast, selective, and reliable operation protection.**

***Index Terms*—Distributed generation (DG), energy storage, islanding, low voltage (LV), microgrid, protection, smart grids.**

I. INTRODUCTION

LARGE-SCALE integration of distributed energy resources (DERs), including distributed generation (DG), electricity storages, electric vehicles, and customers with smart energy meters and controllable loads, to distribution network in future requires creation of a totally new smart-grid concept which will take advantage of the properties of DER. Advanced smart-grid concept allows the use of DER in a coordinated way through intelligent management system and hence allows the potential of DER to be realized for different interest groups, such as distribution system operators (DSOs), DG producers, service providers, consumers, and society. Simultaneously with the development of choices made in the smart-grid concept, the future island-operation (microgrid) possibility should be integrated and supported by minimal changes to the concept. Microgrids are seen as one of the cornerstones of future smart grids [1].

Typically, the term microgrid is used from the low-voltage (LV) network smart grid with island-operation capability (see Fig. 1). However, microgrid concept should be defined in a more general way as a smart distribution grid part with island-operation capability. In this case, microgrid would mean certain part of distribution network with DER, which is managed as a whole with intelligent microgrid management system (MMS). In overall, the role of MMS can be seen as distributed intelligence of distribution management system (DMS) to lower voltage levels in distribution networks. Microgrid is normally operated parallel with utility grid, and e.g., during faults in upstream network, it can be separated quickly from utility grid and operated independently as an island grid. MMS will be responsible from the overall economic and energy-effective operation of microgrid taking into account the technical boundary conditions both in normal and island operation (see Fig. 1).

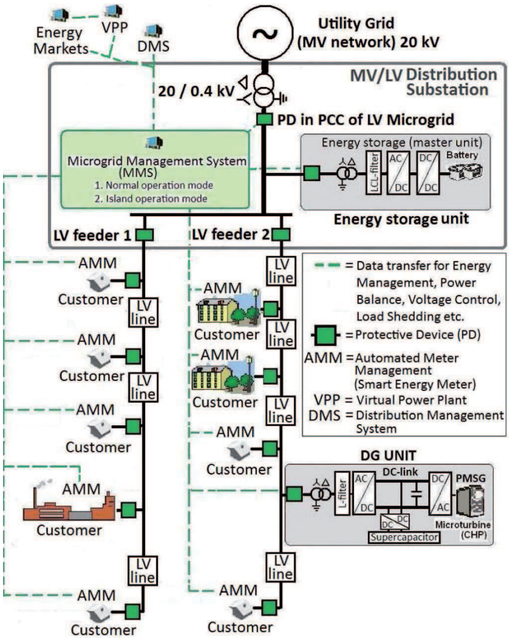

Fig. 1. LV Microgrid.

Realization of future smart grids with island-operation capability requires that all technical issues, such as power and energy balance, and power quality and protection during normal and island operation, are solved. Quite a lot of research has been done to solve these technical challenges, but there are still many things to be solved [2], [3]. One of the most challenging and crucial one is the protection of microgrid. The protection of the future microgrid is very strongly connected to the control and operation issues of a microgrid. The conventional protection in distribution networks is designed to operate for high fault-current levels in radial networks, but during island operation of the microgrid, high fault-currents from the utility grid are not present. Also, most of the DG units that will be connected to the LV microgrids in the future will be converter interfaced with limited fault-current feeding capabilities. This means that the traditional fuse protection of LV network is no longer applicable and new protection methods must be developed. Different kind of protection methods has been proposed in [4]–[13].

Manuscript received July 5, 2010; revised August 5, 2010; accepted August 6, 2010. Date of current version December 27, 2010. Recommended for publication by Associate Editor J. M. Guerrero.

The author is with the Department of Electrical Engineering and Automation, University of Vaasa, FI-65101 Vaasa, Finland (e-mail: hannu.laaksonen@uwasa.fi).

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Digital Object Identifier 10.1109/TPEL.2010.2066990

The developed protection scheme for microgrid must also be supported by the technical choices made in the microgrid operation and control. In the development of the new protection scheme for LV microgrids, many things must be considered including amount of protection zones in LV microgrid, operation speed requirements for microgrid protection in different operation states and configurations, and protection principles for parallel and island operation of the microgrid. However, as also stated in [14], the protection of microgrids cannot be properly resolved without a thorough understanding of microgrid dynamics before, during, and after islanding.

Taking into account the possibility of island operation in the future means, e.g., from the point of view of converter connected DG unit manufacturers, that technical design of the converter must enable both present loss of mains (LoMs) protection requirements and future fault-ride-through (FRT) requirements. Fulfillment of the FRT requirement may require, e.g., to use energy storages like supercapacitors [15] in the dc-links of DG unit converters to control the dc-link voltage rise during faults. In addition, smart-grid compatible DG unit converter must be equipped with fast standard-based communication capabilities.

Section II of this paper discusses briefly about issues related to the protection of LV microgrid, and Section III discusses about proposed LV-microgrid-protection concept. Section IV introduces the operation curves of protective devices (PDs) of the proposed LV-microgrid concept. Few extensions to the proposed LV-microgrid-protection concept are defined and developed in Sections V and VI. Finally, conclusion is stated in Section VII.

II. ISSUES RELATED TO THE PROTECTION OF LV MICROGRID

There are some fundamental structural choices that will determine the speed requirements and operation principles of LV-microgrid protection, and conversely these speed requirements will define certain structural choices needed to fulfill the speed requirements. There are two main reasons for speed requirements of LV-microgrid protection: stability and customer sensitivity. Stability needs to be maintained after sudden changes, i.e., after islanding due to fault in medium-voltage (MV) network during normal parallel operation with utility grid or after fault in LV microgrid during island operation.

Especially if there are directly connected rotating machines in island-operated microgrid, it is essential to ensure that the protection of customers will operate fast enough to minimize fault and voltage-dip duration and especially to ensure that stability can be maintained in islanded microgrid after fault clearance/operation of customer protection. Directly connected rotating machines are very sensitive to lose stability in voltage dips caused by faults in island-operated microgrid, and therefore, they may jeopardize the stability of the whole microgrid. The fast operation of protection improves the ability to maintain synchronism after transition to island operation, which is also crucial from the stability point of view [16], [17]. On the other hand, synchronized reconnection of island-operated LV microgrid back to utility grid should be ensured through coordinated control [18], e.g., by MMS.

DG unit converter control principle during fault has a major impact on fault detection in island-operated microgrids [6], and standards and other regulations are needed to be set for converters fault behavior in the very beginning of the design process [19]. The control of converter-based DG units during faults should support the proposed microgrid-protection concept. Realization of the microgrid concept or smart grid with island-operation capability needs development of grid codes that allows island operation, i.e., microgrid grid code (MGC). When MGCs are defined, it is important to recognize that protection requirements and settings will determine the needed control principles and technical implementation of the converter-based DG units.

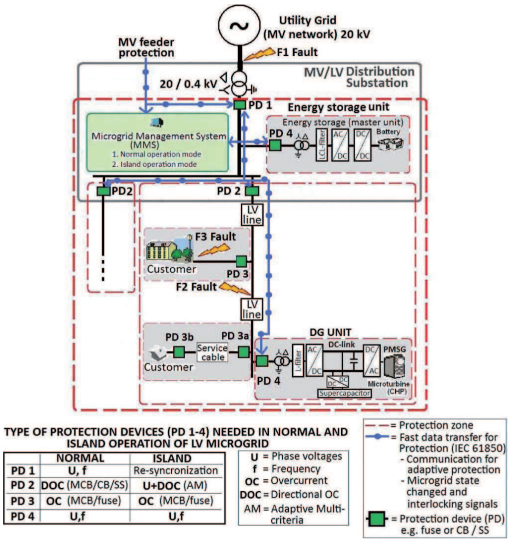
Structural choices that are needed to fulfill the speed requirements may be divided into: 1) switch technology needed; 2) communication technology needed; and 3) size of distributed energy storages or central energy storage on LV microgrid. New technology for fast operating circuit breakers (CBs) or static switches (SSs) has also been suggested, e.g., in [16], [20], and [21]. For example, with larger central energy storage, it is possible to survive from larger oscillations without losing stability and probably also to increase fault-current feeding capability in island-operated microgrid, e.g., to make customer fuses operate faster.

During island operation of LV microgrid, it is also important that the earthing is properly arranged. In [22], it has been concluded that TN-C-S or TT earthing systems are the most suitable for neutral earthing of a LV microgrid and DG units could be operated safely without earthing their neutral points locally, both in normal grid-connected operation and islanded operation.

III. LV-MICROGRID-PROTECTION CONCEPT

In this paper, like in previous studies [15], [17], [23], [24], it has been chosen to study microgrid concept with one central, energy-storage-based, master unit located at MV/LV distribution substation. Therefore, control of DG units is also different than, e.g., those in [25]–[32].

One essential issue from island-operated microgrid-protection point of view is the loss of neutral connection of MV/LV transformer during island operation when PD 1 is located downstream from MV/LV transformer. For this reason, it has been chosen as master unit needs to be connected to microgrid through delta-wye grounded transformer (i.e., microgrid side of this transformer is directly earthed) to ensure path for neutral current and high earth fault currents. On the other hand, still in many countries DG units are required to be connected to network through transformers for galvanic isolation. However, in the LV-microgrid-protection concept discussed in the following also DG units have been chosen to be connected to LV microgrid with delta-wye grounded connection transformers. The size and number of LV-microgrid-protection zones will define the needed amount of PDs for microgrid protection. The size of microgrid-protection zone must be such that it fulfills the requirements of customers and at the same time is economically feasible. Key fundamental properties required from the



TYPE OF PROTECTION DEVICES (PD 1-4) NEEDED IN NORMAL AND ISLAND OPERATION OF LV MICROGRID

	NORMAL	ISLAND
PD 1	U, f	Re-syncronization
PD 2	DOC (MCB/CB/SS)	U+DOC (AM)
PD 3	OC (MCB/fuse)	OC (MCB/fuse)
PD 4	U,f	U,f

U = Phase voltages
f = Frequency
OC = Overcurrent
DOC = Directional OC
AM = Adaptive Multi-criteria

Fig. 2. Number of protection zones and type of protection devices (PD 1–4) needed in normal and island operation of LV microgrid.

future LV-microgrid-protection concepts include: 1) adaption capability; 2) utilization of high-speed standard-based communication IEC 61850; 3a) high-speed operation in deep voltage dips due to faults to maintain stability in healthy part of LV microgrid; 3b) high-speed operation to fulfill needs of very sensitive customers; 4) selective operation in every kind of faults; and 5) unnecessary operation of PDs and disconnection of DG units must be avoided.

In [24], protection concept for LV microgrid was developed. In Fig. 2, number of LV-microgrid-protection zones, type of PDs (PD 1–PD 4) chosen for this protection concept are presented, and in Fig. 3, functions needed from PDs in normal and island operation are presented.

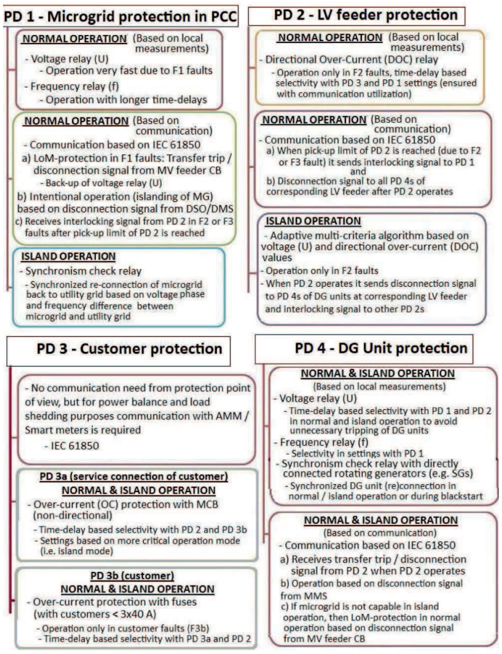
The needed protection devices (PD 1–4) are as follows.

PD 1: Microgrid protection in point of common coupling (PCC) including relay and CB or fast SS.

PD 2: LV feeder protection including miniature CB (MCB), CB, or SS.

PD 3: Service connection for customer with MCB and customer protection with fuse or MCB or in case of LV customer microgrid (DC or AC) with very sensitive customers SS may be needed.

PD 4: Production/DG unit protection.



PD 1 - Microgrid protection in PCC

NORMAL OPERATION (Based on local measurements)
- Voltage relay (U)
  - Operation very fast due to F1 faults
- Frequency relay (f)
  - Operation with longer time-delays

NORMAL OPERATION (Based on communication)
- Communication based on IEC 61850
a) LoM-protection in F1 faults: Transfer trip / disconnection signal from MV feeder CB
  - Back-up of voltage relay (U)
b) Intentional operation (islanding of MG) based on disconnection signal from DSO/DMS
c) Receives interlocking signal from PD 2 in F2 or F3 faults after pick-up limit of PD 2 is reached

ISLAND OPERATION
- Synchronism check relay
  - Synchronized re-connection of microgrid back to utility grid based on voltage phase and frequency difference between microgrid and utility grid

PD 2 - LV feeder protection

NORMAL OPERATION (Based on local measurements)
- Directional Over-Current (DOC) relay
  - Operation only in F2 faults, time-delay based selectivity with PD 3 and PD 1 settings (ensured with communication utilization)

NORMAL OPERATION (Based on communication)
- Communication based on IEC 61850
a) When pick-up limit of PD 2 is reached (due to F2 or F3 fault) it sends interlocking signal to PD 1
and
b) Disconnection signal to all PD 4s of corresponding LV feeder after PD 2 operates

ISLAND OPERATION
- Adaptive multi-criteria algorithm based on voltage (U) and directional over-current (DOC) values
- Operation only in F2 faults
- When PD 2 operates it sends disconnection signal to PD 4s of DG units at corresponding LV feeder and interlocking signal to other PD 2s

PD 3 - Customer protection

- No communication need from protection point of view, but for power balance and load shedding purposes communication with AMM / Smart meters is required
  - IEC 61850

PD 3a (service connection of customer)
NORMAL & ISLAND OPERATION
- Over-current (OC) protection with MCB (non-directional)
  - Time-delay based selectivity with PD 2 and PD 3b
  - Settings based on more critical operation mode (i.e. island mode)

PD 3b (customer)
NORMAL & ISLAND OPERATION
- Over-current protection with fuses (with customers < 3x40 A)
  - Operation only in customer faults (F3b)
  - Time-delay based selectivity with PD 3a and PD 2

PD 4 - DG Unit protection

NORMAL & ISLAND OPERATION
(Based on local measurements)
- Voltage relay (U)
  - Time-delay based selectivity with PD 1 and PD 2 in normal and island operation to avoid unnecessary tripping of DG units
- Frequency relay (f)
  - Selectivity in settings with PD 1
- Synchronism check relay with directly connected rotating generators (e.g. SGs)
  - Synchronized DG unit (re)connection in normal / island operation or during blackstart

NORMAL & ISLAND OPERATION
(Based on communication)
- Communication based on IEC 61850
a) Receives transfer trip / disconnection signal from PD 2 when PD 2 operates
b) Operation based on disconnection signal from MMS
c) If microgrid is not capable in island operation, then LoM-protection in normal operation based on disconnection signal from MV feeder CB

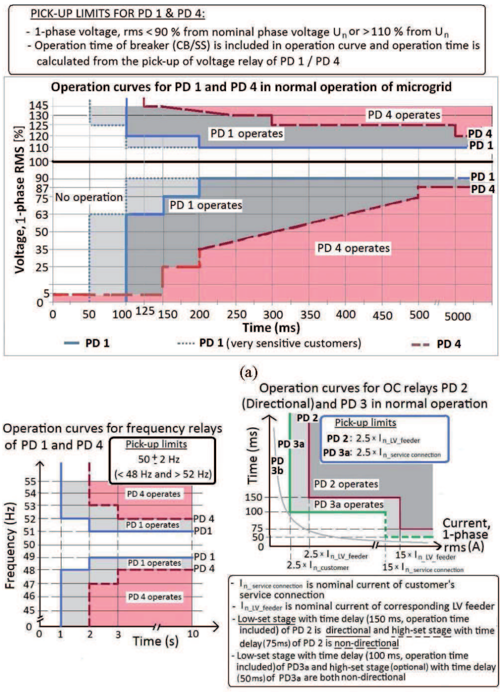
Fig. 3. Functions needed from LV-microgrid protection in normal and island operation based on local measurements and communication (see Fig. 2). [24]

Fast real-time communication is needed for microgrid protection purposes between PDs (PD 1 and PD 2) and also with master unit and DG units during microgrid island operation (see Fig. 2). In addition, MMS needs to be able to communicate in real time with all these microgrid components as well as with customer loads. Therefore, communication between different network components and MMS based on common standard like IEC 61850 is the most sensible and economical option in overall. MMS is used to change settings and pick-up limits of PDs (PD 2s) when microgrid configuration changes (see Fig. 2). MMS will send state-changed signal from normal to island operation to different PDs of microgrid to adapt to the changed microgrid configuration (see Fig. 2).

Correspondingly, the fault detection and localization with dc power systems can be based on communication [33]. Utilization of high-speed communication could be also beneficial in the protection of DC microgrids to solve challenges, e.g., with protection coordination mentioned in [34].

IV. OPERATION CURVES OF PDs IN LV-MICROGRID-PROTECTION CONCEPT

In the following, operation curves for PDs (see Fig. 4) in LV-microgrid-protection concept during normal and island operation are described. One important issue is that operation curves for PD 1 in normal and PD 2 in island operation also represent FRT requirements for DG units connected to the LV microgrid, because they are created so that stability of LV microgrid or healthy part of LV microgrid could be maintained after fault clearance also in cases where directly connected synchronous generators (SGs) was connected in LV microgrid. Voltage relay operation curve of PD 4 ensures selectivity with settings of PD 1 in normal operation and PD 2 in island operation to avoid



(a)

(b)

Fig. 4. (a) Operation curves for voltage relays (PD 1 in normal operation and PD 4 in normal and island operation). (b) Operation curves frequency relays of PD 1 and PD 4 in normal and island operation of microgrid and operation curves for OC relays of PD 2 (directional low-set stage and nondirectional high-set stage) in normal operation and PD 3 in normal and island operation.

unnecessary tripping of DG units. Frequency relay of PD 1 and PD 4 is only used to protect microgrid customers from possible long-term frequency deviations from nominal 50 Hz, e.g., caused by disturbances due to power imbalance in high-voltage network which cannot be seen from phase-voltage measurements. Operation curves for frequency relay of PD 4 will also represent FRT required from DG and energy storage units based on frequency. Pick-up and operation limits for PD 3s overcurrent (OC) settings should be quite low, because their operation speed should also be same in island operation, where fault-current level will be much lower than in normal operation [24].

In Fig. 4, requirements for the operation of microgrid PDs (PD 1, PD 2, PD 3, and PD 4) during normal operation of microgrid are presented. The operation limits for low-set and high-set stages of PD 2 and PD 3a in Fig. 4(b) are instructional, based on simulation studies done in [24]. The protection of LV feeders with PD 2s in normal operation is based on directional OC relays [see Fig. 4(b)]. The direction of the current must be to corresponding LV feeder with such time delay that all possible F3 type of customer faults will be cleared with PD 3s before possible operation of PD 2. The chosen time delays in Fig. 4(b) between PD 2 and PD 3a are quite small and selectivity may be hard to achieve between them in reality without communication-based interlocking signals from PD 3a.

The operation curve for PD 4 must be such that it will never unnecessarily disconnect DG unit due to any type of fault, i.e., PD 4 needs to be time selective with PD 1, PD 2, and PD 3, both in normal and in island operation of microgrid. In [24], an extra definition for PD 4 was also specified, i.e., disconnection of DG unit with PD 4 based on undervoltage should only take place <150 ms after pick-up limit is reached if voltage in all three phases (A, B, and C) is <12 V [see Fig. 4(a)] and voltages for PD 4 are measured from microgrid side of delta-wye grounded transformer. Fulfillment of the LV-microgrid protection requires FRT ability from the DER units which in practice also means that converter-based DER units need phase-locked loop (PLL) with negative sequence filtering [16], [23] or some other stable and reliable synchronization method with FRT capability (see [35] and [36]).

Main difference in the protection of LV microgrid during island operation is the needed change in the protection algorithm of PD 2s. Based on the simulations, adaptive multicriteria algorithm for PD 2 was created in [24]. Adaptivity means that protection of PD 2 during island operation takes into account the number and type of DG units at corresponding LV feeder and also their fault-current feeding capability. In addition, multicriteria algorithm of PD 2 is based on both phase-voltage and phase-current measurements. Fast and selective operation between different PD 2s during island operation is achieved by intelligent utilization of high-speed communication.

Another option for protection of radially operated LV feeders during island operation with only voltage relays at PD 2s could be the comparison of voltage measurements between PD 2s which are measured some distance away from MV/LV distribution substation at corresponding LV feeders with high-speed communication to PD 2s. This way lower phase voltage/voltages at the faulted LV feeder could be seen more clearly.

V. EXTENSIONS TO THE LV-MICROGRID-PROTECTION CONCEPT

In this section, few additions to the LV-microgrid concept presented in Sections III and IV will be defined. In Section III-A, protection of long LV feeders with section CB is examined. In Section III-B, connection of large DG units to LV microgrid is discussed, and in Section III-C, protection issues related to possible ring operation of LV feeders are viewed.

A. *Long LV feeders With Section CBs and Open-Ring Connection*

For example with longer radially operated LV feeders, it may in some cases be beneficial to divide feeders into two protection zones (see Fig. 5). In addition, by adding PD 2_{ring} (see Fig. 5), which is normally open, between LV feeders, the self-healing capability of LV microgrid could be increased. By closing PD 2_{ring} (see Fig. 5) due to a fault at LV feeder section between PD 2a and PD 2b instantaneously when PD 2a is opened, the number of customers affected by the fault could be reduced. When PD 2a opens, it will send closing signal to PD 2_{ring} and

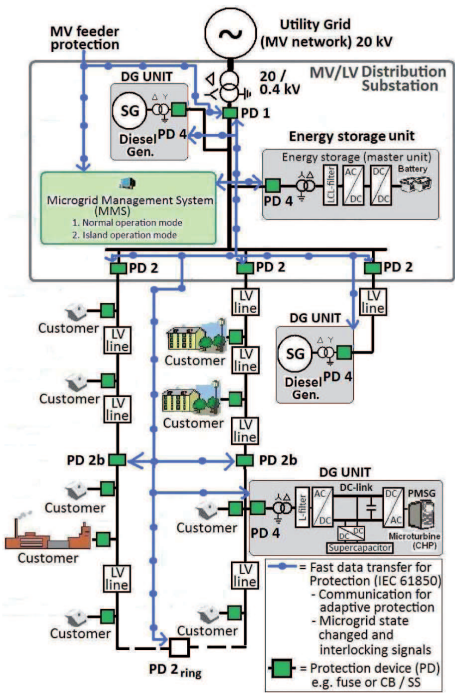


Fig. 5. Long LV feeders with section CBs (PD 2b, PD $2_{\rm ring}$) and connection of large DG units.

interlocking signal to other PD 2s in LV microgrid. On the other hand, if fault occurs after PD 2b at corresponding LV feeder, then time delay in operation of PD 2a must be such that interlocking signal from PD 2b can reach PD 2a before it will operate. In addition, selective operation of PD 2a and PD 2b with PD 3 must be always ensured.

When fault occurs after PD 2b at corresponding LV feeder, then during both normal and island operation, PD 2a and PD 2b will detect the fault simultaneously. However, only PD 2b will send interlocking signal immediately to PD 2a of the same LV feeder before PD 2a operates otherwise. To ensure selective operation between PD 2a and PD 2b, PD 2a sends interlocking signal to PD 2b and closing signal to PD $2_{\rm ring}$ not until it has opened. Although, to confirm selective operation of LV-microgrid protection also during island operation PD 2b could send measured phase-voltage values with timestamp as an attachment of interlocking signal to PD 2a. If phase voltages measured by PD 2a at the same time are lower than the ones received from PD 2b, then PD 2a will be opened despite the interlocking signal received.

B. Connection of Large DG Units

Connection of large DG units, e.g., >50 kVA, which also have relatively high fault-current feeding capability, i.e., directly connected SGs, is discussed in the following. Fault-current feeding capability of directly connected SGs may be circa six times the nominal current (I_n) for a short duration and possibly fault current of converter connected DG units can be even four times I_n for a while in future [37]. Connection of large DG units with high fault-current feeding capability directly to LV feeders may make it difficult to achieve selective protection during island operation of LV microgrid. Therefore, large DG units should be connected either: 1) directly; or 2) with own LV feeder to the MV/LV distribution substation (see Fig. 5). Such a DG unit connection is also beneficial for both normal and island operation of LV microgrid if this unit is, e.g., heat-producing combined heat and power (CHP) unit, because it will always remain connected regardless of possible faults at other LV feeders (see Fig. 5).

C. Ring-Connected LV Feeders in Normal Operation

In normal operation of LV microgrid, it can be beneficial from voltage-level-control point of view to connect LV feeders to ring operation. This means that PD $2_{\rm ring}$ is needed (see Fig. 5) and it will be closed during normal operation. Section CBs, PD 2b in Fig. 5, are not necessarily needed. During normal operation of LV microgrid, this ring connection of LV feeders may require changes to the LV-microgrid-protection concept. However, during island operation of LV microgrid, the PD $2_{\rm ring}$ (see Fig. 5) must be opened for radial operation of LV feeders to ensure selective operation of microgrid protection.

In Section VI, four faults in different locations of ring-connected LV feeders are simulated to determine needed changes in the protection concept of LV microgrid during normal operation due to ring connection.

VI. Fault Simulations During Normal Operation of the Ring-Connected LV Microgrid

A. Studied LV Microgrid

The studied LV microgrid in this section is presented in Fig. 6. The system consists of one 500-kVA MV/LV-transformer which normally feeds LV feeders 1 and 2. At the connection point of the microgrid, before the feeders 1 and 2, there is a converter connected energy storage unit (battery, $S_n = 150$ kVA). In the LV feeder 2 there is a frequency converter connected permanent magnet synchronous generator (PMSG) based DG unit ($S_n = 300$ kVA, in simulations $P = 100$ kW, $Q = 0$ kVAr). The PSCAD models of the master unit and DG unit are shown in Fig. 7 and filter and control parameters of these units are presented in the Appendix. The load in the microgrid consists of quite large induction motor (IM) load (in simulations $P = 51$ kW, $Q = 34$ kVAr before fault) at feeder 1, four three-phase passive loads on each feeder and few single-phase passive loads (see Fig. 6) on both feeders, which means that the load between phases is asymmetrical. LV feeder resistance and reactance are shown in Fig. 6. The fault level and *R*/*X*-ratio of the feeding utility network (20 kV, 50 Hz) are 200 MVA and 0.1, respectively.

The control of energy-storage-based master unit during normal operation is presented in Fig. 8(a). During possible island operation of LV microgrid, it will be operated in a single master operation mode, which in this case means that the

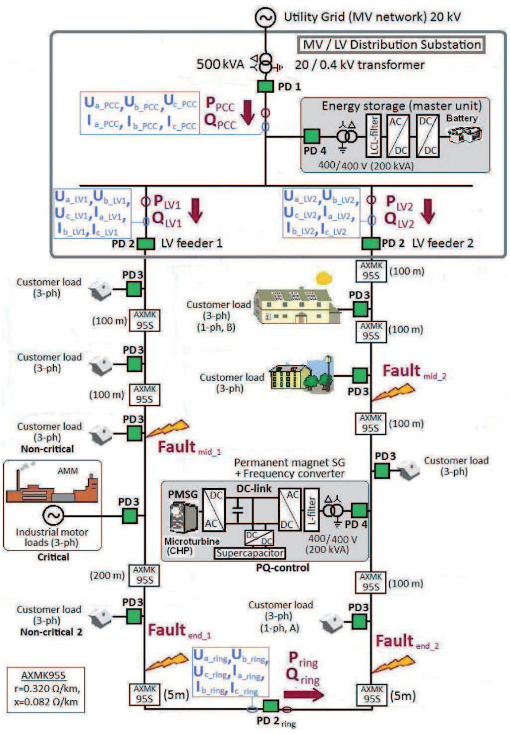


Fig. 6. Studied LV microgrid with ring-connected LV feeders.

battery-storage-based DER unit (see Fig. 6) will act as the master unit and it has the main responsibility to control the voltage and frequency in microgrid when islanded [see Fig. 8(b)]. The negative sequence filtering with PLL [see Fig. 8(a)], presented as positive sequence detector and with more details in [16], is done to improve the stability of the converter-based master unit especially during asymmetrical faults. Utilization of negative sequence filtering also from the current reference I_{ref} in converter control system (see Fig. 8) reduces the current THD during normal operation and asymmetrical faults. During island operation of LV microgrid, especially when microgrid load is not symmetrical between all phases, the distortions in voltage and current THD will also be lower, [23]. However, the negative sequence filtering from current reference I_{ref} does not remove the ripple from dc-link voltage during asymmetrical fault.

B. Simulation Results

In the following, simulation results from four different two-phase earth fault simulations are presented. Locations of these four faults can be seen in Fig. 6. First measured phase currents, phase voltages, and active and reactive powers before faults in different locations are presented in Table I. Locations of these measurements done by different PDs are shown in Fig. 6.

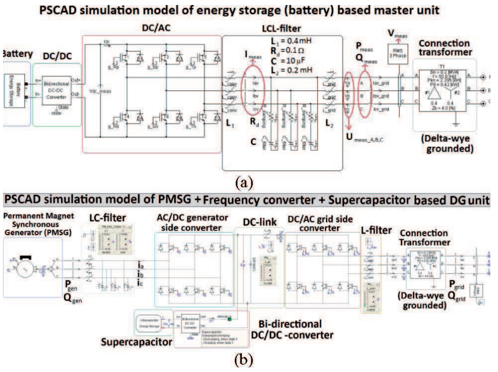


Fig. 7. PSCAD simulation model of (a) master unit, and (b) PMSG with frequency converter and supercapacitor-based DG unit.

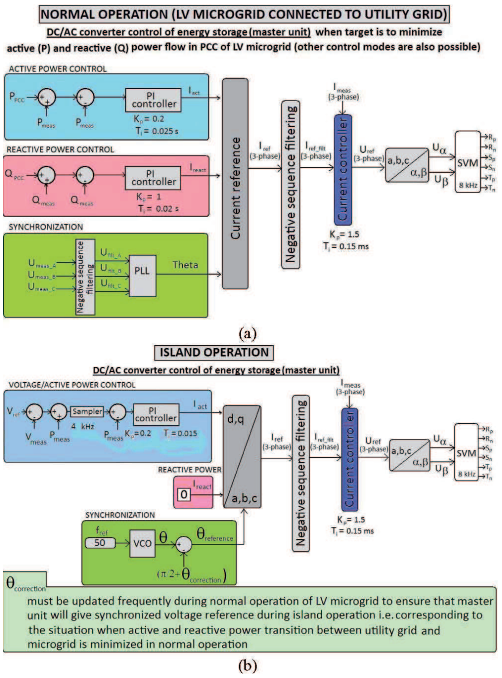


Fig. 8. Control of master unit dc/ac- converter (a) in normal operation and (b) in island operation.

Simulation results 100 ms after beginning of two-phase earth fault are presented in Tables II–V from faults at the end of LV feeder 1 (fault$_{\mathrm{end\_1}}$ in Fig. 6), at the end of LV feeder 2 (fault$_{\mathrm{end\_2}}$ in Fig. 6), in the middle of LV feeder 1 (fault$_{\mathrm{mid\_1}}$ in Fig. 6), and in the middle of LV feeder 2 (fault$_{\mathrm{mid\_2}}$ in Fig. 6), respectively. In Fig. 9, measurements of PD 2$_{\mathrm{ring}}$, that are also

TABLE I
MEASURED PHASE CURRENTS, VOLTAGES, ACTIVE, AND REACTIVE POWERS BEFORE FAULTS IN DIFFERENT LOCATIONS (SEE FIG. 6)

Location	Active / Reactive Power [kW]/[kVAr]	Phase Currents (rms) [A] / Phase Voltages (rms) [V]
PCC	0 / 0	5, 7, 9 / 236, 236, 236
LV1	68 / 38	117, 112, 111 / 236, 236, 236
LV2	10 / 21	31, 40, 29 / 236, 236, 236
Ring	- 41 / -7	57, 64, 65 / 237, 238, 238

TABLE II
MEASURED PHASE CURRENTS, VOLTAGES, ACTIVE, AND REACTIVE POWERS 100 ms AFTER BEGINNING OF FAULT AT THE END OF LV FEEDER 1 (SEE FIG. 6)

Location	Active / Reactive Power [kW]/[kVAr]	Phase Currents (rms) [A] / Phase Voltages (rms) [V]
PCC	900 / 300	2400, 2230, 280 / 230, 200, 230
LV1	570 / 220	1350, 1300, 320 / 230, 200, 230
LV2	500 / 220	1250, 1200, 220 / 230, 200, 230
Ring	- 130 / -190	1600, 1400, 70 / 90, 80, 220

TABLE III
MEASURED PHASE CURRENTS, VOLTAGES, ACTIVE, AND REACTIVE POWERS 100 ms AFTER BEGINNING OF FAULT AT THE END OF LV FEEDER 2 (SEE FIG. 6)

Location	Active / Reactive Power [kW]/[kVAr]	Phase Currents (rms) [A] / Phase Voltages (rms) [V]
PCC	950 / 350	2500, 2400, 350 / 228, 198, 228
LV1	580 / 250	1400, 1350, 320 / 228, 198, 228
LV2	520 / 250	1320, 1280, 240 / 228, 198, 228
Ring	45 / 200	1400, 1250, 70 / 80, 80, 218

TABLE IV
MEASURED PHASE CURRENTS, VOLTAGES, ACTIVE, AND REACTIVE POWERS 100 ms AFTER BEGINNING OF FAULT IN THE MIDDLE OF LV FEEDER 1 (SEE FIG. 6)

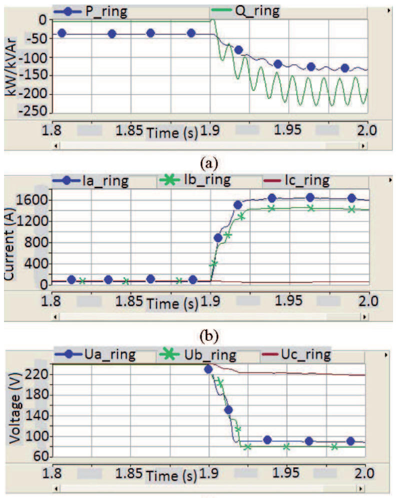
Location	Active / Reactive Power [kW]/[kVAr]	Phase Currents (rms) [A] / Phase Voltages (rms) [V]
PCC	1350 / 400	3200, 3000, 600 / 215, 198, 228
LV1	1100 / 400	2800, 2600, 350 / 215, 198, 228
LV2	330 / 140	770, 740, 280 / 215, 198, 228
Ring	- 205 / -115	1150, 1100, 60 / 105, 95, 210

TABLE V
MEASURED PHASE CURRENTS, VOLTAGES, ACTIVE, AND REACTIVE POWERS 100 ms AFTER BEGINNING OF FAULT IN THE MIDDLE OF LV FEEDER 2 (SEE FIG. 6)

Location	Active / Reactive Power [kW]/[kVAr]	Phase Currents (rms) [A] / Phase Voltages (rms) [V]
PCC	1200 / 560	3250, 3030, 330 / 225, 187, 228
LV1	350 / 175	850, 840, 290 / 225, 187, 228
LV2	950 / 500	2700, 2500, 250 / 225, 187, 228
Ring	95 / 155	800, 780, 90 / 132, 108, 228

presented in Table II during fault at the end of LV feeder 1 ($\text{fault}_{\text{end}\_1}$ in Fig. 6) are shown.

When simulation results of Tables II–V are examined, it becomes clear that selective operation of PD 2s [see Fig. 4(c)] at the beginning of LV feeders during normal operation of ring-connected LV microgrid is not possible without utilization of high-speed communication at PD 2_{ring}. At PD 2_{ring}, same kind of protection settings, as presented in Fig. 4(c), for PD 2s of LV feeders can be used, but in addition, high-speed interlocking signal must be sent to PD 2 of the healthy LV feeder before it will operate [see Fig. 4(c)], i.e., in less than 75 ms, which includes the signal transfer and processing time and the operation time is calculated from pick-up of directional OC relay of PD 2_{ring}. From Tables II–V, it can be seen how direction of fault current at PD 2_{ring} can also be seen from active and reactive power measurements.



(a)

(b)

(c)

Fig. 9. Measurements of PD 2_{ring} (a) active and reactive power, (b) phase currents, and (c) phase voltages during fault at the end of LV feeder 1 ($\text{fault}_{\text{end}\_1}$ in Fig. 6).

VII. CONCLUSION

Realization of future smart LV grids with island-operation capability requires that all technical issues, such as power and energy balance, power quality and protection, are solved. One of the most crucial one is the protection of LV microgrid during normal and island operation. Realization of LV microgrids as an integrated part of future smart grids needs new grid codes where the protection requirements and settings for LV microgrids are clearly determined. These grid codes will also determine the required DG unit behavior and control principles during normal operation and faults. Therefore, the technical implementation of converter-based DG units, which is capable of fulfilling the requirements, will also be specified by the future grid codes.

In this paper, protection issues and principles for LV microgrids has been discussed, one possible new protection concept for LV microgrid has been presented and new additions to this novel protection concept has been developed. Essential in the future protection concept for LV microgrids will be the utilization of high-speed communication to achieve fast, selective, and reliable operation. This need was also demonstrated in this paper through fault simulations with PSCAD simulation software during normal operation of ring-connected LV microgrid when extensions to the proposed LV-microgrid-protection concept were developed.

TABLE VI
STUDY SYSTEM PARAMETERS

	Parameter	**Value**
Master Unit Converter (DC/AC)	Modulation method	SVM
	Switching frequency	8 kHz
	Filter L_1, R_d, C, L_2	0.4 mH, 0.1 Ω, 10 µF, 0.2 mH
Current PI-controller of Master Unit	Gain $K_{current}$	1.5
	Integrator time constant $T_{c\ i}$	0.15 ms
Active Power PI-controller (Master Unit)	Gain K_p	0.2
	Integr. time const.$T_{p\ i}$	0.025 s
	Sampling rate	4 kHz
Reactive Power PI-controller (Master Unit)	Gain K_Q	1
	Integr. time const.$T_{q\ i}$	0.02 s
	Sampling rate	4 kHz
PMSG with Frequency Converter	Modulation method (Grid side converter)	PWM
	Switching Frequency (Grid side converter)	8 kHz
	Filter L	2.5 mH
	DC-link capacitor	12000 µF
Supercapacitor	Capacitance / cell	3000 F
	Number of cells	213
	Cell max. voltage	2.7 V
DC-DC Buck-boost Converter (Master Unit)	Reference dc voltage V_{DC}	0.7 kV
	Gain $K_{dc/dc}$	0.3
	Integrator time constant $T_{dc/dc\ i}$	0.06 s
	Sampling rate_dc/dc	1 kHz
	DC-link capacitor	5000 µF

APPENDIX

Study system parameters, especially master and DG unit filter and control parameters, used in the simulations are presented in Table VI. The used solution time step was 5 μs.

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Hannu Jaakko Laaksonen was born in Vaasa, Finland, on November 22, 1977. He received the Master's degree in electrical power engineering from the Tampere University of Technology, Tampere, Finland, in 2004.

He is currently a Research Scientist and Ph.D. student at the Department of Electrical Engineering and Automation, University of Vaasa, Vaasa, Finland. His employment experience includes working as a Research Scientist in VTT Technical Research Centre of Finland in Vaasa. His research interests include integration and active management of distributed energy resources in smart distribution networks and power electronics in future smart-grid concepts (e.g., microgrids).