

Advanced Architectures and Control Concepts for

MORE MICROGRIDS

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**Tools for Coordinated Voltage Support and
Coordinated Frequency Support**

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Foreword

Coordination of voltage VAR control in MV distribution networks is addressed here with the purpose of improving system operation conditions (such as minimizing active power losses and keeping voltage profiles within desired levels) by exploiting, in a combined way, the control capabilities of DG units, microgrid (that can be regarded as active cells), OLTC transformers, capacitor banks and SVCs. Specific physical and technical limitations of all these controllable devices are taken into account, as well as physical (thermal) limits in network branches. Special restrictions that may result from the downstream microgeneration availability and operation characteristics are also considered here. Concerning this issue, different optimization methods are tested and compared.

The University of Manchester and ICCS/NTUA provide tools based on conventional approaches while INESC Porto exploits particle swarm optimization techniques to deal with this problem. ISET assesses the VAR-exchange and the transient active power sharing via the MV-system by means of simulation (ATP-EMTP) and measurements with the MV simulator installed at DemoTec.

The contributions given by the partners INESC Porto, University of Manchester, ICCS / NTUA and ISET, regarding the topics present in Task TD3.2 – Coordinated Voltage Support, are presented in the 4 following parts of this document.

INESC PORTO CONTRIBUTION

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Acronyms and Abbreviations

AVR – Automatic Voltage Regulator

CAMC – Central Autonomous Management Controller

CHP – Combined Heat and Power

DG – Distributed Generation

DMS – Distribution Management System

DSM – Demand Side Management

DSO – Distribution System Operator

EMS – Energy Management System

EPSO – Evolutionary Particle Swarm Optimization

HV – High Voltage

LC – Load Controller

LV – Low Voltage

MC – Microsource Controller

MGCC – MicroGrid Central Controller

MV – Medium Voltage

OF – Objective Function

OLTC – On-Line Tap Changing

OPF – Optimal Power Flow

RTU – Remote Terminal Unit

SVC – Static VAR Compensator

VCA – Voltage Control Area

1. General Introduction

A microgrid as defined so far comprises a Low Voltage (LV) feeder with several microsources, storage devices and controllable loads connected on that same feeder. A scheme of such a system may be seen in Fig. 1.

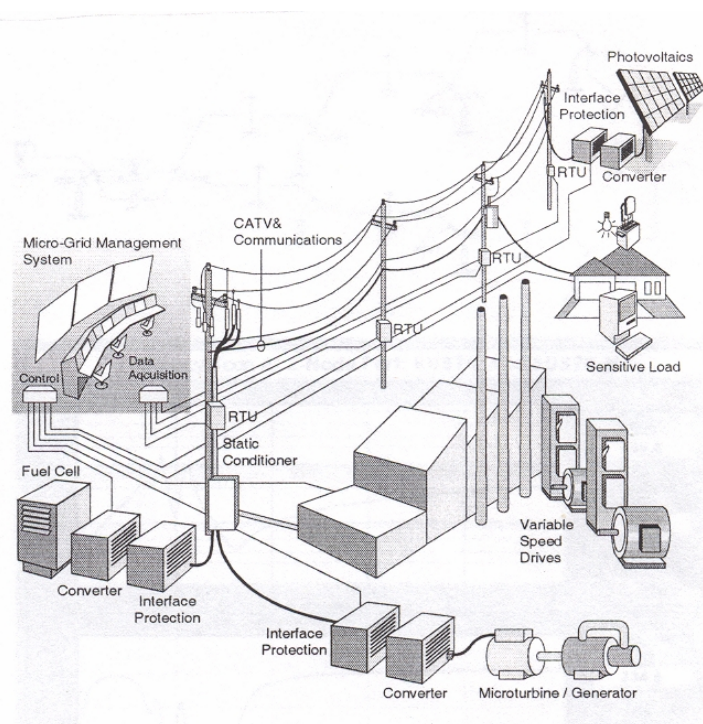


Fig. 1 – Typical MicroGrid System

A control scheme for microgrid operation requires three different control levels that may be seen in Fig. 2:

- Local Microsource Controllers (MC) and Load Controllers (LC)
- MicroGrid Central Controller (MGCC)
- Distribution Management System (DMS)

The new concept of multi-microgrids is related to a higher level structure, formed at the Medium Voltage (MV) level, consisting of several LV microgrids and Distributed Generation (DG) units connected on adjacent MV feeders. Microgrids, DG units and MV loads under Demand Side Management (DSM) control can be considered in this network as active cells for control and management purposes.

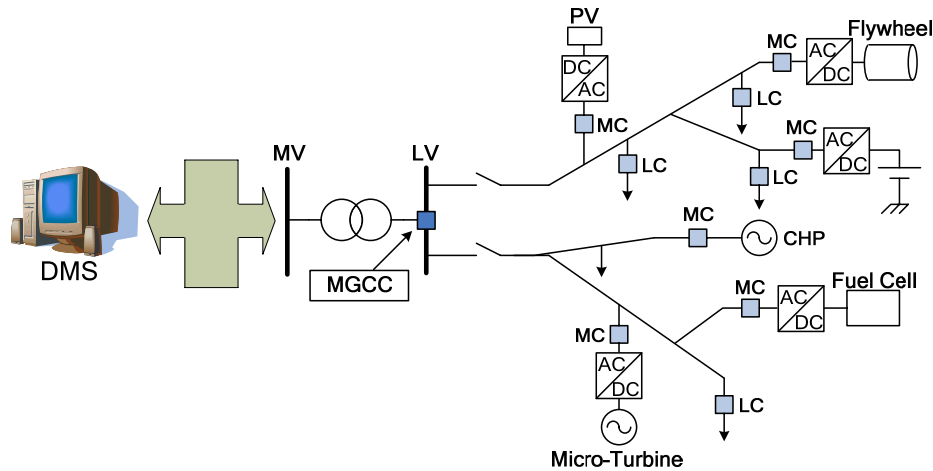


Fig. 2 – MicroGrid Control Architecture

Technical operation of such a system requires transposing the microgrid concept to the MV level where all these active cells, as well as MV/LV passive substations, shall be controlled by a Central Autonomous Management Controller (CAMC) to be installed at the MV bus level of a HV/MV substation, serving as an interface to the Distribution Management System (DMS), under the responsibility of the Distribution System Operator (DSO). In fact, the CAMC may be seen as one DMS application that is in charge of one part of the network.

The main issue when dealing with control strategies for multi-microgrids is the use of individual controllers acting as agents with the ability of communicating with each other in order to make decisions [1]. The controllers should aggregate several devices of the same type in order to obtain a more “operational” system – Load Controllers (LC) controlling groups of loads or Microsource Controllers (MC) controlling groups of microgenerators. A decentralized scheme is justified by the tremendous increase in dimension and complexity of the system so that the management of multi-microgrids requires the use of a more flexible control and management architecture [2].

Nevertheless, decision making using decentralized control strategies must still retain a hierarchical structure [1]. A central controller should collect data from multiple agents and establish rules for low-rank individual agents. These rules for each controller must be set by the high level central controller (DMS) which may delegate some tasks to lower level controllers (CAMC or MGCC). In this case, a purely central management would not be effective enough because

of the large amount of data to be processed and treated, and therefore would not ensure an autonomous management namely during islanded mode of operation. The CAMC must then communicate with other “local” controllers such as MGCCs or with DG sources or loads connected to the MV network, serving as an interface for the DMS.

Therefore, the CAMC will be playing a key role in a multi-microgrid system: it will be responsible for the data acquisition process, for enabling the dialogue with the DMS upstream, for running specific network functionalities and for scheduling the different agents in the downstream network [2]. In general terms, this new management and control architecture is described in Fig. 3.

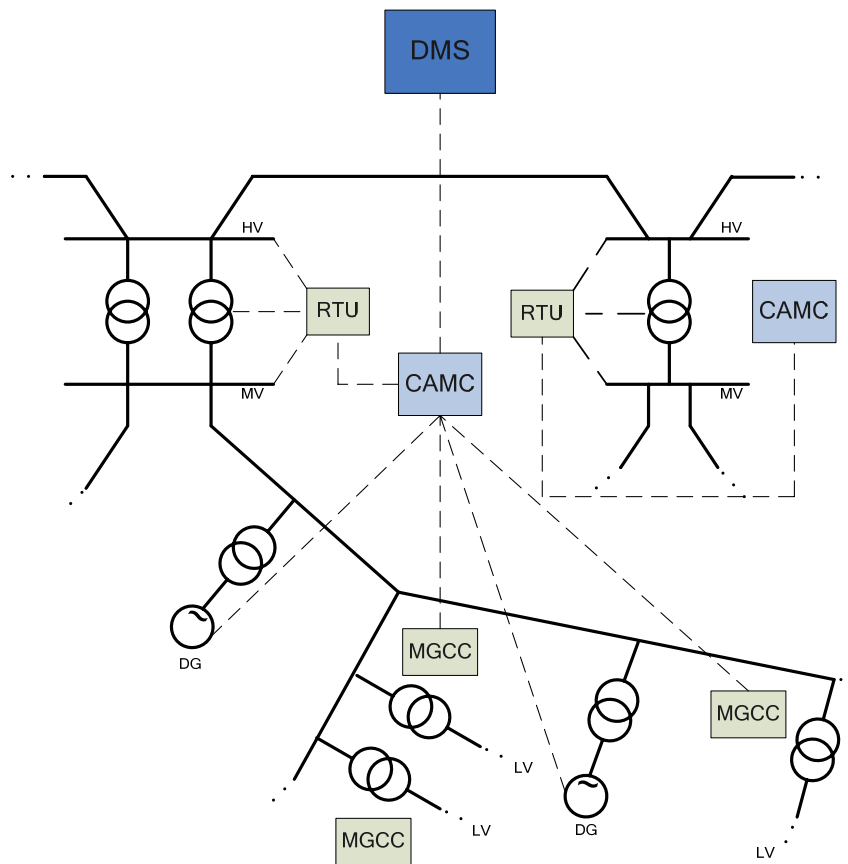


Fig. 3 – Control and Management Architecture of a Multi-MicroGrid System

Existing DMS functionalities need to be adapted due to the operational and technical changes that result from multi-microgrid operation and the introduction of the CAMC concept and corresponding hierarchical control architecture.

The management of the multi-microgrid (MV network included) will be performed through the CAMC. This controller will be responsible for acting as

an intermediate to the DMS, receiving information from the upstream DMS, measurements from Remote Terminal Units (RTUs) located in the MV network and existing MGCCs. It will also have to deal with constraints and contracts to manage the multi-microgrid in both HV grid-connected operating mode and emergency operating mode. A first set of functionalities to integrate the CAMC may be seen in Fig. 4.

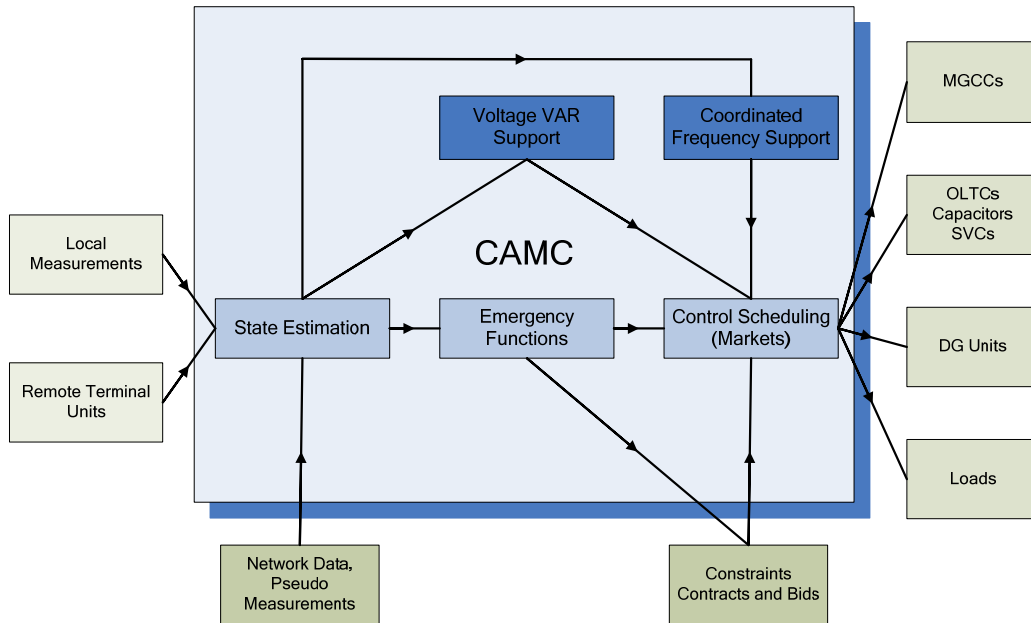


Fig. 4 – CAMC Functionalities

However, not all these functionalities need to be available in every multi-microgrid system. Their availability will depend on the characteristics of the MV network and on the local DG units present.

The Voltage VAR Support functionality presented in Fig. 4 is described in this document.

2. Introduction to Voltage Support

Following the widespread penetration of DG in distribution networks, electric power systems have been led up to a point where the operating conditions are becoming more and more stressed, namely regarding voltage profiles. In addition, reliability and security has become a primary concern for power system operation as it impacts strongly on the quality of supply. Following the restructuring process in power systems, voltage service is considered to be an important part of ancillary services provision. Hence, the

development of control functionalities for DG units concerning voltage control has been a topic for investigation in recent years.

In general, DG is not subject to a centralized dispatch and reactive power generation is usually restricted by operation rules defined by the DSO. However, a significant growth of DG penetration requires a new operation philosophy to exploit reactive power generation capability of DG with the objective of optimizing network operation by minimizing active power losses and maintaining voltage profiles. This implies that DG should be capable of adjusting their reactive power generation, *i.e.* be able to supply an ancillary service of voltage and reactive power control.

The feasibility and the technical advantages that result from implementing this operational strategy are investigated in this work by analyzing the impact of the proposed strategies for voltage control in distribution networks.

Basically, the identification of control action needs may be assessed by solving an optimization problem, where active power losses are minimized, subject to a set of technical constraints [3]. The control variables to consider are: DG reactive power generation, OLTC transformers settings and capacitors banks settings. In this case, active power generation is not subject to any type of control.

In conventional systems, voltage control is usually formulated as a decentralized control problem. This is mainly due to the fact that voltage is predominantly a local/regional problem.

However, the characteristics of the future distribution networks may impose severe restrictions to the design of an efficient system for voltage control, namely:

- The use of power electronic interfaces in most generating units
- The use of new generating technologies with new control systems
- The possibility of performing Demand Side Management
- The possibility of both interconnected and islanded operation
- The creation of a market for ancillary services provision
- The “Fit and Forget” philosophy for DG connection

In addition to the growth in DG penetration, microgeneration is also expected to develop considerably and therefore contribute to the possibility of implementing an efficient voltage control scheme. Consequently, following the widespread diffusion of both microgrids and DG in distribution systems, this vision needs now to be revised.

For this new scenario, a hierarchical voltage control scheme must be envisaged by exploiting communication and control possibilities available for microgrid operation. The approach to implementing this type of voltage control is described in the next sections of this document.

Also, in order to be able to implement this strategy, several mechanisms need to be developed, namely the possibility of giving a fair remuneration for voltage control services. This topic is, however, out of the scope of this work.

Finally, operation must be optimized for both normal and emergency conditions, *i.e.* interconnected and islanded operation. The work developed so far comprises the possibility of DG and microgeneration contributing to voltage control in interconnected mode of operation.

3. Hierarchical Voltage Control

Some kind of hierarchical control should be established for voltage control in distribution systems with large penetration of DG and microgeneration, similarly to what happens in frequency control.

A hierarchic voltage control scheme may be divided into three control levels, according to areas of action and deployment time [2]. These three levels are presented next:

- Primary Voltage Control – It keeps the voltage within specified limits of the reference values. Automatic Voltage Regulators (AVRs) are used to control voltage in primary control and their action takes effect in a few seconds.
- Secondary Voltage Control – It has the main goal of adjusting, and maintaining, voltage profiles within an area and of minimizing reactive power flows. Its action can take up to a few minutes. The control actions associated with secondary control include modifying reference values for AVRs, DG units or microgrids (through the corresponding MGCCs),

switching Static VAR Compensators (SVCs) and adjusting On-Line Tap Changing (OLTC) transformers. Usually a reference bus is used to represent the voltage profile of a certain area in order to define the reference for secondary control.

- Tertiary Voltage Control – It has the goal of achieving an optimal voltage profile and of coordinating the secondary control in accordance to both technical and economical criteria. It may use an algorithm such as an Optimal Power Flow (OPF) routine. The time-frame of this control action is around some tens of minutes. The control variables used are generator voltage references, reference bus voltages and state of operation of reactive power compensators.

In Fig. 5, a scheme of the hierarchical voltage control architecture is presented.

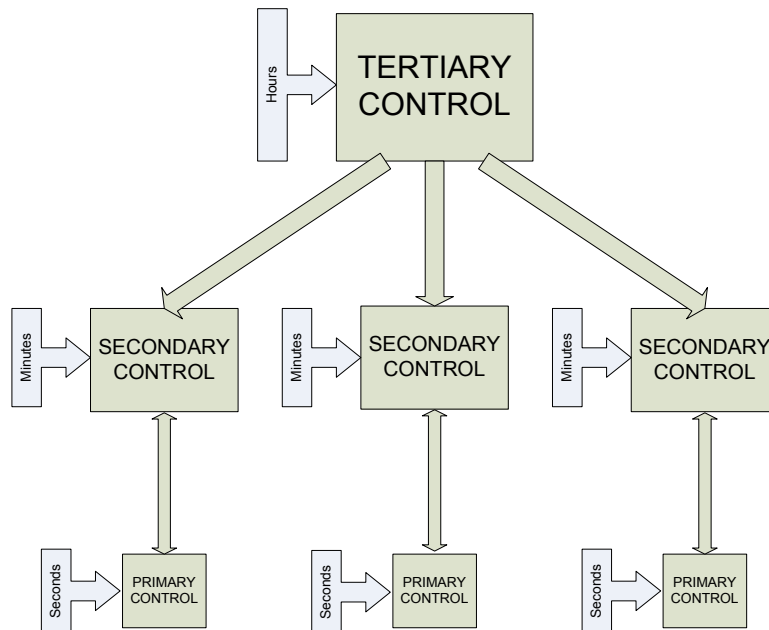


Fig. 5 – Hierarchical Voltage Control

The main subject to be addressed here is Secondary Voltage Control in multi-microgrids. These services may be provided in either grid-connected or emergency modes of operation. Tertiary Voltage Control services, however, may be provided but be active only in grid-connected mode.

The CAMC will have a key role in this task since it will have the ability to control the power flows of several microgrids (through the corresponding MGCCs) as well as the ability to control DG units, thus optimizing global system

operation of multi-microgrid systems (in order to minimize active power losses, reduce reactive power flows and improve voltage profiles).

The main aim of the implementation of this method is to ensure an optimized coordinated voltage control strategy between the several voltage levels in the distribution system.

4. Characterization of the Voltage VAR Control Problem

As stated above, a hierarchical voltage control scheme must be envisaged by exploiting communication and control possibilities available for microgrid operation. Such a method will enable dealing even with extreme situations, where microgrid penetration, combined with multiple DG sources, is so high that voltages raise considerably, especially in LV networks, leading to inadmissible voltage profiles.

This effect is particularly serious in rural networks, for it is known that the connection of DG fundamentally alters distribution network operation, thus creating several well-documented impacts, with voltage rise being the dominant one [4].

In these situations, reactive power control will not be adequate enough to maintain efficient system operation. In order to overcome this, active power management must also be used, by means of generation shedding, of both microgeneration and DG sources. Hence, a new procedure must be developed that includes optimizing operating conditions by using DG, microgrid and OLTC transformer control capabilities. Voltage control in multi-microgrids has a strong hierarchic structure that may imply dealing with voltage sub-areas, due mainly to the size of the electrical distribution systems. Once a solution has been found to the global problem, sub-solutions for individual microgrids are tested in order to evaluate their feasibility. If the voltage profiles are not satisfactory, a generation shedding scheme is used. The optimization procedure then requires a sequence of local sub-problems solutions and global problem solutions in order to converge to a near-optimum solution.

For the optimization procedure, the MV and LV networks are both fully modelled but are considered as being decoupled. This means that a solution at the MV level is tried first and then its feasibility at the LV side is tested. If the

solution is feasible, the solution is then kept. This avoids having to deal with a larger network comprising several different voltage levels. The main aim of this method is to achieve a coordinated strategy between the MV and LV levels in the distribution system.

In order to implement this notion, several preliminary studies were performed in order to assess the expected contributions from microgrids to the voltage support functionality.

Also, some initial assumptions concerning LV microgrid modelling were made and are presented next:

- Each LV microgrid was considered as a single bus with an equivalent generator (sum of all micro-source generations) and equivalent load (sum of all LV loads)
- Q limits for each microgrid consider a $\tan(\varphi) = 0,25$ based on the microgrid nominal active power generation

4.1 Mathematical Formulation

The mathematical formulation for the Voltage VAR control problem is presented next:

- Type of Problem: Mixed, non-linear minimization problem
- Control Variables: Reactive power generation in each active cell (microgrid or DG unit), transformer taps position (discrete variable) and capacitor banks level (discrete variable)
- Objective Function: Minimization of active power losses and/or improvement of voltage profiles and/or reduction of reactive power flows etc.
- Constraints: Technical (representing operational limits of equipments and other physical limits imposed to system operation)
 - o Voltage limits in all buses
 - o Reactive power generation limits for active cells
 - o Power flow limits in lines and transformers
 - o Transformer tap ratio limits
 - o Capacitor steps limits

Mathematically, this may be represented as follows:

min $OF(\underline{X})$

subject to:

$$V_i^{\min} \leq V_i \leq V_i^{\max}$$

$$S_{ik}^{\min} \leq S_{ik} \leq S_{ik}^{\max}$$

$$t_i^{\min} \leq t_i \leq t_i^{\max}$$

$$Q_i^{\min} \leq Q_i \leq Q_i^{\max}$$

where:

OF – Objective Function

$\underline{X}$ – Control variables

V_i – Voltage at Bus i

$V_i^{\min}, V_i^{\max}$ – Minimum and maximum voltage at bus i

S_{ik} – Power Flow in Branch ik

$S_{ik}^{\min}, S_{ik}^{\max}$ – Minimum and maximum power flows in Branch ik

t_i – Transformer tap of or capacitor step position

$t_i^{\min}, t_i^{\max}$ – Minimum and maximum tap

4.1.1 Defining an Objective Function

The definition of the Objective Function (OF) to be used by the algorithm should be the main concern when formulating the Voltage VAR control problem.

The most common goals for coordinated voltage/reactive power control are:

- Keep bus voltages within specified limits
- Control transformer, line and feeder loading
- Minimize active power losses
- Manage reactive power sources
- Control the power factor

Naturally, some of these objectives are conflicting objectives, so we are in fact dealing with a multi-objective problem.

One strategy that may be employed in order to conjugate these objectives is to combine them by creating a general OF with different weights for each

individual goal. This procedure turns a multi-objective problem into a single objective problem. The general OF has the following structure:

$$OF(\underline{X}) = w_1 \cdot OF(\underline{X}_1) + w_2 \cdot OF(\underline{X}_2) + \dots + w_n \cdot OF(\underline{X}_n)$$

where:

OF_i – Objective Function

w_i – Weight i

$\underline{X}_i$ – Control variable i

In order to build this global OF, it is necessary to normalize the individual OFs. This can be done in a simple way by dividing each value of each individual OF by the maximum value of the corresponding OF at each run of the algorithm.

The adjustment of the weights w_i allows favouring the objectives that are considered to be more important for the problem.

Obviously, all the weights have to have a unity sum.

Several studies need to be performed in order to be able to identify adequate values for the weights to use in the generic OF, depending on the test case network chosen.

The main objective functions (detailed next) considered in this work were:

- reducing active power losses
- maintaining voltage profiles

Reducing Active Power Losses

Managing adequately reactive power generation may reduce active power losses in distribution feeders. The optimization of reactive power flows to aid voltage support should be one of the main concerns of the algorithm.

Maintaining Voltage Profiles

In order to ensure the maintenance of voltage profiles within admissible limits, two different approaches may be envisaged.

One approach involves monitoring and controlling voltage at all buses in the network. This approach may not be suitable given the dimension of the network, as it may represent a computational burden for the algorithm.

Another approach that may be employed is dividing the network into several Voltage Control Areas (VCA) and selecting adequate Pilot Nodes. Pilot nodes are buses that are considered to be representative of the voltage profile in a given area [5]. Thus, controlling voltage at a pilot node enables to control voltage in a particular area of the network. This method is particularly useful if the size of the network is already a problem. In order to divide the network into VCAs, one may use a method such as electrical distance calculation [5], [6]. The method used for calculating electrical distances is presented in Annex I.

Consequently, one of these two strategies may be used for maintaining voltage profiles: controlling voltage at all buses or only at pilot buses.

4.1.2 Defining the Control Variables

The control variables used are:

- Reactive power from DG sources
- Reactive power from microgrid buses by means of capacitor banks located at the MV/LV transformer substation of each microgrid
- OLTC settings at distribution transformers

The vector of the control variables may then be:

$$Q_{\mu G1} | Q_{\mu G2} | \dots | Q_{\mu Gn} | Q_{DG1} | Q_{DG2} | \dots | Q_{DGm} | t_{transf1} | t_{transf2} | \dots | t_{transfo}$$

where:

$Q_{\mu Gi}$ – reactive power provided by microgrid i

Q_{DGi} – reactive power provided by DG unit i

$t_{transfi}$ – transformer tap value for transformer i

4.1.3 Optimization Tool

Several different optimization methods may be employed. In particular, one of two groups of methods may be chosen: methods based on conventional

optimization approaches and methods based on meta-heuristic processes. In this work, the latter group was selected for the implementation of the algorithm due to some specific characteristics that make it extremely useful for this type of problems.

Hence, the optimization procedure used here is based on a meta-heuristic called Evolutionary Particle Swarm Optimization (EPSO). This method is a powerful optimization algorithm developed at INESC Porto which combines traditional PSO strategies, developed by Kennedy and Eberhardt [7] and Genetic Algorithms, developed by Holland [8]. Thus, it combines the benefits from both PSO and Evolutionary Strategies, creating a very robust algorithm.

This algorithm has been extensively tested in recent years, applied to optimization problems in electrical power systems [9], [10].

In addition to the optimization algorithm based on an EPSO strategy, active power generation control is also performed by means of a generation shedding algorithm that acts in extreme situations where the voltage is outside the limits defined for safe operation (typically 10% for LV networks and 5% for MV networks). This generation shedding scheme is performed outside the main optimization function and it shed proportionally to the voltage deviation from the admissible range.

4.2 Methodology

The voltage support functionality is designed to be a real-time application to aid the DSO in managing the distribution network.

Nevertheless, the implementation of this functionality relies on 2 different stages:

- A preliminary stage where several studies are performed offline to evaluate the performance and the characteristics of the network in order to be able to select adequate parameters for the optimization problem formulation.
- A final stage that comprises the use of the optimization tool in real-time operation, made available to the operator.

As previously mentioned, in order to have an efficient means to control voltage in multi microgrid systems it is necessary to be able to control not only reactive power but also active power.

Active power control for volt/VAR control is based on generation shedding whenever voltage reaches inadmissible values due to high DG and microgrid penetration.

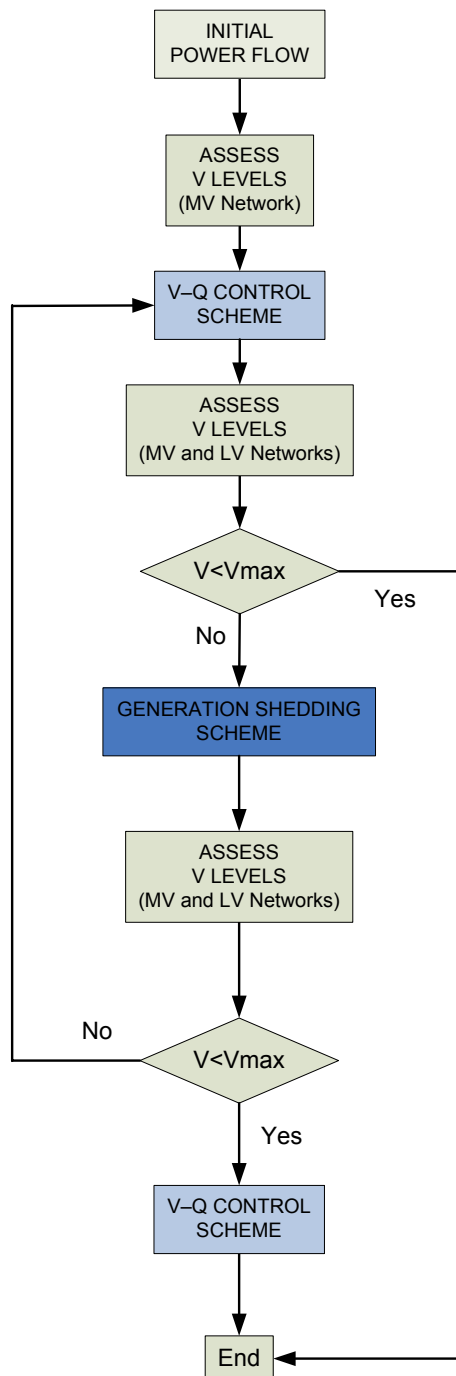


Fig. 6 – Algorithm for Volt/VAR Control

The methodology employed for this work is based in a combination of the EPSO algorithm for voltage support based on reactive power control (presented in Section 4.1) with a generation shedding algorithm, exploiting active power control, if the voltages in the network are over their admissible range.

This methodology is schematically described in Fig. 6.

The algorithm comprises 2 main steps: A V-Q Control Scheme and a Generation Shedding Scheme.

The V-Q scheme is a “soft” control based on the tuning of reactive power generation (from DG and microgrids) and on the setting of OLTC transformers and capacitor banks. It uses the EPSO algorithm to optimize operating conditions according to the chosen objective function, as seen in Section 4.1.

The Generation Shedding scheme is a “last resort” control strategy based on the shedding of active power generation in DG units and microgrids. The shedding is proportional to the voltage deviation from the admissible limits in DG and microgeneration buses.

Several iterations of the algorithm may be performed until no voltage violations are found.

Thus, the algorithm is terminated whenever voltage values reach admissible values.

5. Test Networks

In order to test the EPSO algorithm for volt/VAR control, two distribution networks must be used: one LV distribution network and one MV distribution network.

The algorithm here developed was first tested using the INESC Porto/ICCS-NTUA study-case MV network used in Task TD3.3 (Coordinated Frequency Support) and a study-case LV network used in Task TB3 (Online Security Assessment).

However, due to the very specific characteristics of this network (relatively small size, correctly dimensioned lines and transformers, moderate penetration of DG and microgeneration, etc.), it was not possible to test the EPSO algorithm for volt/VAR control to full extent.

In order to properly test the algorithm developed, two real networks were used. The two networks used were presented in WPG and WPH as the typical MV and LV rural networks and are shown in Fig. 7 and Fig. 8, respectively. Both networks have been slightly modified in order to accommodate large DG penetration (MV network) and large microgeneration penetration (LV network). The full data for these networks was provided by the Portuguese utility EDP and is presented in Deliverable DG1.

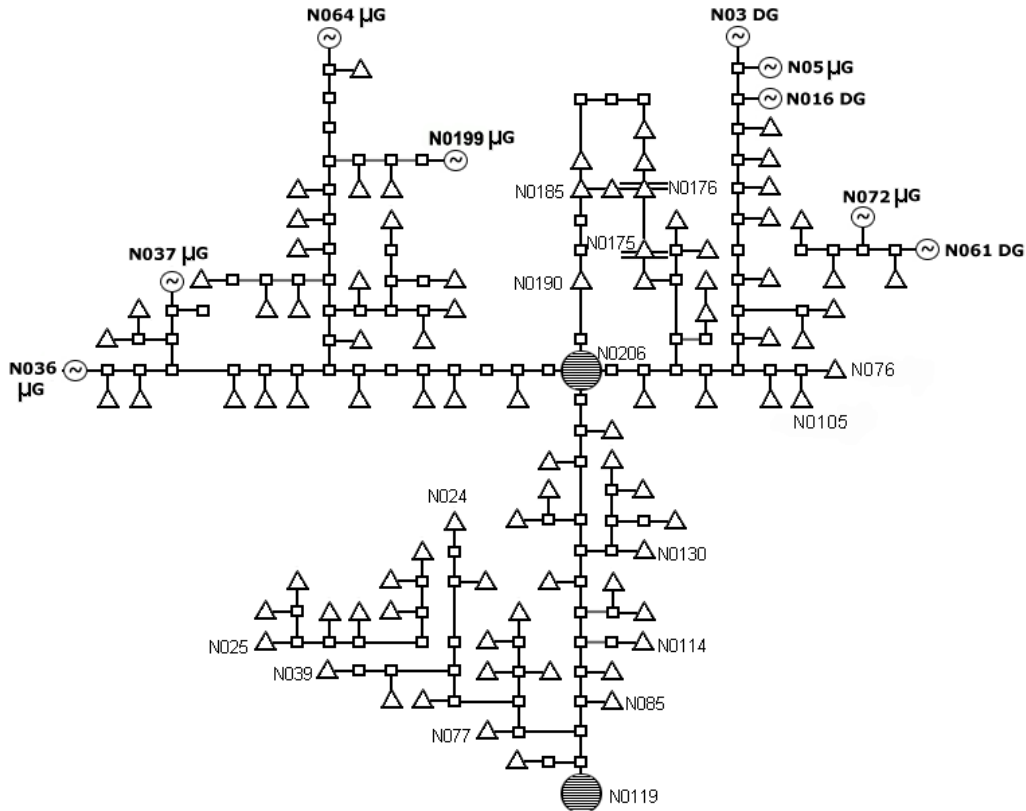


Fig. 7 – Rural MV Distribution Network (Multi-MicroGrid)

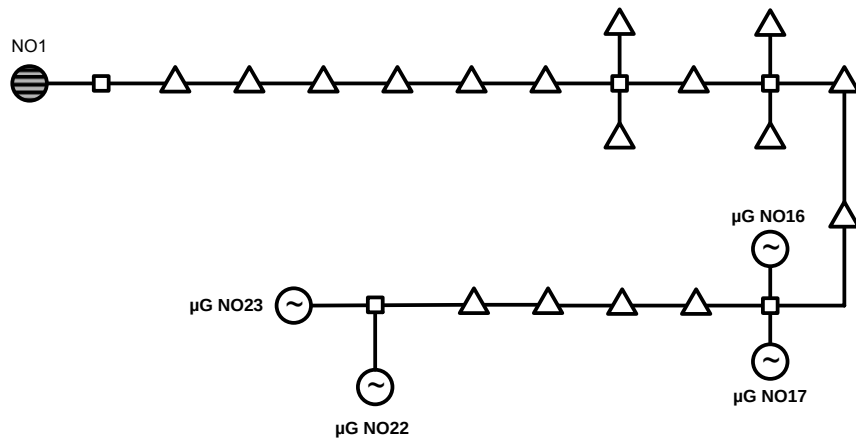


Fig. 8 – Rural LV Distribution Network (MicroGrid)

The MV network is a real rural network with 2 distinct areas with different voltage levels: 15kV and 30kV and a 30 kV/15 kV transformer at node 206.

The LV network is a typical, real rural network with a radial structure.

Scenarios with high DG and microgrid penetration were then developed in order to enable the analysis of the behaviour of the volt/VAR algorithm in extreme situations.

The characteristics of the DG and microgrid generation used for the base case are summarized in Table 1. This base case is used as the starting point for all simulations presented in Section 6.

Table 1 – DG and MicroGrid Characteristics

Node	Type	P (MW)	Pmax (MW)	Pmin (MW)	Q (MVAR)	Qmax (MVAR)	Qmin (MVAR)
5	μG	0,1	0,2	0	0,01	0,04	-0,02
36	μG	0,1	0,2	0	0,01	0,02	-0,02
37	μG	0,1	0,2	0	0,01	0,02	-0,02
64	μG	0,1	0,2	0	0,01	0,04	-0,02
72	μG	0,1	0,2	0	0,01	0,04	-0,02
199	μG	0,1	0,2	0	0,01	0,04	-0,02
3	DG	1,5	1,5	0	0	0,8	-0,4
16	DG	1,0	1,0	0	0	0,4	-0,2
61	DG	1,0	1,0	0	0	0,4	-0,2

The control variables used were:

- Reactive power at three DG buses (see Table 1)
- Reactive power at six microgrid buses, *i.e.* capacitor banks located at the MV/LV transformer substation of each microgrid (see also Table 1)
- OLTC settings at one transformer (node 206-2063)

Therefore, the control variables used are:

$$Q_{\mu G1} | Q_{\mu G2} | Q_{\mu G3} | Q_{\mu G4} | Q_{\mu G5} | Q_{\mu G6} | Q_{DG1} | Q_{DG2} | Q_{DG3} | t_{transf1}$$

where:

$Q_{\mu Gi}$ – reactive power provided by microgrid i

Q_{DG_i} – reactive power provided by DG unit i

$t_{transfi}$ – transformer tap value for transformer i

In addition, active power generation at DG and microgrid buses may be also controlled by means of generation shedding.

6. Results

In this work, two different multi-objective functions have been considered: **Objective Function 1 (OF1)**, which combines active power loss reduction (weight $w_1 = 0,33$) with maintenance of voltage profiles at all buses (weight $w_2 = 0,66$) and **Objective Function 2 (OF2)** that combines active power loss reduction (weight $w_1 = 0,33$) with maintenance of voltage profiles at pilot buses (weight $w_2 = 0,66$).

Preliminary studies have been conducted in order to be able to identify adequate values for the weights used in this particular case. Given the specific characteristics of the MV network used, the weight concerning the maintenance of voltage profiles is dominant, since the main problem regarding this particular case is the high voltage profiles in the MV and LV networks due to the high penetration of DG and microgeneration.

In addition, two scenarios have been developed for the networks presented in Section 5. One scenario corresponds to peak hours with higher consumption (**Peak**). The other corresponds to valley hours, with lower consumption but also lower microgrid generation (**Valley**), since microgeneration in this network is expected to be based only on micro-CHP and micro-wind generation at valley hours (micro-PV does not contribute in those periods). These scenarios were built in order to enable the analysis of the behaviour of the voltage control functionality in extreme situations.

6.1 Objective Function 1

The objective function considered involves the maintenance of voltage profiles within admissible limits at all buses in conjunction with the reduction of active power losses.

6.1.1 Peak Scenario

For this case, the main results obtained are presented in the next tables and figures.

Table 2 shows the active and reactive power generation in the nodes with microgrids and DG and the setting of the OLTC transformer, *i.e.* the values of the control variables for this optimization problem.

Note that a negative active power value P in Table 2 means that the microgrid is now consuming active power, instead of injecting active power such as in the base case situation.

Table 2 – Control Variables (OF1, Peak)

Node No	Control Type	Q (MVAR)	Q _{initial} (MVAR)	P (MW)	P _{initial} (Mw)	t	t _{initial}
5	Q _{μG}	0,0013	0,01	-0,0764	0,1	–	–
36	Q _{μG}	0,0074	0,01	0,1000	0,1	–	–
37	Q _{μG}	-0,0025	0,01	0,1000	0,1	–	–
64	Q _{μG}	0,0234	0,01	0,1000	0,1	–	–
72	Q _{μG}	0,0010	0,01	-0,0004	0,1	–	–
199	Q _{μG}	0,0146	0,01	0,1000	0,1	–	–
3	Q _{DG}	-0,2518	0	1,1066	1,5	–	–
16	Q _{DG}	-0,0682	0	0,7590	1,0	–	–
61	Q _{DG}	-0,0303	0	0,8735	1,0	–	–
206	t _{tap}	–	–	–	–	1,02	1,00

The reactive power generation and the transformer tap setting were adjusted by the V-Q control algorithm but the soft control strategy was not sufficient to ensure efficient operation within admissible voltage limits. Therefore, some generation shedding was also needed in order to aid the voltage support functionality. In total, 1,04 MW were shedded (corresponding to approximately 25% of the 4,1 MW total DG and microgrid generation). The shedding occurred for all DG sources (DG₁, DG₂ and DG₃) and for two microgrids (μG₁ and μG₅).

Fig. 9 shows the bus voltage in the buses where the voltage was higher prior to the action of the voltage control functionality. It may be seen that the

highest voltages can be significantly reduced with the application of the voltage support scheme. Fig. 10 shows the most relevant statistical data for voltage in the MV network.

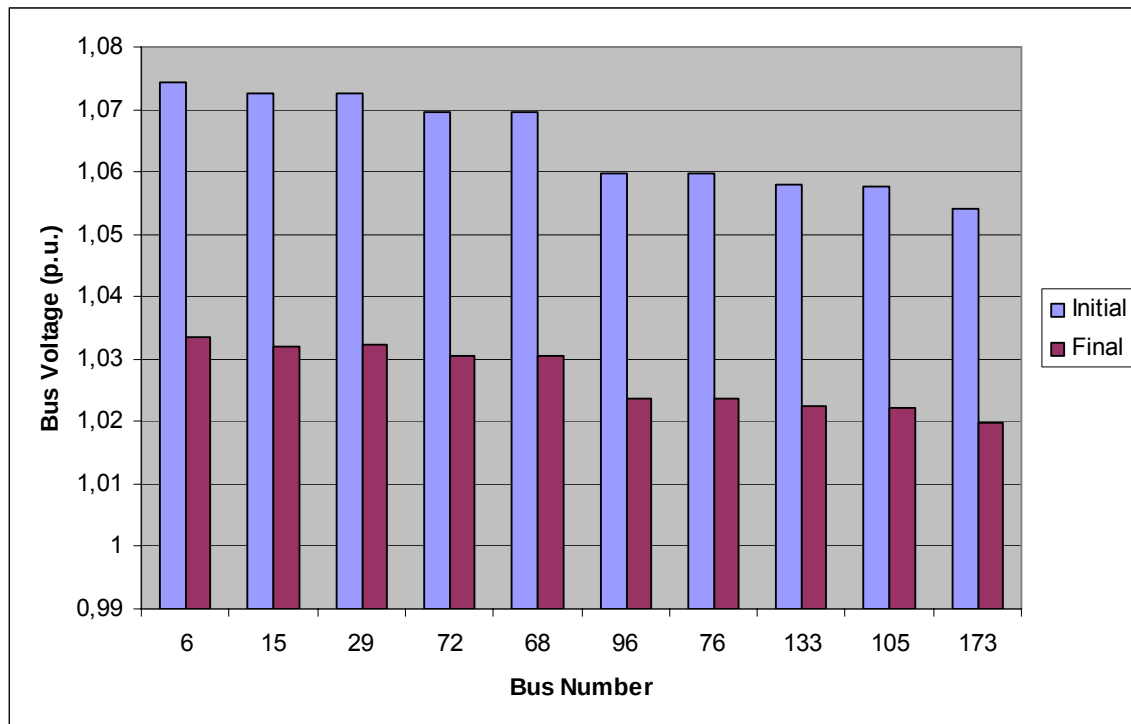


Fig. 9 – Ten Highest Voltages in the MV Network (OF1, Peak)

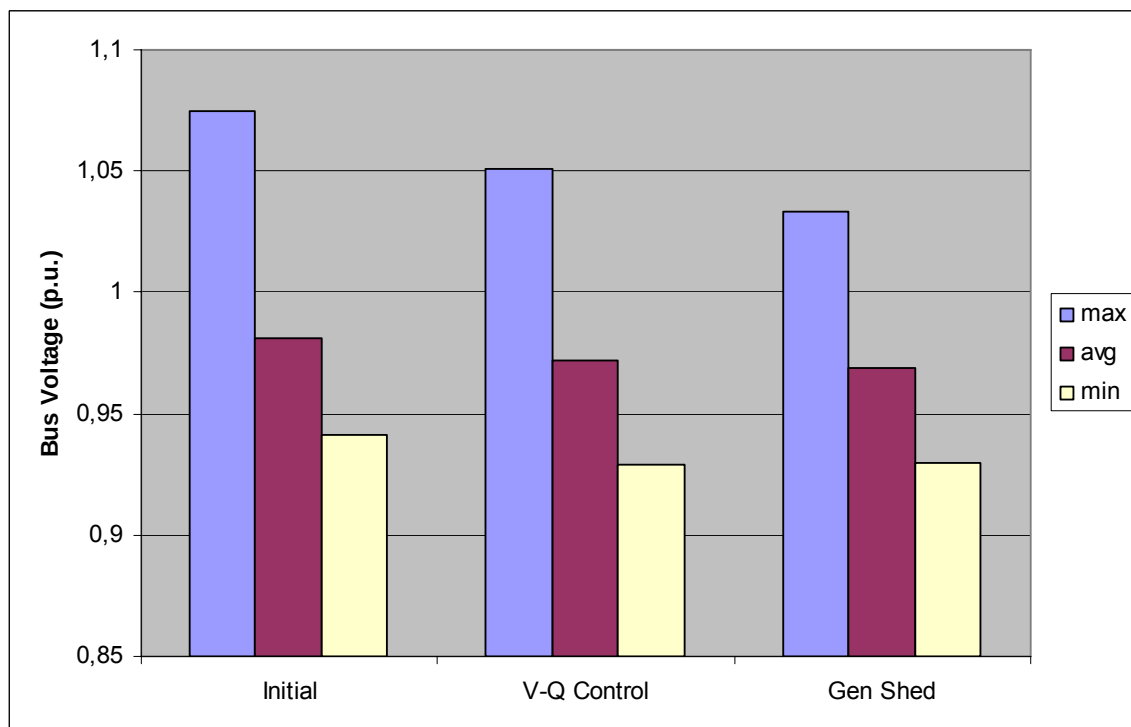


Fig. 10 – Voltage Profiles – Maximum, Average and Minimum Voltage – in the MV Network (OF1, Peak)

Fig. 11 illustrates the evolution of the voltage in the most loaded feeder in terms of voltage values, before and after the volt/VAR control scheme.

The total generation shed in this feeder was about 0,80 MW.

It may also be seen that the voltage increases starting from the injector node (NO119) until the end of the feeder (NO3). This happens because of the high DG and microgeneration penetration.

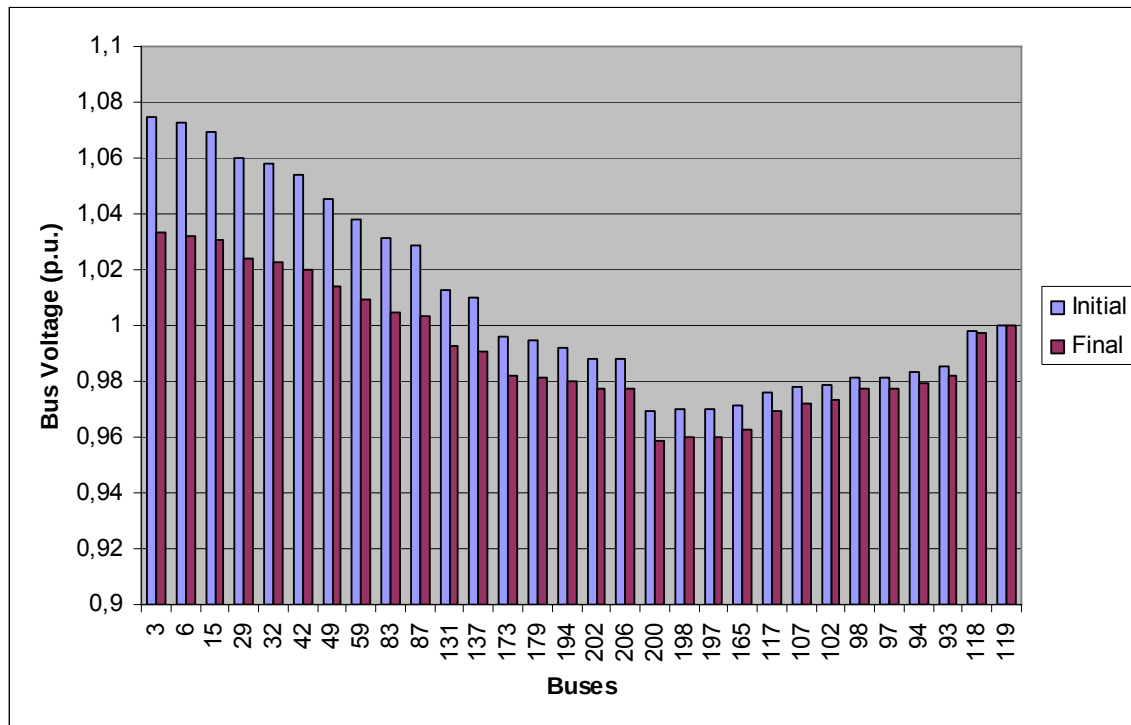


Fig. 11 – Voltage Values in the Worst Feeder in the MV Network (OF1, Peak)

Fig. 12 shows the active power losses in the MV network for each step of the control algorithm: V-Q control and generation shedding scheme. It may be seen that the losses rise in a first stage as a result of the improvement of the global voltage profiles. In a second stage, when generation is shed, the losses drop considerably. Apparently, this contradicts the general belief that the penetration of DG and microgeneration contributes to a reduction in active power losses. In fact, this is still valid. Although in this case, given the high initial penetration of DG and microgeneration (with a total of 4,1 MW) in face of the current demand (around 6,3 MW), the losses are higher.

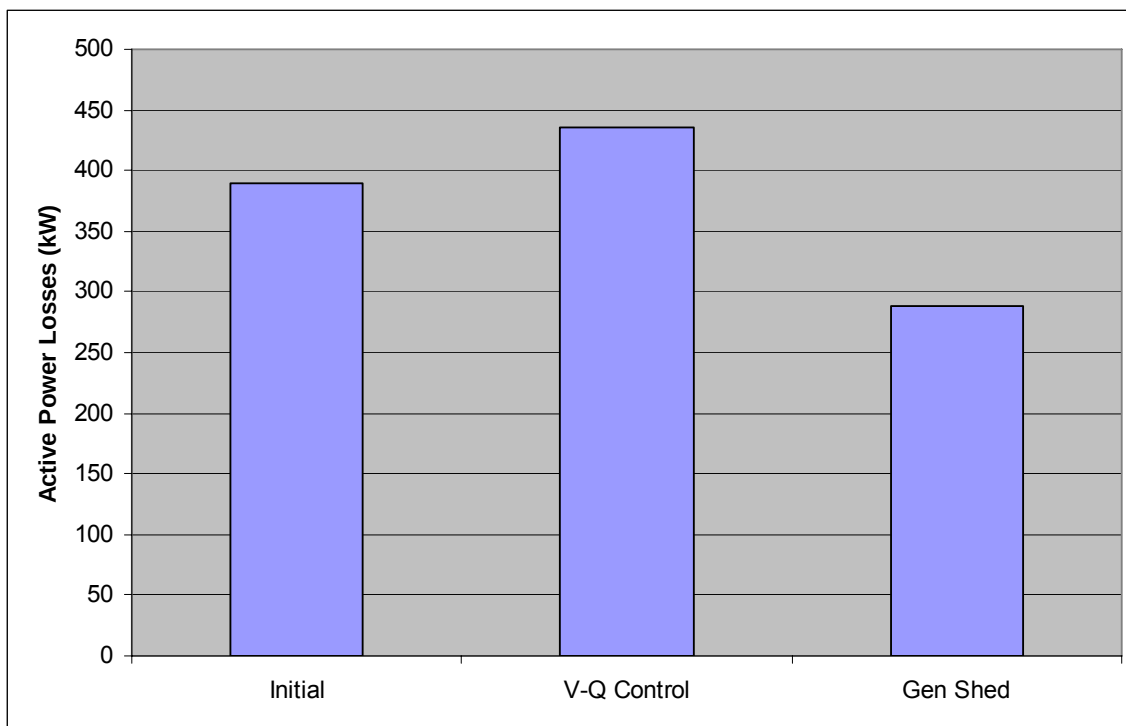


Fig. 12 – Active Power Losses in the MV Network (OF1, Peak)

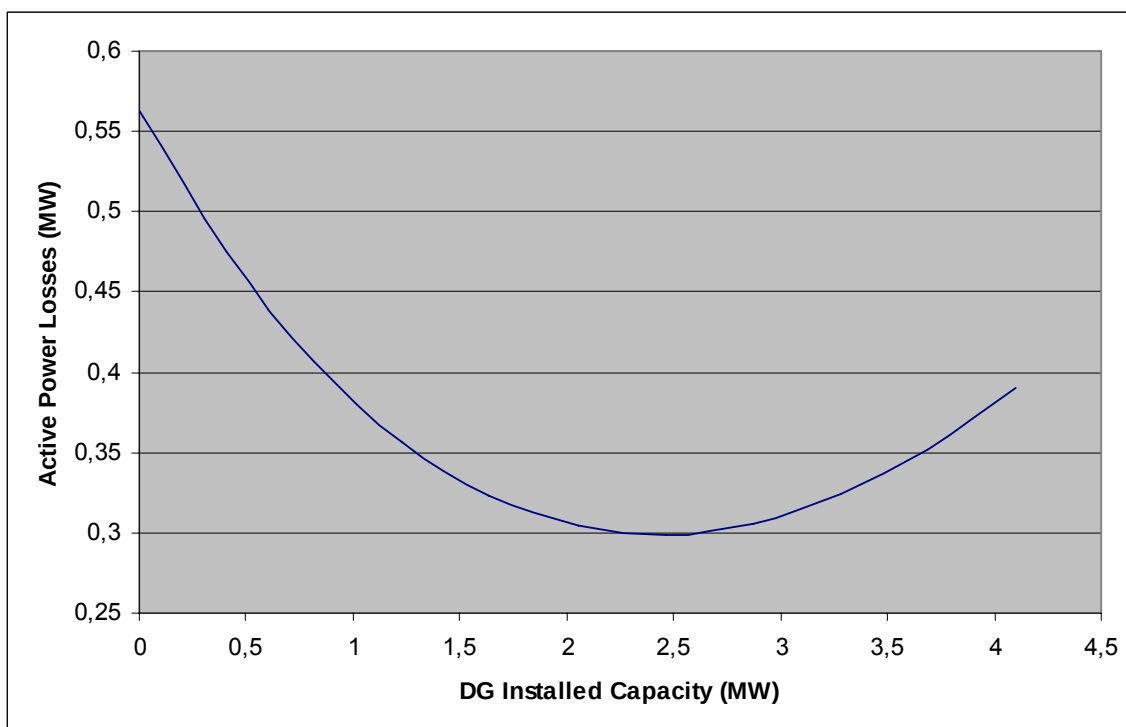


Fig. 13 – Evolution of MV Network Active Power Losses as a Function of DG Installed Capacity

The behaviour of the losses as a function of DG capacity (considering the sites for DG and microgeneration defined in Section 5) is shown in Fig. 13. This plot shows that for DG and microgeneration penetration under 2,5 MW, the

losses are reduced with the rise of the penetration level, but over that value begin increasing.

Concerning the LV network, the voltage profiles in the six microgrids for the two steps of the control algorithm are presented in Table 3. It may be seen that the voltages do not exceed the limit of 1,1 p.u. considered as the maximum admissible value for voltage in LV networks (the most critical cases concerning the microgrids with higher voltage profiles that needed microgeneration shedding are highlighted in the table).

Table 3 – Voltage Values in the LV Network (OF1, Peak)

LV Network		μG_1	μG_2	μG_3	μG_4	μG_5	μG_6
Initial	Max V (p.u.)	1,21	1,11	1,11	1,10	1,19	1,10
	Avg V (p.u.)	1,14	1,03	1,03	1,02	1,11	1,02
	Min V (p.u.)	1,07	0,95	0,95	0,95	1,04	0,95
V-Q Control	Max V (p.u.)	1,19	1,10	1,10	1,09	1,17	1,09
	Avg V (p.u.)	1,12	1,02	1,02	1,01	1,09	1,01
	Min V (p.u.)	1,05	0,94	0,94	0,94	1,02	0,94
Gen Shed	Max V (p.u.)	1,03	1,10	1,10	1,09	1,10	1,09
	Avg V (p.u.)	1,02	1,02	1,02	1,01	1,05	1,01
	Min V (p.u.)	1,01	0,94	0,94	0,94	1,01	0,94

Table 4 shows the active power losses in the six microgrids. It may be seen that the losses reduced significantly in the microgrids that had microgeneration shedding and increased only slightly in the others. This is once again due to the fact that microgeneration penetration was too high and the location was not ideal for an efficient operation of the grid.

Table 4 – Active Power Losses in the LV Network (OF1, Peak)

LV Network	P_{losses} (kW)					
	μG_1	μG_2	μG_3	μG_4	μG_5	μG_6
Initial	13,4	16,0	16,1	16,2	14,0	16,2
V-Q Control	13,9	16,0	16,1	16,2	14,0	16,2
Gen Shed	2,0	16,3	16,4	16,5	5,0	16,5

6.1.2 Valley Scenario

In this scenario, voltage profiles are more unfavourable than in the previous case. The main results obtained are presented in the next tables and figures.

Table 5 shows the active and reactive power generation in the nodes with microgrids and DG and the setting of the OLTC transformer, *i.e.* the values of the control variables for this optimization problem.

Table 5 – Control Variables (OF1, Valley)

Node No	Control Type	Q (MVAR)	Q _{initial} (MVAR)	P (MW)	P _{initial} (Mw)	t	t _{initial}
5	Q _{μG}	-0,0089	0,01	-0,0592	0,08	–	–
36	Q _{μG}	0,0147	0,01	0,0800	0,08	–	–
37	Q _{μG}	0,0120	0,01	0,0800	0,08	–	–
64	Q _{μG}	-0,0104	0,01	0,0800	0,08	–	–
72	Q _{μG}	0,0177	0,01	-0,0051	0,08	–	–
199	Q _{μG}	-0,0023	0,01	0,0800	0,08	–	–
3	Q _{DG}	0,0582	0	1,1167	1,5	–	–
16	Q _{DG}	-0,0597	0	0,7645	1,0	–	–
61	Q _{DG}	0,3653	0	0,8638	1,0	–	–
206	t _{tap}	–	–	–	–	1,00	1,00

As in the previous scenario, the reactive power generation and the transformer tap setting were adjusted by the V-Q control algorithm but the soft control strategy was not sufficient to ensure efficient operation within admissible voltage limits. Therefore, one step of generation shedding was needed. In total, 1,00 MW were shed (corresponding to approximately 25% of the 3,98 MW total DG and microgrid generation). The shedding occurred in all DG sources and all microgrids.

Fig. 14 shows the bus voltage in the buses where the voltage was higher prior to the action of the voltage control functionality. It may be seen that the highest voltages can be significantly reduced with the application of the voltage support scheme. Fig. 15 shows the most relevant statistical data for voltage in the MV network.

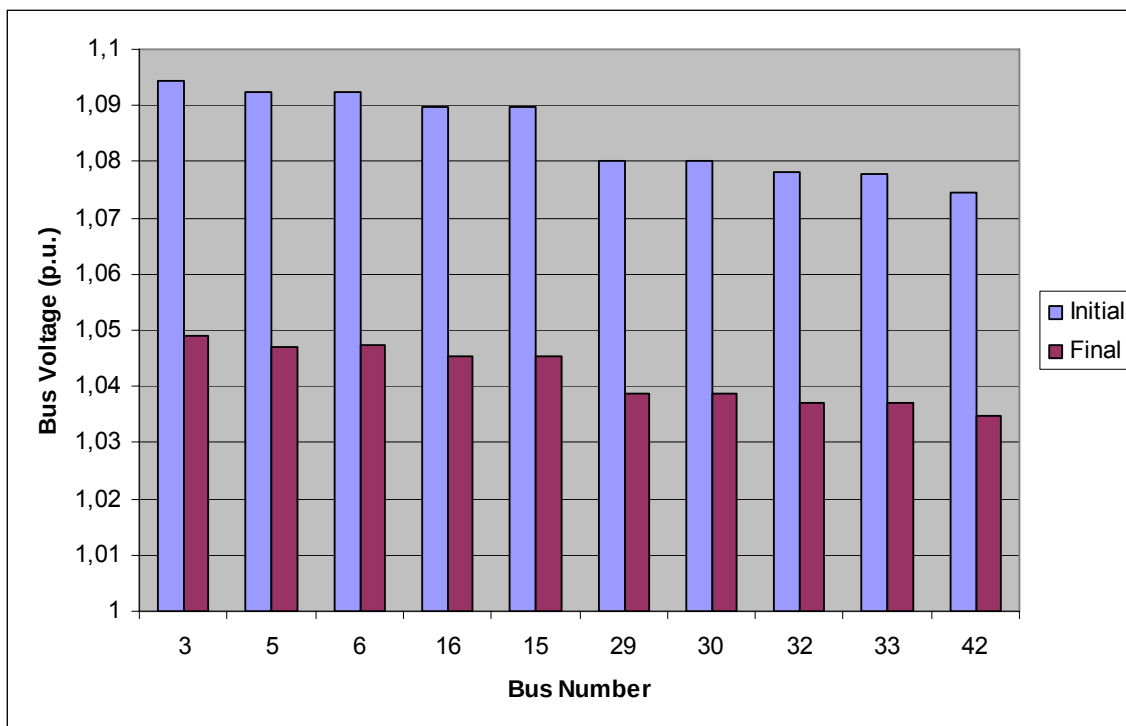


Fig. 14 – Ten Highest Voltages in the MV Network (OF1, Valley)

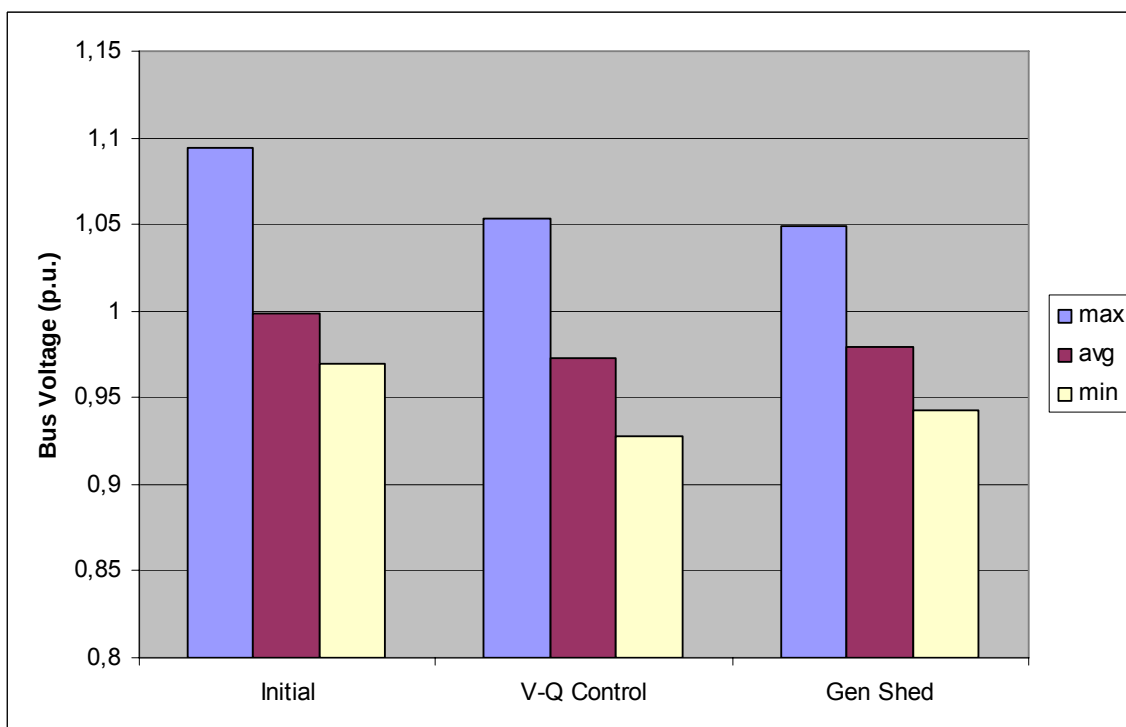


Fig. 15 – Voltage Profiles – Maximum, Average and Minimum Voltage – in the MV Network (OF1, Valley)

Fig. 16 illustrates the evolution of the voltage in the most loaded feeder in terms of voltage values, before and after the volt/VAR control scheme.

The total generation shed in this feeder was about 0,76 MW.

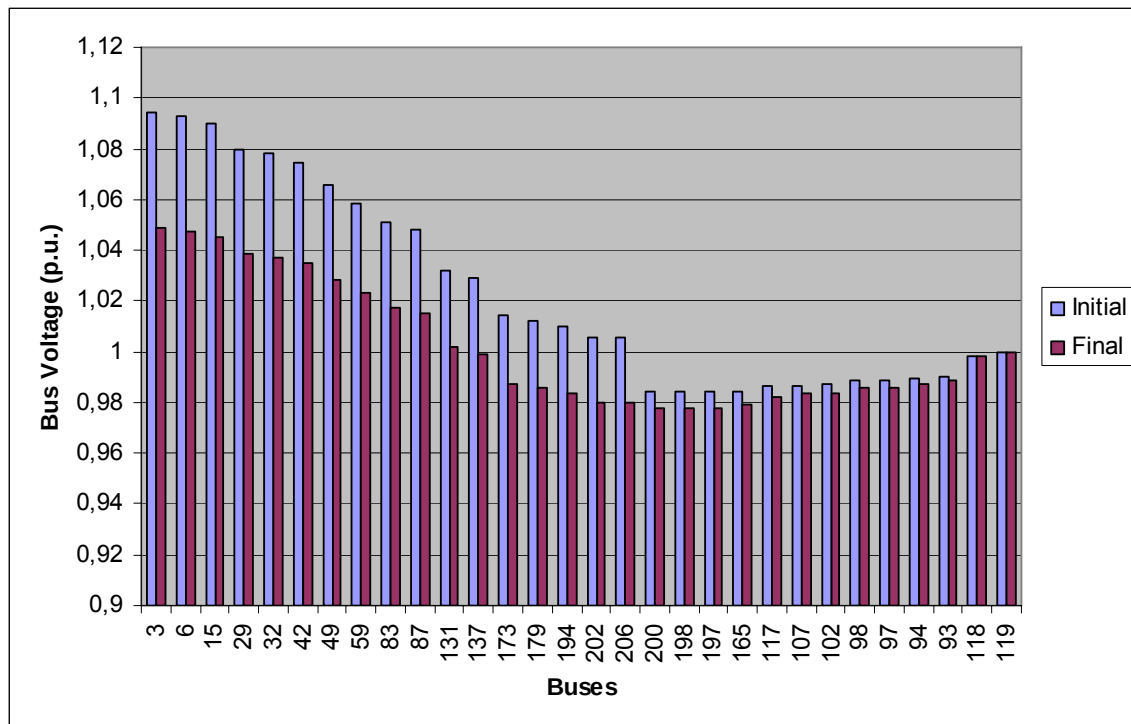


Fig. 16 – Voltage Values in the Worst Feeder in the MV Network (OF1, Valley)

Fig. 17 shows the active power losses in the MV network for each step of the control algorithm: V-Q control and generation shedding scheme. The losses develop similarly to what happened in the previous case and for the same reason, since a figure similar to Fig. 13 could be obtained for this scenario.

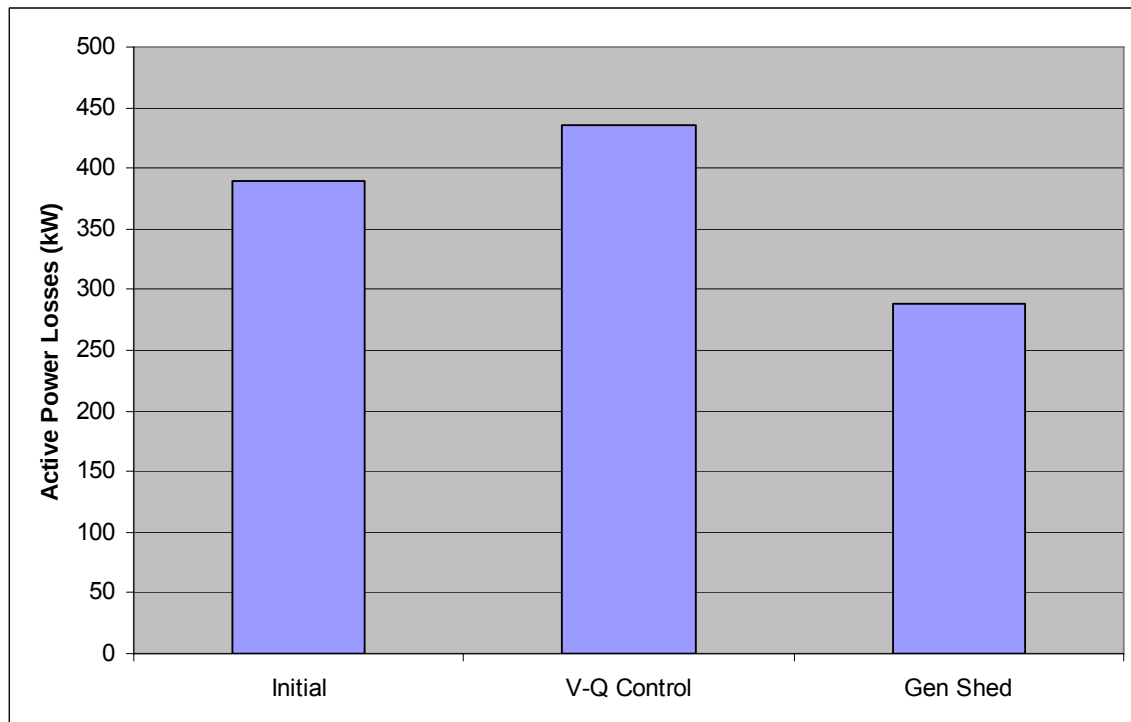


Fig. 17 – Active Power Losses in the MV Network (OF1, Valley)

Concerning the LV network, the voltage profiles in the six microgrids for the two steps of the control algorithm are presented in Table 6. It may be seen that the voltages do not exceed the limit of 1,1 p.u. considered as the maximum admissible value for voltage in LV networks (the critical cases concerning the microgrids with high voltage profiles that needed microgeneration shedding are highlighted in the table).

Table 6 – Voltage Values in the LV Network (OF1, Valley)

LV Network		μG_1	μG_2	μG_3	μG_4	μG_5	μG_6
Initial	Max V (p.u.)	1,21	1,10	1,10	1,10	1,18	1,10
	Avg V (p.u.)	1,15	1,04	1,04	1,03	1,12	1,03
	Min V (p.u.)	1,09	0,98	0,98	0,98	1,06	0,97
V-Q Control	Max V (p.u.)	1,17	1,07	1,07	1,06	1,14	1,06
	Avg V (p.u.)	1,11	1,00	1,00	1,00	1,08	0,99
	Min V (p.u.)	1,05	0,94	0,94	0,93	1,03	0,93
Gen Shed	Max V (p.u.)	1,05	1,08	1,08	1,08	1,09	1,08
	Avg V (p.u.)	1,04	1,01	1,01	1,01	1,05	1,01
	Min V (p.u.)	1,03	0,95	0,95	0,95	1,03	0,95

Table 7 shows the active power losses in the 6 microgrids. It may be seen that the losses were significantly reduced in all microgrids, since there was microgeneration shedding in all microsources.

Table 7 – Active Power Losses in the LV Network (OF1, Valley)

LV Network	P_{losses} (kW)					
	μG_1	μG_2	μG_3	μG_4	μG_5	μG_6
Initial	8,7	10,4	10,4	10,4	9,1	10,4
V-Q Control	9,2	11,1	11,1	11,2	9,6	11,2
Gen Shed	1,2	10,8	10,8	10,9	2,9	10,9

6.2 Objective Function 2

The objective function considered involves the maintenance of voltage profiles within admissible limits at pilot buses in conjunction with the reduction of active power losses.

The location of the pilot buses (marked in red), defined according to the methodology described previously, is shown in Fig. 18.

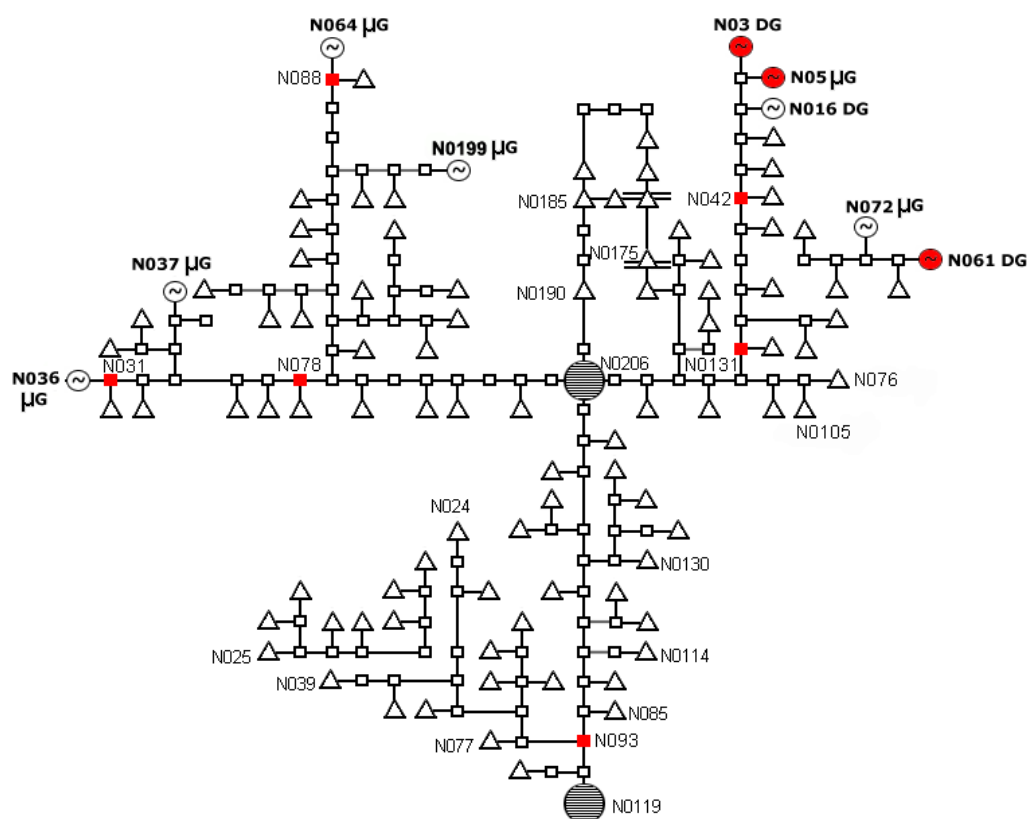


Fig. 18 – Pilot Buses in the MV Network (OF2)

6.2.1 Peak Scenario

For this case, the main results obtained are presented in the next tables and figures.

Table 8 – Control Variables (OF2, Peak)

Node No	Control Type	Q (MVAR)	Q _{initial} (MVAR)	P (MW)	P _{initial} (Mw)	t	t _{initial}
5	Q _{μG}	-0,0091	0,01	-0,0723	0,1	–	–
36	Q _{μG}	-0,0087	0,01	0,1000	0,1	–	–
37	Q _{μG}	-0,0022	0,01	0,1000	0,1	–	–
64	Q _{μG}	0,0266	0,01	0,1000	0,1	–	–
72	Q _{μG}	-0,0014	0,01	-0,0107	0,1	–	–
199	Q _{μG}	0,0116	0,01	0,1000	0,1	–	–
3	Q _{DG}	-0,3099	0	1,1236	1,5	–	–
16	Q _{DG}	-0,1049	0	0,7673	1,0	–	–
61	Q _{DG}	0,2462	0	0,8584	1,0	–	–
206	t _{tap}	–	–	–	–	1,02	1,00

Again, the reactive power generation and the transformer tap setting were adjusted by the V-Q control algorithm but the soft control strategy was not sufficient to ensure efficient operation within admissible voltage limits. Therefore, some generation shedding was also needed in order to aid the voltage support functionality. In total, 1,04 MW were shed (corresponding to approximately 25% of the 4,1 MW total DG and microgrid generation). The shedding occurred for all DG sources (DG₁, DG₂ and DG₃) and for two microgrids (μ G₁ and μ G₅).

Fig. 19 shows the bus voltage at the pilot buses. It may be seen that the highest voltages can be significantly reduced but at the expense of the lowest voltages that also have to decrease. This behaviour is expected, as the main problem with this network is the general high voltage profile. Fig. 20 shows the most relevant statistical data for voltage in the MV network.

Fig. 21 illustrates the evolution of the voltage in the most loaded feeder in terms of voltage values, before and after the volt/VAR control scheme.

The total generation shed in this feeder was about 0,80 MW.

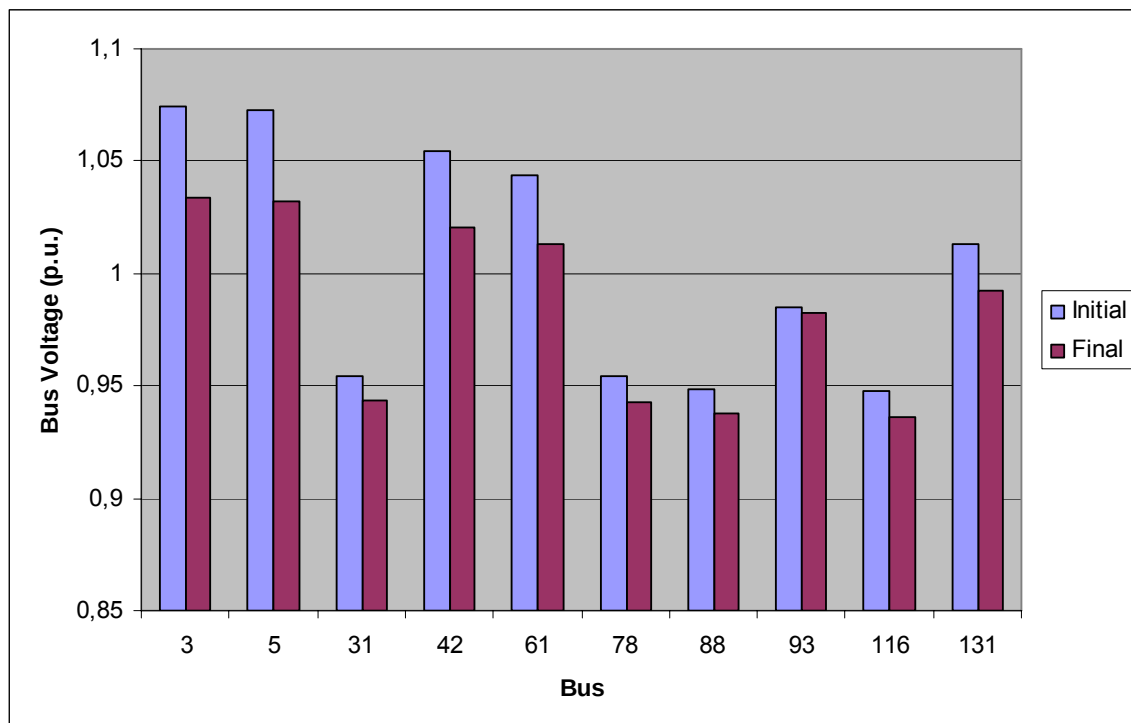


Fig. 19 – Voltages at the Pilot Buses in the MV Network (OF2, Peak)

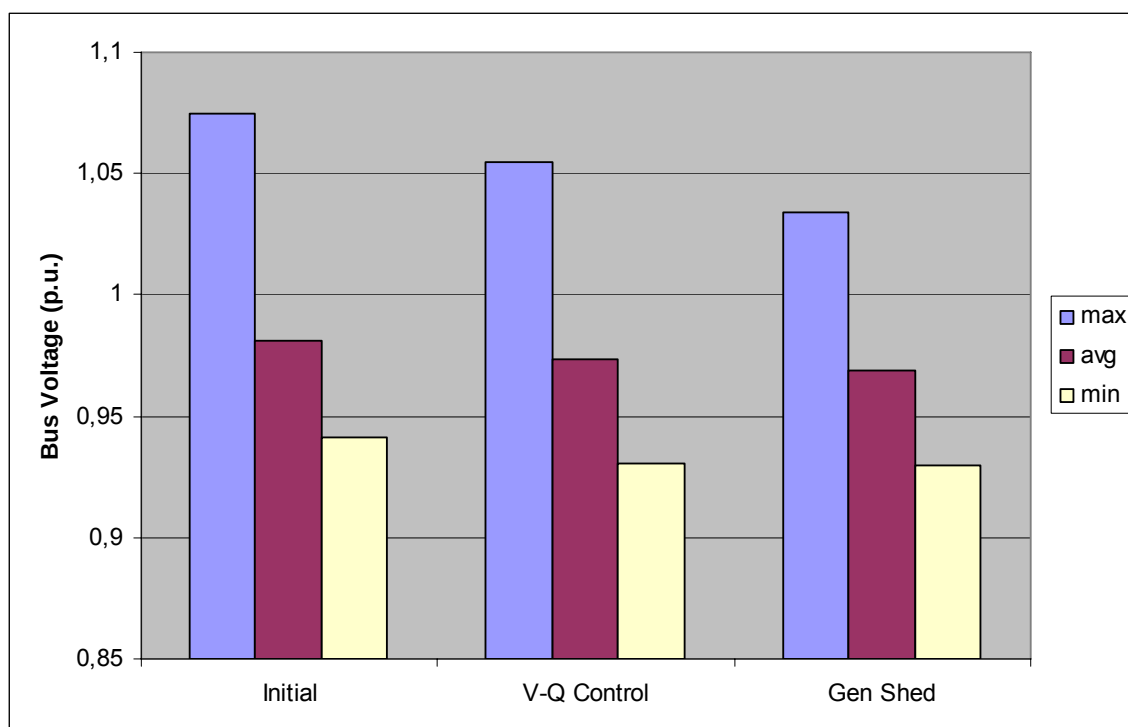


Fig. 20 – Voltage Profiles – Maximum, Average and Minimum Voltage – in the MV Network (OF2, Peak)

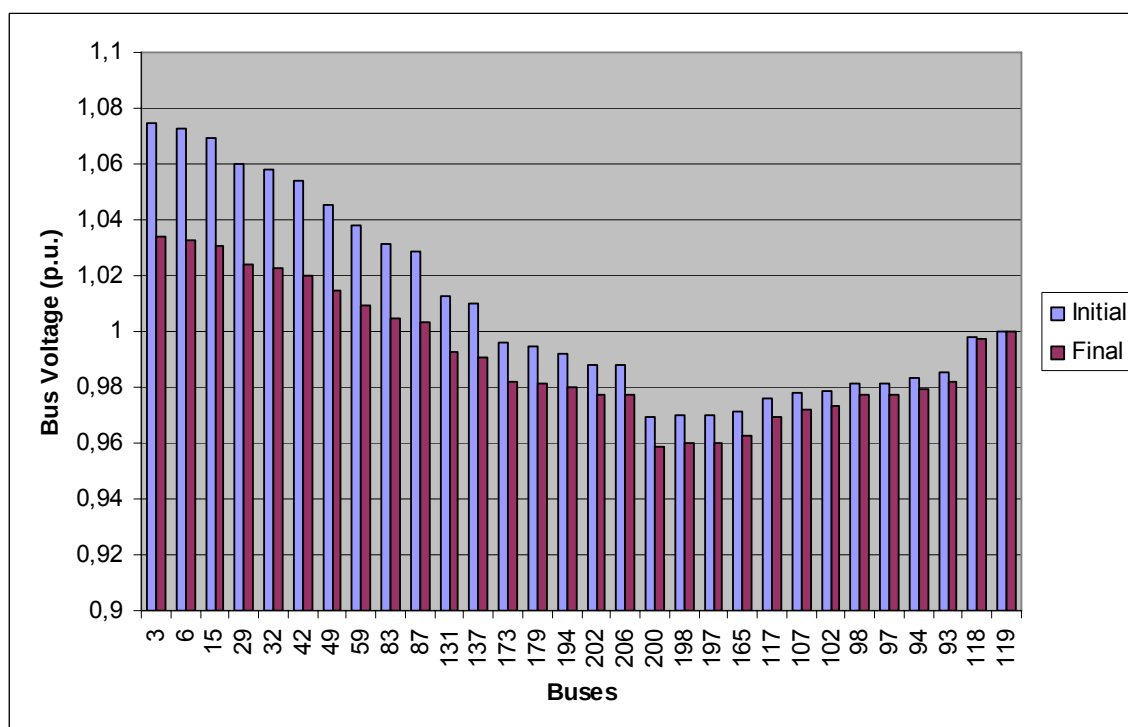


Fig. 21 – Voltage Values in the Worst Feeder in the MV Network (OF2, Peak)

Fig. 22 shows the active power losses in the MV network. Again, the losses develop similarly to what happens in the previous case and for the same reason.

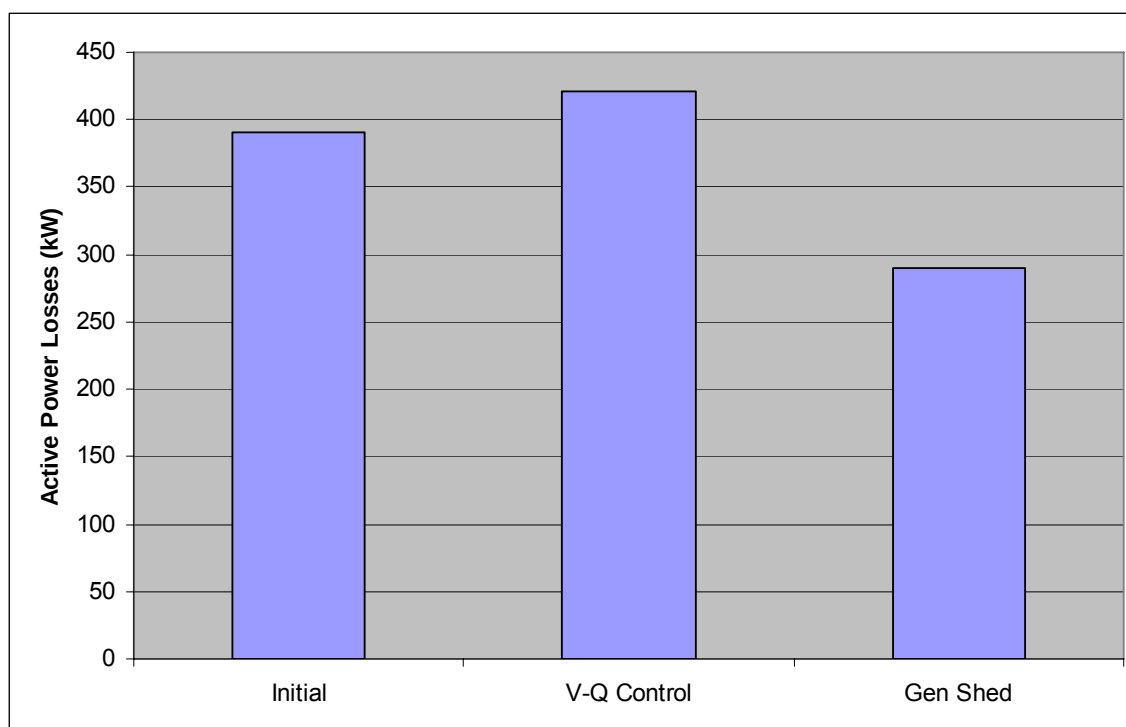


Fig. 22 – Active Power Losses in the MV Network (OF2, Peak)

Concerning the LV network, the voltage profiles in the six microgrids for the two steps of the control algorithm are presented in Table 9. It may be seen that the voltages do not exceed the limit of 1,1 p.u. considered as the maximum admissible value for voltage in LV networks (the most critical cases concerning the microgrids with higher voltage profiles that needed microgeneration shedding are highlighted in the table).

Table 9 – Voltage Values in the LV Network (OF2, Peak)

LV Network		μG_1	μG_2	μG_3	μG_4	μG_5	μG_6
Initial	Max V (p.u.)	1,21	1,11	1,11	1,10	1,19	1,10
	Avg V (p.u.)	1,14	1,03	1,03	1,02	1,11	1,02
	Min V (p.u.)	1,07	0,95	0,95	0,95	1,04	0,95
V-Q Control	Max V (p.u.)	1,20	1,10	1,10	1,10	1,17	1,09
	Avg V (p.u.)	1,12	1,02	1,02	1,01	1,10	1,01
	Min V (p.u.)	1,05	0,94	0,94	0,94	1,03	0,94
Gen Shed	Max V (p.u.)	1,04	1,10	1,10	1,09	1,09	1,09
	Avg V (p.u.)	1,02	1,02	1,02	1,01	1,04	1,01
	Min V (p.u.)	1,01	0,94	0,94	0,94	1,01	0,94

Table 10 shows the active power losses in the 6 microgrids. It may be seen that the losses reduced significantly in the microgrids that had microgeneration shedding and increased only slightly in the others.

Table 10 – Active Power Losses in the LV Network (OF2, Peak)

LV Network	P _{losses} (kW)					
	μG_1	μG_2	μG_3	μG_4	μG_5	μG_6
Initial	13,4	16,0	16,1	16,2	14,0	16,2
V-Q Control	13,8	16,3	16,4	16,5	14,3	16,5
Gen Shed	1,8	16,3	16,4	16,5	4,2	16,5

For the peak scenario, comparing the results obtained through the control of voltage at all buses (OF1) and controlling only voltage at pilot buses (OF2), one can conclude that the results are extremely close. This means that it is in fact sufficient to monitor voltage at only specific nodes, given that the selection procedure is adequate as the one that was proposed in this work. In addition, this method reduces simulation time.

6.2.2 Valley Scenario

In this scenario, voltage profiles are more unfavourable than in the previous case. The main results obtained are presented next.

Table 11 – Control Variables (OF2, Valley)

Node No	Control Type	Q (MVAR)	Q _{initial} (MVAR)	P (MW)	P _{initial} (Mw)	t	t _{initial}
5	Q _{μG}	0,0067	0,01	-0,0535	0,08	–	–
36	Q _{μG}	0,0062	0,01	0,0800	0,08	–	–
37	Q _{μG}	0,0159	0,01	0,0800	0,08	–	–
64	Q _{μG}	-0,0156	0,01	0,0800	0,08	–	–
72	Q _{μG}	0,0104	0,01	-0,0193	0,08	–	–
199	Q _{μG}	-0,0048	0,01	0,0800	0,08	–	–
3	Q _{DG}	-0,3238	0	1,1461	1,5	–	–
16	Q _{DG}	-0,1582	0	0,7769	1,0	–	–
61	Q _{DG}	0,0836	0	0,8416	1,0	–	–
206	t _{tap}	–	–	–	–	1,03	1,00

Table 11 shows the active and reactive power generation in the nodes with microgrids and DG and the setting of the OLTC transformer, *i.e.* the values of the control variables for this optimization problem.

The reactive power generation and the transformer tap setting were adjusted by the V-Q control algorithm but the soft control strategy was not sufficient to ensure efficient operation within admissible voltage limits. Therefore, one step of generation shedding was needed. In total, 1,00 MW were shed (corresponding to approximately 25% of the 3,98 MW total DG and microgrid generation). The shedding occurred in all DG sources and all microgrids.

Fig. 23 shows the bus voltage at the pilot buses. Once again, it may be seen that the highest voltages can be significantly reduced but at the expense of the lowest voltages which also have to decrease. Fig. 24 shows the most relevant statistical data for voltage in the MV network.

Fig. 25 illustrates the evolution of the voltage in the most loaded feeder in terms of voltage values, before and after the volt/VAR control scheme.

The total generation shed in this feeder was about 1,39 MW.

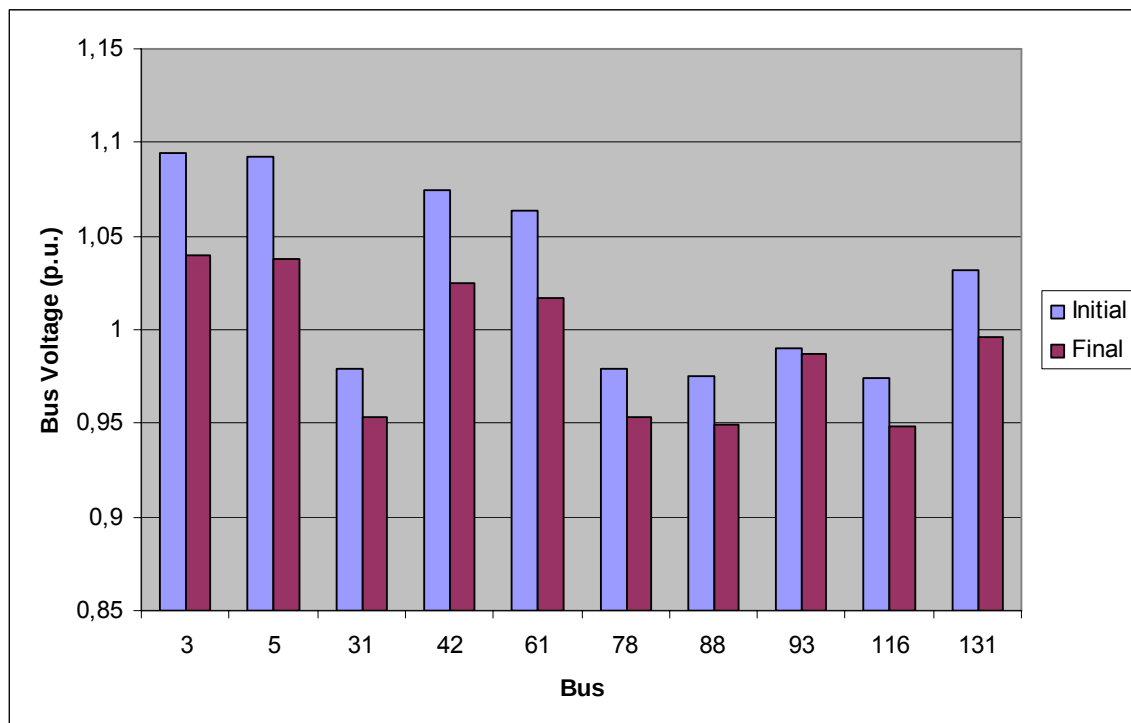


Fig. 23 – Voltages at the Pilot Buses in the MV Network (OF2, Valley)

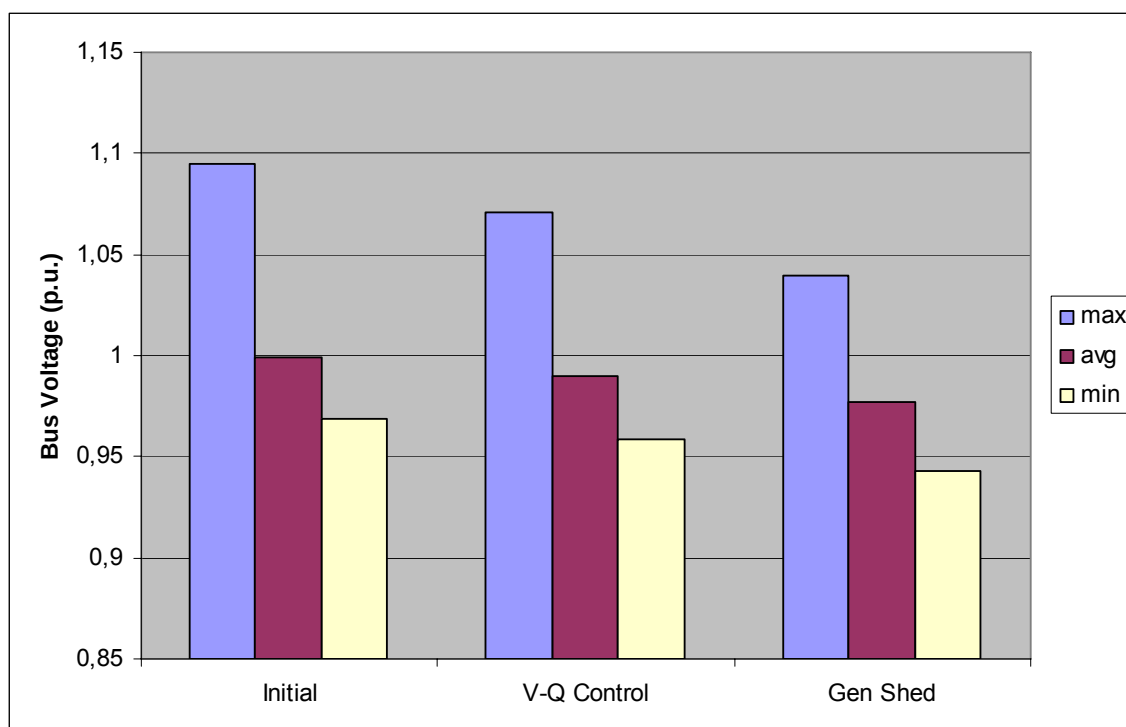


Fig. 24 – Voltage Profiles – Maximum, Average and Minimum Voltage – in the MV Network (OF2, Valley)

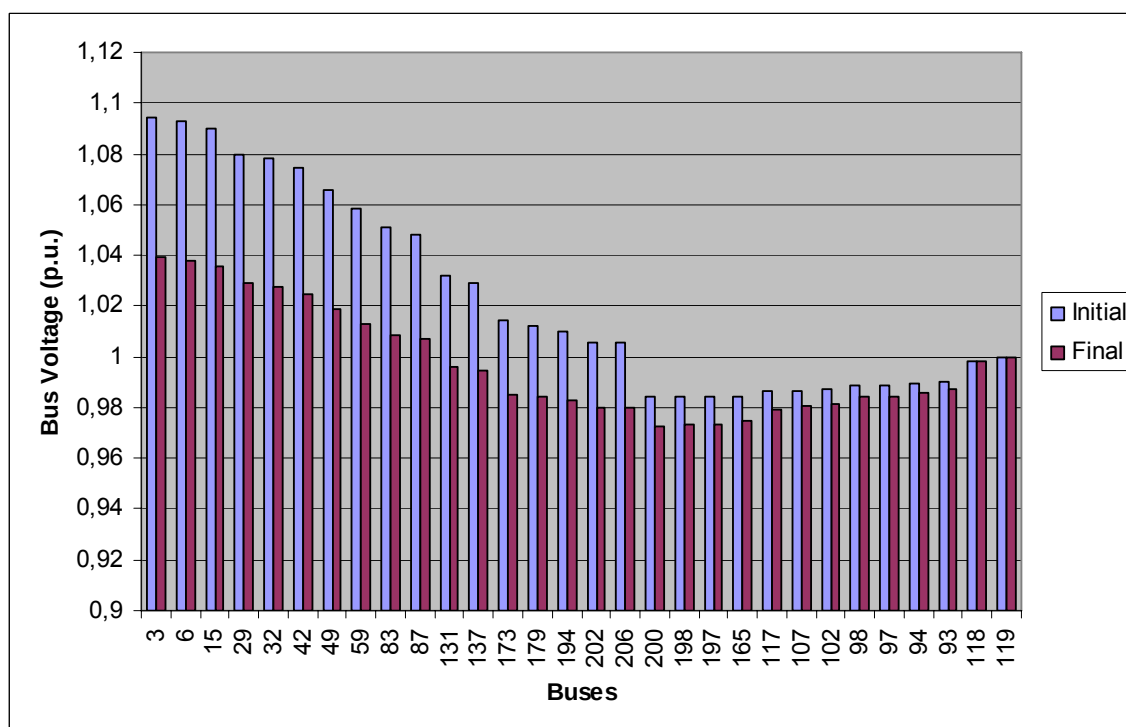


Fig. 25 – Voltage Values in the Worst Feeder in the MV Network (OF2, Valley)

Fig. 26 shows the active power losses in the MV network. Again, the losses develop similarly to what happened in the previous case and for the same reason.

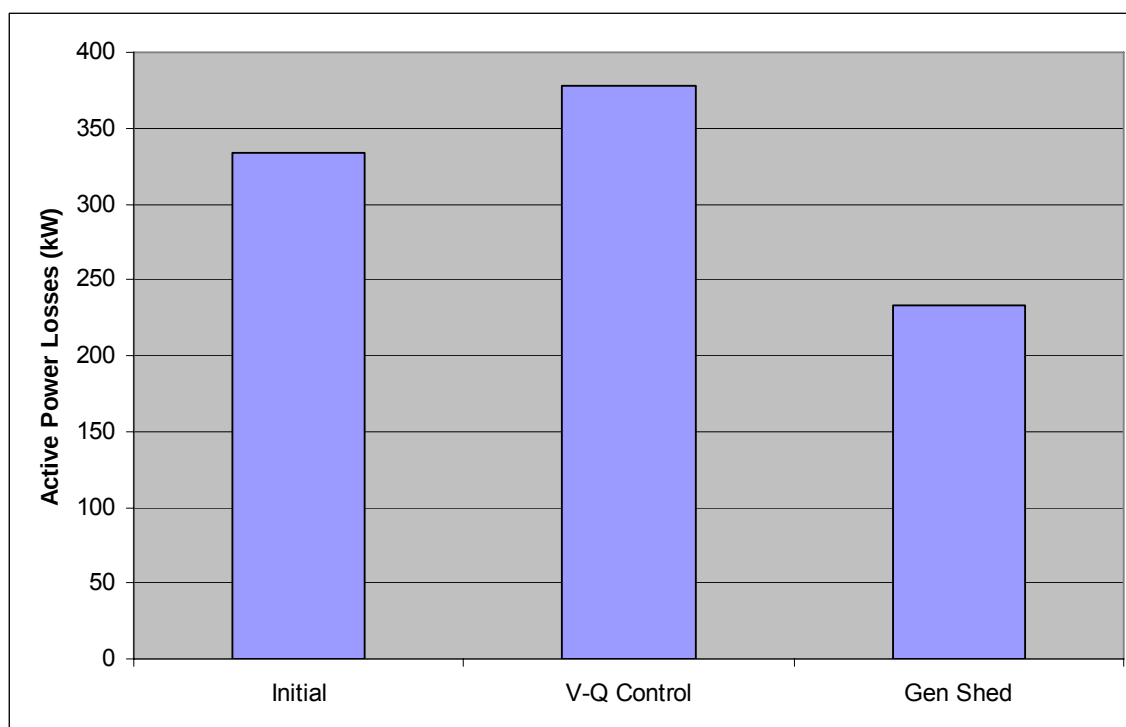


Fig. 26 – Active Power Losses in the MV Network (OF2, Valley)

Concerning the LV network, the voltage profiles in the 6 microgrids for the 2 steps of the control algorithm are presented in Table 12. It may be seen that the voltages do not exceed the limit of 1,1 p.u. considered as the maximum admissible value for voltage in LV networks (the critical cases concerning the microgrids with high voltage profiles that needed microgeneration shedding are highlighted in the table).

Table 12 – Voltage Values in the LV Network (OF2, Valley)

LV Network		μG_1	μG_2	μG_3	μG_4	μG_5	μG_6
Initial	Max V (p.u.)	1,21	1,10	1,10	1,10	1,18	1,10
	Avg V (p.u.)	1,15	1,04	1,04	1,03	1,12	1,03
	Min V (p.u.)	1,09	0,98	0,98	0,98	1,06	0,97
V-Q Control	Max V (p.u.)	1,18	1,09	1,09	1,09	1,16	1,09
	Avg V (p.u.)	1,12	1,03	1,03	1,02	1,10	1,02
	Min V (p.u.)	1,07	0,97	0,97	0,96	1,04	0,96
Gen Shed	Max V (p.u.)	1,05	1,08	1,08	1,08	1,07	1,08
	Avg V (p.u.)	1,04	1,01	1,01	1,01	1,03	1,01
	Min V (p.u.)	1,03	0,95	0,95	0,95	1,02	0,95

Table 13 shows the active power losses in the 6 microgrids. It may be seen that the losses were significantly reduced in all microgrids, since there was microgeneration shedding in all microsources.

Table 13 – Active Power Losses in the LV Network (OF2, Valley)

LV Network	P _{losses} (kW)					
	μG_1	μG_2	μG_3	μG_4	μG_5	μG_6
Initial	8,7	10,4	10,4	10,4	9,1	10,4
V-Q Control	9,0	10,5	10,5	10,6	9,3	10,6
Gen Shed	1,1	10,8	10,8	10,9	2,1	10,9

For the valley scenario, comparing the results obtained through the control of voltage at all buses (OF1) and controlling only voltage at pilot buses (OF2), one can conclude that the final results are extremely close.

7. Conclusions

In conclusion, voltage support functionalities in distribution systems integrating DG sources and microgrids may be implemented with great benefits to the DSO, especially in grid-connected mode.

The Voltage VAR control problem must be seen in a global perspective and not in a local perspective (despite the fact that voltage is often considered a local problem) especially in cases where there is high penetration of DG and microgeneration. In these extreme cases, reactive power control is not sufficient to maintain secure operation and therefore drastic measures may have to be taken that involve generation shedding.

Voltage control should be implemented based on a hierarchic structure, similarly to what happens in frequency control. Therefore, this functionality was formulated as a hierarchic optimization problem that must be analyzed in a coordinated way between the several voltage levels (LV and MV) of the distribution systems.

The algorithm developed comprises 2 stages: a “soft control” strategy based on reactive power management (through the control of DG and microgeneration reactive power, transformer taps and capacitor banks) and a “last resort” control strategy based on active power generation shedding. The combination of these two strategies was shown to be essential to the operation of these new distribution systems, particularly in the presented case, where DG and microgeneration penetration is extremely high and their location is not conveniently chose.

It was also seen that the most relevant objectives for these cases are reducing active power losses and maintaining voltage within admissible ranges. The objectives, however, may be contradictory in some situations. Consequently, these two objectives were weighed in the simulations performed, and a global goal was achieved.

Voltage may be monitored and controlled at all buses or only at specific buses, chosen by a method such as electrical distance to select pilot nodes to control voltage. Comparing the two strategies, it was seen that the performance is quite similar for both cases, which should mean that the selection of pilot

nodes was efficient in order to find buses that are representative of a certain area.

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Annex I – Electrical Distance Calculation

The concept of electrical distance involves the matrix $[\partial Q/\partial V]$, which is a part of the Jacobian matrix J , and its inverse $[\partial V/\partial Q]$, called the sensitivity matrix.

The magnitude of voltage coupling between two buses may be quantified by the maximum attenuation of voltage variation among these two buses (using matrix $[\partial V/\partial Q]$).

A matrix of attenuations between all the buses of the electrical system, whose terms are written as α_{ij} is then available and we have $\Delta V_i = \alpha_{ij} \cdot \Delta V_j$,

where $\alpha_{ij} = \left(\frac{\partial V_i}{\partial Q_j} \right) \div \left(\frac{\partial V_j}{\partial Q_j} \right)$

A step-by-step method to obtain separate Voltage Control Areas is presented next:

1. Calculate the Jacobian matrix J and hence obtain the sub-matrix J_4 , where

$$J_4 = [\partial Q / \partial V]$$

2. Invert J_4 . Say $B = \left[\frac{\partial V}{\partial Q} \right] = J_4^{-1}$

3. The elements of matrix B are written as b_{ij} , where $b_{ij} = \frac{\partial V_i}{\partial Q_j}$

4. Obtain attenuation matrix, α_{ij} , between all the nodes as follows $\alpha_{ij} = \frac{b_{ij}}{b_{jj}}$

5. Calculate electrical distances D_{ij} as $D_{ij} = -\log(\alpha_{ij}, \alpha_{ji})$

Once electrical distances for any couple of nodes are defined, it is possible to define the boundary of the Voltage Control Areas.

Voltage Control Areas are then defined by applying the minimax criterion to the Electrical Distances matrix D_{ij} .

This method considers one Voltage Control Area per generator node (microgrid or DG bus) and groups each generator node with the load nodes that are “electrically closer” to it.

Annex II – Test Network Data

The bus and branch data of the MV and LV networks used are presented next.

MV Network Bus Data

Bus Number	P Load (MW)	Q Load (MVAR)	Base Voltage (kV)
1	0.08	0.0325	30
2	0.02	0.0075	30
3	0.055	0.0225	15
4	0.0337	0.0137	30
5	0.0712	0.0287	15
6	0	0	15
7	0.0438	0.0175	30
8	0	0	30
9	0.0362	0.015	30
10	0	0	30
11	0	0	30
12	0	0	30
13	0.0312	0.0125	30
14	0	0	30
15	0	0	15
16	0.0475	0.0188	15
17	0.0112	0.005	30
18	0	0	30
19	0.0025	0.0012	30
20	0.5362	0.215	30
21	0	0	30
22	0	0	30
23	0	0	30
24	0.0412	0.0162	30
25	0.195	0.0775	30
26	0	0	30
27	0	0	30
28	0.0087	0.0038	15
29	0	0	15
30	0.0325	0.0125	15

Bus Number	P Load (MW)	Q Load (MVAR)	Base Voltage (kV)
31	0	0	15
32	0	0	15
33	0.0462	0.0188	15
34	0.055	0.0212	15
35	0	0	15
36	0.0212	0.0087	15
37	0.0075	0.0025	15
38	0	0	15
39	0.0038	0.0012	30
40	0.0262	0.01	15
41	0	0	30
42	0	0	15
43	0	0	15
44	0	0	15
45	0.015	0.0062	15
46	0.035	0.0137	15
47	0	0	30
48	0	0	15
49	0	0	15
50	0	0	15
51	0.0038	0.0012	15
52	0	0	15
53	0.045	0.0188	30
54	0.1112	0.045	15
55	0	0	30
56	0.0812	0.0325	15
57	0	0	15
58	0.0388	0.015	15
59	0	0	15
60	0.0212	0.0087	30
61	0.085	0.0337	15
62	0	0	15
63	0.0937	0.0375	15
64	0.0025	0.0012	15
65	0	0	15
66	0.1362	0.055	15
67	0	0	15
68	0	0	15

Bus Number	P Load (MW)	Q Load (MVAR)	Base Voltage (kV)
69	0	0	30
70	0	0	30
71	0.0887	0.035	30
72	0.0212	0.0087	15
73	0.0087	0.0038	15
74	0.0812	0.0325	30
75	0	0	30
76	0.0237	0.01	15
77	0.0275	0.0112	30
78	0	0	15
79	0	0	30
80	0.025	0.01	30
81	0.0588	0.0237	30
82	0.065	0.0262	15
83	0	0	15
84	0.0012	0	30
85	0.0337	0.0137	30
86	0.0087	0.0038	15
87	0	0	15
88	0	0	15
89	0.0087	0.0038	15
90	0	0	15
91	0.135	0.0537	15
92	0.0812	0.0325	15
93	0	0	30
94	0	0	30
95	0	0	15
96	0.0412	0.0162	15
97	0	0	30
98	0	0	30
99	0	0	15
100	0	0	30
101	0.0188	0.0075	30
102	0	0	30
103	0	0	15
104	0	0	30
105	0.03	0.0125	15
106	0	0	15

Bus Number	P Load (MW)	Q Load (MVAR)	Base Voltage (kV)
107	0	0	30
108	0	0	15
109	0.0325	0.0125	30
110	0	0	30
111	0	0	30
112	0	0	15
113	0	0	15
114	0.585	0.2337	30
115	0	0	15
116	0	0	15
117	0	0	30
118	0	0	30
119	0	0	30
120	0	0	15
121	0.0512	0.02	15
122	0.0262	0.01	15
123	0.065	0.0262	15
124	0.07	0.0275	15
125	0	0	15
126	0	0	15
127	0	0	30
128	0.0525	0.0212	15
129	0	0	15
130	0.0188	0.0075	30
131	0	0	15
132	0	0	15
133	0.0412	0.0162	15
134	0	0	15
135	0.0025	0.0012	15
136	0	0	15
137	0	0	15
138	0	0	15
139	0.3125	0.125	15
140	0	0	15
141	0.0375	0.015	15
142	0	0	15
143	0.01	0.0038	15
144	0.0125	0.005	15

Bus Number	P Load (MW)	Q Load (MVAR)	Base Voltage (kV)
145	0	0	15
146	0	0	15
147	0	0	15
148	0	0	15
149	0.02	0.0075	15
150	0.1762	0.0712	30
151	0	0	30
152	0	0	30
153	0	0	15
154	0.0388	0.015	15
155	0	0	15
156	0	0	15
157	0.0475	0.0188	15
158	0.0275	0.0112	15
159	0	0	15
160	0.0062	0.0025	30
161	0	0	30
162	0	0	15
163	0.005	0.0025	15
164	0.0287	0.0112	15
165	0	0	30
166	0	0	15
167	0	0	15
168	0	0	15
169	0.0075	0.0025	15
170	0.0262	0.01	15
171	0.05	0.02	15
172	0.0087	0.0038	15
173	0	0	15
174	0.16	0.0637	15
175	0.0712	0.0287	15
176	0.2725	0.1087	15
177	0	0	15
178	0.045	0.0175	15
179	0	0	15
180	0.0212	0.0087	30
181	0	0	15
182	0.0325	0.0137	15

Bus Number	P Load (MW)	Q Load (MVAR)	Base Voltage (kV)
183	0	0	15
184	0.0388	0.015	15
185	0.1087	0.0438	15
186	0	0	15
187	0	0	15
188	0	0	15
189	0	0	15
190	0.4025	0.1612	15
191	0.2725	0.1087	15
192	0.0162	0.0062	15
193	0	0	15
194	0	0	15
195	0.0062	0.0025	30
196	0	0	15
197	0	0	30
198	0	0	30
199	0.0325	0.0137	15
200	0	0	30
201	0	0	15
202	0	0	15
203	0	0	15
204	0	0	30
205	0.1375	0.055	30
206	0	0	15
207	0.0262	0.01	30
208	0.02	0.0075	15
209	0.0262	0.01	30

MV Network Branch Data

From Bus	To Bus	Resistance r (p.u.)	Reactance x (p.u.)
1	8	0.2047	0.1103
2	12	0.1268	0.0683
3	6	0.1415	0.0763
4	12	0.1814	0.0978
5	6	0.2068	0.0699
6	15	0.217	0.1984

From Bus	To Bus	Resistance r (p.u.)	Reactance x (p.u.)
7	8	0.0055	0.0019
8	10	0.0676	0.0228
9	11	0.0553	0.0298
10	11	0.0396	0.0134
10	17	0.0518	0.0279
11	18	0.1462	0.0494
12	14	0.0268	0.0144
13	14	0.0013	0.0004
14	21	0.0794	0.0428
15	16	0.0068	0.0037
15	29	0.4408	0.403
18	19	0.075	0.0404
18	21	0.078	0.0263
20	22	0.0416	0.0177
21	27	0.1462	0.0494
22	23	0.109	0.0277
22	27	0.1424	0.0606
23	24	0.0963	0.0245
25	26	0.0001	0
26	41	0.2183	0.1177
27	47	0.3495	0.1487
28	31	0.193	0.104
29	30	0.1049	0.0566
29	32	0.0948	0.0866
31	36	0.3823	0.206
31	48	11.241	0.6059
32	33	0.0835	0.045
32	42	0.174	0.1591
34	44	0.206	0.1111
35	38	0.0448	0.0242
37	38	0.1453	0.0362
38	43	0.1039	0.056
39	41	0.0314	0.008
40	42	0.0039	0.0021
41	47	0.2609	0.0664
42	49	0.4222	0.386
43	44	0.386	0.1304
43	50	0.499	0.269

From Bus	To Bus	Resistance r (p.u.)	Reactance x (p.u.)
44	45	0.3469	0.1172
46	49	0.2259	0.1218
47	55	0.2067	0.088
48	50	0.584	0.3148
48	51	0.2461	0.1327
49	59	0.3764	0.3441
50	52	0.0663	0.0357
52	54	0.1428	0.0482
52	57	0.2855	0.1539
53	55	0.0988	0.0533
55	70	0.1623	0.0691
56	57	0.2525	0.0853
57	78	0.4794	0.2584
58	62	0.1962	0.1058
59	62	0.1475	0.0795
59	83	0.2648	0.242
60	69	0.0996	0.0537
61	68	0.1803	0.0972
62	65	0.1788	0.0964
63	78	10.034	0.2554
64	88	0.5042	0.2718
65	67	0.123	0.0663
65	73	0.2771	0.0936
66	68	0.2173	0.1171
67	68	0.057	0.0307
67	72	0.0789	0.0426
69	71	0.0067	0.0036
69	75	0.0688	0.0371
70	75	0.0378	0.0204
70	79	0.0618	0.0263
74	75	0.0176	0.0095
75	81	0.0324	0.0175
76	112	16.337	0.4159
77	79	0.0037	0.002
78	99	0.4483	0.2416
79	93	0.1406	0.0598
80	97	0.0866	0.0467
82	83	0.5953	0.3209

From Bus	To Bus	Resistance r (p.u.)	Reactance x (p.u.)
83	87	0.098	0.0896
84	100	0.0817	0.044
85	94	0.0577	0.0311
86	90	0.0528	0.0285
87	90	0.1284	0.0692
87	131	0.6507	0.5949
88	89	0.0041	0.0022
88	95	0.1258	0.0678
90	96	0.2214	0.1194
91	103	0.4638	0.1181
92	106	0.5553	0.1876
93	94	0.0681	0.0501
93	118	0.2905	0.2138
94	97	0.0637	0.0469
95	113	0.3209	0.173
97	98	0.0035	0.0026
98	102	0.153	0.1126
98	110	0.0891	0.0379
99	103	0.4853	0.2616
99	106	0.2313	0.1247
100	101	0.0014	0.0005
100	102	0.0083	0.0045
102	107	0.0486	0.0357
103	108	0.3099	0.167
104	111	0.0171	0.0062
105	112	0.2902	0.0739
106	115	0.3037	0.1637
107	109	0.0013	0.0004
107	117	0.088	0.0648
108	116	0.8409	0.4533
108	134	12.249	0.3118
110	114	0.0001	0.0001
111	118	0.0754	0.0321
112	132	13.514	0.344
113	136	10.006	0.5394
115	125	0.4096	0.2208
116	120	0.5514	0.2972
116	140	0.8183	0.2764

From Bus	To Bus	Resistance r (p.u.)	Reactance x (p.u.)
117	127	0.0978	0.033
117	165	0.2989	0.22
118	119	0.0487	0.0358
120	121	0.0064	0.0016
120	126	0.2964	0.1598
122	132	0.2456	0.1324
123	126	0.0542	0.0292
124	125	0.0158	0.0053
125	166	0.7455	0.4019
126	129	0.3266	0.0831
127	130	0.0226	0.0076
127	152	0.1983	0.067
128	129	0.1443	0.0488
129	136	0.1918	0.0488
131	133	0.0088	0.0048
131	137	0.1223	0.1118
132	137	0.3695	0.094
134	135	0.0625	0.0211
134	142	0.353	0.0899
136	156	0.9744	0.248
137	173	0.628	0.5741
138	139	0.0088	0.0017
138	146	0.206	0.111
140	148	0.2126	0.0718
140	154	0.4309	0.1456
141	148	0.18	0.0608
142	146	0.1286	0.0328
142	153	0.3278	0.1767
143	145	0.0333	0.0112
144	162	0.7668	0.1952
145	148	0.0318	0.0108
146	147	0.0486	0.0124
147	149	0.0065	0.0037
150	151	0.004	0.0009
151	152	0.0303	0.0102
152	161	0.0703	0.0238
153	155	0.1286	0.0434
153	164	0.2271	0.1224

From Bus	To Bus	Resistance r (p.u.)	Reactance x (p.u.)
156	158	0.4256	0.2294
156	189	11.513	0.2931
157	167	0.2284	0.1231
159	162	0.0523	0.0282
159	168	0.2601	0.0662
159	179	0.3629	0.1956
160	161	0.0013	0.0004
161	180	0.1066	0.036
162	163	0.0341	0.0184
165	197	0.121	0.089
165	204	0.168	0.0906
166	169	0.02	0.0067
166	177	0.1472	0.0793
167	168	0.2711	0.0916
167	170	0.0296	0.01
168	171	0.2323	0.0591
171	175	0.0585	0.0103
172	173	0.0714	0.0241
173	179	0.0665	0.0608
174	176	0.0706	0.0221
174	185	0.1267	0.0262
175	176	0.013	0.0041
176	182	0.073	0.0128
177	183	0.0634	0.0342
178	183	0.0336	0.0114
179	194	0.1142	0.1044
181	184	0.0222	0.007
181	188	0.093	0.0083
182	184	0.0341	0.0107
183	203	0.6081	0.3278
185	186	0.0193	0.0043
185	191	0.0631	0.0122
186	187	0.0032	0.0007
187	190	0.0377	0.0084
188	193	0.1864	0.0242
189	192	0.0715	0.0182
189	196	0.2876	0.0972
190	201	0.4383	0.2363

From Bus	To Bus	Resistance r (p.u.)	Reactance x (p.u.)
191	193	0.0111	0.0025
194	202	0.2091	0.1911
194	208	0.9957	0.2481
195	197	0.0008	0.0004
196	199	0.1212	0.0235
197	198	0.0056	0.0041
198	200	0.0473	0.0348
198	207	0.0989	0.0533
200	2063	0.0386	0.0284
201	206	0.0102	0.0032
202	206	0.0098	0.0031
203	206	0.0072	0.0022
204	205	0.0033	0.0018
204	209	0.0498	0.0268
206	2063	0	1.158

LV Network Bus Data

Bus Number	P Load (MW)	Q Load (MVAR)	Base Voltage (kV)
1	0	0	15
2	0	0	0.4
3	0	0	0.4
4	0.0013	0.0005	0.4
5	0.0057	0.0023	0.4
6	0.0064	0.0025	0.4
7	0.0083	0.0033	0.4
8	0.007	0.0028	0.4
9	0.0064	0.0025	0.4
10	0.0025	0.001	0.4
11	0.0146	0.0059	0.4
12	0.0045	0.0018	0.4
13	0.0006	0.0003	0.4
14	0.0108	0.0043	0.4
15	0.0038	0.0015	0.4
16	0.0019	0.0008	0.4
17	0.0019	0.0008	0.4
18	0.0115	0.0046	0.4

Bus Number	P Load (MW)	Q Load (MVAR)	Base Voltage (kV)
19	0.0019	0.0008	0.4
20	0.0019	0.0008	0.4
21	0.0032	0.0013	0.4
22	0.0019	0.0008	0.4
23	0.0038	0.0015	0.4

LV Network Branch Data

From Bus	To Bus	Resistance r (p.u.)	Reactance x (p.u.)
1	2	0.0122	0.0381
2	3	0.0016	0.0007
3	4	0.0046	0.001
4	5	0.0069	0.0012
5	6	0.0066	0.0012
6	7	0.0061	0.0011
7	8	0.008	0.0014
8	9	0.0053	0.0009
9	10	0.0047	0.0008
10	11	0.0163	0.0029
10	12	0.0008	0.0001
12	13	0.0033	0.0006
13	14	0.0233	0.0041
13	15	0.0083	0.0015
15	16	0.0064	0.0011
16	17	0.0091	0.0016
17	18	0.0355	0.0045
17	19	0.0249	0.0044
19	20	0.0091	0.0016
20	21	0.015	0.0027
21	22	0.0111	0.002
22	23	0.0083	0.0015

UNIVERSITY OF MANCHESTER

CONTRIBUTION

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List of acronyms

AVC	Automatic Voltage Control relay
AVR	Automatic Voltage Regulator
AVRS	Automatic Voltage Reference Setting
CHP	Combined Heat and Power
CO ₂	Carbon dioxide
CSVC	Coordinated Secondary Voltage Control
DEFRA	Department for Environment Food and Rural Affairs
DG	Distributed Generation
DGCG	Distributed Generation Coordination Group
DMSC	Distribution Management System Controller
DN	Distribution Network
DNO	Distribution Network Operator
DSE	Distribution State Estimation
DTI	Department of Trade and Industry
EMS	Energy Management System
EU	European Union
GDS	Generic Distribution System
IEA	International Energy Agency
LDC	Line Drop Compensation
OLTC	On Load Tap Changing transformer
OPF	Optimal Power Flow
ROC	Renewable Obligation Certificate
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition system
SDSE	Statistical Distribution State Estimator
WLS	Weighted Least Squares

1 Introduction

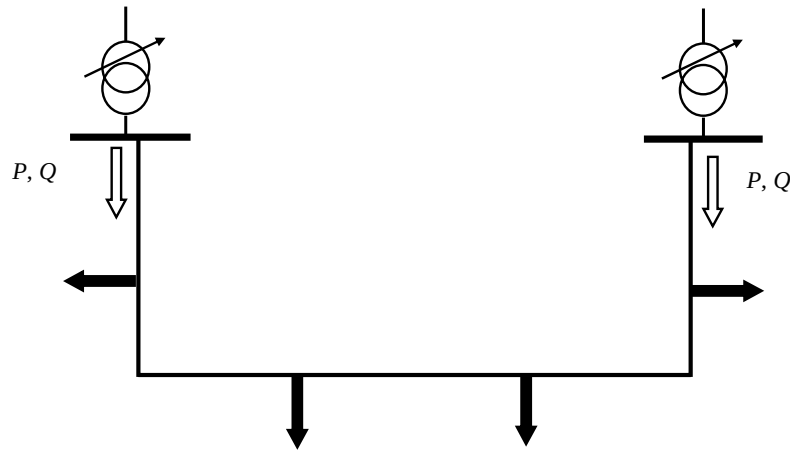
The management of instantaneous power flows and network voltage profiles in Microgrids is a difficult challenge. Microgrids networks are characterised by a relatively high resistance (i.e. low X/R ratio), where R can be three times higher or at least equal to X. This results in strong coupling of real and reactive power, and therefore voltage regulation based on reactive power injection, as is conventionally done in transmission systems, is virtually impossible (unless excessive amounts of reactive power are available). Also, active power injection influences voltage magnitude and hence represents an additional factor to be considered in voltage control.

The principal factors that affect voltage magnitude in Microgrids networks are identified in this report. A mathematical model of a distribution network with distributed generation is presented showing different strategies for active voltage control in Microgrids. The architecture of a Distribution Management System Controller (DMSC) suitable to implement these active voltage functions is illustrated. Different DMSC architectures suitable for segment, area and regional control are also presented and the difficulties faced with real-time network assessment via state estimations outlined. A suitable technique for distribution state estimation in a DMSC is outlined based on existing techniques.

1.1 Existing distribution system – passive networks

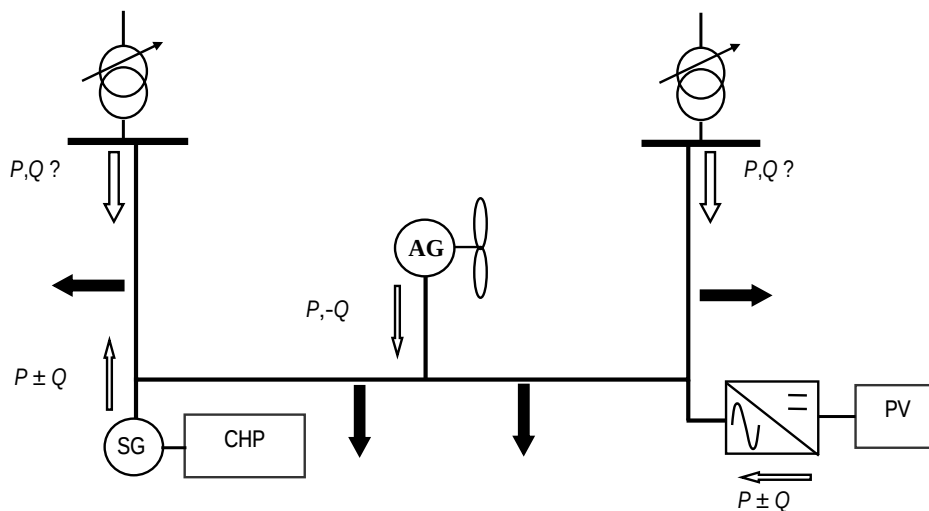
Figure 1 shows the arrangement of a simple passive distribution network (Jenkins *et al*, 2000). The black arrows represent the loads and the white arrows represent the power flows. In passive networks, the power flow is always unidirectional from higher voltage levels to customers at lower voltage levels. The fault level is predictable and simple protection co-ordination settings are used to protect the network. These networks use simple voltage management schemes such as an On Load Tap Changer (OLTC) to control the 33/11kV primary substation voltage. This way of operation with minimal real-time control of the network is described as passive management. Passive networks generally require no real-time intervention to control power flows, fault levels or characteristics such as voltage experienced by consumers.

The design and operation of the electricity distribution networks always assumed power flows from higher voltage networks to lower voltage networks (passive networks). However, in Microgrids the connection and operation of significant distributed energy resources (of varying technologies) and storage devices alters many network characteristics making the existing assumptions of network design and operation less applicable.

Figure 1. Passive distribution network (Jenkins *et al*, 2000).

1.2 Distribution systems with generation (Microgrids) – active networks

Figure 2 is a schematic of a simple distribution network with distributed generation (Jenkins *et al*, 2000). In this network, the CHP plant with a synchronous generator exports real power P to the network when generation exceeds local demand and the reactive power Q may be absorbed or supplied by adjusting the generator excitation system. The wind turbine with an asynchronous generator injects P into the network and absorbs Q . Similarly the Photovoltaic (PV) system will allow injection of P at a set power factor but may inject harmonic currents into the system.

Figure 2. Distributed system with distributed generation (Jenkins *et al*, 2000).

There are many characteristics of a Microgrid (Figure 2) that differ from a typical passive distribution network:

- i) the power flow is not unidirectional any more. The direction of power flows and the voltage magnitudes on the network depend on the demand and the injected generation.

- ii) these networks give rise to a wide range of fault currents and hence complex protection and coordination settings are required to protect the network.
- iii) the reactive power flow on the network is independent of the active power flows.
- iv) many types of distributed generation are interfaced through power electronics and may inject harmonics to the network.

1.3 Active Network Control

One of the main challenges associated to Microgrids is that of voltage control (voltage rise) due to the presence of distributed generators (DTI, 2003). It has been proposed that active control of network voltage can increase the connected capacity by at least three times compared to the passive control of the network voltage (Liew and Strbac, 2002; Masters, 2002). Therefore, a methodology that provides active voltage control of the network may increase the capacity of distribution networks to accommodate generation.

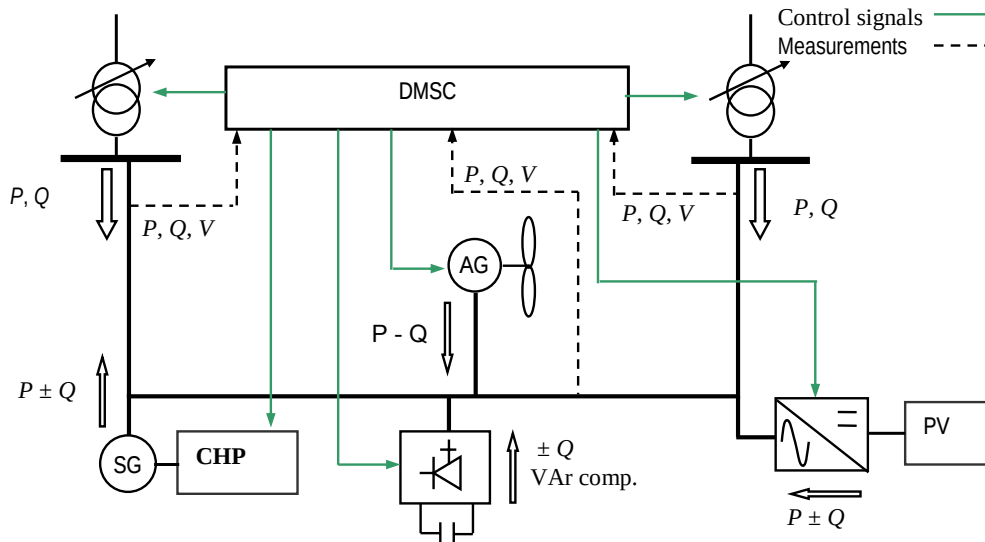


Figure 3. Active management scheme for a Microgrid.

Figure 3 shows a controller scheme suitable for achieving functions of active voltage control in Microgrids. In this scheme a Distribution Management System Controller (DMSC) assesses the network conditions and takes actions to control the network voltages and power flows. The DMSC obtains measurements from the network and sends signals to the devices under its control. Control actions may be transformer tap operation, altering the output from distributed generators, and injection or absorption of reactive power.

2 Voltage control options in Microgrids

In a passive network, the power flows from the supply point to the load creating a voltage drop on the feeder. The primary substation voltage is therefore kept at a high setting so that during periods of high demand, the voltage at the extreme nodes from the substation is above a

permissible minimum value (Figure 4). In contrast, in a Microgrid the power injection of a distributed generator at an extreme node reduces the power flow from the substation and consequently the voltage drop along the feeder. This causes the voltage profile along the feeder to rise towards the distributed generator busbar, and during low demand conditions to exceed the permissible maximum limit.

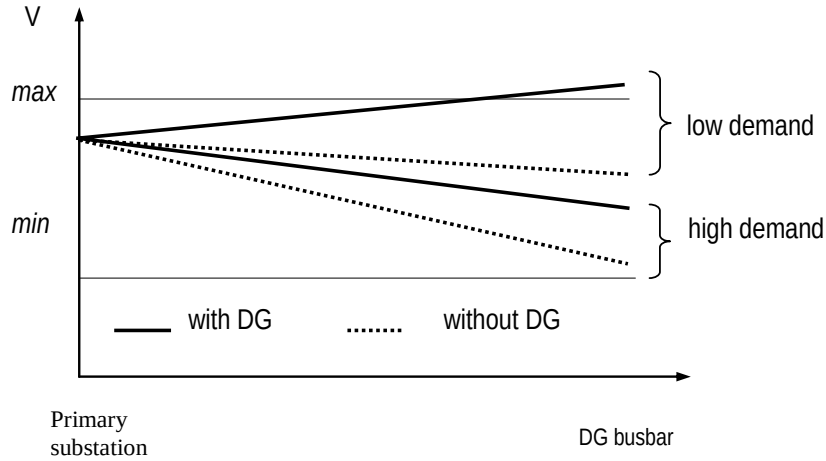


Figure 4. Voltage gradient along a simple feeder with distributed generation.

Distributed generation connected to the Microgrid network usually has the effect of increasing the voltage at the connection point. This is demonstrated using the hypothetical Microgrid network shown in Figure 5. In this network, the distributed generation is connected to busbar j and is typically subjected to large fluctuations in voltage magnitude.

The symbols in Figure 5 have the following meanings

$P_{DG} \pm jQ_{DG}$	Distributed generation active and reactive power injection
$R_{ij} + jX_{ij}$	network impedance between busbar i and j
$\bar{V}_j$	node j complex voltage
$\bar{I}_{ij}$	complex current vector from busbar i to j
$P_j + jQ_j$	load at busbar j

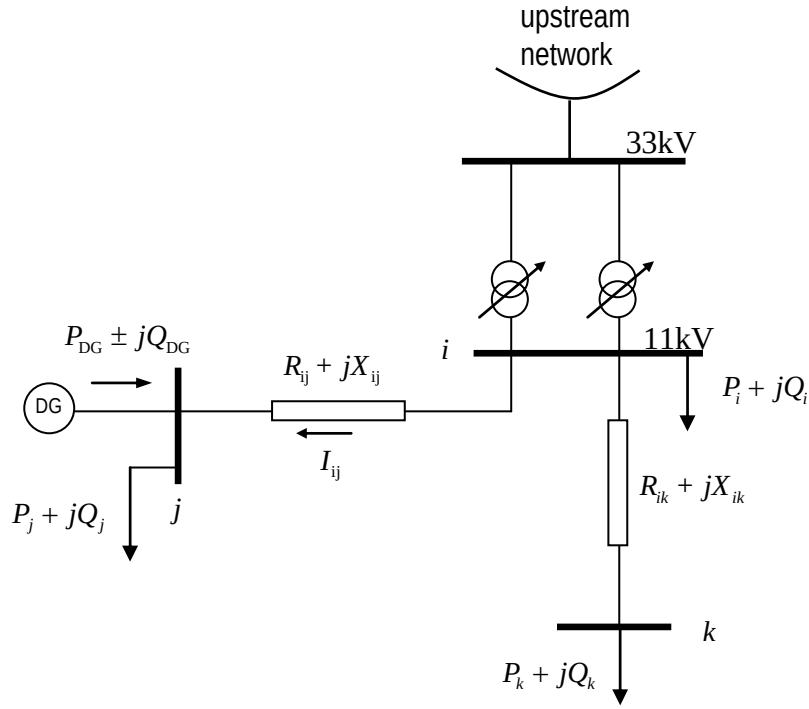


Figure 5. A hypothetical Microgrid network.

The complex power flow into busbar j is

$$(P_j - P_{DG}) - j(Q_j \mp Q_{DG}) = \bar{V}_j^* \bar{I}_{ij} \quad (1)$$

The complex voltage at node i is

$$\bar{V}_i = \bar{V}_j + \bar{I}_{ij}(R_{ij} + jX_{ij}) \quad (2)$$

Substituting Equation (1) into Equation (2), the complex voltage at node j can be obtained.

$$\bar{V}_j = \bar{V}_i + \frac{(P_{DG} - P_j)R_{ij} + (\mp Q_{DG} - Q_j)X_{ij}}{\bar{V}_j^*} + j \frac{(P_{DG} - P_j)X_{ij} + (\mp Q_{DG} + Q_j)R_{ij}}{\bar{V}_j^*} \quad (3)$$

Equation (3) expresses the busbar voltage at node j in terms of load, generation, network impedance and the upstream busbar voltage. The X/R ratio is relatively low for distribution networks and the voltage angle drop represented by the imaginary part of Equation (3) is small and may be ignored. Hence, Equation (3) is approximated as,

$$V_j \approx V_i + \frac{(P_{DG} - P_j)R_{ij} + (\mp Q_{DG} - Q_j)X_{ij}}{V_j} \quad (4)$$

The minimum load condition of $P_j + jQ_j = 0$ and the operation of distributed generation at unity power factor create the scenario for minimum distributed generation injection. For this scenario, in the absence of active voltage control or any network reinforcement, the penetration of generation is limited to P_{DG}^{max} that would just increase the voltage at busbar j to its upper limit, V_j^{max} as shown in Equation (5).

$$V_j^{max} \approx V_i^{fixed} + \frac{P_{DG}^{max} R_{ij}}{V_j^{max}} \quad (5)$$

Equations (4) and (5) show four variables that could be used to control the voltage on busbar j . That is the primary substation voltage V_i , the amount of reactive power $\pm Q_{DG}$, the amount of active power P_{DG} , and the network impedance $R_{ij} + jX_{ij}$.

2.1 Primary substation voltage

For the minimum load condition, Equation (5) shows that the voltage at busbar j is above the upstream busbar voltage when the distributed generation starts to inject active power. Now, if the substation voltage is reduced in Equation (5) from an old setting $V_i^{cntrl,old}$ to a new setting $V_i^{cntrl,new}$, the voltage profile along the feeder reduces and allows a new increased generation P_{DG}^{new} for the same V_j^{max} . The lowest allowable limit on $V_i^{cntrl,min}$ then determines how much generation can be accommodated at the maximum permissible voltage on busbar j . Equation (6) shows the fraction of P_{DG}^{max} that can be accommodated by adjusting the substation voltage from an old setting $V_i^{cntrl,old}$ to a new setting $V_i^{cntrl,new}$.

$$P_{DG}^{new} \approx P_{DG}^{max} \left(\frac{V_j^{max} - V_i^{cntrl,new}}{V_j^{max} - V_i^{cntrl,old}} \right) \quad (6)$$

Assuming P_{DG}^{max} is the penetration level with the primary substation voltage held at 1.0 pu then 1% reduction in V_i^{cntrl} will approximately accommodate an additional 20% of Distributed Generation (DG) at busbar j . This assumes V_j^{max} is kept at 1.05 pu.

2.2 Reactive power

The effectiveness of reactive power absorption to counteract voltage rise depends on the network X/R ratios. Reactive voltage drop on lines can become effective when the distance between primary substation and the distributed generation busbar is long. However, the reactive power absorption will increase the total losses on the feeder.

The absorption of reactive power (from distributed generation) in Equation (4) leads to a reactive power drop being subtracted from the active power voltage boost by the DG connected feeder. Now, by controlling the absorption of reactive power Q_{DG}^{cntrl} , the voltage at the DG busbar can be controlled, and in doing so the amount of DG active power injection can be increased to a new P_{DG}^{new} . This is shown in Equation (7) as:

$$V_j \approx V_i + \frac{P_{DG}^{new} R_{ij} - Q_{DG}^{cntrl} X_{ij}}{V_j} \quad (7)$$

The additional DG capacity due to a change in reactive power absorption from an old Q_{DG}^{old} setting to a new setting Q_{DG}^{new} at the DG busbar is given in Equation (8).

$$P_{DG}^{new} \approx P_{DG}^{max} + (Q_{DG}^{cntrl,new} - Q_{DG}^{cntrl,old}) \frac{X}{R} \quad (8)$$

This equation shows that the X/R ratio should be large for this method of voltage control to be effective. However, distribution networks have low X/R ratios compared to transmission networks and are less effective on 11kV cables ($X_C \approx 0.1 \Omega/\text{km}$) as compared to 11kV overhead lines ($X_{OH} \approx 0.4 \Omega/\text{km}$).

Reactive power control can be implemented using the AVR of a distributed generator in the case of synchronous machines. Alternatively, Reactive power control can also be achieved using thyristor control reactors (SVCs) and STATCOMs if available on the network.

2.3 Generation curtailment

The extreme condition of minimum load and maximum generation occurs during a small number of hours in a year. The electricity price increases with demand and this extreme condition normally occurs in summer periods when the price of electricity is cheap. The value of curtailed generation is unlikely to be high if it coincides with cheap electricity periods. Therefore, it may be beneficial to allow generation to be curtailed during low demand periods and to have large injection during times of high demand on the network. This method of active power control (to vary with the demand profile) could potentially allow connection of high capacity generators.

2.4 Line voltage regulators

Primary substation voltage reduction is one of the most effective ways to increase the penetration of generation. However, volt drop on adjacent feeders limits how much the substation voltage can be reduced. In Figure 5, if the voltage of the primary substation is reduced, then the voltage at busbar k is further lowered. This can lead to situations where voltage at busbar k is outside permissible limits.

Equation (9) shows the voltage at the adjacent busbar k . Depending on the power flows and feeder impedances, this equation shows any reduction in V_i leads to further reduction in V_k .

$$V_k \approx V_i - \frac{P_k R_{ik} + Q_k X_{ik}}{V_k} \quad (9)$$

A co-ordinated area voltage control can overcome the limitation on V_i . A voltage regulator can be introduced at a strategic location in the feeder to provide independent control. One possibility is to place the regulator in the feeder where the DG is connected. The regulator and the DG interact to control the voltage on the feeder, while the OLTC and the AVC relay controls the primary substation voltage. The other possibility is to place the regulator on the most susceptible feeder to changes in primary substation voltage. The DG and the OLTC regulates the network voltage while the regulator maintains the voltage on the susceptible feeder.

2.5 Combination of controls

Any combination of V_i^{ctrl} , Q_{DG}^{ctrl} , $P_{DG}^{ctrl,curtail}$ can be utilised to regulate the network voltage. An example of this could be an OLTC tap increment/decrement followed by a reduction in generation output or it can be generation curtailment followed by reactive power absorption.

3 Integrated voltage control in Microgrids

The voltage control options discussed in the previous section can be used in real time to mitigate the voltage rise in Microgrids due to DG. Real time control of distribution network requires the network conditions to be assessed prior to any control actions. Depending on these conditions, control actions can be performed on the devices connected to the network to control voltage and to maximise DG penetration.

3.1 The DMSC Architecture

Figure 6 shows the DMSC building blocks intended for assessing operating conditions and finding control settings for devices connected to the network. The key functions of the DMSC are state estimation, bad data detection and optimal control settings calculation.

State estimation and bad data detection

The DMSC receives a limited number of real time measurements at set intervals from the network nodes. The intervals could be from half to hourly periods or even shorter. The measurements are normally voltage, load injections and power flow measurements from primary substation and other secondary substations. These measurements are used to calculate network operating conditions.

In addition to these real time measurements, the DMSC uses load models to forecast load injections at each node on the network for a given period that coincides with the real time measurements. The network topology information and impedances are also supplied to the DMSC. The state estimator uses this data to assess the network conditions in terms of node voltage magnitudes, line power flows and network injections. Bad measurements coming to the system are filtered using bad data detection and identification methods.

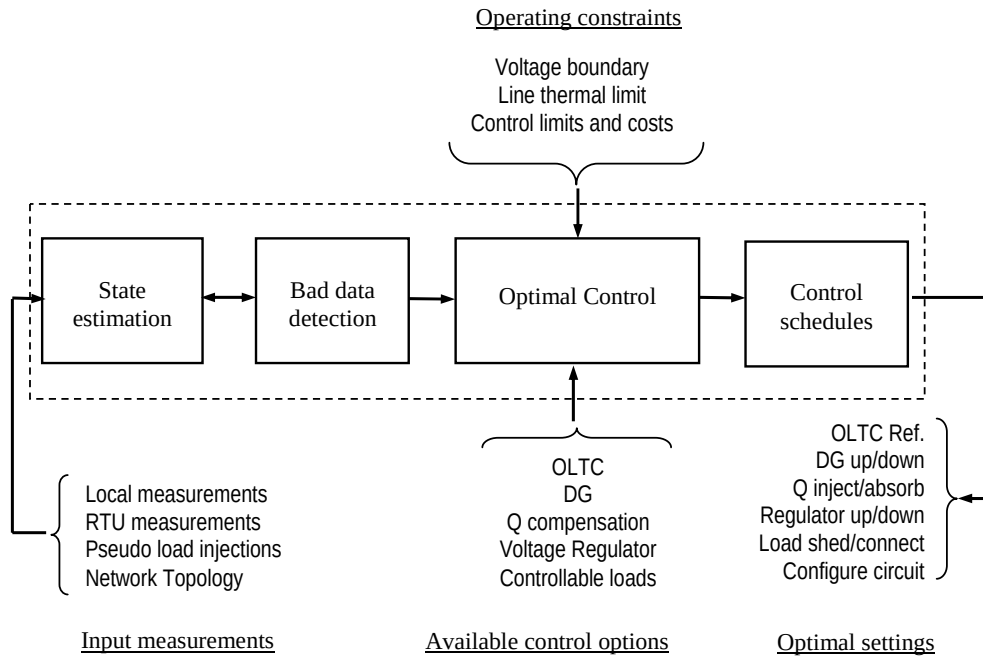


Figure 6. Architecture of the DMSC.

Optimal Control

When the network operating conditions have been assessed, the control algorithm identifies whether the network is operating within its permissible boundaries. This is normally assessed by analysing the network voltage magnitudes at each busbar. The optimisation algorithm is supplied with all the available active control options, the limits on these controls and the network operating constraints. Limits on controls are permissible lower and higher settings of the equipment. Operating constraints are usually voltage limits and thermal ratings of the lines and equipment.

The optimal control algorithm calculates the required control settings for the current operating conditions that optimise the device settings without violating constraints and operating limits.

Control Schedules

The solution from the control algorithm is optimal control schedules that are sent to the devices connected to the network. Such control actions can be single or multiple control actions that would alter the set point of any of the devices below:

- Alter the reference of an OLTC transformer/voltage regulator relay.
- Request the AVR or the governor of a synchronous generator to alter the reactive/active power of the machine.
- Send signals to wind farm Supervisory Control And Data Acquisition (SCADA) systems to increase or decrease wind farm output power.
- Shed or connect controllable loads on the network.
- Increase or decrease the settings of any reactive power compensation devices on the network.
- Reconfigure the network by opening and closing certain circuit connection points.

3.2 Levels of Integrated Operation

A number of possible controller configurations have been proposed for regulating the distribution network voltage (Hird, 2003). These configurations can be mainly grouped into three main levels and are shown in Figure 7.

Segment control

Segment control is the simplest control level with minimum number of measurements. This level of control uses local measurements, measurements from Remote Terminal Units (RTU) located at the DG busbar and other strategic locations on the network. The network maximum and minimum voltage magnitudes are obtained through direct use of measurements or via state estimation and the reference of the AVC relay is calculated using rule-based or optimized techniques. Segment level control is suitable for radial networks with a single DG requiring only one point of control. An example of this is the control of primary substation voltage.

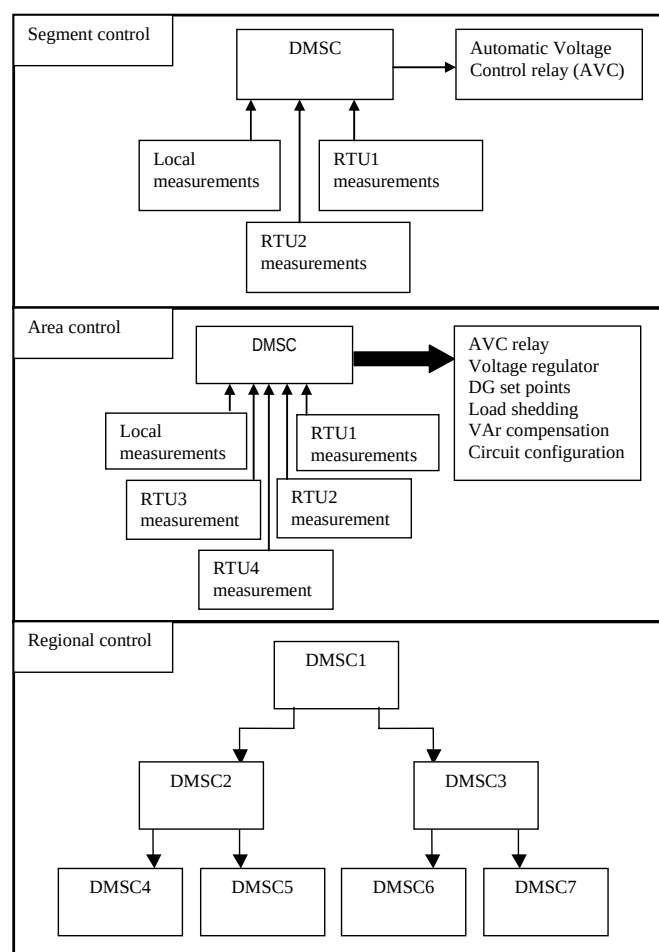


Figure 7. Different levels of DMSC integration (Hird, 2003).

Area control

Area control is a more advanced form of segment control. Area control utilises local measurements and multiple RTUs to supply measurements from key points on the network. Area control is complex and requires the control actions to be optimised. Multiple devices are operated to ensure network voltage is regulated within permissible limits. Area control is suitable for controlling networks with multiple devices. An example of this is the control of multiple DGs, shedable loads, reactive power compensators and reconfigurable open points in a specified area. One of the key challenges for area control is to obtain a reliable estimate of the network conditions.

Regional control

Regional control is suitable for a large part of a distribution network with many DGs and controllable devices. Regional control is a hierarchical control where each of the controllers shown in Figure 7 plays a role in controlling a given area of the network. At the lowest level, the DMSCs are situated at the 33/11kV primary substations where each one controls a given area of

the network. At the second level, the DMSCs are situated possibly at 132/33kV substations controlling the voltage at this level. At the highest level, the DMSC is situated closest to the grid supply point of the DNO.

3.3 Control for Integrated Operation

33/11kV primary substations use an AVC relay to control the network voltage. This method of voltage control is limited to substation voltage control only and is not designed for integrated operation of DG and the network. Therefore, direct use of AVC relays for active control of multiple devices is not possible.

Priority list or rule based techniques are suitable for calculating settings for single devices. For instance, a rule-based technique can adjust the reference of an AVC relay based on network voltage and DG output. One weakness with priority list and rule based techniques is that the control is not optimised for the operating conditions. It is also difficult to implement multiple control actions into such algorithms. For example, it will be difficult to prioritise curtailment of multiple generators on the network.

To overcome this difficulty, the DMSC control settings need to be calculated based on optimisation. The controller should also be capable of calculating optimal settings that would minimise the cost of control settings for the devices under the control of the DMSC.

3.4 Coordinated control of OLTC and a controlled microsource

A multi level control scheme incorporating reactive power and OLTC control can be used in MicroGrids. In this scheme, shown in Figure 8, reactive power control is the primary control that responds instantaneously to reduce voltage deviations. The slower secondary control is provided by the OLTC which responds to reduces reactive power output of a selected MicroSource (Control MicroSource)

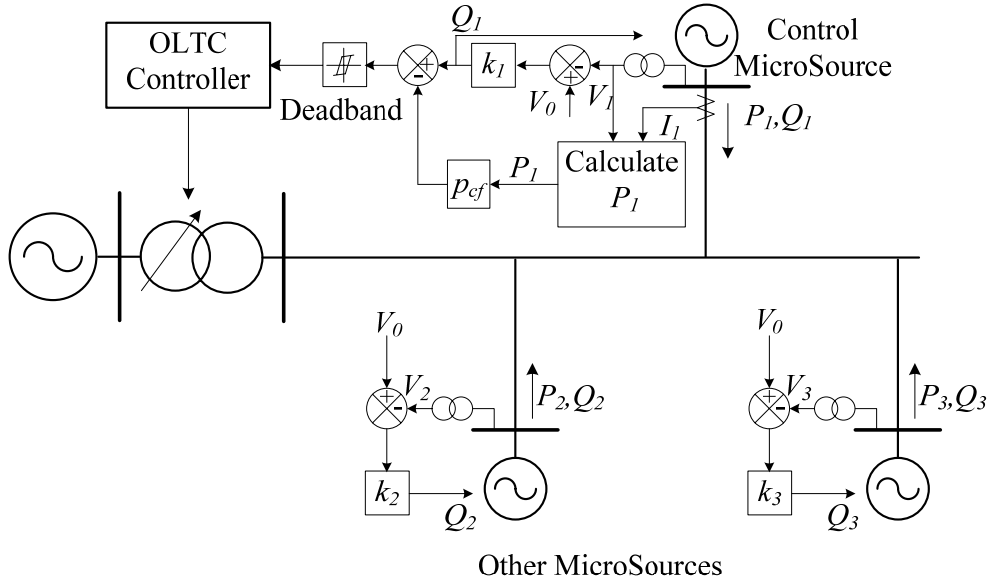


Figure 8: Voltage control scheme

The reactive power output of the MicroSources is controlled according to voltage droop characteristic $Q = -k(V - V_0)$, where Q is the reactive power output of the generator, V is its terminal voltage, V_0 is its nominal voltage, and k is the inverse of the droop line slope.

Voltage levels in the resistive Microgrid are mainly affected by active power. An increase in active power injection from any generator increases the voltage of all busbars. An example is shown in Figure 9, where the voltage of one node on the microgrid has increased from point 1 to 2 due to an increase in active power. Reactive power injected by all MicroSources will then be reduced by the droop control thus bringing the operating point to 3. The OLTC controller receives the value of the reactive power generated by the Control MicroSource and changes the taps in order to maintain the reactive power within a specified dead-band thus taking the operating point to 4.

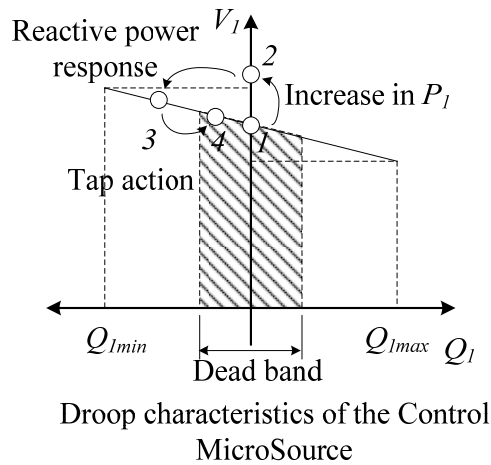


Figure 9: Control system response to a change in active power injection

The control scheme was applied to the model system described in [Papathanassiou et. al., 2005] which comprises a Microgrid and a Passive Distribution Feeder as shown in Figure 10. All loads and generation are assumed to be balanced across all three phases. The generators that are connected to the same busbar were lumped together.

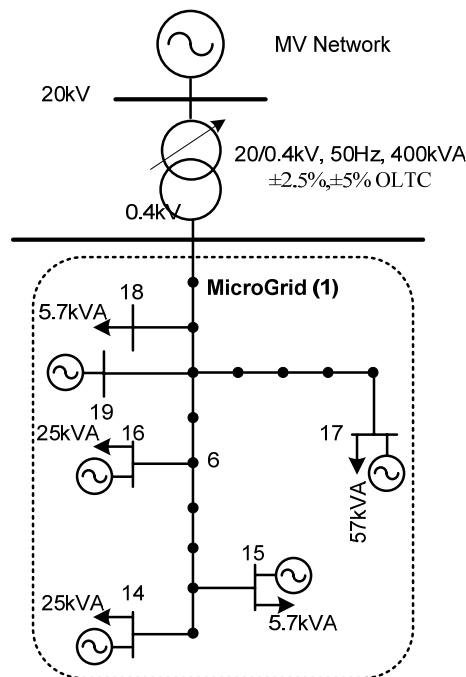


Figure 10: System model

Figure 11 shows the allowable power generation with all loads set to zero and only one generator is generating. The following cases were considered:

1. One generator is producing active power with zero reactive power output from all the generators
2. One generator is producing active and reactive power while all the other generators are on the reactive power droop control and the OLTC tap setting is 1 p.u.
3. One generator is producing active and reactive power while all the other generators are on the reactive power droop control. The reactive power control of the control MicroSource is coordinated with the OLTC control (multi-level control).

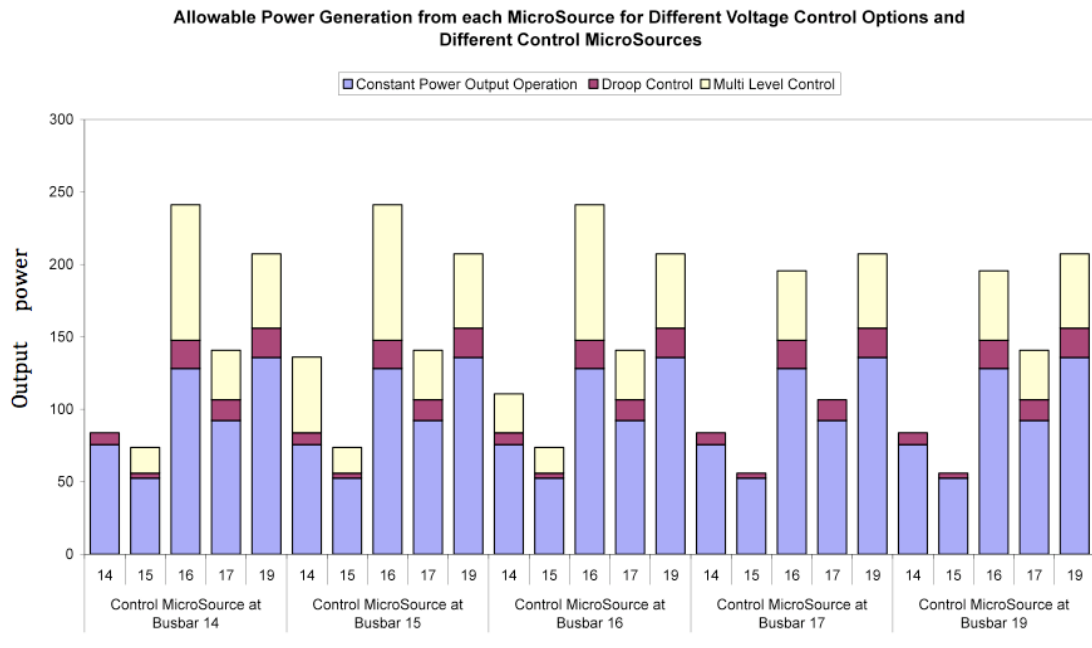


Figure 11: Maximum power generation at no load

The maximum possible generation on Figure 11 are based on the voltage limit of the MicroGrid. The leftmost bar chart is for MicroSource 14, where only that is generating and that also acts as the control MicroSource. The second one corresponds to MicroSource 15, where MicroSource 14 acts as the control MicroSource. When MicroSource 14 is generating and acting as the control MicroSource, it can generate approximately 75 kW without violating the upper limit of the voltage. However, if all the generators are on a droop then generation of MicroSource 14 can be increased to 80 kW. No increase can be achieved with multi-level control. According to Figure 11, it is clear that Multi-level control can increase the power generating capability of a generator without violating the voltage limits. This increase depends on the Control MicroSource. The proper selection of the Control MicroSource allows higher power to be generated and higher loads to be connected without violating the voltage limits.

4 State Estimation in Electrical Power Systems

A state estimator is a mathematical algorithm formulated to minimise the errors between real time measurements and calculated values of measurements at a given instance in time. The state estimator provides the best estimate of the system state variables, which are normally busbar voltage magnitudes and phase angles and transformer tap positions.

State estimation in Energy Management Systems (EMS) is used to calculate the transmission system operating condition. An added advantage of using state estimation in EMS systems is that the state estimation helps to identify bad data and it filters out errors in the telemetered measurements. Practical state estimation algorithms in use are formulated as over determined systems (with high system redundancy level) of non-linear equations and solved as a Weighted Least Squares (WLS) problem. The solution of these equations is not limited only to the WLS method. Many other approaches to solve the power system state estimation problem exist in the literature.

4.1 Transmission System State Estimation

The idea of state estimation for real time monitoring and control of electrical power system was initially proposed in 1970s by Schweppe *et al.* Since then, two main approaches to the problem of transmission system state estimation have emerged. One of them is the approach in which the time evolution of the state vector is considered (the dynamic state estimator) and the other is the approach, which considered the time invariance of the state vector (the static state estimator). Although the two approaches have the common goal of obtaining the knowledge of the system state vector, the modelling and implementation requirements are rather different.

4.1.1 Dynamic State Estimators

The dynamic state estimator models the time behaviour of the system state variables using a sequence of measurements through time. Therefore, the processing of the present information to obtain the system state is made with regard to the past. For this type of estimator, the dynamic behaviour of the state vector at instant t_k is modelled as in Equation (20) and the scan of measurements at the instant t_k is modelled according to Equation (21).

$$\mathbf{x}(t_k) = \mathbf{x}(t_{k-1}) + \Delta\mathbf{x}(t_k) \quad (10)$$

$$\mathbf{z}(t_k) = \mathbf{h}(\mathbf{x}(t_k)) + \Delta\mathbf{z}(t_k) \quad (11)$$

where,

$\mathbf{x}(t_k)$ state vector at instant t_k

$\Delta\mathbf{x}(t_k)$ white noise process; state vector changes from t_{k-1} to t_k

$\mathbf{z}(t_k)$ measurement vector at instant t_k

$\mathbf{h}(\cdot)$ vector of non-linear functions relating measurements to states at instant t_k

$\Delta \mathbf{z}(t_k)$ measurement error vector at instant t_k

The vectors $\Delta \mathbf{x}(t_k)$ and $\Delta \mathbf{z}(t_k)$ are assumed to have zero mean and are uncorrelated in time as well as between each other. The algorithms modelling the dynamic state estimators can be further classified into three groups (Monticelli, 1999). They are the tracking estimators, the linear estimators and the non-linear estimators.

4.1.1.1 Tracking State Estimator

The scan of measurements by this type of estimators is described by Equation (11). These estimators assume that if the scan interval between t_{k-1} and t_k are small, then the correction between consecutive estimates is minimal and an update of state estimates can be obtained in a single iteration. The tracking estimator does not model the time behaviour of the state vector described by the Equation (10).

4.1.1.2 Linear Dynamic State Estimator

These algorithms used Equation (10) and a linear form of Equation (11) to model the system measurements. The linear form of measurement vector is obtained using the Taylor series expansion of $\mathbf{h}(\cdot)$ in Equation (11). Linear dynamic estimator algorithms are solved using the iterative Kalman Filter techniques.

4.1.1.3 Non-linear Dynamic State Estimator

Algorithms belonging to this category used the non-linear models shown in Equations (10) and (11). Non-linear estimators can be solved with successive linearization using iterative Kalman Filter technique (Monticelli, 1999). Generally non-linear dynamic models predict system states much better than the linear models if the network experiences rapid changes in load and generation.

4.1.2 Static State Estimators

In static state estimators, the information received at any time is processed without regard to the past information of the system. The static estimator uses Equation (22) to establish the relationship between real time measurements and their modelled values. The solution of the static estimator is obtained by optimising a selected criterion of the measurement error shown in Equation (23).

$$\mathbf{z} = \mathbf{h}(\mathbf{x}) + \boldsymbol{\eta} \quad (12)$$

$$\min \mathbf{f}(\boldsymbol{\eta}) \quad (13)$$

Where

$\mathbf{z}$	vector of system measurements
$\mathbf{x}$	system state vector
$\mathbf{h}(\mathbf{x})$	vector of non-linear functions relating measurements to states
$\boldsymbol{\eta}$	measurement error vector
$f(\boldsymbol{\eta})$	objective function to be minimised

The most commonly used criterion for minimisation of the static estimator is the weighted sum of the squares of the measurement errors and is known as the WLS method.

Even though, the dynamic state estimator algorithms are suitable to track the power system closely, the modelling and the implementation of the time behaviour of dynamic algorithms are complex. In contrast, the static state estimators avoid complex modelling of the time behaviour of the system state.

4.2 Distribution system state estimation

The techniques developed for transmission networks are tailored for Distribution State Estimators (DSE). Transmission state estimators use a large number of flow, injection and voltage magnitude measurements. In contrast, the distribution state estimator has only available to it limited measurements of primary substation feeder power flows, voltage magnitudes and current magnitudes. Since the distribution estimator cannot be solved with these limited measurements, historical information of load injections are used in the estimator.

Traditionally, distribution networks have been passively operated with radial topology and state estimation has not been widely applied on these networks. The techniques developed for distribution state estimation used three-phase models with unbalanced loads. These distribution state estimator algorithms are specially oriented for radial networks and may not be suitable for partially meshed networks. Distribution networks may be run as partially meshed networks with integration of significant DG and use of such algorithms to distribution networks with DG is considered not directly applicable. Three phase state estimators require more processing and memory requirements. In the UK, the distribution networks are operated with fairly balanced loads. Therefore, an estimator algorithm based on single-phase model is more suitable to reduce processing and memory requirements.

4.2.1 Practical distribution state estimator features

The number of customers connected to any distribution network is large. For this reason, it is and will be impractical to monitor all points on the distribution system in real time. Therefore, a practical distribution state estimator suitable for use in the DMSC should be built on the following features:

- **Substation measurements.** The DSE must use all the types of measurements available to the estimator at the primary or distribution substations.

- *Few measurements from critical points on the network.* The observability of the estimator cannot rely on the real time measurements. Any affordable measurements need to be critically placed on the network to reduce the standard deviation of the estimated system states.
- *Large number of customer load estimates.* The distribution state estimator must be based on a large number of load injection measurements. Basically the observability of the estimator is achieved using these measurements.
- *Network topology.* Although conventionally distribution networks have been operated as passive radial networks, there may be instances in future where the network may be operated partially meshed due to the presence of DG on the network. Therefore, the DSE algorithm must be able to perform adequately on radial and meshed networks.

4.2.2 The choice of distribution state estimator

The dynamic estimator algorithms are suitable for tracking rapidly changing electrical networks. However, the dynamic estimator algorithms have not been widely used on real time electrical network state estimation due to modelling complexity. Therefore, the application of dynamic algorithms to distribution network state estimation is considered inappropriate.

The static state estimators have been widely used in transmission network state estimation. The most commonly used estimator in transmission system is the decoupled form of the WLS estimator. Therefore, the WLS estimator algorithm is considered to be an appropriate method for the distribution state estimation. However, the decoupled form of the WLS algorithms may not be suitable on distribution networks state estimation. This is because the decoupling assumes that the ratio of the line reactance to resistance is large, which is not valid for distribution networks (Baran and Kelly, 1995). Additionally, the presence of large number of pseudo load injection measurements may give rise to convergence problems when applied to distribution networks (El-Ela, 1992).

The observability of the DSE algorithm has to be achieved with a large number of pseudo load injection measurements (poor measurements). Since the accuracy of the pseudo load injection measurements are inferior compared to the real-time measurements, the estimated uncertainties of the voltages and flows could be used in addition to the expected values when scheduling DMSC control functions. Normally in transmission systems, only the expected values are used. This is because state estimators in transmission systems do not normally use poor measurements while the same is not true for the DSE.

The state estimator gain matrix is used to calculate the estimated standard deviations of the voltage magnitudes and line flows. The gain matrix of the estimator is restructured in all the numerically robust techniques. Therefore, with numerically robust techniques, an additional computational burden in terms of memory and processing time may be required to obtain the standard deviations of the estimated quantities.

Due to the above reasons, the normal form of uncoupled WLS method is considered the most appropriate choice for the state estimator in the DMSC. As mentioned before, the WLS method is the most widely used technique for transmission state estimation and can be easily extended to obtain the variances of the state vector and variances of the line power flows. These statistics will be beneficial in scheduling control functions within the DMSC due to limited measurements on the network.

5 Distribution Management System Control

Adequate control of voltage and reactive power in the electrical power systems helps to provide a reliable and good quality supply to the customers. Many concepts have been implemented to control the power system voltage and reactive power. Apart from generator automatic voltage control, one seldom finds a unified concept for voltage and reactive power control similar to that used to control the active power. This is because the control of voltage and reactive power is generally decoupled from that of active power control and is usually seen as a local control problem.

In the past, much attention was given to the control of transmission networks. Due to open access and restructuring of the electrical power industry, the electrical network is now operated under tighter constraints and closer to its physical limits. Recently, electrical distribution networks have seen a huge increment in the connection of DG. It is envisaged that the integrated control of DG and DN will increase penetration of generation through better utilisation of the network.

5.1 Transmission Network Control Methods

The concepts used in many utilities to control the transmission network voltage and reactive power can be generally decomposed into three hierarchical levels (Tesseron *et al*, 1988; Bjelogrić *et al*, 1990). The first level of this control is associated with primary control facilities on the network. The second level of this control is a zone oriented control (secondary control) and is associated with control facilities belonging to a zone. The third level is centralised control (tertiary control) that optimally alters the set points of the devices participating in the primary and secondary control.

Primary control

Primary control compensates for fast local voltage and reactive power disturbances. These control actions are performed through the automatic voltage regulators (AVRs) on the generators and due to these controls, the generator terminal voltage is maintained within $\pm 5\%$ of the rated value. Primary control actions have a response time of few seconds. This type of control is considered to be a local control.

Secondary control

Secondary control aims to maintain the voltage profile and reactive power flow inside a defined network zone. These control actions compensate for slower voltage variations and

reactive power demands in the zone. Secondary control is mainly achieved through the operation of the capacitor banks, SVCs, STATCOMs and OLTC transformers available in the zone. The operation of the devices participating in the secondary control often requires adjustments to the reference values of the AVRs that participate in the primary control. The response time of secondary control is slower than the primary control and is from several seconds to about three minutes. The secondary control is considered as a regional control.

Tertiary control

Tertiary control determines optimal settings for the devices participating in the primary and secondary control. The purpose of this control is to achieve the optimal voltage profile and reactive power control of the whole network based on the network security constraints and economic criteria. The tertiary control uses some type of optimal power flow (OPF) algorithm to calculate the optimal settings for the controlled devices. The response time of this control is around ten minutes or on demand. The present practice on tertiary control is mainly manual.

In the last decade, many utilities have implemented automatic secondary voltage control to improve voltage profile across the network, enhance system security with greater reactive power reserves and to reduce transmission losses (Tesseron *et al*, 1988). The implementation of the secondary voltage control requires the power system to be divided into controlled zones. The identification and selection of secondary control zones are based on the following criteria (Lagonotte *et al*, 1989):

1. Each controlled zone of the network is selected to have a pilot node that could reflect variations in voltage magnitudes in the other nodes of the zone. The pilot node of each zone corresponds to the substation that has the most central position with respect to devices used in the secondary control.
2. Sufficient amounts of voltage and reactive power controllable devices should be available in the zone
3. The secondary control zones should be sufficiently uncoupled from its neighbouring zones. This is to ensure minimal impact on a zone due to control actions carried out in the other zones. Such influence may lead to voltage oscillations and instability.

The application of voltage and reactive power control over a large region through a combination of primary and secondary control during critically high system load conditions provides good voltage stability to the power system (Vu *et al*, 1996). The Coordinated Secondary Voltage Control (CSVC) takes advantage of this approach. It has been applied to simultaneously control multiple zones in the transmission network.

5.2 Distribution network control methods

Techniques have been developed to regulate the distribution system voltage and reactive power using OLTC and switched capacitor banks. These control techniques aim to maintain the distribution network voltage at permissible levels and try to improve the substation power factor

5.2.1 Control of on load tap changing transformer

In the UK, the 33/11kV primary substation voltage is regulated using OLTC transformers (East Midlands Electricity, 2002). The basic arrangement used to control an OLTC transformer is shown in Figure 12. OLTC transformers used some type of motorised mechanical switching arrangements that alter the turns ratio of the transformer

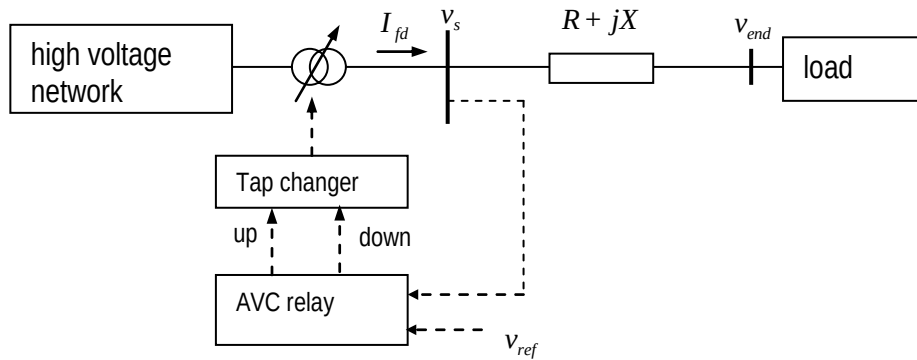


Figure 12. Simple OLTC scheme.

The Tap changer of an OLTC transformer is controlled using an AVC relay to maintain the 11kV substation voltage v_s at a desired voltage reference v_{ref} . The AVC relay compares v_s and v_{ref} to ensure v_s is within a defined voltage dead band v_d of the AVC relay. The dead band of the AVC relay prevents hunting of the tap changer. If $v_s > v_{ref} + v_d / 2$, the AVC relay instructs the tap changer to reduce v_s and if $v_s < v_{ref} - v_d / 2$, the AVC relay instructs the tap changer to increase v_s . The AVC relay has been designed for passive distribution networks with unidirectional power flows.

Advanced AVC relays incorporate line drop compensation to keep the voltage v_{end} at a remote busbar at a desired level. The line drop compensation senses the feeder current I_{fd} and then calculates the voltage drop along the feeder using R and X of the feeder. The calculated voltage drop is compensated for inside the AVC relay so that v_{end} is kept at a desired level rather than v_s .

5.2.1.1 AVC relay target voltage control using an AVRS technique

The AVC relay has been designed for passive distribution networks with unidirectional power flow. Within the AVC relay algorithm, at most, the volt drop of a feeder is simulated but has no knowledge of the individual node voltage magnitudes of busbars supplied from the primary substation. The connection of DG at a remote location gives rise to bidirectional flows on the feeder and the AVC relay may fail to provide acceptable voltage control with DG.

An Automatic Voltage Reference Setting (AVRS) algorithm acting as an outer control loop to the basic AVC relay has been developed to regulate the distribution network voltage with DG (Leite *et al*, 2003). The AVRS algorithm uses the maximum voltage v_{max} and the minimum voltage v_{min} from potential points on the network to alter v_{ref} of the AVC relay. The AVRS algorithm compares the v_{max} and v_{min} with the network upper and lower voltage limits v_{upper} and v_{lower} respectively. If $v_{max} > v_{upper}$ or $v_{min} < v_{lower}$, the control algorithm calculates the required voltage reference correction $\pm \Delta v$ to be added to the current v_{ref} of the AVC relay. The shift in v_{ref} moves the dead band of the AVC relay forcing the tap changer to tap up or down to bring the violated v_{max} or v_{min} within allowable feeder voltage limits.

The potential points for the measurements of v_{max} and v_{min} are identified using load flow studies based on maximum and minimum network loading. A more comprehensive controller calculated v_{max} and v_{min} for the AVRS algorithm based on voltage magnitude estimation (Hird *et al*, 2004). This controller combined distribution network state estimation with the AVRS algorithm to control the AVC relay target voltage. The controller based on AVRS algorithm is only limited to alteration of the OLTC set point. Further, if the network voltage condition is outside v_{max} and v_{min} simultaneously, the controller is unable to make any corrective measures.

5.2.1.2 AVC target voltage control using decision tree

Decision Tree (DT) methods are based on learning from examples (Quinlan, 1986). The whole idea behind a DT is collecting off-line data (called the learning set) regarding a particular problem and then arranging the data into decisions forming a tree. The DT is built based on selected attributes and thresholds that are pertinent to the problem. Once the DT is built, the rules for on line application are then extracted directly from the DT.

5.2.2 OLTC and capacitor bank control methods

Many techniques have been developed to provide an integrated control of the OLTC and the primary substation or feeder capacitor (CAP) banks

5.2.2.1 Supervisory control

Typically, the OLTC and the capacitor banks are controlled independently using local measurements. A supervisory control method constantly monitors voltage drop along the feeders connected to a substation and then operates the OLTC and the capacitor banks local to the substation (Baran and Hsu, 1999). The controller calculates the feeder voltage drop v_{drop} using the feeder current I_{fd} similar to the line drop compensation in the AVC relay. Instead of directly using R and X of the feeder to calculate the volt drop, an effective impedance z_{eff} obtained from a series of load flows under various load conditions was used. The main aim of z_{eff} was to overcome the practical difficulty of defining load centres due to spread of the load on the feeder.

The substation capacitor (CAP) banks are switched based on the reactive power demand measurement Q_{dem} obtained from the substation feeders. The CAP bank is switched in if $Q_{dem} > 60\%CAP_{rating}$ and is switched out if $Q_{dem} < 40\%CAP_{rating}$. The 60% and 40% threshold values are selected to avoid overcompensation of reactive power demand as the CAP bank is switched in and out. A study of this control algorithm reduced the overall number of transformer tap operations compared to the conventional LDC control. However, the switching of the CAP banks lead to the operation of the substation OLTC whenever the CAP bank is switched in/out.

5.2.2.2 Integrated control

An integrated control method is proposed in (Borozan and Novosel, 2001) to operate the OLTC transformer and the CAP banks on a large area of a distribution network. The method uses measurements from feeder ends and other key points on the network. The main aim of this control is to reduce energy loss and to improve voltage profile of the network.

In this proposed method, the operation of the OLTC is based on the telemetered feeder end voltage measurements from the Primary Control Devices (PCDs) at feeder CAP banks that are furthest from the primary substation. The PCD receives voltage measurements from feeder ends and sends the minimum voltage measurement among them to the main controller at the primary substation. The OLTC is then adjusted based on this measurement. In networks where the feeder end voltage measurements are not available, they are calculated using the method proposed in (Baran and Hsu, 1999).

The control of CAP banks is based on three approaches. The first approach is a local control where the switching is based on the local reactive power flow measurement Q_{meas} at the PCD location. In the second approach, the switching is based only on the primary substation reactive power flow measurement. Finally, in the third approach, the switching is based on the reactive power flow measurement at the PCD location and the primary substation. The CAP banks are switched in if $Q_{meas} > d^{max}CAP_{rating}$ and are switched out if $Q_{meas} < d^{min}CAP_{rating}$. The d^{max} and d^{min} are the percentage threshold levels to turn the CAP banks on/off. The switching is also

prioritised using a rule-based algorithm. The largest CAP bank is switched in first and is the last to be switched off. CAP banks with equal ratings are switched according to their distance from the primary substation. The furthest CAP bank is switched in first and is the last to be switched off.

5.2.3 Power flow based control concepts

Power flow methods are applicable to control transmission as well as distribution networks. Power flows provide the voltage profile and line flows on the network using the load demand of the system.

In (Hatziaargyriou *et al*, 1997; Hatziaargyriou and Karakatsanis, 1997) a probabilistic load flow method is applied on a 20kV distribution feeder model to control the distribution networks with wind farms. This method uses probability distribution functions to model the network load injections. The density functions of the wind farm active and reactive injections are obtained from the mean expected value and the standard deviation of the wind velocity. The probability density functions of the voltages, line power flows and losses in the network are calculated with these node injections using a linearised power flow method. The probabilistic load flow method uses three separate control levels to regulate the network voltage and reactive power.

In the first level, the set points of MV/LV substations taps and switch setting of the capacitor banks are calculated using the monthly load injection density functions. In the second level, the optimal settings for the capacitor banks are calculated for daily load injection density functions using MV/LV substations taps from first level. The second level control provides readjustments of the capacitor banks while minimising system losses. The third level control uses the capacitor bank settings from second level control and optimises the tap operation of the primary substation considering hourly load variations.

The probabilistic load flow method applied to control a feeder with two wind farms (total capacity 2MW) has shown increased risk of low voltage being violated on the network due to reactive power demand. The wind farms caused increased operation of the primary substation taps and required the network to be operated with maximum compensation.

Control and regulation of distribution network voltage can also be achieved using OPF method similar to that used in transmission networks. The OPF is an advanced form of load flow where operating limits of the network can be used as solution constraints. This makes the OPF a credible candidate for power system control. The OPF algorithms can potentially provide solutions to operating conditions where an ordinary power flow may fail to converge.

A possible use of the OPF method to control distribution network with DG is proposed in (Strbac *et al*, 2002). Potential controls that could be used in the distribution network are OLTC transformers, DG active power curtailment, reactive power compensators and shedable loads available on the network. Many factors that would affect the choice of controls to be used have been identified. These include, operating conditions of the network, the cost of using the available

controls and the sensitivity of each control in maintaining the network within allowable network limits.

5.3 Comments on control methods

The regulation of voltage and control of reactive power on distribution systems have been achieved mainly through the OLTC transformers, switched capacitor banks and reactive power compensators. The supervisory control method adjusted the OLTC tap using a local current measurement. The integrated control method adjusted the OLTC tap based on the feeder end voltage measurements. The two methods controlled the network voltage using an estimated voltage drop or a feeder end voltage measurement obtained from a radial feeder that had no generation. Therefore, the calculation of key voltage measurement by the supervisory and integrated control methods may become inadequate with DG.

Controls based on the oriented discrete coordinate descent methods are optimised for the operation of OLTC and CAP banks. This technique is very attractive as it uses minimum number of control steps to regulate the distribution network voltage and reactive power. However, these control methods were developed without regard to DG and in the UK, capacitor banks are not used on the 33 and 11kV networks.

The controls based on AVRS and decision tree approach were developed considering DG. These methods only used the OLTC target voltage as the control variable and as a result under performed in situation where voltage violation in one part of the network is below the permissible limits while elsewhere it is above the permissible limits.

Distribution networks have limited controllable devices compared to a transmission network. This makes the control of distribution networks different from that of a transmission network. The controls have been applied to electrically formed sub sections rather than a region of the network with many sub sections. However, future distribution networks are envisaged to have many DGs. There may be multiple controllable devices such as OLTCs, inline voltage regulators, STATCOMS and shedable loads. With many controlled devices, a coordinated distribution control approach similar to that of a CSVSC needs to be adopted.

A control method based on OPF can minimise a given cost function with multiple controls. The OPF is applicable to small distribution sub sections and to large areas of distribution networks and can provide coordinated controls. Therefore, an OPF method is an appropriate choice for DMSC control applications.

A linear programming (LP) based OPF algorithm to increase system solvability is presented in (Yao *et al*, 1999; Radi, 1999). This algorithm used slack variables (fictitious control) for load shedding and reactive power support at each node on the network. The algorithm also used generation ramp/shed slack variables at each generator node to increase or decrease available injection at these nodes. This OPF algorithm was implemented as an appropriate choice to integrate with the state estimator to use in the DMSC.

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ICCS / NTUA CONTRIBUTION

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1. Introduction

DG sources connected to the distribution network are in principle capable of regulating their output power factor (pf). However, the potential for pf regulation is currently under-exploited, as most DG units are typically operated at unity pf.

In this report, the possibilities offered and the potential benefits from power factor control for DG sources connected to the LV network are explored, considering three power factor regulation algorithms. The main evaluation criteria are the improvement on voltage regulation, the reduction on power and energy losses and the total power factor of the LV feeders.

The power factor regulation is assumed to be performed independently for each DG source, using locally available information, such as the voltage deviation from the nominal value at the connection point of each DG source. Further, although the possible variations of the upstream network voltage have been considered, no attempt has been made to coordinate the action of the local regulators with other voltage regulation means in the network (such as capacitors and OLTCs). Apparently this constitutes a decentralized voltage regulation policy, lacking any central coordination. Hence the results obtained do not necessarily reflect the benefits from a coordinated voltage control policy, which would definitely be more substantial.

2. Study Case LV network

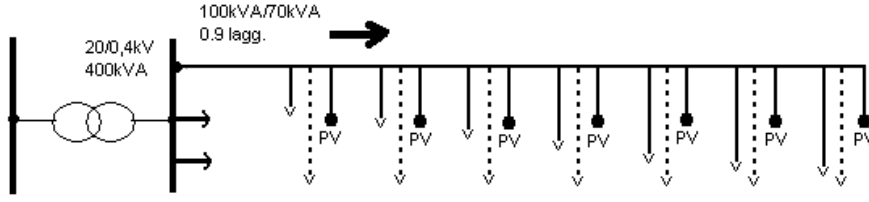


Figure 1. Simplified LV network with embedded PV generation. Uniform (---) and triangular (—) load distributions are shown.

Consider a simplified low - voltage network as shown in Fig.1. It consists of three feeders of length L , fed by an MV/LV substation. The feeders are either underground cables (300 m long, $0.264 \Omega/\text{km}$) or overhead lines (400 m long, $0.397 \Omega/\text{km}$). The total load per feeder is approximately 100 kVA, or 70 kVA (overhead lines). The load power factor is assumed to be 0.9 ind. in all cases. Notably, the length and load of the feeders have been chosen order to provide approximately a 4% voltage drop along the feeder.

A continuous load and DG spatial distribution has been assumed, as it is typical for urban (or semi-urban) areas with high load densities, to represent the multitude of small consumers and sources along each feeder. Further, two cases have been studied regarding the load and DG power distribution, a uniform one (for the overhead lines) or a triangular (for the underground cables), as shown in Figure 2.



Figure 2: Uniform and triangular distribution of load and DG generation along the feeder.

The active and reactive power densities along the feeder are described by the following equations (subscripts L and G denote respectively load and DG):

$$p_L(s) = p_L \times (1 - n_1) \times \frac{s}{L} + p_L \times n_1 \quad (1.a)$$

$$q_L(s) = q_L \times (1 - n_1) \times \frac{s}{L} + q_L \times n_1 \quad (1.b)$$

$$p_G(s) = p_G \times (1 - n_2) \times \frac{s}{L} + p_G \times n_2 \quad (1.c)$$

where s is the distance from the substation and

n_1, n_2 are constants (0 for triangular and 1 for uniform distribution).

p_L, q_L, p_G are derived from the active and reactive power of the load and DG along the feeder:

$$P_{total_Load} = \sqrt{3} \times pf \times V_n \times I_L = \int_0^L p_L(s) ds \Rightarrow p_L = \frac{2 \times \sqrt{3} \times pf \times V_n \times I_L}{L \times (1 + n_1)} \quad (2.a)$$

Likewise:

$$Q_{total_Load} = \sqrt{3} \times \sqrt{1 - pf^2} \times V_n \times I_L \Rightarrow q_L = \frac{2 \times \sqrt{3} \times \sqrt{1 - pf^2} \times V_n \times I_L}{L \times (1 + n_1)} \quad (2.b)$$

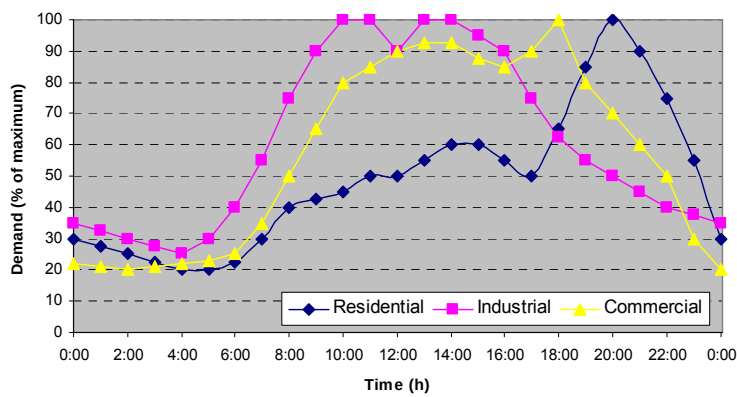
$$P_{total_gen} = \sqrt{3} \times pf \times pen \times V_n \times I_L \Rightarrow p_G = \frac{2 \times \sqrt{3} \times pf \times pen \times V_n \times I_L}{L \times (1 + n_2)} \quad (2.c)$$

where pf is the load power factor and

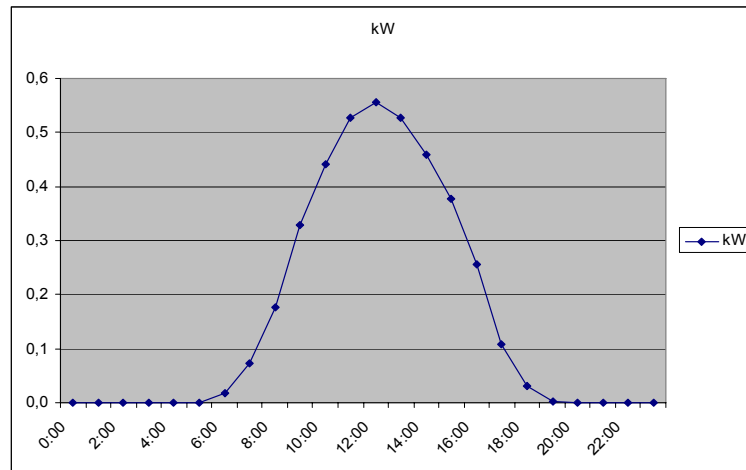
pen is the DG penetration level

In this study DG penetration levels varying from 0% to 50% of the peak load demand of the feeder have been examined.

The daily load curves of the three load types considered are shown in Fig. 3(a). Both, daily and evening maximum load conditions are thus included. The daily load curve for the output power per installed kW of photovoltaics is shown in Fig. 3(b) (average annual hourly values for the insolation levels encountered in the Mediterranean region).



(a)



(b)

Figure 3. (a) Daily load curves for the three different load types considered.

(b) Average annual daily PV production curve per installed kW of PVs.

3. Mathematical formulation

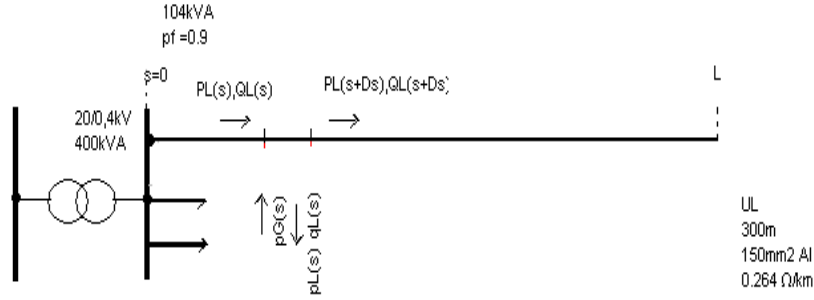


Figure 4. Feeder with distributed load and PV generation .

The power flow along the feeder is described in Figure 4. From this figure the following equations are obtained:

$$P_{total}(s + \Delta s) = P_{total}(s) - [p_L(s) \times \Delta s - p_G(s) \times \Delta s] \Rightarrow$$

$$Q_{total}(s + \Delta s) = Q_{total}(s) - [q_L(s) \times \Delta s + q_G(s) \times \Delta s]$$

$$P_{total}(s + \Delta s) - P_{total}(s) = -\Delta s \times [p_L(s) - p_G(s)] \Rightarrow$$

$$Q_{total}(s + \Delta s) - Q_{total}(s) = -\Delta s \times [q_L(s) + q_G(s)]$$

$$\frac{dP_{total}(s)}{ds} = -p_L(s) + p_G(s) \quad (3.a)$$

$$\frac{dQ_{total}(s)}{ds} = -q_L(s) - q_G(s) \quad (3.b)$$

$$U(s + \Delta s) = U(s) - [r \times P_{total}(s) \times \Delta s + x \times Q_{total}(s) \times \Delta s] \quad (4)$$

In these equations all quantities are expressed in per unit. Notably, generation convention is adopted for p_G , but load convention for q_G (i.e. positive when consumed by the source). With $r+jx$ the feeder impedance per unit length is denoted.

$$\begin{aligned} (4) \Rightarrow \frac{dU(s)}{ds} &= -r \times P_{total}(s) - x \times Q_{total}(s) \Rightarrow \frac{d^2U(s)}{ds^2} = -r \times \frac{dP_{total}(s)}{ds} - x \times \frac{dQ_{total}(s)}{ds} \\ \Rightarrow \frac{d^2U(s)}{ds^2} &= r \times [p_L(s) - p_G(s)] + x \times [q_L(s) + q_G(s)] \end{aligned} \quad (5)$$

The interaction between voltage $U(s)$ and DG reactive power density $q_G(s)$ is evident in equation (5). Therefore an efficient $q_G(s)$ control might improve voltage regulation and losses. Whatever the DG power factor regulation method selected, it should respect the rating of the DG units, as well as any inherent power factor variation limits.

The pf regulation method will be expressed by a suitable relation:

$$\frac{q_G(s)}{p_G(s)} = f(U(s)) \quad (6)$$

Substituting in equation (5) yields:

$$\frac{d^2 U(s)}{ds^2} = r \times p_L(s) + x \times q_L(s) + [x \times f(U(s)) - r] \times p_G(s) \quad (7)$$

subject to the boundary conditions:

$$U(0) = U_0 - \Delta U_{TR} \quad (8.a)$$

$$\left. \frac{dU(s)}{ds} \right|_{s=L} = 0 \quad (8.b)$$

where U_0 is the voltage at the MV bus of the MV/LV substation and

ΔU_{TR} is the voltage drop on the transformer:

$$\Delta U_{TR} = \frac{3 \times [rTR \times P_{total, line} + xTR \times Q_{total, line}]}{V_n^2}$$

4. Power factor regulation algorithms

Three alternative methods of pf regulation are examined.

A. Constant power factor

$$pf_G = \sigma\tau\alpha\theta\epsilon\rho\phi \Rightarrow f(U(s)) = \pm \frac{\sqrt{1 - pf^2_G}}{pf_G}$$

The pf is maintained at a constant value. Pf values considered here are 0.93, 0.95, 0.97 (all leading), as well as 1. Hence the Q injection appears as a constant fraction of the active DG output and does not relate to the voltage at connection point.

B. Q_G injection/absorption in proportion to voltage deviation

$$f(U(s)) = a \times [U(s) - U_{ref}] + b \Rightarrow \frac{q_G(s)}{p_G(s)} = a \times [U(s) - U_{ref}] + b$$

In this case, the Q injection is defined as a fraction of the active DG output, which varies in proportion to the deviation of the voltage at the DG connection point from rated. The action of this regulation is tuned via constants a and b.

The rationale behind this algorithm is that the DG sources should generate reactive power (negative Q) in network under-voltage conditions and consume (positive Q) in case of over-voltages. Hence, the terminal voltage will tend to be regulated towards the nominal value U_{ref} .

C. Q_G injection/absorption varies with voltage deviation, with inherent limit

$$pf_G = (1 - \lim_{pf}) \times \exp\{-c \times |U(s) - U_{ref}|\} + \lim_{pf} \Rightarrow f(U(s)) = \pm \frac{\sqrt{1 - pf^2_G}}{pf_G}$$

The rationale of this method is exactly the same as for the previous Method B. Hence, the power factor can vary depending on the deviation of the voltage, but it cannot exceed an inherent maximum regulation limit.

The pf regulation methods (B) and (C) are presented in Figures 5 and 6 for indicative values of their control parameters. Regulation method B, while relatively insensitive to small voltage deviations, it tends to decrease dramatically the DG pf when large voltage deviations occur. This will result in PV power factors varying significantly along the feeder, possibly to values rather unrealistic, if constant a is large.

Regulation method C, on the other hand, is more sensitive to small voltage drops or increases, whereas for large deviations the power factor tends to stabilize at the inherent limit (assumed to be 0.9 in this study).

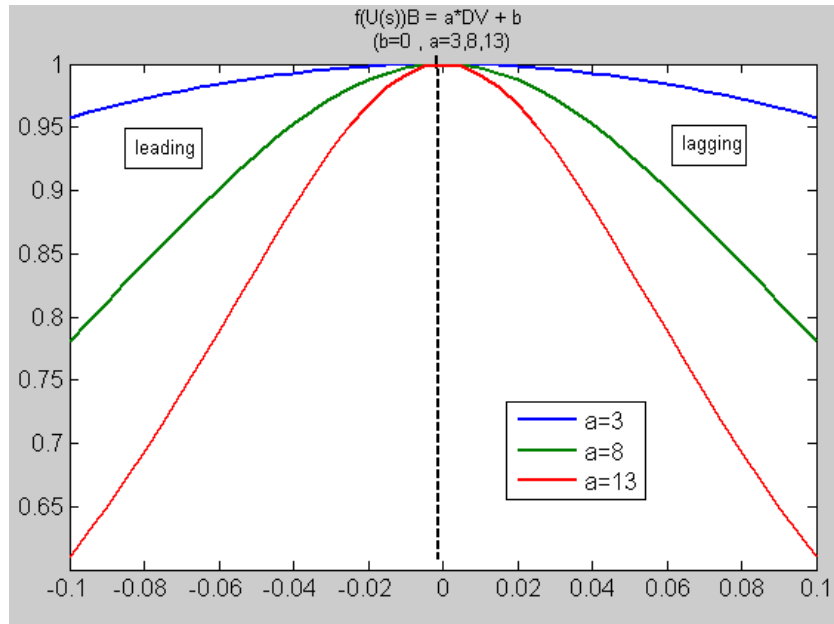


Figure 5. Method B - Variation of pf_G as a function of voltage deviation.

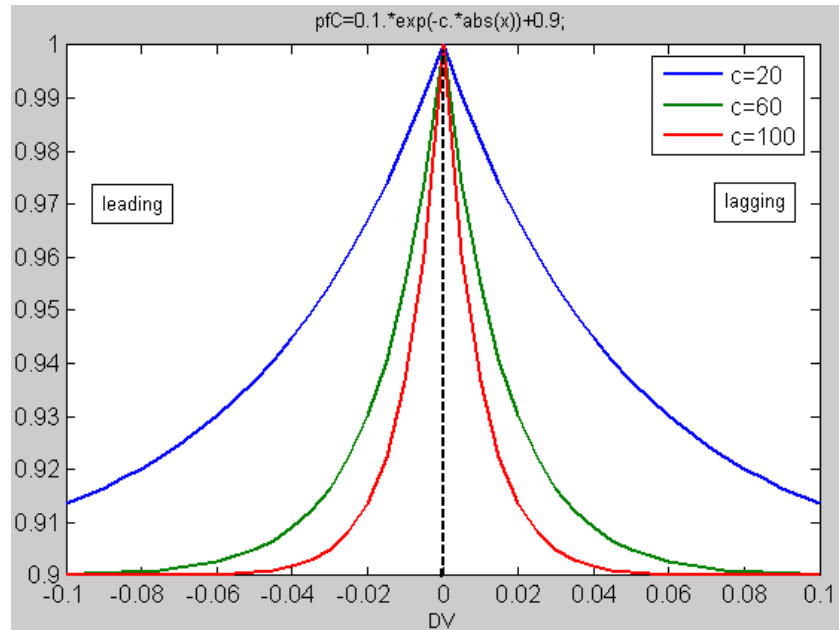


Figure 6. Method C - Variation of pf_G as a function of voltage deviation.

5. Results

In this section selected results are presented for:

- Residential and industrial load
- Triangular and uniform load and DG distributions
- PV penetration of 50%
- All three regulation algorithms

Further, the possible fluctuation of the MV bus voltage has been considered. A fluctuation limit of $\pm 3\%$ is assumed. Residential and industrial load present their peaks at a different time of the day. The demand for industrial load occurs between 10:00 and 14:00, approximately the same time as the PV maximum generation. On the other hand, residential load presents a peak at 20:00, when PV generation is zero.

5.1 Triangular distribution – Residential load

Here, the results for a feeder with triangular distribution of residential-type load are presented. The main criteria (voltage regulation, losses and total power factor of the feeder) are examined for nominal MV bus voltage (1 p.u). Voltage at the end of the feeder and the total power factor at its origin is also examined for different MV bus voltages. For this purpose, the system has been set to operate at steady 0.97 p.u or 1.03 p.u MV bus voltage, although this might not be realistic, since the MV network voltage will vary during the day. Nevertheless, the respective curves provide an indication of the pf regulation performance under non-ideal upstream system conditions.

5.1.a Control method (A)

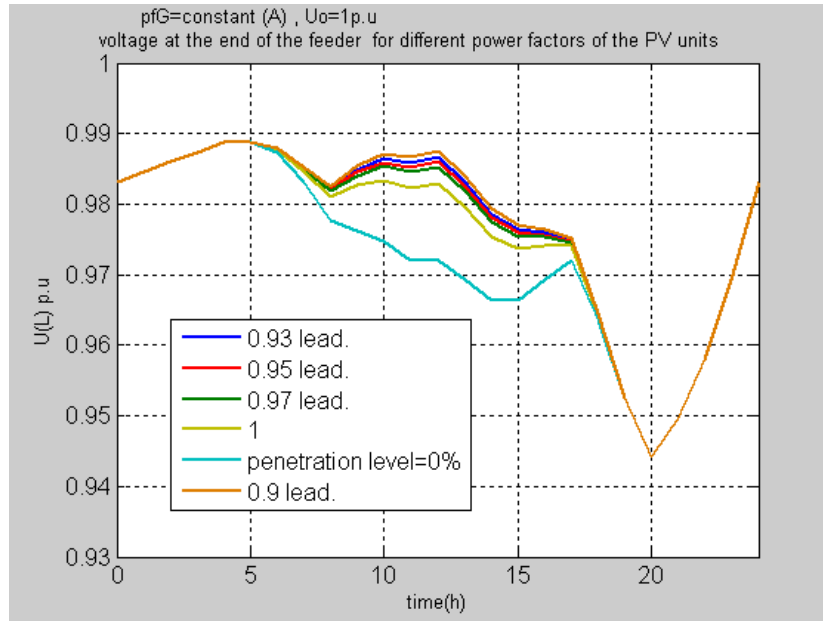


Figure 7. Voltage at the end of the feeder for different constant power factors of the PV units (regulation method A) and for residential load with triangular distribution. MV bus voltage=1 p.u

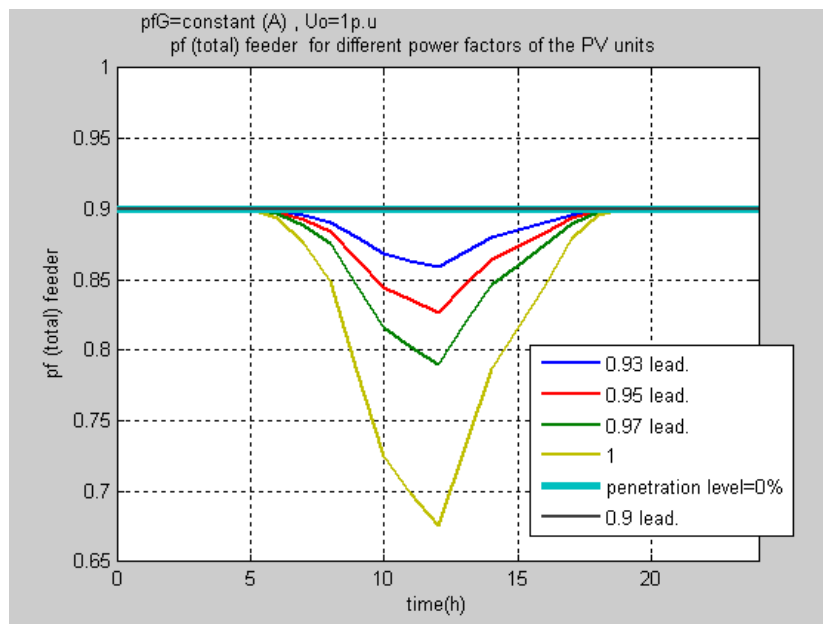


Figure 8. Total power factor of the feeder for different constant power factors of the PV units (regulation method A) and for residential load with triangular distribution. MV bus voltage=1 p.u

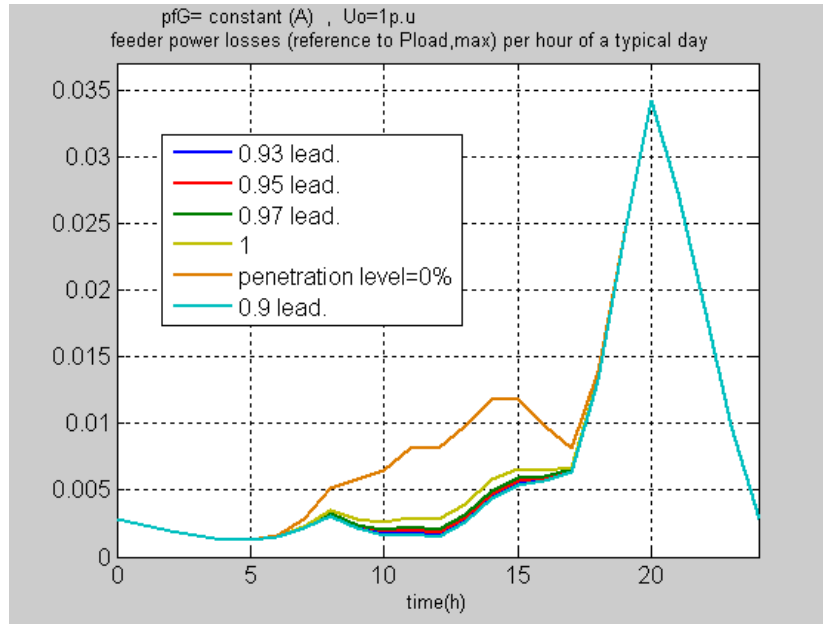


Figure 9. Feeder power losses for different constant power factors of the PV units (regulation method A) and for residential load with triangular distribution. MV bus voltage=1 p.u

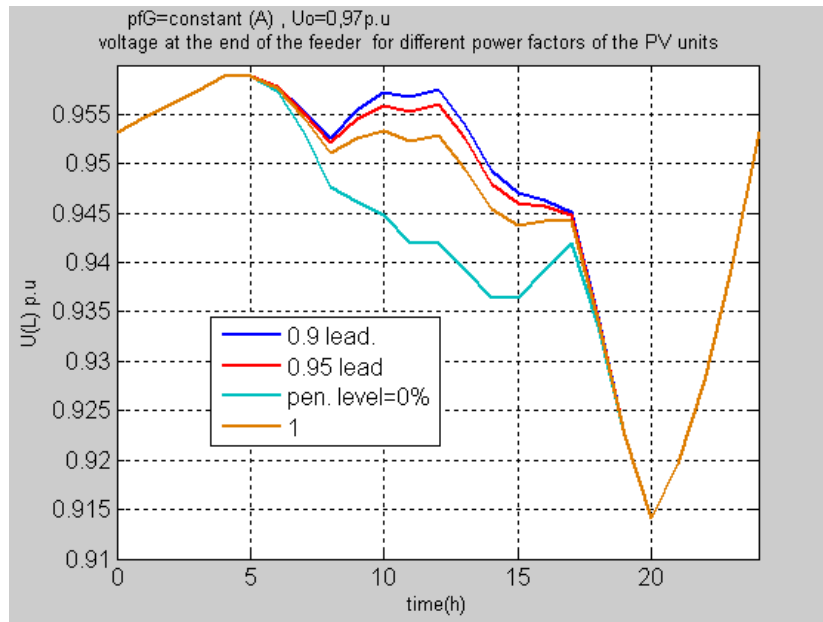


Figure 10. Voltage at the end of the feeder for different constant power factors of the PV units (regulation method A) and for residential load with triangular distribution. MV bus voltage=0.97p.u.

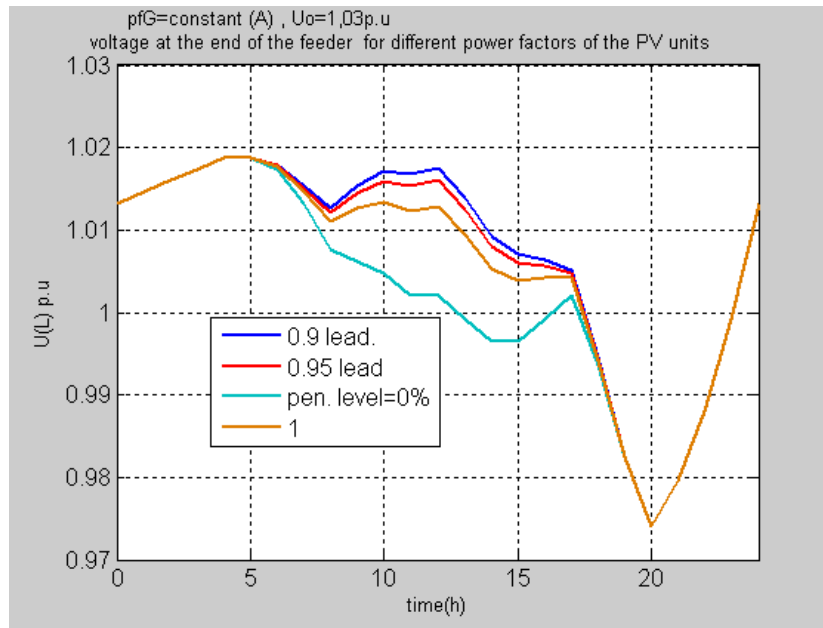


Figure 11. Voltage at the end of the feeder for different constant power factors of the PV units (regulation method A) and for residential load with triangular distribution. MV bus voltage=1.03 p.u.

The performance of control method A is illustrated in Figures 6 to 9 and 10 to 11. A significant improvement is caused mainly by the DG active power injection. While voltage regulation and feeder losses improve, the total pf of the feeder deteriorates, which is expected since the peak of PV generation occurs at low load demand hours (fig. 8).

Specifically, the voltage increases by 1% due to the active power injection and up to an additional 0.5% due to Q injection. This is valid for both $U_o=1$ p.u. and 0.97 p.u. voltage at the M bus (figures 7 and 10). The total pf of the feeder can improve substantially as pf_G tends to 0.9 leading.

A leading value of pf_G results in a further increase in voltage when $U_o=1.03$ p.u (fig.11) at a time of low load demand. Hence the voltage obtains values that exceed nominal voltage but are not prohibitive.

The annual energy losses of the feeder and the MV/LV T/F for 0% DG penetration (base case) are:

- Feeder annual energy losses: 7.9 MWh
- T/F annual energy losses: 12.8 MWh

In Table 1 the annual energy losses for 50% penetration are presented. The decrease in power and energy losses is caused mainly by the DG active power injection. Power losses have a 0.5% reduction due to active power injection and another 0.12% due to reactive injection (fig.9). The decrease in feeder energy losses is 18% due to active injection. Reactive injection adds up another 4% reduction (Table.1).

	Feeder annual losses (change % w.r.t. base case)	T/F annual losses (change % w.r.t. base case)
$pf_G=1$	6.48 MWh (-18.0%)	11.51 MWh (-10.2%)
$pf_G=0.97$ lead.	6.28 MWh (-20.5%)	11.33 MWh (-11.5%)
$pf_G=0.95$ lead.	6.23 MWh (-21.1%)	11.28 MWh (-11.8%)
$pf_G=0.93$ lead.	6.19 MWh (-21.6%)	11.25 MWh (-12.1%)
$pf_G=0.9$ lead.	6.15 MWh (-22.15%)	11.2 MWh (-12.5%)

Table 1. Change in feeder and T/F annual energy losses with pf control method A.

5.1.b Control method (B)

Results from the application of Method B are shown in Figures 12 to 21. Again, a significant improvement is caused mainly by the DG active power injection. Only the total pf of the feeder presents a considerable decrease due to the fact that the peak of PV generation occurs at low load demand.

The voltage increases 1% due to active power and up to an additional 0.2% due to Q injection for a low minimum pf_G (0.85 leading) as shown in fig.13. The increase caused by Q injection is negligible, because during the time that PV generation is significant, voltage deviation is small (low load demand). As it can be observed, power factors are held at values close to 1 during maximum PV generation. Minimum values are obtained when voltage drop increases due to increasing load flow along the feeder. The total pf of the feeder increases only 8%, in spite of the low minimum pf_G values (fig.14). This is due to the fact that the voltage deviations (DV) are small and hence PVs do not operate at significantly reduced power factors.

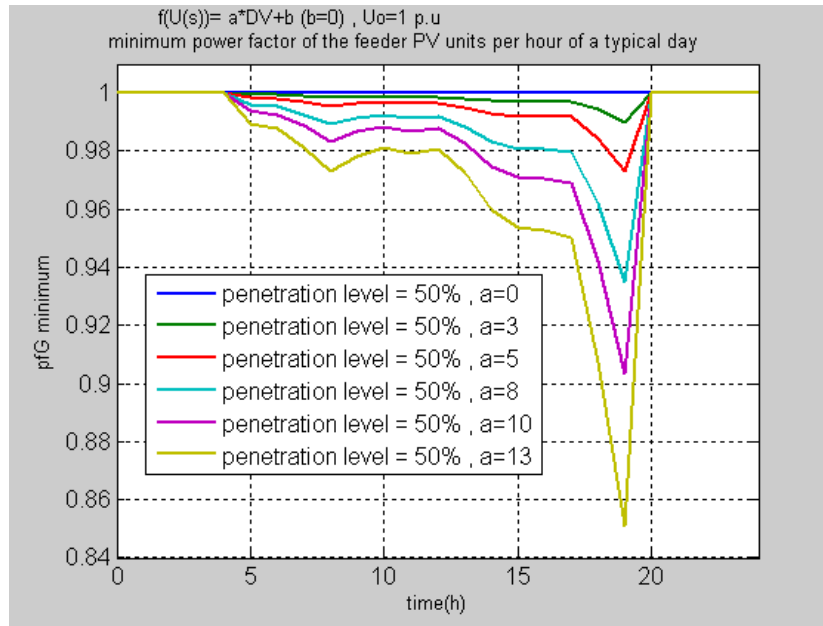


Figure 12. Minimum power factor of the feeder PV units for different values of constant a (regulation method B) and for residential load with triangular distribution. MV bus voltage=1 p.u.

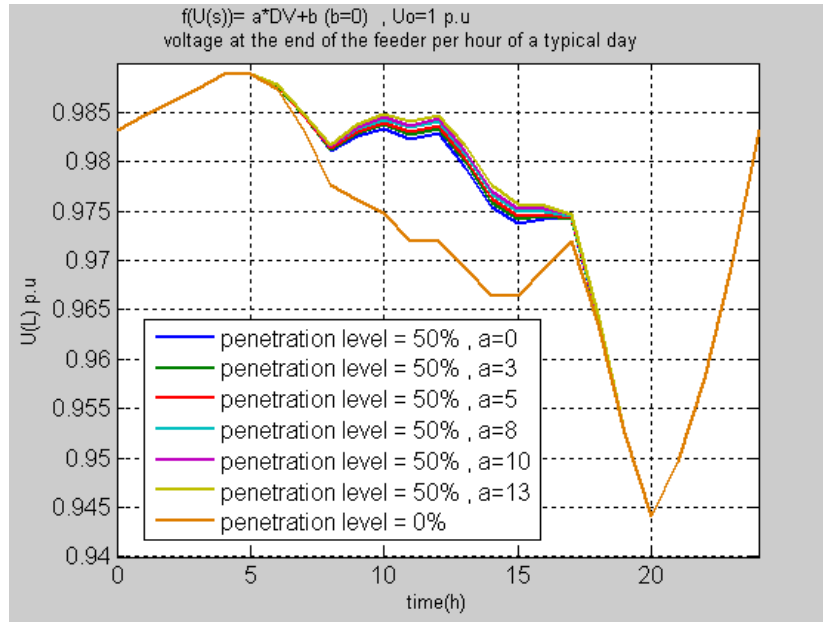


Figure 13. Voltage at the end of the feeder for different values of constant a (regulation method B) and for residential load with triangular distribution. MV bus voltage=1 p.u

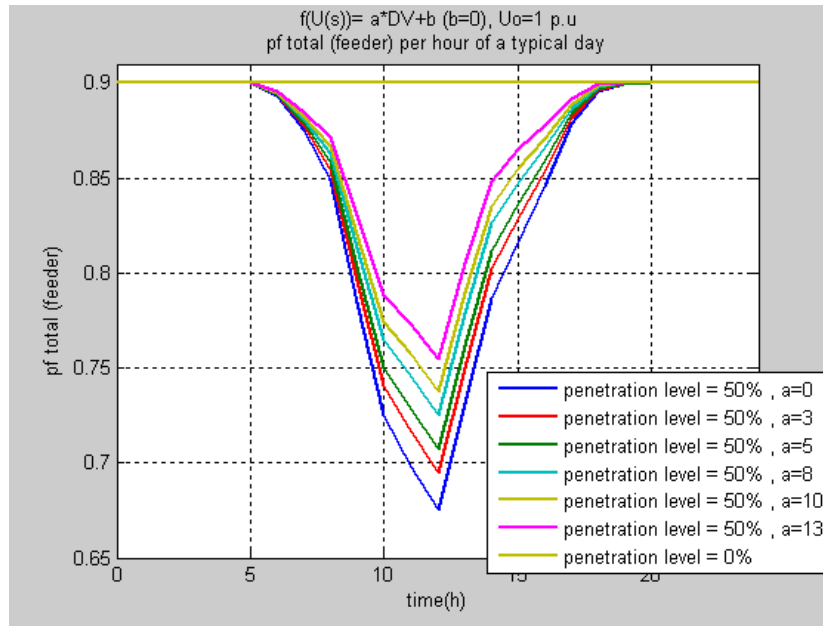


Figure 14. Total power factor of the feeder for different values of constant a (regulation method B) and for residential load with triangular distribution. MV bus voltage=1 p.u

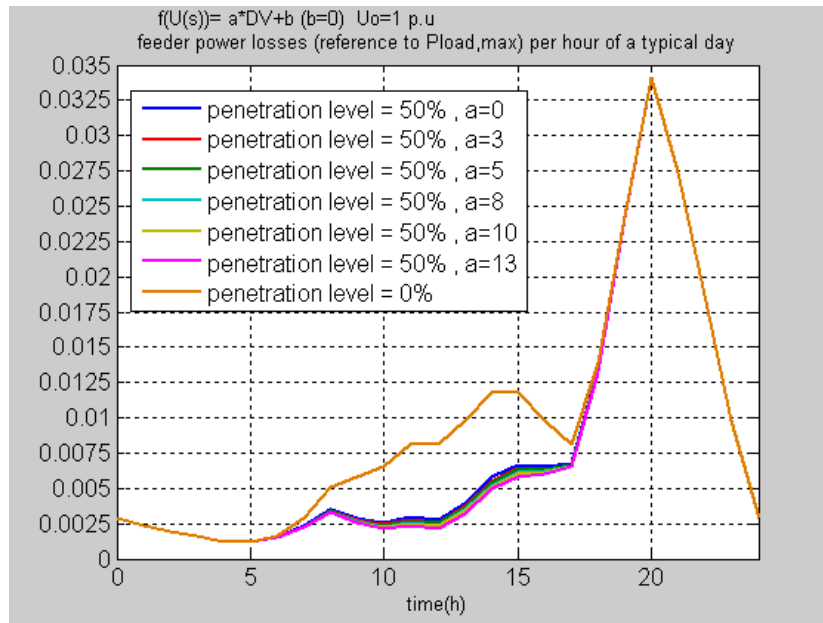


Figure 15. Feeder power losses for different values of constant a (regulation method B) and for residential load with triangular distribution. MV bus voltage=1 p.u

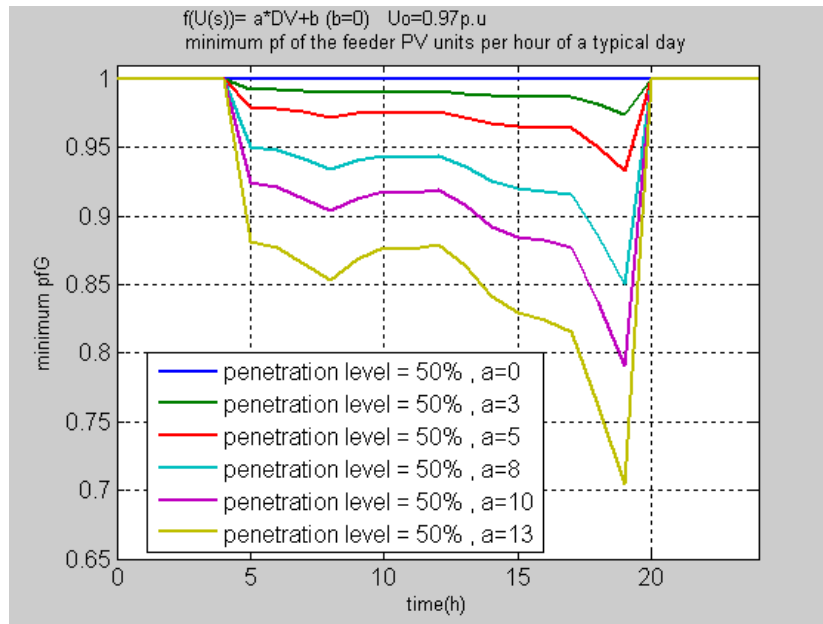


Figure 16. Minimum power factor of the feeder PV units for different values of constant a (regulation method B) and for residential load with triangular distribution. MV bus voltage=0.97 p.u

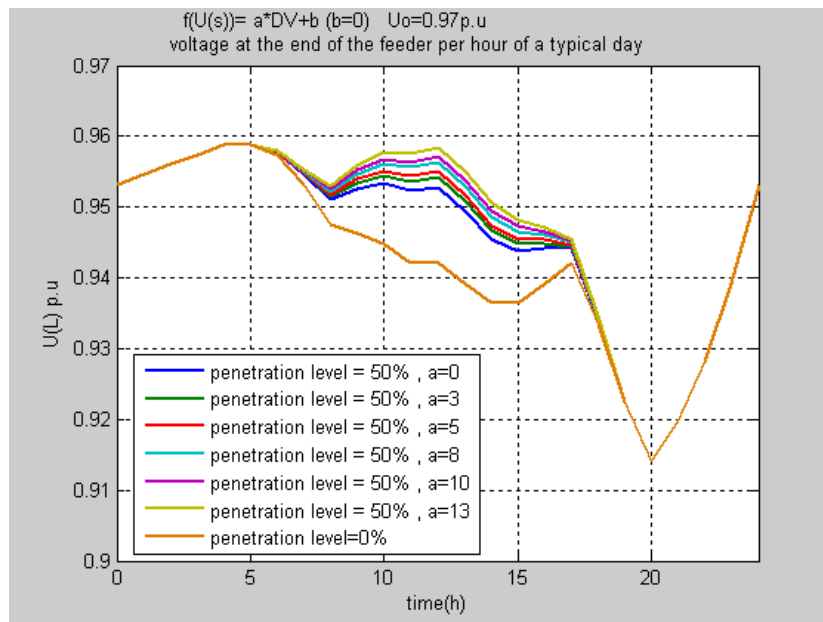
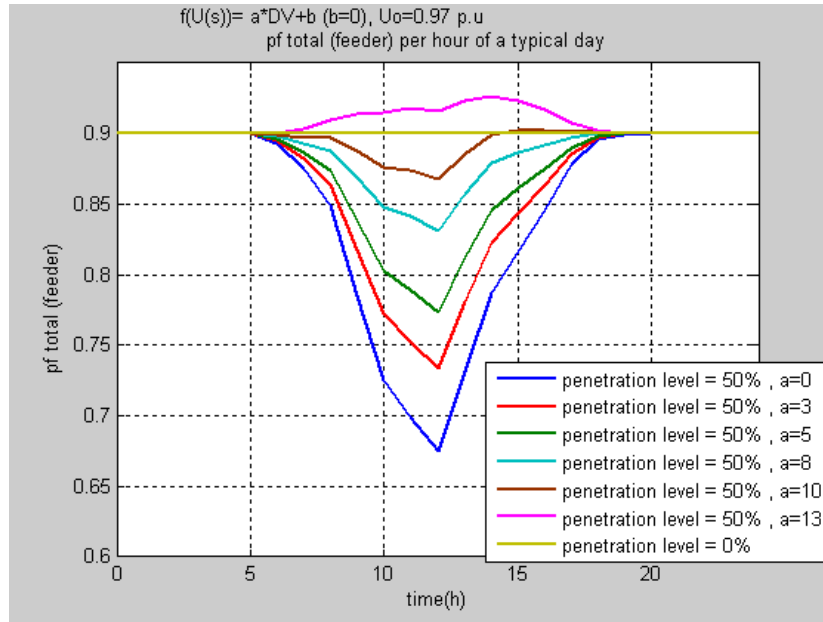


Figure 17. Voltage at the end of the feeder for different values of constant a (regulation method B) and for residential load with triangular distribution. MV bus voltage=0.97 p.u



Figure(18). Total power factor of the feeder for different values of constant a (regulation method B) and for residential load with triangular distribution. MV bus voltage=0.97 p.u.

For $U_o=0.97$ p.u., the voltage deviation from rated, DV, is large enough to obtain reduced PV power factors, which lead to significant Q injection that reduces in turn voltage drop to approximately 0.56% (fig.17). The total pf of the feeder is also improved (fig.18).

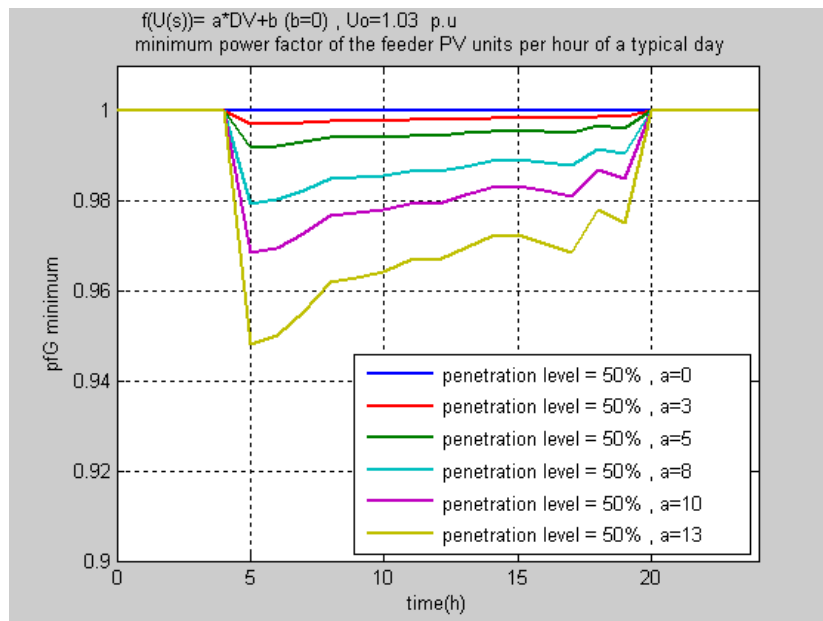


Figure 19. Minimum power factor of the feeder PV units for different values of constant a (regulation method B) and for residential load with triangular distribution. MV bus voltage=1.03p.u

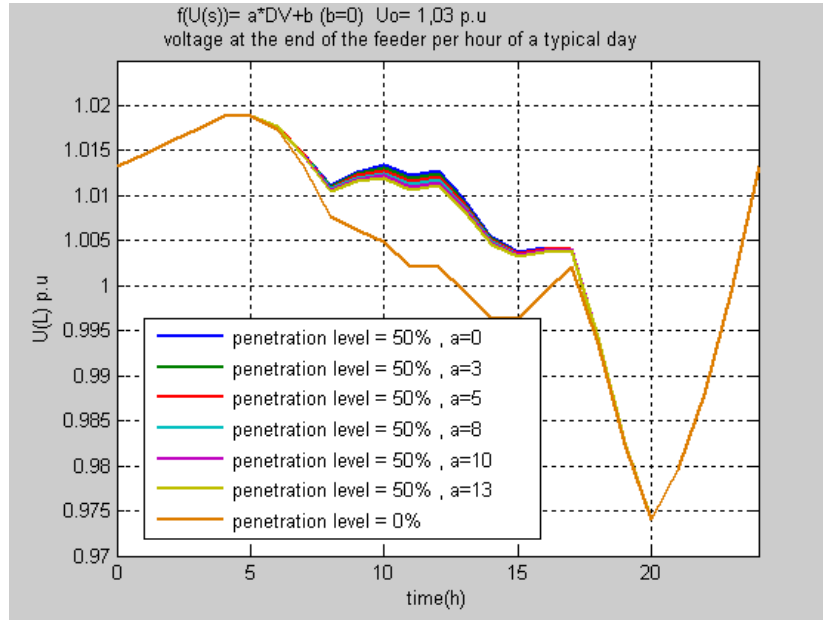


Figure 20. Voltage at the end of the feeder for different values of constant a (regulation method B) and for residential load with triangular distribution. MV bus voltage=1.03 p.u

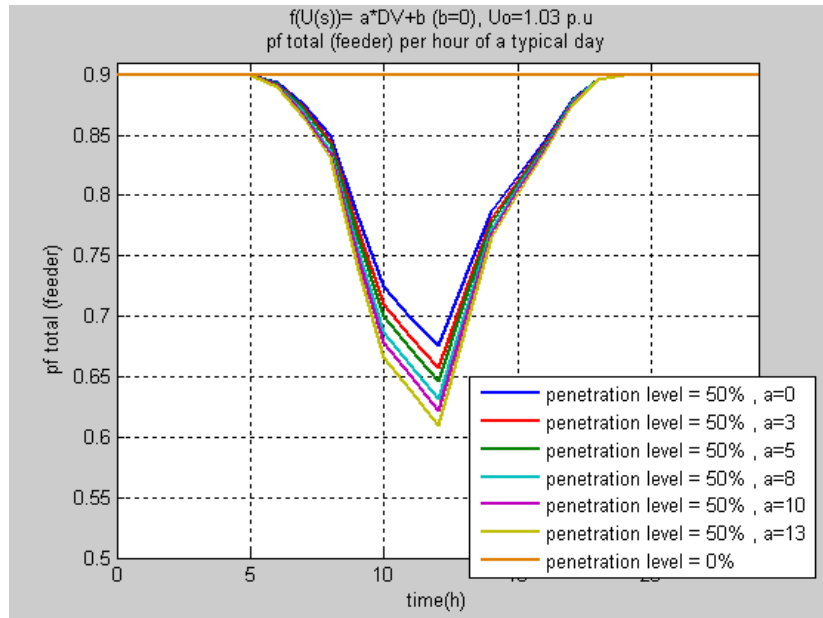


Figure 21. Total power factor of the feeder for different values of constant a (regulation method B) and for residential load with triangular distribution. MV bus voltage=1.03 p.u

For increased MV voltage conditions, $U_0=1.03$ p.u, a reduction in the voltage levels on the feeder is achieved (0.2%) as shown in fig. 20. However, this effect is negligible because voltage deviation do not lead to sufficient Q absorption. In addition the total feeder pf decreases approximately by 7% (fig.21).

The annual energy losses of the feeder and the T/F for 0% penetration (base case) are:

- Feeder annual energy losses: 7.9 MWh
- T/F annual energy losses: 12.8 MWh

The annual energy losses for 50% DG penetration are presented in Table 2. The decrease in power and energy losses is caused mainly by the DG active power injection. Regulation method B contributes an additional 0.08% reduction in power losses, to the 0.5% reduction due to the DG active power injection (fig.15). The contribution to feeder energy losses reduction is an additional 4%, compared to the 18% reduction already achieved by the P_{DG} injection, as shown in Table 2.

Constant a	Min DG pf	Feeder annual losses (change % w.r.t. base case)	T/F annual losses (change % w.r.t. base case)
0	1	6.48 MWh (-18.0%)	11.51 MWh (-10.2%)
3	0.99	6.43 MWh (-18.6%)	11.47 MWh (-10.4%)
5	0.97	6.40 MWh (-19%)	11.44 MWh (-10.6%)
8	0.94	6.36MWh (-19.5%)	11.4 MWh (-10.9%)
10	0.9	6.33MWh (-19.9%)	11.38 MWh (-11.1%)
13	0.85	6.29 MWh (-20%)	11.35 MWh(-11.3%)

Table 2. Change in feeder and T/F annual energy losses with pf control method B.

5.1.c Control method (C)

Results from the application of Method C are shown in Figures 22 to 31. More or less the same remarks hold as for Method B, although certain improvements do exist, as commented in the following.

The voltage increases by 1% due to active power and up to an additional 0.5% due to Q injection (fig.22). The total pf of the feeder increases significantly for a minimum pf_G of 0.9 leading (fig.24). Voltage deviation (DV) is small, but the increased sensitivity of

regulation algorithm (C) to small voltage drops results in power factor values that can lead to a significant Q injection.

For decreased MV system voltage, $U_0=0.97\text{p.u.}$, the voltage deviations DV along the feeder are significant, leading to large Q injections that reduce voltage drop by approximately 0.5% (fig.27). The total pf of the feeder is also improved (fig.28).

On the other hand, at increased MV voltages, $U_0=1.03\text{p.u.}$, the pf control reduces the voltage along the feeder (by 0.5%) as shown in fig.30. In addition the total feeder pf decreases by approximately 20%, since the DG sources consume additional reactive power.

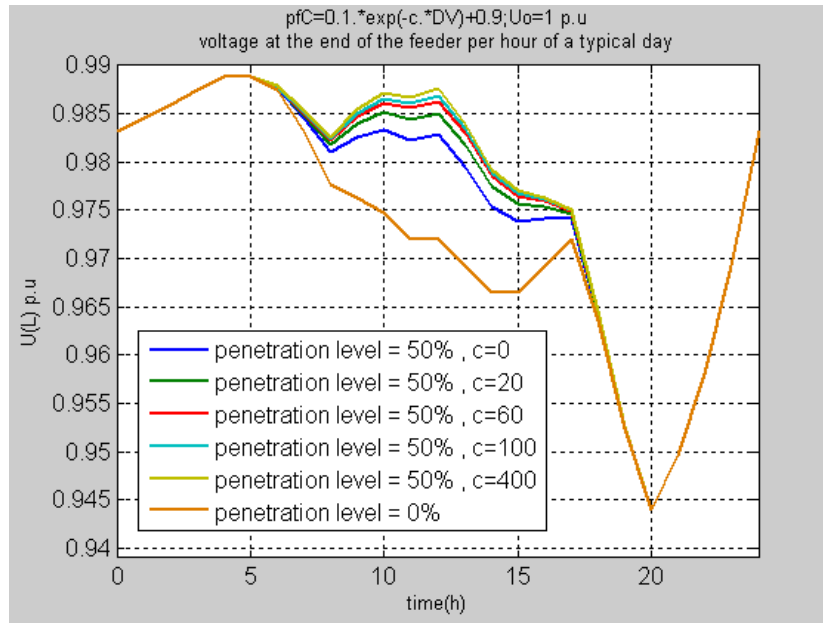


Figure 22. Voltage at the end of the feeder for different values of constant c (regulation method C) and for residential load with triangular distribution. MV bus voltage=1 p.u.

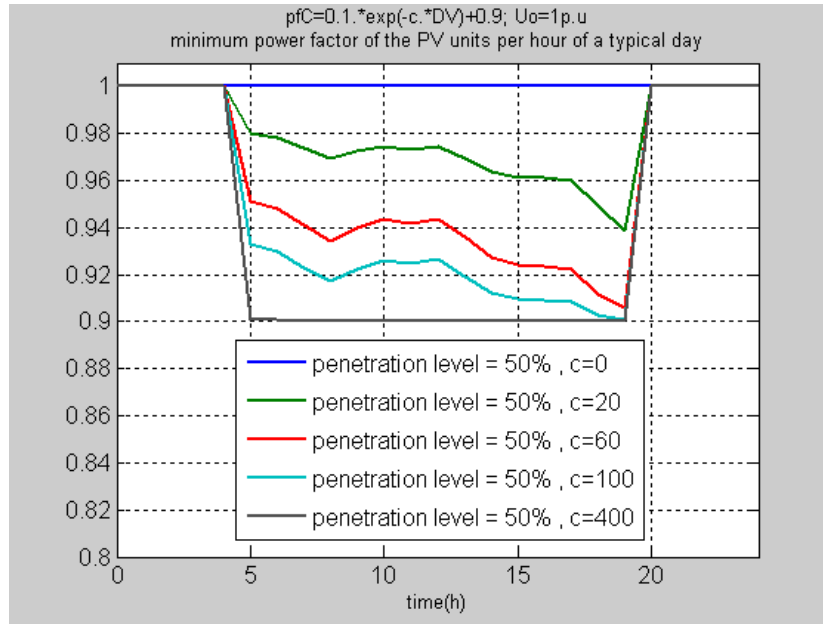


Figure 23. Minimum power factor of the feeder PV units for different values of constant c (regulation method C) and for residential load with triangular distribution. MV bus voltage=1 p.u.

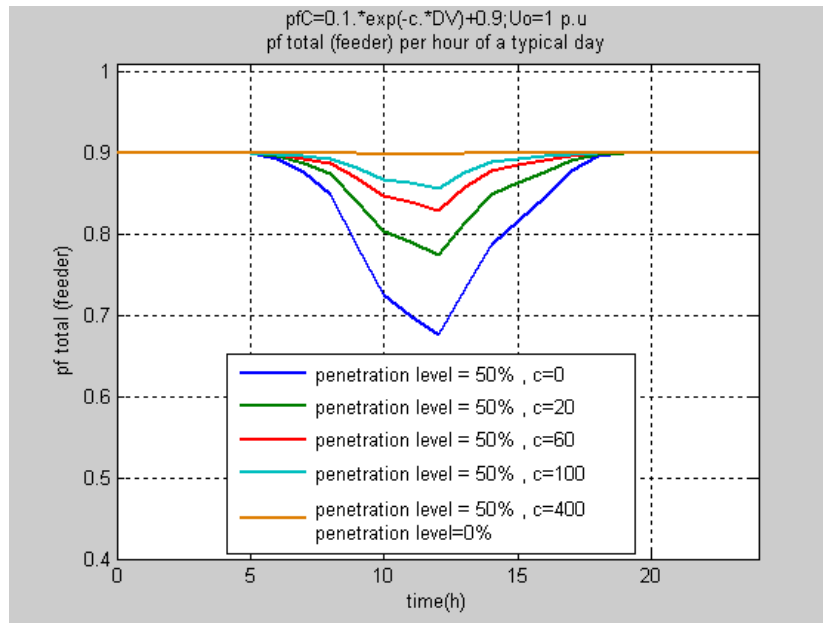


Figure 24. Total power factor of the feeder for different values of constant c (regulation method C) and for residential load with triangular distribution. MV bus voltage=1 p.u.

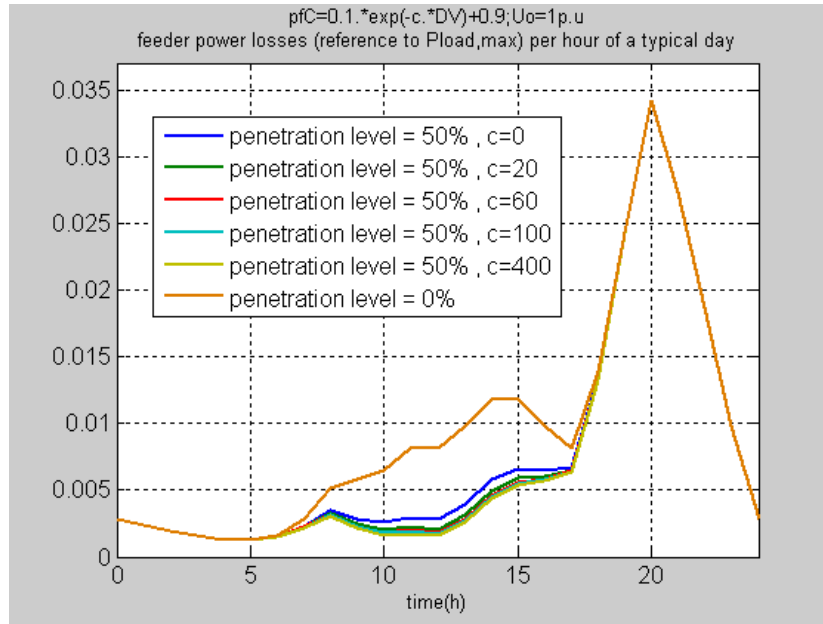


Figure 25. Feeder power losses for different values of constant c (regulation method C) and for residential load with triangular distribution. MV bus voltage=1 p.u.

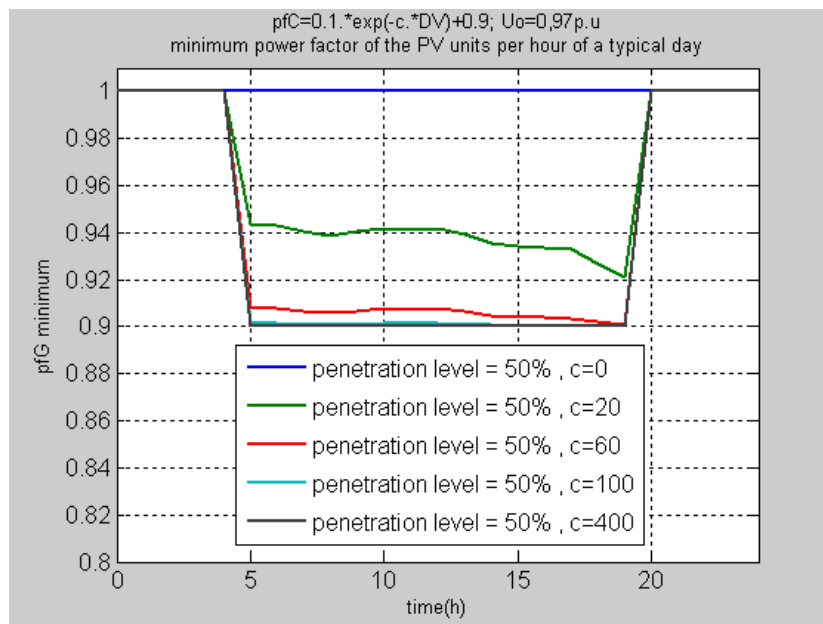


Figure 26. Minimum power factor of the feeder PV units for different values of constant c (regulation method C) and for residential load with triangular distribution. MV bus voltage=0.97 p.u

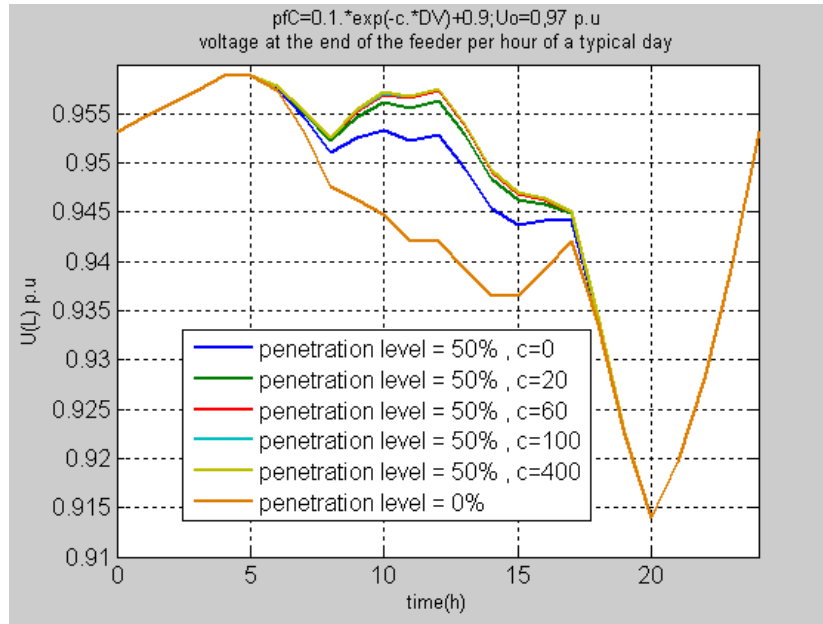


Figure 27. Voltage at the end of the feeder for different values of constant c (regulation method C) and for residential load with triangular distribution. MV bus voltage=0.97 p.u

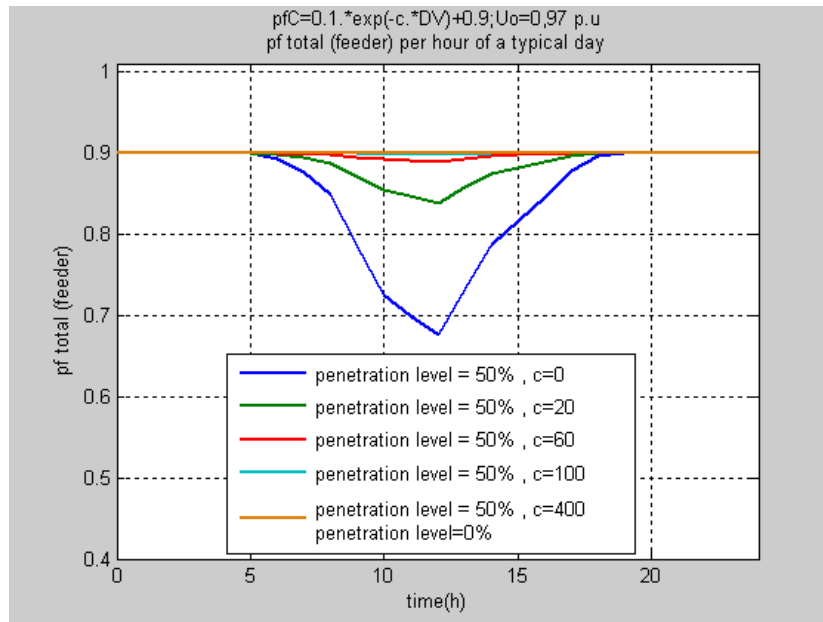


Figure 28. Total power factor of the feeder for different values of constant c (regulation method C) and for residential load with triangular distribution. MV bus voltage=0.97 p.u

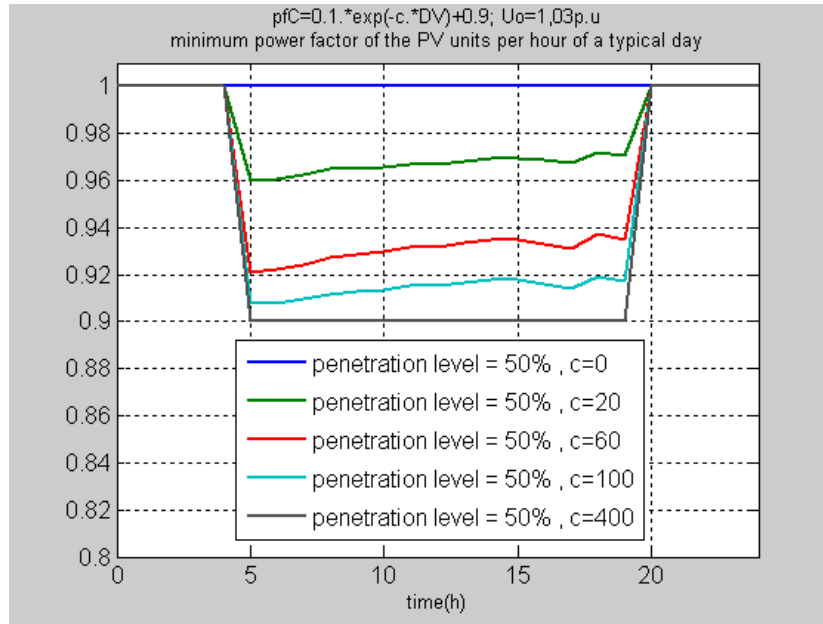


Figure 29. Minimum power factor of the feeder PV units for different values of constant c (regulation method C) and for residential load with triangular distribution. MV bus voltage=1.03 p.u

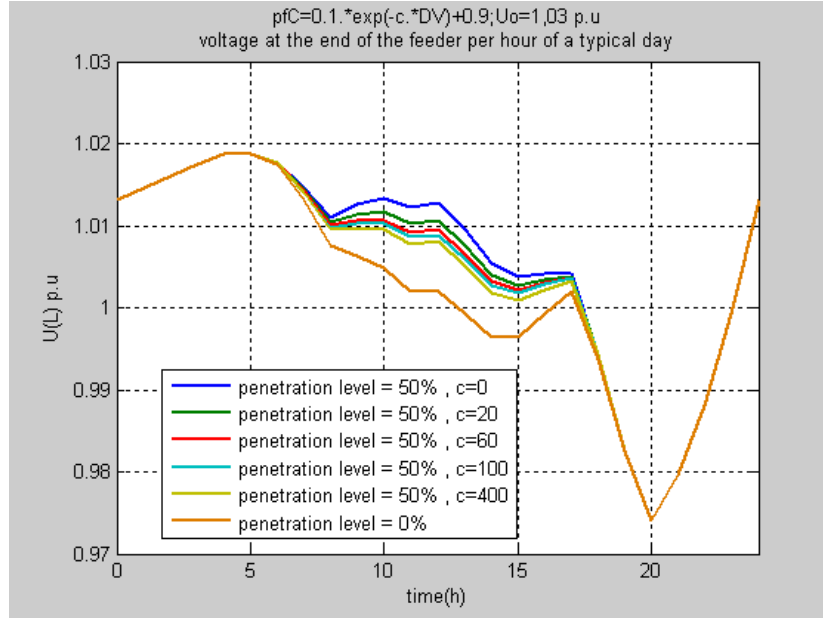


Figure 30. Voltage at the end of the feeder for different values of constant c (regulation method C) and for residential load with triangular distribution. MV bus voltage=1.03 p.u

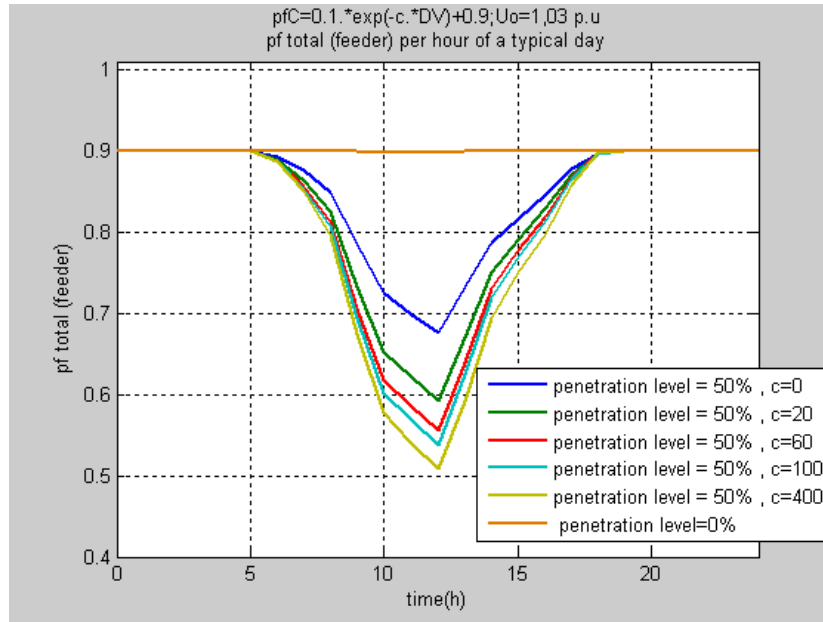


Figure 31. Total power factor of the feeder for different values of constant c (regulation method C) and for residential load with triangular distribution. MV bus voltage=1.03 p.u

The annual energy losses of the feeder and the T/F for 0% penetration (base case) are:

- Feeder annual energy losses: 7.9 MWh
- T/F annual energy losses: 12.8 MWh

In Table 3 are presented the annual energy losses for 50% penetration:

Constant c	Min DG pf	Feeder annual losses (change % w.r.t. base case)	T/F annual losses (change % w.r.t. base case)
0	1	6.48 MWh (-18.0%)	11.51 MWh (-10.2%)
20	0.94	6.28 MWh (-20.5%)	11.31 MWh (-11.5%)
60	0.91	6.20 MWh (-21.5%)	11.25MWh (-12.1%)
100	0.9	6.17MWh (-21.9%)	11.22 MWh (-12.3%)
400	0.9	6.16MWh (-22%)	11.2 MWh (-12.5%)

Table 3. Change in feeder and T/F annual energy losses with pf control method C.

The decrease in power and energy losses is caused mainly by the DG active power injection. Regulation method C adds up to energy losses a 4% reduction for the feeder and 2% for the T/F (table 3). Feeder power losses present an additional 0.122% reduction due to Q injection (fig.25).

5.2) Triangular distribution – Industrial load

Here, the results for a feeder with triangular distribution and industrial load are presented. Industrial load is not typical for lines with a multitude of consumers, represented by continuous load distributions. Nevertheless, it has been used in this study to demonstrate the system's performance when the PV generation and load curves present peaks at the same hours.

5.2.a) Control method (A)

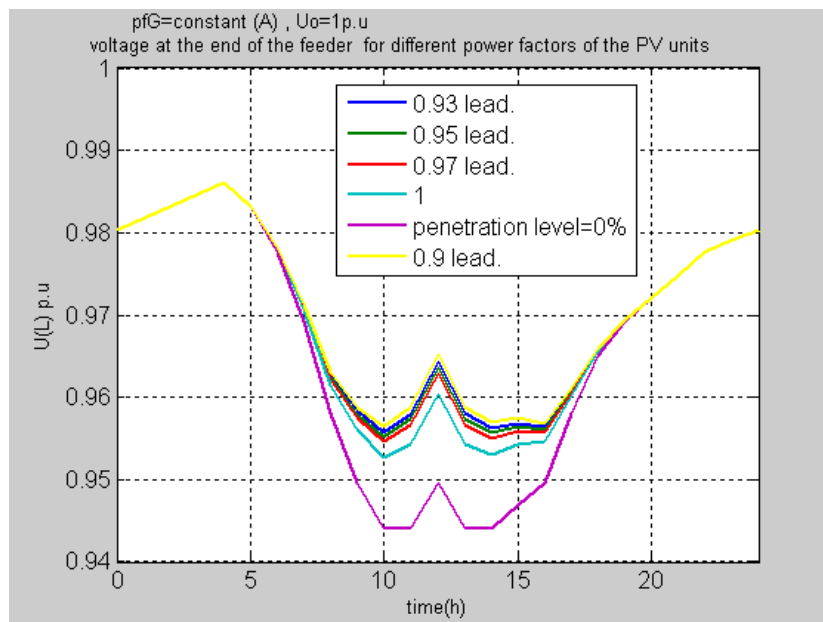


Figure 32. Voltage at the end of the feeder for different constant power factors of the PV units (regulation method A) and for industrial load with triangular distribution. MV bus voltage=1 p.u

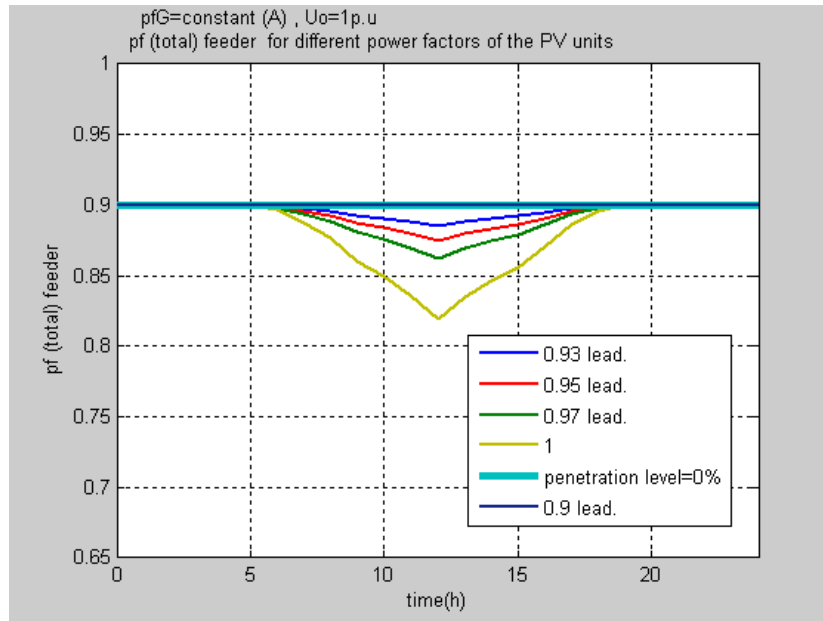


Figure 33. Total power factor of the feeder for different constant power factors of the PV units (regulation method A) and for industrial load with triangular distribution. MV bus voltage=1 p.u

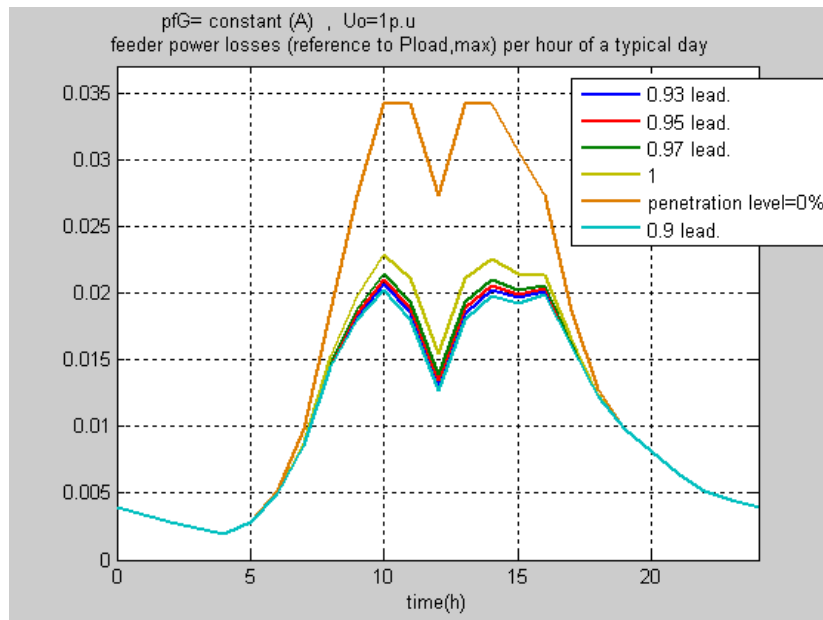


Figure 34. Feeder power losses for different constant power factors of the PV units (regulation method A) and for industrial load with triangular distribution. MV bus voltage=1 p.u

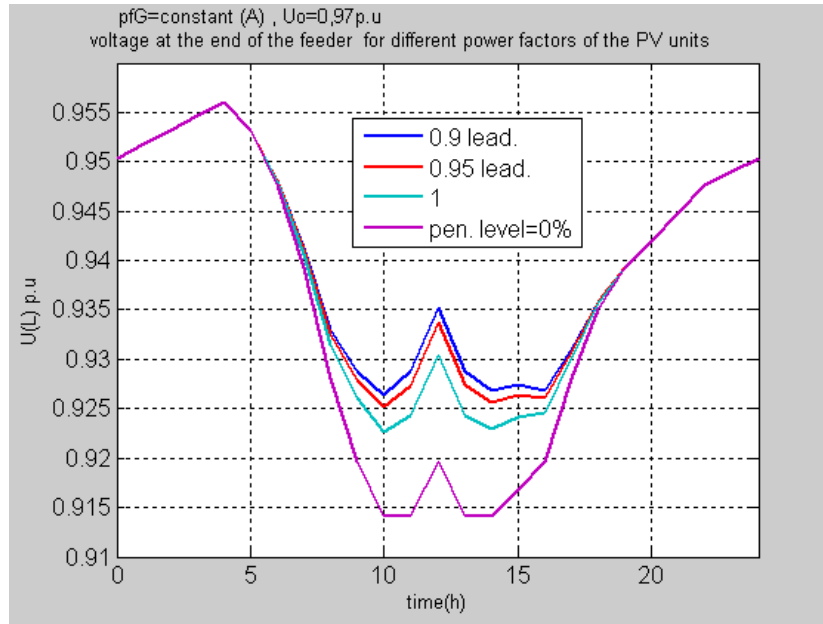


Figure 35. Voltage at the end of the feeder for different constant power factors of the PV units (regulation method A) and for industrial load with triangular distribution. MV bus voltage=0.97 p.u

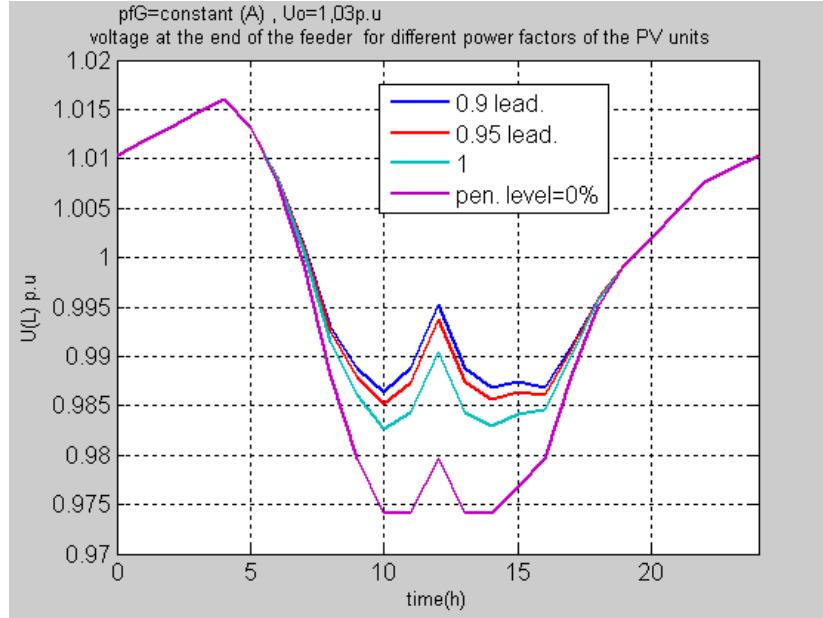


Figure 36. Voltage at the end of the feeder for different constant power factors of the PV units (regulation method A) and for industrial load with triangular distribution. MV bus voltage=1.03 p.u

A significant improvement is caused mainly by the DG active power injection. Only the total pf of the feeder has a decrease. This decrease is smaller than the one with residential load, because the peaks of industrial load and PV generation coincide.

The voltage increases 1% due to active power and up to an additional 0.4% due to Q injection for $U_0=1$ p.u and 0.97 p.u (figures 32 and 35). The total pf of the feeder can improve substantially as pf_G tends to 0.9 leading (fig.33).

A leading pf_G results in an increase in voltage when $U_0=1.03$ p.u (fig.36) at a time of maximum load demand. Voltage obtains values that do not exceed 1 p.u.

The annual energy losses of the feeder and the T/F for 0% penetration (base case) are:

- Feeder annual energy losses: 12.6 MWh
- T/F annual energy losses: 16.9 MWh

In Table 4 are presented the annual energy losses for 50% penetration:

	Feeder annual losses (change % w.r.t. base case)	T/F annual losses (change % w.r.t. base case)
$pf_G=1$	9.5 MWh (-24.6%)	14.26 MWh (-15.8%)
$pf_G=0.97$ lead.	9.11 MWh (-27.6%)	13.92 MWh (-17.8%)
$pf_G=0.95$ lead.	8.99 MWh (-28.6%)	13.82 MWh (-18.3%)
$pf_G=0.93$ lead.	8.89 MWh (-29.4%)	13.74 MWh (-18.9%)
$pf_G=0.9$ lead.	8.78 MWh (-30.3%)	13.64 MWh (-19.3%)

Table 4. Change in feeder and T/F annual energy losses with pf control method A.

The decrease in power and energy losses is caused mainly by the DG active power injection. Power losses have a 1.12% reduction due to active power injection and another 0.3% due to reactive injection (fig.34). The decrease in feeder energy losses is 24.6% due to active injection. Reactive injection adds up another 5.7% reduction (Table.4).

5.1.b) Control method (B)

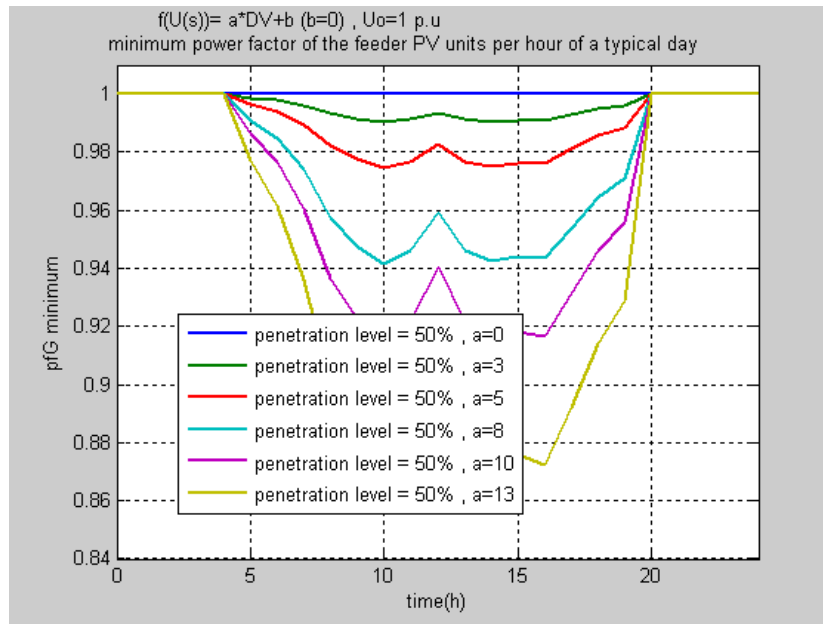


Figure 37. Minimum power factor of the feeder PV units for different values of constant a (regulation method B) and for industrial load with triangular distribution. MV bus voltage=1 p.u

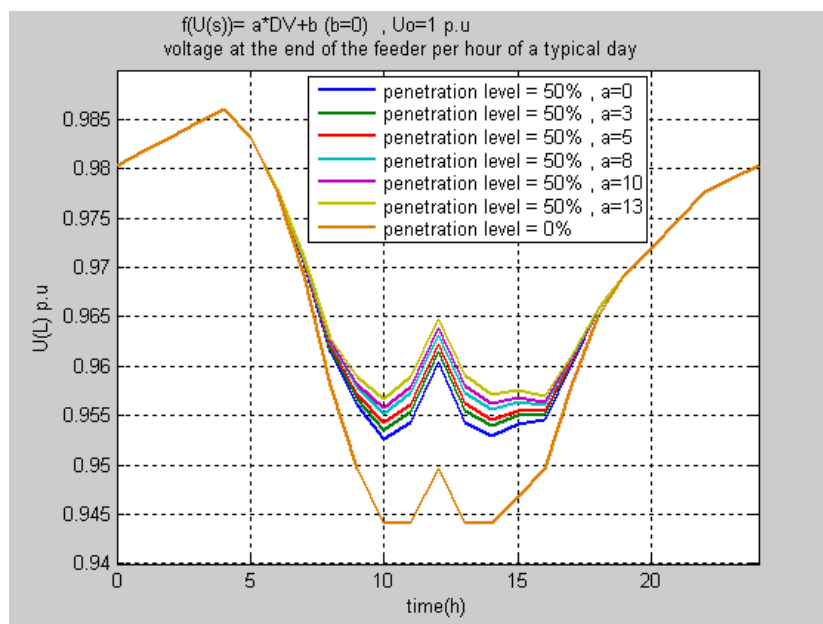


Figure 38. Voltage at the end of the feeder for different values of constant a (regulation method B) and for industrial load with triangular distribution. MV bus voltage=1 p.u

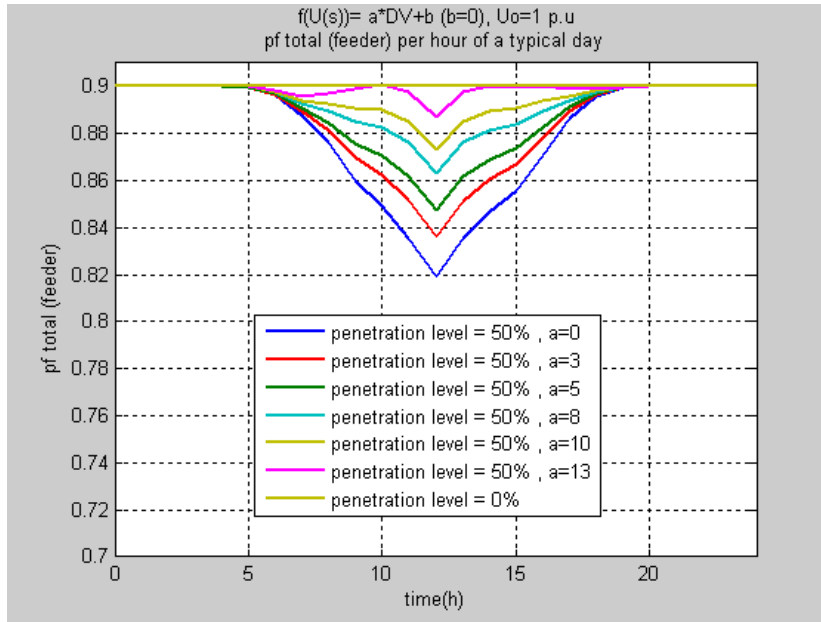


Figure 39. Total power factor of the feeder for different values of constant a (regulation method B) and for industrial load with triangular distribution. MV bus voltage=1 p.u

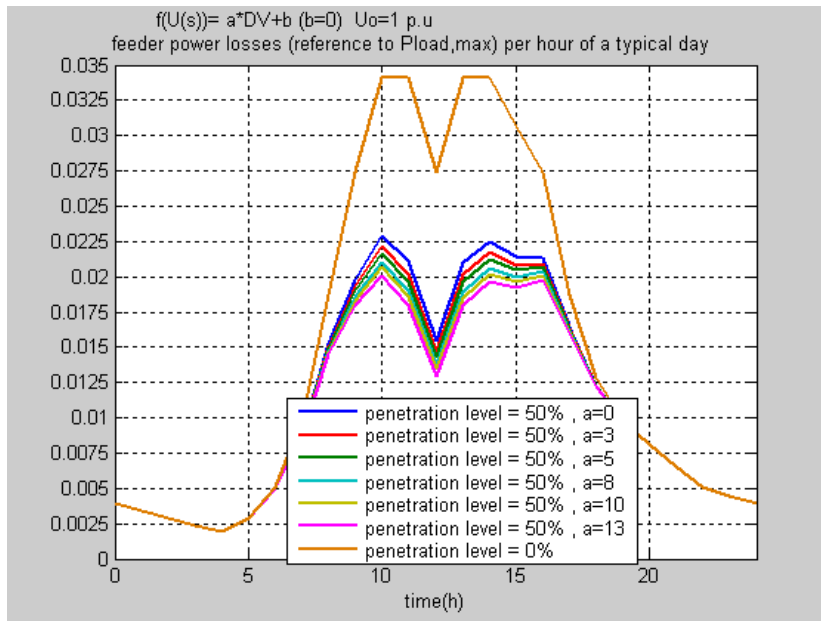


Figure 40. Feeder power losses for different values of constant a (regulation method B) and for industrial load with triangular distribution. MV bus voltage=1 p.u

A significant improvement is caused mainly by the DG active power injection. Only the total pf of the feeder has a decrease.

The voltage increases 1% due to active power and up to an additional 0.4% due to Q injection for a low pf_G (0.87 leading) as shown in figure 38. For $U_o=0.97$ p.u, DV

increases enough. As a result smaller PV power factors are obtained, which lead to significant Q injection that reduces voltage drop approximately 0.7%. The total pf of the feeder is also improved.

The increase in voltage is more important than the one with residential load. Voltage deviation is bigger here and DG pf reaches lower minimum values during considerable PV generation.

The total pf of the feeder increases 7% for maximum reduction of the minimum pf_G (fig.39).

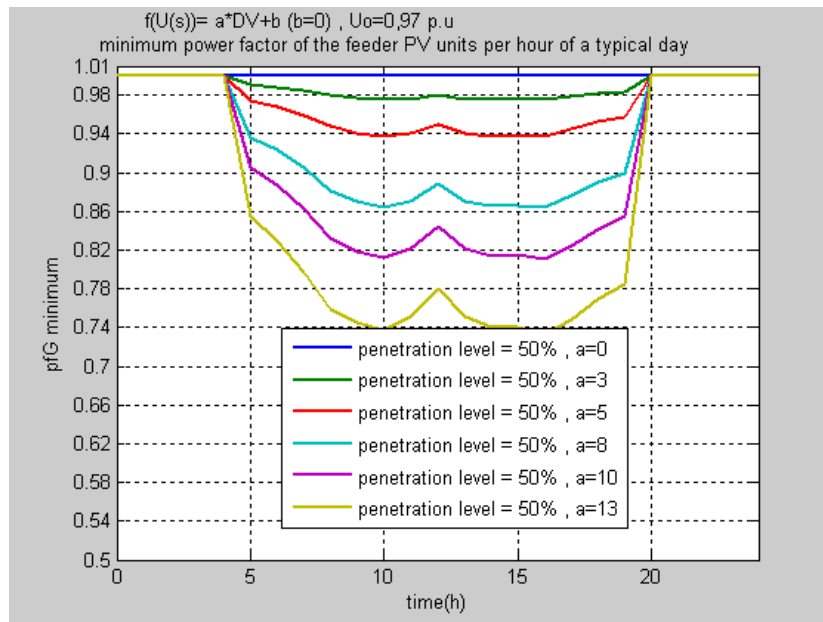


Figure 41. Minimum pf of the feeder PV units for different values of constant a (regulation method B) and for industrial load with triangular distribution. MV bus voltage=0.97 p.u

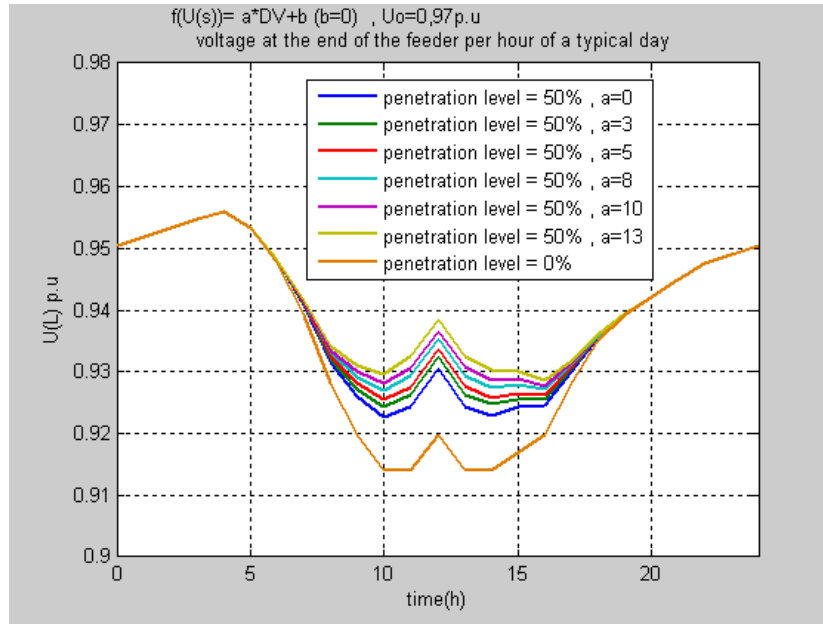


Figure 42. Voltage at the end of the feeder for different values of constant a (regulation method B) and for industrial load with triangular distribution. MV bus voltage=0.97 p.u

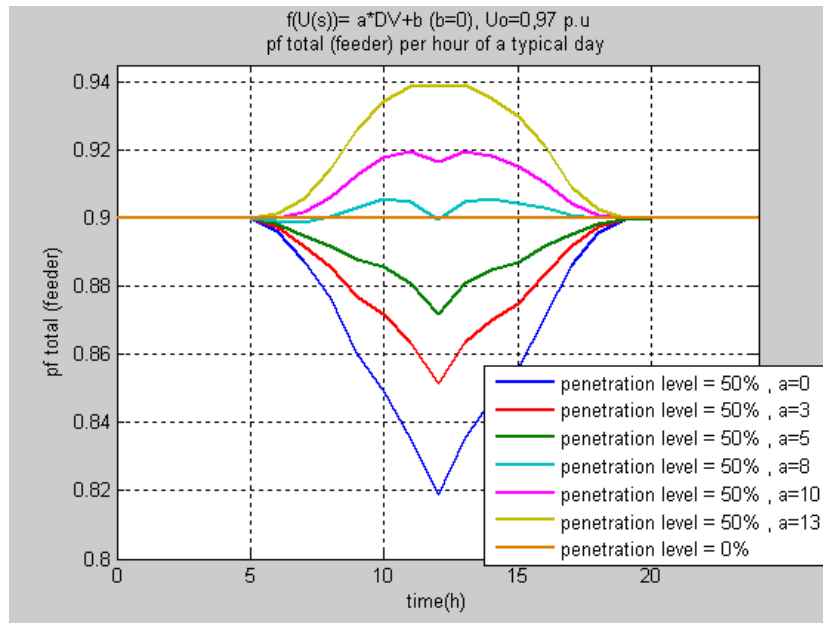


Figure 43. Total pf of the feeder for different values of constant a (regulation method B) and for industrial load with triangular distribution. MV bus voltage=0.97 p.u

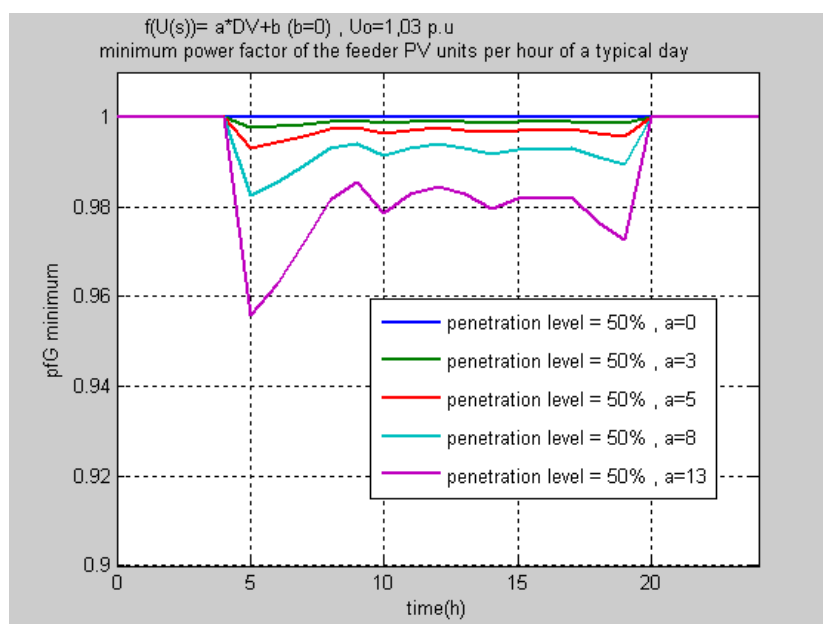


Figure 44. Minimum pf of the feeder PV units for different values of constant a (regulation method B) and for industrial load with triangular distribution. MV bus voltage=1.03 p.u

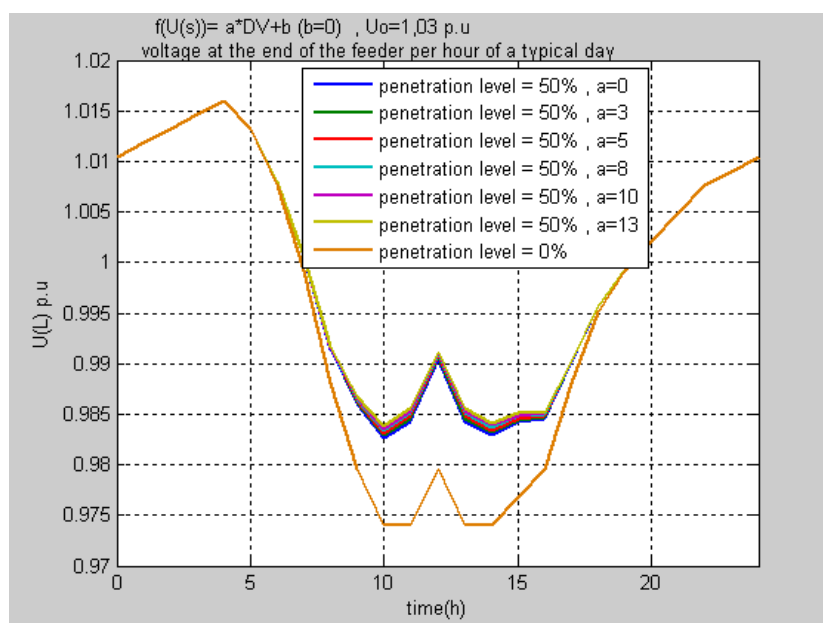


Figure 45. Voltage at the end of the feeder for different values of constant a (regulation method B) and for industrial load with triangular distribution. MV bus voltage=1.03 p.u

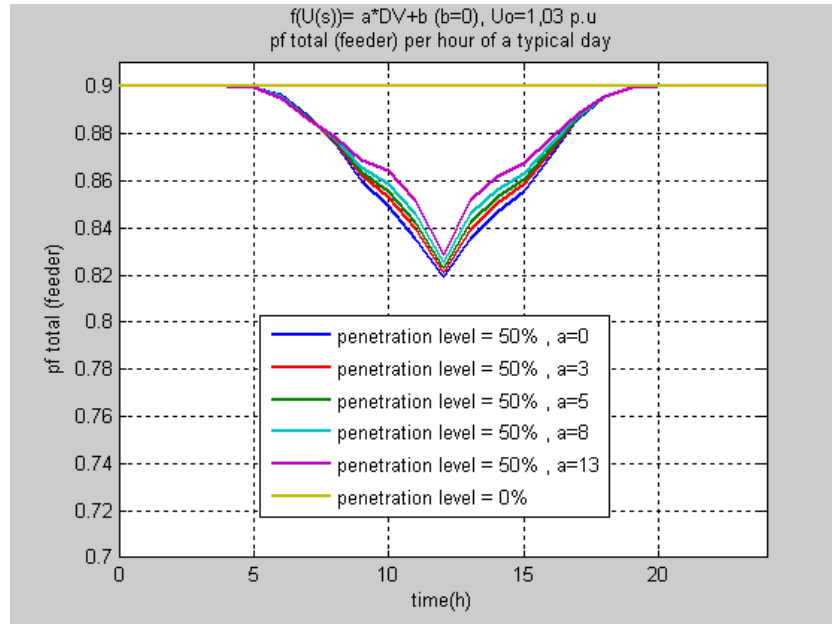


Figure 46. Total pf of the feeder for different values of constant a (regulation method B) and for industrial load with triangular distribution. MV bus voltage=1.03 p.u

For $U_0=1.03\text{p.u.}$, an insignificant increase in voltage is obtained (0.1%). That result is negligible because voltage deviation can not lead to enough Q injection (min $\text{pf}_G=0.96$). In addition, the total feeder pf increases approximately 1%.

In figure 46, between 5:00 and 7:00 it is observed that the total pf of the feeder decreases slightly for an increasing constant a . The reason is that voltage deviation during that time is positive (voltage exceeds 1p.u) and the control algorithm tends to reduce the voltage by absorbing reactive power.

The annual energy losses of the feeder and the T/F for 0% penetration (base case) are:

- Feeder annual energy losses: 12.6 MWh
- T/F annual energy losses: 16.9 MWh

In Table 5 are presented the annual energy losses for 50% penetration:

a	Min DG pf	Feeder annual losses (change % w.r.t. base case)	T/F annual losses (change % w.r.t. base case)
0	1	9.5 MWh (-24.6%)	14.3 MWh (-15.8%)
3	0.99	9.3 MWh (-26.2%)	14.1 MWh (-16.6%)

5	0.97	9.2 MWh (-27%)	14.0 MWh (-17.8%)
8	0.94	9.0 MWh (-28.6%)	13.9 MWh (-10.9%)
10	0.91	8.9MWh (-29.4%)	13.8 MWh (-18.3%)
13	0.87	8.8 MWh (-30.2%)	13.7 MWh(-18.9%)

Table 5. Change in feeder and T/F annual energy losses with pf control method B.

The decrease in power and energy losses is caused mainly by the DG active power injection. Power losses have a 1.12% reduction due to active power injection and another 0.3% due to reactive injection (fig.34). The decrease in feeder energy losses is 24.6% due to active injection. Reactive injection adds up another 5.6% reduction for feeder and 3.1% for the T/F.

5.2.c) Control method (C)

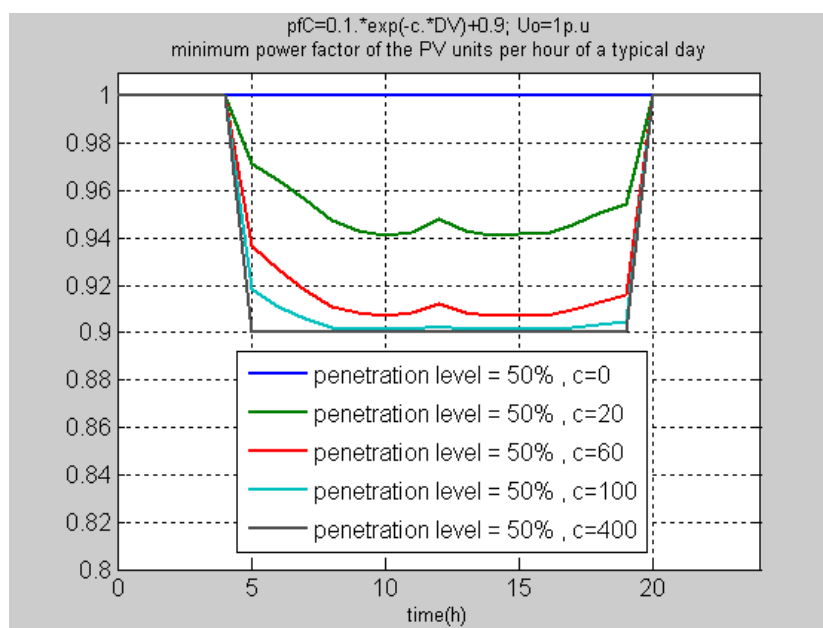


Figure 47. Minimum power factor of the feeder PV units for different values of constant c (regulation method C) and for industrial load with triangular distribution. MV bus voltage=1 p.u

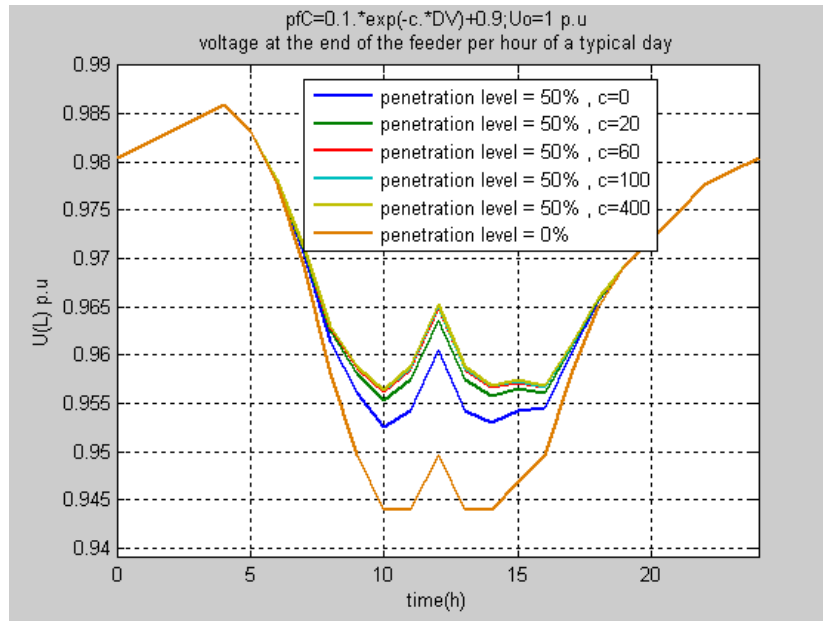


Figure 48. Voltage at the end of the feeder PV units for different values of constant c (regulation method C) and for industrial load with triangular distribution. MV bus voltage=1 p.u

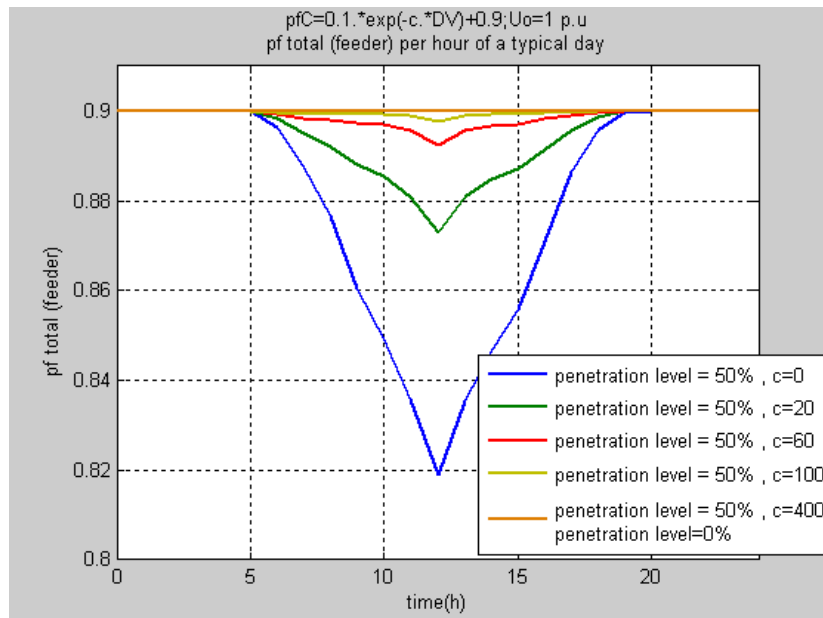


Figure 49. Total pf of the feeder PV units for different values of constant c (regulation method C) and for industrial load with triangular distribution. MV bus voltage=1 p.u

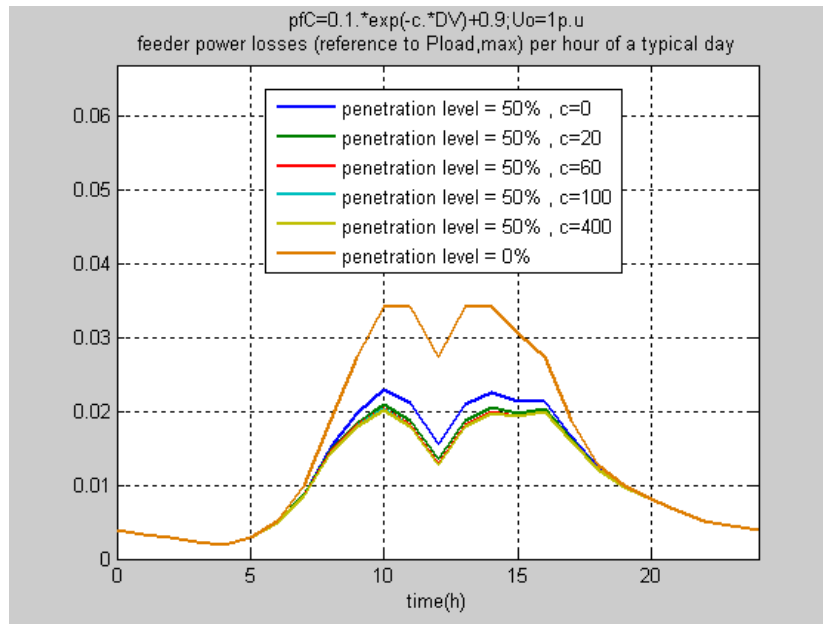


Figure 50. Power losses of the feeder PV units for different values of constant c (regulation method C) and for industrial load with triangular distribution. MV bus voltage=1 p.u

A significant improvement is caused mainly by the DG active power injection. Only the total pf of the feeder has a decrease.

The voltage increases 1% due to active power and up to an additional 0.4% due to Q injection. The total pf of the feeder increases significantly (8%) for a minimum pf_G at 0,9 leading.

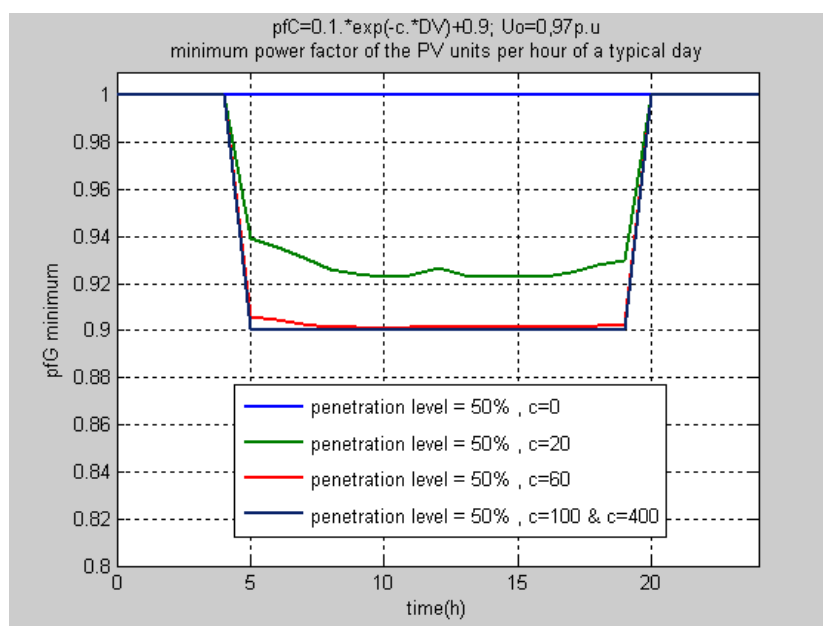


Figure 51. Minimum power factor of the feeder PV units for different values of constant c (regulation method C) and for industrial load with triangular distribution. MV bus voltage=0.97 p.u

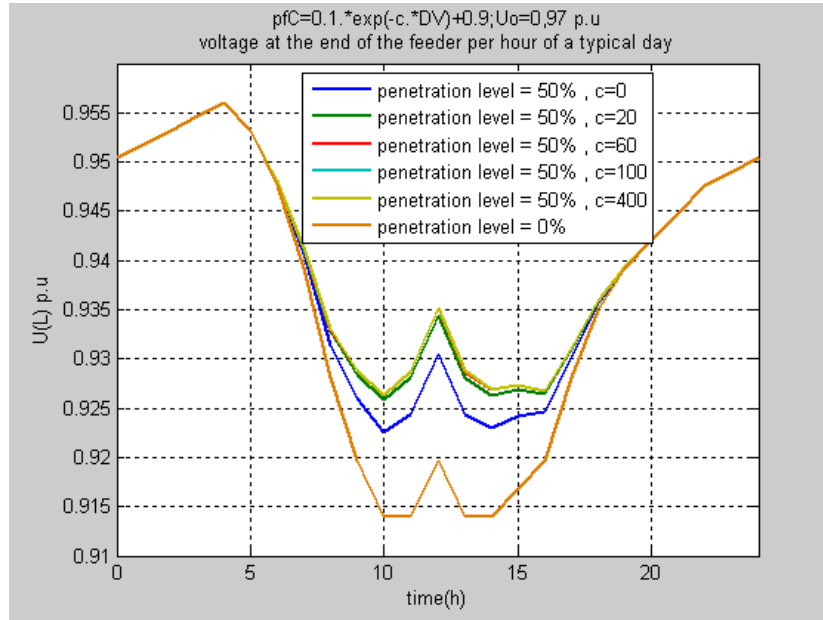


Figure 52. Voltage at the end of the feeder PV units for different values of constant c (regulation method C) and for industrial load with triangular distribution. MV bus voltage=0.97 p.u

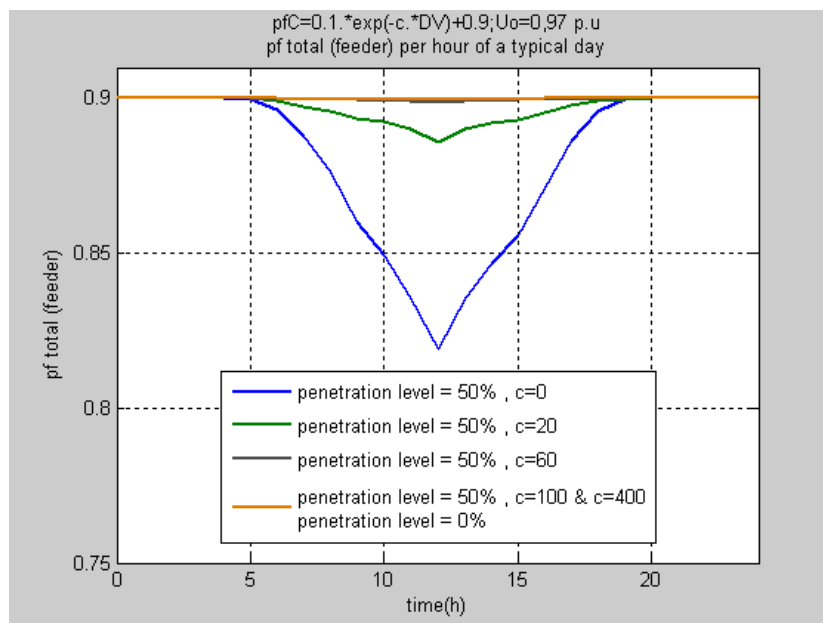


Figure 53. Total pf of the feeder PV units for different values of constant c (regulation method C) and for industrial load with triangular distribution. MV bus voltage=0.97 p.u

For $U_0=0.97\text{p.u.}$, DV increases enough and would lead to lower pf values if there was not an inherent limit. There is a Q injection that reduces voltage drop approximately 0.4%. The total pf of the feeder is also improved.

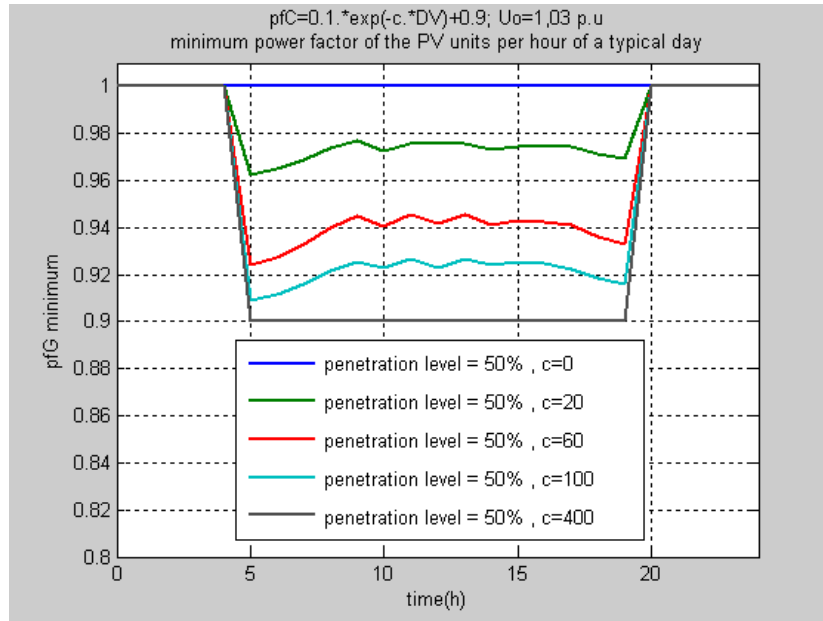


Figure 54. Minimum power factor of the feeder PV units for different values of constant c (regulation method C) and for industrial load with triangular distribution. MV bus voltage=1.03 p.u

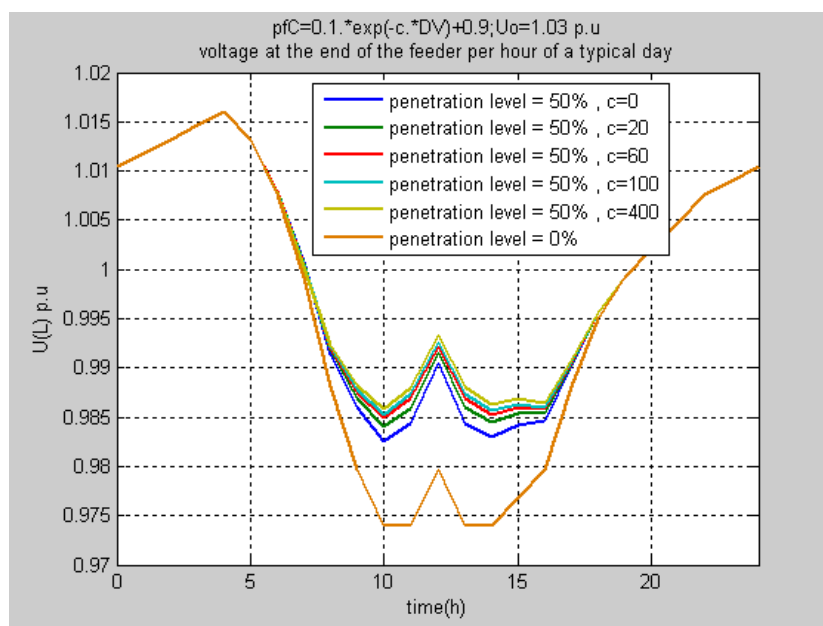


Figure 55. Voltage at the end of the feeder PV units for different values of constant c (regulation method C) and for industrial load with triangular distribution. MV bus voltage=1.03 p.u

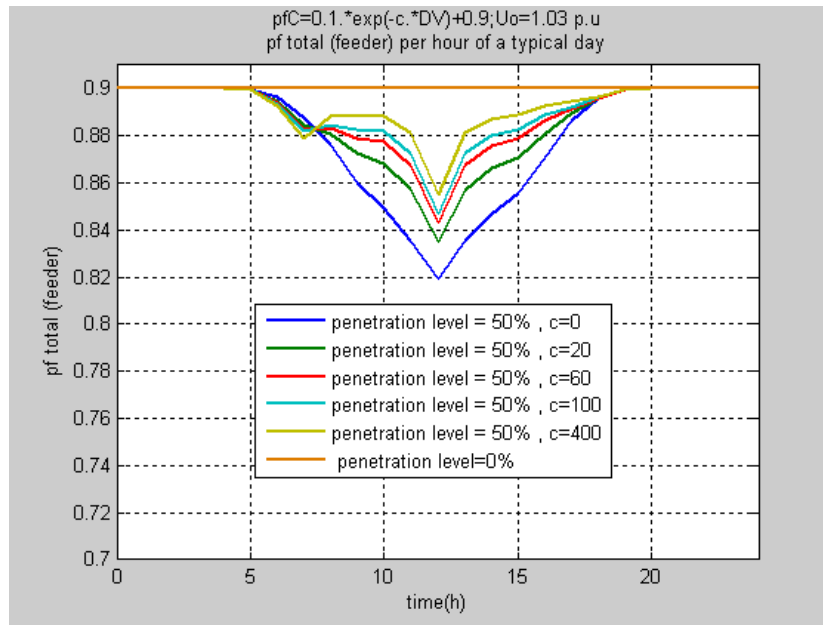


Figure 56. Total pf of the feeder PV units for different values of constant c (regulation method C) and for industrial load with triangular distribution. MV bus voltage=1.03 p.u

For $U_0=1.03$ p.u., an increase in voltage is obtained (0.4%). In addition the total feeder pf increases approximately 2%. In figure 56, between 5:00 and 7:00 it is observed that the total pf of the feeder decreases for an increasing constant a . The reason is that voltage deviation during that time is positive (voltage exceeds 1 p.u) and the control algorithm tends to reduce the voltage by absorbing reactive power.

The annual energy losses of the feeder and the T/F for 0% penetration (base case) are:

- Feeder annual energy losses: 12.6 MWh
- T/F annual energy losses: 16.9 MWh

In Table 6 are presented the annual energy losses for 50% penetration:

c	Min DG pf	Feeder annual losses (change % w.r.t. base case)	T/F annual losses (change % w.r.t. base case)

			case)
0	1	9.5 MWh (-24.6%)	14.26 MWh (-15.8%)
20	0.94	9.0 MWh (-28.6%)	13.81 MWh (-18.3%)
60	0.91	8.82 MWh (-30%)	13.68MWh (-19.5%)
100	0.9	8.79 MWh (-30.2%)	13.65 MWh (-19.2%)
400	0.9	8.78 MWh (-30.3%)	13.64 MWh (-19.3%)

Table 6. Change in feeder and T/F annual energy losses with pf control method C.

The decrease in power and energy losses is caused mainly by the DG active power injection. Power losses have a 1.12% reduction due to active power injection and another 0.3% due to reactive injection. The decrease in feeder energy losses is 24.6% due to active injection. Regulation method C adds up to energy losses a 5.7% reduction for the feeder and 3.5% for the T/F.

5.3 Uniform distribution – Residential load

Here, indicative results for uniformly distributed residential load are cited in order to prove that the conclusions drawn in Sections 5.1 and 5.2 are still valid.

5.3.a) Control method A

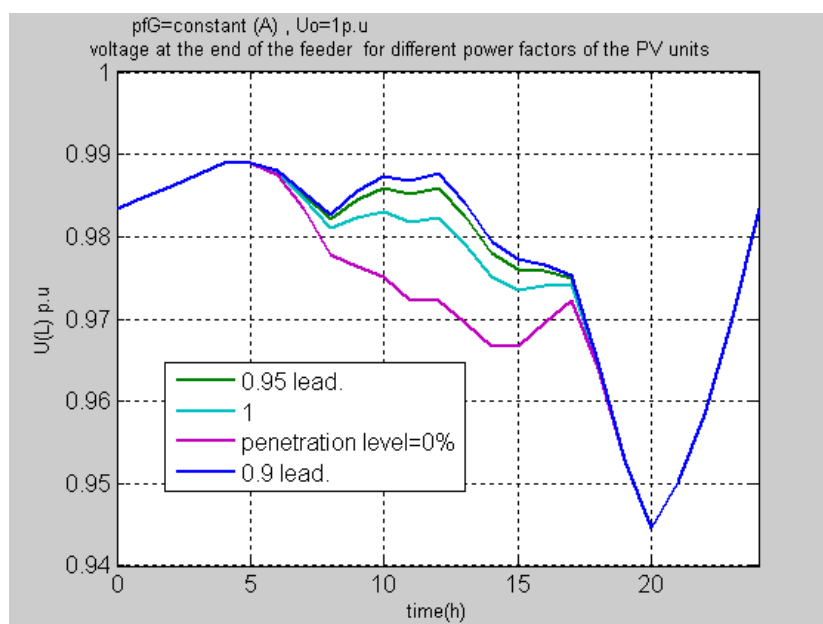


Figure 57. Voltage at the end of the feeder for different constant power factors of the PV units (regulation method A) and for residential load with uniform distribution. MV bus voltage=1 p.u

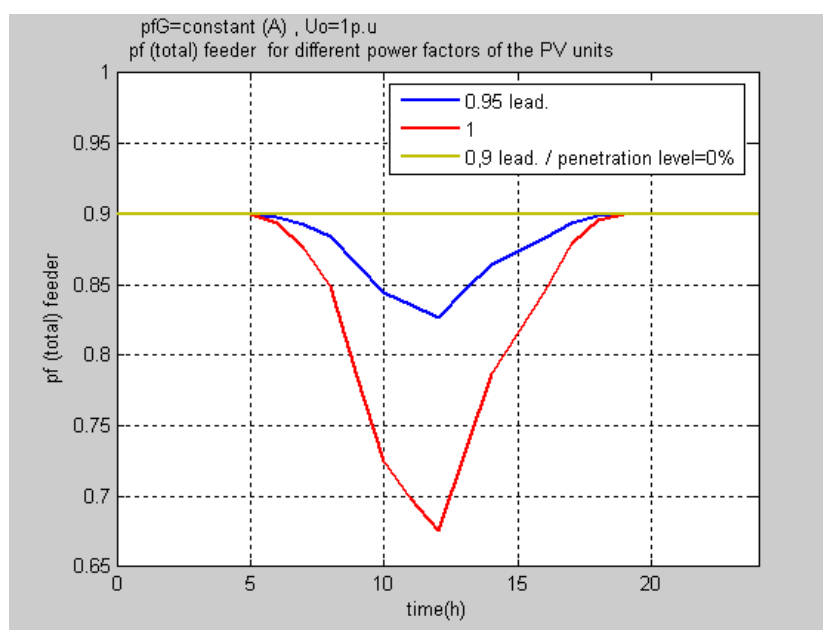


Figure 58. Total pf of the feeder for different constant power factors of the PV units (regulation method A) and for residential load with uniform distribution. MV bus voltage=1 p.u

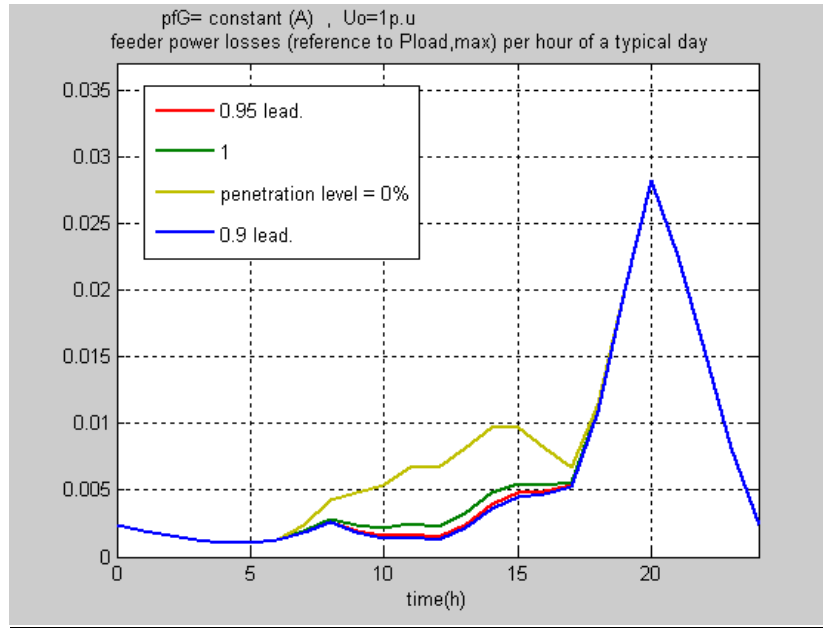


Figure 59. Feeder power losses for different constant power factors of the PV units (regulation method A) and for residential load with uniform distribution. MV bus voltage=1 p.u

A significant improvement is caused mainly by the DG active power injection. Only the total pf of the feeder has a considerable decrease due to the fact that the peak of PV generation occurs at low load demand (fig.58). The voltage increases 1% due to active power and up to an additional 0.5% due to Q injection for $U_0=1$ p.u (figure 57). The total pf of the feeder can improve substantially as pf_G tends to 0.9 leading.

The decrease in power and energy losses is caused mainly by the DG active power injection. Power losses have a 0.5% reduction due to active power injection and another 0.116% due to reactive injection (fig.59).

5.3.b) Control method B

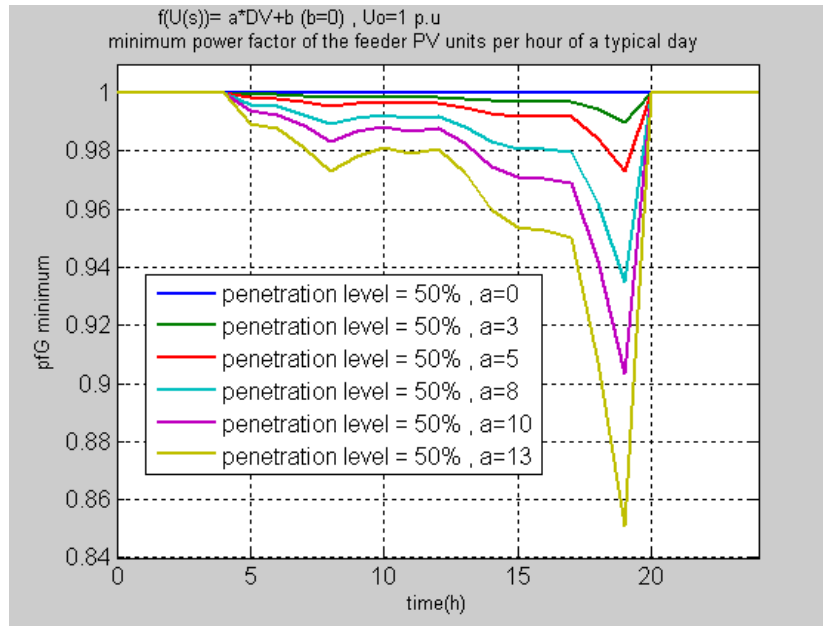


Figure 60. Minimum pf of the feeder PV units for different values of constant a (regulation method B) and for residential load with uniform distribution. MV bus voltage=1 p.u

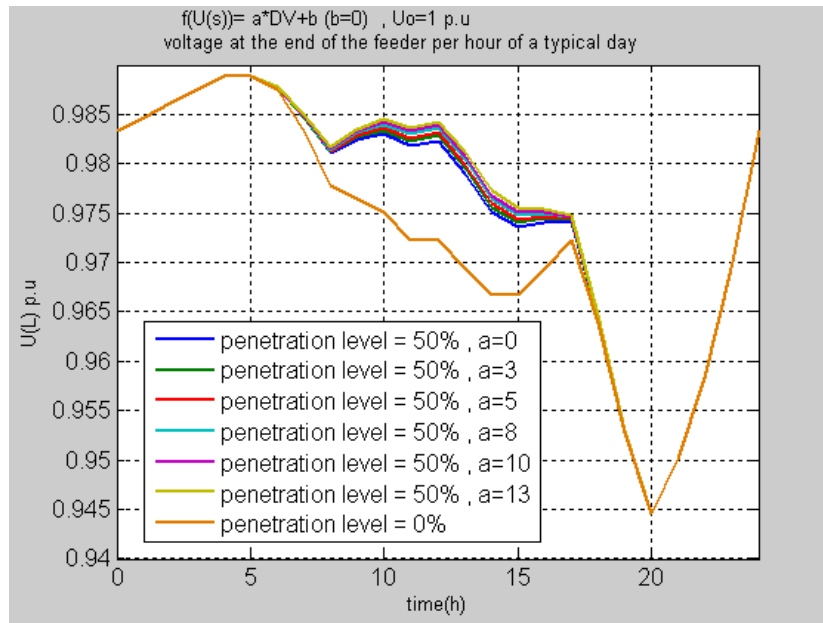


Figure 61. Voltage at the end of the feeder for different values of constant a (regulation method B) and for residential load with uniform distribution. MV bus voltage=1 p.u

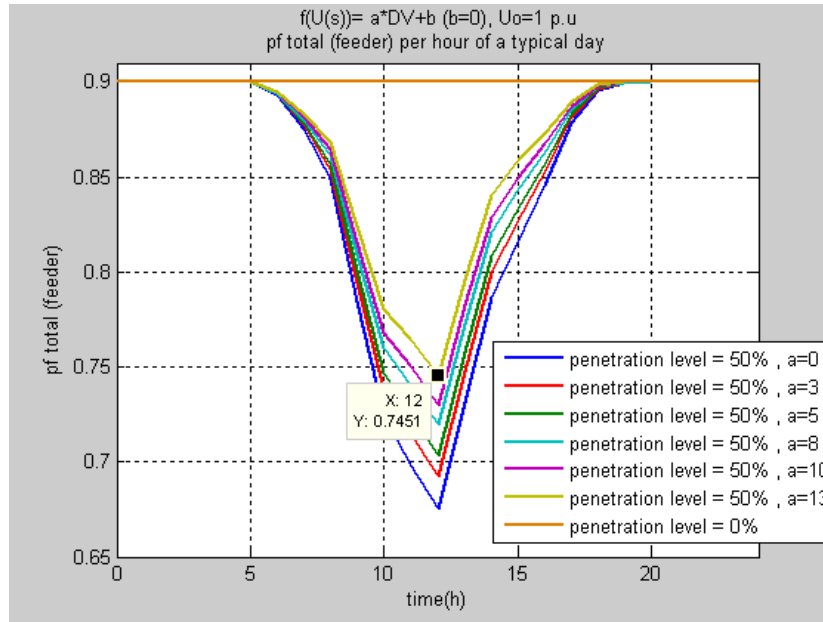


Figure 62. Total pf of the feeder for different values of constant a (regulation method B) and for residential load with uniform distribution. MV bus voltage=1 p.u

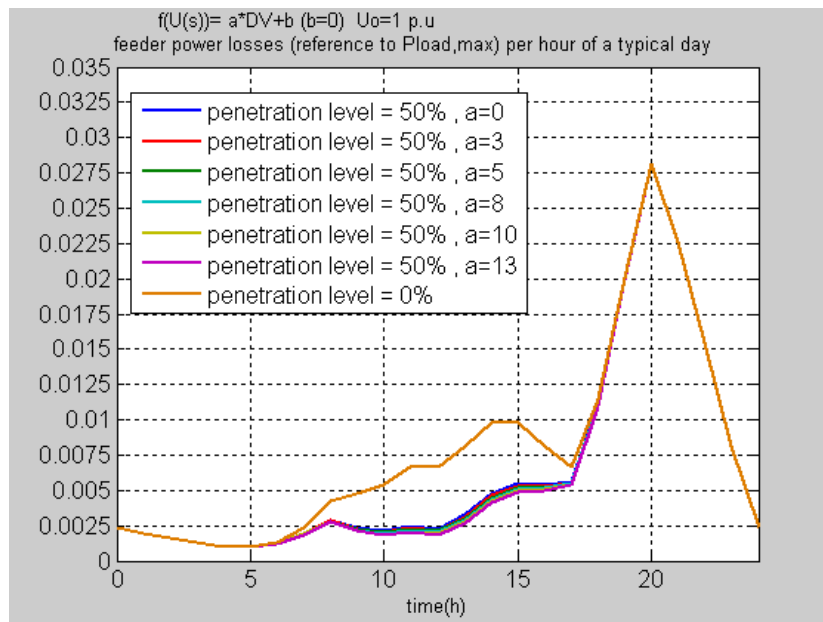


Figure 63. Feeder power losses for different values of constant a (regulation method B) and for residential load with uniform distribution. MV bus voltage=1 p.u

A significant improvement is caused mainly by the DG active power injection. Only the total pf of the feeder has a considerable decrease due to the fact that the peak of PV generation occurs at low load demand.

The voltage increases 1% due to active power and up to an additional 0.2% due to Q injection for a low minimum pf_G (0.85 leading) as shown in fig.61. The increase caused

by Q injection is negligible, because during the time that PV generation is significant, voltage deviation is small (low load demand) and can not produce through algorithm

B, enough reactive power. As it can be observed, power factors are held at values close to 1 during maximum PV generation. Minimum values are obtained when voltage drop increases due to increasing load flow along the feeder.

The total pf of the feeder increases only 7% for an important reduction of the minimum pf_G (fig.62). The increase is smaller than the one for triangular distribution. The reason is that with triangular distribution of PV generation, more PV units are located at points with large voltage deviation.

The decrease in power and energy losses is caused mainly by the DG active power injection. Regulation method B adds up to power losses only 0.07% reduction for a low minimum pf_G to the 0.5% owing to active injection (fig.63).

5.3.c) Control method C

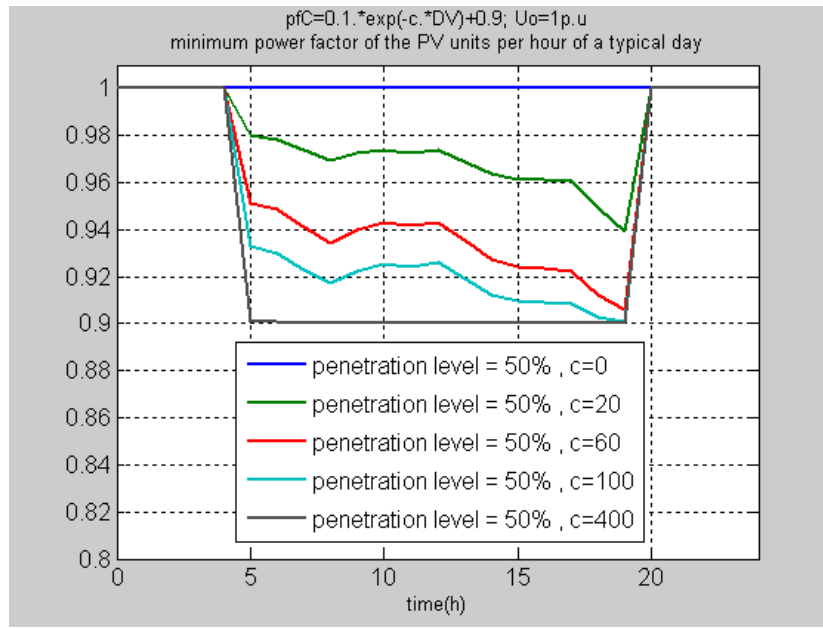


Figure 64. Minimum pf of the feeder PV units for different values of constant c (regulation method C) and for residential load with uniform distribution. MV bus voltage=1 p.u

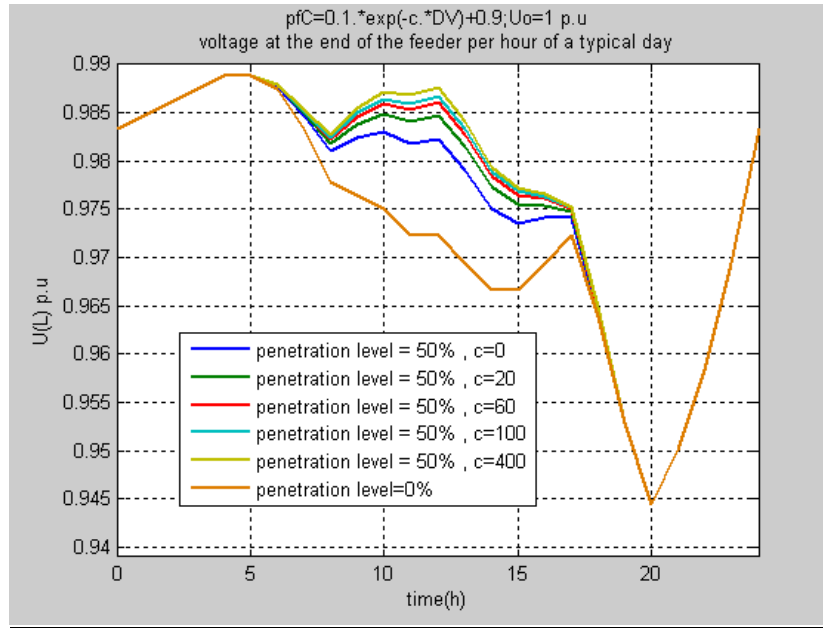


Figure 65. Voltage at the end of the feeder for different values of constant c (regulation method C) and for residential load with uniform distribution. MV bus voltage=1 p.u

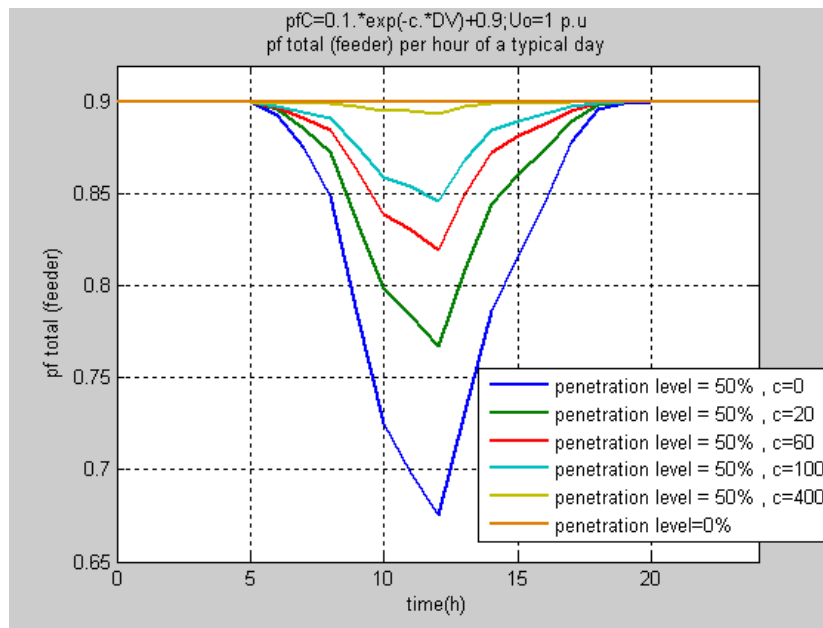


Figure 66. Total pf of the feeder for different values of constant c (regulation method C) and for residential load with uniform distribution. MV bus voltage=1 p.u

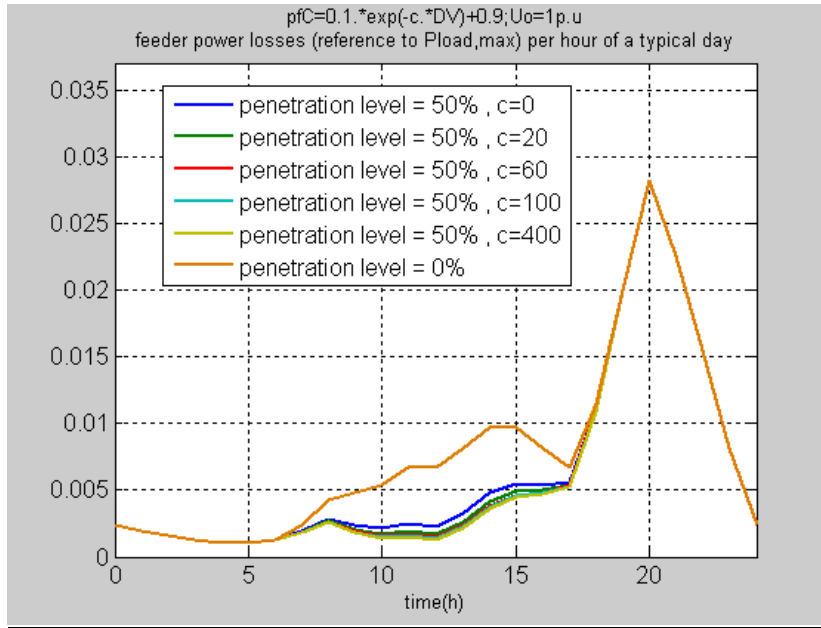


Figure 67. Feeder power losses for different values of constant c (regulation method C) and for residential load with uniform distribution. MV bus voltage=1 p.u

A significant improvement is caused once again mainly by the DG active power injection and only the total pf of the feeder has a considerable decrease.

The voltage increases 1% due to active power and up to an additional 0.5% due to Q injection (fig.65). The total pf of the feeder increases significantly for a minimum pf_G at 0.9 leading (fig.66). Voltage deviation (DV) is small, but regulation algorithm (C) makes use of small voltage drops and provides power factors which can lead to a significant Q injection.

The decrease in power and energy losses is caused mainly by the DG active power injection. Feeder power losses present an additional 0.116% reduction due to Q injection (fig.67).

6. Conclusions

From the results presented in Section 5 it is evident that regulation method A (constant leading power factors of the PV units) has a positive effect on voltage regulation, losses and total power factor of the feeder. Yet, as the DG unit operation is limited to slightly leading pf values, the results are not impressive. An increase in minimum feeder voltage of about 0.5%, along with a small reduction in power and energy losses, can be achieved by this method. Further, maintaining a constant pf value is an easily realizable and obviously stable regulation method, regardless of network voltage variations. It can be seen that low DG power factors are not justified by system performance. A pf around 0.95 leading appears to be sufficient.

Regulation method B ($f(U(s))=a \cdot DV$) has similar results to method A, regarding voltage regulation and losses reduction. The total pf of the feeder, particularly for residential load is not efficiently controlled. The main drawback is that DG power factor is not restrained and can reach very low values, especially in case of voltage drops in the network. With Method B issues will definitely exist for large voltage deviations (remote locations, MV voltage deviations, abnormal conditions etc.).

The need for limitation of DG power factor leads to control method C. In this case DG pf is restrained by an inherent limit. Voltage profile and losses reduction are similar to method B, but the total pf of the feeder is improved notably, as for method A. Hence, control method C is preferable to B, mainly due to its better effect on the total feeder pf and the limitation of DG pf.

The performance of the aforementioned regulation algorithms on the study case network proves that the capability of DG sources to control the voltage independently is rather limited. This fact underlines the need for devising more sophisticated voltage control policies, in order to fully exploit the potential offered by the reactive power regulation capabilities of the DG sources.

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ISET CONTRIBUTION

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1. Executive summary

The integration of several Microgrids in MV operation needs to be carefully investigated in terms of electrical interactions, considering the operational and physical restrictions of the Microgrids, either in terms of normal steady state operation or for emergency conditions. One aspect for the managements of multi-Microgrids concerns voltage control in MV distribution networks.

Distributed generations (DGs) may utilize the droop concept for controlling output active power and voltage depending on frequency and reactive power. However, as outlined in [Engler], in LV networks both power and voltage become interrelated due to the predominantly resistive character of LV lines. When coupling DGs, which are controlled in this manner via a MV network, any active power sharing goes along with a necessary change of reactive power produced by the DGs. This of course will affect the voltage level as well.

In this task ISET has assessed the VAR-exchange and the transient active power sharing via the MV-system by means of calculation, simulation and measurements with the Medium-Voltage simulator installed at DeMoTec for inverters which are controlled with the 'droop concepts' (f-P and V-Q static control characteristics).

For micro-grids, which are powered with this kind of inverters, the following results have been found:

- o By experiment it could be proofed, that parallel operation of inverters operated with the 'droop concepts' is possible, even the inverters are coupled via a MV network without any dedicated communication.
- o Active power sharing is done according to the relations of the inverse impedance values of the connecting network elements.
- o Reactive loads are shared by the inverters according to the (controllable) voltages at the inverters, while the line parameters are of secondary importance.
- o The measurements also show that the controls implemented in the used inverters do not quickly lead to a stationary operation point of the system. Furthermore it may happen that one inverter is delivering active power, while at the same time the other inverter is consuming active power. An improvement of the implemented controls seems required.
- o Changes of active power demands may lead to changes in the reactive power. In the investigated configuration these interrelations are small; however in other configurations the dependency may become stronger.
- o Especially for reactive type loads the droop parameters must be selected carefully in order to guarantee that the voltage stays within certain limits.
- o In contrast to coupling of the inverters in low voltage network works, coupling of the inverters via medium voltage network requires the stronger consideration of network impedance determined by lines and transformers.
- o The potential for voltage regulation control has been analysed basically.

2. Introduction

The integration of several micro grids in MV systems needs to be carefully investigated in terms of electrical interactions, considering the operational and physical restrictions of these active cells, either in terms of normal steady state operation or for emergency conditions.

One aspect related to the management of the multi-Microgrids concerns coordinated voltage support and flow control. A way of controlling voltage locally is utilised by inverters utilising a droop relation between voltage and reactive power and a droop between active power and frequency. A drawback of this approach is that active and reactive power delivery in-directly coupled in LV network due to their resistive nature. When coupling Microgrids via MV systems this will of course affect the reactive power flow and voltage level on the MV side as well.

In the present work we have analysed these relations more deeply, by experiments and accompanied simulations

- o chapter 3 provides the theoretical basis
- o chapter 4 describes the experimental setup
- o chapter 5 presents the results from targeted experiments and simulations

Into the electricity supply are integrated in the future more distributed generators (DGs) from renewable energy sources. Presently, they have to feed in only a limited active power into the interconnected network. The limit is determined due to the voltage increase at the interconnection point [EE MV] and [EE LV].

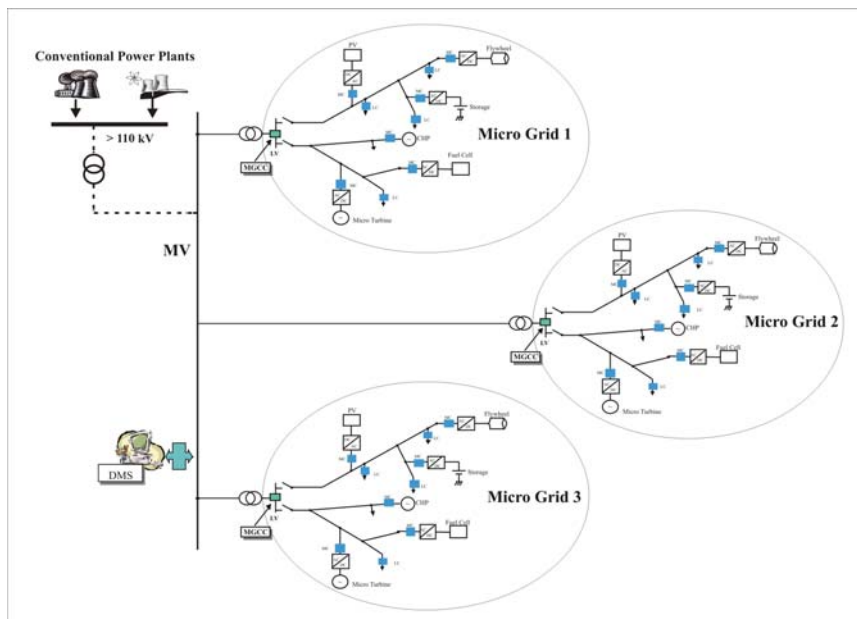


Fig. 1: Structure of interconnection between Micro grids and into power supply system

A special case is the disconnection of the micro grid from the superior grid and the crossover to islanding operation. Here the control capabilities of all DGs get a particular relevance. This operation mode is not examined sufficiently yet.

Within this task the reciprocal effect of two micro grids is analysed in order to define the basic requirements for a stable operation of the DGs, in the first instance for controllable inverters. (cf. section 3).

3. Development of theoretical basics for analysis of voltage support and flow control

Fig. 2 (taken from [Annex I]) shows a typical structure of a Micro-grid. The grid shown here is of radial type; loads and local generators are connected along the feeders. Compared to meshed grid topologies the radial type topology is easier to manage for operational control and protection. For the theoretical analysis superposition methods (cf. sec. 3.2) are applicable. By this way the effect of loads and generators can be treated independently. Among the different parameters of the electrical grid operation voltage changes at the network nodes as well as active and reactive power flows are in the focus of our investigations.

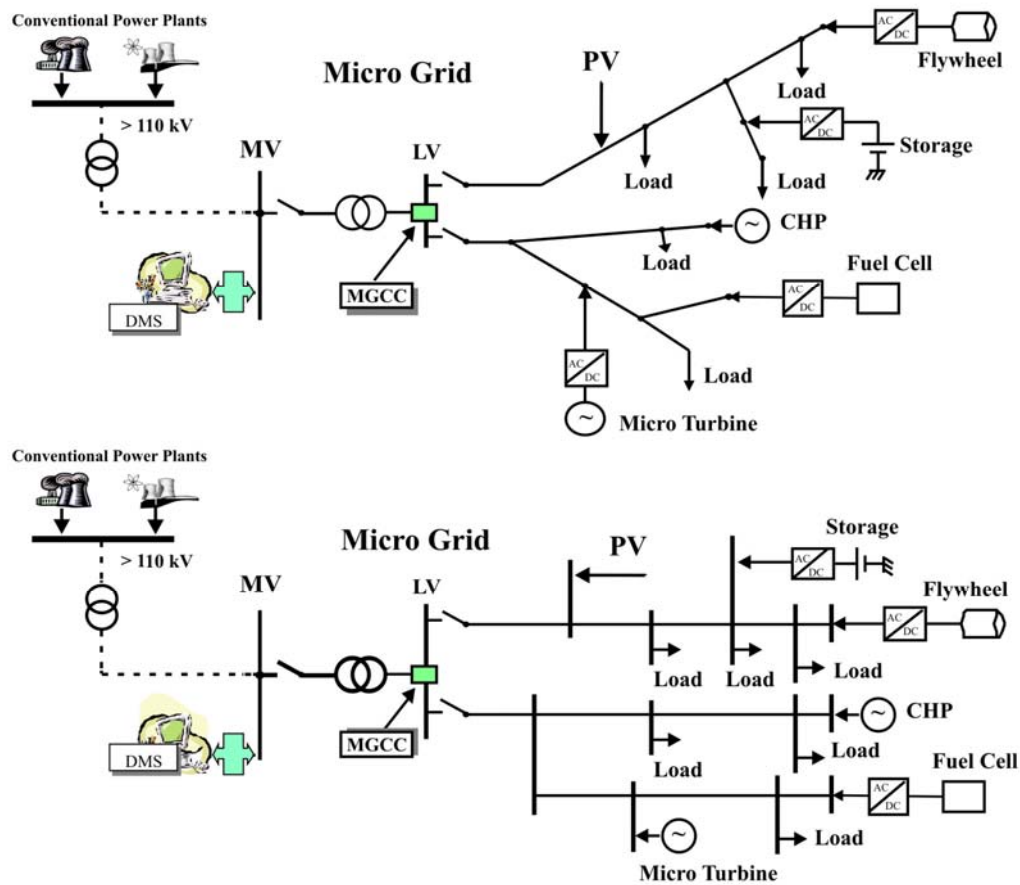


Fig. 2: Micro grid structure and circuit diagram

Active and reactive power flows will be jointly investigated. In grid connected mode (micro grid connected to the superior grid) grid stability and frequency control are not relevant. However, when turning into islanded mode (micro grid disconnected from superior grid) grid stability and frequency control is a major issue and must be organised with the local generators. While in theory most questions are solved, the practice gives a number of challenges. Amongst these are:

- The lack of controllability of many DGs, which are currently installed, e.g. wind turbine generators with induction generator, small CHP units and micro-hydro

power plants where control is not designed or only hardly possible, especially for DGs with induction generators.

- Most inverter coupled generators are operated in grid-following mode and lack any grid forming capabilities. Furthermore they normally are obliged to switch off in island situations. In this case all consumers of micro grids (more hundred households) do not have an electricity supply. In order to avoid these disadvantages new capabilities of inverters and their control strategies for safety electricity supply of customers are developed.
- The number of DGs is increasing rapidly, however the development and implementation of advanced control and integration concepts including communication capabilities is lagging behind. New grid codes which will define these requirements are currently not in force.
- On top of the different control strategies the requirements of the liberalised market superimpose economic aspects, which make the power systems behaviour even more complex.

By developing adequate controls for the DGs many of the above mentioned problems could be reduced or even completely solved. As already mentioned the main focus of Task 3.2 is „Coordinated Voltage Support and Flow Control“. The contribution of ISET is to assess the VAr-exchange and the transient active power sharing via the MV-system by means of simulation (ATP-EMTP) and measurements with the Medium-Voltage simulator installed at DeMoTec”.

3.1. VAr-exchange

Active and reactive power flows are of fundamental importance for the proper function of any power system in terms of frequency, voltage, power quality etc. In traditional power systems a central power station, or a cluster of power stations, operate as basic generation system, taking care of instantaneous balancing of the active power in the system. This type of generating unit must have a reasonable large control range for active and reactive power.

When going to island mode, this task must be taken over by one or more DGs connected to the micro-grid. The following constraints must be considered:

- the active power demand, defined by customer requirements
- to ensure power quality requirements, as set out in standards
- the control of the terminal voltage, reactive and active power delivery of each DG unit in order to secure the operation of the system under normal and fault conditions,

Within the frame of this task ISET has analysed two approaches for the system control, which aim at securing the balance of power in the system. A mechanical equivalent is used to illustrate the approach.

3.1.1. Case 1: The system reference point is the connection point to the customer (consumer loads).

Input:

- o Lines: $Z_{1,4}$, $Z_{3,4}$, $k_Z = Z_{1,4} / Z_{3,4} = 5,22$
- o Load: $S_{Load} = 0$ till $S_{Load}^{Max} = 100$ kW

- o Inverter: Nominal active power $P_{Inv\ 1} = P_{Inv\ 2} = 100\ kW$
- o Rated voltage: $U_4 \cong U_N \cong 10\ kV$

Objective: Which values for the voltages $U(NP1)$, $U(NP3)$ and power $P1$, $Q1$, $P3$, $Q3$ are required to achieve system balance of powers in respectively system with two Microgrids?

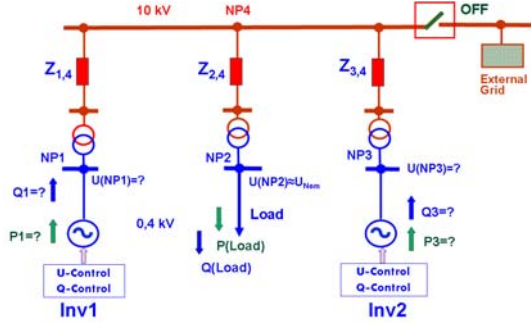


Fig. 3: Micro grid with two inverters and one load

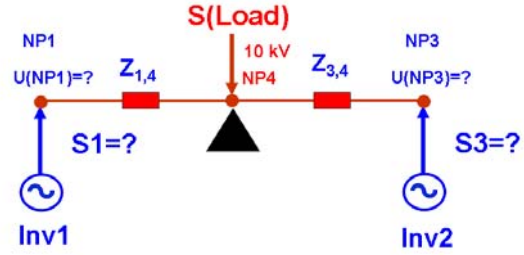


Fig. 4: Mechanical model of Micro grid

According to the rules of theoretical mechanics, the balance of power condition for the system of Fig. 4 is depicted as:

$$S_1 \cdot Z_{1,4} = S_3 \cdot Z_{3,4}$$

$$S_1 \cdot k_1 \cdot Z_{Sum} = S_3 \cdot k_3 \cdot Z_{Sum}$$

Here k_1 and k_3 is the ratio of the impedances

$$k_1 = \frac{Z_{3,4}}{Z_{1,4} + Z_{3,4}} \quad \text{and} \quad k_3 = \frac{Z_{1,4}}{Z_{1,4} + Z_{3,4}}$$

where $k_1 + k_3 = 1$ and $Z_{1,4} + Z_{3,4} = Z_{Sum}$.

To fulfil this equation inverter 1 and 2 have to feed the following apparent power into the grid:

$$S_1 = P_1 + jQ_1 = (P_{Load} + jQ_{Load}) \cdot k_1 + (\Delta P_{1,4} + jQ_{1,4}) = (P_{Load} + jQ_{Load}) \cdot k_1 + \frac{(k_1 \cdot S_{Load})^2}{U_N^2} \cdot Z_{1,4}$$

$$S_3 = P_3 + jQ_3 = (P_{Load} + jQ_{Load}) \cdot k_3 + (\Delta P_{3,4} + jQ_{3,4}) = (P_{Load} + jQ_{Load}) \cdot k_3 + \frac{(k_3 \cdot S_{Load})^2}{U_N^2} \cdot Z_{3,4}$$

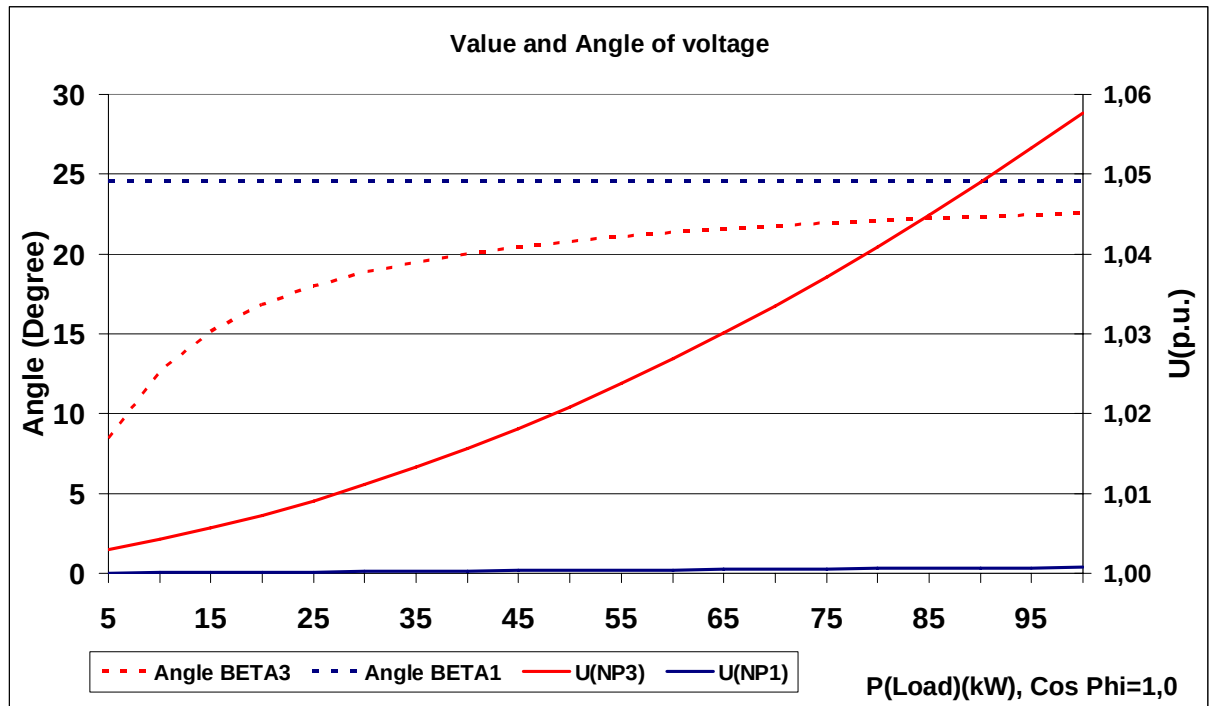
In this case the voltages on nodes NP1 and NP3 will be

$$\underline{U}(NP1) = \underline{U}_{Load} + \frac{S_{Load}}{\sqrt{3} \cdot U_{Load}} \cdot Z_{1,4} = U(NP1) \cdot \exp(j\beta_{NP1})$$

$$\underline{U}(NP3) = \underline{U}_{Load} + \frac{S_{Load}}{\sqrt{3} \cdot U_{Load}} \cdot Z_{3,4} = U(NP3) \cdot \exp(j\beta_{NP3})$$

With β_{NP1} and β_{NP3} being the angles between the voltages $U(NP1)$, $U(NP3)$ and the voltage at load connection $U(NP4)$.

Values derived from application of the above equations are complex. Fig. 5 to Fig. 7 basically show the graphs obtained from the evaluation of the above equations describing the mechanical model of Fig. 4. The required voltages are displayed under various load conditions. The calculations have been performed taking network data corresponding to the experimental 10kV Line Impedance Network Simulator (LINS) at ISET's DeMoTec, which is described in more detail in chapter 4.



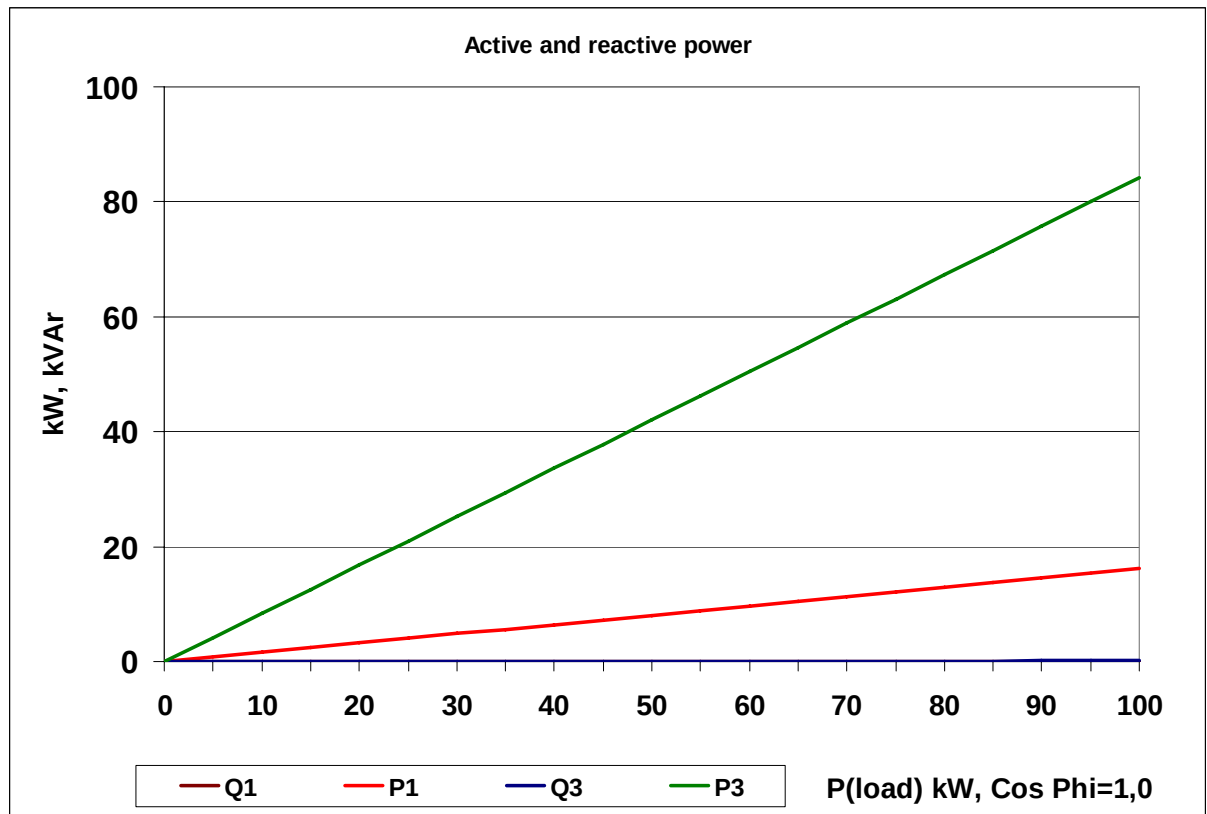


Fig. 5: Voltages, active and reactive power at the connection points of the inverters and power factor of the load with $\cos(\varphi) = 1.0$

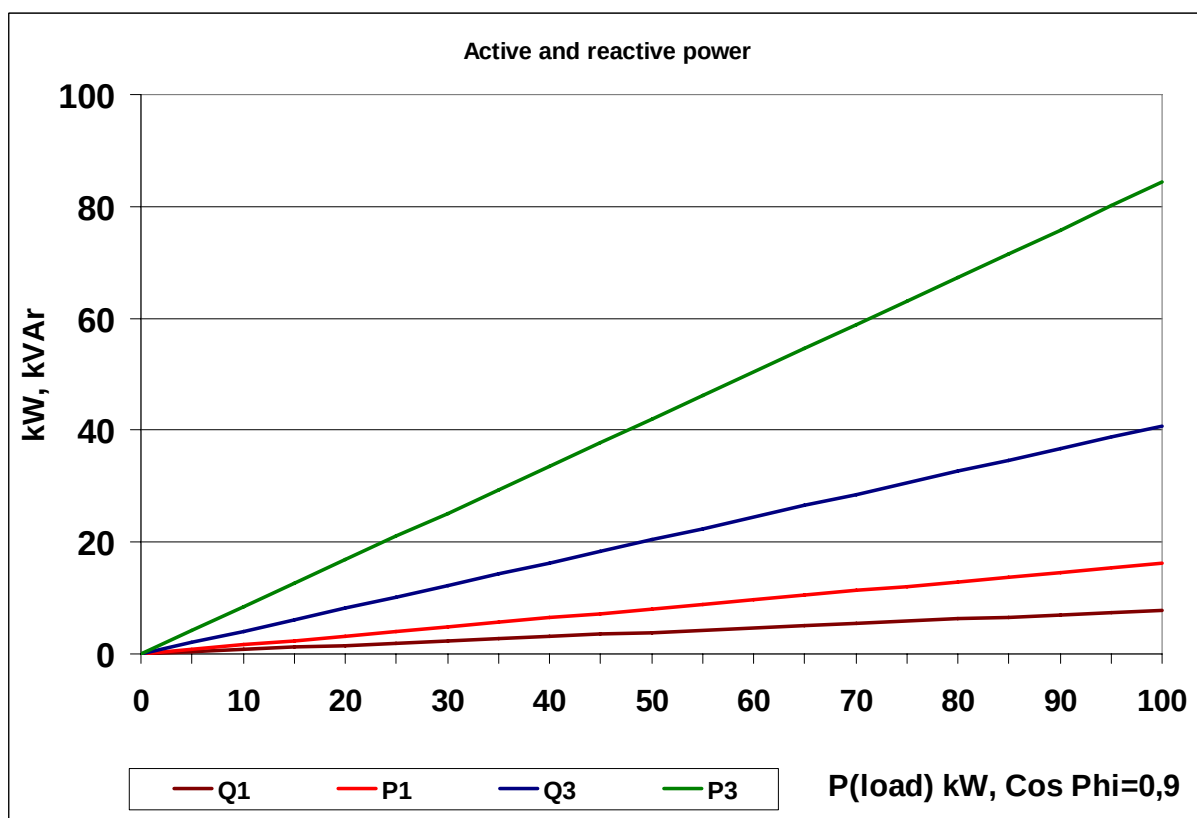
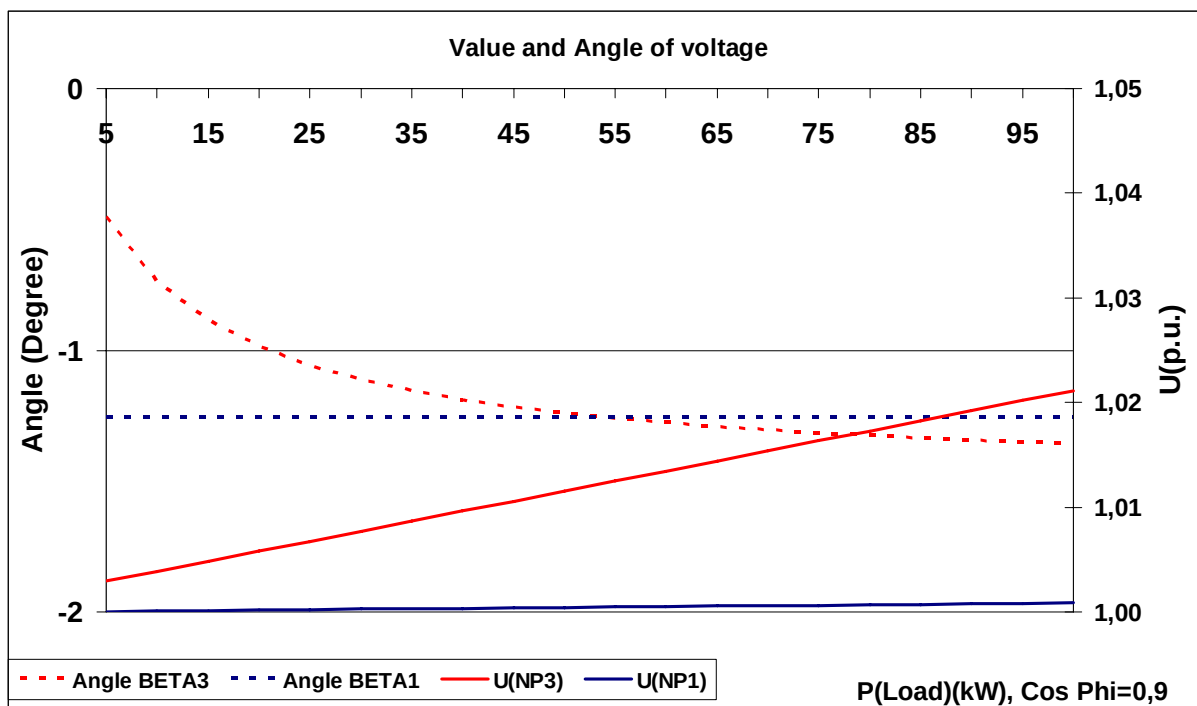


Fig. 6: Voltages at the connection points of the inverters and power factor of the load with $\cos(\varphi) = 0.9$

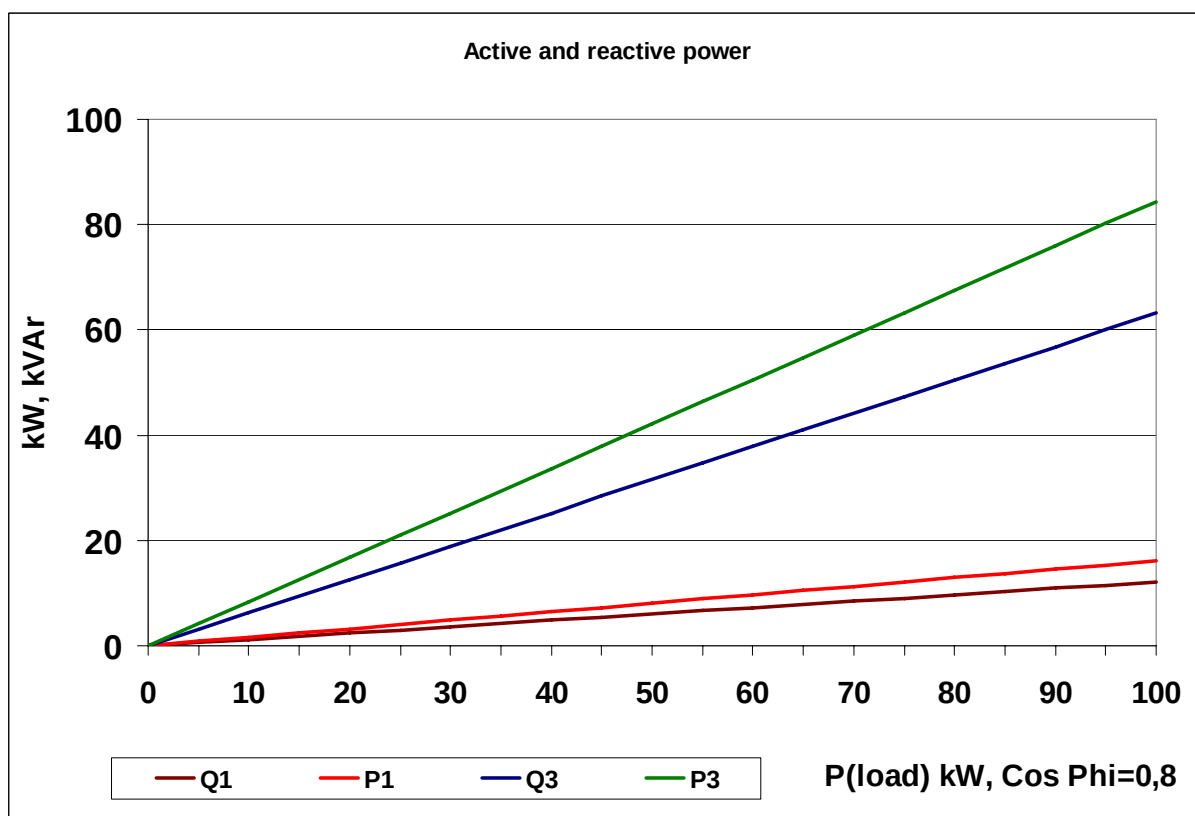
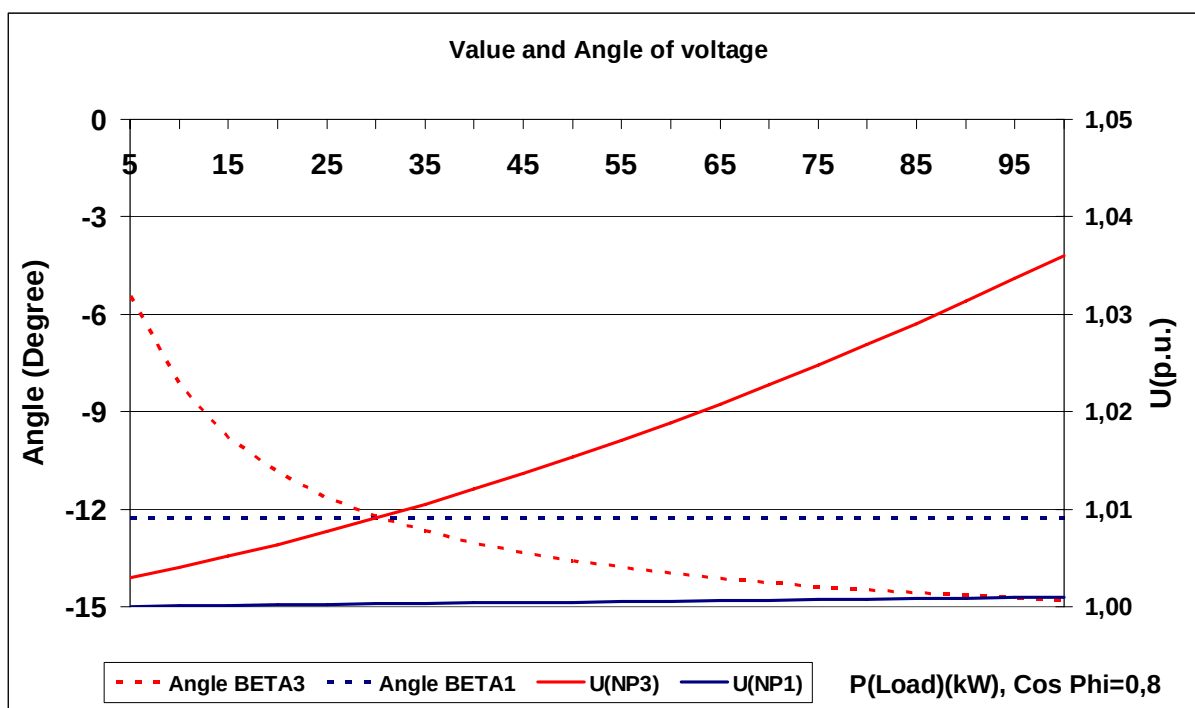


Fig. 7: Voltages at the connection points of the inverters and power factor of the load with $\cos(\varphi) = 0.8$

From the relations and calculations the following conclusions can be drawn:

- the required values for active and reactive power production are determined by the load, active power losses in lines and transformers, as well as by parameters of lines
- for the system shown in Fig. 3 and Fig. 4 with $k_Z = Z_{1,4} / Z_{3,4} = 5,22$ inverter *Inv2*, which is located nearer to the load, should feed in the 5,22 times more active and reactive power than inverter *Inv1*. That means assuring a local balance of power has a bigger importance than the superior one under consideration of feed in of other DG units of the system. This could be considered for the simplification of control algorithms in order to reduce them without a loss of control quality.
- This system will act stable if the control of the inverters have implemented the following equations $S_1 = (Z_{3,4} / Z_{1,4}) \cdot S_3 = (1 / 5,22) \cdot S_3 = 0,192 \cdot S_3$ and $S_3 = (Z_{1,4} / Z_{3,4}) \cdot S_1 = 5,22 \cdot S_1$. The factor of influence of the balance of power of the inverter located nearer to the load, in this case inverter *Inv2*, is in contrary $5,22 / 0,192 = 27,2$. That means that the control for the assurance of the power balance in the micro grid is possible but the increasing numbers of loads and DGs complicate the equation.
- Alternative solutions should be developed for the control. An approach is discussed in the following.

3.1.2. Case 2: The system reference point is the connection point of one inverter

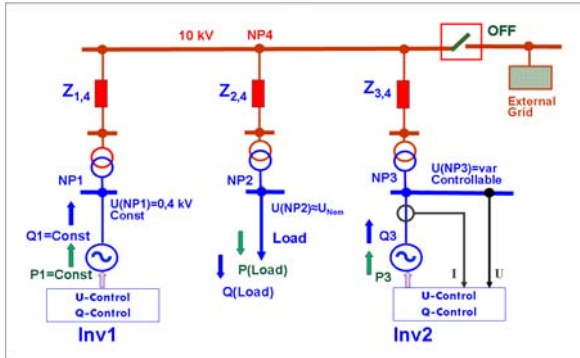


Fig. 8: Micro grid with one uncontrollable and one controllable inverters in micro grid

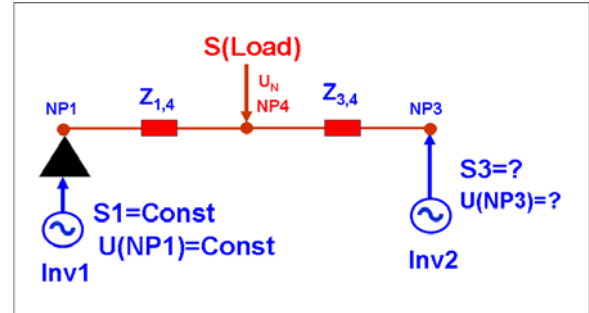


Fig. 9: Mechanical model of Micro grid

In this case it is assumed that inverter *Inv1* operates as fixed power source (S and U constant).

Input:

- o Lines: $Z_{1,4}$, $Z_{3,4}$, $k_Z = Z_{1,4} / Z_{3,4} = 5,22$,
- o Load: $S_{Load} = 0$ till $S_{Load}^{Max} = 100 \text{ kW}$,
- o Inverter: Nominal active power $P_{Inv1} = P_{Inv2} = 100 \text{ kW}$,
- o Rated voltage $U_4 \cong U_N \cong 10 \text{ kV}$
- o Constant voltage of *Inv1* $\underline{U}_1 = U_1 \cdot j0 \text{ kV}$

- o Inverter *Inv1* is producing its power according to the following rules:

$$\begin{aligned} S_1 &= P_1 + jQ_1 \cong P_{Load} + jQ_{Load}, \text{ if } S_1 \leq m_1 \cdot S_{Load}^{Max} \\ S_1 &= P_1 + jQ_1 \cong P_{Load} + j0, \text{ if } S_1 > m_1 \cdot S_{Load}^{Max} \end{aligned} \quad (*)$$

Here m_1 is a fraction of the maximum values of the load S_{Load}^{Max} . If the load is smaller than $m_1 \cdot S_{Load}^{Max}$, it will be supplied by inverter *Inv1* only.

Objective: Which values for $U(NP3)$, $P3$ and $Q3$ are required to achieve system balance?

As above, the system is stable if

$$S_{Load} \cdot Z_{1,4} = S_3 \cdot Z_{Sum}$$

From which follows

$$S_3 = S_{Load} \cdot \frac{Z_{1,4}}{Z_{Sum}}$$

In the last equations the apparent power S_3 depends from load. But for the conformance of equation (*) the flow direction has to be controlled. This will be done by the voltage controlling at NP3 with $S_3 = f[U(NP3)]$. For this reason $\underline{U}(NP3)$ should be controllable according to value and phase. In order to ensure the power flow from NP3 to the load it should be considered that $\underline{U}(NP3) \geq \underline{U}(NP1)$ is true. The required voltage difference leads to a flow of compensating power in the respective part of the network

$$S_3 = S_{Load} \cdot \frac{Z_{1,4}}{Z_{Sum}} + \frac{\underline{U}_N}{Z_{Sum}} \cdot [\underline{U}(NP3) - \underline{U}(NP1)]. \quad (**)$$

With voltage $\underline{U}_1 = U_1 \cdot j0 \text{ kV}$ (see above for input data) the voltage $\underline{U}_3 = U_3 \cdot j\beta_3$ can be calculated as follows:

$$\underline{U}(NP3) = F[S_{Load}, S_1, Z_{1,4}, Z_{Sum}]. \quad (***)$$

Equations (**) and (***) describe a non-linear system which can be solved by applying an iteration approach. The solutions are depicted in Fig 6, assuming the same data as for case 1 (cf. section 3.1.1).

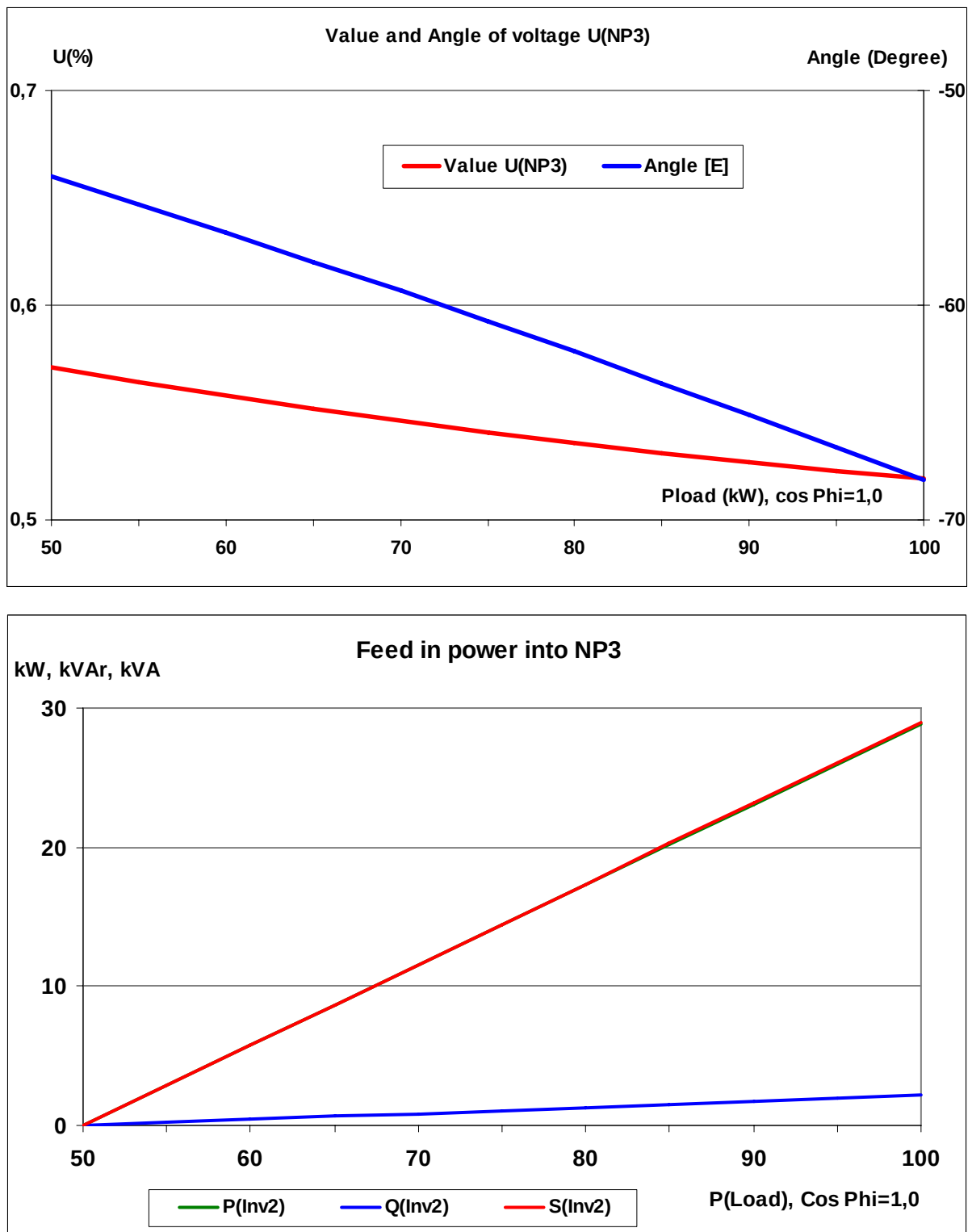


Fig. 10: Voltages and powers required for power balance in micro grid for different loads and power factor $\cos(\varphi) = 1.0$

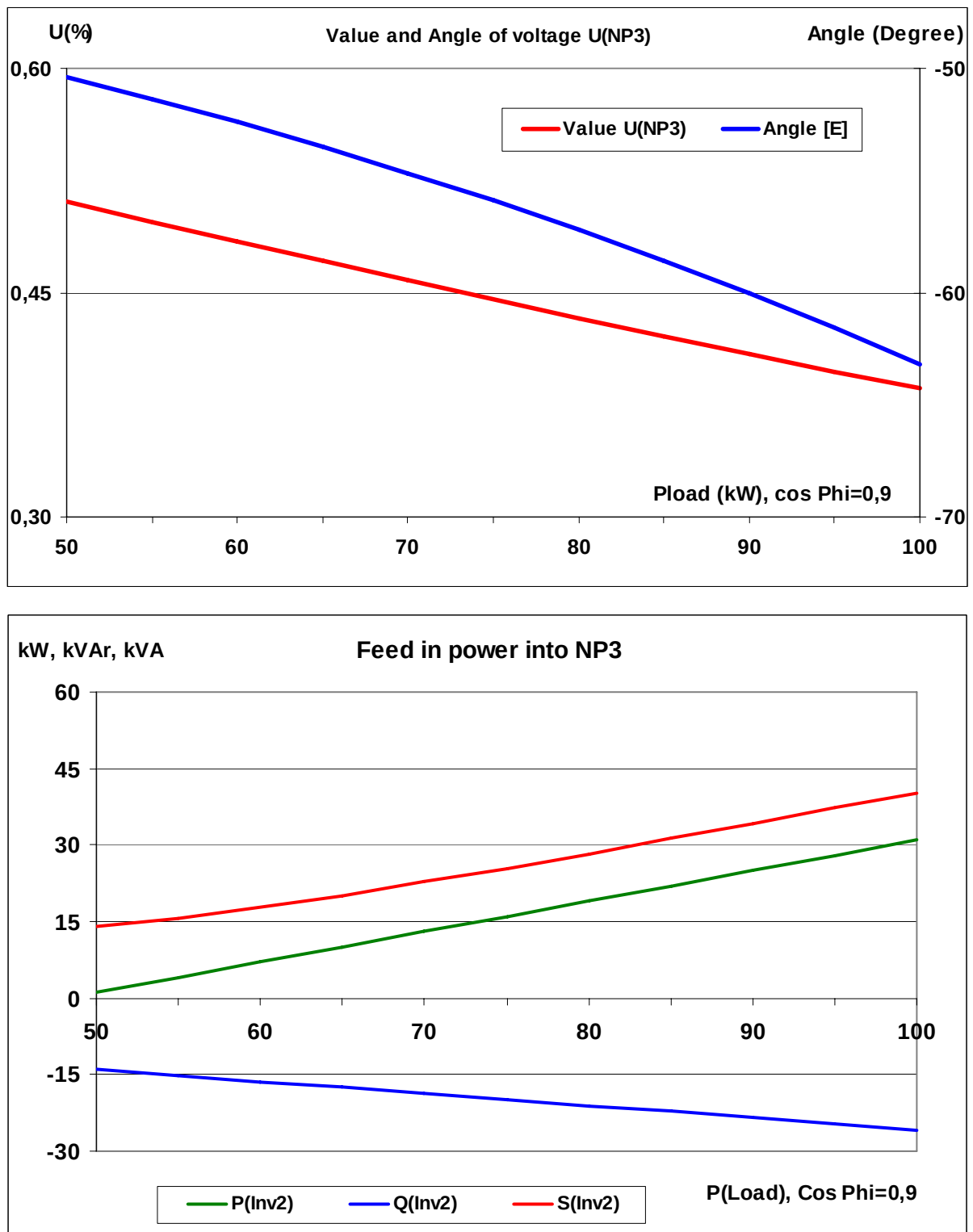


Fig. 11: Voltages and powers required for power balance in micro grid for different loads and power factor $\cos(\varphi) = 0.9$

From Fig. 10 und Fig. 11 follows that the required voltages and power from inverter no. 2 have to be controlled according to the diagrams of Fig. 11 in order to balance the demand from the load. The relations are non-linear but are simple enough for implementation in controllers for DG. In contrast to case 1 grid balance can be achieved easily, because only one grid point must be controlled.

3.2. Voltage support

For the MV and LV network the *voltage change* can be calculated as the product of the changes of the ratio of active and reactive power at the point of distributed resources connection (**PDC** - point of DGS connection)¹. In Fig. 12 and Fig. 13 an extract of the Micro grid from Fig. 2 is given to point out the influence of load and DG on the voltage. The magnitude of voltage change is of particular importance in the case of load and DG connected to the same node.

The voltage $\underline{U}_V$ at the PDC “V” depends on the magnitude of the voltage differential at the connection point $d\underline{U}_{Q,V}$ and can be lower or higher than the voltage $\underline{U}_Q$ at the infeed from the external grid.

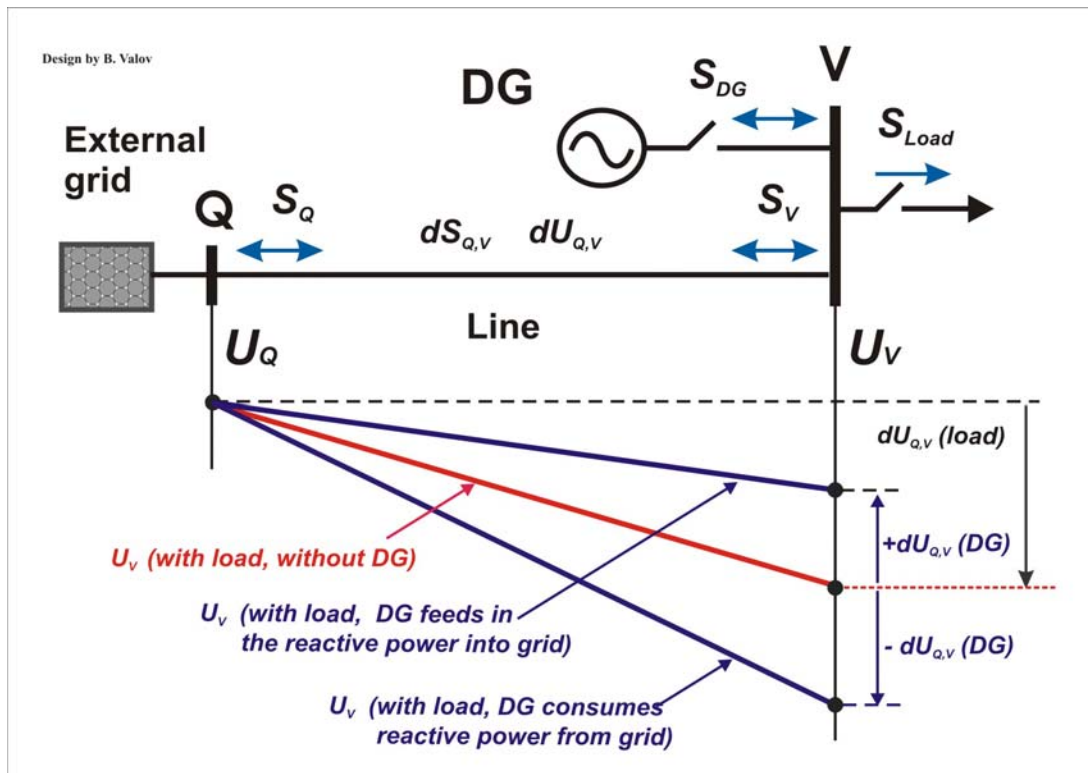


Fig. 12: Voltage in grid with load and DG

¹ The point where a distributed resources unit is electrically connected in an electric power system.: INTERCONNECTING DISTRIBUTED RESOURCES WITH ELECTRIC POWER SYSTEMS; IEEE, Std 1547-2003

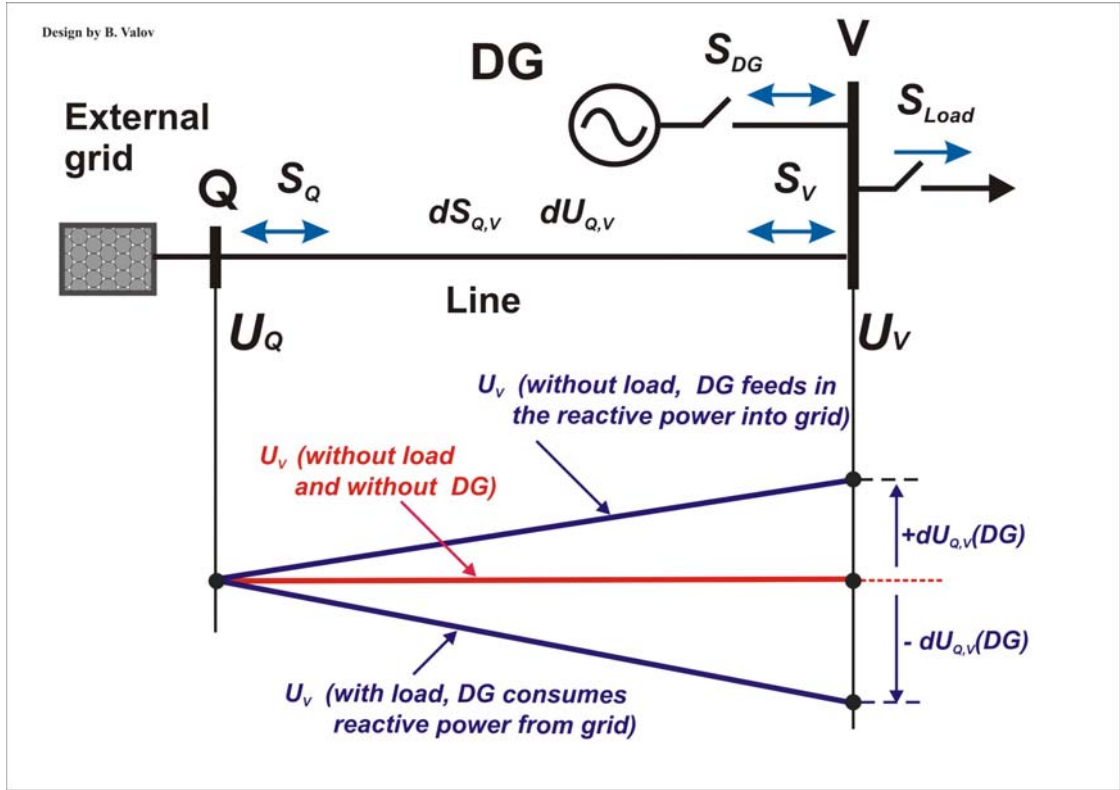


Fig. 13: Voltage in grid without load and DG

After connecting a controllable DG to the Micro grid the load flow at the PDC S_V is equal to the geometrical sum of apparent powers of the load S_{Load} and the one fed in by the DG S_{DG} :

$$\begin{aligned}
 \underline{U}_V &= \underline{U}_Q - \frac{S_{Load}}{\sqrt{3} \cdot U_V} \cdot Z_{Q,V} = \underline{U}_Q - \frac{S_{Load} \pm S_{DG}}{\sqrt{3} \cdot U_V} \cdot Z_{Q,V} = \\
 &= \underline{U}_Q - \frac{S_{Load}}{\sqrt{3} \cdot U_V} \cdot Z_{Q,V} \pm \frac{S_{DG}}{\sqrt{3} \cdot U_V} \cdot Z_{Q,V} = \underline{U}_Q - \underline{dU}(Load) \pm \underline{dU}(DG).
 \end{aligned}
 \tag{1}$$

From this equation it is obvious that the voltage behaviour at the node “V” depends on both the load and the DG and that these two influencing factors can be considered separately. Therefore in the following for the voltage change $\pm \underline{dU}(DG)$ at the PDC only the behaviour of the DG is taken into account.

The voltage change at the PDC with power flow from DGs can be calculated as follows [Valov]:

$$\begin{aligned}
\sqrt{3} \cdot dU(DG) &= \sqrt{3} \cdot \frac{S_{DG}}{\sqrt{3} \cdot U_V} \cdot Z_{Q,V} = \\
&= \frac{(-P_{DG}) + j(\pm Q_{DG})}{U_V} \cdot (R_{Q,V} + j \cdot X_{Q,V}) = \\
&= \frac{(-P_{DG}) \cdot R_{Q,V} + (\pm Q_{DG}) \cdot X_{Q,V}}{U_V} + j \frac{(-P_{DG}) \cdot X_{Q,V} - (\pm Q_{DG}) \cdot R_{Q,V}}{U_V} = \\
&= \Delta U_V + j \delta U_V.
\end{aligned}
\tag{2}$$

In the equations 1 and 2 active and reactive power fed in by the DG is negative in contrast to the positive algebraic sign of the power supplying the load. All separate terms of equation (2) are described in Fig. 14.

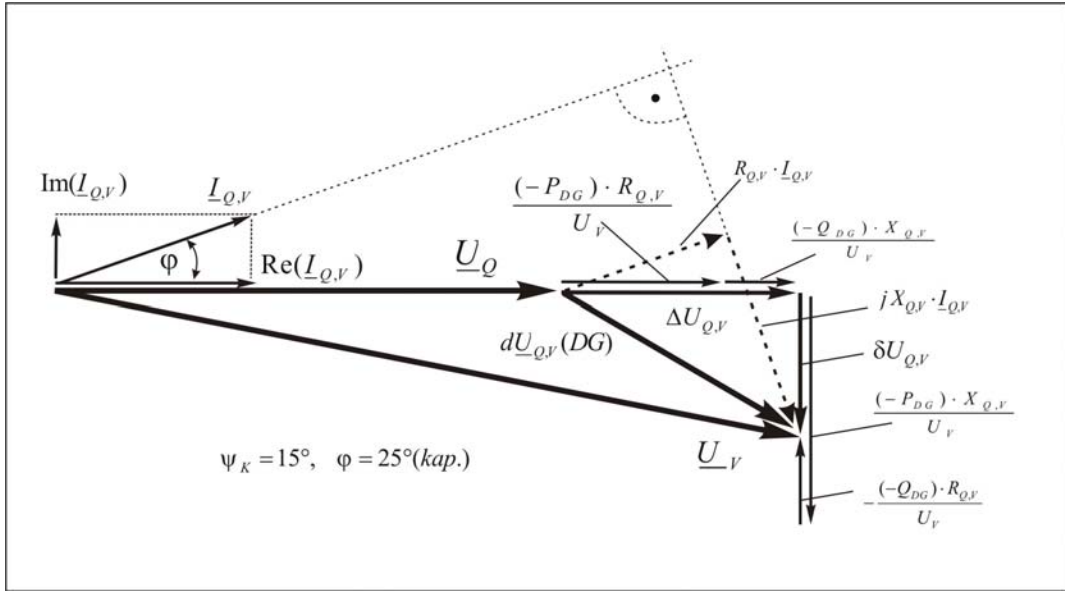


Fig. 14: Phase diagram of voltage in grid corresponding to Fig. 12

Here the voltage at the feed-in point “Q” is assumed to be constant with an angle of zero. For this reason the phase has been placed on the x-axis. From the presentation above it can be derived that by varying the phase difference φ the longitudinal and transverse voltage drop can be changed and the voltage at the PDC “V” is influenced. In practice it is common to give voltage changes in per-unit values (p.u.) related to nominal voltage. For node “V” the resulting longitudinal voltage drop $\Delta U_{Q,V}(\%)$ is equal to

$$\begin{aligned}
\Delta U_{Q,V}(\%) &= 100 \cdot \frac{\Delta U_V}{U_{nV}} = \frac{(-P_{DR}) \cdot R_{Q,V} + (\pm Q_{DR}) \cdot X_{Q,V}}{U_{nV}^2} = \\
&= -100 \cdot \frac{c}{k_{DR}''} \cdot [\cos \psi_{kV} - \operatorname{tg} \varphi \cdot \sin \psi_{kV}].
\end{aligned}
\tag{3}$$

Similarly the resulting transverse voltage drop $\delta U_{Q,V}$ (%) is

$$\delta U_{Q,V} (\%) = 100 \cdot \frac{c}{k_{DR}''} \cdot [\sin \psi_{kV} + \operatorname{tg} \varphi \cdot \cos \psi_{kV}]. \quad (4)$$

In this formula the following formula symbols are used:

- $k_{DG}'' = S_{kV}'' / P_{DG}$ is the ratio of short-circuit powers, calculated from the short-circuit power at node “V” without DG S_{kV}'' and the active power from the DG P_{DG} .
- φ is the phase difference between active and reactive power of the DG.
- ψ_{kV} is the network impedance phase angle at the PDC “V”.

The value of the voltage at node “V” $\underline{U}_V$ is the geometrical sum of the voltage phase at the point of feed-in “Q” and the voltage change $d\underline{U}_V$:

$$U_V = \sqrt{(U_Q + \Delta U_{Q,V})^2 + \delta U_{Q,V}^2} \quad (5)$$

For the p.u. voltage change at the PDC “V” we have the following equation:

$$dU_V (\%) = 100 \cdot \frac{U_V(\text{with DG}) - U_V(\text{without DG})}{U_n} = 100 \cdot \frac{U_V(\text{with DG}) - U_Q}{U_n}. \quad (6)$$

As obvious from equations (3) and (4) the voltage change at the PDC depends on

a) the characteristics of the Micro grid ψ_{kV} , S_{kV}''

and

b) the characteristics of the DGs P_{DG} , $\pm Q_{DG}$, φ

The characteristics of the Micro grid and different DGs will be described in the following paragraphs.

3.3. Relevant capabilities of grids

Typically Micro grids are connected to a superior grid forming interconnected network operation. Hence, for the following investigations the electrical characteristics of both the superior grid and the Micro grid are considered.

The parameters of *superior grids* vary from one country to another. Nevertheless basic characteristics which are important for this project can be determined. For this purpose special investigations have been conducted analysing parameters of electrical networks from all over the world.

The parameters of *Micro grids* mainly depend on influencing factors like network configuration, number and type of electrical equipment etc. The influence of the superior grid is only of minor importance.

The data obtained during the analyses are also applied in other WPs.

Fig. 15 shows the single-line diagram used for the identification of the electrical characteristics of grids. For the objectives of this project the short-circuit power S_{sc}'' and the short-circuit network impedance angle ψ_{sc} are of special interest. For the estimation of these parameters of both the superior grid and the Micro grid the typical characteristics of

- the superior grid,
- the cables / overhead lines and
- the transformers

shall be analysed.

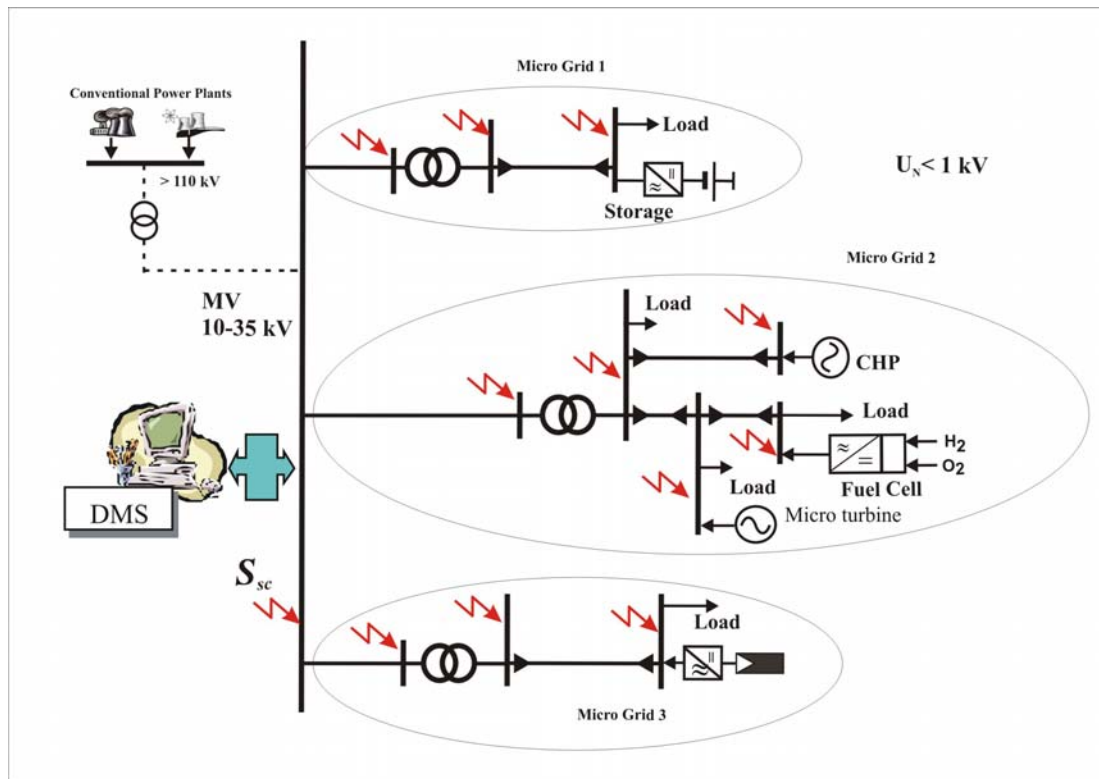


Fig. 15: Connection diagram of network with three micro grids

3.3.1. Impacts of the superior grid

For the network parameters S_{SC}'' and ψ_{SC} the internal configuration of the superior grid (radial or meshed) is regarded to be an equivalent. The results of the investigations done by ISET are shown in Table 1, giving average values for different voltage levels worldwide.

No.	Rated voltage	Short-circuit power S_{SC}'' (GVA)		Network impedance phase angle ψ_{SC} (degree)	
		from	to	from	to
	kV				
1.	420 - 440	4,0	40	86 (X/R=14,301)	86 (X/R=14,301)
2.	300 - 362	2,3	35	85 (X/R=11,430)	86 (X/R=14,301)
3.	220 - 245	1,7	20	80 (X/R=5,671)	86 (X/R=19,081)
4.	110	0,5	6,0	79 (X/R=5,145)	86 (X/R=14,301)
5.	30 - 35	0,2	1,0	82 (X/R=7,115)	86 (X/R=14,301)
6.	20 - 23	0,03	0,5	26 (X/R=0,488)	86 (X/R=14,301)
7.	10 - 15	0,01	0,2	39 (X/R=0,810)	85 (X/R=11,430)

Table 1: Average values of the short-circuit power and the network impedance phase angle worldwide

Lines 1 to 4 are valid for the superior grids of 110 kV and more (cities and countries). Lines 5 to 7 give the results for the busbars of the MV substations (maximum values) and have been used for the further investigations in this project.

If the values for S_{SC}'' and ψ_{SC} are known for one node of the considered network, the parameters of the superior network R_{Grid} and X_{Grid} can be calculated as follows (Fig. 16):

$$R_{Grid} = \frac{U_N^2 \cdot c}{S_{SC}''} \cdot \cos \psi_{SC} \quad (Ohm) \text{ and}$$

$$X_{Grid} = \frac{U_N^2 \cdot c}{S_{SC}''} \cdot \sin \psi_{SC} \quad (Ohm).$$

(7)

With U_N rated voltage of the network and c voltage factor. In medium voltage networks c can be set to 1,1 and in low voltage networks $c = 1.05$ [EE MV, EE LV]. In Fig. 16 examples for the description of the superior network by an electrical equivalent are given for three network points (SC, SC1 and SC2).

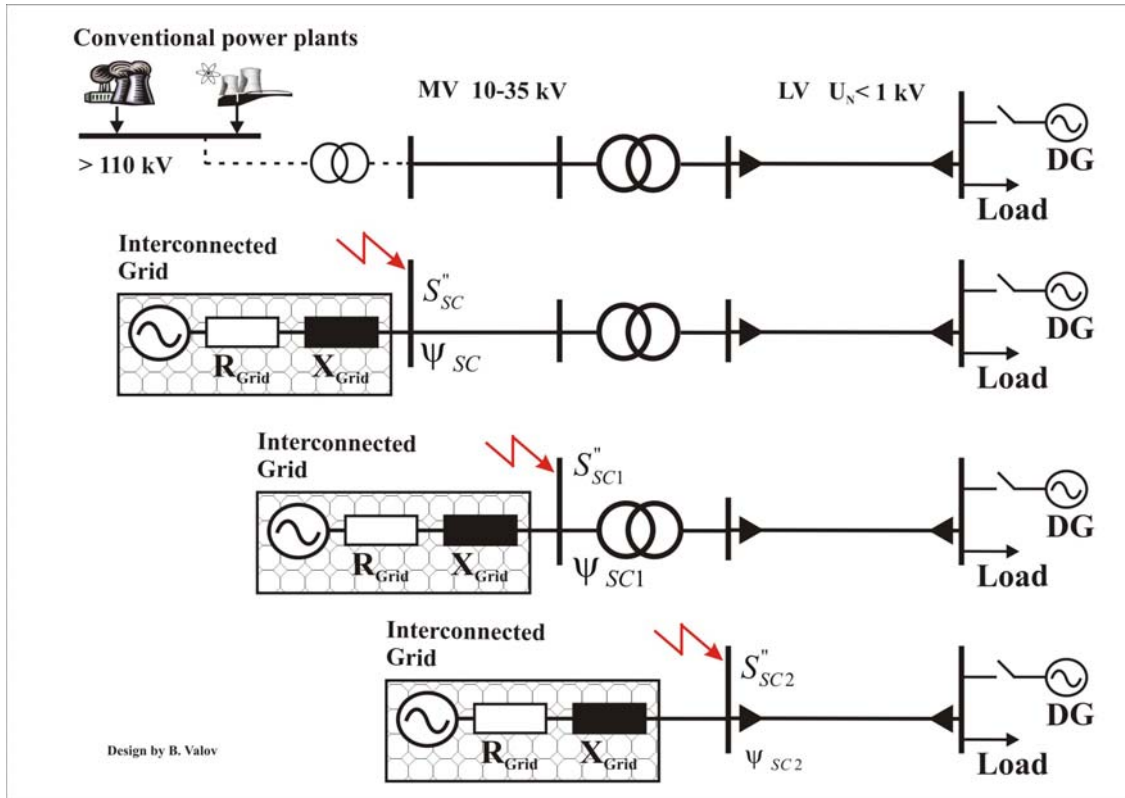


Fig. 16: Example for the description of the superior network by an electrical equivalent for three network points

3.3.2. Cables and over head lines

At the MV busbars (Fig. 1) several Micro grids are connected in parallel. Every Micro grid usually consists of a MV cable, a distribution transformer and a LV cable (Fig. 2). Within this configuration only the MV cable can be missing. Interactions regarding the electrical operation of different Micro grids are possible due to the shared MV connection point. In Europe there is a standard for MV and LV cables. Table 2 and Table 3 show the average values of the parameters for MV and LV overhead-lines and cables recommended for connection planning of DGs.

Type	Cross section	Resistance	Inductive resistance	Short-circuit angle	Maximum current
	A	R'	X'	ψ_{SC}	I_{Max}
	mm ²	Ohm / km	Ohm / km	Degree	A
Aluminium cable					
NA2XS2Y	50	0.641	0.136	11.98	171
NA2XS2Y	120	0.253	0.118	25.00	283
NA2XS2Y	240	0.125	0.106	40.30	413
NA2XS2Y	300	0.100	0.103	45.85	466
NA2XS2Y	400	0.078	0.099	51.84	529
NA2XS2Y	500	0.061	0.109	60.77	302
Copper cable					

N2XS2Y	50	0.387	0.136	19.36	220
N2XS2Y	120	0.153	0.118	37.64	363
N2XS2Y	240	0.0754	0.106	54.57	526
N2XS2Y	300	0.0601	0.103	59.74	591
N2XS2Y	400	0.0470	0.099	64.60	662
N2XS2Y	500	0.0366	0.109	71.44	744
Overhead line aluminium / steel					
AL/ST	25/4	1.2028	0.40	18.39	130
AL/ST	35/6	0.8353	0.39	25.03	175
AL/ST	50/8	0.5946	0.38	32.58	210
AL/ST	70/12	0.4130	0.37	41.86	265
AL/ST	95/12	0.3058	0.36	49.65	330

**Table 2: Average parameters of MV cables / overhead lines
[Kabel, Nexans, Handbuch, Faber, VDE]**

The short-circuit network impedance angle ψ_{SC} is determined for the case in which a DG is connected to one end of the line and a short-circuit occurring at the other end. Assuming operation at maximum current and the maximum permissible voltage drop of 10% [EN50160] for the MV cables and overhead lines respectively the highest connection lengths and their typical impedances can be calculated.

Cross section	Resistance	Inductive resistance	Maximum current	Apparent power	Ratio	Short-circuit angle	Length
F	R'	X'	I _{max}	S _{max}	R' / X'	ψ_{SC}	L _{max}
mm ²	Ohm / km	Ohm / km	A	kVA	p.u.	Degree	km
4	5.460	0.1065	44	30.48	51.268	1.12	0.096
6	3.630	0.1008	56	38.80	35.996	1.59	0.114
10	2.170	0.0946	75	51.96	22.948	2.50	0.142
16	1.360	0.0895	99	68.59	15.190	3.77	0.171
25	0.864	0.0880	128	88.68	9.822	5.81	0.208
35	0.627	0.0851	155	107.39	7.365	7.73	0.235
50	0.464	0.0848	184	127.48	5.470	10.36	0.266
70	0.321	0.0823	226	156.58	3.900	14.38	0.308
95	0.232	0.0820	272	188.45	2.829	19.46	0.345
120	0.184	0.0804	310	214.77	2.288	23.61	0.371
150	0.150	0.0804	348	241.10	1.865	28.20	0.390
185	0.121	0.0804	394	272.97	1.505	33.61	0.403

Table 3: Average parameters of LV cables [Kabel, Nexans, Handbuch, Faber, VDE]

Taking into account the data of Table 2 and Table 3 the maximum permissible connection length can be calculated as follows:

$$L_{\max} = \frac{dU(\%) \cdot U_N}{100} \cdot \frac{1}{\sqrt{3} \cdot I_{\max} \cdot \sqrt{(R' \cdot \cos \varphi + X' \cdot \sin \varphi)^2 + (X' \cdot \cos \varphi - R' \cdot \sin \varphi)^2}} \quad (8)$$

The diagrams of Fig. 17 to Fig. 19 show the values calculated with the equation above.

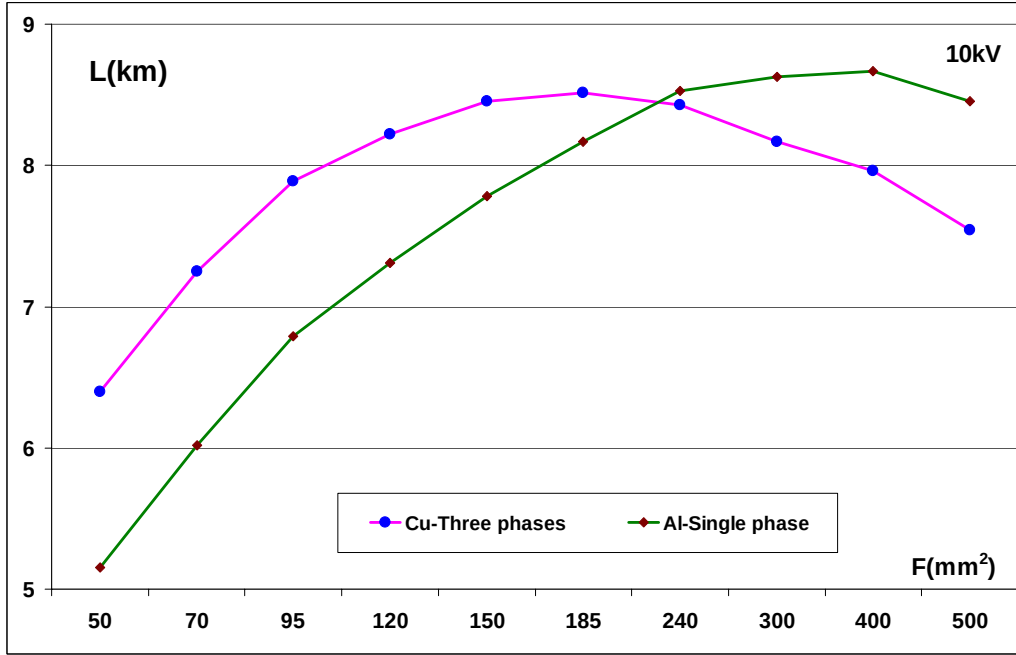


Fig. 17: Maximum permissible length of a 10 kV connection

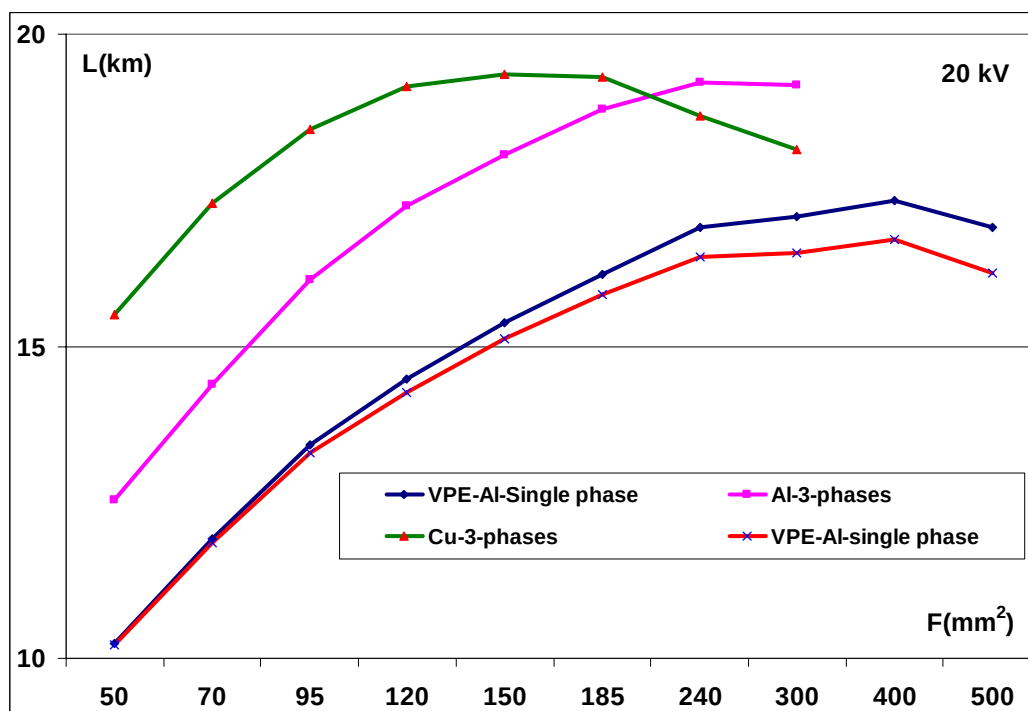


Fig. 18: Maximum permissible length of a 20 kV connection

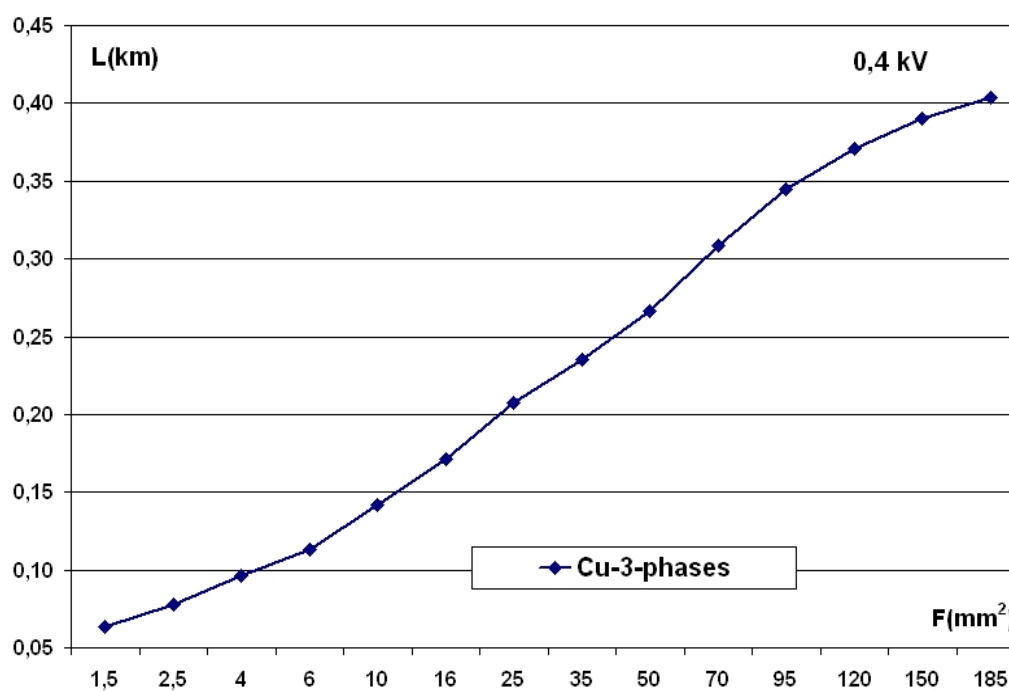


Fig. 19: Maximum permissible length of a LV connection

On the basis of the maximum permissible connection lengths the resulting impedances are calculated and listed in Table 6.

3.3.3. Transformers

The LV Micro grids are connected to the superior grid via an oil-filled distribution transformer. Typical parameters of those transformers hardly differ from one country to another (Table 4 and Table 5).

Nominal apparent power	Short- circuit losses	Short-circuit voltage	Resistance	Inductive resistance	Short- circuit angle
$S_{N.Tr}$	P_k	u_k	R_{Tr}	X_{Tr}	ψ_k
kVA	kW	%	(Ohm)	(Ohm)	degree
100	1,46	4	14.60	37.24	68.59
250	3.26	4	5.22	15.13	70.97
400	4.60	4	2.88	9.58	73.29
630	5.60	6	1.41	9.42	81.48
1000	10.20	6	1.02	5.91	80.21
1600	16.70	6	0.65	3.69	79.98
2500	20.10	6	0.32	2.38	82.30

Table 4: Characteristic values of 10 kV distribution transformers

Nominal apparent power	Short- circuit losses	Short-circuit voltage	Resistance	Inductive resistance	Short- circuit angle
$S_{N.Tr}$	P_k	u_k	R_{Tr}	X_{Tr}	ψ_{SC}
kVA	kW	%	(Ohm)	(Ohm)	degree
100	1.10	4	44.00	153.83	74.04
250	2.55	4	16.32	61.88	75.23
400	4.30	4	10.75	38.53	74.41
630	6.90	6	6.95	37.46	79.48
1000	9.60	6	3.84	23.69	80.79
1600	14.00	6	2.19	14.84	81.61
2500	20.00	6	1.28	9.51	82.34

Table 5: Characteristic values of 20 kV distribution transformers

The contribution of a distribution transformer to the short-circuit network impedance angle ψ_{SC} can be calculated by taking the resistance R_{Tr} and the inductive resistance X_{Tr} related to the MV side of the transformer:

$$\begin{aligned}
Z_{Tr} &= \frac{u_K}{100} \cdot \frac{U_N^2}{S_N} \\
R_{Tr} &= P_K \cdot \frac{U_N^2}{S_N^2} \\
X_{Tr} &= \sqrt{Z_{Tr}^2 - R_{Tr}^2} \\
\Psi_{SC} &= a \tan (X_{Tr} / R_{Tr})
\end{aligned} \tag{9}$$

3.3.4. Total parameters of Micro grids

When comparing Table 2 to Table 5 it can be noticed that the network impedance angle of the overhead line or the cable respectively varies in a range of 11 to 73 degree whilst the one of the transformer lies in a narrow area of 70 to 83 degree. This complies with the ratio of R / X for cables and overhead lines in the range of 0.4 to 4.8 for MV grids and 1.5 to 50 for LV grids. Ohmic resistance and the inductive resistance of the cable are almost equal for big cross sections. High values of the ratio can be found for LV cables with small and medium cross sections. For the transformers the inductive resistance is always greater than the ohmic one. As the transformer and the cable are connected in series (Fig. 15) the ratio R / X and the values S_{SC} and Ψ_{SC} respectively can differ for the connection of a DG. For the determination of these values all ohmic $R_{\Sigma} = R_{Grid} + R_{cab}(MV) + R_{Tr} + R_{cab}(LV)$ and inductive $X_{\Sigma} = X_{Grid} + X_{cab}(MV) + X_{Tr} + X_{cab}(LV)$ resistances of the electrical equipment from the superior grid down to the considered node have to be added up. In Fig. 15 and Fig. 16 these are

- MV grid (R_{Grid} , X_{Grid}),
- MV cable ($R_{cab}(MV)$, $X_{cab}(MV)$),
- Transformer (R_{Tr} , X_{Tr}) and
- LV cable ($R_{cab}(LV)$, $X_{cab}(LV)$).

All parameters shall be relating to the MV level. The data received from those considerations are given in Table 6.

$S_{N.Tr}$	10 kV grid $S_{SC} = 100 MVA$ $\psi_K = 85^\circ$		10kV-Al cable		Trans- former		LV-Cu cable 0.25 km		Sum			
	R_{Grid}	X_{Grid}	R_{MV}	X_{MV}	R_{Tr}	X_{Tr}	R_{LV}	X_{LV}	R_{Σ}	X_{Σ}	$\frac{R_{\Sigma}}{X_{\Sigma}}$	ψ_k
kVA	Ohm	Ohm	Ohm	Ohm	Ohm	Ohm	Ohm	Ohm	Ohm	Ohm	p.u.	degree
100	0.096	1.096	3.30	0.70	14.6	37.24	92.10	12.51	110.1	51.5	2.1	25.1
250	0.096	1.096	3.30	0.70	5.22	15.13	46.05	6.25	54.7	23.2	2.4	23.0
400	0.096	1.096	3.30	0.70	2.88	9.58	23.02	3.13	29.3	14.5	2.0	26.3

630	0.096	1.096	3.30	0.70	1.41	9.42	15.35	2.08	20.2	13.3	1.5	33.4
1000	0.096	1.096	3.30	0.70	1.02	5.91	9.21	1.25	13.6	9.0	1.5	33.3
1600	0.096	1.096	3.30	0.70	0.65	3.69	5.76	0.78	9.8	6.3	1.6	32.6
2500	0.096	1.096	3.30	0.70	0.32	2.38	3.68	0.50	7.4	4.7	1.6	32.3

Table 6: Total parameters at the PDC for a 10 kV interconnected network and a LV-Cu cable of 0.25 km length

The calculations in Table 6 are based on the maximum permissible length of a 10 kV cable with a cross section of 35 mm² transmitting 100 kVA which were determined to be 0.25 km. For other loadings of the distribution transformer the number of listed LV cables connected in parallel was adjusted to get calculation results which are comparable. As can be seen from this table the impedance of the LV cable with a length of 0.25 km exceeds the impedance of the transformer. For other smaller line lengths the respective calculation results are given in Table 7 below. A cable length of $L = 0$ corresponds to the case of a DG connected to the LV terminals of the transformer.

$S_{N.Tr}$	LV-Cu cable $L=0$ km		LV-Cu cable $L=0.1$ km		LV-Cu cable $L=0.2$ km		LV-Cu cable $L=0.3$ km	
	$\frac{R_{\Sigma}}{X_{\Sigma}}$	ψ_k	$\frac{R_{\Sigma}}{X_{\Sigma}}$	ψ_k	$\frac{R_{\Sigma}}{X_{\Sigma}}$	ψ_k	$\frac{R_{\Sigma}}{X_{\Sigma}}$	ψ_k
kVA	p.u.	<i>Degree</i>	p.u.	<i>Degree</i>	p.u.	<i>Degree</i>	p.u.	<i>Degree</i>
100	0.5	65.2	1.3	37.8	1.9	27.3	2.5	22.1
250	0.5	63.0	1.4	34.8	2.1	25.0	2.7	20.3
400	0.6	61.1	1.3	38.3	1.8	28.5	2.3	23.3
630	0.4	66.8	0.9	46.9	1.4	36.0	1.8	29.6
1000	0.6	60.2	1.0	44.7	1.4	35.6	1.7	29.9
1600	0.7	53.6	1.1	41.8	1.5	34.5	1.8	29.6
2500	0.9	48.3	1.2	39.7	1.5	33.9	1.7	29.7

Table 7: Total parameters at the PDC for a 10 kV interconnected network and different lengths of the LV-Cu cable

$S_{N.Tr}$	20 kV grid $S_{SC} = 100 \text{ MVA}$ $\psi_K = 85^\circ$		20kV-Al cable		Trans- former		LV-Cu cable $L=0.25$ km		Sum			
	R_{Grid}	X_{Grid}	R_{MV}	X_{MV}	R_{Tr}	X_{Tr}	R_{LV}	X_{LV}	R_{Σ}	X_{Σ}	$\frac{R_{\Sigma}}{X_{\Sigma}}$	ψ_k
kVA	Ohm	Ohm	Ohm	Ohm	Ohm	Ohm	Ohm	Ohm	Ohm	Ohm	p.u.	degree
100	0.383	4.383	6.567	1.193	44.0	153.8	396.6	53.8	419.3	209.4	2.0	26.5
250	0.383	4.383	6.567	1.193	16.3	61.9	198.3	26.9	207.5	92.5	2.2	24.0
400	0.383	4.383	6.567	1.193	10.8	38.5	99.1	13.5	109.8	56.6	1.9	27.3

630	0.383	4.383	6.567	1.193	6.95	37.5	66.1	9.0	75.3	51.4	1.5	34.3
1000	0.383	4.383	6.567	1.193	3.84	23.7	39.7	5.4	47.6	34.3	1.4	35.7
1600	0.383	4.383	6.567	1.193	2.19	14.8	24.8	3.4	32.2	23.5	1.4	36.2
2500	0.383	4.383	6.567	1.193	1.28	9.5	15.9	2.2	23.0	17.1	1.3	36.7

Table 8: Total parameters at the PDC for a 20 kV interconnected network and a LV-Cu cable of 0.25 km length

$S_{N.Tr}$	LV-Cu cable $L=0$ km		LV-Cu cable $L=0.1$ km		LV-Cu cable $L=0.2$ km		LV-Cu cable $L=0.3$ km	
	$\frac{R_{\Sigma}}{X_{\Sigma}}$	ψ_k	$\frac{R_{\Sigma}}{X_{\Sigma}}$	ψ_k	$\frac{R_{\Sigma}}{X_{\Sigma}}$	ψ_k	$\frac{R_{\Sigma}}{X_{\Sigma}}$	ψ_k
kVA	p.u.	<i>Degree</i>	p.u.	<i>Degree</i>	p.u.	<i>Degree</i>	p.u.	<i>Degree</i>
100	0.3	72.3	1.1	41.0	1.8	29.0	2.3	23.2
250	0.3	71.0	1.3	37.5	2.0	26.2	2.6	21.0
400	0.4	68.1	1.2	41.0	1.8	29.7	2.3	23.9
630	0.3	72.1	0.9	49.3	1.3	37.2	1.7	30.2
1000	0.4	69.8	0.8	49.9	1.3	38.5	1.6	31.7
1600	0.4	65.9	0.9	49.0	1.2	38.8	1.6	32.4
2500	0.5	61.4	0.9	47.7	1.2	39.0	1.5	33.1

Table 9: Total parameters at the PDC for a 20 kV interconnected network and different lengths of the LV-Cu cable

The following conclusions can be drawn from the tables above:

- Considering a line from the transformer to the most distant PDC the network impedance phase angle in a 10 kV and 20 kV MV grid ranges from 22 to 33 degree corresponding to a ratio R/X from 1.5 to 2.7.
- The value of the ohmic resistance exceeds the value of the inductive resistance and the total impedance at the PDC is only resistive.
- The electrical characteristics of the LV cable have a stronger impact on the total network impedance than the MV connection and the transformer.
- When connected directly to the LV terminals of the transformer the network impedance phase angle reaches **67 degree** for 10 kV (Table 7) and **72 degree** for 20 kV (Table 9)
- For the conditions of the recent bullet the ratio R/X ranges from 0.5 to 0.9 for 10 kV and from 0.3 to 0.9 for 20 kV and within the total impedance at the PDC the share of the inductive resistance is bigger than the one of the ohmic resistance.

With the data from Table 6 now the short-circuit power $S''_{SC}(LV)$ at the PDC can be calculated (Fig. 2):

$$S''_{SC}(LV) = \frac{U_N^2(MV) \cdot c}{\sqrt{(R_{\Sigma})^2 + (X_{\Sigma})^2}} \quad (10)$$

For the following analysis of the voltage increase in a Micro grid the ratio of the short-circuit power $S_{SC}''(LV)$ and the nominal apparent power of the DG S_N is significant. Since the nominal apparent power of the DG S_N should not exceed the nominal apparent power of the transformer $S_{N,Tr}$ the case $S_N = S_{N,Tr}$ was considered as the worst case. The ratio of short-circuit powers K_{SC}'' can be calculated with the equation $K_{SC}'' = S_{SC}''(LV) / S_{Tr}$.

In Table 10 and Table 11 the calculated values for $S_{SC}''(LV)$ and K_{SC}'' are given for two different rated voltages of the MV grid and for different parameters S_{SC}'' and ψ_k of the superior grid. The determination of the impact of S_{SC}'' on the PDG parameters $S_{SC}''(LV)$ and K_{SC}'' was done assuming the two typical limiting values 100 and 1000 MVA.

$S_{N,Tr}$	kVA	100	250	400	630	1000	1600	2500
$S_{SC}''(LV)$ for 10 kV MV grid and $S_{SC} = 100MVA$, $\psi_k = 85^\circ$	MVA	0.91	1.85	3.37	4.56	6.75	9.45	12.56
K_{SC}''	p.u.	9.0	7.4	8.4	7.2	6.7	5.9	5.0
$S_{SC}''(LV)$ for 10 kV MV grid and $S_{SC} = 1000MVA$, $\psi_k = 85^\circ$	MVA	0.91	1.87	3.42	4.67	7.00	9.94	13.42
K_{SC}''	p.u.	9.1	7.5	8.5	7.4	7.0	6.2	5.4

Table 10: Calculated values for $S_{SC}''(LV)$ and K_{SC}'' at the PDC for a 10 kV Micro grid

$S_{N,Tr}$	kVA	100	250	400	630	1000	1600	2500
$S_{SC}''(LV)$ for 20 kV MV grid and $S_{SC} = 100MVA$, $\psi_k = 85^\circ$	MVA	0.94	1.94	3.56	4.83	7.50	11.04	15.37
K_{SC}''	p.u.	9.4	7.7	8.9	7.7	7.5	6.9	6.1
$S_{SC}''(LV)$ for 20 kV	MVA	0.94	1.95	3.62	4.96	7.83	11.78	16.82

MV grid and $S_{SC} = 1000 \text{ MVA}$ $\psi_K = 85^\circ$								
K_{SC}''	p.u.	9.4	7.8	9.1	7.9	7.8	7.4	6.7

Table 11: Calculated values for $S_{SC}''(LV)$ and K_{SC}'' at the PDC for a 20 kV Micro grid

As can be seen from Table 10 and Table 11

- the higher rated voltage (20 kV) of the superior MV grid leads to a small increase of $S_{SC}''(LV)$, as the network resistances $R_{Grid} = U_N^2 \cdot c \cdot \cos \psi_{SC} / S_{SC}'' (MV)$ and $X_{Grid} = U_N^2 \cdot c \cdot \sin \psi_{SC} / S_{SC}'' (MV)$ do not significantly contribute to the values of the total impedances $R_\Sigma = R_{Grid} + R_{cab}(MV) + R_{Tr} + R_{cab}(LV)$ and $X_\Sigma = X_{Grid} + X_{cab}(MV) + X_{Tr} + X_{cab}(LV)$ (Table 6 and Table 7),
- an increase of the short-circuit power S_{SC}'' of the superior grid from 100 to 1000 MVA leads to a similar trend for $S_{SC}''(LV)$,
- the ratio $K_{SC}'' = S_{SC}''(LV) / S_{Tr}$ for 10 kV and 20 kV MV grids ranges only from **5.0** to **9.4** indicating the minor impact of the nominal voltage and the short circuit power S_{SC}'' of the superior grid,
- the total impedance at the PDC of the LV grid can be both inductive and resistive and mainly depends on the length of the LV cable.

In practice usually the relation $S_{DG} \leq S_{Tr}$ is valid. Therefore the ratio K_{SC}'' in Table 10 and Table 11 shall be greater than 9.4. For further calculations the ratio is assumed to have a value in the range of 5 to 40.

The calculated values for the short circuit power and the network impedance phase angle represent the basic data for the following network investigations.

3.4. Capabilities of distributed generation units for voltage support

The results of the analyses of parameters in Micro grids done in paragraph 3.3 and the theoretical background from 3.1 and 3.2 allow an estimation of the voltages at different network nodes with controlled DGs. For the determination of the voltages the network configuration of Fig. 12 and Fig. 13 is considered. As shown in these figures for the considered node the parameters of the network S_{SC}'' and ψ_{SC} and for the DG the parameters P_{DG} and $\pm Q_{DG}$ shall be known. From these parameters also the value of $K_{SC}'' = S_{SC}''(LV)/S_{DG}$ can be calculated.

The results of the calculations done with the equations (3) to (6) from paragraph 3.2 and the data from paragraph 3.3 are given in Fig. 20 below.

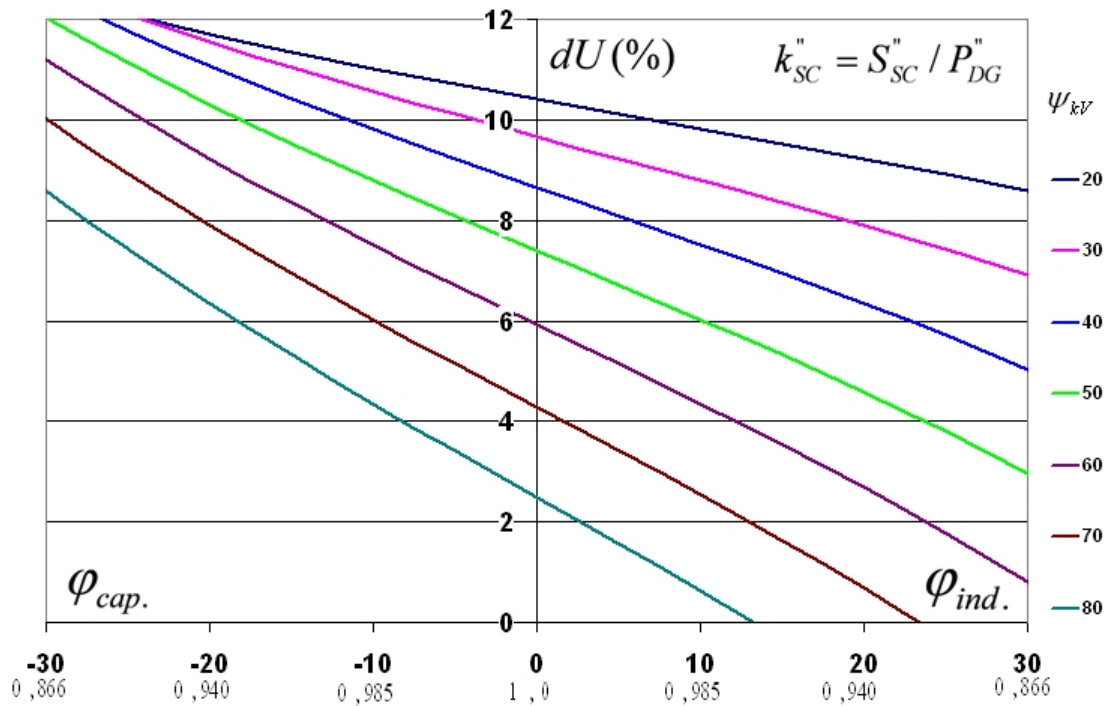


Fig. 20: Voltage increase at the PDC for $K_{SC}'' = 10$

As can be seen in Fig. 20 both active and reactive power of the DG has a separate impact on the voltage at the considered node. Operating points on the y-axis are given for a DG feeding in only active power which is in our case ten times smaller than the short-circuit power at the considered node ($K_{SC}'' = 10$). If in addition to the active power also capacitive reactive power is fed in voltage is increased to a greater extent. By consuming inductive reactive power the voltage increase can also be reduced.

Moreover Fig. 20 also shows that for the same value of fed in active power at a LV and MV node with $\psi_{SC} = 20^\circ$ to 40° a higher voltage increase can be reached than at a HV node with $\psi_{SC} = 50^\circ$ to 80° (paragraph 3.3). This means that voltage control in LV and MV grids can mainly only have a local impact. An impact on the voltage at a distant HV node is possible but only to a limited extent. In general we can ascertain that the more DGs are installed in LV and MV grids the higher this impact will become.

The diagram of Fig. 20 shows an example for $K_{SC}'' = 10$. In Table 12 the height of the voltage increase at a 110 kV and a 0.4 kV node are given.

Rated voltage at the network node	110 kV node	0.4 kV node
Short-circuit power	$S_{SC}'' = 2000 \text{ MVA}$ (Table 1)	$S_{SC}'' = 1 \text{ MVA}$ (Table 10, Table 11)
Network impedance phase angle	$\psi_{SC} = 80^\circ$ (Table 1)	$\psi_{SC} = 30^\circ$ (Table 8, Table 9)
Sum of rated power of all connected DGs in relation to the considered network node	$P_{SC} = S_{SC}'' / K_{SC}'' =$ $= 2000/10 = 200 \text{ MW}$	$P_{SC} = S_{SC}'' / K_{SC}'' =$ $= 1/10 = 0.1 \text{ MW}$
Voltage increase	2,5%	9,5%

Table 12: Voltage increase at a 110 kV and a 0.4 kV network node for $K_{SC}'' = 10$

For other ratios K_{SC}'' the values of the voltage increase are given in Fig. 21.

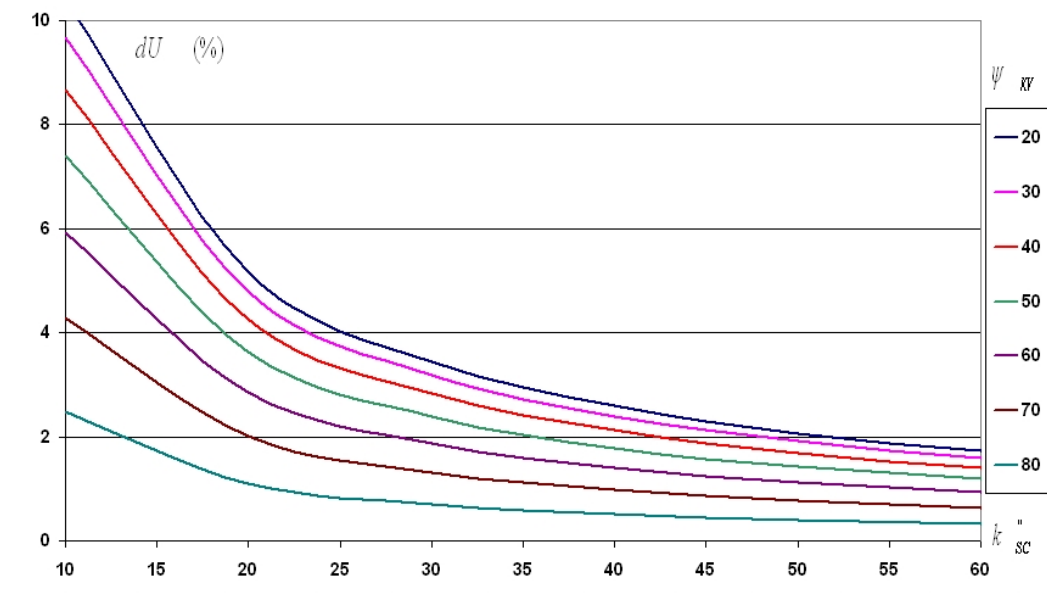


Fig. 21: Voltage increase for different values of K_{SC}''

The diagram of Fig. 20 is valid for a reactive power control in the range of 30° capacitive to 30° inductive. In practice modern DGs with inverter-coupled synchronous generators can be controlled in all four quadrants. Nevertheless for normal operation conditions the grid operator usually limits control of $\cos \phi$ (Fig. 22) to values in the range of $\cos \phi = 0.95$ (about 162°) in the 2nd quadrant (inductive consumption) to $\cos \phi = 0.95$ (about -162°) in the 3rd quadrant (capacitive infeed to the grid).

If there exists the demand of feeding in additional reactive power, e.g. for voltage stabilisation during a fault, the value of fed in active power has to be limited. Due to thermal limits of the DGs only those combinations of active power P_{DG} and reactive power $\pm Q_{DG}$ are possible for which the value of apparent power does not exceed the maximum permissible apparent power of the considered DG.

$$S_{DG} = \sqrt{P_{DG}^2 + Q_{DG}^2} \leq S_{DG, \max} \quad (10)$$

The ratio of active and reactive power can be seen from the equation $Q_{DG} = P_{DG} \cdot \tan \varphi$ and the diagram in Fig. 22.

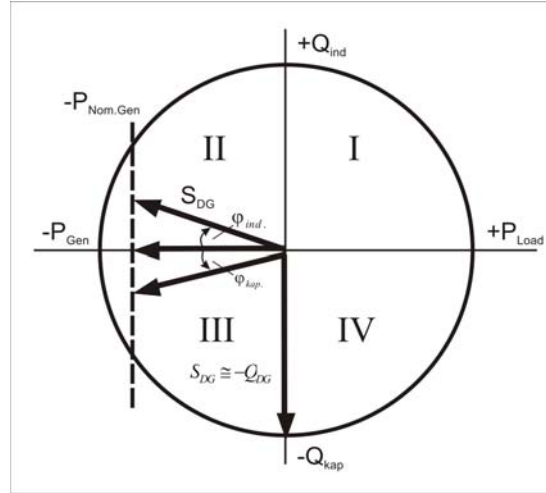


Fig. 22: Power conditions of a DG

It has to be noticed that DGs in a Micro grid due to their impact on the voltage at a superior grid node also have an impact on the voltage in other Micro grids. To give an example Fig. 23 illustrates how the voltage in Micro grids 2 and 3 is increased by a voltage change in Micro grid 1.

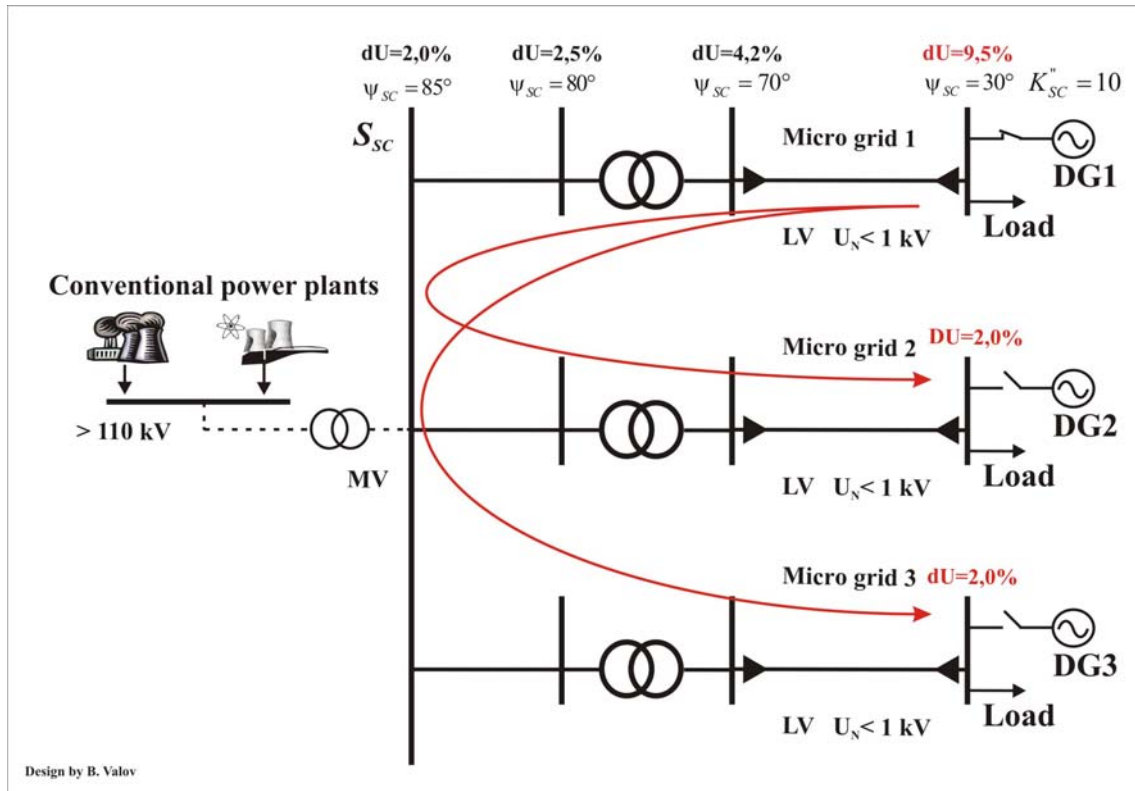


Fig. 23: Example of voltage changes in three Micro grids

This impact shall be considered for grid operation, network planning and protection coordination.

4. Experimental setup and Simulations

In order to study the reactive power exchange (VAr-exchange) and the transient active power sharing via the medium voltage grid (MV-grid) laboratory measurements and simulations have been done.

Within this chapter the experimental setup and the approach of the simulation are described. The part belonging to the experimental setup introduces the used hardware like the MV-line impedance network simulator (LINS), the inverters, different loads and measurement devices which are available at the Design-Centre for Modular Supply Technology (DeMoTec), the well-known test laboratory of ISET. The subsequent part shows how this experimental setup was reproduced within the numerical simulation tool ATP-EMTP.

4.1. Experimental setup at the DeMoTec

In Fig. 24 an overview of the DeMoTec hall is shown. On the left side of the picture the used equipment for the experiment can be seen. From the front to the back the asynchronous motor, the ohmic load, the two three phase Sunny Island clusters and the MV line impedance network simulator can be recognised. All these devices are described more detailed later on.



Fig. 24: Overview of the DeMoTec

It was planned to build three micro grids (see Fig. 23) which are connected via medium voltage. Two of these micro grids consist of inverters (DG1 and DG2), the third micro grid acts as a load. The principle schematic diagram is shown in Fig. 25. For the experiment no connection to the external grid existed. Also it was possible to separate the micro grids from the medium voltage by switches.

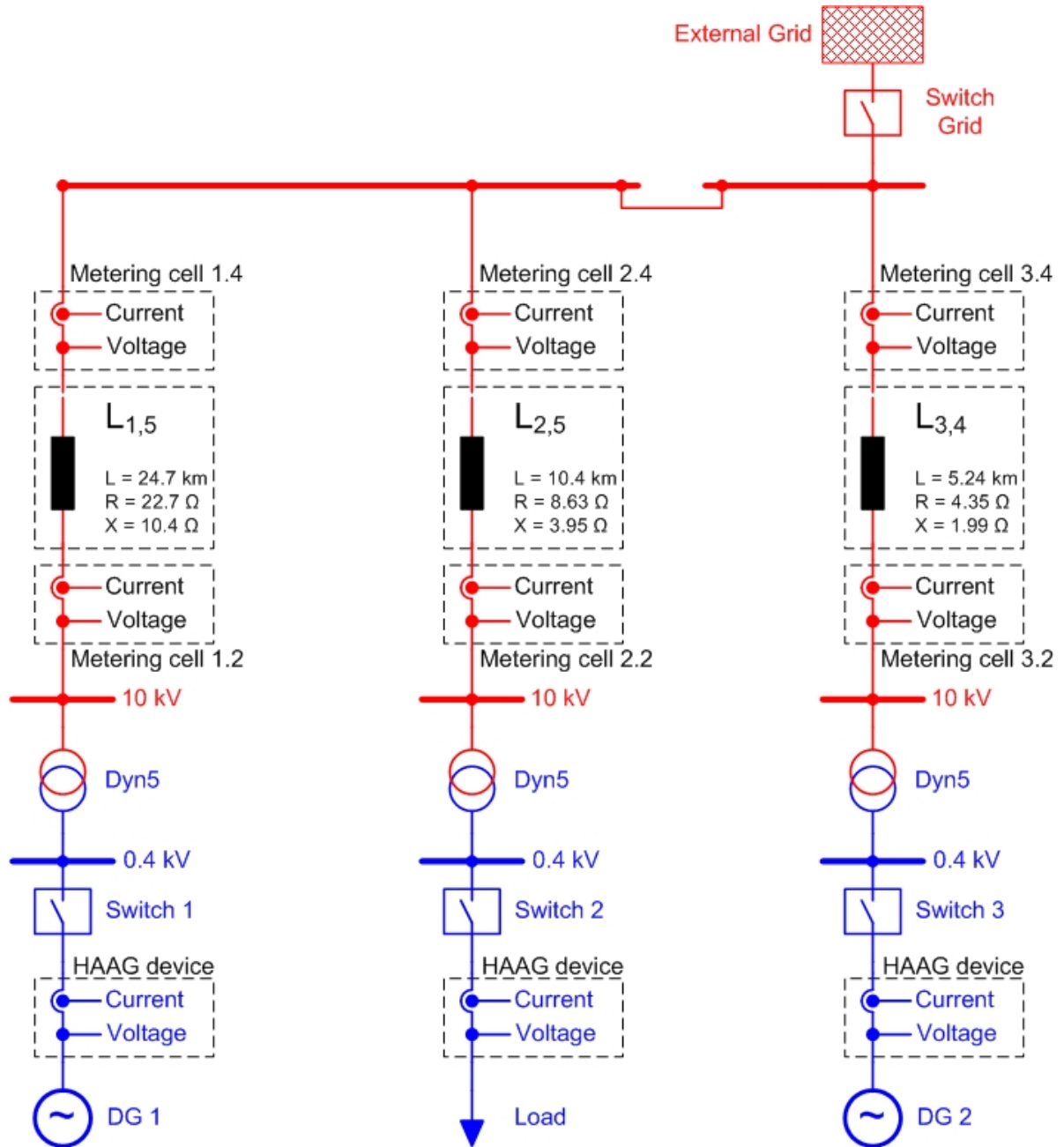


Fig. 25: Principle schema of the 10 kV line impedance simulation network

4.1.1. The Line Impedance Simulation Network

The Line Impedance Simulation Network is able to provide a configurable MV-grid. It consists of three coupled transmission circuits $L_{1,5}$, $L_{2,5}$ and $L_{3,4}$ as shown in Fig. 25. These interlinked transmission circuits can simulate either overhead lines or cables. Through the variation of the resistance and the reactance of each transmission circuit different line lengths can be simulated.

Six measurement cells on the MV-side provide the possibility to get a detailed view of the active and reactive power flows.

The low voltage grid is connected by a 10 kV/0.4 kV Dyn5 transformer with a nominal apparent power of 100 kVA. In Fig. 26 the LINS is shown, furthermore in Fig. 27 you can see the medium voltage switchgear of the LINS and in Fig. 28 the line impedance is presented.



Fig. 26: Line Impedance Simulation Network (LINS) at the DeMoTec



Fig. 27: Medium voltage switchgear of the LINS



Fig. 28: Line impedance with switchable R, X and C

4.1.2. The battery inverter Sunny Island 4500

For the power sources DG1 and DG2 (see Fig. 25) two clusters of Sunny Island 4500 (SI 4500) Inverters have been used. Each cluster consists of three single phase SI 4500 battery inverters from the SMA Technology AG. The two clusters are shown in Fig. 29.



Fig. 29: Two three phase Sunny Island 4500 battery inverter clusters at the DeMoTec with connected Haag measurement devices (see section 4.1.4)

In Table 13 the most important technical specifications of the inverters are summarised. These values are considered for single phase operation.

Parameter	Value
Continuous output power	3600 VA
AC output power for 30 min. (ambient air temperature +25° C)	4500 VA
Maximal output power for 20 sec.	6600 VA
Maximal efficiency	≥ 90 %
Nominal battery voltage	60 V
Nominal battery current	60 A

Nominal RMS output voltage	230 V
Nominal RMS output current	16 A
Nominal frequency	50 Hz or 60 Hz
Range of RMS output voltage	200 V - 260 V
Range of frequency	48 Hz - 62 Hz
Harmonic distortion in output voltage	< 3 %
Voltage ripple	< 5 %
Weight	45 kg

Table 13: Technical data of the Sunny Island 4500 battery inverter

Because of the clustering the three phase continuous nominal apparent power output can be determined as 10.8 kVA.

The control approach of the Sunny Island battery inverters is based on the *selfsync*TM method [Engler], which is described in Fig. 30. With the measured values of the current and the voltage the active and reactive power is calculated. Afterwards a decoupling takes place. With the help of droops the frequency and the voltage magnitude set points are designated. The behaviour of the droops is presented in Fig. 31. By knowing the frequency and the voltage magnitude a reference signal for the output voltage can be formed.

Depending on the calculated active power, the frequency is changed. E.g. if the active output power is similar to the nominal output power of the inverter P_n the frequency set point has to be decreased by 2% as can be seen in Fig. 31 which accords to a frequency of 49 Hz if the nominal frequency f_0 is set to 50 Hz.

The same calculations can be done for the voltage, but in this case the reactive power is used. The slope is set to -6% in this example. It has to be mentioned that the voltage droop is not able to regulate the voltage exactly but it provides a voltage which is within a certain voltage range.

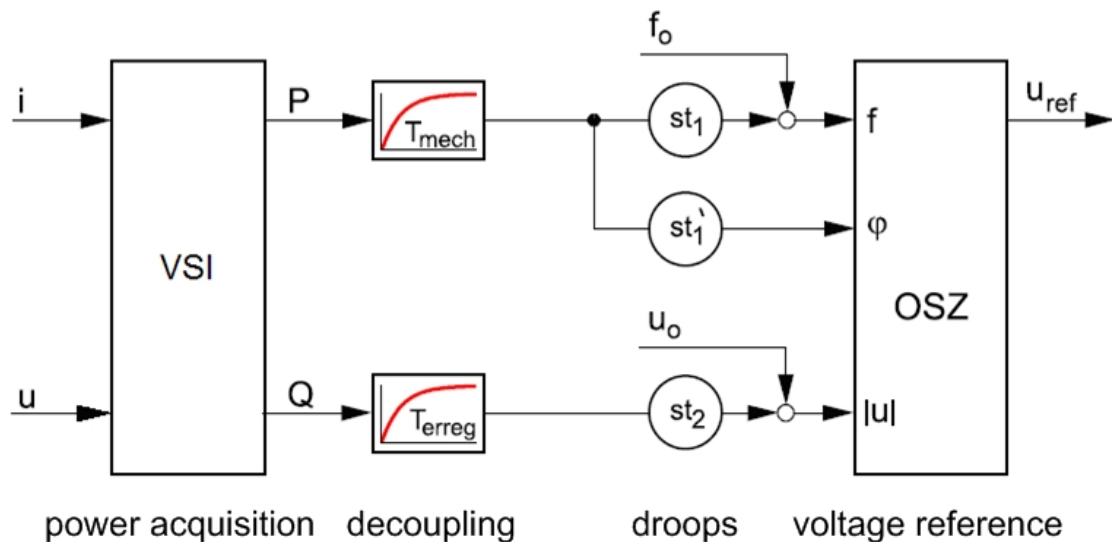


Fig. 30: Control approach *selfsync*TM by ISET e.V., Kassel, Germany

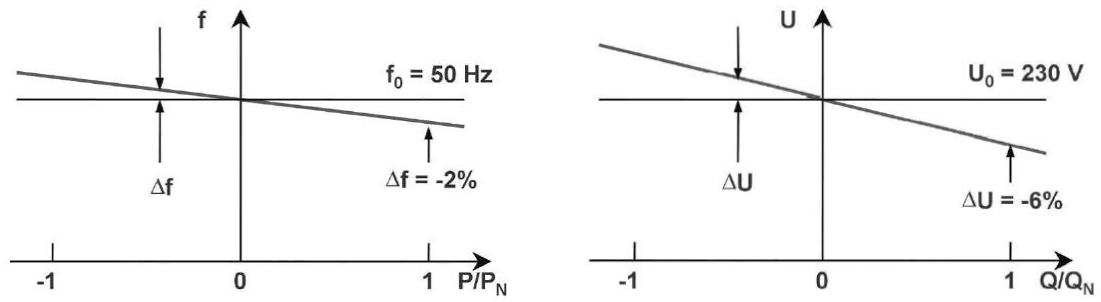


Fig. 31: Frequency $f(P)$ and voltage $U(Q)$ droops

4.1.3. Loads

For a first understanding of the behaviour of the interaction between the inverters and the load it is recommended to use a pure ohmic load. For the experiments a 12 kW three phase load shown on the left side of Fig. 32 was used.

In order to achieve a bigger VAR-exchange the usage of an asynchronous motor is taken into account. Therefore a motor of the company VEM (G21R 160 M 4 HW) is utilised (see Fig. 32 right side). The motor is only driven in no-load operation. It also allows dynamic studies within this experiment by doing a start up of the motor. The rated electrical power is specified at 11 kW. In Table 14 the technical data of the motor is given.

Manufacturer	VEM Motors GmbH
Number of pole pairs	2
Connection	Y
Rated electrical active power $P_{e,r}$	11 kW
Rated electrical apparent power S_r	13.2 kVA
Rated mechanical active power $P_{m,r}$	12.6 kW
Rated power factor $\cos\phi$	0.83
Rated electrical frequency f_r	50 Hz
Rated mechanical speed n_r	1545 r.p.m.
Rated voltage U_r	400 V

Table 14: Technical data of the VEM asynchronous motor

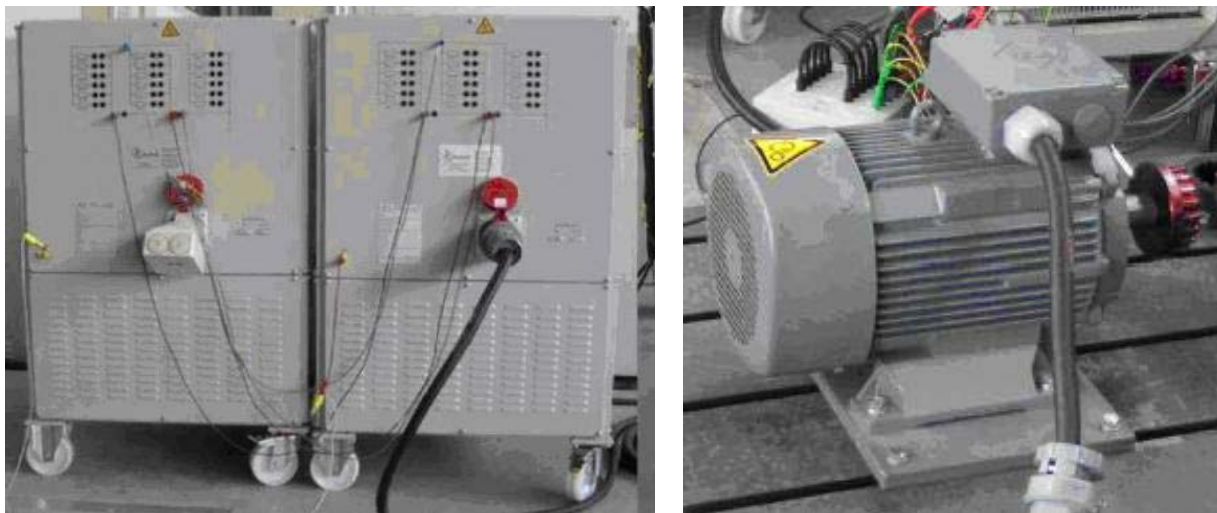


Fig. 32: Ohmic load bank with a three phase power of 12 kW on the left side and the VEM asynchronous motor with 11 kW rated power in the right picture

4.1.4. Measurement devices

As can be seen in Fig. 25 there are nine measurement points in total, three on the low voltage side and six on the medium voltage side. At every measurement point the voltages and currents of the three phases are metered. With these values a number of derived quantities are calculated by the measurement device itself. The following two subsections describe the used measurement devices more detailed.

4.1.4.1. Measurements on the low voltage side

For the measurements on the low voltage side power analysers from the company Haag GmbH were used. Two types of the devices were used the first is called “Combi-Quant” the second “Euro-Quant”. In Fig. 33 they are shown. The devices are connected to Ethernet so that a comfortable access from one central computer is feasible. Also the time of all devices is synchronised by DCF 77.

With the help of special software, it is possible to verify which values and derived quantities could be logged and later be evaluated.



Fig. 33: The “Haag Euro-Quant” device on the left side and the possibility of displaying online measurement values from the devices during the experiment

4.1.4.2. Measurement on the medium voltage side

At the medium voltage side a so called **Multifunctional Intelligent Digital Relay (MIDR)**, belonging to the LINS equipment, was developed by ISET e.V. earlier. With this device it is possible to control the circuit breakers of the LINS. Also this MIDR contains a voltage and current measurement units at the beginning and the end of the interlinked transmission lines. With the help of LabView it is possible to make the measurement data of the metering cells at the MV available. In Fig. 34 the main elements of the MIDR are shown

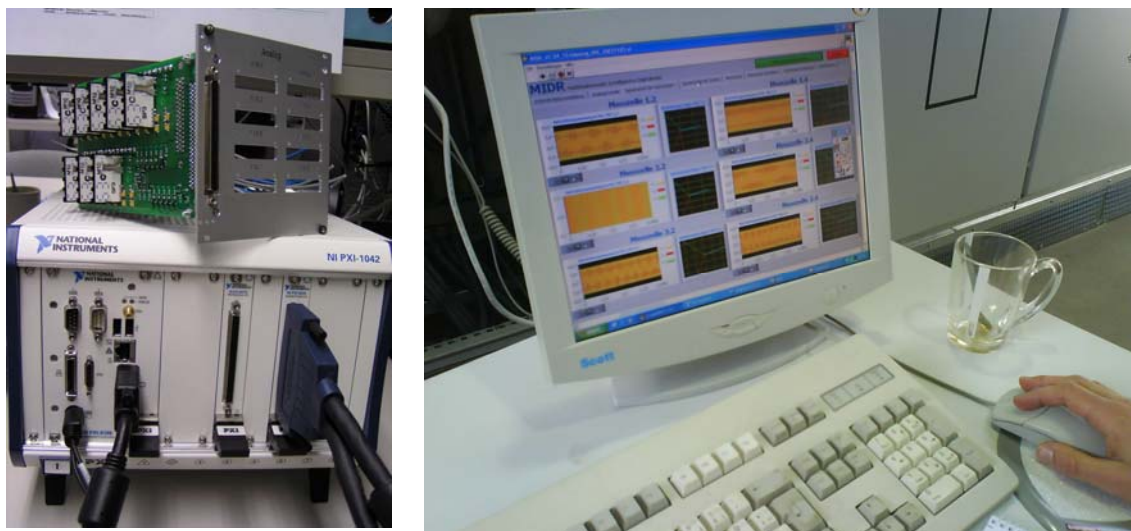


Fig. 34: Some elements of the Multifunctional Intelligent Digital Relay (MIDR), A/D-conversion of measurement values on the left side and control of the MIDR with LabView on the right side

4.2. Simulations

4.2.1. ATP-EMTP

ATP-EMTP (*Alternative Transient Program* version of the *ElectroMagnetic Transients Program*) as one of the most frequently used transient program for the simulation of electromagnetic transients in power systems has extensive modelling capabilities. Besides actual simulation module there exist several non-simulation supporting routines, which can be used to generate model data like computation of line parameters or derivation of coupled RL matrix to represent multi-phase, multi-winding transformers in the time domain simulation.

4.2.2. Simulation of the experiment

The operation of the experimental system was simulated in ATP-EMTP simulation tool. The simulation circuit diagram is shown in Fig. 35. The components used in the experiment have already existing models in ATP-EMTP library and some models were developed at ISET. The labelled components include the droop controlled three-phase battery inverters, Inverter 1 and Inverter 2 with their output impedance connected in series, measurement units for three phase quantities and labelled according to their measurement points in the circuit, voltage probes, transformers and lines. The transformers are connected in Dyn5 vector group. The scenarios simulated include the active power sharing and reactive power exchange through the MV system. Some results of the simulations are presented and compared with experimental results in the following sections. Following is a short description of the droop controlled battery inverter model in ATP-EMTP.

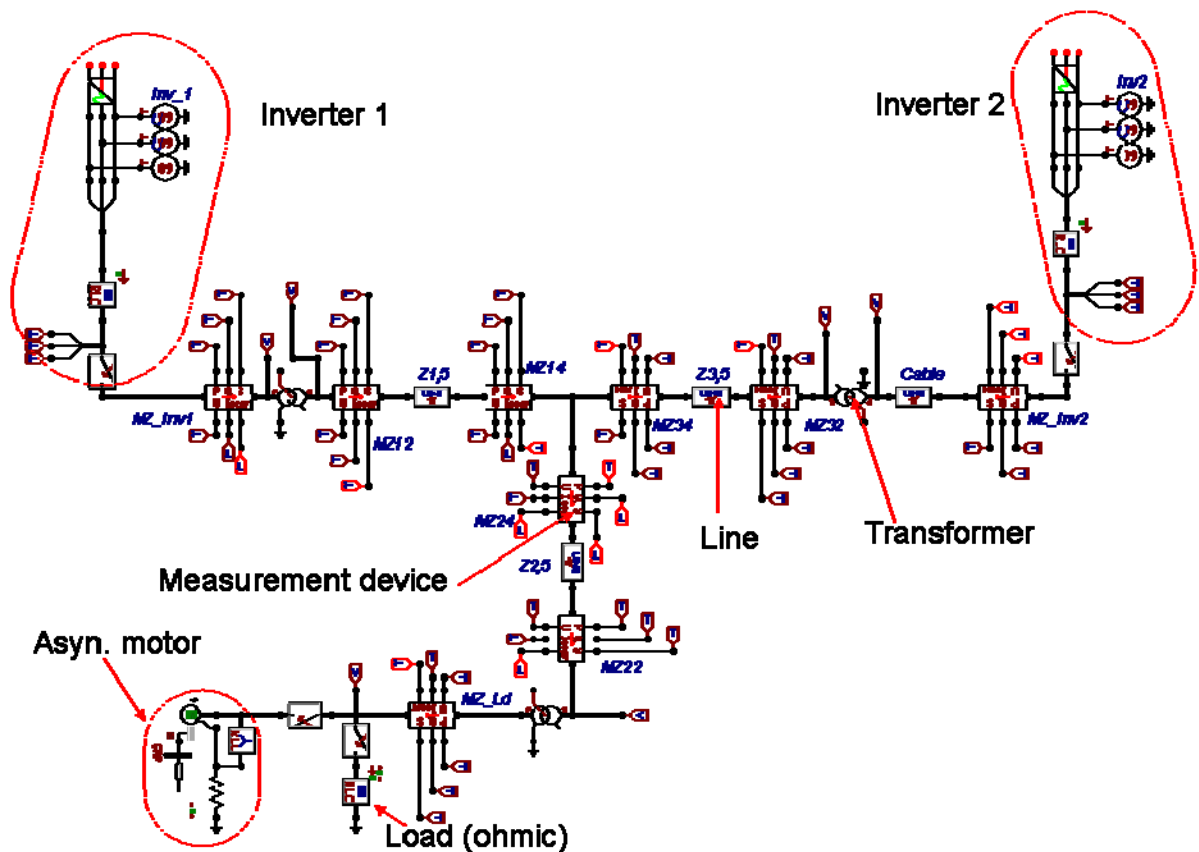


Fig. 35: The circuit diagram for the simulation in ATP-EMTP

4.2.3. Model of the inverter

The model of the battery inverter used here was developed at ISET e.V. and applies for the time step simulation, therefore calculates the instantaneous values of voltage, current and power. The inverter (Voltage Source Inverter - VSI) is considered to be ideal AC voltage source controlled by the SELFSYNC™ approach as explained in section 4.1.2.

Using the “Models”-language, which is a feature of ATP-EMTP, such inverters are encoded as a kind of macro that can be graphically connected to lines, transformers and loads. The graphical representation is shown in Fig. 36 and Fig. 37. The current inputs (black) are referred to the measuring devices (“T” elements), which provide instantaneous current values for the phases A, B and C. The voltage outputs (red) provide instantaneous voltage values for the phases A, B and C. The output inductance of inverter is represented by the RLC-block. In the graphical interface window the following parameters are placed:

- f- idle frequency of the VSI (Hz)
- Amp- amplitude value of the output voltage (V)
- tau (T_{mech} , T_{exc}) - time delay for the active and reactive power acquisition (s)
- kp- frequency droop coefficient (Hz/W)
- kq- voltage droop coefficient (V/Var)
- kph- phase correction (phase feed forward) (rad/W)

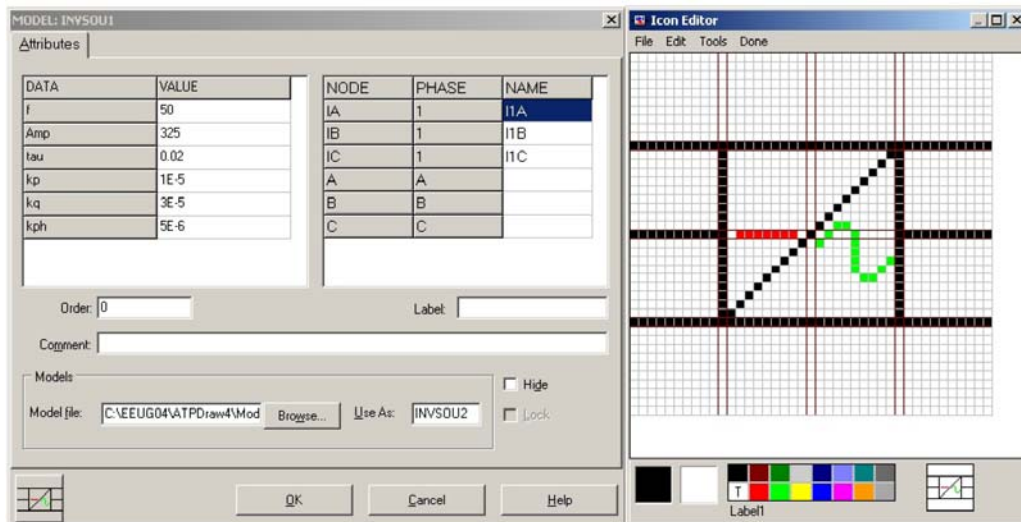


Fig. 36: Graphical work interface of the VSI

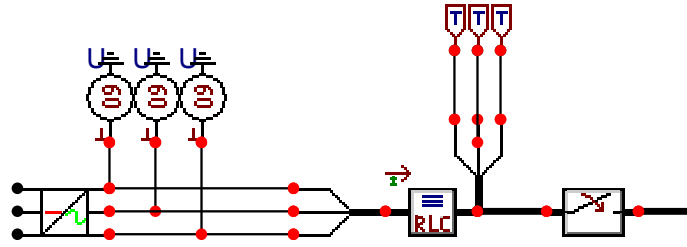


Fig. 37: Graphical representation of the VSI

EXEC

f1:=f-STP	-- frequency droop / reference
w1:=2*pi*f1	-- cycle frequency
wt:=integral(w1)	-- reference angle (time function)
Amp1:=Amp+STQ	-- voltage droop / reference

A:=Amp1*sin(wt-STPH)	-- output voltage A
B:=Amp1*sin(wt+2*pi/3-STPH)	-- output voltage B
C:=Amp1*sin(wt+4*pi/3-STPH)	-- output voltage C

UB1:=2/3*(sqrt(3)/2*B-sqrt(3)/2*C)	-- Clarke transformation
UA1:=2/3*(A-0.5*B-0.5*C)	-- for voltages and
IB1:=2/3*(sqrt(3)/2*IB-sqrt(3)/2*IC)	-- currents
IA1:=2/3*(IA-0.5*IB-0.5*IC)	--

P:=(UA1*IA1+UB1*IB1)/2	-- calculation of active power
Q:=(UB1*IA1-UA1*IB1)/2	-- calculation of reactive power
S:=sqrt(P*P+Q*Q)	-- apparent power (just info)

LAPLACE(PV/P):=(1 s0)/(1 s0+tau s1)	-- decoupling delay
LAPLACE(QV/Q):=(1 s0)/(1 s0+tau s1)	-- decoupling delay

LAPLACE(PV11/PV):=(1 s0)/(1 s0+tau s1)	-- time delay of inverter
LAPLACE(QV11/QV):=(1 s0)/(1 s0+tau s1)	--

STP:=PV11*kp	-- frequency droop
STQ:=QV11*kq	-- voltage droop
STPH:=PV11*kph	-- phase correction

ENDEXEC

Fig. 38: Executable part of ATP-EMTP models description for the frequency and voltage variable 3-phase inverter

5. Results and discussion of the experiment

In this section the results of the measurements and some according simulations are presented and compared. The VAr exchange via the medium voltage is assessed. For this, different scenarios are explored:

- No load operation
- Ohmic load with step changes
- Inductive load

The first scenario, the no load operation should serve to determine the no load losses for active and reactive power. Also a first idea of the active power sharing between the DG units can be achieved.

This active power sharing is investigated more detailed with the help of an ohmic load with different load values in the second scenario.

In the third scenario an inductive load is connected to the system. This causes an additional VAr-exchange via the MV-system. The effects to the voltage behaviour and the sharing of the reactive power will be of special interest.

All these scenarios are also simulated with ATP-EMTP. Therefore the inverters were set to the same static parameters regardless of the distance each is from the supplied load. Therefore the slopes of the droops and the line parameters are the most important parameters (see section 4.2.2):

- $k_p = -1\% \cdot \frac{f_n}{P_n}$
- $k_q = -6\% \cdot \frac{U_n}{Q_n}$
- The line parameters used in the simulation are those indicated on the diagram of Fig. 25.

5.1. No load operation

For this case it is of interest how much active and reactive power is needed to cover the no load operation losses of the MV-system. It has to be considered that no additional active power transfer from DG1 to DG2 or contrary takes place when the no load operation losses are determined because of the possibility of additional VAR-exchange. This special case can occur if one inverter cluster loads the battery of the other cluster for example.

Another interesting point is the active and reactive power sharing between the two DG units because of different line lengths.

Also a consideration of the active and reactive power dispersion on the three phases can be of interest because an inverter cluster consists of three single phase inverters whereas every single phase inverter controls itself.

5.1.1. Test arrangement

The detailed experiment setup for this case is shown in Fig. 25. The two three phase inverter clusters (DG1 and DG2) feeding the transformers and the lines. Switch 2 is opened so that no load is connected to the MV-side. Also the switch to the external grid is opened. Switch 1 and switch 3 are closed so that the two DG units can feed the MV-system.

The following measurement results were recorded on the low voltage side by the Haag devices (see Fig. 25).

5.1.2. Experiment results for the no load operation

In Fig. 39 the no load operation losses for the active and reactive power are shown.



Fig. 39: No load operation losses of active and reactive power per inverter cluster (DG1 in blue, DG2 in green) and totalised (red) for a duration of five minutes

They are treated as three phase values, in blue the three phase active and reactive power of DG 1, in green for DG2 and in red the totalised value of DG1 and DG2 are presented. The time duration is five minutes.

During the shown time period the active power of the two inverter clusters is positive which indicates that both contribute active power for the no load operation losses.

The totalised active power is constant and about 1300 W. The contribution of the inverter clusters DG1 and DG2 in order to cover the no load losses vary in time. It is obvious that the inverter cluster DG1 produces a higher amount of active power for the MV-system what could be caused by the higher ohm resistance of the the $L_{1,5}$ (see Fig. 25) to which DG1 is connected.

The reactive power is about -1600 VAR. The minus sign indicates that inductive reactive power is delivered to the MV-system. Compared to the active power sharing, the amount of reactive power provided by the inverter clusters is more stable. But it is noticeable that most of the reactive power is made available by DG1. This behaviour results from the longer line DG1 is connected to.

In addition to the consideration of the three phase power also the single phase contribution for the no load operation losses are evaluated. These values are plot in Fig. 40. The two subplots for the active power separated for DG1 and DG2 show an unequal injection of active power. Especially these values vary for the inverter cluster DG1.

In contrary the injection of reactive power can be regarded as symmetrical. Further the difference in the amount of the provided reactive power between DG1 and DG2 can be seen clearly.

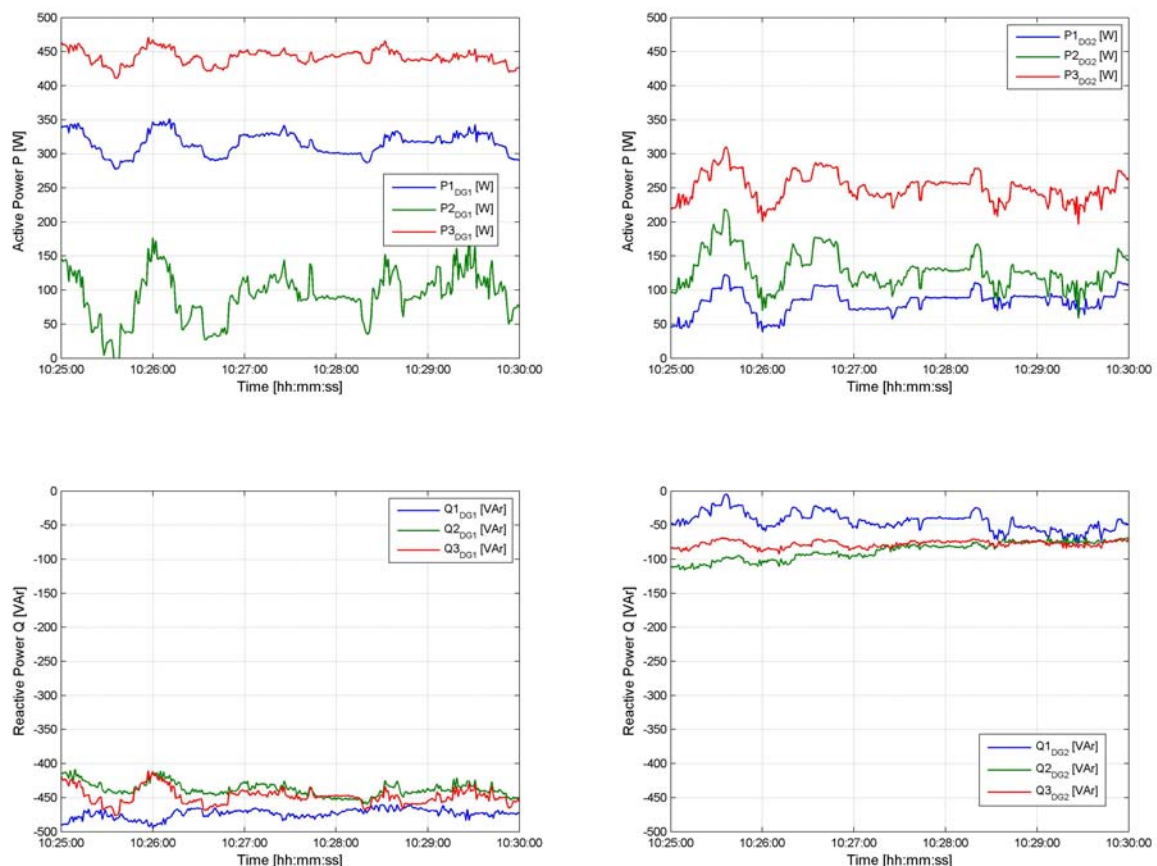


Fig. 40: No load operation losses of active and reactive power separated by phase (phase 1 is blue, phase 2 is green and phase 3 is red) and cluster for a duration of five minutes

In Fig. 41 the phase voltages of DG1 and DG2 are shown. The voltage level of DG1 is from 227 V up to 228 V while the voltage level of DG2 is about 0.8 V lower, valid for phase 1 and 3. Phase 2 does not behave this way, the voltage level difference of DG1 and DG2 is not that high. The evolution of the voltage seems to be constant besides slight variations.

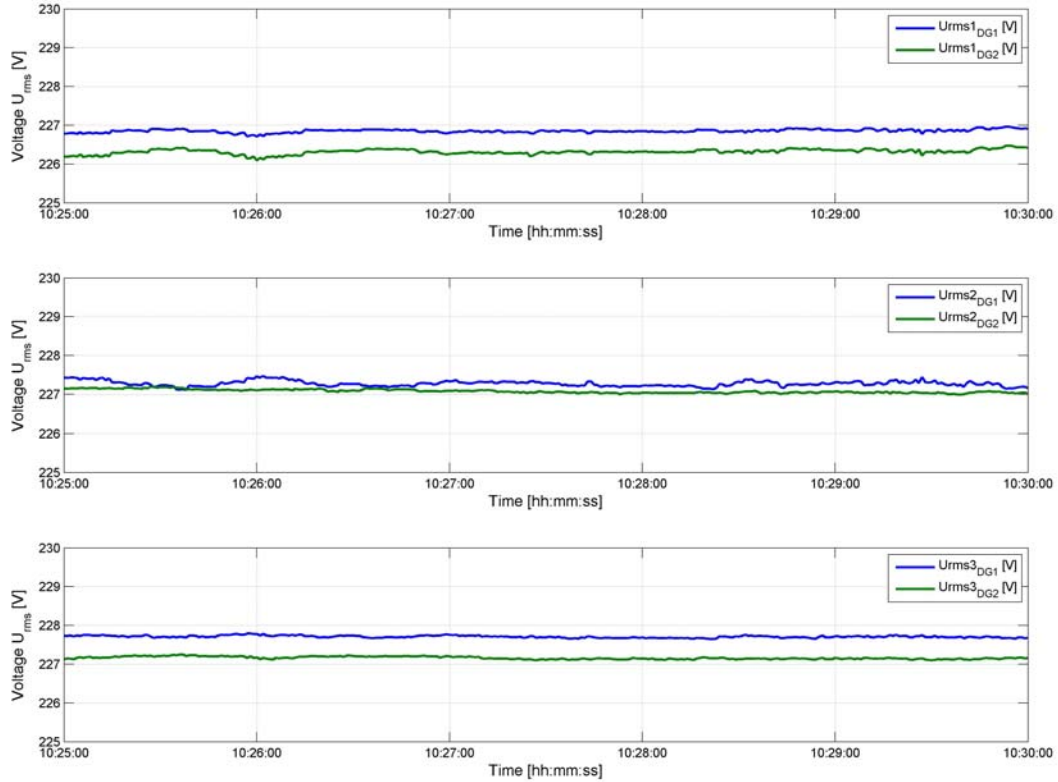


Fig. 41: No load operation voltages of DG1 (blue) and DG2 (green) for each phase and a duration of five minutes

5.1.3. Simulation results

Below in Fig. 42 the simulation results of the no load operation for active and reactive power sharing are shown. Be aware that the amount of the reactive power is used.

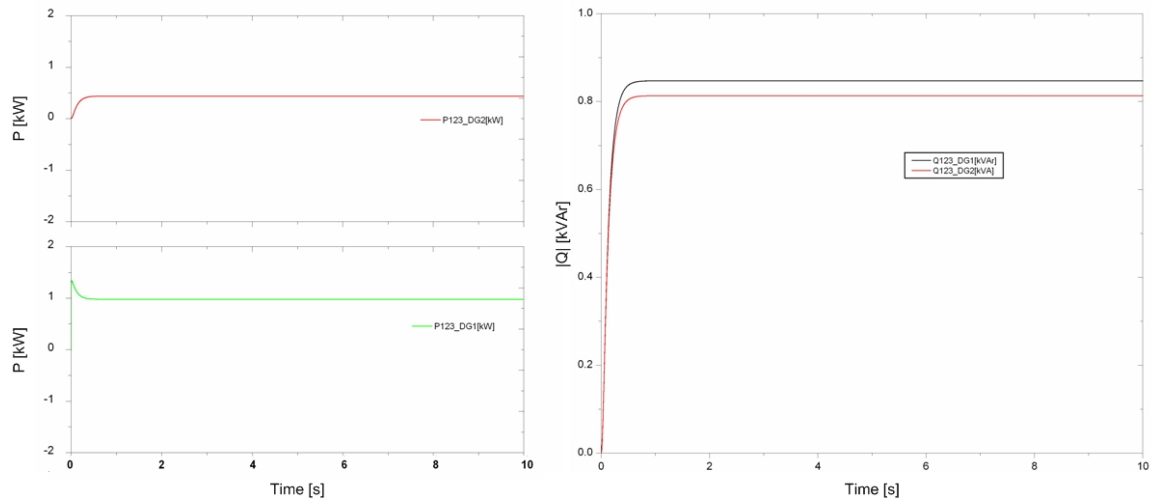


Fig. 42. Results of the simulation for active and reactive power sharing at no load operation

As can be seen, the simulation shows almost the same result for active and reactive power case where DG1 takes on average more than 800 W and leaves DG2 with around 500 W. However, for the reactive power, the two DGs share almost equally the no-load reactive losses. The graphs show that the simulation agrees with the measured data. If the contribution of any DG unit to the losses is considered only for the active power, the simulation is consistent with the measurements. But for the reactive power in the simulation, the contribution is approximately equal, but in the experiment, DG1 is providing the biggest part of the reactive power.

5.1.4. Conclusions for the no load operation

The no-load operation losses for active power are about 1.3 kW and for the reactive power about 1.6 kVA. The data accord to the calculated and the simulated one.

The active power sharing is entered as the simulation shows, only the share of reactive power differs between the experiment and the simulation.

Also a difference at the contribution of active power of each single phase of the inverter cluster, especially from DG1 has to be mentioned.

5.2. Active power sharing

In this case the behaviour of the reactive power by an active power exchange through the MV-system has to be investigated. It is assumed that an active power exchange will cause an additional reactive power demand. This results from two phenomena. The first one is well founded by the Ohm's law. Additional active power leads to a higher current which raises the needed reactive power at the lines. However this amount is not that high for the actual used values of active power exchange. The second phenomenon depends on the droops used for the control of the inverters. Because of additional active power the voltage decreases which results in a change of the reactive power as described in chapter 4.1.2.

5.2.1. Test arrangement

A load is connected at the end of the line $L_{2,5}$ and Switch 2 in Fig. 25 is now closed, the switch to the external grid is still opened. The values of the load are changed in steps up to 4.5 kW. Switch 1 and 3 are closed so that the two DG units can feed the MV-system and therefore the load. All shown measurement graphs are recorded on the low voltage side.

5.2.2. Experimental results for ohmic load operation

In Fig. 43 the three phase active and reactive power for DG1, DG2 and the sum of all inverters are shown.

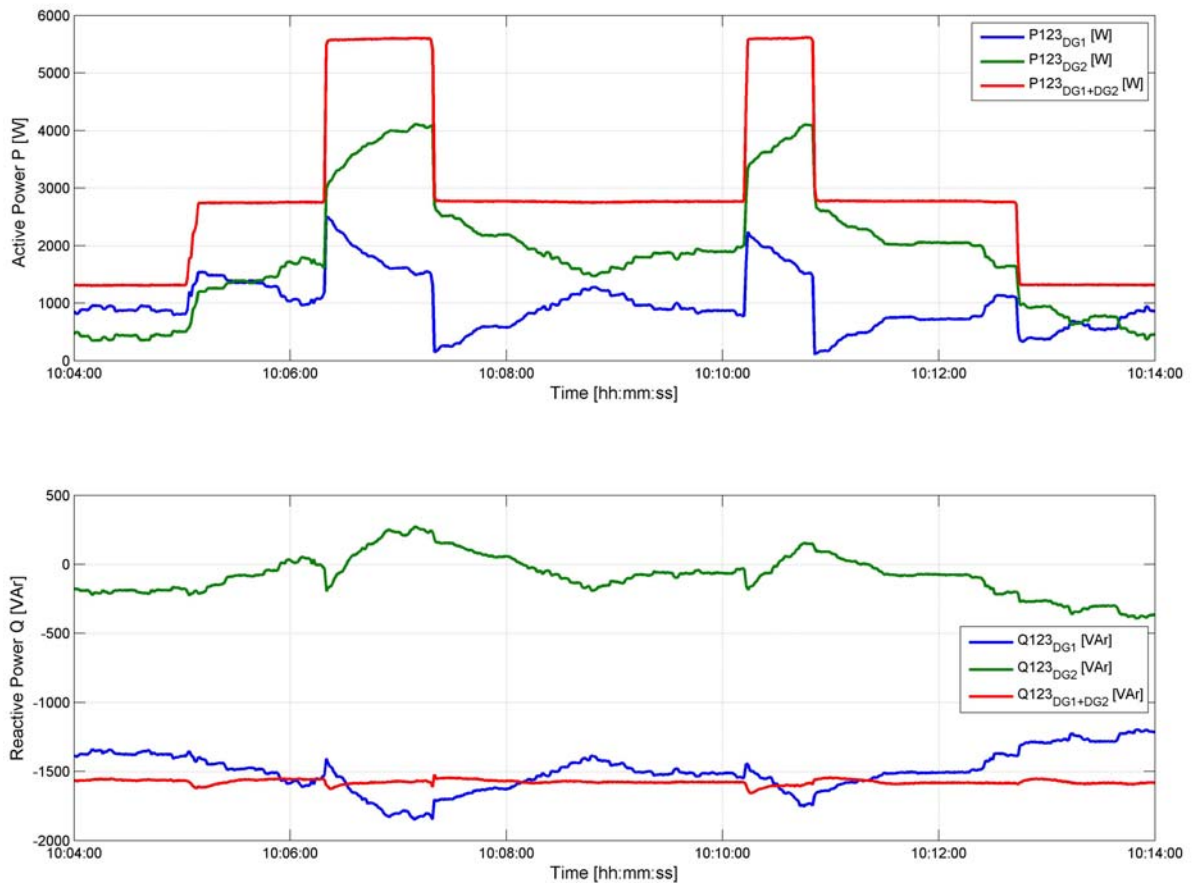


Fig. 43: Three phase active and reactive power per inverter cluster (DG1 in blue, DG2 in green) and totalised (red)

The steps of the load connect to switch 2 are 1.5 kW and 4.5 kW for three phase power. It has to be mentioned that $P_{123_{DG1+DG2}}$ contains also the no load operation losses. The splitting of the active power distribution between DG1 and DG2 can also be assessed in Fig. 43 whereupon DG2 bears the bigger part. A reason could be the shorter line to the load. Another reason could be the state of charge (SOC) of the battery. If the SOC is too low, the inverter is going to charge the battery from the MV-grid. Further the ration of the delivered active power by the two inverters is not constant.

The reactive power of the inverters changes in little steps when a load variation happens. For a maximum three phase load of 4.5 kW the amount of additional reactive power is about 150 VAr as shown in Fig. 44. With this zoomed view of the total three phase reactive power $Q_{123_{DG1+DG2}}$ some statements about the VAr-exchange can be made. If there is a step in the active power at the load the reactive power carries out a transient effect. Starting with a step the reactive power swings into until a constant final value is arrived. This is associated with the droops and internal control system of the inverter and respectively the additional need of reactive power through the higher current of the lines and transformers on the MV-side.

In order to determine this additional need of reactive power in Fig. 45 calculations have been carried out. The used line and transformer parameters correspond to Fig. 25. These calculations have been made in dependency of the active power. The form of the curve is parabolic. For that reason the additional reactive power with a value lower than 15 VA for the load values used in this experiment is nearly negligible.

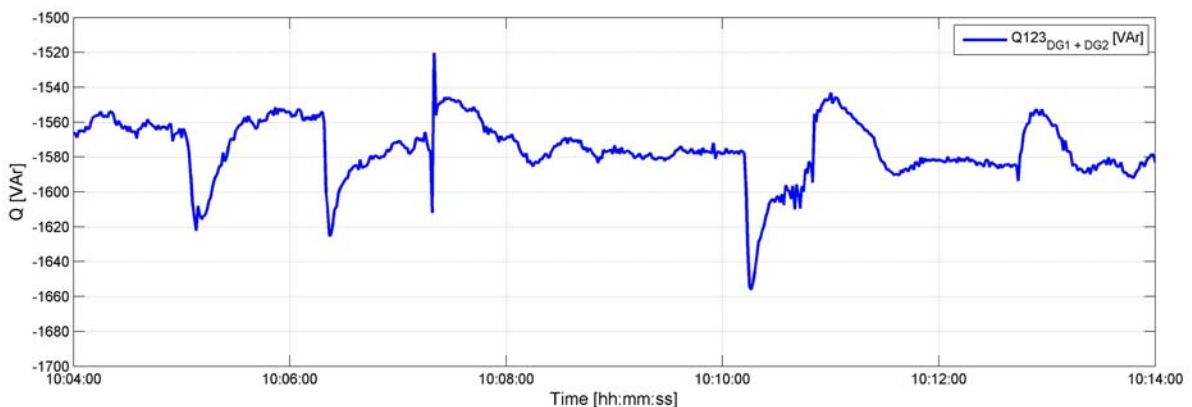
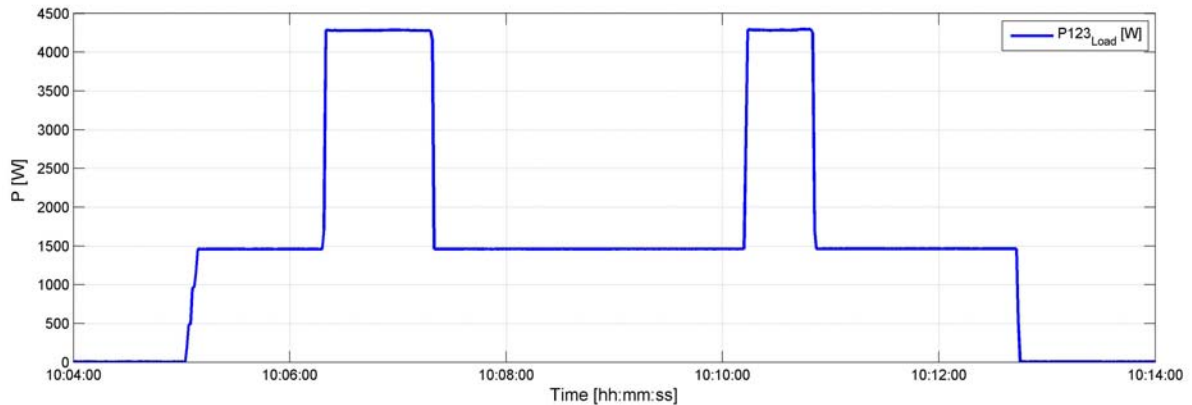


Fig. 44: Active power of the load and total reactive power from the inverters

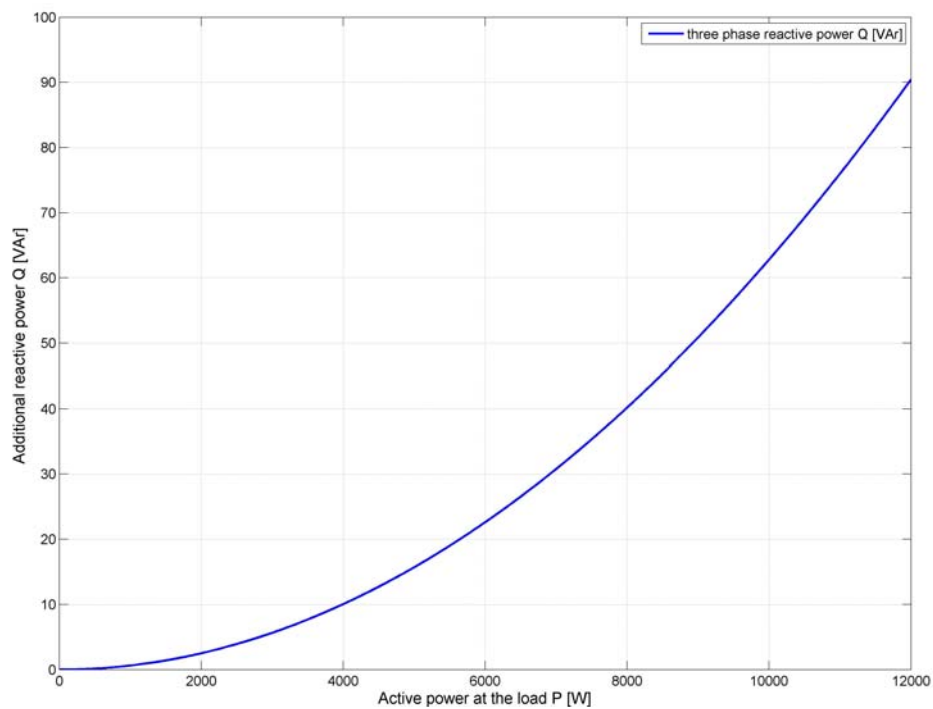


Fig. 45: Additional reactive power for the MV-system in dependence of the load, calculations are made for single phase

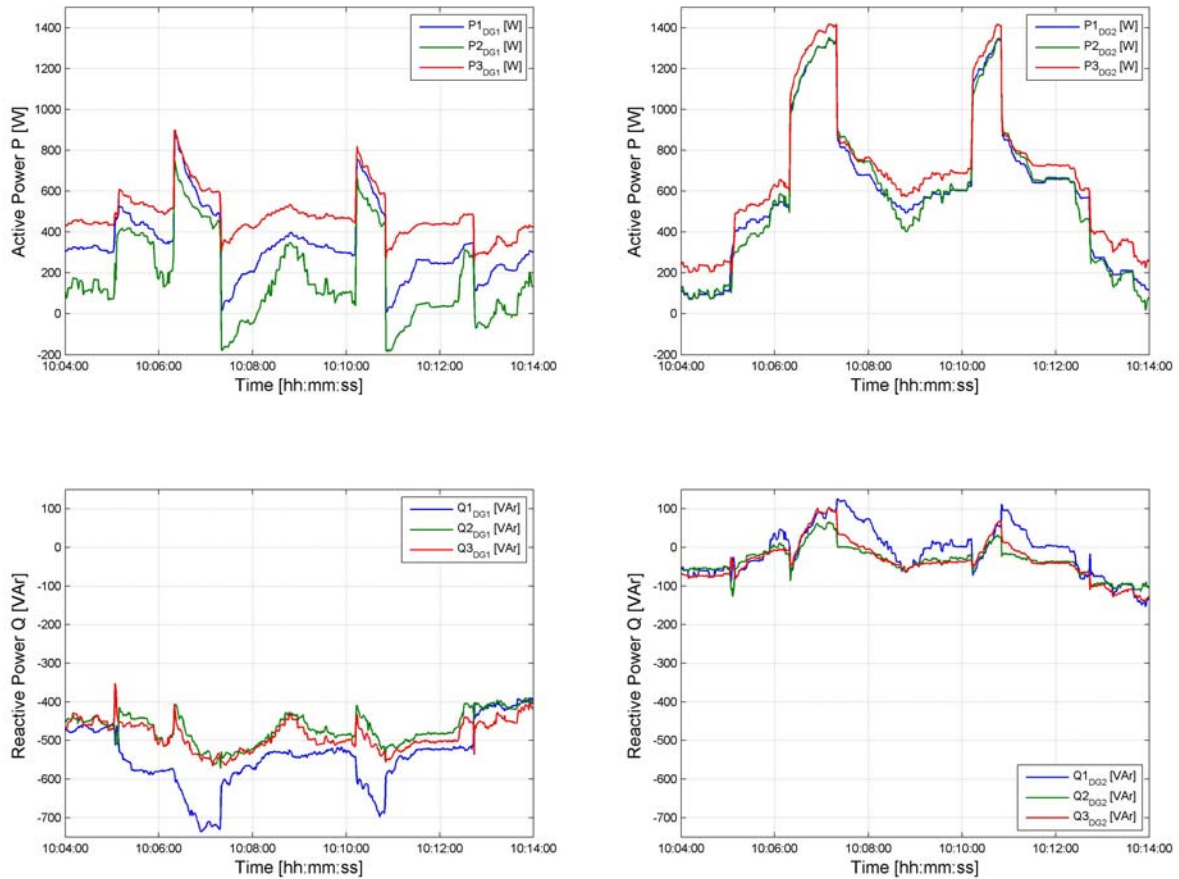


Fig. 46: Active and reactive power separated by phases (phase 1 is blue, phase 2 is green and phase 3 is red) and clusters for different ohm loads

For a detailed consideration the single phase behaviour of the reactive power and also of the voltages has to be assessed. In Fig. 46 the active and reactive power for the single phases of DG1 and DG2 are presented. The inverter cluster DG1 has an unsymmetrical active and reactive power injection, especially phase 1 is differing from phase 2 and phase 3 for the reactive power. The active power of phase 2 of DG1 also has negative values which indicate an active power reception from the MV-grid. DG2's active and reactive power splitting is nearly symmetrical. The curves of the reactive power of DG2 cross zero from negative to positive. That means that the inverter is not providing reactive power to the MV-grid but is now receiving inductive reactive power. At this point DG1 supplies the MV-system with reactive power.

In Fig. 47 the consumption of the total reactive power for each phase of DG1 and DG2 is shown. It is easy to realise that a change in the active power at the load leads to a change of the reactive power and a change of the phase voltage. However regarding the reactive power phase 1 behaves in opposite to phase 2 and 3. If the load's active power is raised the amount of the reactive power injected by phase 1 increases. The opposite behaviour shows phase 2 and 3 where the amount of reactive power decreases. The changes of the reactive power have a directly influence on the voltage. If the amount is decreased, the voltage rises and vice versa.

The voltage profile of the load shows an additional voltage drop in comparison to the voltage profiles of DG1 and DG2. This results from voltage losses at transformers and lines and the amount of the drop depends on the present electrical grid. Of course these losses increase with higher load values. Through injection of additional reactive power the voltage profiles could be raised.

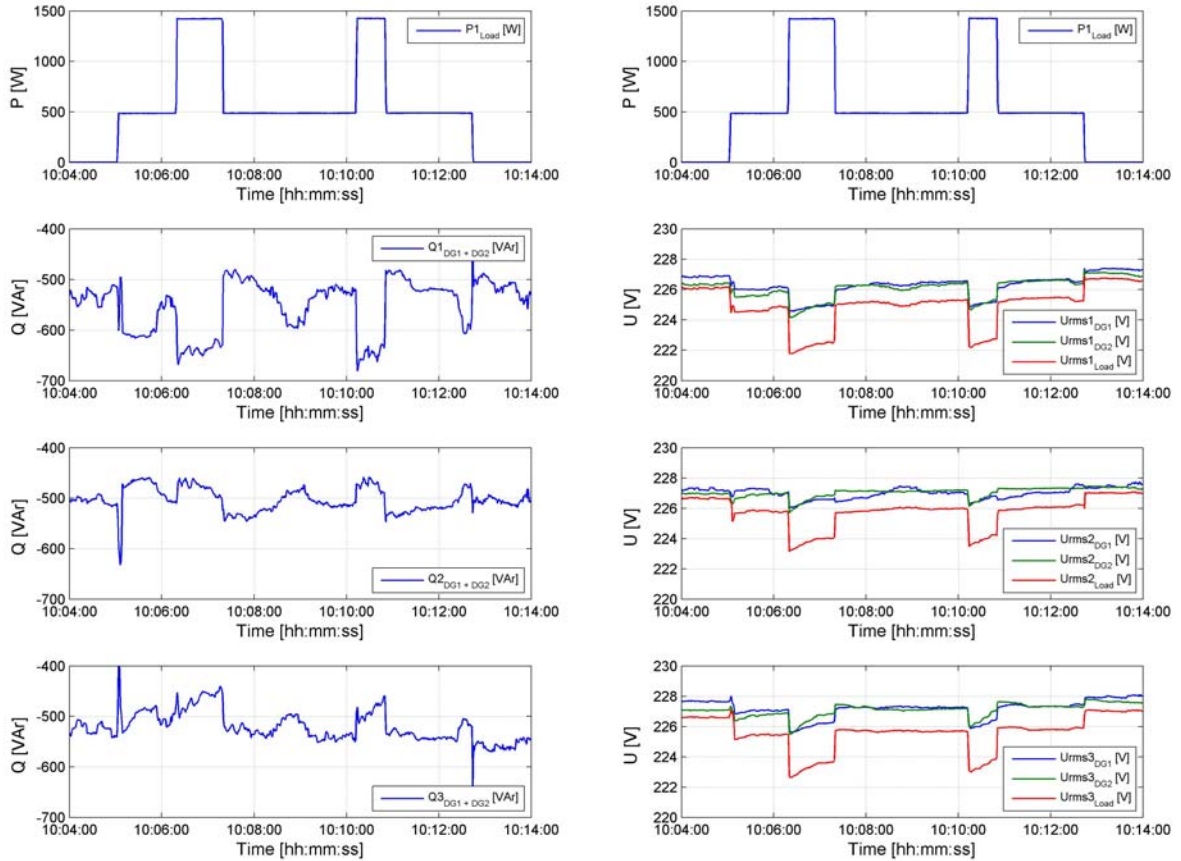


Fig. 47: Reactive power and voltages separated by phases (phase 1 is blue, phase 2 is green and phase 3 is red) for different ohm loads

5.2.3. Simulation results for ohmic load operation

Numerical Simulations for the above described experiment have been carried out. In contrast to the ‘no load’ case described in section 5.1.3, the results from the simulations show significant deviations compared to the measurements. The reasons for this could not be identified yet and are subject of current work.

5.2.4. Conclusions for the ohmic load operation

The two inverter clusters share the needed active power of the load. DG2 delivers more active power, what can be explained by the shorter line and the lower resistance. When the active power changes also a variation of the reactive power takes place. An increase of active power results in a higher reactive power. But this additional amount of reactive power is smaller than 150 VAr for the used load values. The reasons are the additional reactive power for the lines and transformers and the droops of the inverter.

5.3. VAr-exchange

Standpoints for the analysis are the sharing of the needed reactive power for an inductive load between the two DG units and also the behaviour of the voltages during the operation of that inductive load. Only steady-state values are taken into account.

5.3.1. Inductive load connected to line $L_{2,5}$

5.3.1.1. Test arrangement

In this case, instead of an ohmic load as before, a motor as an inductive load is used. The motor doesn't power a mechanical load so here is only presented the no load operation of the motor. More information concerning the technical data of the motor can be looked up in chapter 4.1.3. The motor is connected to the line $L_{2,5}$. The switch to the external grid is still opened. Switch 1 and 3 are closed so that the two DG units can feed the MV-system and therefore the motor. All shown data are measured on the low voltage side as before.

5.3.1.2. Experimental results for inductive load operation at line $L_{2,5}$

From Fig. 48 the expiration of the experiment can be derived.

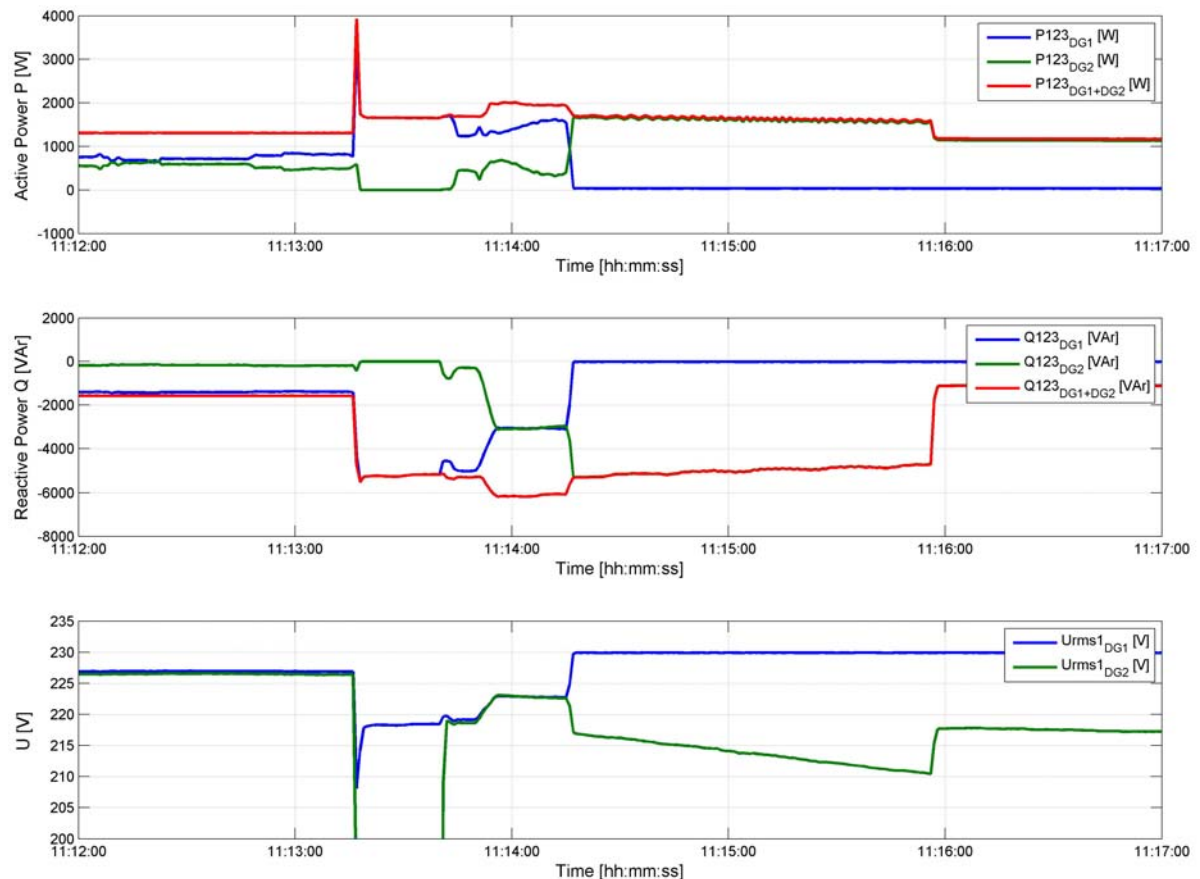


Fig. 48: Three phase active and reactive power per inverter cluster (DG1 in blue, DG2 in green) and totalised (red); voltage phase 1 of DG1.

In the beginning switch 2, where the motor is connected to, is opened (see Fig. 25). The DG units DG1 and DG2 provide the no load operation losses. Around the time

11:13:20 switch 2 is closed which brings about a peak in the active power up to 4 kW. Because of this the inverters of DG2 are tripped of but they reconnect about a half minute later. During this time all needed active and reactive power must be delivered by DG1. This results in a degradation of the phase voltages in this case lower than 220 V (exemplary shown for phase 1). It is notable that after the reconnection of DG2 and some transient phenomena both DG units share the needed reactive power one half each what leads to an increase of the voltage.

At the time 11:14:20 DG1 is broken up from the MV-grid by opening Switch 1 (see Fig. 25). Now the inverter cluster DG2 has to feed the whole system. As seen before the voltage decrease cause of the higher amount of reactive power provided by DG2.

A detailed view of each phase for active and reactive power is shown in Fig. 49.

As already seen in chapter 5.1 the active power of DG1 is not split in equal shares on the three phases at the no load operation. After the connection of the motor this behaviour changes and all three phases provide the same active power (cp. Fig. 49 at 11:14:00). At DG2 the active power contribution of the phases 2 and 3 are the same but phase 1 delivers more than the other two.

Regarding the reactive power the values of the three phases are on the same level which means that they are symmetrical for the no load operation. If the motor is connected there are differences between the amounts of reactive power up to 300 VAR.

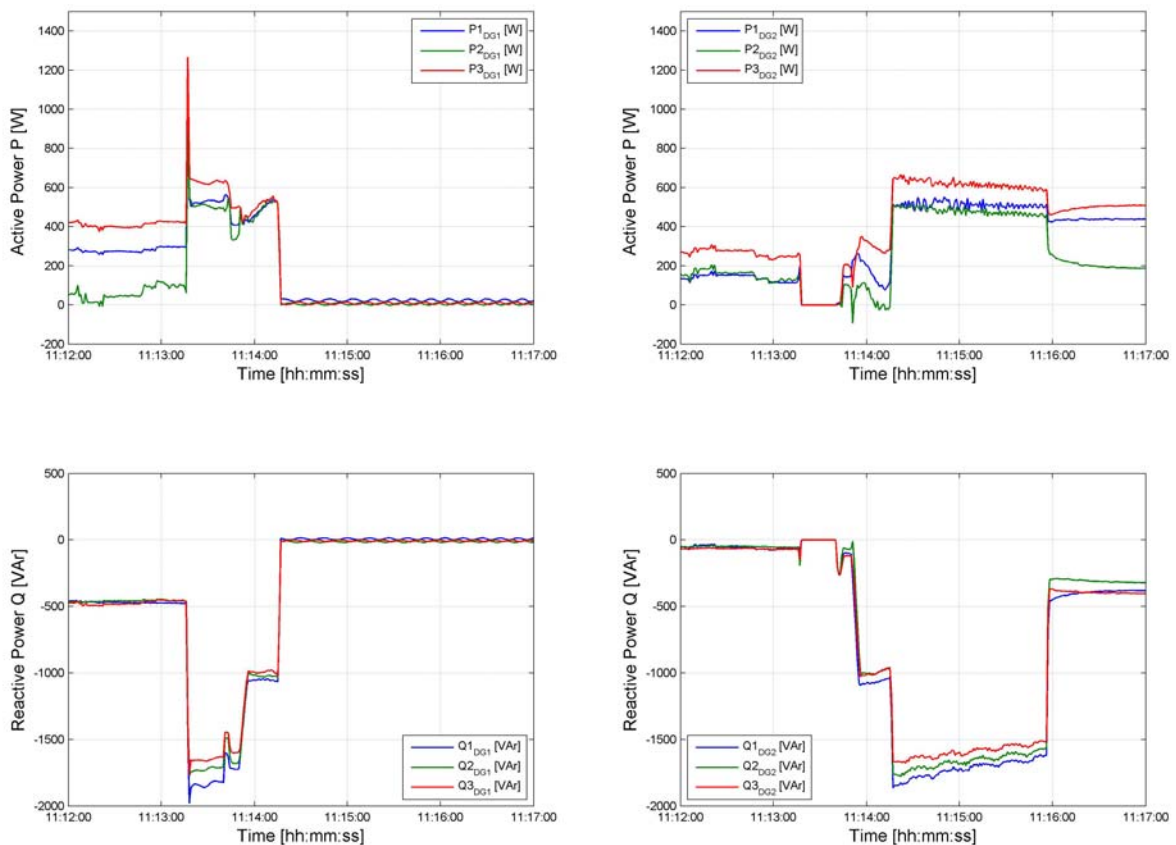


Fig. 49: Active and reactive power separated by phases (phase 1 is blue, phase 2 is green and phase 3 is red) and clusters at motor operation

In Fig. 50 the added reactive power for each phase from DG1 and DG2 and the corresponding voltages are shown. The voltage behaviour of all three phases is similar. Through the reactive power for the motor the voltages are strongly influenced. But in comparison to chapter 5.2 the voltage drop between the load and the inverters isn't that high as if a pure ohmic load will be used. For this case the slope for the droop of the

inverter must not set too high. If it would be too high even small reactive loads could decrease the voltage enormously. Also the additional reactive power for the MV-system has to be considered for an optimal choice of the slope.

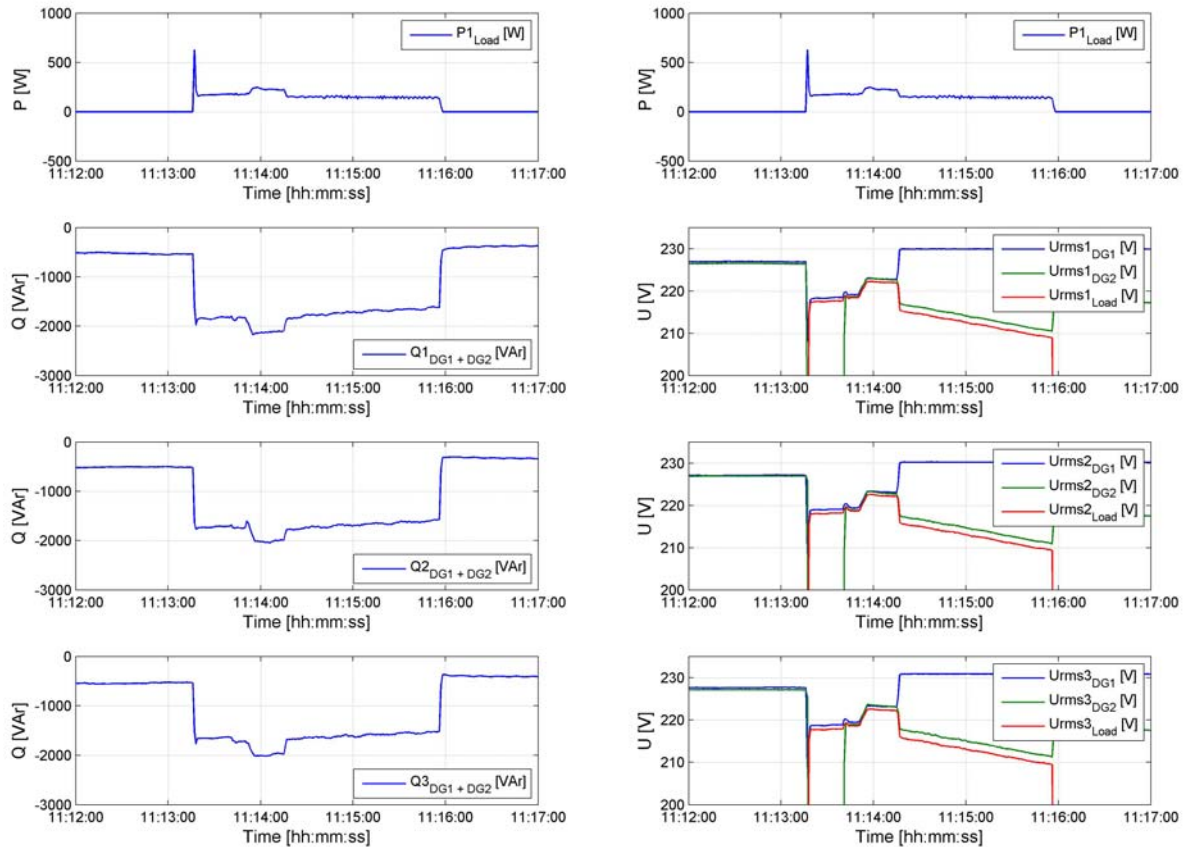


Fig. 50: Total reactive power and voltages separated by phases (phase 1 is blue, phase 2 is green and phase 3 is red) for motor operation

5.3.1.3. Conclusions for inductive load operation

Both inverters share the needed reactive power for the motor. The amount which every inverter contributes depends on the voltage level at the motor. The additional reactive power leads to a decrease in voltage due to the droops. So it is important to choose the slope of the droop for the reactive power carefully.

5.3.2. Inductive load connected to the busbar of DG2

The aim of this scenario consists in the assessment of the dynamic operation with non-mechanical load by running an unloaded motor, load flow distributions during motor start-up and shut-down.

5.3.2.1. Test arrangement

In contrary to section 5.3.1 the motor is not operating any longer at line $L_{2,5}$ but now switched to the same busbar, DG2 is connected to. Here the distribution of the inductive load between the DGs, the start behaviour at the DGs and the voltage profile on the several busbars are shown. This test arrangement is shown in Fig. 51. The motor is first supplied by DG1 and DG2 is switched on to share the load. The measurement data are taken on the low voltage and medium voltage side.

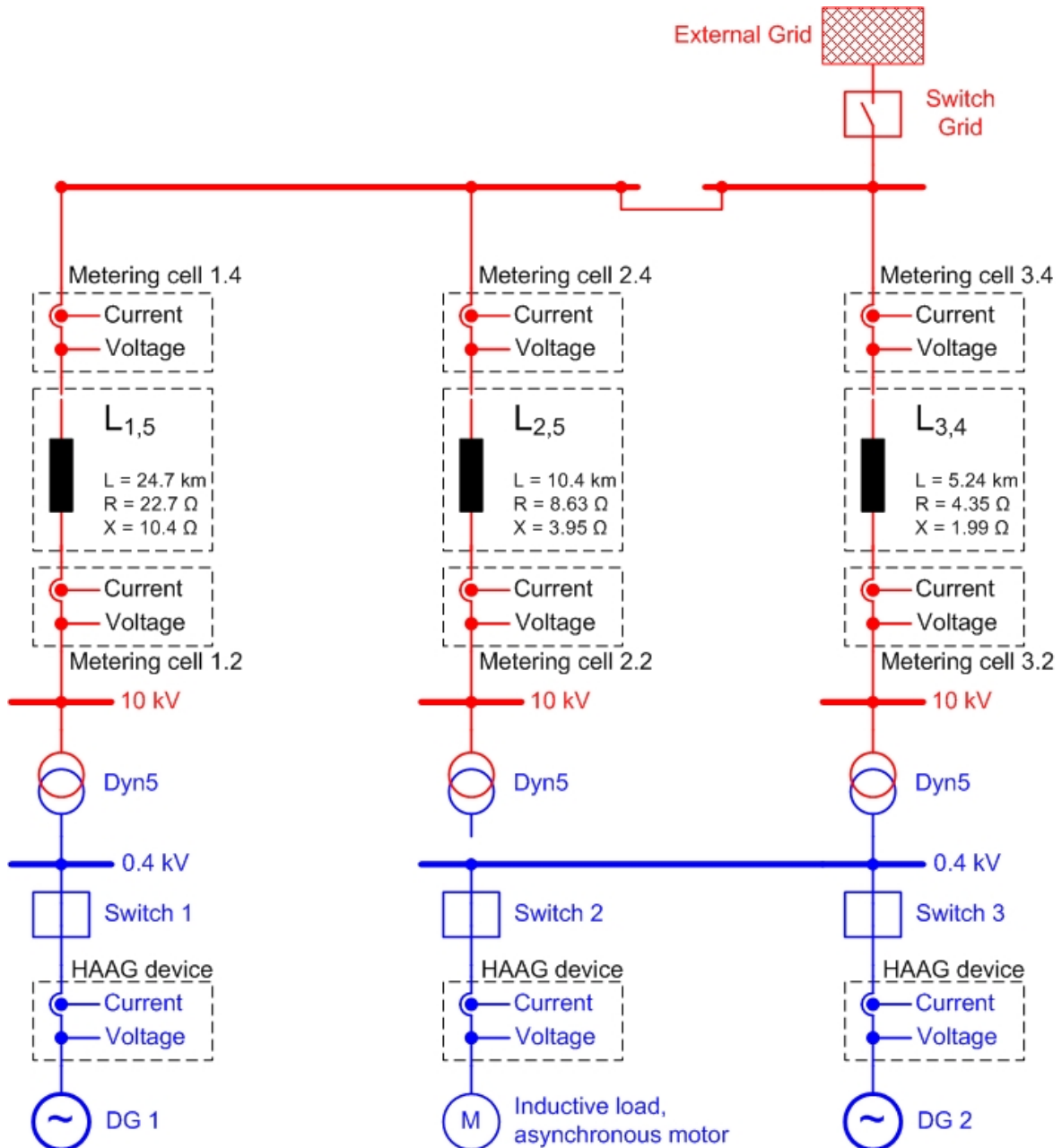


Fig. 51: Principle schema of the 10 kV line impedance simulation network for the actual experiment, the motor is connected to the busbar of DG2

5.3.2.2. Experimental results for inductive load operation

In Fig. 52 the three phase reactive power on the measurement devices on the low and medium voltage side is presented. The yellow curve represents the reactive power at the motor.

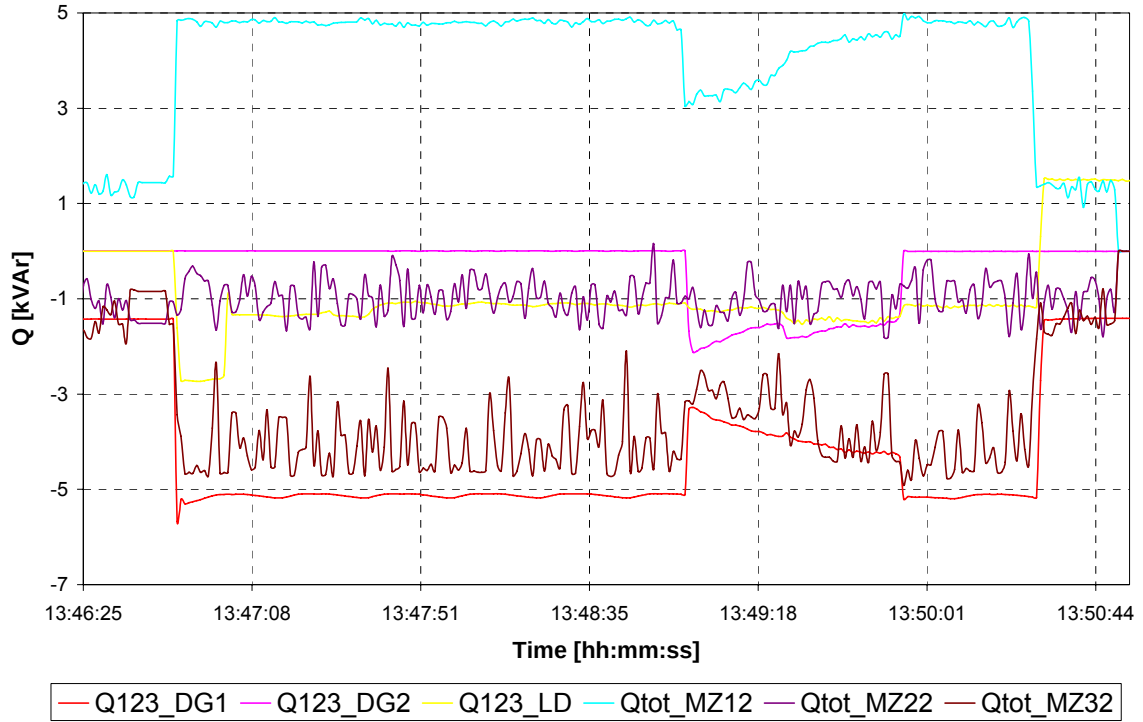


Fig. 52: Three phase reactive power measured on the low and medium voltage side

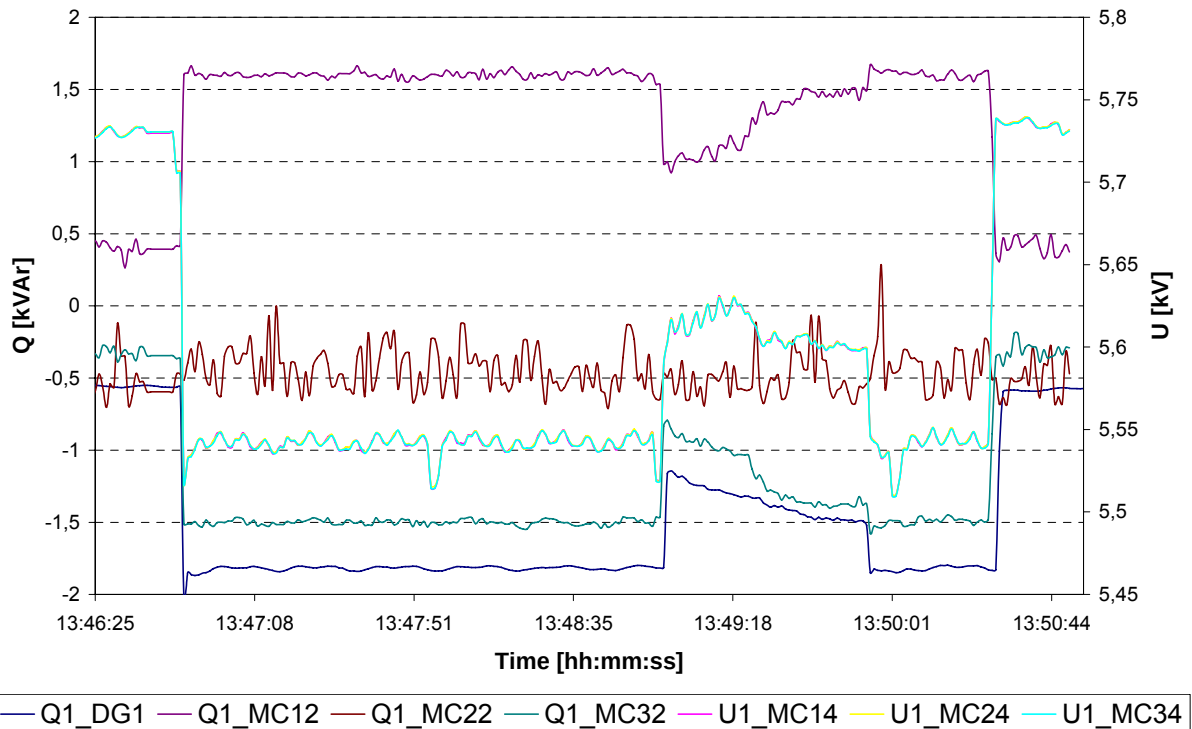


Fig. 53: Single phase voltage profile of phase 1 on the low and medium voltage side

At the time of 13:45:50 the motor starts and the reactive power is provided by DG1 (red curve). Also the reactive power losses can be marked out as the difference between these curves. Around 13:48:00 DG2 is switched on. This results in a splitting of the reactive power by the two clusters and also in a rising of the totally delivered reactive power.

The consequence is an increase of the voltage as shown in Fig. 53. When DG2 is disconnected again around 13:49:00 the available reactive power decreases and the voltage fall again on the level before DG2 was connected.

In Fig. 54 the behaviour of the active power sharing can be seen. When DG2 is connected the active power of phase 1 of DG1 rises for the first time but then it decreases under the value before the connection of DG2.

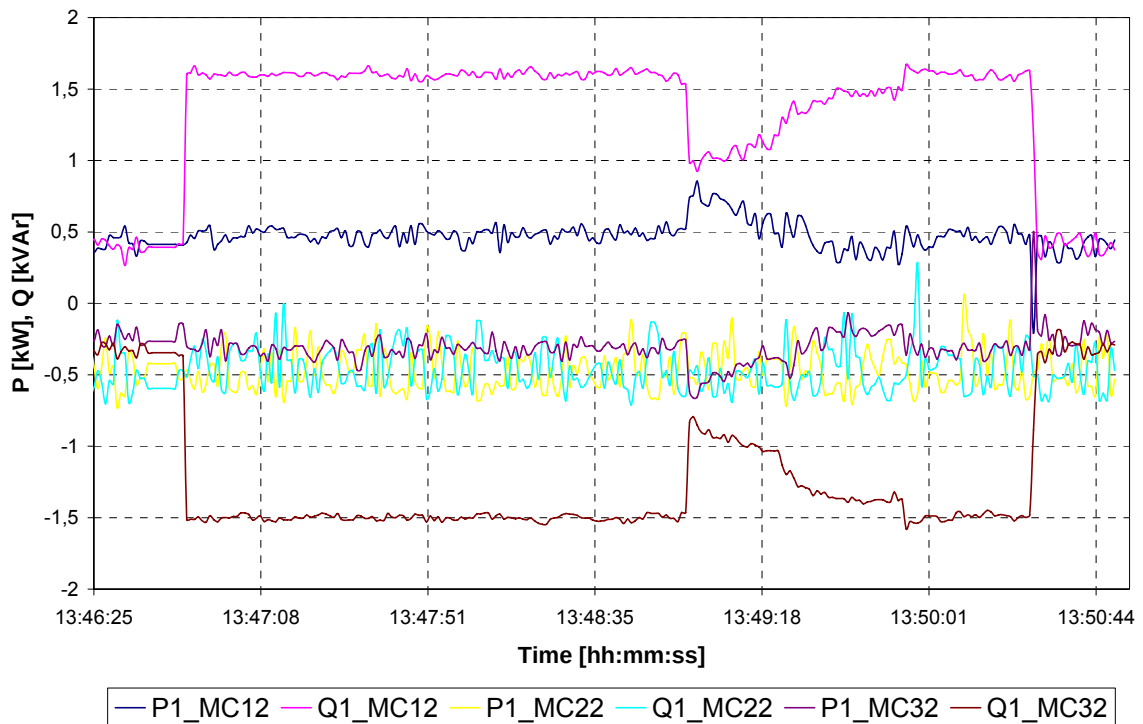


Fig. 54: Single phase active and reactive power on the medium voltage side

5.3.2.3. Conclusions for inductive load operation at the busbar of DG2

DG1 is able to feed the motor across the MV. When DG2 also provides reactive power, the voltage at the motor rises. Much less reactive power has to be delivered from the other DG unit across the MV at this point.

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7. List of Abbreviations

HV	High voltage
MV	Medium voltage
LV	Low voltage
DG	Distributed generator
BB	Bus bar
PDC	Point of distributed resources connection
LISN	Line Impedance Simulation Network
MIDR	M ultifunctional I ntelligent D igital R elay

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