Advanced Architectures and Control Concepts for

MORE MICROGRIDS

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Definition of Ancillary Services and Short-Term Energy Markets

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Coordination: João Abel Peças Lopes[1] jpl@fe.up.pt

Authors:
André Madureira[1] agm@inescporto.pt
Ricardo Bessa[1] rbessa@inescporto.pt
Mário Hélder Gomes[1,2] mgomes@ipt.pt
João Tomé Saraiva[1] jsaraiva@inescporto.pt
Danny Pudjanto[3] d.pudjianto@imperial.ac.uk
Pierluigi Mancarella[3] p.mancarella@imperial.ac.uk
Goran Strbac[3] goran.strbac@imperial.ac.uk
Antonios Tsikalakis[4] atsikal@power.ece.ntua.gr
Georgia Assimakopoulou[4] gasimako@power.ece.ntua.gr
Nikos Hatziargyriou[4] nh@power.ece.ntua.gr

[1] INESC Porto
[2] Polytechnic Institute of Tomar
[3] Imperial College
[4] ICCS / NTUA

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Structure of the Document

This deliverable encompasses two different tasks of Work Package D: Task TD5 – "Ancillary Services Markets" and Task TD6 – "Short-term Market Participation".

This document includes contributions from **INESC Porto**, **Imperial** and **ICCS/NTUA**.

INESC Porto has developed a proposal for ancillary services markets simulation regarding voltage and reserves. In this case, voltage and reserve markets were studied for both interconnected and islanded operation of multi-microgrid systems where each agent submits its bid to the corresponding market and the market is settled in order to minimize operation cost. These ancillary services markets are considered to be separate from the main energy market. Additionally, a market mechanism approach to be implemented in microgrids in order to activate a short-term adjustment market was developed, as well as to determine the adequate level of reactive power/voltage control and the generation required to balance active losses. Extensive tests for both ancillary services markets and short-term market participation have been performed using the test network (with small variations) developed within WPD.

Another approach was followed by **Imperial** that focused on the development of optimisation algorithms for setting controllers response characteristics in relation to the opportunities in energy and ancillary services (especially reserve) markets. This energy and reserve co-optimisation approach aims at maximising the benefits to microsources (including demand response) from participating in both energy and ancillary services markets. This includes voltage and thermal constraints consideration in the distribution network.

Finally, **ICCS/NTUA** has studied the functions incorporated within the MGCC and particularly the information exchange between CAMC and MGCC with emphasis on ancillary services provision. Some additional operations of the MGCC have also been defined and the contribution of the microgrids to voltage violation management has been investigated. These functions were evaluated using a typical network in order to illustrate how these can provide solutions to ancillary services issues. Furthermore, the impact of horizon of short-term market operation was also analysed. This was done by calculating the economic impact of various forecasting horizons for wind power, market prices and load.

Ancillary Services Markets for Voltage and Reserves

Table of Contents

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

HV – High Voltage

LC – Load Controller

LOLE – Loss Of Load Expectation

LOLP – Loss Of Load Probability

LV – Low Voltage

MAPE – Mean Absolute Percentage Error

MC – Microsource Controller

MGCC – MicroGrid Central Controller

MV – Medium Voltage

NWP – Numerical Weather Prediction

OLTC – On-Line Tap Changing

OPF – Optimal Power Flow

RTU – Remote Terminal Unit

SVC – Static VAR Compensator

VAR – Volt-Ampere Reactive

VPP – Virtual Power Plant

1. Multi-MicroGrid Concept

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 can be seen in Figure 1.

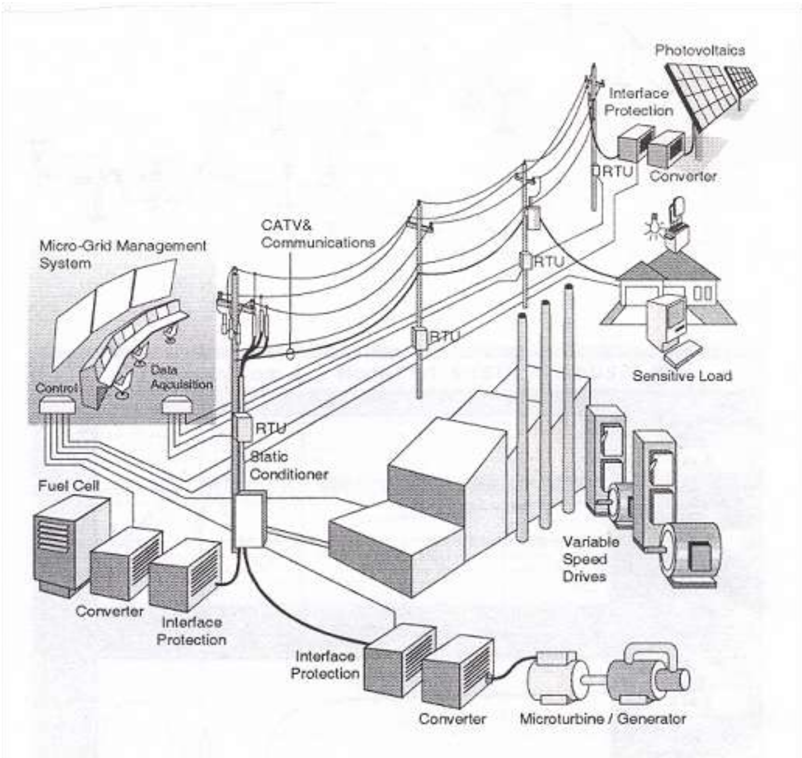

Figure 1: Typical MicroGrid System

A control scheme for microgrid operation requires three different control levels that can be seen in Figure 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.

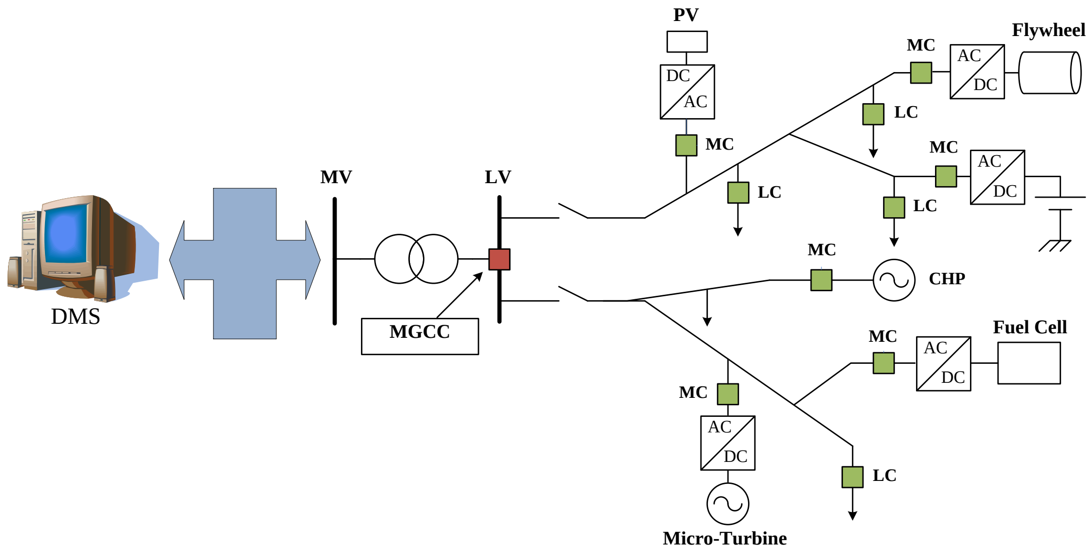

Figure 2: Microgrid Control Architecture

The 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 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 new DMS application that is in charge of one part of the network.

The main issue when dealing with control strategies for multi-microgrids concerns the use of individual controllers acting as agents with the ability of communicating with each other in order to make decisions [1]. 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 hold 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 management system (DMS) which may delegate some tasks in other 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. Therefore, the CAMC must have the ability to 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.

The CAMC will be playing a key role in a multi-microgrid system: it will be responsible for the local 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 Figure 3.

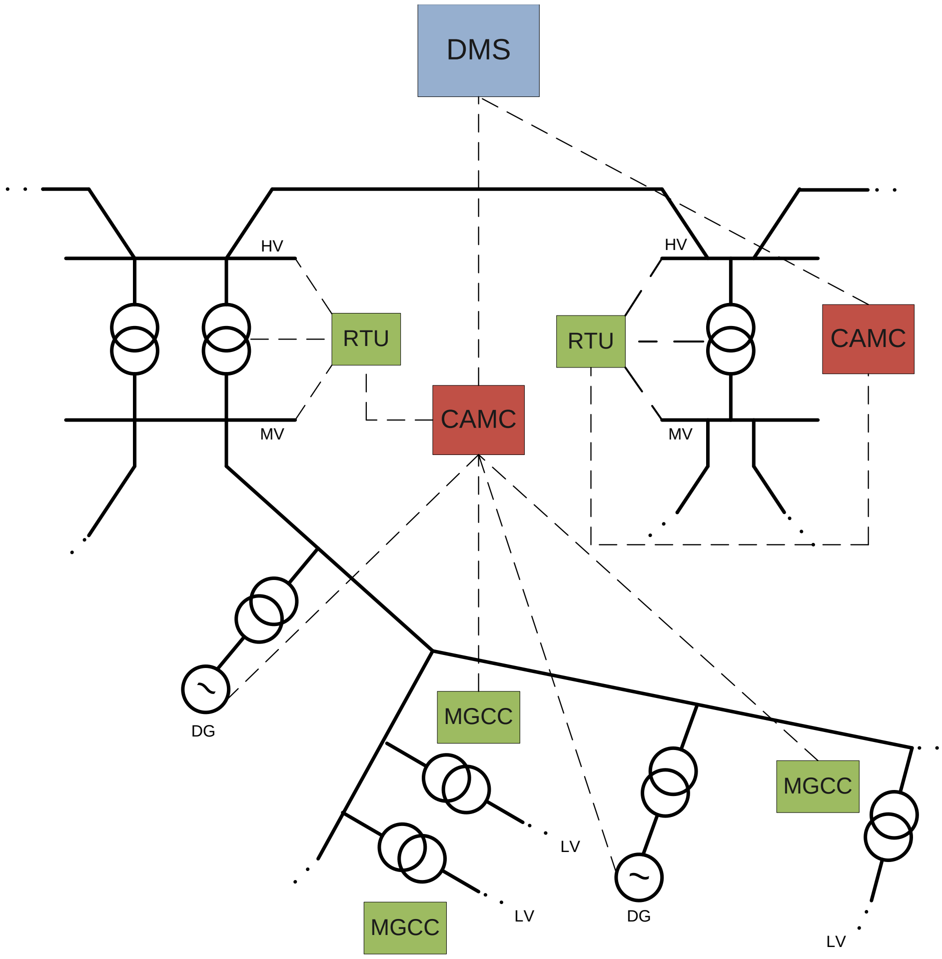

Figure 3: Control and Management Architecture of a Multi-MicroGrid System

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 (RTU) 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 can be seen in Figure 4.

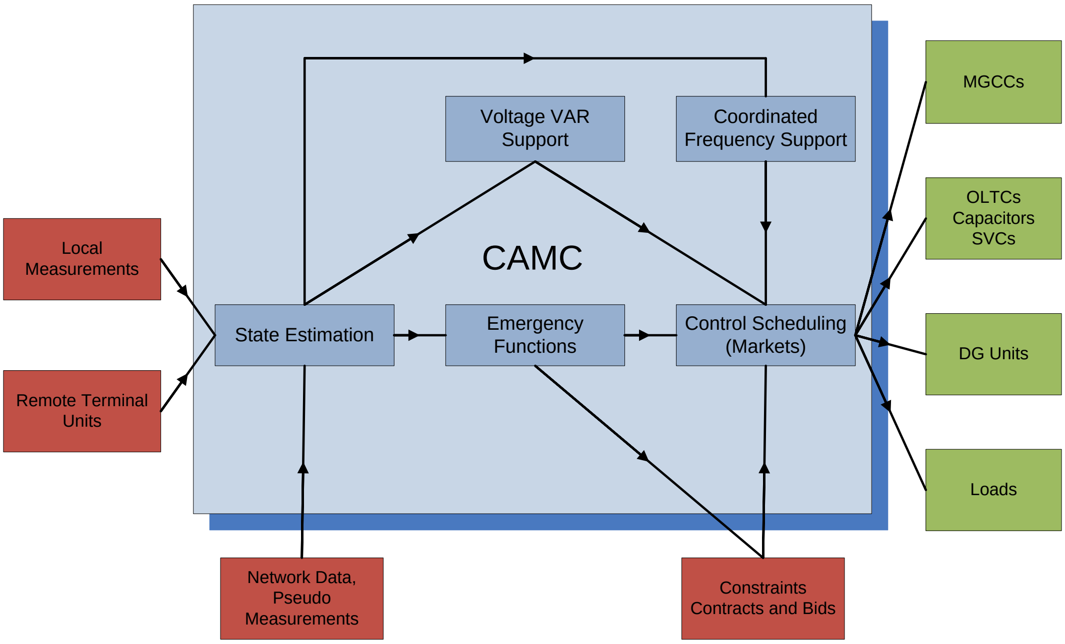

Figure 4: CAMC Functionalities

However, it should be stressed that not all these functionalities will be available in any multi-microgrid system. Their availability will depend on the characteristics of the MV network and on the local DG units present.

From the functionalities shown in Figure 4, Voltage VAR Support and Coordinated Frequency Support have already been addressed in Deliverable DD1 “Tools for Coordinated Voltage Support and Coordinated Frequency Support” [3], State Estimation has been presented in Deliverable DD2 “Algorithms for State Estimation in MV Multi-MicroGrids” [4] and Emergency Functions (Islanding and Blackstart) have been described in Deliverable DD3 “Strategies for Emergency Functions” [5].

In this deliverable, Control Scheduling (Markets) is addressed in detail mainly concerning the definition of Ancillary Services Markets and Short-Term Market Participation.

2. Ancillary Services Markets

Operation of electricity markets is becoming more and more decentralised. Recent market designs (such as the ones in Norway and the United Kingdom) allow participants to self-dispatch and manage their access to the electricity networks on a competitive basis. System operation economics is becoming fully decentralised, but security of the system is still dealt with centrally.

However, the development of DG and microgeneration will challenge the fundamental paradigm of central management of system security. With a very large penetration of small-scale generation, *i.e.* with the increased number of independent decision-making entities, a radical change from central management system to distributed management of the entire system operation will be required [6].

In this context, in order to provide incentives for the widespread of DG and microgrids, a market structure that is able to accommodate the services provided by these units should be developed. With the development of this new market structure, major institutional changes will have to take place and some of them have already begun. However, some service markets are at a relatively immature stage and a lot of reforming is required [7].

Competitive markets opened to generation for providing both energy and ancillary services should be encouraged because they may contribute to improve efficiency and eventually lower electricity bills. This structure, mainly concerning ancillary services provision, may go beyond the generation level by having load participation in several services. In particular, ancillary service markets can be seen as a great opportunity for DG and microgrids especially for voltage support and reserves.

In addition, a distributed control approach to manage distribution systems that integrate DG and microgrids is required. Microgrids can play a key role in this since the exploitation of the microgrid concept, and its corresponding control architecture, brings the possibility of smart metering and distributed control of devices both from the generation and demand side, thus providing a flexible framework for the implementation of energy and ancillary services markets. This will enable real-time price control for microgrids for market issues as well as for system operation.

In order to fully achieve these goals, from the multi-microgrid system perspective, the coordination of multiple microgrids and other sources seen at the MV level can be attained by exploiting the Virtual Power Plant (VPP) concept. By aggregating components following the VPP concept, microgrids are able to bid and offer energy and ancillary services to the external system. Within the microgrid, the MGCC will be responsible for coordinating the distributed resources among available loads and microgenerators.

3. VAR Market

3.1 Introduction

A type of hierarchical control can be established for voltage control. This voltage control scheme can 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, 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 uses an algorithm of Optimal Power Flow (OPF). 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 Figure 5, a scheme of the hierarchical voltage control architecture is presented.

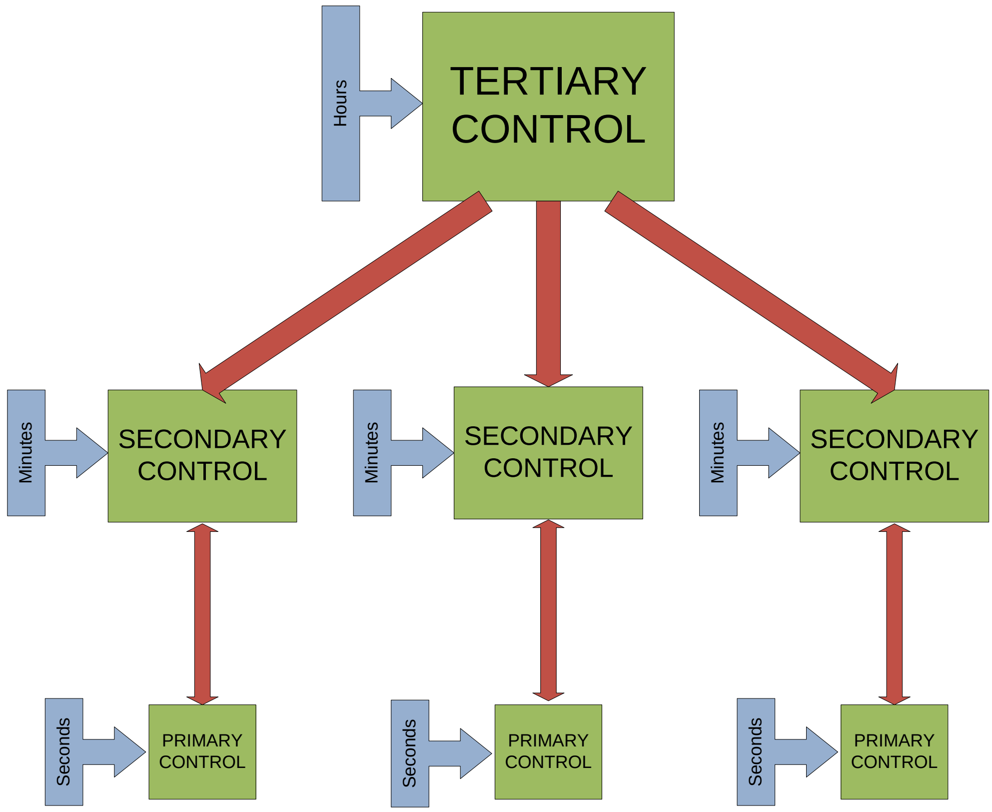

Figure 5: Hierarchical Voltage Control [2]

The most common goals, related to coordinated voltage/reactive power control, are:

- Keeping bus voltages within specified limits
- Controlling transformer, line and feeder loading
- Minimizing active power losses
- Managing reactive power sources
- Controlling the power factor

3.2 VAR Market Proposal

Concerning voltage support, reactive power supply is essential in order to maintain system security in power systems. In the new unbundled organization of electricity markets, voltage and reactive power control is usually integrated in the provision of ancillary services. Therefore, there is a need for an improved regulatory model to address reactive power and voltage control services in a scenario of restructuring and re-regulation of power systems. In addition, new competitive mechanisms are needed in order to guarantee system security together with a minimization of operation costs. Following the liberalization process in energy markets, it ancillary services will have separate procurement and remuneration mechanisms.

Nowadays, the integration of large amounts of DG and microgeneration poses new additional challenges for voltage control. Usually, generation units are expected to be the main service providers, although other VAR sources can also procure the service. The task of the DSO is to define the volume of service for the participants in the energy market. In addition to this, the DSO must also define who will participate in the voltage control service, how the service is going to be provided and how is it regulated.

The DSO will run VAR market that accommodates the VAR capacity bids from the several agents and distributes the VAR needs among them in order to satisfy the VAR requirements. The utilization of VAR will also be remunerated based on a regulated price (not subject to market).

This market is asymmetric, since the several bids are sorted in order to provide a pre-defined fixed reactive power load, according to Figure 7. Also, the type of pricing adopted for the VAR market is based on uniform prices equal to the bid of the marginal unit, *i.e.* each unit is remunerated at the market clearing price.

An overview of the VAR market proposal is shown in Figure 6.

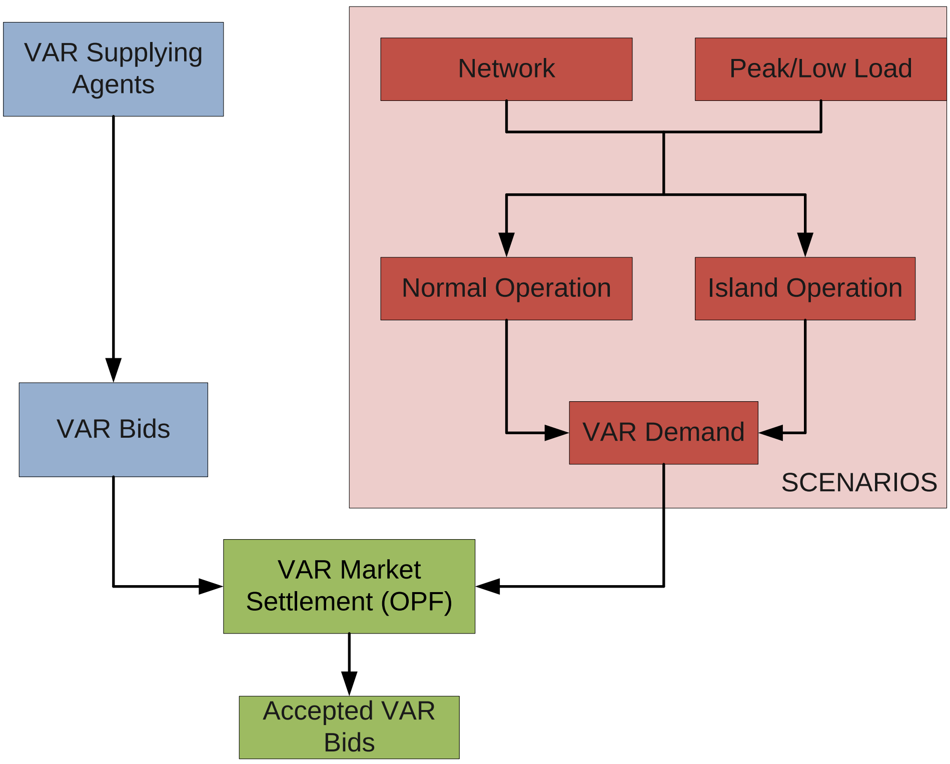

Figure 6: Overview of the VAR Market Proposal

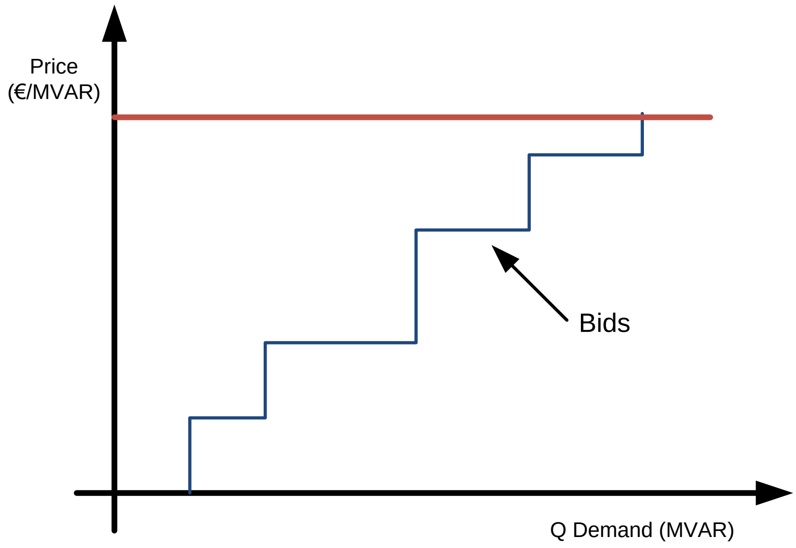

Figure 7: VAR Market Structure

In the next sections, the main issues related to the VAR market as it is presented in Figure 6 will be addressed in detail.

3.2.1 VAR Supplying Agents

Several different agents may want to access the VAR market. DG units directly connected to the MV level of the distribution system may wish to bid their reactive power generation capacity or, alternatively, some capacity that is required by the DSO may be bought from the upstream HV distribution network. New agents that may be able to bid in this market are microgrids. Their bidding should be submitted thorough the corresponding MGCC that aggregates the offers from the several units within the microgrid.

Therefore, the VAR supplying agents considered can be:

- HV Network (if available – refer to Section 3.2.3)
- DG Sources
- MicroGrids
- Loads at the MV level
- Capacitor Banks

3.2.2 VAR Bids

The several agents that wish to participate in the VAR market must supply their bids to the DSO. These bids should be organized in several blocks: a pre-determined amount of reactive power capacity at a rated price as shown in Figure 8. This means that an amount of Q_1 MVAR will be priced at p_1 €/MVAR, an amount of Q_2 MVAR will be priced at p_2 €/MVAR and so on.

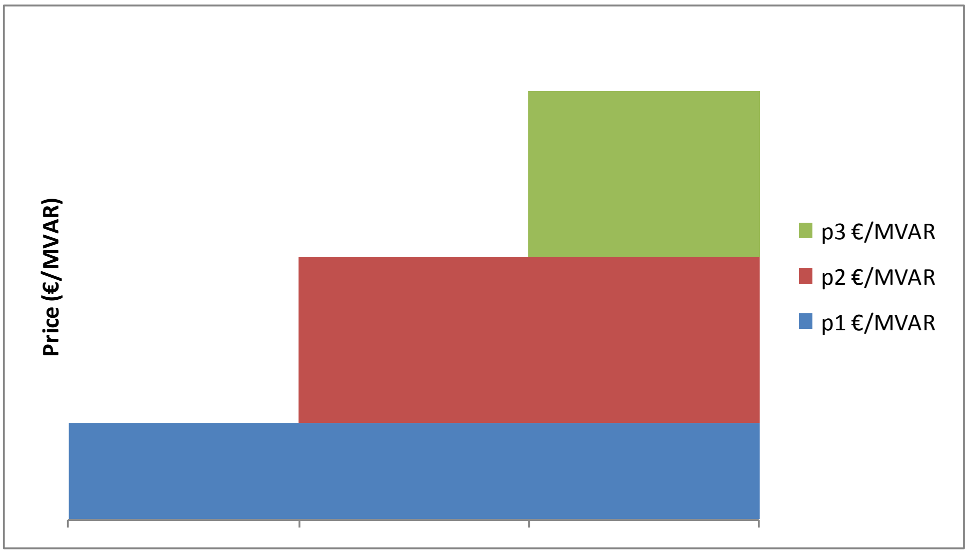

Figure 8: VAR Bids (Including 3 Capacity Blocks Offered)

Of course, the agents should define their bids in such a way as to cover their own costs.

3.2.3 Scenario Definition and VAR Demand

It is necessary to consider different scenarios to compute the VAR demand, which will serve as an input for the market settlement procedure. As it was seen in the previous sections, the multi-microgrid system may be operated in two different situations:

- Normal Interconnected Operation
- Emergency (Islanded) Operation

In addition, and in order to be able to request the bids from the multiple agents for providing the service, it is necessary that the DSO defines the most demanding scenarios concerning VAR demand. Therefore, to identify the volume of VAR demand needed, two different types of scenarios have been considered:

- Peak Hours → settles the requirements for VAR generation needs
- Valley Hours → assesses the system needs for VAR absorption

These scenarios concern the volume of demand at the MV level, where the market settlement will be achieved. In order to determine the possible contribution to the requested service by microgrids, two microgrid policies are considered:

- "Good-citizen" policy (requesting zero reactive power from the grid)
- "Ideal-citizen" policy (buying and selling reactive power from/to the grid)

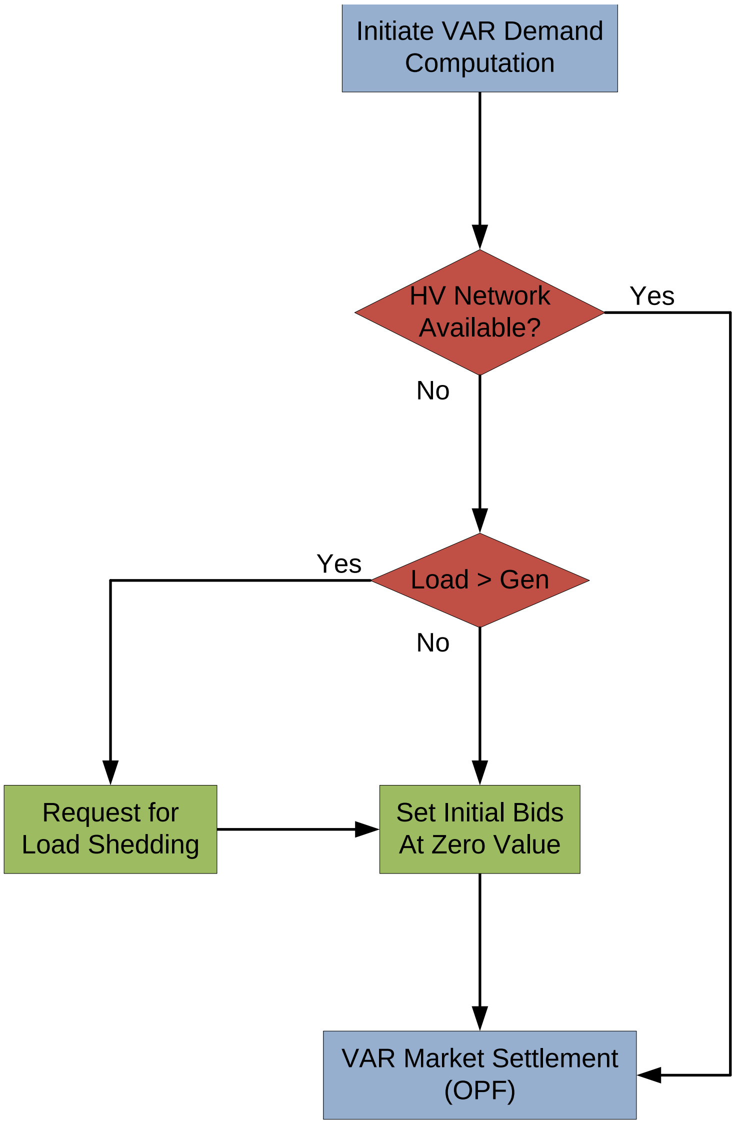

Figure 9: VAR Demand and Scenario Definition

Figure 9 presents the overview of the process in order to define the scenarios and compute VAR demand for the market settlement. As previously stated, two market structures are envisaged for normal and emergency operation. In normal operation, all agents (DG, microgrids, etc.) may present their reactive power bids to the market settlement.

However, in emergency mode, a mandatory regulation capacity should be defined for all market participants. There is no remuneration for this part of the service and these bids enter the market at with zero-price. Moreover, market participants may offer additional regulation capacity of VAR by bidding and submitting more quantities to the market. This strategy will reduce the risk of blackout that can be caused by the lack of offers to participate in the VAR emergency market.

In addition, all VAR sources are scheduled and controlled by DSO on a daily basis.

3.2.4 VAR Market Settlement

The DSO, in order to perform the market settlement, must assess the operating conditions of the grid given the VAR capacity distribution among the several agents for the scenarios defined in the previous section. Therefore, the methodology employed for the VAR market settlement is to solve an OPF-like problem, formulated as shown below:

$$\min \sum_{j=1}^{M} Price_j^{Qbid} \quad (1)$$

subject to

$$\begin{gathered} P_i^G - P_i^L = \sum_{k=1}^{N} V_i \cdot V_k \cdot (G_{ik} \cdot \cos\theta_{ik} + B_{ik} \cdot \sin\theta_{ik}) \\ Q_i^G - Q_i^L = \sum_{k=1}^{N} V_i \cdot V_k \cdot (G_{ik} \cdot \sin\theta_{ik} - B_{ik} \cdot \cos\theta_{ik}) \\ V_i^{min} \leq V_i \leq V_i^{max} \\ Q_i^{min} \leq Q_i^G \leq Q_i^{max} \\ S_{ik}^{min} \leq S_{ik} \leq S_{ik}^{max} \end{gathered} \quad (2)$$

for *i* = 1 : N

where:

$Price_j^{Qbid}$ is the price of the reactive power bid from unit *j*

P_i^G and P_i^L are the active power generation and consumption at bus *i*, respectively

Q_i^G and Q_i^L are the reactive power generation and consumption at bus *i*, respectively

V_i and V_i are the voltage magnitude at bus *i* and bus *k*, respectively

G_{ik} Is the real part of the element in the Ybus corresponding to the *i*th row and *k*th column

B_{ik} is the imaginary part of the element in the Ybus corresponding to the i^{th} row and k^{th} column

θ_{ik} is the difference in voltage angle between the i^{th} and k^{th} buses

V_i^{min} and V_i^{max} are the minimum and maximum admissible value for voltage magnitude at bus *i*, respectively

Q_i^{min} and Q_i^{max} are the minimum and maximum admissible value for reactive power generation at bus *i*, respectively

4. Reserve Market

4.1 Introduction

Maintaining frequency at the rated value requires that active power generation and/or consumption must be controlled, by balancing load and generation. A specific amount of active power (frequency control reserve) must be available in order to perform this type of control.

Usually, three control levels are used to maintain this balance between load and generation [8]. Figure 10 shows the traditional frequency control scheme and the types of control used [2].

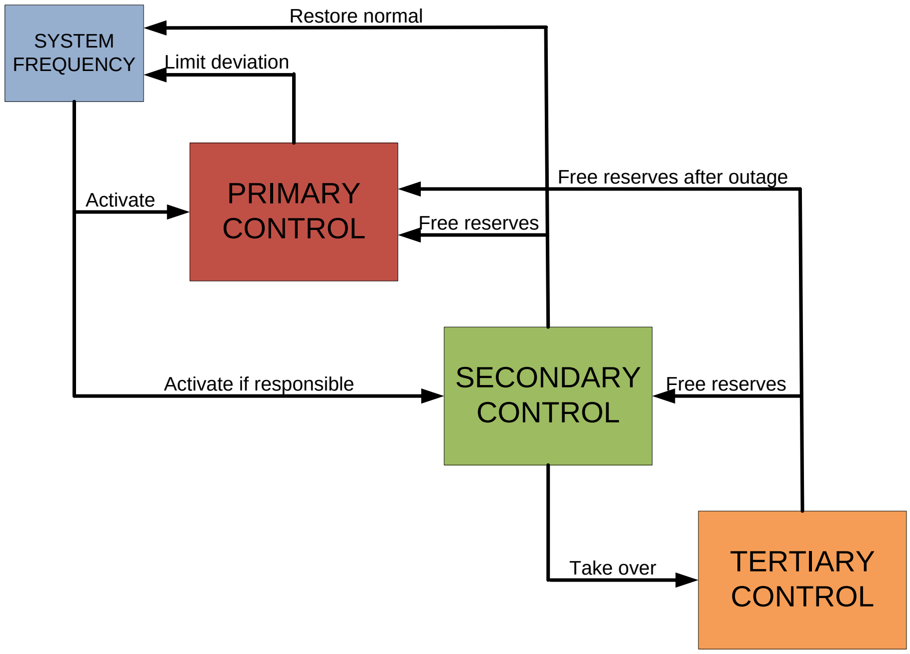

Figure 10: Frequency Control Scheme [2]

Primary frequency control is a type of local automatic control that adjusts the active power generation of generating units and the consumption of controllable loads in order to restore quickly the balance between load and generation and counteract frequency variations [8], [9].

Secondary frequency control is a centralized automatic control that adjusts the active power generation of the generating units in order to restore frequency and power flow in interconnections with other systems to their target values following an imbalance [8], [9]. In other words, while primary control limits and stops frequency excursions, secondary control brings the frequency back to its target value.

Tertiary frequency control is related to manual changes in dispatch and commitment of generating units [8], [9].

In this work, a market proposal has been developed in order to address the provision of secondary reserve.

4.2 Secondary Reserve Market Proposal

The reserve market presented in this section is designed to operate in emergency (islanded) operation only. This is due to the fact that, in interconnected operation, a reserve market such as the one proposed here would not be suitable since reserve provision could be guaranteed from the upstream HV network. For a multi-microgrid a secondary reserve market proposal can be designed for a six hours-ahead market since it was considered that islanded operation would not be sustained for larger periods than this. The offers are updated every 2 hours and consequently the reserve requirements.

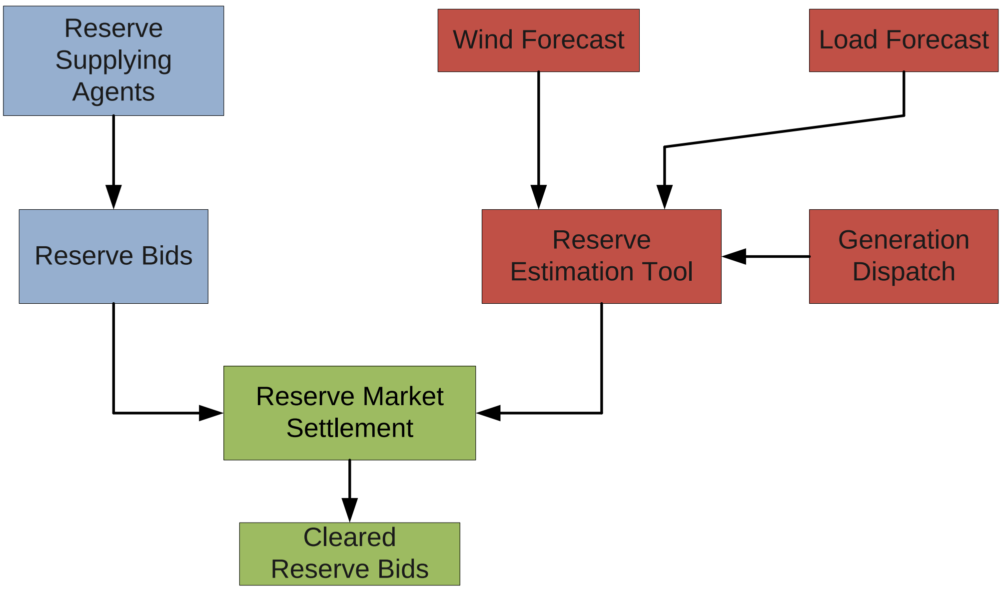

Figure 11: Overview of the Reserve Market Proposal

The reserve market is assumed to work in the following framework, according to what is shown in Figure 12:

- At t = 17:00, for instance, the DSO determines and publishes the hourly reserve needs (based on the generation dispatch and load and wind power forecasts) for each look-ahead time step of a six hours time horizon. The time gap between the beginning of six hours operational period and the decision instant is one hour.

- From t = 17:00 to t = 18:00 the DSO launches the reserve market where the market agents willing to participate in the reserve market present their bids in the following format: reserve capacity [MW], hour, bus number, price of contracted reserve capacity [€/MW], bid number.
- At t = 17:30, the period for offering reserve services closes and the DSO performs the market settlement based on the reserve bids and the reserve needs, and then a reserve margin is assigned to each market agent.

Note that the same framework is applied for the following markets (after 2 hours) with updated forecasts and offers.

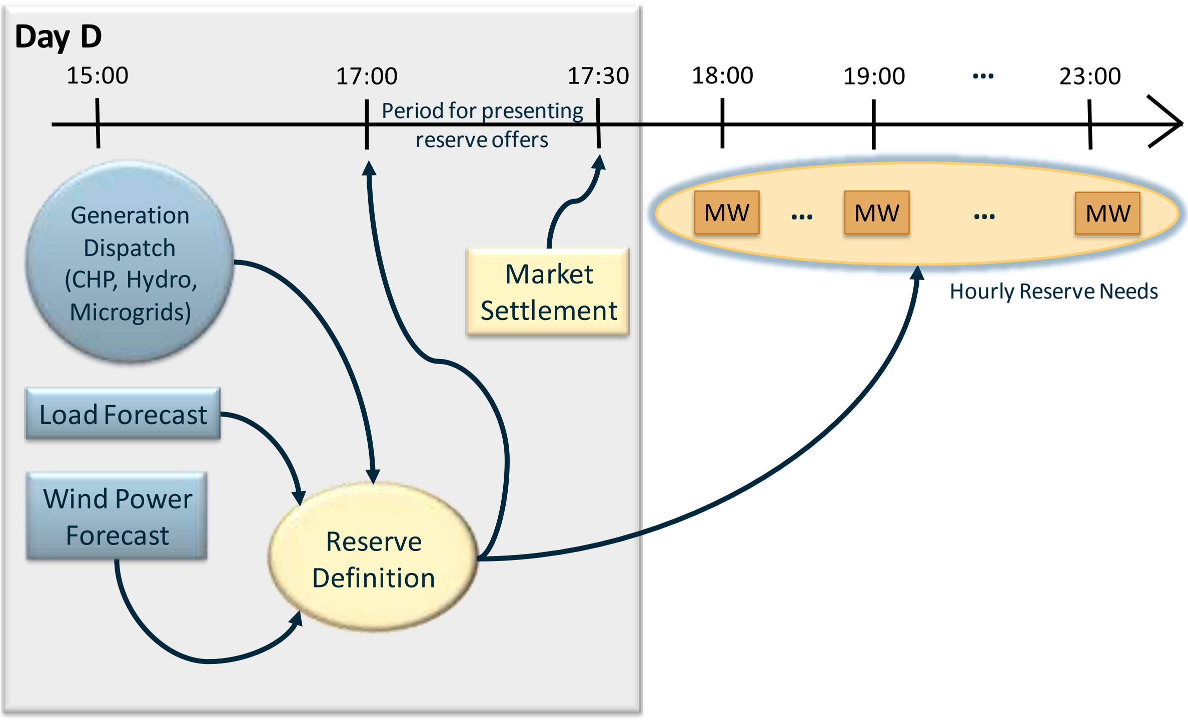

Figure 12: Reserve Market Framework

These reserve amounts settled by the market are secondary reserve, defined as the unused capacity, which can be activated following a request from the DSO, provided by devices that are synchronized to the network and able to affect the active power. In addition, units that can provide reserve within 15 minutes are considered secondary reserve [10], [11].

The relevant inputs to the reserve market are:

- Total local load and local wind power forecast uncertainty made at time instant t = 17:00 for each look-ahead time step of the next six hours.

- Local scheduled generation by technology (CHP, hydro and microgrids) decided by a unit commitment made by the DSO at time instant t = 17:00 for each look-ahead time of the next six hours.

The failures rates of the conventional generation were not used because it was assumed that there is a very low probability of failure in the next six hours period considered.

4.2.1 Secondary Reserve Supplying Agents

Several devices are able to participate in the reserve market. Both load and generation may bid to the reserve market by submitting their proposals for raising or lowering their active power levels in order to meet the requirements of the DSO. In addition, microgrids are also able to bid since they can be regarded as VPPs which are able to submit their bids via the corresponding MGCC. Each MGCC serves as an aggregator of generation and load within the microgrid and communicates with the upper level control level (CAMC).

Therefore, the agents considered for reserve supply can be:

- Controllable DG Sources
- MicroGrids

Note that controllable loads may provide downward reserve by disconnecting, if necessary, and submit bids to the reserve market with their available capacity to decrease. However, the downward reserve is not addressed in this document since it is analogous to the upward reserve methodology presented.

4.2.2 Secondary Reserve Bids

All agents that wish to participate in the reserve markets should submit their bids to the market, similarly to what was proposed in the VAR market proposal in Section 3.2.

4.2.3 Secondary Reserve Estimation Tool

The approach for defining the secondary reserve is based on the rule described in [12] and [13]. It consists in computing the standard deviation of the system margin (amount that the available generating capacity exceeds the system load) for each look-ahead time, by taking into account the load and wind power forecast errors.

Because the uncertainties of load and wind power generation are assumed to be independent and represented by Gaussian distributions, the standard deviation σ_{SM} of the system margin can be computed by:

$$\sigma_{SM} = \sqrt{\sigma_W^2 + \sigma_L^2} \tag{3}$$

where:

σ_W and σ_L are the standard deviation of the uncertainty distribution for wind and load respectively.

Conventional generation (Diesel, CHP, Hydro, etc.) is assumed to be deterministic; therefore, the failure rates of the units were not considered since the probability of having a unit outage in the next six hours is very low.

For a specific level of operating reserve R, the system margin distribution describes the probability of the reserve being (un)sufficient to cover the deficit of generation. In the second step, an acceptable risk level can be defined to set the reserve requirements for each hour of the time horizon.

For instance, if σ_W is 30 MW and σ_L is 20 MW, a reserve equal to $3\sigma_{SM}$ (3 x 36 = 108 MW) can be defined, which means that this reserve will cover 99.74% of the system margin deviations. This corresponds to a Loss Of Load Probability (LOLP) equal to 0.0013 and a Loss Of Load Expectation (LOLE) equal to 0.078 min/h.

An autoregressive statistical model [14] was used to produce data point forecasts for the next six hours of the wind farm. In addition, an estimation of the uncertainty of the wind power forecast for the next six hours was also required. The uncertainty is modelled by a Gaussian distribution with a given the standard deviation computed using typical values presented in [15].

It is important to stress that the Gaussian distribution is only an approximation of the wind power forecast uncertainty, which can also be modelled by non-parametric representations (*e.g.* a set of quantiles). Generally, the uncertainty distribution presents a high skewness due to the combination of the non-linear nature of the power curve and errors of the Numerical Weather Prediction (NWP) model. However, since an autoregressive model is being used, which uses only as input the measurements of wind generation (NWP forecasts and an estimation of the power curve are not considered), the hypothesis of a Gaussian distribution is acceptable.

The load uncertainty is also modelled through a Gaussian distribution, with a given standard deviation and zero mean [16]. A relation between the value of the Mean Absolute Percentage Error (MAPE) and the standard deviation σ, assuming Gaussian distribution of the forecast errors is established:

$$P(|e| < MAPE) = 0.5 \quad \leftrightarrow \quad P(e > MAPE) = 0.25 \tag{4}$$

Then, the relation between the two is MAPE=0.67449σL.

4.2.4 Secondary Reserve Market Settlement

After all bids have been collected from the different agents participating in the reserve market, the DSO is able to perform market settlement by sorting all the proposals in ascending cost order and ranking the proposals in order to meet the required reserve levels as defined by the secondary reserve estimation tool.

5. Test Network

The study-case network used to test the ancillary service market simulation is the one presented in "DD1. Tools for Coordinated Voltage Support and Coordinated Frequency Support" [3] and fully described in "TD3.3 Test Network Description" [17]. The study-case network is shown in Figure 13. This network has two distinct areas: one with a typical urban topology (loop, on the left-hand side of Figure 13) and another with a rural topology (radial, on the right-hand side of Figure 13).

The load and generation data considered in this work are presented in Appendix A.

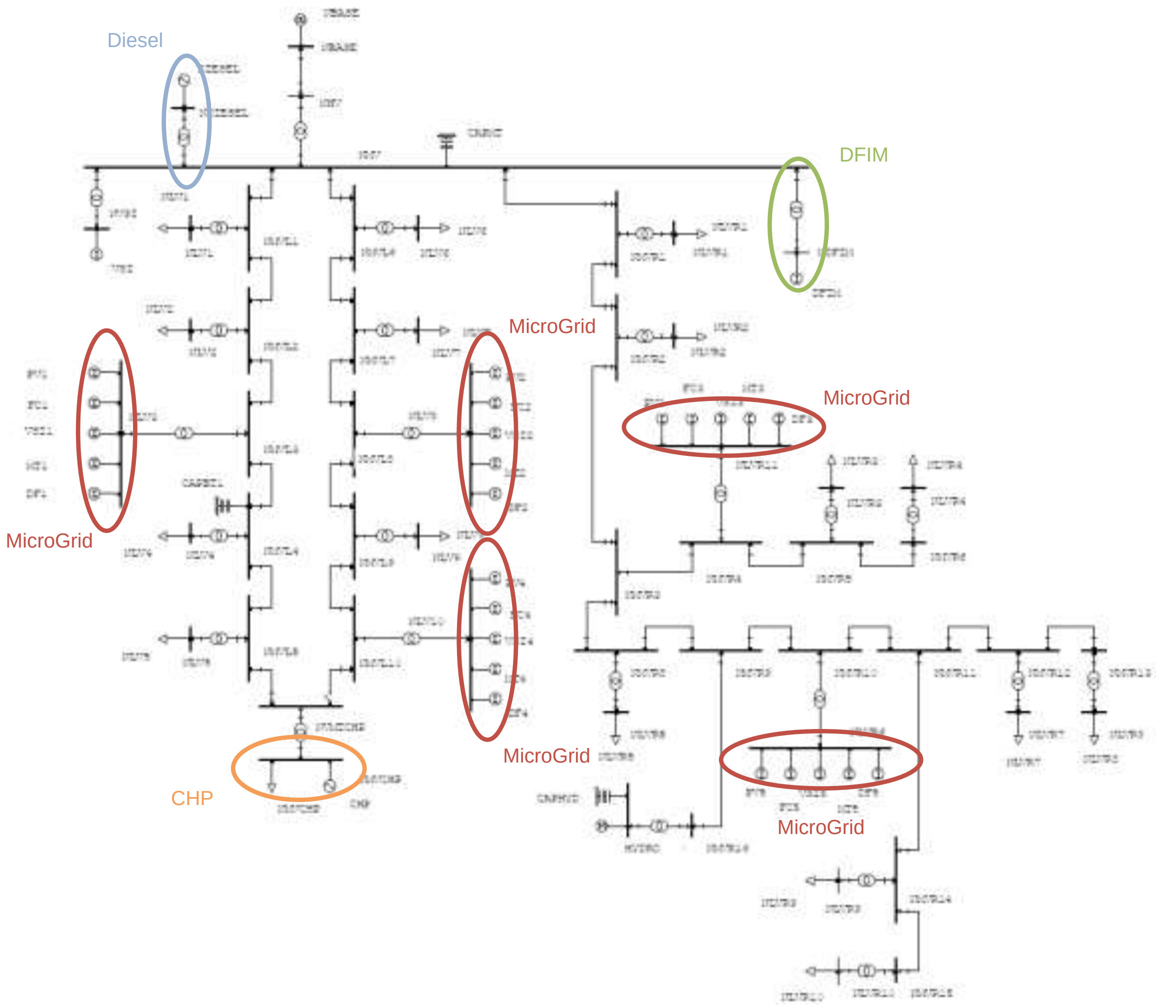

Figure 13: Study-case Test Network

6. Main Results

6.1 VAR Market

In this section, some results on the VAR market settlement defined in Section 3.2.4 will be presented using the study-case test network presented in Section 5. The VAR supplying agents are the 3 DG units (CHP, DFIM and Diesel) and the 5 microgrids shown in Figure 13. Although there is also a hydro unit present, it is not able to bid to the VAR market since it is considered to be an induction generator.

Finally, two operation scenarios will be considered:

- Normal Interconnected Operation (presented in Section 6.1.1)
- Emergency – Islanded – Operation (presented in Section 6.1.2)

The VAR bids considered in this section are detailed in Appendix B.

6.1.1 Interconnected Mode

In this section, results on the VAR market settlement in interconnected mode are presented considering the two microgrid operation policies presented in Section 3.2.3:

- Microgrid “Good Citizen” Policy
- Microgrid “Ideal Citizen” Policy

These results are obtained considering a peak demand scenario, *i.e.* an extreme scenario where the need for VAR generation is more significant.

For the scenario considered, the DSO was able to achieve the market settlement successfully without voltage limits violations and without branch congestions.

Figure 14 and Figure 15 show the market settlement considering the “Good Citizen” and the “Ideal Citizen” policies, respectively. Considering the “Ideal Citizen” policy, the microgrids are able to bid VAR capacity to the market and there is no need to import VAR from the upstream network.

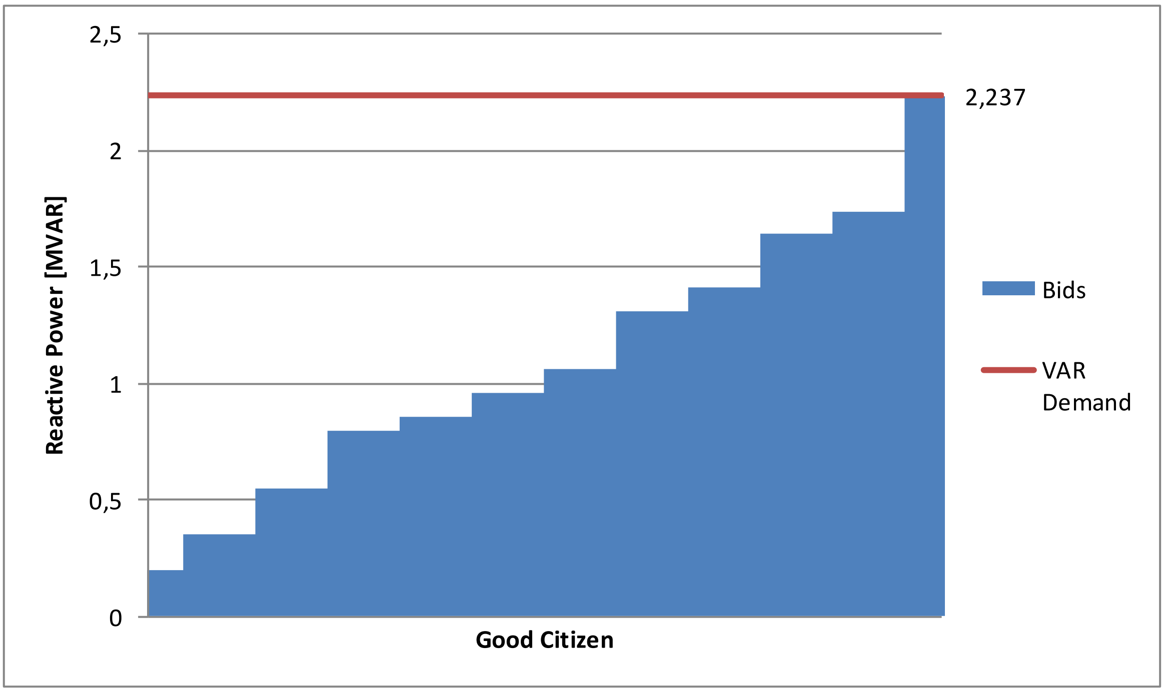

Figure 14: Results from the VAR Market Settlement ("Good Citizen" Policy)

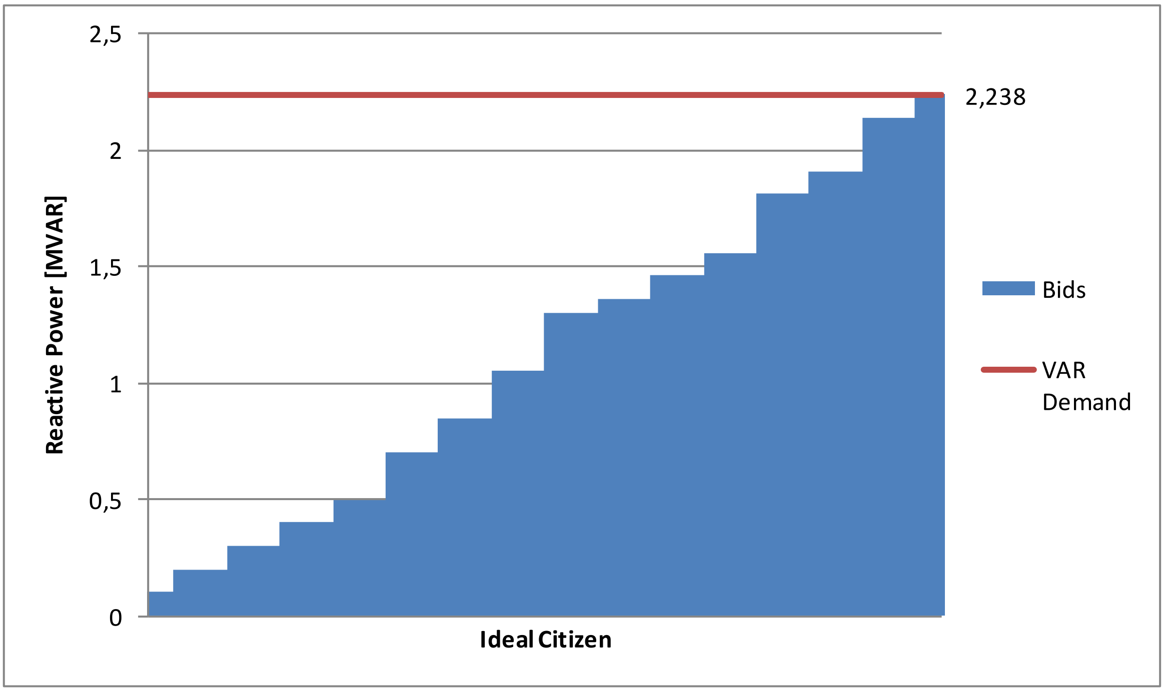

Figure 15: Results from the VAR Market Settlement ("Ideal Citizen" Policy)

The selected VAR bids per technology are presented in Figure 16, comparing the "Good Citizen" and the "Ideal Citizen" policies.

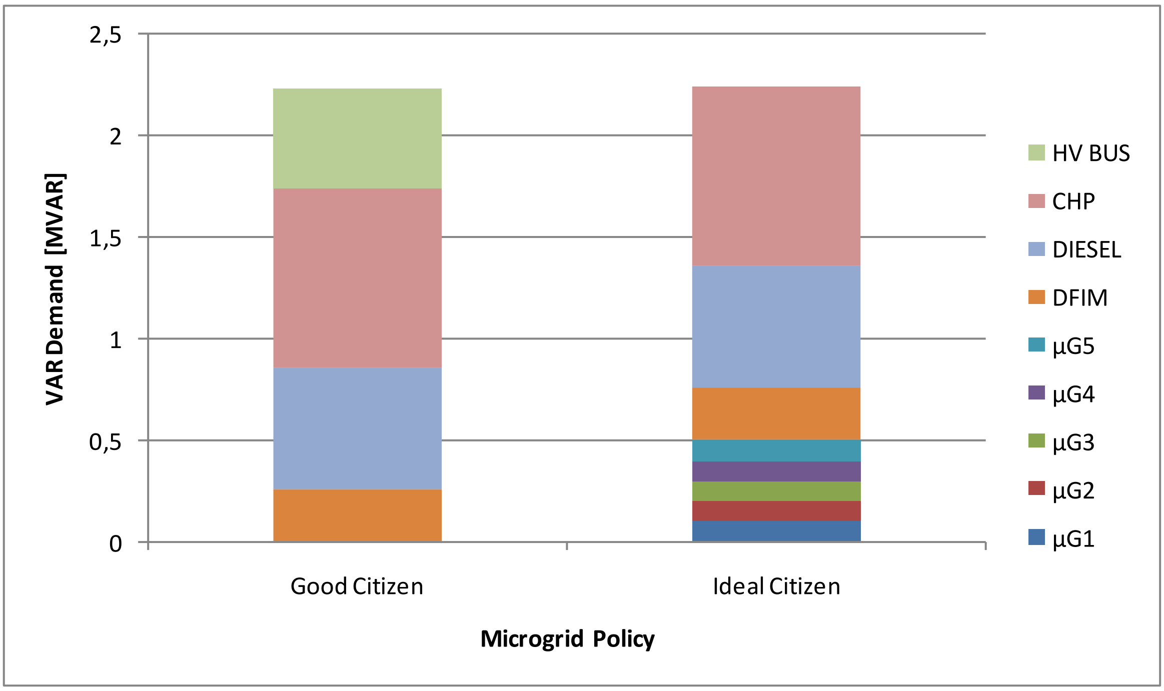

Figure 16: Selected VAR Bids ("Good Citizen" Policy *vs.* "Ideal Citizen" Policy)

Table I and Table II show the VAR bids and prices after the market settlement considering the "Good Citizen" and the "Ideal Citizen" policies, respectively. As it was seen previously, the bid of the marginal unit defines the uniform market price. Therefore, in the "Ideal Citizen" policy the market clearing price is higher than in the "Good Citizen" policy since it is more expensive to import VAR.

Table I: VAR Bids and Prices ("Good Citizen")

Bus Name	***Q [MVAR]***	***Price [€/MVAR/h]***	***Price [€/h]***
NMVCHP	0.88	0.13	0.11
NDFIM	0.26	0.13	0.03
NDIESEL	0.60	0.13	0.08
NHV	0.00	0.13	0.00
NLV8	0.10	0.13	0.01
NLVR11	0.10	0.13	0.01
NLV3	0.10	0.13	0.01
NLV10	0.10	0.13	0.01
NLVR6	0.10	0.13	0.01
Total	**2.24**	–	**0.29**

Table II: VAR Bids and Prices ("Ideal Citizen")

Bus Name	***Q [MVAR]***	***Price [€/MVAR/h]***	***Price [€/h]***
NMVCHP	0.88	1.50	1.32
NDFIM	0.26	1.50	0.39
NDIESEL	0.60	1.50	0.90
NHV	0.50	1.50	0.75
NLV8	0.00	1.50	0.00
NLVR11	0.00	1.50	0.00
NLV3	0.00	1.50	0.00
NLV10	0.00	1.50	0.00
NLVR6	0.00	1.50	0.00
Total	**2.24**	**–**	**3.36**

6.1.2 Islanded Mode

In this section, results on the VAR market in islanded operation will be presented. In the case considered here, prior to the islanding of the multi-microgrid system, the multi-microgrid load was higher than the available generation.

As previously explained in Section 3.2.3, in order to overcome this it was necessary to shed some load. The load shedding procedure was applied proportionally to all load nodes of the study-case test network. Nevertheless, other load shedding schemes may be employed that are able to preserve vital load that must be supplied. Therefore, a total of approximately 0.718 MW was shed in order to keep the load/generation balance.

Finally, as mentioned also in Section 3.2.3, initial bids submitted to the market by all units providing the service are marked at zero-price.

Figure 17 shows the VAR market settlement for islanded operation mode.

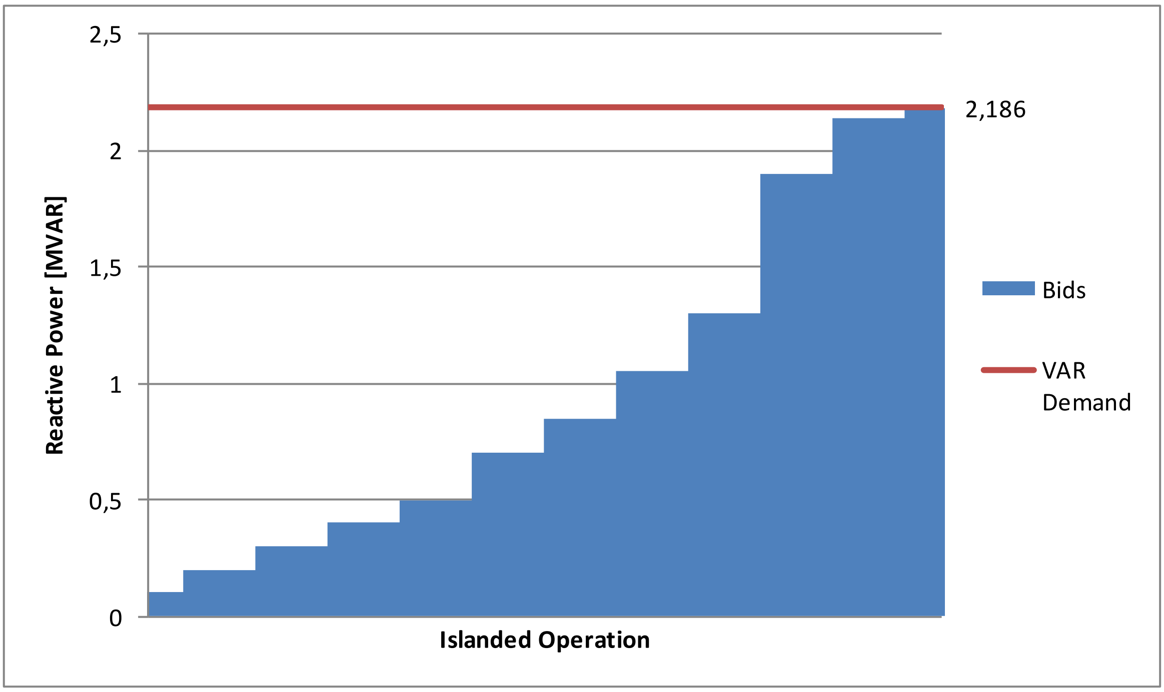

Figure 17: Results from the VAR Market Settlement (Islanded Operation Mode)

Table III shows the VAR bids and prices after the market settlement in islanded operation mode.

Table III: VAR Bids and Prices (Islanded Operation Mode)

Bus Name	*Q [MVAR]*	*Price [€/MVAR/h]*	*Price [€/h]*
NMVCHP	0,40	0,11	0,04
NMVHYD	0,00	0,11	0,00
NDFIM	0,82	0,11	0,09
NDIESEL	0,46	0,11	0,05
NLV8	0,10	0,11	0,01
NLVR11	0,10	0,11	0,01
NLV3	0,10	0,11	0,01
NLV10	0,10	0,11	0,01
NLVR6	0,10	0,11	0,01
Total	**2.19**	**–**	**0.24**

6.2 Reserve Market

In this section, some results concerning the secondary reserve market are presented. The operating scenario considered is emergency (islanded) operation.

The methodology is demonstrated using a single bus model for the 4 MW wind farm of the study-case test network shown in Figure 13 and considering a peak load of 8.58 MW at hour 20:00. The load and wind power point forecasts are depicted in Figure 18 and Figure 19, respectively. The standard deviation of the load and wind forecast errors are shown in Figure 20 and Figure 21.

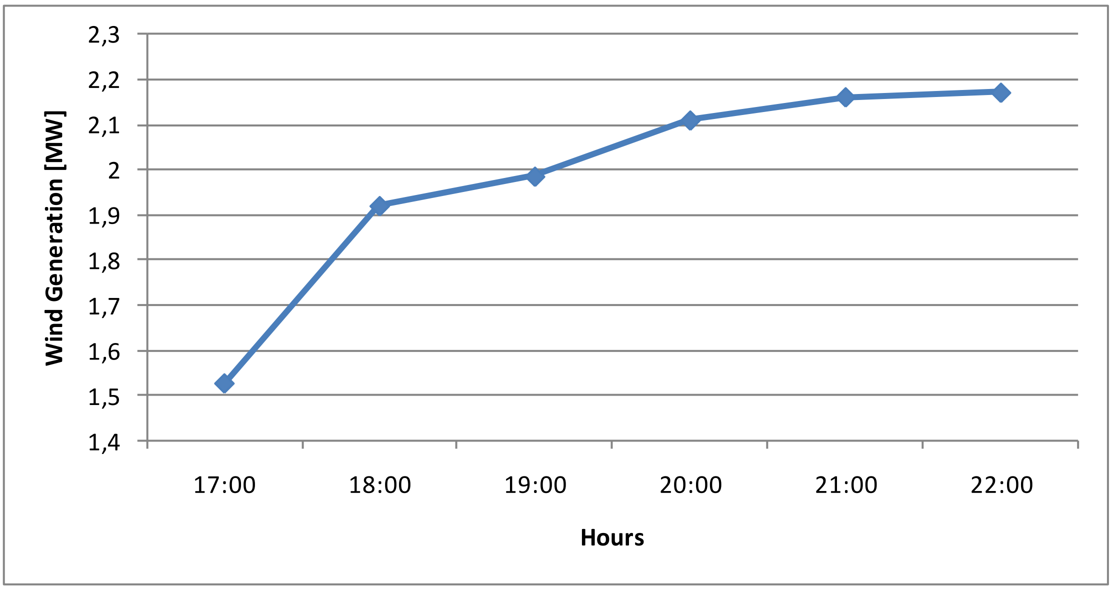

Figure 18: Wind Power Point Forecast for the Next Six Hours

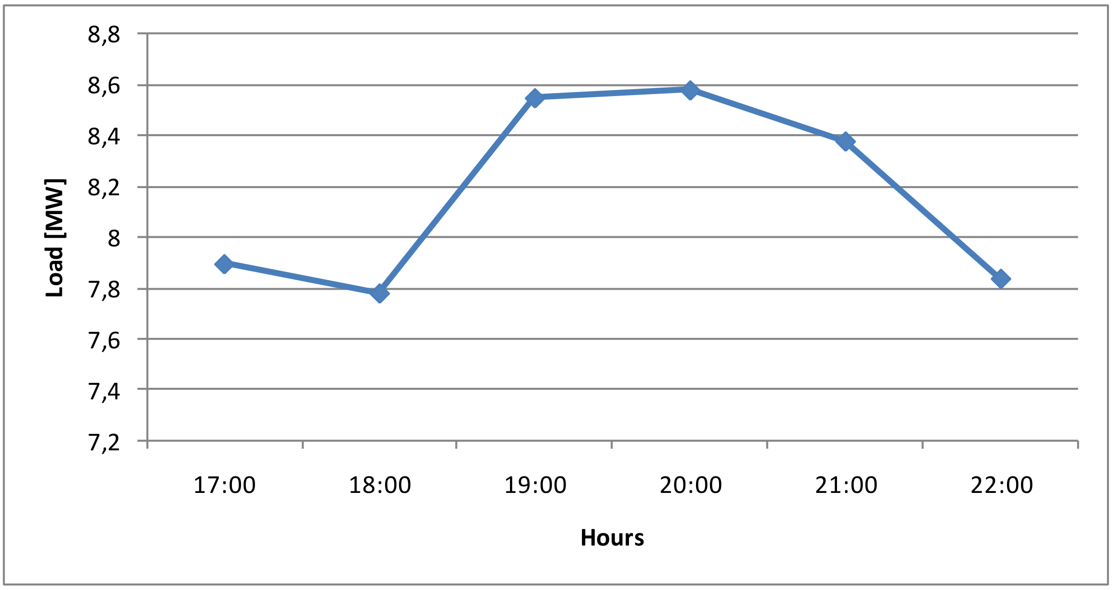

Figure 19: Load Point Forecast for the Next Six Hours

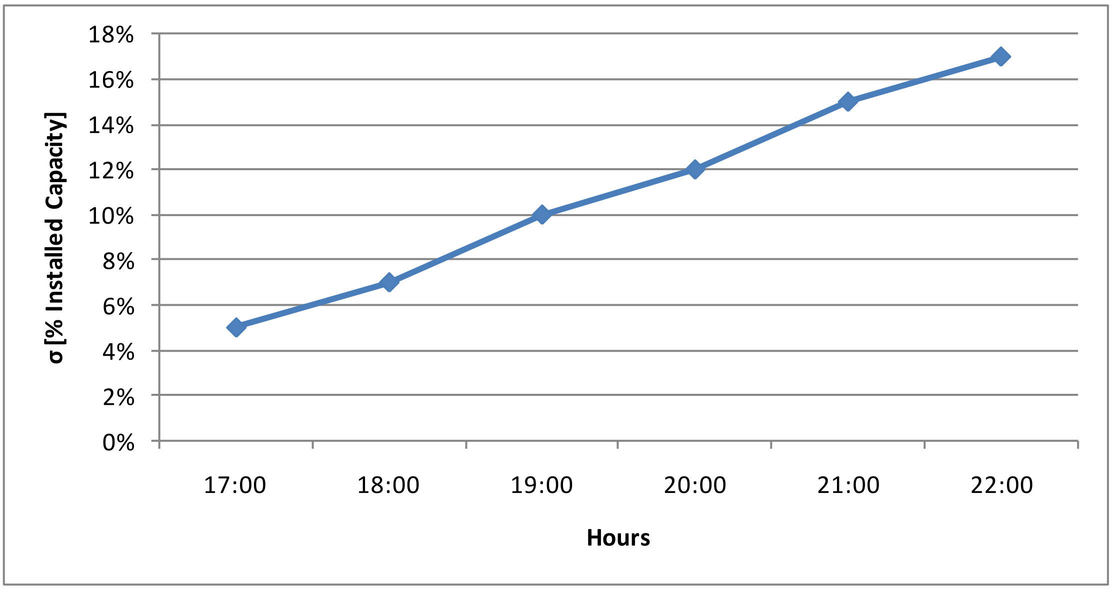

Figure 20: Standard Deviation of the Wind Power Forecast Error for the Next Six Hours

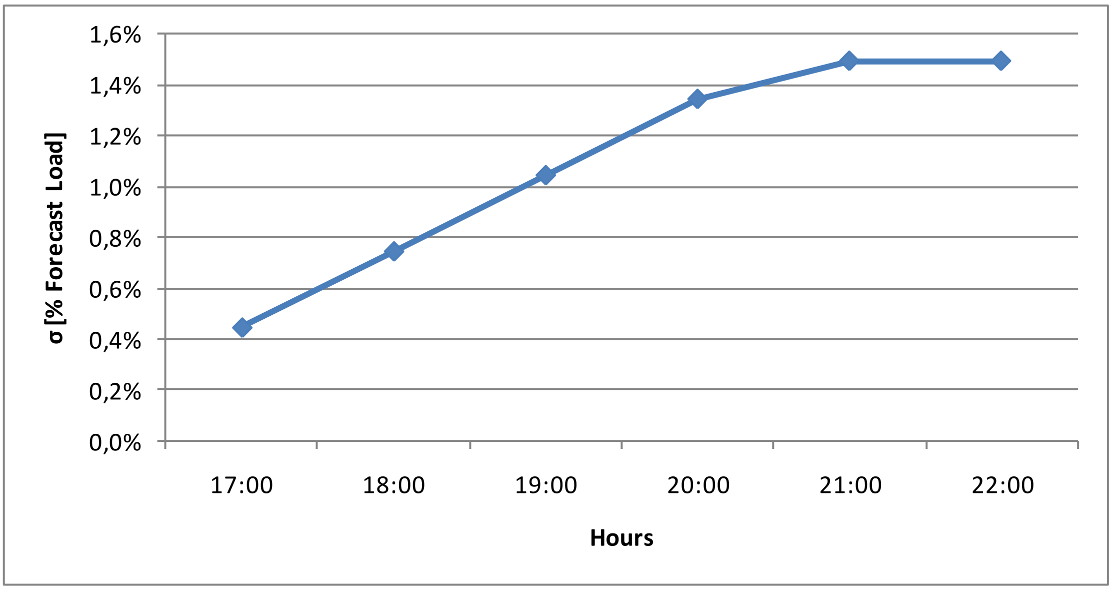

Figure 21: Standard Deviation of the Load Forecast Error for the Next Six Hours

The dispatched conventional generation is considered as the difference between the load and wind power point forecasts.

In this test, the reserve needs are estimated by the DSO for the next six hours, and then bids offering that reserve capacity are presented, as described in Section 4.2.

A situation where a threshold for the LOLE was previously set by the DSO (in this case 1 min/hour) was simulated. Subsequently, the reserve level can be obtained directly from the rule presented in (3) using $2.13\sigma_{SM}$ which corresponds to 96.66% of the total system deviations (LOLP = 0.016). The reserve needs for the next six hours are presented in Table IV.

Table IV: Reserve Needs for the Next Six Hours and LOLE=1 min/h

Hour	***Reserve [MW]***
17:00	0.433
18:00	0.609
19:00	0.873
20:00	1.051
21:00	1.305
22:00	1.470

Figure 22 to Figure 27 show the reserve market settlement for each hour of the six-hour period.

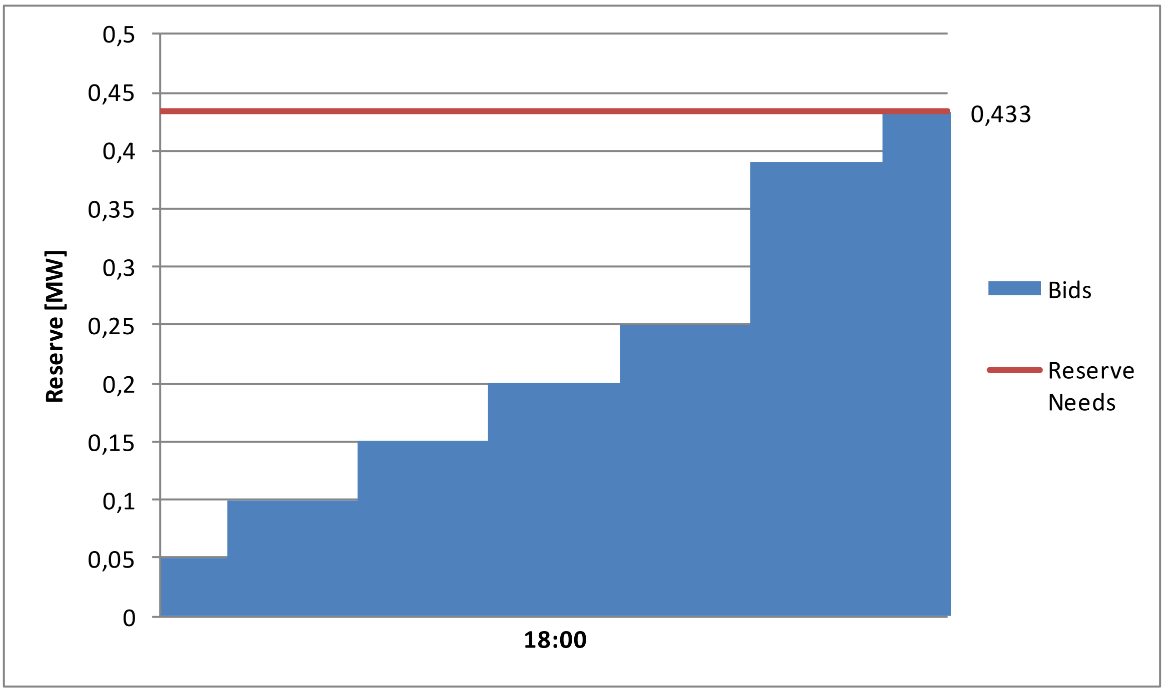

Figure 22: Reserve Market Settlement (18:00)

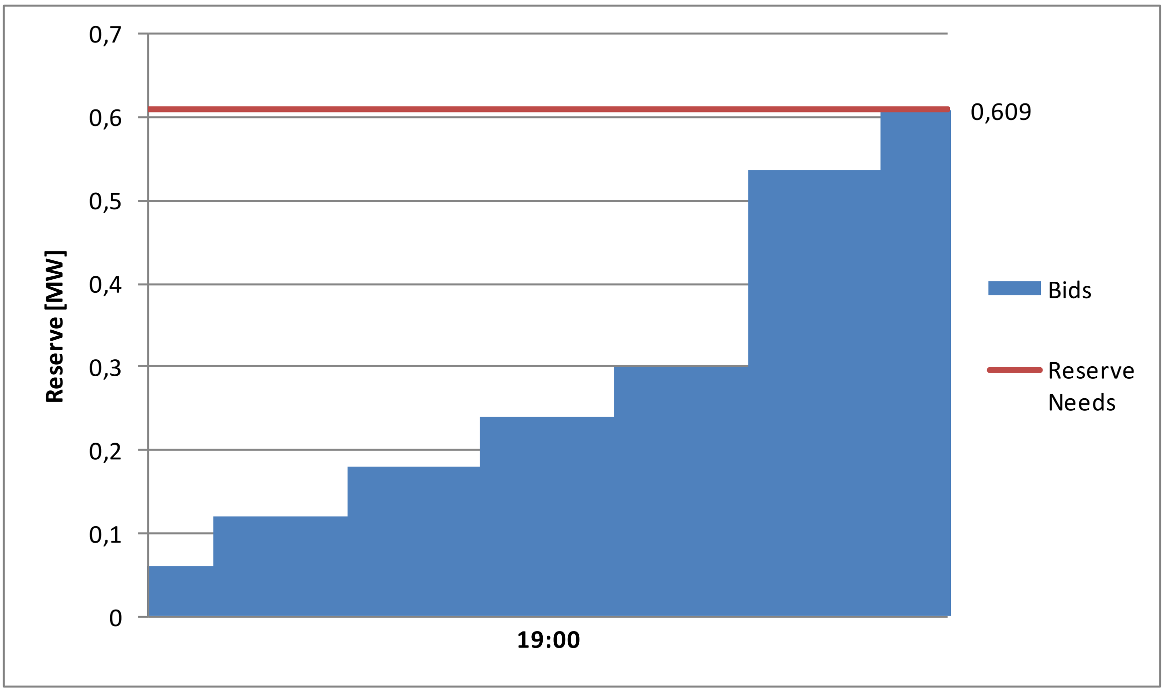

Figure 23: Reserve Market Settlement (19:00)

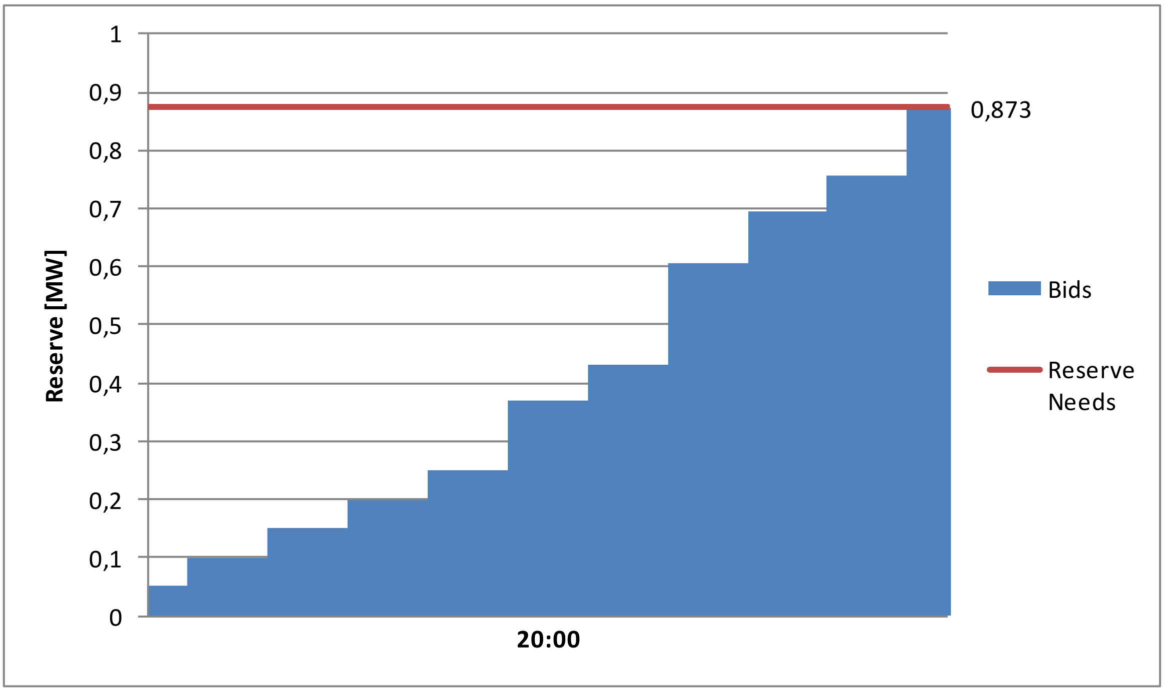

Figure 24: Reserve Market Settlement (20:00)

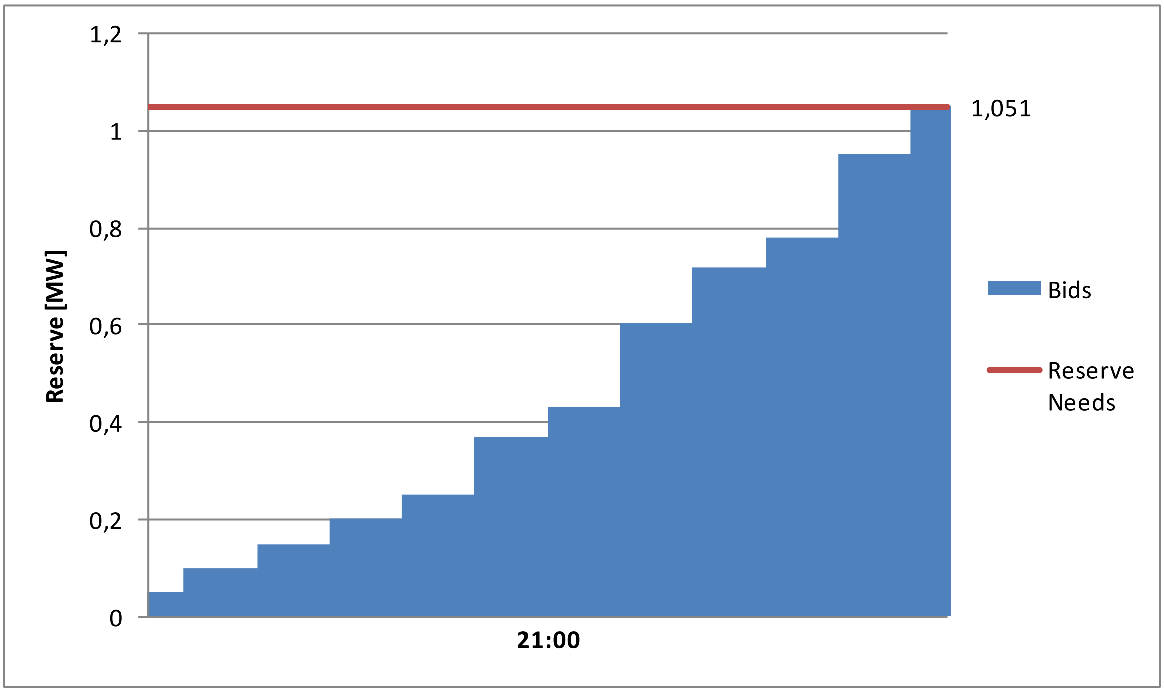

Figure 25: Reserve Market Settlement (21:00)

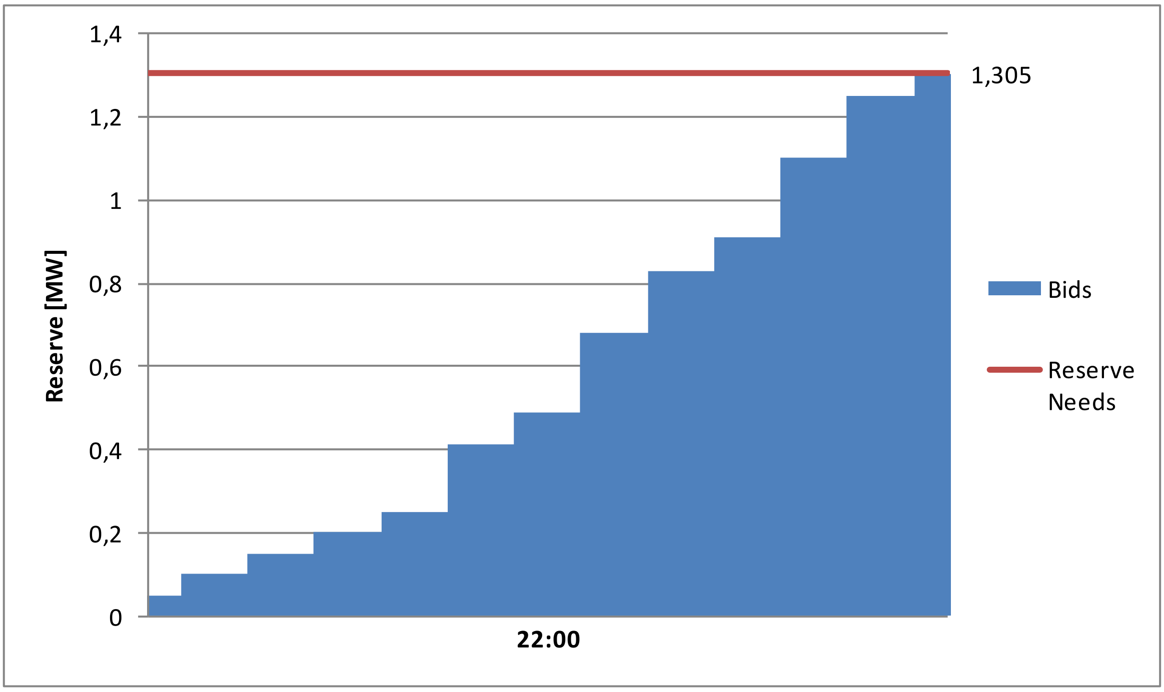

Figure 26: Reserve Market Settlement (22:00)

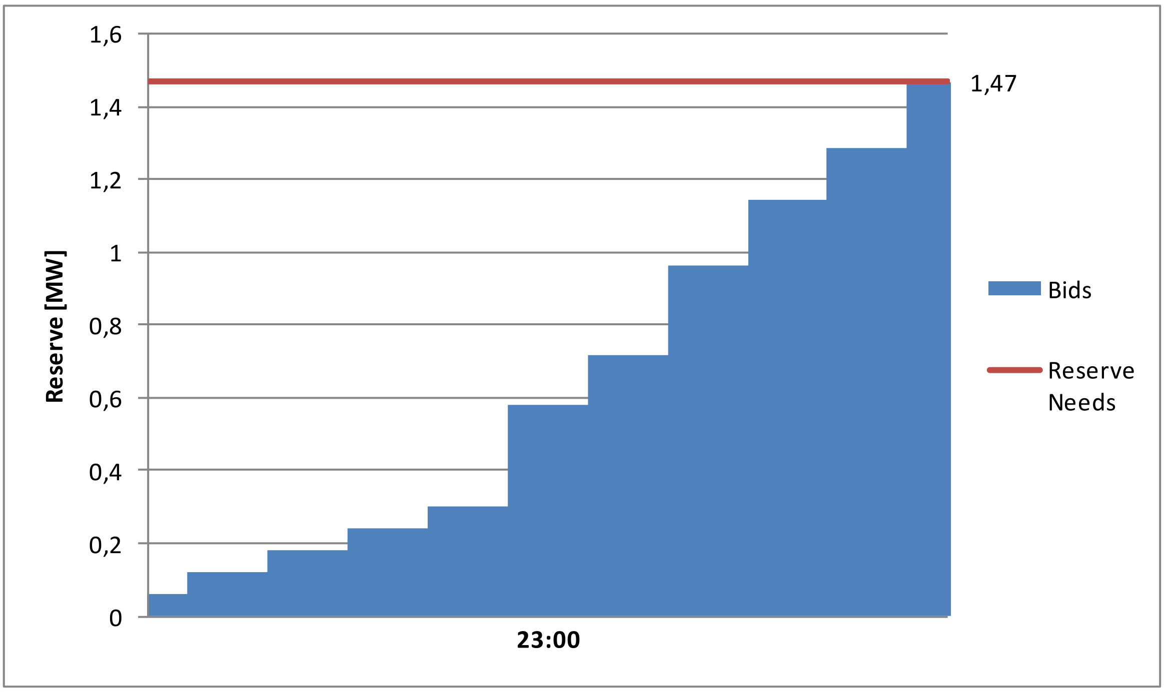

Figure 27: Reserve Market Settlement (23:00)

Figure 28 presents a comparison between the reserve levels required and the total reserve available that was bid in the reserve market. It should be stressed that the reserve needs grow with time due to the increase of the uncertainty of the load and of the wind generation forecast.

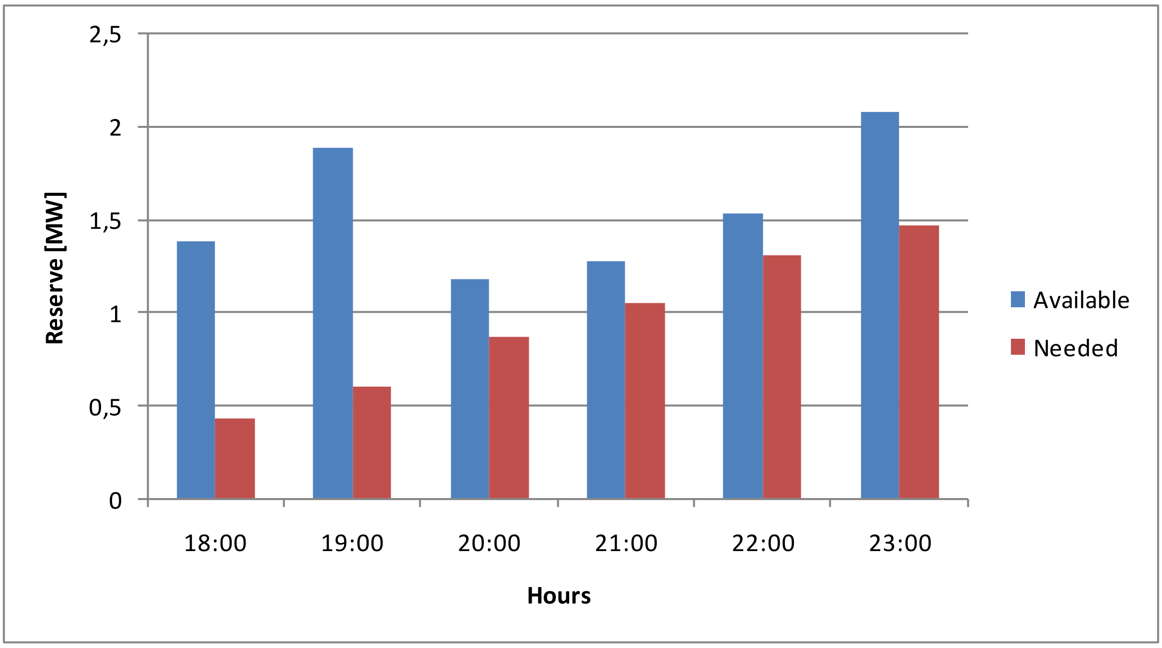

Figure 28: Available Reserve *vs.* Needed Reserve

After the reserve needs have been defined for the next six hours, it is necessary to distribute them amongst the several reserve providing agents. Figure 29 shows the contribution of each agent to the reserve needs following the market settlement.

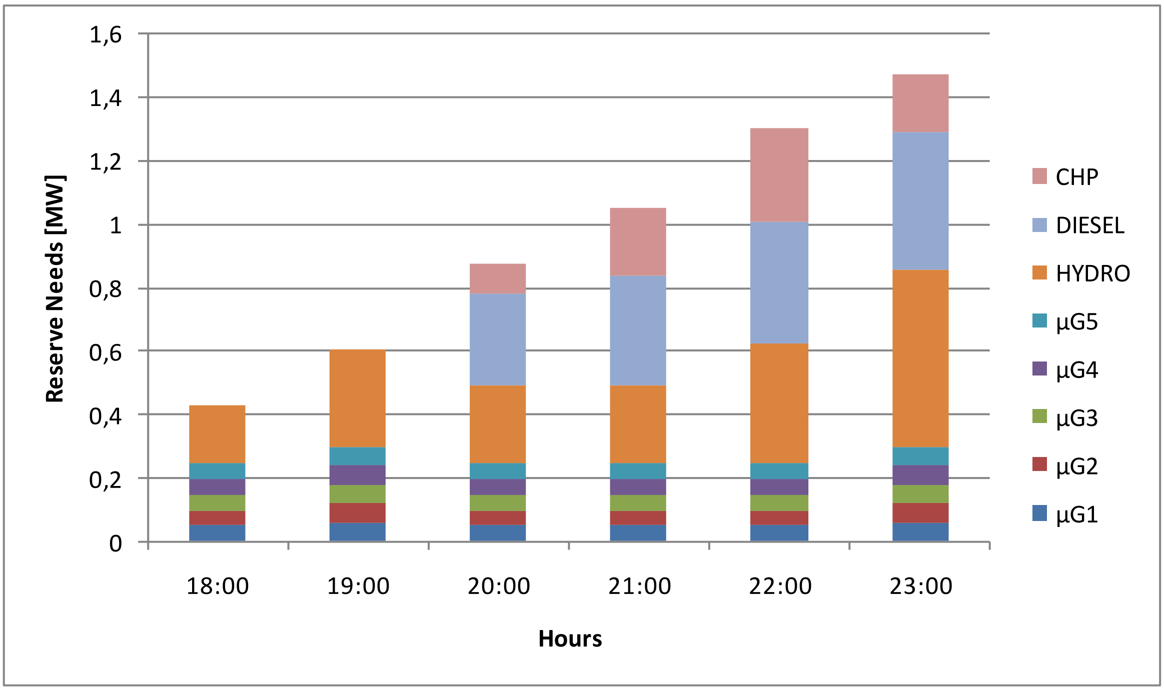

Figure 29: Reserve Needs per Technology

7. Conclusions

In this deliverable, the development of ancillary services markets (VAR and reserve) for distribution systems with multi-microgrids is addressed. In this context, a microgrid is considered to operate as a VPP from the MV distribution system point of view.

A VAR market approach has been developed that is able to incorporate bids from several different agents (DG at the MV level, microgrids…) and distribute VAR between the all ancillary services providers in order to minimize the total cost to the DSO. Different scenarios must be considered in order to settle VAR needs for the VAR market, including operating mode (normal or emergency). In interconnected mode, two policies for microgrid participation were modelled: “Good citizen” and “Ideal citizen”. It was seen that the “Ideal citizen” policy for microgrids may avoid the need for importing VAR from the upstream HV network and thus minimize the total costs to the DSO and support network operation. In islanded operation mode, the VAR market considers two distinct situations: “generation > load” and “generation < load”. In this last situation, it is necessary to curtail load in order to be able to safely operate the system. In both cases, initial bids by VAR providing units are set at zero-price.

In addition, a reserve market approach was developed to include generation uncertainties (such as wind power) in order to allow the DSO to compute reserve requirements during emergency (islanded) operation. In this situation, microgrids are able to offer reserve capacity to the market which will be used to compensate for load / generation variations. This approach will allow an increase of renewable energy sources at the MV network and improve the controllability of the whole distribution system, especially in islanded operation.

8. References

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9. Appendix A – Scenarios Data

Table A-I: Study-case Test Network Load Data

Bus Name	***Load [MW]***	***Load [MVAR]***
NMVCHP	0.810	0.392
NLV1	1.077	0.354
NLV6	1.077	0.354
NLV7	1.077	0.354
NLV2	1.077	0.354
NLV4	0.539	0.177
NLV5	0.539	0.177
NLV9	0.539	0.177
NLVR1	0.324	0.157
NLVR2	0.203	0.098
NLVR3	0.203	0.098
NLVR4	0.129	0.062
NLVR5	0.324	0.157
NLVR7	0.203	0.098
NLVR8	0.129	0.062
NLVR9	0.203	0.098
NLVR10	0.129	0.062

Table A-II: Study-case Test Network Generation Data

Bus Name	*Generation [MW]*	*Generation [MVAR]*
NMVCHP	1.476	0
NLV8	0.250	0
NMVHYD	0.548	0
NLVR11	0.250	0
NDFIM	1.376	0
NDIESEL	1.377	0
NLV3	0.250	0
NBASE	0.653	0
NLV10	0.250	0
NLVR6	0.250	0

10. Appendix B – Bids Data

Table B-I: Reactive Power Bids for the VAR Market (Good Citizen)

Bus Name	*Block No.*	*Quantity [MVAR]*	*Price [€/MVAR]*
NMVCHP	1	0.15	0.09
	2	0.25	0.10
	3	0.25	0.12
	4	0.23	0.13
NDFIM	1	0.06	0.10
	2	0.10	0.11
	3	0.10	0.13
NDIESEL	1	0.20	0.08
	2	0.20	0.09
	3	0.10	0.11
	4	0.10	0.12
NHV	1	2.00	1.50
	2	2.00	1.50
	3	2.00	1.50

Table B-II: Reactive Power Bids for the VAR Market (Ideal Citizen)

Bus Name	***Block No.***	***Quantity [MVAR]***	***Price [€/MVAR]***
NMVCHP	1	0.15	0.09
	2	0.25	0.10
	3	0.25	0.12
	4	0.23	0.13
NDFIM	1	0.06	0.10
	2	0.10	0.11
	3	0.10	0.13
NDIESEL	1	0.20	0.08
	2	0.20	0.09
	3	0.10	0.11
	4	0.10	0.12
NHV	1	2.00	1.50
	2	2.00	1.50
	3	2.00	1.50
NLV8	1	0.10	0.07
NLVR11	1	0.10	0.07
NLV3	1	0.10	0.07
NLV10	1	0.10	0.07
NLVR6	1	0.10	0.07

Table B-III: Active Power Bids for the Reserve Market (Hour 18:00)

Bus Name	***Block No.***	***Quantity [MW]***	***Price [€/MW]***
NMVCHP	1	0.114	0.08
	2	0.114	0.10
	3	0.114	0.11
	4	0.038	0.13
NMVHYD	1	0.140	0.03
	2	0.070	0.05
	3	0.070	0.08
	4	0.070	0.10
NDIESEL	1	0.200	0.06
	2	0.200	0.09
NLV8	1	0.050	0.02
NLVR11	1	0.050	0.02
NLV3	1	0.050	0.02
NLV10	1	0.050	0.02
NLVR6	1	0.050	0.02

Table B-IV: Active Power Bids for the Reserve Market (Hour 19:00)

Bus Name	***Block No.***	***Quantity [MW]***	***Price [€/MW]***
NMVCHP	1	0.15	0.08
	2	0.15	0.1
	3	0.15	0.11
	4	0.05	0.13
NMVHYD	1	0.236	0.03
	2	0.118	0.05
	3	0.118	0.08
	4	0.118	0.1
NDIESEL	1	0.25	0.06
	2	0.25	0.09
NLV8	1	0.06	0.02
NLVR11	1	0.06	0.02
NLV3	1	0.06	0.02
NLV10	1	0.06	0.02
NLVR6	1	0.06	0.02

Table B-V: Active Power Bids for the Reserve Market (Hour 20:00)

Bus Name	***Block No.***	***Quantity [MW]***	***Price [€/MW]***
NMVCHP	1	0.09	0.08
	2	0.09	0.1
	3	0.09	0.11
	4	0.03	0.13
NMVHYD	1	0.12	0.03
	2	0.06	0.05
	3	0.06	0.08
	4	0.06	0.1
NDIESEL	1	0.175	0.06
	2	0.175	0.09
NLV8	1	0.05	0.02
NLVR11	1	0.05	0.02
NLV3	1	0.05	0.02
NLV10	1	0.05	0.02
NLVR6	1	0.05	0.02

Table B-VI: Active Power Bids for the Reserve Market (Hour 21:00)

Bus Name	***Block No.***	***Quantity [MW]***	***Price [€/MW]***
NMVCHP	1	0.114	0.08
	2	0.114	0.1
	3	0.114	0.11
	4	0.038	0.13
NMVHYD	1	0.12	0.03
	2	0.06	0.05
	3	0.06	0.08
	4	0.06	0.1
NDIESEL	1	0.175	0.06
	2	0.175	0.09
NLV8	1	0.05	0.02
NLVR11	1	0.05	0.02
NLV3	1	0.05	0.02
NLV10	1	0.05	0.02
NLVR6	1	0.05	0.02

Table B-VII: Active Power Bids for the Reserve Market (Hour 22:00)

Bus Name	***Block No.***	***Quantity [MW]***	***Price [€/MW]***
NMVCHP	1	0.15	0.08
	2	0.15	0.1
	3	0.15	0.11
	4	0.05	0.13
NMVHYD	1	0.16	0.03
	2	0.08	0.05
	3	0.08	0.08
	4	0.08	0.1
NDIESEL	1	0.19	0.06
	2	0.19	0.09
NLV8	1	0.05	0.02
NLVR11	1	0.05	0.02
NLV3	1	0.05	0.02
NLV10	1	0.05	0.02
NLVR6	1	0.05	0.02

Table B-VIII: Active Power Bids for the Reserve Market (Hour 23:00)

Bus Name	***Block No.***	***Quantity [MW]***	***Price [€/MW]***
NMVCHP	1	0.18	0.08
	2	0.18	0.1
	3	0.18	0.11
	4	0.06	0.13
NMVHYD	1	0.28	0.03
	2	0.14	0.05
	3	0.14	0.08
	4	0.14	0.1
NDIESEL	1	0.245	0.06
	2	0.245	0.09
NLV8	1	0.06	0.02
NLVR11	1	0.06	0.02
NLV3	1	0.06	0.02
NLV10	1	0.06	0.02
NLVR6	1	0.06	0.02

Adjustment Market and Provision of Reactive Power/Voltage Control Support, Active Loss Balancing and Demand Curtailment Services in MicroGrids

Table of Contents

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 is given in Figure 1.1. In order to ensure its proper operation it is necessary to implement decentralized control mechanisms as illustrated in Figure 1.2. This involves local controlling devices associated with the microgrid generation sources and loads as well as a Microgrid Central Controller, MGCC, installed in the MV/LV substation.

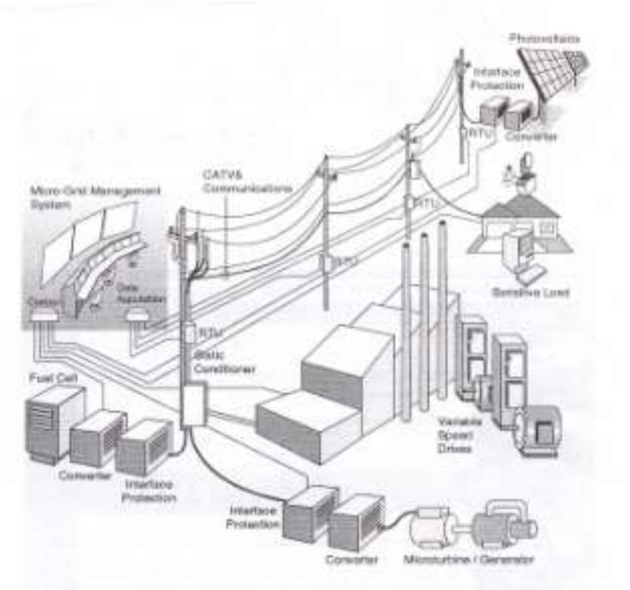

Figure 1.1– Typical microgrid system.

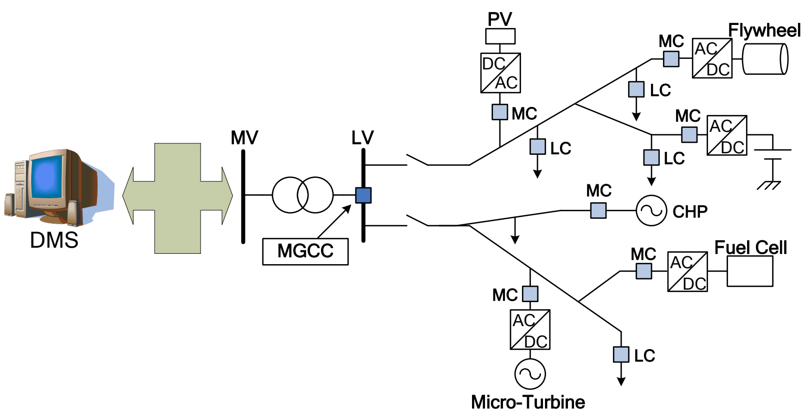

Figure 1.2 – Microgrid control architecture.

Apart from this, the development of market mechanisms in the electricity sector encourages the development of tools to allow the integration of the microgrid sources and loads in markets. This can correspond to a new feature to be installed in the MGCC in order to allow it to communicate generation and demand bids to the Market Operator, MO. This feature can be seen as an automatic one in the sense that it should parameterized once the characteristics of the microgrid sources and the elasticity of the demand are known. From an economic point of view, this ultimately means that, apart from other functions, the MGCC also acts as an interface between the microgrid and the MO.

Once the MO runs the hourly day ahead uniform price auctions, it communicates the results to the MGCC that should then act as a System Operator in terms of validating from a technical point of view this hourly economic schedule. This implies, for instance, running AC Power Flow problems for each hour of the next day in order to evaluate nodal voltages and branch flows, namely to check if they assume feasible values. If that is not the case, that is, if one branch flow or voltage magnitude violates its limits then it will be activated an Adjustment Market based on adjustment bids communicated by the microgrid sources and loads. This means identifying the set of changes on the pure economic schedule obtained by the Market Operator so that technical operation feasibility is regained inside the microgrid, providing that one is changing as little as possible in the economic schedule provided by the MO. This reasoning is justified in view of the fact that schedule obtained by the MO is optimal from the economic point of view and so one should only change it if that is required from a technical point of view.

Given this generic architecture and function assignment, this report details 4 models to be used by the MGCC in the scope of its System Operator functions to conduct these technical validation studies. These models are based on the mentioned adjustment bids communicated by the microgrid sources and loads and aim at identifying the set of changes on the MO schedule that turn the dispatch feasible while allocating the active power to compensate active losses inside the microgrids and assigning the reactive power/voltage control.

The original model has an AC nature, and so it was adopted a Sequential Linear Programming, SLP, technique that sequentially runs an AC Power Flow problem to get an operation point of the microgrid, runs a linearized optimisation problem to obtain active power generation and demand adjustments, and runs again an AC Power Flow problem to update the operation point till convergence is obtained. Once this is reached, one obtains the final generation and demand profile, the load curtailment values if they are required from a technical point of view or because they correspond to a cheap strategy given the price included in the corresponding adjustment bids, the voltage profile, the reactive power generation values and the allocation of active power to compensate active losses.

The first two models to be detailed in Section 2 correspond to the implementation of these ideas. They were then improved recognizing that some constraints display a soft nature, as it is in fact recognized in several grid codes. This is the case of voltage limit constraints and branch flow limits. In view of these, Models 1 and 2 were improved to Models 3 and 4 adopting fuzzy membership functions to represent the degree of satisfaction of complying with a constraint. In this case, the objective function of the initial Models 1 and 2 is converted in a constraint using an aspiration level for it and the new objective to attain in Models 3 and 4 corresponds to the maximization of the satisfaction degree of complying with the soft constraints. This means that Models 3 and 4 correspond to fuzzy linear optimisation models.

In view of this, these models have a number of features:

- They are based on market mechanisms, thus increasing the transparency of the process;
- They represent a new set of functions that can be assigned to the MGCC, in terms of acting as an interface with the MO and being responsible for the activation of the microgrid internal adjustment market. This corresponds to run one of the models, Models 1 to 4, to be detailed in Section 2;
- This adjustment market is based in adjustment bids submitted by the microgrid generation sources and loads. Allowing the participation of the demand corresponds to recognize that in some cases they can play a significant role to help enforcing system constraints (as voltage limits or branch flow limits). This ultimately means that the developed models help turning electricity markets more symmetric since the elasticity of the demand can be improved;
- On the other hand, the developed models output the allocation of reactive power along the microgrid sources as well as the allocation of the active power required to balance active losses inside the microgrid. These features can serve as the basis to the development of ancillary service markets since it is available a

transparent and systematic way of allocating these two services by the microgrid providers;

- Finally, Models 3 and 4 recognize the possibility of violating crisp voltage and branch flow limits modelling them as soft constraints using Fuzzy Set concepts. This enlarges the flexibility of operating the microgrid, given that it is usual that some violations are acceptable provided that they do not last more than a specified period of time.

Apart from this introductory Section, this report details the four adjustment market models in Section 2, describes the test network in Section 3, describes the case study that was used to illustrate the developed models in Section 4 and includes final comments and conclusions in Section 6.

2. Development of the Mathematical Models

2.1 General Description of the Models

Electricity is not an easily marketable product or, in other words, it is far from being a true commodity. This is due to a number of reasons, namely it is not possible to store it in large quantities, it must be produced at the same time it is consumed, physical laws determine power system operation and there is a network that often prevents the implementation of optimal economic generation strategies. Apart from that, in most countries the technical characteristics and technologies in the generation mix are very different, the time lag between the decision to build an asset and its commissioning is usually large and finally the demand still displays a very inelastic behaviour regarding price changes.

In this scope, it is also important not to forget that when addressing electricity markets one usually refers to active power markets, neglecting for instance reactive power/voltage control. The lack of attention paid to reactive power is explained because it is not so directly priced as active power and, in any case, there is the idea that its price is much more reduced when compared with the active power price. However, active and reactive powers are inherently married for a large number of reasons namely:

- The operation of synchronous generators is determined by capability PQ diagrams. This means that a reactive power requirement issued by the System Operator may be unfeasible given the active power already scheduled by the Market Operator. If the active output is reduced, the income of that generator will decrease regarding the value expected from the daily market, leading to what is known as an opportunity cost;
- Secondly, active and reactive powers are coupled in terms of the AC power flow equations and both of them lead to the branch flows used to evaluate branch thermal limits;
- Finally, reactive power is closely linked with voltage control and their local nature is well known as well as their importance to ensure the secure operation of power systems. This means that in several cases more costly bids originally not

accepted in the day-ahead market may have to be used to enforce branch limits or to alleviate voltage constraints.

As a result, the coupling between active and reactive power should be adequately modelled and internalized in several models because several market implementations are just based on a sequence of activities that may not reflect in an adequate way the characteristics of electricity. In view of this, in this report we detail an approach to remarry to a certain extent active and reactive powers while retaining competitive aspects. This approach is based on the economic dispatch prepared by the Market Operator together with the Bilateral Contract injections. The System Operator evaluates this set of injections and if they lead to an unfeasible operation point, it uses adjustment supply and demand bids to identify a new dispatch that minimizes branch active losses together with the cost of these adjustments. This strategy aims at ensuring that the final active dispatch is as close as possible regarding the initial one. This means that the initial active injections will only be changed if that is required from a technical point of view thus contributing to ensure the transparency of the whole procedure. The results include the final active and reactive dispatch, the generator adjustments required to enforce voltage or branch limit constraints, the generator adjustments needed to balance branch active losses and eventual load curtailment if that is required to enforce constraints or if that strategy becomes attractive given the adjustment bid price of the demand.

2.2 Market Operator Initial Economic Dispatch

Typical electricity markets are organized in terms of a set of activities that are usually assigned to different entities. In day n-1 the Market Operator receives selling and buying bids from market agents that, in their simplest version, Simple Bids, include pairs (quantity, price). The Market Operator orders selling bids by the ascending order of its price and buying bids in the descending order of the corresponding price so that they are built the aggregated generation and demand curves for the trading period under analysis. The intersection of these two curves leads to the Clearing Quantity and to the Clearing Price, interpreted as the short-term marginal price of the generation system.

This problem can be modelled by (2.1) to (2.4). In this formulation Cd_j and Cg_i are the buying and selling prices, Pd_j^{bid} and Pg_i^{bid} are the maximum demand and generation bid quantities, Pd_j and Pg_i are the demand and generation at the final solution, that is the decision variables of the problem, and Nd and Ng are the number of buying and selling bids. The objective function Z in (2.1) corresponds to the Social Welfare Function, and in graphical terms it represents the area between the aggregated demand and generation curves. This objective function is subjected to limits on the demand (2.2) and on the generation (2.3) and to a demand / supply balance equation (2.4).

$$\max\ Z = \sum_{j=1}^{Nd} Cd_j . Pd_j - \sum_{i=1}^{Ng} Cg_i . Pg_i \tag{2.1}$$

$$\text{subj to } 0 \le Pd_j \le Pd_j^{bid} \tag{2.2}$$

$$0 \le Pg_i \le Pg_i^{bid} \tag{2.3}$$

$$\sum_{j=1}^{Nd} Pd_j = \sum_{i=1}^{Ng} Pg_i \tag{2.4}$$

As a result of solving this problem, we get the economic dispatch in terms of generations and demands that once accepted by the dispatch maximize the Social Welfare Function given by (2.1). This function represents the surplus between the benefit that demand can take from using electricity and the generation cost. Apart from the economic dispatch, we can also obtain the corresponding system marginal price because it is associated with the dual variable of the balance equation (2.4). In the following sections this price is denoted by λ.

The above problem uses simple bids and it corresponds to a single step formulation that can be enhanced in several ways. In the first place, generators can be allowed to transmit to the Market Operator bids structured in a number of blocks as sketched in Figure 2.1.

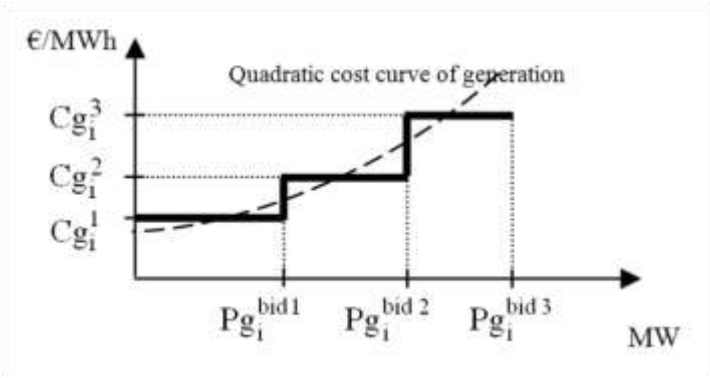

Figure 2.1 - Selling bids organized in blocks.

Admitting the organization of selling bids in blocks allows generation agents to better follow the generators' cost curve and eventually the first block can be declared indivisible. Indivisibility means that, if scheduled by the Market Operator, the first block should be entirely dispatched. This can be used to cope with minimum technical limits of thermal generators. On the other hand, generators can also include in their bids information about up and down ramps, for instance, that transforms the initially independent 24 hourly schedules into a single coupled problem. This would mean passing from Simple Bids to Complex Bids, as this concept is usually termed in the literature.

In the developed models we used simple selling bids having block structure. This means that generator bids include information about blocks and the corresponding selling prices and the demand communicates bids including powers and buying prices.

2.3 Synchronous Generator Capability Diagram

The operation of synchronous generators is characterized by coupled active/reactive power diagrams as the one sketched in Figure 2.2.

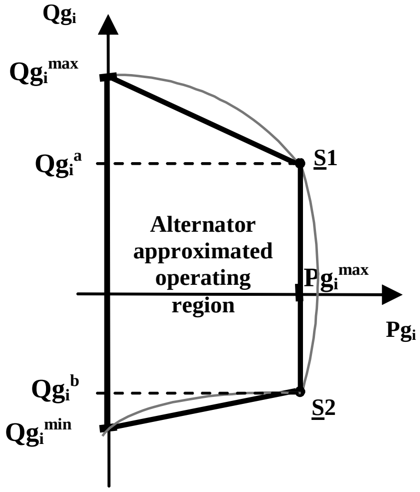

Figure 2.2 - Synchronous generator capability diagram.

This diagram delimits the generator feasible operation points in the PQ plan. The limiting curve results from the combination of the curves associated with different constraints determining the operation of synchronous generators. In this case, we modelled the capability diagram of Figure 2.2 using the following three curves:

- Curve 1, between $Qg_i^{\max}$ and $\underline{S}_1$, represents the rotor field current limit;
- Curve 2, from $\underline{S}_1$ to $\underline{S}_2$, is the armature limit;
- Curve 3, the arc between $Qg_i^{\min}$ and $\underline{S}_2$, represents the stability limit.

These curves can be approximated by linear expressions, as it will be used in Sections 2.4 and 2.5. Given this diagram, it is important to realize that a reactive power requirement can be unfeasible, even if both the P and the Q individual and separate limits are not violated. This fact is important because the Market Operator can assign a particular generator a P schedule that turns unfeasible the Q requirement issued afterwards by the System Operator. This problem is even more relevant given that reactive power has a well-known local nature and in some cases a particular generator must in fact provide reactive power due to voltage considerations and to its particular location in the network. In this case, if the active power output regarding the Market Operator schedule has to be reduced, then the expected revenue of that generator is also reduced. This corresponds to the opportunity cost mentioned in several publications and it becomes obvious that electricity markets should be designed in a way to provide some sort of compensation if such situations occur.

In the developed models, the System Operator must know the data characterizing the capability diagram of each generator so that it is possible to formulate equations for the curves indicated above. This includes the values of the following parameters: $Pg_i^{\max}$, $Qg_i^{\max}$, $Qg_i^{\min}$, Qg_i^{a} and Qg_i^{b}.

2.4 Generator Adjustment Bids

The developed models use the economic schedule prepared by the Market Operator together with the injections from Bilateral Contracts as the initial information to be validated by the System Operator, the MGCC in this case. In view of this information, if no operation or security constraint is violated this set of Market Operator and Bilateral Contract injections are technically feasible. However, they may have to be changed if there is congestion or if voltage limit constraints are violated. In this case, the System Operator activates a secondary market, an Adjustment Market, which uses adjustment bids both from generators and loads. This way, it will be possible to conduct this technical study in a transparent way because it is based on a competitive mechanism.

Generator adjustment bids are sent to the System Operator and include the acceptable maximum variation, vg_i^{tol}, that the Market Operator based schedule or the Bilateral Contract generations can suffer together with the adjustment price, Cg_i^{A}.

In case a generator was not originally dispatched, its maximum possible adjustment can correspond to a percentage of its installed capacity. If this generator is required by the System Operator to help solving some system constraint its revenue will then correspond to the product of the adjustment price by the allocated power meaning that it is not explicitly present any fixed start up cost. In order not to destroy the continuity of the problem, such start up cost could be diluted in the value of the offered adjustment price. Alternatively, considering an explicit start up cost would require the use of binary variables and more time-consuming solution techniques.

2.5 Demand Adjustment Bids

The regulatory framework in force in several power systems already includes the possibility of reducing load if that is required to ensure the security of the system.

These mechanisms are known as interruptible contracts and they include some sort of compensation for loads that admit providing this service. This concept is based on the fact that power system constraints can be alleviated not only by re-dispatching generation but also in some cases if one admits load adjustments. Using this concept, load adjustment bids include information regarding the maximum reduction a load admits to be curtailed regarding the amount scheduled by the Market Operator or related to a Bilateral Contract, as well as the corresponding adjustment price.

This information is sent to the agent responsible for system operation so that this entity knows all the available resources of this nature. This entity will then eventually accept some of these bids depending on the violated constraints and on the relation of prices included in the adjustment generation and demand bids. This certainly increases the flexibility that the System Operator has to regain feasibility apart from increasing the competition and liquidity of this secondary adjustment market creating the conditions to increase the participation of the demand.

2.6 Crisp Linearized Models

2.6.1 Model 1 – Model using Adjustment Bids

The model to be described in this section corresponds to an integrated AC dispatch problem that uses the active power economic dispatch obtained by the Market Operator. The original model is non linear namely due to non linear AC injected power expressions and to the non linear nature of the capability diagram of synchronous generators. However, the model to be described corresponds to a linearized version in which the non linear expressions are linearized using an operation point obtained by solving an AC Power Flow problem. This means that the solution algorithm uses a Sequential Linear Programming (SLP) strategy in which:

- In the first place, it is obtained a first operation point using the active power economic dispatch identified by the Market Operator. This active power dispatch is complemented by running an AC Power Flow problem in order to obtain nodal voltages and phases as well as branch flows and reactive powers;
- If there is at least a nodal voltage or a branch flow violation it will be run the problem to be described in order to identify a set of active power deviations (either in terms of generation and/or demand) so that the violated constraints

are enforced. The results of this problem will the active and reactive generation and demand deviations regarding the previous operation point;

- Since the optimization problem mentioned in the previous step has a linear nature, its output will have to be corrected by running a new AC Power Flow problem. This new operation point will be used as a new linearization point. This defines an iterative process, in terms of the SLP procedure, that will converge when the absolute value of all power deviations are smaller than a specified threshold.

The linear problem to be solved in each iteration of the SLP procedure sketched above will now be detailed admitting a system having Ng generators, Nc loads and Nl branches.

$$Min\ Z = \sum_{k=1}^{Nl} \Delta Pperd_k(\Delta V, \Delta\theta) \cdot \lambda + \sum_{i=1}^{Ng} |\Delta Pg_i| \cdot Cg_i^{ajt} + \sum_{j=1}^{Nc} |\Delta Pc_j| \cdot Cc_j^{ajt} \tag{2.5}$$

Subject to:

$$\Delta V_i^{\min} \le \Delta V_i \le \Delta V_i^{\max} \tag{2.6}$$

$$\Delta\theta_{ij}^{\min} \le \Delta\theta_{ij} \le \Delta\theta_{ij}^{\max} \tag{2.7}$$

$$\Delta Pg_i^{\min} \le \Delta Pg_i \le \Delta Pg_i^{\max} \tag{2.8}$$

$$-\frac{vg_i^{tol}}{100} \cdot Pg_i \le \Delta Pg_i \le \frac{vg_i^{tol}}{100} \cdot Pg_i \tag{2.9}$$

$$0 \le \Delta Pg_i \le \frac{vg_i^{tol}}{100} \cdot Pg_i^{\max} \tag{2.10}$$

$$-Pc_j \le \Delta Pc_j \le 0 \tag{2.11}$$

$$Qg_i \ge Qg_i^{\min} + \frac{Qg_i^b - Qg_i^{\min}}{Pg_i^{\max}} \cdot (Pg_i + \Delta Pg_i) \tag{2.12}$$

$$Qg_i \le Qg_i^{\max} - \frac{Qg_i^{\max} - Qg_i^a}{Pg_i^{\max}} \cdot (Pg_i + \Delta Pg_i) \tag{2.13}$$

$$\Delta P_i\ (\Delta V, \Delta\theta) = \Delta Pg_i - \Delta Pc_i \tag{2.14}$$

$$\Delta Q_i\ (\Delta V, \Delta\theta) = \Delta Qg_i - \Delta Qc_i \tag{2.15}$$

$$\Delta S_{ij}^{\min} \le \Delta S_{ij}(\Delta V, \Delta\theta) \le \Delta S_{ij}^{\max} \tag{2.16}$$

The objective function of this formulation (2.5) minimizes the sum of the following three terms:

- Cost of the loss deviations in each branch computed using the voltage and phase deviations. This sum is multiplied by the uniform price, λ, obtained in the Uniform Price Auction conducted by the Market Operator for each hour of operation in the next day;
- Cost of the generator deviations. These generator deviations are multiplied by the corresponding generator deviation bid cost;
- Cost of the demand deviations. These demand deviations are multiplied by the corresponding demand deviation bid cost.

The model includes the following constraints:

- Constraints (2.6) to (2.8) impose minimum and maximum limits to the voltages, to nodal phase differences and to the active powers of generators or related to the interconnection node of upper voltage level networks;
- Constraints (2.9) to (2.11) represent the limits allowed to the adjustments of the dispatched generators, of the generators that were not dispatched and of the loads dispatched in the day-ahead market. In this scope, vg_i^{tol} represents, in percentage, the maximum adjustment that can affect the power output of a generator. This means that for the dispatched generators, their output can increase or decrease according to the value of vg_i^{tol} that was specified (2.9). For the generators that were not dispatched, its output can raise to the percentage vg_i^{tol} of its capacity (2.10) and regarding the load in node j, its value can decrease from the dispatched amount to zero representing the possibility of load curtailment according to the operation needs of the entity in charge of system operation;
- Constraints (2.12) and (2.13) represent the linearized models of the lower and upper curves of the capability diagram of the synchronous generator connected to node i. These expressions were obtained according to Figure 2.2 considering that:

- for Curve 1, constraint (2.13), it was calculated the linear expression knowing the following pair of points: (0, $Qg_i^{\max}$) and (Qg_i^b, $\underline{S}_2$);
- for Curve 2, a vertical line, the corresponding constraint is modelled by a maximum active power constraint as for instance (2.8) provided that the limit is set according to Figure 2.2;
- for Curve 3, constraint (2.12), it was calculated the linear expression knowing the following pair of points: (0, $Qg_i^{\min}$) and ($\underline{S}_2$, Qg_i^b);

- Constraints (2.14) and (2.15) represent linearized expressions for the AC injected active and reactive nodal power equations written in terms of the active and reactive power deviations and in terms of the voltage and phase deviations. These linearized expressions are established using the Taylor Series of the corresponding exact expression and the operation point obtained from the previous AC Power Flow problem;
- Finally, constraints (2.16) correspond to the minimum and maximum limits of the apparent power flow in branch ij. The expression for ΔS_{ij} is established in terms of the voltage and phase in the extreme nodes of that branch and it is a linearized expression obtained from the Taylor Series of the exact expression, considering the operation point obtained in the previous AC Power Flow problem.

As a result, when the SLP procedure converges, we will get a feasible operation point both from the point of view of nodal voltages and branch flows together with the corresponding active and reactive dispatch and the allocation of active power losses by the generation system. In any case, this new dispatch is as close as possible regarding the active power economic dispatch input by the Market Operator because any change regarding this initial dispatch is penalized in the objective function (2.5) using the generation and demand adjustment bid costs.

2.6.2 Model 2 – Model with Loss Allocation and Adjustment Bids

In this section the model formulated in section 2.6.1 will be enhanced in order to explicitly model the contribution of each generator to balance active power losses. This means that apart from addressing Reactive Power/ Voltage Support Ancillary service we are now also contributing to better define the active power loss balancing service determining in an accurate way the contribution of each generator to provide this service and computing the respective remuneration. Once again, the formulation (2.17) to (2.30) admits a system having Ng generators, Nc loads and Nl branches.

$$Min\ Z = \sum_{i=1}^{Ng} \Delta Pg_i^{perd} \cdot \lambda + \sum_{i=1}^{Ng} |\Delta Pg_i^{ajt}| \cdot Cg_i^{ajt} + \sum_{j=1}^{Nc} |\Delta Pc_j| \cdot Cc_j^{ajt} \tag{2.17}$$

Subject to:

$$\Delta V_i^{\min} \le \Delta V_i \le \Delta V_i^{\max} \tag{2.18}$$

$$\Delta \theta_{ij}^{\min} \le \Delta \theta_{ij} \le \Delta \theta_{ij}^{\max} \tag{2.19}$$

$$0 \le \Delta Pg_i^{perd} \le \Delta Pg_i^{\max} \tag{2.20}$$

$$-\frac{vg_i^{tol}}{100} \cdot Pg_i \le \Delta Pg_i^{ajt} \le \frac{vg_i^{tol}}{100} \cdot Pg_i \tag{2.21}$$

$$0 \le \Delta Pg_i^{ajt} \le \frac{vg_i^{tol}}{100} \cdot Pg_i^{\max} \tag{2.22}$$

$$\Delta Pg_i^{\min} \le \Delta Pg_i^{ajt} + \Delta Pg_i^{perd} \le \Delta Pg_i^{\max} \tag{2.23}$$

$$-Pc_j \le \Delta Pc_j \le 0 \tag{2.24}$$

$$Qg_i \ge Qg_i^{\min} + \frac{Qg_i^b - Qg_i^{\min}}{Pg_i^{\max}} \cdot (Pg_i + \Delta Pg_i^{ajt} + \Delta Pg_i^{perd}) \tag{2.25}$$

$$Qg_i \le Qg_i^{\max} - \frac{Qg_i^{\max} - Qg_i^a}{Pg_i^{\max}} \cdot (Pg_i + \Delta Pg_i^{ajt} + \Delta Pg_i^{perd}) \tag{2.26}$$

$$\sum_{k=1}^{Nl} \Delta Pperd_k(\Delta V, \Delta\theta) = \sum_{i=1}^{Ng} \Delta Pg_i^{perd} \tag{2.27}$$

$$\Delta P_i(\Delta V, \Delta\theta) = (\Delta Pg_i^{ajt} + \Delta Pg_i^{perd}) - \Delta Pc_i \tag{2.28}$$

$$\Delta Q_i(\Delta V, \Delta\theta) = \Delta Qg_i - \Delta Qc_i \tag{2.29}$$

$$\Delta S_{ij}^{\min} \le \Delta S_{ij}(\Delta V, \Delta\theta) \le \Delta S_{ij}^{\max} \tag{2.30}$$

The objective function (2.17) minimizes the global adjustment cost required to the turn the operation of the system feasible, namely in terms of generator and/or demand variations regarding the values obtained in the initial Market Operator economic dispatch. This global cost is the result of the addition of three terms, as follows:

- The first term in (2.17) represents the cost associated with the generator active power deviations in order to balance active losses. This cost is given by the product of the cost of this power by the contribution of each generator to compensate losses, ΔPg_i^{perd}. In this formulation, we admitted that active power losses are priced at the system marginal price, λ, as defined in Section 2.2;
- The second and the third terms correspond to the deviations costs associated to the active generated power and to the demand regarding the base program inherent to the initial dispatch obtained by the Market Operator. These costs are expressed by the product of the adjusted amounts by the respective adjustment costs.

Therefore, and comparing this formulation with the one in Section 2.6.1, there are now two types of active power adjustment variables. The first ones, ΔPg_i^{perd}, represent in an individual way the contribution of each generator or connection with upper voltage level networks to balance the system active power losses. The second ones, ΔPg_i^{ajt}, model the active power generation adjustments of generator i regarding the value obtained by the Market Operator and required to eliminate branch congestion or required to diminish the active power output in order to increase the reactive power to a level required by the System Operator namely to enforce voltage constraints. This separation in ΔPg_i^{perd} and ΔPg_i^{ajt} adjustment variables allows one to assign, for instance, the active power to balance active losses to the more adequate generators from the system point of view, thus enabling defining and remunerating this ancillary service in a better and more transparent way.

The mentioned objective function is now subjected to the following constraints:

- Constraints (2.18) and (2.19) represent the minimum and maximum limits of the nodal voltage variations and of the phase difference between pairs of nodes;
- The active power of each generator i can vary regarding the initial value to contribute to balance active losses, ΔPg_i^{perd}, and/or due to adjustments required to enforce system constraints, ΔPg_i^{ajt}. In this scope, constraint (2.20) imposes the limit to the contribution of each generator to balance active losses and constraints (2.21) and (2.22) impose the technical or operational limits of the

adjustments of the generators that were dispatched and not dispatched by the Market Operator. On the other hand, constraints (2.23) establish the limits for the addition of these two types of active power deviations and constraints (2.24) represent the feasible adjustment of each active power demand. In line with what was detailed in Section 2.5, demand adjustments will always be associated to load curtailment;

- Constraints (2.25) and (2.26) correspond to the lower and upper curves that delimit the capability diagram of each generator, that is to linear segments approximating the real non linear Curves 3 and 1 sketched in Figure 2.2;
- Constraint (2.27) corresponds to the balance between the total active power losses and the active power losses assigned to each generator. This constraint was established in a way that in each cycle of the SLP the sum of the deviations of active losses in each branch is equal to the addition of the adjustment variables representing the contribution of each generator to balance active losses, ΔPg_i^{perd}. The active power loss deviation in each branch is computed using a linearized expression resulting from the application of the Taylor Series to the exact expression of the active power losses, in which the values of the partial derivatives are computed using the operation point obtained by the AC Power Flow study, in the scope of the SLP procedure;
- Constraints (2.28) and (2.29) are related with the linearized expressions of the active and reactive injected powers for node i. These linear expressions are established using the respective Taylor Series computed for the operation point obtained with the previous AC Power Flow problem;
- Finally, constraints (2.30) impose the minimum and maximum limits for the apparent power in branch ij.

2.7 Fuzzy Linearized Models

2.7.1 Soft Limits

Some operation limits allow some degree of violation without placing problems for power system operation and some grid codes indicating rules for power system operation include larger branch flow limits provided that these operation situations are limited in time. This suggests representing voltage and branch flow constraints using Fuzzy Sets as it will be detailed below. For instance, regarding the limit of a branch flow, we admit a leeway as illustrated in Figure 2.3. In this case, the membership function of the flow x is 1.0 if it is not larger than x_1. From x_1 to x^{max} the membership level decreases till 0.0. This membership function can be modelled by (2.31).

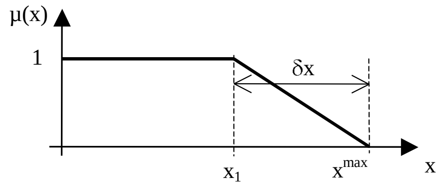

Figure 2.3 - Membership function of the limit of a variable x.

$$\mu(x)=\begin{cases}1 & \text{if } x \le x_1\\ ]0;1[& x_1 < x \le x^{max}\\ 0 & \text{if } x > x^{max}\end{cases} \tag{2.31}$$

In a similar way, Figure 2.4 represents the membership function of the voltage in node i. Voltages from V_{i1} to V_{i2} have the maximum membership degree. Voltages lower than V_{i1} or higher than V_{i2} can be still accepted but their membership values decrease from 1.0 to 0.0 till V_i^{min} and V_i^{max}. Expression (2.32) represents this fuzzy membership function.

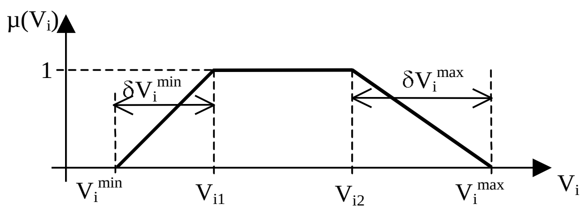

Figure 2.4 - Membership function of voltage limits.

$$\mu(V_i)=\begin{cases}1 & \text{if } V_{i1} \le V_i \le V_{i2}\\ ]0;1[& \text{if } V_i^{min} \le V_i < V_{i1} \text{ or } V_{i2} < V_i \le V_i^{max}\\ 0 & \text{if } V_i < V_i^{min} \text{ or } V_i > V_i^{max}\end{cases} \tag{2.32}$$

2.7.2 Model 3 – Fuzzy Model using Adjustment Bids

This model corresponds to an integrated PQ dispatch formulation that includes several soft constraints, resulting in a fuzzy linear programming problem. This model, in line with the models detailed in Sections 2.6.1 and 2.6.2, is developed in a pool market environment that admits that the Market Operator ran in the first place an Uniform Price Auction determining a purely economic dispatch and the corresponding system marginal price, λ. As a result, Model 3 detailed in this section corresponds to the fuzzy version of Model 1 detailed in Section 2.6.1.

Once the initial purely economic dispatch obtained by the Market Operator is known, the System Operator solves the problem (2.34) to (2.49) aiming at maximizing the satisfaction degree μ related with the membership function of the relaxed constraints and with the objective function of the original deterministic problem given by (2.33).

$$FO = \sum_{k=1}^{Nl} \Delta Pperd_k(\Delta V, \Delta\theta) \cdot \lambda + \sum_{i=1}^{Ng} |\Delta Pg_i| \cdot Cg_i^{ajt} + \sum_{j=1}^{Nc} |\Delta Pc_j| \cdot Cc_j^{ajt} \tag{2.33}$$

This expression includes two sets of terms. The first summation corresponds to the active power losses in the Nl branches of the system expressed in terms of voltage and phase variations. As in Model 1, we also admit that the power required to balance active losses is priced at the system marginal price, λ, obtained in the daily market. The second and third terms are related with the adjustment costs of generators and loads and they include the product of the adjustment variables by the adjustment bid costs offered by each agent.

Using a formulation similar to the one detailed for the soft constraints, the objective function (2.33) is converted in constraint (2.35) in which $\mathrm{FO}^{\mathrm{des}}$ represents the maximum value that the objective function can assume for the satisfaction degree of 1 and δ^{FO} is the admitted tolerance.

$$Max\ \mu \tag{2.34}$$

Subject to:

$$FO + \mu \cdot \delta^{FO} \leq FO^{des} + \delta^{FO} \tag{2.35}$$

$$\Delta V_i - \mu \cdot \delta^{V\min} \geq \Delta V_i^{\min} - \delta^{V\min} \tag{2.36}$$

$$\Delta V_i + \mu \cdot \delta^{V\max} \leq \Delta V_i^{\max} + \delta^{V\max} \tag{2.37}$$

$$\Delta\theta_{ij}^{\min} \leq \Delta\theta_{ij} \leq \Delta\theta_{ij}^{\max} \tag{2.38}$$

$$\Delta Pg_i^{\min} \leq \Delta Pg_i \leq \Delta Pg_i^{\max} \tag{2.39}$$

$$-\frac{vg_i^{tol}}{100} \cdot Pg_i \leq \Delta Pg_i \leq \frac{vg_i^{tol}}{100} \cdot Pg_i \tag{2.40}$$

$$\Delta Pg_i \leq \frac{vg_i^{tol}}{100} \cdot Pg_i^{\max} \tag{2.41}$$

$$Qg_i \geq Qg_i^{\min} + \frac{Qg_i^b - Qg_i^{\min}}{Pg_i^{\max}} \cdot (Pg_i + \Delta Pg_i) \tag{2.42}$$

$$Qg_i \leq Qg_i^{\max} - \frac{Qg_i^{\max} - Qg_i^a}{Pg_i^{\max}} \cdot (Pg_i + \Delta Pg_i) \tag{2.43}$$

$$-Pc_j \leq \Delta Pc_j \leq 0 \tag{2.44}$$

$$\Delta S_{ij}(\Delta V, \Delta\theta) \geq \Delta S_{ij}^{\min} \tag{2.45}$$

$$\Delta S_{ij}(\Delta V, \Delta\theta) + \mu \cdot \delta_{ij}^{S_{ij}} \leq \Delta S_{ij}^{\max} + \delta_{ij}^{S_{ij}} \tag{2.46}$$

$$\Delta P_i\ (\Delta V, \Delta\theta) = \Delta Pg_i - \Delta Pc_i \tag{2.47}$$

$$\Delta Q_i\ (\Delta V, \Delta\theta) = \Delta Qg_i - \Delta Qc_i \tag{2.48}$$

$$0 \leq \mu \leq 1 \tag{2.49}$$

In this formulation constraints (2.36) and (2.37) represent the minimum and maximum limits of the voltage magnitudes admitting leeways δ^{Vmin} and δ^{Vmax}, constraints (2.38) imposes limits for phase differences and (2.39) imposes the global limits for the generator deviations. For the generators dispatched by the Market Operator, constraints (2.40) impose the adjustment limits considering the tolerance

vg_i^{tol} and the base generation program obtained by the Market Operator, Pg_i. For the generators not dispatched by the Market Operator, constraints (2.41) represent the maximum possible adjustment in its output. Constraints (2.42) and (2.43) correspond to the limits of reactive power of the generators according to their linearized capability diagrams, and constraints (2.44) impose the limits on load adjustments. Constraint (2.45) imposes the minimum limit (zero MVA) to the apparent power flow in branch ij and constraints (2.46) represents the relaxed version of the maximum limit of the apparent power in that branch admitting the leeway δ_{ij}^{Sij}, as sketched in Figure 2.5.

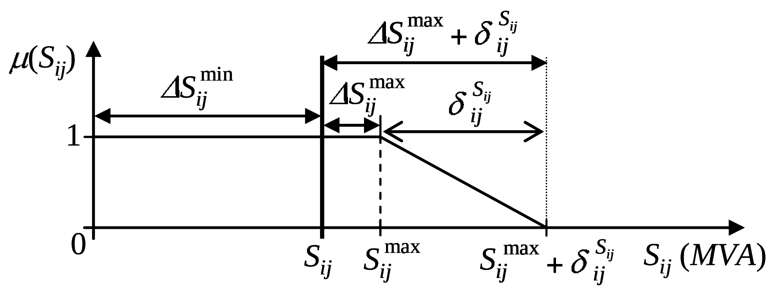

Figure 2.5 – Membership function of the apparent power in branch ij, admitting a tolerance in the value of the capacity.

Finally, constraints (2.47) and (2.48) are associated with the linearized expression for the active and reactive injected powers in node i and constraint (2.49) specifies the range of membership degrees μ, in [0,1].

2.7.3 Model 4 – Fuzzy Model with Load Allocation and Adjustment Bids

Model 4 can be interpreted as a development of Model 3, if one admits the enhancements that were explained when passing from Model 1 to Model 2. It can also be considered as the fuzzy version of Model 2 detailed in Section 2.6.2.

Admitting the first of these two interpretations, we can consider that Model 3 was developed decomposing the generator adjustment variables in two terms as follows. The first term, ΔPg_i^{perd}, represents the contribution of the generator i to compensate the active losses in the system. The second term, ΔPg_i^{ajt}, corresponds to the variation of the active power of a generator regarding the value in the initial dispatch that is required to enforce operation constraints of the system or to turn the problem feasible from the point of view of the reactive power/voltage control needs.

This decomposition originates several changes in Model 3. The original objective function (2.29) is substituted by (2.46), and constraints (2.35), (2.38), (2.39) and (2.43) will now be replaced by (2.47) to (2.50). The problem also includes a new constraint (2.51) imposing that the addition of the active power contributions of the generators to compensate active losses is equal to the addition of the losses in the branches of the system computed in terms of the deviations of voltages and phases. In the remaining constraints, the variable ΔPg_i of Model 3 is replaced by ΔPg_i^{ajt}.

$$FO = \sum_{i=1}^{Ng} \Delta Pg_i^{perd} \cdot \lambda + \sum_{i=1}^{Ng} |\Delta Pg_i^{ajt}| \cdot Cg_i^{ajt} + \sum_{j=1}^{Nc} |\Delta Pc_j| \cdot Cc_j^{ajt} \tag{2.46}$$

$$0 \le \Delta Pg_i^{ajt} + \Delta Pg_i^{perd} \le \Delta Pg_i^{\max} \tag{2.47}$$

$$Qg_i \ge Qg_i^{\min} + \frac{Qg_i^b - Qg_i^{\min}}{Pg_i^{\max}} \cdot (Pg_i + \Delta Pg_i^{ajt} + \Delta Pg_i^{perd}) \tag{2.48}$$

$$Qg_i \le Qg_i^{\max} - \frac{Qg_i^{\max} - Qg_i^a}{Pg_i^{\max}} \cdot (Pg_i + \Delta Pg_i^{ajt} + \Delta Pg_i^{perd}) \tag{2.49}$$

$$\Delta P_i\ (\Delta V, \Delta\theta) = (\Delta Pg_i^{ajt} + \Delta Pg_i^{perd}) - \Delta Pc_i \tag{2.50}$$

$$\sum_{i=1}^{Ng} \Delta Pg_i^{perd} = \sum_{k=1}^{Nl} \Delta Pperd_k (\Delta V, \Delta\theta) \tag{2.51}$$

Under these conditions, Model 4 is given by (2.52) to (2.68).

$$Max\ \mu \tag{2.52}$$

Subject to:

$$FO + \mu \cdot \delta^{FO} \le FO^{des} + \delta^{FO} \tag{2.53}$$

$$\Delta V_i - \mu \cdot \delta^{V\min} \ge \Delta V_i^{\min} - \delta^{V\min} \tag{2.54}$$

$$\Delta V_i + \mu \cdot \delta^{V\max} \le \Delta V_i^{\max} + \delta^{V\max} \tag{2.55}$$

$$\Delta\theta_{ij}^{\min} \le \Delta\theta_{ij} \le \Delta\theta_{ij}^{\max} \tag{2.56}$$

$$0 \le \Delta Pg_i^{ajt} + \Delta Pg_i^{perd} \le \Delta Pg_i^{\max} \tag{2.57}$$

$$-\frac{vg_i^{tol}}{100} \cdot Pg_i \le \Delta Pg_i^{ajt} \le \frac{vg_i^{tol}}{100} \cdot Pg_i \tag{2.58}$$

$$\Delta Pg_i^{ajt} \le \frac{vg_i^{tol}}{100} \cdot Pg_i^{\max} \tag{2.59}$$

$$Qg_i \ge Qg_i^{\min} + \frac{Qg_i^b - Qg_i^{\min}}{Pg_i^{\max}} \cdot (Pg_i + \Delta Pg_i^{ajt} + \Delta Pg_i^{perd}) \tag{2.60}$$

$$Qg_i \le Qg_i^{\max} - \frac{Qg_i^{\max} - Qg_i^a}{Pg_i^{\max}} \cdot (Pg_i + \Delta Pg_i^{ajt} + \Delta Pg_i^{perd}) \tag{2.61}$$

$$-Pc_j \le \Delta Pc_j \le 0 \tag{2.62}$$

$$\Delta S_{ij}(\Delta V, \Delta\theta) \ge \Delta S_{ij}^{\min} \tag{2.63}$$

$$\Delta S_{ij}(\Delta V, \Delta\theta) + \mu \cdot \delta_{ij}^{S_{ij}} \le \Delta S_{ij}^{\max} + \delta_{ij}^{S_{ij}} \tag{2.64}$$

$$\Delta P_i\ (\Delta V, \Delta\theta) = (\Delta Pg_i^{ajt} + \Delta Pg_i^{perd}) - \Delta Pc_i \tag{2.65}$$

$$\Delta Q_i\ (\Delta V, \Delta\theta) = \Delta Qg_i - \Delta Qc_i \tag{2.66}$$

$$\sum_{i=1}^{Ng} \Delta Pg_i^{perd} = \sum_{k=1}^{Nl} \Delta Pperd_k(\Delta V, \Delta\theta) \tag{2.67}$$

$$0 \le \mu \le 1 \tag{2.68}$$

This model can still evolve in order to include generations and demands linked by bilateral contracts. This would mean admitting two commercial frameworks – the Market Operator and Bilateral Contracts – using the same network infrastructure and so all this information should be include in the Model. Once that is done, one can still choose to admit cross adjustments between these two contractual frameworks or, on the contrary, integrate constraints imposing that each of these mechanisms – the Market Operator and the Bilateral Contracts – are closed. This would mean that a change for instance in a Market Operator dispatched generator could only be balanced by a change in another Market Operator dispatched generator or by a Market

Operator dispatched load. This formulation is more restrictive and therefore would display an adjustment cost not inferior than the cost of the initial one.

3. Test Network

The models detailed in Section 2 were tested using Case Studies based on the Test Network detailed in the reference entitled "Description of a Test Network to be used for Simulation Platform Development" and corresponding to the deliverable TD3.3 of Work Package D of this project. This network is sketched in Figure 3.1.

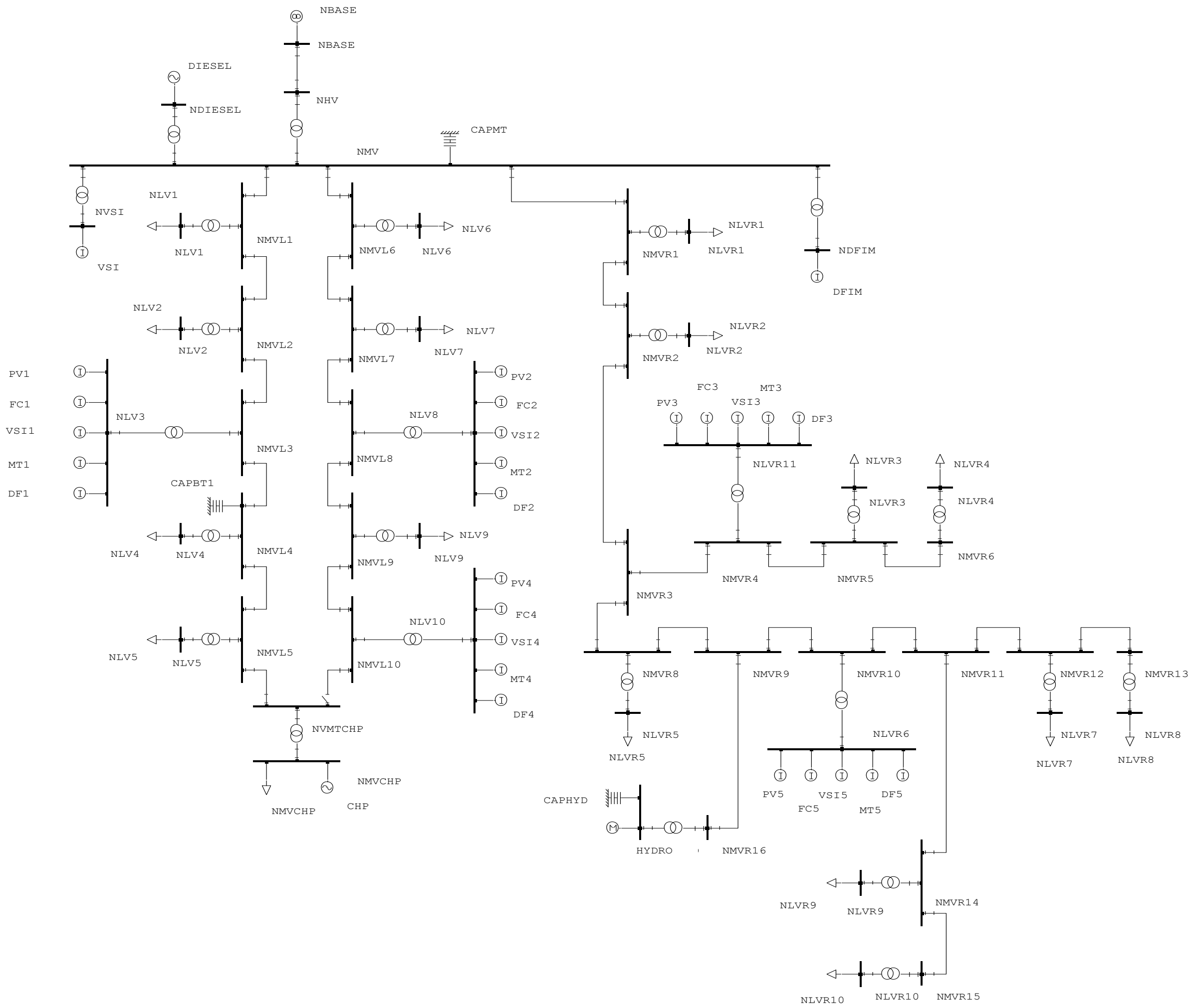

Figure 3.1 - Single line diagram of the test network.

Based on this network, the simulations were performed considering the following two networks derived from the original one, as follows:

- Test network that does not include the microgrids. In this case, the network has 50 nodes and regarding the network in Figure 3.1 they were eliminated the nodes 49 to 53 and the nodes 54 and 55 were renumbered passing to nodes 49 and 50. The required changes were also made on the connectivity data of the branches;

- Test network that includes the microgrids and respective connection transformers. This network has 55 nodes and corresponds to the one depicted in Figure 3.1.

It is also important to mention that the simulations were conducted considering Case Studies in which:

- The whole system is topologically radial, that is, in which the loop breaker connected between nodes NMVL5 and NMVL10 is opened;
- The mentioned breaker is closed creating a loop that involves NMVL1 to NMVL10 together with NMVCHP.

Finally, both test networks include capacitors connected to nodes 1 and 5 with a rated power of 2.0 Mvar and 0.5 Mvar, respectively.

The complete data for the 50 node and for 55 node networks is detailed in Annex 1, including the data for the generation/supply system, load data, and branch data. Apart from the usual technical information, this data also includes:

- The active and reactive minimum and maximum powers of each generator, required to model the respective capability diagram;
- The maximum adjustment active power and respective adjustment price of each generator;
- The adjustment price of each load, interpreted as the remuneration that each load wants to receive if it is necessary to curtail it.

4. Results of the Simulations

4.1 Description of the Simulations Performed

Using the four models detailed in Section 2 together with an AC Power Flow application and the SLP iterative process, we conducted several tests using the networks described in Section 3. These tests were run for different operating conditions of the network as it will be detailed in the next paragraphs:

Case 0-0: Distribution network operated in open loop (breaker between nodes 11 and 12 opened) and supplied by the HV/MV substation as well as by the distributed generation sources. In this case, we did not consider the microgrids. The total demand is 6.739 MW and 2.457 Mvar and the network has 50 nodes and 49 branches;

Case 0-1: Distribution network operated in closed loop (breaker between nodes 11 and 12 closed) and supplied by the HV/MV substation as well as by the distributed generation sources. In this case, we did not consider the microgrids. The total demand is 6.739 MW and 2.457 Mvar and the network has 50 nodes and 50 branches;

Case 1-0: Distribution network operated in open loop (breaker between nodes 11 and 12 opened) and supplied by the HV/MV substation as well as by the distributed generation sources and by the microgrid sources. The total demand is 6.739 MW and 2.457 Mvar and the network has 55 nodes and 54 branches;

Case 1-1: Distribution network operated in closed ring (breaker between nodes 11 and 12 closed) and supplied by the HV/MV substation as well as by the distributed generation sources and by the microgrid sources. The total demand is 6.739 MW and 2.457 Mvar and the network has 55 nodes and 55 branches;

Case 2-0: Distribution network operated in open loop (breaker between nodes 11 and 12 opened) and supplied by the HV/MV substation as well as by the distributed generation sources and by the microgrid sources. The total demand is increased by 10% regarding the demand considered in Case 1-0 and the network has 55 nodes and 54 branches;

Case 3-0: Distribution network operated in open loop (breaker between nodes 11 and 12 opened) and supplied by the HV/MV substation as well as by the distributed generation sources and by the microgrid sources. The total demand is increased by 20% regarding the demand considered in Case 1-0 and the network has 55 nodes and 54 branches.

For each of these Cases, we used the Models 1, 2, 3 and 4 detailed in Section 2 to simulate the operation conditions of the network, to validate (or to change if required) the active power economic dispatch, to assign the active power loss compensation and to assign reactive power/voltage control. This means a total of 24 simulations. The results of these simulations will be detailed in the next Section.

The data for this network is available in Tables A1, A2 and A3 of Annex A. This data is according with the information provided in the report entitled "Description of a Test Network to be used for Simulation Platform Development", MORE MICROGRIDS, WORK PACKAGE D – TD3.3.

4.2 Simulations using the Crisp Models

4.2.1 General Data

When considering the Crisp Models, Models 1 and 2 detailed in Section 2, we used the following general data:

- Voltage limits were set at 0.97 pu and 1.03 pu;
- The system marginal price obtained from the Market Operator was set at 3.0 €/MW.h. This value is well below typical current electricity market prices but it has little influence in the results given the small amount of active losses. Apart

from that, having a reduced value for the cost of active losses allows the identification of the solution of the SLP approach to be more strongly determined by the adjustment costs. This implies a large preference for solutions having little adjustments, that is, closer to active power schedule obtained by the Market Operator.

4.2.2 Model 1

4.2.2.1 Case 0-0

Using Model 1 in this Case, we obtained the following general results:

- There are no demand adjustments, meaning that the entire initial input demand is supplied. In a different way, this also indicates that it is possible to enforce system constraints by only acting on the generation schedules;
- The capacitor banks connected to nodes 1 and 5 inject 1.5 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.0218 MW and are balanced in node 50 (HV/MV substation);
- There are no branch congestions in the network in this case.

The detailed results are indicated in Tables 4.1 (generation and demand) and 4.2 (voltage magnitudes and phases).

Table 4.1 – Generation and demand values for Case 0-0 and using Model 1.

Bus i	∆Pgi MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0.4	0.5	0	0.9	0.436
14	-	-	-	0	0.838	0.275
15	-	-	-	0	0.838	0.275
16	-	-	-	0	0.419	0.138
17	-	-	-	0	0.419	0.138
18	-	-	-	0	0.838	0.275
19	-	-	-	0	0.838	0.275
20	-	-	-	0	0.419	0.138
36	-	-	-	0	0.216	0.105
37	-	-	-	0	0.135	0.065
38	-	-	-	0	0.135	0.065
39	-	-	-	0	0.086	0.042
40	-	-	-	0	0.216	0.105

41	-	-	-	0	0.135	0.065
42	-	-	-	0	0.086	0.042
43	0	1.5	0.386	-	-	-
44	-	-	-	0	0.135	0.065
45	-	-	-	0	0.086	0.042
46	0	0.7	0.05	-	-	-
47	0	0	0.008	-	-	-
48	0	0.8	-0.263	-	-	-
50	0.022	3.36	0.05	-	-	-

Table 4.2 – Voltage magnitude and phases for Case 0-0 and using Model 1.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	1.008	-0.990	26	1.009	-0.770
2	1.007	-1.000	27	1.013	-0.690
3	1.007	-1.010	28	1.016	-0.620
4	1.006	-1.020	29	1.015	-0.620
5	1.006	-1.030	30	1.013	-0.620
6	1.006	-1.040	31	1.012	-0.620
7	1.007	-0.990	32	1.012	-0.620
8	1.007	-1.000	33	1.021	-0.540
9	1.007	-1.000	34	1.012	-0.620
10	1.007	-1.000	35	1.012	-0.620
11	1.007	-1.000	36	0.995	-2.460
12	1.006	-1.040	37	0.996	-2.380
13	1.007	-1.750	38	0.996	-2.310
14	0.996	-2.900	39	0.995	-2.300
15	0.995	-2.920	40	1.000	-2.220
16	0.994	-2.940	41	0.999	-2.150
17	0.994	-2.940	42	0.999	-2.140
18	0.996	-2.890	43	1.030	1.500
19	0.995	-2.900	44	0.999	-2.150
20	0.995	-2.910	45	0.999	-2.140
21	1.008	-0.910	46	1.010	0.000
22	1.009	-0.840	47	1.008	-0.990
23	1.011	-0.770	48	1.006	-0.530
24	1.010	-0.770	49	1.008	-0.040
25	1.009	-0.770	50	1.008	-0.030

4.2.2.2 **Case 0-1**

Using Model 1 in this Case, we obtained the following general results:

- As in Case 0-0 there are no demand adjustments;
- The capacitor banks connected to nodes 1 and 5 inject 1.6 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.0212 MW and are balanced in node 50 (HV/MV substation);
- There are no branch congestions in the network in this case.

The detailed results are indicated in Tables 4.3 (generation and demand) and 4.4 (voltage magnitudes and phases).

Table 4.3 – Generation and demand values for Case 0-1 and using Model 1.

Bus i	ΔPgi MW	Pgi MW	Qgi Mvar	ΔPci MW	Pci MW	Qci Mvar
13	0	0.4	0.5	0	0.9	0.436
14	-	-	-	0	0.838	0.275
15	-	-	-	0	0.838	0.275
16	-	-	-	0	0.419	0.138
17	-	-	-	0	0.419	0.138
18	-	-	-	0	0.838	0.275
19	-	-	-	0	0.838	0.275
20	-	-	-	0	0.419	0.138
36	-	-	-	0	0.216	0.105
37	-	-	-	0	0.135	0.065
38	-	-	-	0	0.135	0.065
39	-	-	-	0	0.086	0.042
40	-	-	-	0	0.216	0.105
41	-	-	-	0	0.135	0.065
42	-	-	-	0	0.086	0.042
43	0	1.5	0.392	-	-	-
44	-	-	-	0	0.135	0.065
45	-	-	-	0	0.086	0.042
46	0	0.7	0.039	-	-	-
47	0	0	0.01	-	-	-
48	0	0.8	-0.279	-	-	-
50	0.021	3.36	0.028	-	-	-

Table 4.4 – Voltage magnitude and phases for Case 0-1 and using Model 1.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	1.008	-0.990	26	1.009	-0.760
2	1.008	-1.000	27	1.014	-0.680
3	1.007	-1.010	28	1.017	-0.600
4	1.007	-1.020	29	1.015	-0.610
5	1.007	-1.030	30	1.013	-0.610
6	1.007	-1.030	31	1.013	-0.610
7	1.008	-1.000	32	1.012	-0.610
8	1.007	-1.010	33	1.021	-0.530
9	1.007	-1.020	34	1.013	-0.610
10	1.007	-1.020	35	1.012	-0.610
11	1.007	-1.030	36	0.995	-2.450
12	1.007	-1.030	37	0.996	-2.370
13	1.008	-1.740	38	0.996	-2.300
14	0.996	-2.900	39	0.996	-2.290
15	0.996	-2.910	40	1.000	-2.210
16	0.996	-2.930	41	0.999	-2.140
17	0.995	-2.940	42	0.999	-2.130
18	0.996	-2.900	43	1.030	1.520
19	0.996	-2.910	44	0.999	-2.140
20	0.995	-2.930	45	0.999	-2.130
21	1.009	-0.910	46	1.009	0.000
22	1.010	-0.830	47	1.009	-0.990
23	1.011	-0.760	48	1.005	-0.530
24	1.010	-0.760	49	1.008	-0.040
25	1.010	-0.760	50	1.008	-0.030

4.2.2.3 **Case 1-0**

Using Model 1 in this Case, we obtained the following general results:

- As in Case 0-0 there are no demand adjustments;
- The capacitor banks connected to nodes 1 and 5 inject 1.95 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.0281 MW and are balanced in node 55 (HV/MV substation);
- There are no branch congestions in the network in this case.

The detailed results are indicated in Tables 4.5 (generation and demand) and 4.6 (voltage magnitudes and phases).

Table 4.5 – Generation and demand values for Case 1-0 and using Model 1.

Bus i	∆Pgi MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0.4	0.472	0	0.9	0.436
14	-	-	-	0	0.838	0.275
15	-	-	-	0	0.838	0.275
16	-	-	-	0	0.419	0.138
17	-	-	-	0	0.419	0.138
18	-	-	-	0	0.838	0.275
19	-	-	-	0	0.838	0.275
20	-	-	-	0	0.419	0.138
36	-	-	-	0	0.216	0.105
37	-	-	-	0	0.135	0.065
38	-	-	-	0	0.135	0.065
39	-	-	-	0	0.086	0.042
40	-	-	-	0	0.216	0.105
41	-	-	-	0	0.135	0.065
42	-	-	-	0	0.086	0.042
43	0	1.5	0.271	-	-	-
44	-	-	-	0	0.135	0.065
45	-	-	-	0	0.086	0.042
46	0	0.7	-0.081	-	-	-
47	0	0	0.01	-	-	-
48	0	0.8	-0.273	-	-	-
49	0	0.25	0.093	-	-	-
50	0	0.25	0.1	-	-	-
51	0	0.25	0.1	-	-	-
52	0	0.25	0.1	-	-	-
53	0	0.25	0.097	-	-	-
55	0.028	2.117	-0.093	-	-	-

Table 4.6 – Voltage magnitude and phases for Case 1-0 and using Model 1.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	1.005	-0.990	29	1.019	-0.460
2	1.004	-1.010	30	1.017	-0.460
3	1.004	-1.020	31	1.016	-0.470
4	1.004	-1.030	32	1.016	-0.470

5	1.003	-1.040	33	1.024	-0.370
6	1.003	-1.040	34	1.016	-0.470
7	1.005	-1.000	35	1.016	-0.470
8	1.004	-1.010	36	0.993	-2.430
9	1.005	-1.000	37	0.996	-2.320
10	1.004	-1.010	38	0.998	-2.200
11	1.005	-1.000	39	0.998	-2.190
12	1.003	-1.050	40	1.002	-2.090
13	1.004	-1.760	41	1.003	-1.980
14	0.993	-2.920	42	1.003	-1.980
15	0.992	-2.930	43	1.030	1.660
16	0.992	-2.950	44	1.003	-1.980
17	0.992	-2.960	45	1.003	-1.980
18	0.993	-2.910	46	1.003	0.000
19	0.993	-2.920	47	1.005	-0.990
20	0.993	-2.920	48	1.002	-0.540
21	1.007	-0.890	49	1.015	0.730
22	1.009	-0.780	50	1.016	0.750
23	1.013	-0.670	51	1.016	0.750
24	1.013	-0.660	52	1.024	1.060
25	1.012	-0.670	53	1.030	1.240
26	1.011	-0.67	54	1.005	-0.39
27	1.016	-0.57	55	1.005	-0.39
28	1.019	-0.47	---	---	---

4.2.2.4 **Case 1-1**

Using Model 1 in this Case, we obtained the following general results:

- As in Case 0-0 there are no demand adjustments;
- The capacitor banks connected to nodes 1 and 5 inject 1.8 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.02725 MW and are balanced in node 55 (HV/MV substation);
- There are no branch congestions in the network in this case.

The detailed results are indicated in Tables 4.7 (generation and demand) and 4.8 (voltage magnitudes and phases).

Table 4.7 – Generation and demand values for Case 1-1 and using Model 1.

Bus i	∆Pgi MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0.4	0.5	0	0.9	0.436
14	-	-	-	0	0.838	0.275
15	-	-	-	0	0.838	0.275
16	-	-	-	0	0.419	0.138
17	-	-	-	0	0.419	0.138
18	-	-	-	0	0.838	0.275
19	-	-	-	0	0.838	0.275
20	-	-	-	0	0.419	0.138
36	-	-	-	0	0.216	0.105
37	-	-	-	0	0.135	0.065
38	-	-	-	0	0.135	0.065
39	-	-	-	0	0.086	0.042
40	-	-	-	0	0.216	0.105
41	-	-	-	0	0.135	0.065
42	-	-	-	0	0.086	0.042
43	0	1.5	0.266	-	-	-
44	-	-	-	0	0.135	0.065
45	-	-	-	0	0.086	0.042
46	0	0.7	-0.45	-	-	-
47	0	0	0.01	-	-	-
48	0	0.8	-0.297	-	-	-
49	0	0.25	0.1	-	-	-
50	0	0.25	0.1	-	-	-
51	0	0.25	0.1	-	-	-
52	0	0.25	0.1	-	-	-
53	0	0.25	0.096	-	-	-
55	0.027	2.116	-0.022	-	-	-

Table 4.8 – Voltage magnitude and phases for Case 1-1 and using Model 1.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	1.005	-1.000	29	1.019	-0.470
2	1.005	-1.020	30	1.017	-0.470
3	1.004	-1.030	31	1.016	-0.470
4	1.004	-1.040	32	1.016	-0.470
5	1.004	-1.050	33	1.024	-0.380
6	1.004	-1.050	34	1.016	-0.470
7	1.005	-1.020	35	1.016	-0.470

8	1.005	-1.030	36	0.994	-2.440
9	1.004	-1.030	37	0.996	-2.320
10	1.004	-1.040	38	0.998	-2.200
11	1.004	-1.040	39	0.998	-2.200
12	1.004	-1.050	40	1.002	-2.090
13	1.006	-1.760	41	1.003	-1.990
14	0.993	-2.930	42	1.003	-1.980
15	0.993	-2.940	43	1.030	1.660
16	0.993	-2.960	44	1.003	-1.990
17	0.993	-2.960	45	1.003	-1.980
18	0.993	-2.930	46	0.994	0.000
19	0.993	-2.940	47	1.006	-1.000
20	0.993	-2.950	48	1.002	-0.550
21	1.007	-0.890	49	1.016	0.720
22	1.010	-0.790	50	1.016	0.720
23	1.013	-0.680	51	1.016	0.710
24	1.013	-0.670	52	1.025	1.060
25	1.012	-0.670	53	1.030	1.240
26	1.012	-0.67	54	1.006	-0.4
27	1.016	-0.57	55	1.006	-0.4
28	1.02	-0.47	---	---	---

4.2.2.5 **Case 2-0**

Using Model 1 in this Case, we obtained the following general results:

- As in Case 0-0 there are no demand adjustments;
- The capacitor banks connected to nodes 1 and 5 inject 1.8 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.02731 MW and are balanced in node 55 (HV/MV substation);
- There are no branch congestions in the network in this case.

The detailed results are indicated in Tables 4.9 (generation and demand) and 4.10 (voltage magnitudes and phases).

Table 4.9 – Generation and demand values for Case 2-0 and using Model 1.

Bus i	∆Pgi MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0.4	0.5	0	0.99	0.479
14	-	-	-	0	0.922	0.303
15	-	-	-	0	0.922	0.303

16	-	-	-	0	0.461	0.152
17	-	-	-	0	0.461	0.152
18	-	-	-	0	0.922	0.303
19	-	-	-	0	0.922	0.303
20	-	-	-	0	0.461	0.152
36	-	-	-	0	0.238	0.115
37	-	-	-	0	0.149	0.072
38	-	-	-	0	0.149	0.072
39	-	-	-	0	0.095	0.046
40	-	-	-	0	0.238	0.115
41	-	-	-	0	0.149	0.072
42	-	-	-	0	0.095	0.046
43	0	1.5	0.303	-	-	-
44	-	-	-	0	0.149	0.072
45	-	-	-	0	0.095	0.046
46	0	0.7	-0.271	-	-	-
47	0	0	0.002	-	-	-
48	0	0.8	-0.3	-	-	-
49	0	0.25	0.1	-	-	-
50	0	0.25	0.1	-	-	-
51	0	0.25	0.1	-	-	-
52	0	0.25	0.1	-	-	-
53	0	0.25	0.1	-	-	-
55	0.027	2.795	0.114	-	-	-

Table 4.10 – Voltage magnitude and phases for Case 2-0 and using Model 1.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	1.005	-1.000	29	1.017	-0.500
2	1.004	-1.020	30	1.016	-0.510
3	1.004	-1.040	31	1.015	-0.510
4	1.004	-1.050	32	1.014	-0.510
5	1.004	-1.070	33	1.023	-0.420
6	1.003	-1.070	34	1.015	-0.510
7	1.005	-1.010	35	1.014	-0.510
8	1.004	-1.010	36	0.992	-2.610
9	1.004	-1.010	37	0.994	-2.500
10	1.004	-1.010	38	0.996	-2.390
11	1.004	-1.010	39	0.995	-2.380
12	1.003	-1.080	40	1.000	-2.280
13	1.004	-1.920	41	1.000	-2.190
14	0.992	-3.130	42	0.999	-2.190

15	0.991	-3.140	43	1.030	1.620
16	0.991	-3.180	44	1.000	-2.190
17	0.990	-3.180	45	0.999	-2.190
18	0.992	-3.110	46	0.999	0.000
19	0.992	-3.120	47	1.005	-1.000
20	0.992	-3.120	48	1.002	-0.540
21	1.007	-0.900	49	1.016	0.700
22	1.009	-0.800	50	1.016	0.740
23	1.012	-0.700	51	1.016	0.740
24	1.012	-0.690	52	1.023	1.040
25	1.011	-0.690	53	1.029	1.210
26	1.01	-0.69	54	1.007	-0.21
27	1.015	-0.6	55	1.007	-0.2
28	1.018	-0.51			

4.2.2.6 **Case 3-0**

Using Model 1 in this Case, we obtained the following general results:

- There is one load adjustment since the ΔPci variable takes the value of – 0,00242 MW for node 13. This indicates a load curtailment in this node. This curtailment is due to the following reasons:
  - Branch 1-2 has the limit of 3.5 MVA and the results obtained for the active and reactive flows are 3.45 MW and 0.587 Mvar leading to an apparent power flow of 3.5 MVA;
  - In this case, the demand was increased by 20% regarding the base situations and the network is operated in open loop. This means that the demand in node 13 can only be supplied by the main distribution line and the addition of this demand value to the active losses in the branches would exceed the limit of 3.5 MVA if load curtailment was not done;
- The capacitor banks connected to nodes 1 and 5 inject 2.0 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.05053 MW and are balanced in node 55 (HV/MV substation) by 0.04811 MW and also by the reduction of demand in node 13 with the amount of 0.00242 MW.

The detailed results are indicated in Tables 4.11 (generation and demand) and 4.12 (voltage magnitudes and phases).

Table 4.11 – Generation and demand values for Case 3-0 and using Model 1.

Bus i	∆Pgi MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0.4	0.5	-0.002	1.078	0.522
14	-	-	-	0	1.006	0.331
15	-	-	-	0	1.006	0.331
16	-	-	-	0	0.503	0.165
17	-	-	-	0	0.503	0.165
18	-	-	-	0	1.006	0.331
19	-	-	-	0	1.006	0.331
20	-	-	-	0	0.503	0.165
36	-	-	-	0	0.259	0.125
37	-	-	-	0	0.162	0.078
38	-	-	-	0	0.162	0.078
39	-	-	-	0	0.103	0.05
40	-	-	-	0	0.259	0.125
41	-	-	-	0	0.162	0.078
42	-	-	-	0	0.103	0.05
43	0	1.5	-0.5	-	-	-
44	-	-	-	0	0.162	0.078
45	-	-	-	0	0.103	0.05
46	0	0.7	0.247	-	-	-
47	0	0	0.01	-	-	-
48	0	0.8	0.3	-	-	-
49	0	0.25	0.065	-	-	-
50	0	0.25	0.059	-	-	-
51	0	0.25	0.059	-	-	-
52	0	0.25	-0.1	-	-	-
53	0	0.25	-0.1	-	-	-
55	0.048	3.486	0.397	-	-	-

Table 4.12 – Voltage magnitude and phases for Case 3-0 and using Model 1.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	1.024	-0.950	29	1.025	0.480
2	1.023	-0.970	30	1.023	0.480
3	1.023	-0.990	31	1.022	0.470
4	1.023	-1.000	32	1.022	0.470
5	1.022	-1.020	33	1.030	0.660
6	1.022	-1.030	34	1.022	0.470
7	1.024	-0.960	35	1.022	0.470

8	1.023	-0.960	36	1.007	-2.460
9	1.023	-0.960	37	1.007	-2.170
10	1.023	-0.960	38	1.006	-1.840
11	1.023	-0.960	39	1.006	-1.830
12	1.022	-1.030	40	1.009	-1.610
13	1.021	-1.960	41	1.006	-1.330
14	1.010	-3.190	42	1.006	-1.320
15	1.009	-3.210	43	1.017	2.710
16	1.008	-3.240	44	1.006	-1.330
17	1.008	-3.250	45	1.006	-1.320
18	1.010	-3.170	46	1.030	0.000
19	1.010	-3.180	47	1.024	-0.950
20	1.010	-3.180	48	1.027	-0.510
21	1.023	-0.660	49	1.030	0.700
22	1.023	-0.360	50	1.030	0.740
23	1.024	-0.070	51	1.030	0.740
24	1.023	-0.030	52	1.010	1.700
25	1.022	-0.030	53	1.012	2.200
26	1.022	-0.03	54	1.026	0
27	1.025	0.18	55	1.026	0.01
28	1.027	0.44	---	---	---

4.2.3 Model 2

4.2.3.1 Case 0-0

Using Model 2 in this Case, we obtained the following general results:

- There are no demand adjustments, meaning that the entire initial input demand is supplied. This indicates that all $\Delta \mathrm{Pci}$ variables are zero;
- There are no generation adjustments required to enforce system constraints, namely voltage limits or branch flow limits. This means that ΔPg_i^{ajt} variables are zero;
- The capacitor banks connected to nodes 1 and 5 inject 0.9 Mvar and 0.4 Mvar, respectively;
- Active power losses take the value of 0.02168 MW and are balanced in node 47 (distributed generation). This model includes variables specifically modelling the contribution of each generator to balance active losses. In this case, the ΔPg_i^{perd} variable associated to node 47 has a non zero value of 0.02168 MW in order to compensate active losses;

- There are no branch congestions in the network.

The detailed results are indicated in Tables 4.13 (generation and demand) and 4.14 (voltage magnitudes and phases).

Table 4.13 – Generation and demand values for Case 0-0 and using Model 2.

Bus i	∆Pgi ajt MW	∆Pgi perd MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0	0.4	0.5	0	0.9	0.436
14	-	-	-	-	0	0.838	0.275
15	-	-	-	-	0	0.838	0.275
16	-	-	-	-	0	0.419	0.138
17	-	-	-	-	0	0.419	0.138
18	-	-	-	-	0	0.838	0.275
19	-	-	-	-	0	0.838	0.275
20	-	-	-	-	0	0.419	0.138
36	-	-	-	-	0	0.216	0.105
37	-	-	-	-	0	0.135	0.065
38	-	-	-	-	0	0.135	0.065
39	-	-	-	-	0	0.086	0.042
40	-	-	-	-	0	0.216	0.105
41	-	-	-	-	0	0.135	0.065
42	-	-	-	-	0	0.086	0.042
43	0	0	1.5	0.333	-	-	-
44	-	-	-	-	0	0.135	0.065
45	-	-	-	-	0	0.086	0.042
46	0	0	0.7	0.458	-	-	-
47	0	0.022	0.022	0.01	-	-	-
48	0	0	0.8	0.082	-	-	-
50	0	0	3.339	0.029	-	-	-

Table 4.14 – Voltage magnitude and phases for Case 0-0 and using Model 2.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	1.010	-0.970	26	1.011	-0.730
2	1.009	-0.990	27	1.015	-0.640
3	1.009	-1.010	28	1.018	-0.560
4	1.008	-1.020	29	1.016	-0.560
5	1.008	-1.040	30	1.015	-0.560
6	1.008	-1.040	31	1.014	-0.560
7	1.009	-0.980	32	1.013	-0.560

8	1.009	-0.990	33	1.023	-0.470
9	1.009	-0.990	34	1.014	-0.560
10	1.009	-0.990	35	1.013	-0.560
11	1.009	-0.990	36	0.997	-2.430
12	1.008	-1.050	37	0.998	-2.340
13	1.009	-1.750	38	0.997	-2.260
14	0.998	-2.890	39	0.997	-2.260
15	0.997	-2.900	40	1.001	-2.160
16	0.997	-2.930	41	1.000	-2.090
17	0.997	-2.940	42	1.000	-2.080
18	0.998	-2.870	43	1.030	1.570
19	0.997	-2.880	44	1.000	-2.090
20	0.997	-2.890	45	1.000	-2.080
21	1.010	-0.890	46	1.021	0.000
22	1.011	-0.810	47	1.010	-0.940
23	1.012	-0.720	48	1.011	-0.520
24	1.012	-0.730	49	1.010	-0.040
25	1.011	-0.730	50	1.010	-0.020

4.2.3.2 **Case 0-1**

Using Model 2 in this Case, we obtained the following general results:

- As in Case 0-0, there are no generation or demand adjustments;
- The capacitor banks connected to nodes 1 and 5 inject 2.0 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.02185 MW and are balanced in node 47 (distributed generation), the same node in which active losses were balanced in Case 0-0;
- There are no branch congestions in the network in this case.

The detailed results are indicated in Tables 4.15 (generation and demand) and 4.16 (voltage magnitudes and phases).

Table 4.15 – Generation and demand values for Case 0-1 and using Model 2.

Bus i	∆Pgi ajt MW	∆Pgi perd MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0	0.4	0.5	0	0.9	0.436
14	-	-	-	-	0	0.838	0.275
15	-	-	-	-	0	0.838	0.275

16	-	-	-	-	0	0.419	0.138
17	-	-	-	-	0	0.419	0.138
18	-	-	-	-	0	0.838	0.275
19	-	-	-	-	0	0.838	0.275
20	-	-	-	-	0	0.419	0.138
36	-	-	-	-	0	0.216	0.105
37	-	-	-	-	0	0.135	0.065
38	-	-	-	-	0	0.135	0.065
39	-	-	-	-	0	0.086	0.042
40	-	-	-	-	0	0.216	0.105
41	-	-	-	-	0	0.135	0.065
42	-	-	-	-	0	0.086	0.042
43	0	0	1.5	0.433	-	-	-
44	-	-	-	-	0	0.135	0.065
45	-	-	-	-	0	0.086	0.042
46	0	0	0.7	-0.348	-	-	-
47	0	0.022	0.022	-0.01	-	-	-
48	0	0	0.8	-0.291	-	-	-
50	0	0	3.339	0.016	-	-	-

Table 4.16 – Voltage magnitude and phases for Case 0-1 and using Model 2.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	0.991	-1.030	26	0.992	-0.820
2	0.990	-1.050	27	0.996	-0.750
3	0.990	-1.060	28	1.000	-0.680
4	0.990	-1.070	29	0.998	-0.680
5	0.989	-1.080	30	0.996	-0.680
6	0.989	-1.080	31	0.995	-0.680
7	0.990	-1.050	32	0.995	-0.680
8	0.990	-1.060	33	1.005	-0.610
9	0.990	-1.060	34	0.995	-0.680
10	0.989	-1.070	35	0.995	-0.680
11	0.989	-1.080	36	0.977	-2.560
12	0.989	-1.080	37	0.978	-2.490
13	0.991	-1.810	38	0.978	-2.420
14	0.978	-3.020	39	0.978	-2.410
15	0.978	-3.030	40	0.983	-2.330
16	0.978	-3.050	41	0.982	-2.270
17	0.977	-3.050	42	0.981	-2.260
18	0.978	-3.010	43	1.014	1.500
19	0.978	-3.030	44	0.982	-2.270

20	0.978	-3.040	45	0.981	-2.260
21	0.991	-0.960	46	0.982	0.000
22	0.992	-0.890	47	0.990	-1.000
23	0.994	-0.820	48	0.988	-0.560
24	0.993	-0.820	49	0.991	-0.060
25	0.992	-0.820	50	0.991	-0.050

4.2.3.3 **Case 1-0**

Using Model 2 in this Case, we obtained the following general results:

- As in Case 0-0, there are no generation or demand adjustments;
- The capacitor banks connected to nodes 1 and 5 inject 1.4 Mvar and 0.4 Mvar, respectively;
- Active power losses take the value of 0.02911 MW and are balanced in node 47 (distributed generation), the same node in which active losses are balanced in Case 0-0;
- There are no branch congestions in the network in this case.

The detailed results are indicated in Tables 4.17 (generation and demand) and 4.18 (voltage magnitudes and phases).

Table 4.17 – Generation and demand values for Case 1-0 and using Model 2.

Bus i	∆Pgi ajt MW	∆Pgi perd MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0	0.4	0.485	0	0.9	0.436
14	-	-	-	-	0	0.838	0.275
15	-	-	-	-	0	0.838	0.275
16	-	-	-	-	0	0.419	0.138
17	-	-	-	-	0	0.419	0.138
18	-	-	-	-	0	0.838	0.275
19	-	-	-	-	0	0.838	0.275
20	-	-	-	-	0	0.419	0.138
36	-	-	-	-	0	0.216	0.105
37	-	-	-	-	0	0.135	0.065
38	-	-	-	-	0	0.135	0.065
39	-	-	-	-	0	0.086	0.042
40	-	-	-	-	0	0.216	0.105
41	-	-	-	-	0	0.135	0.065
42	-	-	-	-	0	0.086	0.042

43	0	0	1.5	0.295	-	-	-
44	-	-	-	-	0	0.135	0.065
45	-	-	-	-	0	0.086	0.042
46	0	0	0.7	-0.419	-	-	-
47	0	0.029	0.029	-0.01	-	-	-
48	0	0	0.8	0.061	-	-	-
49	0	0	0.25	0.097	-	-	-
50	0	0	0.25	0.1	-	-	-
51	0	0	0.25	0.1	-	-	-
52	0	0	0.25	0.1	-	-	-
53	0	0	0.25	0.1	-	-	-
55	0	0	2.089	0.102	-	-	-

Table 4.18 – Voltage magnitude and phases for Case 1-0 and using Model 2.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	0.984	-1.050	29	0.998	-0.510
2	0.983	-1.070	30	0.996	-0.510
3	0.983	-1.090	31	0.995	-0.510
4	0.982	-1.100	32	0.995	-0.510
5	0.982	-1.110	33	1.003	-0.420
6	0.982	-1.120	34	0.995	-0.510
7	0.983	-1.060	35	0.995	-0.510
8	0.983	-1.060	36	0.972	-2.550
9	0.983	-1.060	37	0.974	-2.440
10	0.983	-1.060	38	0.977	-2.310
11	0.983	-1.060	39	0.977	-2.310
12	0.982	-1.130	40	0.981	-2.210
13	0.983	-1.870	41	0.982	-2.100
14	0.971	-3.060	42	0.981	-2.090
15	0.971	-3.080	43	1.010	1.700
16	0.970	-3.110	44	0.982	-2.100
17	0.970	-3.120	45	0.981	-2.090
18	0.971	-3.050	46	0.973	0.000
19	0.971	-3.050	47	0.983	-1.000
20	0.971	-3.060	48	0.984	-0.570
21	0.986	-0.940	49	0.994	0.730
22	0.988	-0.830	50	0.995	0.770
23	0.991	-0.720	51	0.995	0.770
24	0.991	-0.710	52	1.003	1.090
25	0.991	-0.720	53	1.010	1.270
26	0.99	-0.72	54	0.985	-0.43

27	0.995	-0.62	55	0.985	-0.42
28	0.998	-0.52	---	---	---

4.2.3.4 **Case 1-1**

Using Model 2 in this Case, we obtained the following general results:

- As in Case 0-0, there are no generation or demand adjustments;
- The capacitor banks connected to nodes 1 and 5 inject 1.5 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.029206 MW and are balanced in node 47 (distributed generation), the same node in which active losses were balanced in Case 0-0;
- There are no branch congestions in the network in this case. For instance, the apparent power flow in branch 1-2 is 2.270 MVA and the corresponding limit is 3.5 MVA.

The detailed results are indicated in Tables 4.19 (generation and demand) and 4.20 (voltage magnitudes and phases).

Table 4.19 – Generation and demand values for Case 1-1 and using Model 2.

Bus i	ΔPgi ajt MW	ΔPgi perd MW	Pgi MW	Qgi Mvar	ΔPci MW	Pci MW	Qci Mvar
13	0	0	0.4	0.5	0	0.9	0.436
14	-	-	-	-	0	0.838	0.275
15	-	-	-	-	0	0.838	0.275
16	-	-	-	-	0	0.419	0.138
17	-	-	-	-	0	0.419	0.138
18	-	-	-	-	0	0.838	0.275
19	-	-	-	-	0	0.838	0.275
20	-	-	-	-	0	0.419	0.138
36	-	-	-	-	0	0.216	0.105
37	-	-	-	-	0	0.135	0.065
38	-	-	-	-	0	0.135	0.065
39	-	-	-	-	0	0.086	0.042
40	-	-	-	-	0	0.216	0.105
41	-	-	-	-	0	0.135	0.065
42	-	-	-	-	0	0.086	0.042
43	0	0	1.5	0.272	-	-	-
44	-	-	-	-	0	0.135	0.065
45	-	-	-	-	0	0.086	0.042

46	0	0	0.7	-0.499	-	-	-
47	0	0.029	0.029	-0.01	-	-	-
48	0	0	0.8	-0.227	-	-	-
49	0	0	0.25	0.076	-	-	-
50	0	0	0.25	0.1	-	-	-
51	0	0	0.25	0.1	-	-	-
52	0	0	0.25	0.071	-	-	-
53	0	0	0.25	0.052	-	-	-
55	0	0	2.089	0.349	-	-	-

Table 4.20 – Voltage magnitude and phases for Case 1-1 and using Model 2.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	0.983	-1.050	29	0.996	-0.360
2	0.982	-1.070	30	0.994	-0.370
3	0.982	-1.080	31	0.993	-0.370
4	0.982	-1.090	32	0.993	-0.370
5	0.982	-1.100	33	1.001	-0.270
6	0.982	-1.100	34	0.993	-0.370
7	0.982	-1.060	35	0.993	-0.370
8	0.982	-1.070	36	0.971	-2.530
9	0.982	-1.080	37	0.973	-2.380
10	0.982	-1.090	38	0.975	-2.220
11	0.982	-1.090	39	0.975	-2.220
12	0.982	-1.100	40	0.979	-2.100
13	0.983	-1.840	41	0.979	-1.960
14	0.971	-3.070	42	0.979	-1.950
15	0.970	-3.080	43	1.006	1.860
16	0.970	-3.100	44	0.979	-1.960
17	0.970	-3.100	45	0.979	-1.950
18	0.971	-3.060	46	0.970	0.000
19	0.970	-3.070	47	0.983	-1.010
20	0.970	-3.090	48	0.983	-0.580
21	0.985	-0.910	49	0.989	0.760
22	0.987	-0.770	50	0.994	0.750
23	0.990	-0.630	51	0.994	0.740
24	0.990	-0.620	52	0.997	1.200
25	0.989	-0.620	53	1.000	1.430
26	0.989	-0.62	54	0.983	-0.43
27	0.993	-0.51	55	0.983	-0.43
28	0.997	-0.38	---	---	---

4.2.3.5 **Case 2-0**

Using Model 2 in this Case, we obtained the following general results:

- As in Case 0-0, there are no generation or demand adjustments;
- The capacitor banks connected to nodes 1 and 5 inject 1.9 Mvar and 0.08 Mvar, respectively;
- Active power losses take the value of 0.02853 MW and are balanced in node 47 (distributed generation), the same node in which active losses are balanced in Case 0-0;
- There are no branch congestions in the network in this case.

The detailed results are indicated in Tables 4.21 (generation and demand) and 4.22 (voltage magnitudes and phases).

Table 4.21 – Generation and demand values for Case 2-0 and using Model 2.

Bus i	∆Pgi ajt MW	∆Pgi perd MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0	0.4	0.5	0	0.99	0.479
14	-	-	-	-	0	0.922	0.303
15	-	-	-	-	0	0.922	0.303
16	-	-	-	-	0	0.461	0.152
17	-	-	-	-	0	0.461	0.152
18	-	-	-	-	0	0.922	0.303
19	-	-	-	-	0	0.922	0.303
20	-	-	-	-	0	0.461	0.152
36	-	-	-	-	0	0.238	0.115
37	-	-	-	-	0	0.149	0.072
38	-	-	-	-	0	0.149	0.072
39	-	-	-	-	0	0.095	0.046
40	-	-	-	-	0	0.238	0.115
41	-	-	-	-	0	0.149	0.072
42	-	-	-	-	0	0.095	0.046
43	0	0	1.5	0.3	-	-	-
44	-	-	-	-	0	0.149	0.072
45	-	-	-	-	0	0.095	0.046
46	0	0	0.7	-0.219	-	-	-
47	0	0.029	0.029	0.01	-	-	-
48	0	0	0.8	-0.106	-	-	-
49	0	0	0.25	0.1	-	-	-
50	0	0	0.25	0.1	-	-	-
51	0	0	0.25	0.1	-	-	-

52	0	0	0.25	0.1	-	-	-
53	0	0	0.25	0.1	-	-	-
55	0	0	2.768	0.155	-	-	-

Table 4.22 – Voltage magnitude and phases for Case 2-0 and using Model 2.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi Degree
1	0.987	-1.040	29	0.999	-0.500
2	0.986	-1.050	30	0.997	-0.510
3	0.985	-1.070	31	0.996	-0.510
4	0.985	-1.080	32	0.996	-0.510
5	0.985	-1.090	33	1.004	-0.420
6	0.984	-1.090	34	0.996	-0.510
7	0.986	-1.040	35	0.996	-0.510
8	0.986	-1.050	36	0.973	-2.700
9	0.986	-1.050	37	0.975	-2.590
10	0.986	-1.050	38	0.977	-2.470
11	0.986	-1.050	39	0.976	-2.460
12	0.984	-1.100	40	0.981	-2.360
13	0.985	-1.970	41	0.981	-2.260
14	0.973	-3.240	42	0.980	-2.250
15	0.972	-3.260	43	1.011	1.700
16	0.971	-3.280	44	0.981	-2.260
17	0.971	-3.290	45	0.980	-2.250
18	0.973	-3.230	46	0.981	0.000
19	0.973	-3.240	47	0.987	-0.990
20	0.973	-3.240	48	0.985	-0.560
21	0.988	-0.930	49	0.997	0.750
22	0.990	-0.820	50	0.998	0.770
23	0.993	-0.710	51	0.998	0.770
24	0.993	-0.710	52	1.005	1.090
25	0.992	-0.710	53	1.011	1.270
26	0.992	-0.71	54	0.988	-0.22
27	0.996	-0.61	55	0.988	-0.21
28	1.000	-0.51			

4.2.3.6 **Case 3-0**

Using Model 2 in this Case, we obtained the following general results:

- As in Case 0-0, there are no generation or demand adjustments;

- The capacitor banks connected to nodes 1 and 5 inject 0.8 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.027348 MW and are balanced in node 47 (distributed generation), the same node in which active losses are balanced in Case 0-0;
- Regarding branch congestions, the active, reactive and apparent power flows in branch 1-2 are 3.453 MW, 0.559 Mvar and 3.5 MVA indicating it is congested given the apparent power limit was set at 3.5 MVA.

The detailed results are indicated in Tables 4.23 (generation and demand) and 4.24 (voltage magnitudes and phases).

Table 4.23 – Generation and demand values for Case 3-0 and using Model 2.

Bus i	∆Pgi ajt MW	∆Pgi perd MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0	0.4	0.5	0	1.08	0.523
14	-	-	-	-	0	1.006	0.331
15	-	-	-	-	0	1.006	0.331
16	-	-	-	-	0	0.503	0.165
17	-	-	-	-	0	0.503	0.165
18	-	-	-	-	0	1.006	0.331
19	-	-	-	-	0	1.006	0.331
20	-	-	-	-	0	0.503	0.165
36	-	-	-	-	0	0.259	0.125
37	-	-	-	-	0	0.162	0.078
38	-	-	-	-	0	0.162	0.078
39	-	-	-	-	0	0.103	0.05
40	-	-	-	-	0	0.259	0.125
41	-	-	-	-	0	0.162	0.078
42	-	-	-	-	0	0.103	0.05
43	0	0	1.5	0.265	-	-	-
44	-	-	-	-	0	0.162	0.078
45	-	-	-	-	0	0.103	0.05
46	0	0	0.7	0.497	-	-	-
47	0	0.027	0.027	0.009	-	-	-
48	0	0	0.8	0.299	-	-	-
49	0	0	0.25	0.1	-	-	-
50	0	0	0.25	0.1	-	-	-
51	0	0	0.25	0.1	-	-	-
52	0	0	0.25	0.1	-	-	-

53	0	0	0.25	0.098	-	-	-
55	0	0	3.438	0.087	-	-	-

Table 4.24 – Voltage magnitude and phases for Case 3-0 and using Model 2.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	1.009	-0.970	29	1.019	-0.430
2	1.008	-1.000	30	1.017	-0.430
3	1.007	-1.020	31	1.016	-0.430
4	1.007	-1.030	32	1.015	-0.430
5	1.007	-1.050	33	1.024	-0.340
6	1.006	-1.050	34	1.016	-0.430
7	1.008	-0.980	35	1.015	-0.430
8	1.008	-0.990	36	0.993	-2.710
9	1.008	-0.990	37	0.995	-2.600
10	1.008	-0.990	38	0.996	-2.480
11	1.008	-0.990	39	0.996	-2.470
12	1.006	-1.060	40	1.000	-2.370
13	1.006	-2.020	41	0.999	-2.260
14	0.994	-3.280	42	0.999	-2.250
15	0.993	-3.300	43	1.030	1.700
16	0.993	-3.330	44	0.999	-2.260
17	0.992	-3.340	45	0.999	-2.250
18	0.994	-3.270	46	1.021	0.000
19	0.994	-3.270	47	1.009	-0.940
20	0.994	-3.270	48	1.012	-0.520
21	1.009	-0.860	49	1.019	0.720
22	1.011	-0.750	50	1.020	0.760
23	1.014	-0.640	51	1.020	0.760
24	1.014	-0.640	52	1.025	1.090
25	1.013	-0.640	53	1.030	1.270
26	1.012	-0.64	54	1.009	-0.010
27	1.016	-0.54	55	1.009	0
28	1.020	-0.44	---	---	---

4.3 Simulations using Fuzzy Models

4.3.1 General Data

When considering the Fuzzy Linearized Models, Models 3 and 4, detailed in Section 2.7 we used the following general data:

- Voltage limits were set at 0.97 pu and 1.03 pu.

- The system marginal price obtained from the Market Operator was set at 3.0 €/MW.h;
- The tolerance of the soft voltage limit constraints was set at ±0.02 pu;
- The tolerance of the soft apparent power flow limit constraint was set at +10%.

4.3.2 Model 3

4.3.2.1 Case 0-0

In this simulation we used 0.180 €/h for the target value of the objective function and the maximum value of 0.300 €/h. These values are used to formulate the constraint (2.35) used in Model 3 detailed in Section 2.7.2. Using these values, we obtained the following general results:

- There are no demand adjustments;
- The capacitor banks connected to nodes 1 and 5 inject 1.9 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.0214 MW and are balanced in node 50 (HV/MV substation);
- There are no branch congestions in the network in this case and the voltage in node 43, 1.035 pu, is above the crisp limit of 1.03 pu;
- It was obtained a satisfaction degree of 0.717 that results from the value of the objective function of the crisp model of 0.214 €/h.

The detailed results are indicated in Tables 4.25 (generation and demand) and 4.26 (voltage magnitudes and phases).

Table 4.25 – Generation and demand values for Case 0-0 and using Model 3.

Bus i	∆Pgi MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0.4	0.5	0	0.9	0.436
14	-	-	-	0	0.838	0.275
15	-	-	-	0	0.838	0.275
16	-	-	-	0	0.419	0.138
17	-	-	-	0	0.419	0.138
18	-	-	-	0	0.838	0.275
19	-	-	-	0	0.838	0.275
20	-	-	-	0	0.419	0.138

36	-	-	-	0	0.216	0.105
37	-	-	-	0	0.135	0.065
38	-	-	-	0	0.135	0.065
39	-	-	-	0	0.086	0.042
40	-	-	-	0	0.216	0.105
41	-	-	-	0	0.135	0.065
42	-	-	-	0	0.086	0.042
43	0	1.5	0.383	-	-	-
44	-	-	-	0	0.135	0.065
45	-	-	-	0	0.086	0.042
46	0	0.7	-0.326	-	-	-
47	0	0	0.01	-	-	-
48	0	0.8	-0.242	-	-	-
50	0.021	3.36	0.028	-	-	-

Table 4.26 – Voltage magnitude and phases for Case 0-0 and using Model 3.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	1.014	-0.980	26	1.015	-0.760
2	1.013	-1.000	27	1.019	-0.680
3	1.013	-1.020	28	1.022	-0.610
4	1.012	-1.040	29	1.020	-0.610
5	1.012	-1.050	30	1.019	-0.610
6	1.012	-1.060	31	1.018	-0.610
7	1.013	-0.990	32	1.018	-0.610
8	1.013	-1.000	33	1.027	-0.530
9	1.013	-1.000	34	1.018	-0.610
10	1.013	-1.000	35	1.018	-0.610
11	1.013	-1.000	36	1.001	-2.430
12	1.012	-1.060	37	1.002	-2.360
13	1.013	-1.760	38	1.002	-2.280
14	1.002	-2.880	39	1.001	-2.280
15	1.001	-2.900	40	1.006	-2.190
16	1.001	-2.930	41	1.005	-2.120
17	1.000	-2.940	42	1.004	-2.120
18	1.002	-2.870	43	1.035	1.490
19	1.001	-2.880	44	1.005	-2.120
20	1.001	-2.880	45	1.004	-2.120
21	1.014	-0.910	46	1.005	0.000
22	1.015	-0.830	47	1.014	-0.980

23	1.017	-0.760	48	1.011	-0.540
24	1.016	-0.760	49	1.014	-0.050
25	1.015	-0.760	50	1.014	-0.040

4.3.2.2 **Case 0-1**

In this simulation we used 0.180 €/h for the target value of the objective function and the maximum value of 0.300 €/h. These values are used to formulate the constraint (2.35) used in Model 3 detailed in Section 2.7.2. Using this model in this Case, we obtained the following general results:

- There are no demand adjustments;
- The capacitor banks connected to nodes 1 and 5 inject 2.0 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.0210 MW and are balanced in node 50 (HV/MV substation);
- There are no branch congestions in the network in this case and the voltage in node 43, 1.035 pu, is above the crisp limit of 1.03 pu;
- It was obtained a satisfaction degree of 0.756 that is associated to a value of the objective function of the crisp model of 0.209 €/h.

The detailed results are indicated in Tables 4.27 (generation and demand) and 4.28 (voltage magnitudes and phases).

Table 4.27 – Generation and demand values for Case 0-1 and using Model 3.

Bus i	∆Pgi MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0.4	0.5	0	0.9	0.436
14	-	-	-	0	0.838	0.275
15	-	-	-	0	0.838	0.275
16	-	-	-	0	0.419	0.138
17	-	-	-	0	0.419	0.138
18	-	-	-	0	0.838	0.275
19	-	-	-	0	0.838	0.275
20	-	-	-	0	0.419	0.138
36	-	-	-	0	0.216	0.105
37	-	-	-	0	0.135	0.065
38	-	-	-	0	0.135	0.065
39	-	-	-	0	0.086	0.042

40	-	-	-	0	0.216	0.105
41	-	-	-	0	0.135	0.065
42	-	-	-	0	0.086	0.042
43	0	1.5	0.374	-	-	-
44	-	-	-	0	0.135	0.065
45	-	-	-	0	0.086	0.042
46	0	0.7	-0.374	-	-	-
47	0	0	0.01	-	-	-
48	0	0.8	-0.085	-	-	-
50	0.021	3.36	-0.152	-	-	-

Table 4.28 – Voltage magnitude and phases for Case 0-1 and using Model 3.

Bus i	Vi pu	θi degree	Bus i	Vi Pu	θi degree
1	1.013	-0.990	26	1.014	-0.780
2	1.012	-1.000	27	1.018	-0.700
3	1.012	-1.020	28	1.021	-0.630
4	1.011	-1.030	29	1.019	-0.630
5	1.011	-1.040	30	1.018	-0.630
6	1.011	-1.040	31	1.017	-0.630
7	1.012	-1.000	32	1.017	-0.630
8	1.012	-1.010	33	1.026	-0.550
9	1.011	-1.020	34	1.017	-0.630
10	1.011	-1.030	35	1.017	-0.630
11	1.011	-1.030	36	0.999	-2.450
12	1.011	-1.040	37	1.000	-2.370
13	1.013	-1.740	38	1.000	-2.300
14	1.000	-2.890	39	1.000	-2.300
15	1.000	-2.900	40	1.004	-2.210
16	1.000	-2.920	41	1.004	-2.150
17	1.000	-2.920	42	1.003	-2.140
18	1.000	-2.880	43	1.035	1.470
19	1.000	-2.900	44	1.004	-2.150
20	1.000	-2.910	45	1.003	-2.140
21	1.013	-0.920	46	1.003	0.000
22	1.014	-0.850	47	1.013	-0.990
23	1.015	-0.770	48	1.012	-0.540
24	1.015	-0.770	49	1.012	-0.050
25	1.014	-0.780	50	1.012	-0.040

4.3.2.3 **Case 1-0**

In this simulation we used 0.200 €/h for the target value of the objective function and the maximum value of 0.350 €/h. These values are used to formulate the constraint (2.35) used in Model 3. Using this model in this Case, we obtained the following general results:

- There are no demand adjustments;
- The capacitor banks connected to nodes 1 and 5 inject 1.8 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.02768 MW and are balanced in node 55 (HV/MV substation);
- There are no branch congestions in the network and the voltage magnitude in nodes 43 and 53 are above the crisp limit of 1.03 pu;
- It was obtained a satisfaction degree of 0.489 that is associated to a value of the objective function of the crisp model of 0.277 €/h.

The detailed results are indicated in Tables 4.29 (generation and demand) and 4.30 (voltage magnitudes and phases).

Table 4.29 – Generation and demand values for Case 1-0 and using Model 3.

Bus i	∆Pgi MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0.4	0.492	0	0.9	0.436
14	-	-	-	0	0.838	0.275
15	-	-	-	0	0.838	0.275
16	-	-	-	0	0.419	0.138
17	-	-	-	0	0.419	0.138
18	-	-	-	0	0.838	0.275
19	-	-	-	0	0.838	0.275
20	-	-	-	0	0.419	0.138
36	-	-	-	0	0.216	0.105
37	-	-	-	0	0.135	0.065
38	-	-	-	0	0.135	0.065
39	-	-	-	0	0.086	0.042
40	-	-	-	0	0.216	0.105
41	-	-	-	0	0.135	0.065
42	-	-	-	0	0.086	0.042
43	0	1.5	0.271	-	-	-
44	-	-	-	0	0.135	0.065

45	-	-	-	0	0.086	0.042
46	0	0.7	-0.416	-	-	-
47	0	0	0.005	-	-	-
48	0	0.8	-0.3	-	-	-
49	0	0.25	0.1	-	-	-
50	0	0.25	0.1	-	-	-
51	0	0.25	0.1	-	-	-
52	0	0.25	0.1	-	-	-
53	0	0.25	0.1	-	-	-
55	0.028	2.117	-0.023	-	-	-

Table 4.30 – Voltage magnitude and phases for Case 1-0 and using Model 3.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	1.010	-0.990	29	1.023	-0.470
2	1.009	-1.010	30	1.022	-0.470
3	1.009	-1.030	31	1.021	-0.470
4	1.009	-1.040	32	1.021	-0.470
5	1.009	-1.050	33	1.029	-0.380
6	1.008	-1.060	34	1.021	-0.470
7	1.010	-1.000	35	1.021	-0.470
8	1.009	-1.000	36	0.998	-2.420
9	1.009	-1.000	37	1.001	-2.300
10	1.009	-1.000	38	1.003	-2.180
11	1.009	-1.000	39	1.003	-2.180
12	1.008	-1.060	40	1.007	-2.080
13	1.010	-1.770	41	1.008	-1.970
14	0.998	-2.900	42	1.007	-1.970
15	0.997	-2.920	43	1.035	1.640
16	0.997	-2.950	44	1.008	-1.970
17	0.997	-2.960	45	1.007	-1.970
18	0.998	-2.890	46	1.000	0.000
19	0.998	-2.900	47	1.010	-0.990
20	0.998	-2.900	48	1.007	-0.540
21	1.012	-0.890	49	1.021	0.700
22	1.014	-0.780	50	1.021	0.730
23	1.017	-0.670	51	1.021	0.730
24	1.017	-0.670	52	1.029	1.040
25	1.017	-0.670	53	1.035	1.220
26	1.016	-0.67	54	1.01	-0.4
27	1.02	-0.57	55	1.01	-0.39
28	1.024	-0.47	---	---	---

4.3.2.4 **Case 1-1**

In this simulation we used 0.200 €/h for the target value of the objective function and 0.350 €/h for its maximum value to formulate the constraint (2.35). Using this model in this Case, we obtained the following general results:

- There are no demand adjustments;
- The capacitor banks connected to nodes 1 and 5 inject 2.0 Mvar and 0.4 Mvar, respectively;
- Active power losses take the value of 0.02682 MW and are balanced in node 55 (HV/MV substation);
- There are no branch congestions and the voltage magnitude in nodes 33, 43, 52 and 53 are above the crisp limit of 1.03 pu;
- It was obtained a satisfaction degree of 0.546 that is associated to a value of the objective function of the crisp model of 0.268 €/h.

The detailed results are indicated in Tables 4.31 (generation and demand) and 4.32 (voltage magnitudes and phases).

Table 4.31 – Generation and demand values for Case 1-1 and using Model 3.

Bus i	∆Pgi MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0.4	0.5	0	0.9	0.436
14	-	-	-	0	0.838	0.275
15	-	-	-	0	0.838	0.275
16	-	-	-	0	0.419	0.138
17	-	-	-	0	0.419	0.138
18	-	-	-	0	0.838	0.275
19	-	-	-	0	0.838	0.275
20	-	-	-	0	0.419	0.138
36	-	-	-	0	0.216	0.105
37	-	-	-	0	0.135	0.065
38	-	-	-	0	0.135	0.065
39	-	-	-	0	0.086	0.042
40	-	-	-	0	0.216	0.105
41	-	-	-	0	0.135	0.065
42	-	-	-	0	0.086	0.042
43	0	1.5	0.263	-	-	-
44	-	-	-	0	0.135	0.065

45	-	-	-	0	0.086	0.042
46	0	0.7	-0.5	-	-	-
47	0	0	0.004	-	-	-
48	0	0.8	-0.3	-	-	-
49	0	0.25	0.1	-	-	-
50	0	0.25	0.1	-	-	-
51	0	0.25	0.1	-	-	-
52	0	0.25	0.1	-	-	-
53	0	0.25	0.1	-	-	-
55	0.027	2.116	-0.077	-	-	-

Table 4.32 – Voltage magnitude and phases for Case 1-1 and using Model 3.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	1.013	-0.990	29	1.027	-0.460
2	1.013	-1.000	30	1.025	-0.460
3	1.013	-1.020	31	1.024	-0.470
4	1.012	-1.020	32	1.024	-0.470
5	1.012	-1.030	33	1.032	-0.370
6	1.012	-1.030	34	1.024	-0.470
7	1.013	-1.000	35	1.024	-0.470
8	1.013	-1.010	36	1.002	-2.400
9	1.012	-1.020	37	1.004	-2.290
10	1.012	-1.020	38	1.007	-2.170
11	1.012	-1.030	39	1.006	-2.160
12	1.012	-1.030	40	1.010	-2.060
13	1.014	-1.730	41	1.011	-1.960
14	1.001	-2.880	42	1.011	-1.950
15	1.001	-2.900	43	1.038	1.630
16	1.001	-2.910	44	1.011	-1.960
17	1.001	-2.910	45	1.011	-1.950
18	1.001	-2.880	46	1.001	0.000
19	1.001	-2.890	47	1.013	-0.990
20	1.001	-2.900	48	1.010	-0.540
21	1.015	-0.880	49	1.024	0.700
22	1.018	-0.780	50	1.024	0.710
23	1.021	-0.670	51	1.024	0.700
24	1.021	-0.660	52	1.032	1.040
25	1.020	-0.660	53	1.038	1.220
26	1.02	-0.66	54	1.013	-0.4
27	1.024	-0.57	55	1.013	-0.39
28	1.028	-0.47	---	---	---

4.3.2.5 **Case 2-0**

In this simulation we used 0.220 €/h for the target value of the objective function and 0.330 €/h for its maximum value to formulate the constraint (2.35). Using this model in this Case, we obtained the following general results:

- There are no demand adjustments;
- The capacitor banks connected to nodes 1 and 5 inject 2.0 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.02700 MW and are balanced in node 55 (HV/MV substation);
- There are no branch congestions and the voltage magnitude in nodes 43 and 53 are above the crisp limit of 1.03 pu;
- It was obtained a satisfaction degree of 0.546 that is associated to a value of the objective function of the crisp model of 0.270 €/h.

The detailed results are indicated in Tables 4.33 (generation and demand) and 4.34 (voltage magnitudes and phases).

Table 4.33 – Generation and demand values for Case 2-0 and using Model 3.

Bus i	∆Pgi MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0.4	0.5	0	0.99	0.479
14	-	-	-	0	0.922	0.303
15	-	-	-	0	0.922	0.303
16	-	-	-	0	0.461	0.152
17	-	-	-	0	0.461	0.152
18	-	-	-	0	0.922	0.303
19	-	-	-	0	0.922	0.303
20	-	-	-	0	0.461	0.152
36	-	-	-	0	0.238	0.115
37	-	-	-	0	0.149	0.072
38	-	-	-	0	0.149	0.072
39	-	-	-	0	0.095	0.046
40	-	-	-	0	0.238	0.115
41	-	-	-	0	0.149	0.072
42	-	-	-	0	0.095	0.046
43	0	1.5	0.353	-	-	-
44	-	-	-	0	0.149	0.072

45	-	-	-	0	0.095	0.046
46	0	0.7	-0.5	-	-	-
47	0	0	0.01	-	-	-
48	0	0.8	-0.051	-	-	-
49	0	0.25	0.1	-	-	-
50	0	0.25	0.1	-	-	-
51	0	0.25	0.1	-	-	-
52	0	0.25	0.1	-	-	-
53	0	0.25	0.1	-	-	-
55	0.027	2.795	-0.199	-	-	-

Table 4.34 – Voltage magnitude and phases for Case 2-0 and using Model 3.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	1.010	-0.990	29	1.023	-0.540
2	1.010	-1.020	30	1.021	-0.540
3	1.009	-1.030	31	1.020	-0.540
4	1.009	-1.050	32	1.020	-0.540
5	1.009	-1.060	33	1.028	-0.460
6	1.009	-1.070	34	1.020	-0.540
7	1.010	-1.000	35	1.020	-0.540
8	1.010	-1.010	36	0.997	-2.590
9	1.010	-1.010	37	0.999	-2.490
10	1.010	-1.010	38	1.001	-2.390
11	1.010	-1.010	39	1.001	-2.380
12	1.008	-1.080	40	1.005	-2.290
13	1.009	-1.910	41	1.005	-2.200
14	0.997	-3.100	42	1.005	-2.200
15	0.997	-3.120	43	1.036	1.560
16	0.996	-3.150	44	1.005	-2.200
17	0.996	-3.160	45	1.005	-2.200
18	0.997	-3.080	46	0.998	0.000
19	0.997	-3.090	47	1.011	-0.990
20	0.997	-3.090	48	1.010	-0.550
21	1.012	-0.900	49	1.021	0.690
22	1.014	-0.810	50	1.022	0.730
23	1.017	-0.710	51	1.022	0.730
24	1.017	-0.710	52	1.029	1.000
25	1.016	-0.710	53	1.034	1.160
26	1.016	-0.71	54	1.01	-0.21
27	1.02	-0.63	55	1.01	-0.2
28	1.024	-0.54	---	---	---

4.3.2.6 **Case 3-0**

In this simulation we used 0.100 €/h for the target value of the objective function and 0.900 €/h for its maximum value to formulate the constraint (2.35). Using this model, we obtained the following general results:

- There are no demand adjustments;
- The capacitor banks connected to nodes 1 and 5 inject 1.4 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.04273 MW and are balanced in node 55 (HV/MV substation);
- Regarding congestions, the apparent flow in branch 1-2 is at the crisp limit, 3.5 MVA. However, this model uses a tolerance of 10% to formulate the soft apparent power limit constraints. The voltage magnitude in node 46, 1.031 pu, is above the crisp limit of 1,03 pu;
- It was obtained a satisfaction degree of 0.591 that is associated to a value of the objective function of the crisp model of 0.427 €/h.

The detailed results are indicated in Tables 4.35 and 4.36.

Table 4.35 – Generation and demand values for Case 2-0 and using Model 3.

Bus i	∆Pgi MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0.4	0.5	0	1.08	0.523
14	-	-	-	0	1.006	0.331
15	-	-	-	0	1.006	0.331
16	-	-	-	0	0.503	0.165
17	-	-	-	0	0.503	0.165
18	-	-	-	0	1.006	0.331
19	-	-	-	0	1.006	0.331
20	-	-	-	0	0.503	0.165
36	-	-	-	0	0.259	0.125
37	-	-	-	0	0.162	0.078
38	-	-	-	0	0.162	0.078
39	-	-	-	0	0.103	0.05
40	-	-	-	0	0.259	0.125
41	-	-	-	0	0.162	0.078
42	-	-	-	0	0.103	0.05

43	0	1.5	-0.335	-	-	-
44	-	-	-	0	0.162	0.078
45	-	-	-	0	0.103	0.05
46	0	0.7	0.5	-	-	-
47	0	0	0.01	-	-	-
48	0	0.8	0.294	-	-	-
49	0	0.25	0.1	-	-	-
50	0	0.25	0.1	-	-	-
51	0	0.25	0.1	-	-	-
52	0	0.25	-0.06	-	-	-
53	0	0.25	-0.063	-	-	-
55	0.043	3.481	0.371	-	-	-

Table 4.36 – Voltage magnitude and phases for Case 2-0 and using Model 3.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	1.019	-0.950	29	1.022	0.290
2	1.018	-0.980	30	1.020	0.290
3	1.018	-1.000	31	1.019	0.290
4	1.017	-1.010	32	1.019	0.290
5	1.017	-1.020	33	1.027	0.450
6	1.017	-1.030	34	1.019	0.290
7	1.018	-0.960	35	1.019	0.290
8	1.018	-0.970	36	1.002	-2.520
9	1.018	-0.970	37	1.002	-2.260
10	1.018	-0.970	38	1.002	-1.970
11	1.018	-0.970	39	1.002	-1.960
12	1.017	-1.040	40	1.005	-1.770
13	1.016	-1.980	41	1.003	-1.530
14	1.004	-3.220	42	1.002	-1.520
15	1.004	-3.240	43	1.018	2.510
16	1.003	-3.270	44	1.003	-1.530
17	1.003	-3.280	45	1.002	-1.520
18	1.004	-3.200	46	1.031	0.000
19	1.004	-3.210	47	1.019	-0.950
20	1.004	-3.210	48	1.022	-0.510
21	1.018	-0.700	49	1.029	0.700
22	1.019	-0.440	50	1.030	0.740
23	1.020	-0.190	51	1.030	0.740
24	1.019	-0.150	52	1.011	1.580
25	1.018	-0.150	53	1.014	2.020
26	1.018	-0.16	54	1.021	0

27	1.021	0.04	55	1.021	0.01
28	1.023	0.26	Xxx	xxx	xxx

4.3.3 Model 4

4.3.3.1 Case 0-0

In this simulation we used 0.040 €/h for the target value of the objective function and 0.150 €/h for its maximum value to formulate the constraint (2.53). Using this model, we obtained the following general results:

- There are no demand adjustments indicating that all ΔPci variables are zero;
- There are no generation adjustments required to enforce system constraints, namely voltage limits or branch flow limits. This means that ΔPg_i^{ajt} variables are zero;
- The capacitor banks connected to nodes 1 and 5 inject 1.8 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.02199 MW and are balanced in node 47 (distributed generation). This means that the ΔPg_i^{perd} variable associated to node 47 has a non zero value of 0.02168 MW;
- There are no branch congestions in the network in this case;
- The voltage magnitudes in all nodes are below the crisp value of 1.03 pu, that is, it was not necessary in this case to use the tolerance admitted for the voltage limit;
- It was obtained a satisfaction degree of 0.767 that is associated to a value of the objective function of the crisp model of 0.066 €/h.

The detailed results are indicated in Tables 4.37 (generation and demand) and 4.38 (voltage magnitudes and phases).

Table 4.37 – Generation and demand values for Case 0-0 and using Model 4.

Bus i	∆Pgi ajt MW	∆Pgi perd MW	Pgi MW	Qgi Mvar	∆Pci MW	Pci MW	Qci Mvar
13	0	0	0.4	0.5	0	0.9	0.436
14	-	-	-	-	0	0.838	0.275
15	-	-	-	-	0	0.838	0.275
16	-	-	-	-	0	0.419	0.138

17	-	-	-	-	0	0.419	0.138
18	-	-	-	-	0	0.838	0.275
19	-	-	-	-	0	0.838	0.275
20	-	-	-	-	0	0.419	0.138
36	-	-	-	-	0	0.216	0.105
37	-	-	-	-	0	0.135	0.065
38	-	-	-	-	0	0.135	0.065
39	-	-	-	-	0	0.086	0.042
40	-	-	-	-	0	0.216	0.105
41	-	-	-	-	0	0.135	0.065
42	-	-	-	-	0	0.086	0.042
43	0	0	1.5	0.444	-	-	-
44	-	-	-	-	0	0.135	0.065
45	-	-	-	-	0	0.086	0.042
46	0	0	0.7	-0.45	-	-	-
47	0	0.022	0.022	-0.003	-	-	-
48	0	0	0.8	-0.216	-	-	-
50	0	0	3.339	0.196	-	-	-

Table 4.38 – Voltage magnitude and phases for Case 0-0 and using Model 4.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	1.000	-1.010	26	1.001	-0.810
2	0.999	-1.030	27	1.006	-0.730
3	0.999	-1.050	28	1.009	-0.660
4	0.999	-1.060	29	1.007	-0.660
5	0.998	-1.070	30	1.006	-0.670
6	0.998	-1.080	31	1.005	-0.670
7	1.000	-1.020	32	1.004	-0.670
8	0.999	-1.030	33	1.014	-0.590
9	0.999	-1.030	34	1.005	-0.670
10	0.999	-1.030	35	1.004	-0.670
11	0.999	-1.030	36	0.987	-2.510
12	0.998	-1.080	37	0.988	-2.440
13	1.000	-1.800	38	0.988	-2.370
14	0.988	-2.960	39	0.988	-2.360
15	0.987	-2.980	40	0.992	-2.280
16	0.987	-3.000	41	0.991	-2.220
17	0.987	-3.010	42	0.991	-2.210
18	0.988	-2.950	43	1.023	1.480
19	0.988	-2.960	44	0.991	-2.220
20	0.987	-2.960	45	0.991	-2.210

21	1.000	-0.940	46	0.989	0.000
22	1.002	-0.870	47	1.000	-0.980
23	1.003	-0.800	48	0.998	-0.550
24	1.002	-0.810	49	1.002	-0.060
25	1.002	-0.810	50	1.002	-0.050

4.3.3.2 **Case 0-1**

In this simulation we used 0.040 €/h for the target value of the objective function and 0.150 €/h for its maximum value to formulate constraint (2.53). Using this model, we obtained the following general results:

- There are no demand adjustments indicating that all ΔPci variables are zero;
- There are no generation adjustments required to enforce system constraints, namely voltage limits or branch flow limits. This means that ΔPg_i^{ajt} variables are zero;
- The capacitor banks connected to nodes 1 and 5 inject 1.7 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.02204 MW and are balanced in node 47 (distributed generation). This means that the ΔPg_i^{perd} variable associated to node 47 has a non zero value of 0.02204 MW;
- There are no branch congestions in the network in this case;
- As in the previous case, the voltage magnitude in all nodes is below the crisp limit of 1.03 pu;
- It was obtained a satisfaction degree of 0.764 that is associated to a value of the objective function of the crisp model of 0.066 €/h.

The detailed results are indicated in Tables 4.39 (generation and demand) and 4.40 (voltage magnitudes and phases).

Table 4.39 – Generation and demand values for Case 0-1 and using Model 4.

Bus i	ΔPgi ajt MW	ΔPgi perd MW	Pgi MW	Qgi Mvar	ΔPci MW	Pci MW	Qci Mvar
13	0	0	0.4	0.5	0	0.9	0.436
14	-	-	-	-	0	0.838	0.275
15	-	-	-	-	0	0.838	0.275
16	-	-	-	-	0	0.419	0.138

17	-	-	-	-	0	0.419	0.138
18	-	-	-	-	0	0.838	0.275
19	-	-	-	-	0	0.838	0.275
20	-	-	-	-	0	0.419	0.138
36	-	-	-	-	0	0.216	0.105
37	-	-	-	-	0	0.135	0.065
38	-	-	-	-	0	0.135	0.065
39	-	-	-	-	0	0.086	0.042
40	-	-	-	-	0	0.216	0.105
41	-	-	-	-	0	0.135	0.065
42	-	-	-	-	0	0.086	0.042
43	0	0	1.5	0.434	-	-	-
44	-	-	-	-	0	0.135	0.065
45	-	-	-	-	0	0.086	0.042
46	0	0	0.7	-0.142	-	-	-
47	0	0.022	0.022	-0.01	-	-	-
48	0	0	0.8	-0.202	-	-	-
50	0	0	3.339	-0.018	-	-	-

Table 4.40 – Voltage magnitude and phases for Case 0-1 and using Model 4.

Bus i	Vi Pu	θi degree	Bus i	Vi Pu	θi degree
1	0.987	-1.030	26	0.988	-0.840
2	0.986	-1.050	27	0.993	-0.770
3	0.986	-1.060	28	0.996	-0.710
4	0.986	-1.070	29	0.994	-0.710
5	0.985	-1.080	30	0.993	-0.710
6	0.985	-1.080	31	0.992	-0.710
7	0.986	-1.050	32	0.991	-0.710
8	0.986	-1.060	33	1.001	-0.640
9	0.986	-1.070	34	0.992	-0.710
10	0.985	-1.070	35	0.991	-0.710
11	0.985	-1.080	36	0.973	-2.580
12	0.985	-1.080	37	0.975	-2.510
13	0.987	-1.820	38	0.975	-2.450
14	0.974	-3.030	39	0.974	-2.440
15	0.974	-3.050	40	0.979	-2.360
16	0.974	-3.070	41	0.978	-2.310
17	0.973	-3.070	42	0.978	-2.300
18	0.974	-3.030	43	1.012	1.480
19	0.974	-3.040	44	0.978	-2.310
20	0.974	-3.060	45	0.978	-2.300

21	0.987	-0.970	46	0.984	0.000
22	0.988	-0.900	47	0.987	-1.000
23	0.990	-0.840	48	0.986	-0.560
24	0.989	-0.840	49	0.988	-0.050
25	0.988	-0.840	50	0.988	-0.040

4.3.3.3 **Case 1-0**

In this simulation we used 0.050 €/h for the target value of the objective function and 0.150 €/h for its maximum value to formulate constraint (2.53). Using this model, we obtained the following general results:

- There are no demand adjustments indicating that all ΔPci variables are zero;
- There are no generation adjustments required to enforce system constraints, namely voltage limits or branch flow limits. This means that ΔPg_i^{ajt} variables are zero;
- The capacitor banks connected to nodes 1 and 5 inject 1.7 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.02864 MW and are balanced in node 47 (distributed generation). This means that the ΔPg_i^{perd} variable associated to node 47 has a non zero value of 0.02864 MW;
- There are no branch congestions in the network in this case;
- Voltage magnitudes in all nodes is below the crisp value of 1.03 pu;
- It was obtained a satisfaction degree of 0.642 that is associated to a value of the objective function of the crisp model of 0.086 €/h.

The detailed results are indicated in Tables 4.41 (generation and demand) and 4.42 (voltage magnitudes and phases).

Table 4.41 – Generation and demand values for Case 1-0 and using Model 4.

Bus i	ΔPgi ajt MW	ΔPgi perd MW	Pgi MW	Qgi Mvar	ΔPci MW	Pci MW	Qci Mvar
13	0	0	0.4	0.449	0	0.9	0.436
14	-	-	-	-	0	0.838	0.275
15	-	-	-	-	0	0.838	0.275
16	-	-	-	-	0	0.419	0.138
17	-	-	-	-	0	0.419	0.138
18	-	-	-	-	0	0.838	0.275

19	-	-	-	-	0	0.838	0.275
20	-	-	-	-	0	0.419	0.138
36	-	-	-	-	0	0.216	0.105
37	-	-	-	-	0	0.135	0.065
38	-	-	-	-	0	0.135	0.065
39	-	-	-	-	0	0.086	0.042
40	-	-	-	-	0	0.216	0.105
41	-	-	-	-	0	0.135	0.065
42	-	-	-	-	0	0.086	0.042
43	0	0	1.5	0.329	-	-	-
44	-	-	-	-	0	0.135	0.065
45	-	-	-	-	0	0.086	0.042
46	0	0	0.7	-0.37	-	-	-
47	0	0.029	0.029	-0.007	-	-	-
48	0	0	0.8	-0.2	-	-	-
49	0	0	0.25	0.1	-	-	-
50	0	0	0.25	0.1	-	-	-
51	0	0	0.25	0.1	-	-	-
52	0	0	0.25	0.1	-	-	-
53	0	0	0.25	0.1	-	-	-
55	0	0	2.089	-0.065	-	-	-

Table 4.42 – Voltage magnitude and phases for Case 1-0 and using Model 4.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	0.992	-1.030	29	1.006	-0.510
2	0.992	-1.050	30	1.005	-0.520
3	0.991	-1.060	31	1.004	-0.520
4	0.991	-1.070	32	1.003	-0.520
5	0.991	-1.080	33	1.012	-0.430
6	0.990	-1.090	34	1.004	-0.520
7	0.992	-1.040	35	1.003	-0.520
8	0.992	-1.040	36	0.980	-2.510
9	0.992	-1.040	37	0.983	-2.400
10	0.992	-1.040	38	0.985	-2.280
11	0.992	-1.040	39	0.985	-2.270
12	0.990	-1.090	40	0.989	-2.180
13	0.990	-1.820	41	0.990	-2.070
14	0.980	-3.010	42	0.990	-2.070
15	0.979	-3.020	43	1.019	1.660
16	0.979	-3.050	44	0.990	-2.070
17	0.979	-3.060	45	0.990	-2.070

18	0.980	-3.000	46	0.983	0.000
19	0.980	-3.000	47	0.992	-0.990
20	0.980	-3.000	48	0.990	-0.560
21	0.994	-0.920	49	1.003	0.730
22	0.997	-0.820	50	1.004	0.760
23	1.000	-0.710	51	1.004	0.760
24	1.000	-0.710	52	1.012	1.060
25	0.999	-0.710	53	1.018	1.230
26	0.999	-0.71	54	0.993	-0.42
27	1.003	-0.62	55	0.993	-0.41
28	1.007	-0.52	---	---	---

4.3.3.4 **Case 1-1**

In this simulation we used 0.050 €/h for the target value of the objective function and 0.150 €/h for its maximum value to formulate constraint (2.53). Using this model, we obtained the following general results:

- There are no demand adjustments indicating that all ΔPci variables are zero;
- There are no generation adjustments required to enforce system constraints, namely voltage limits or branch flow limits. This means that ΔPg_i^{ajt} variables are zero;
- The capacitor banks connected to nodes 1 and 5 inject 1.8 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.02835 MW and are balanced in node 47 (distributed generation). This means that the ΔPg_i^{perd} variable associated to node 47 has a non zero value of 0.02835 MW;
- There are no branch congestions in the network in this case;
- The voltage magnitude in all nodes is below the crisp limit of 1.03 pu;
- It was obtained a satisfaction degree of 0.651 that is associated to a value of the objective function of the crisp model of 0.085 €/h.

The detailed results are indicated in Tables 4.43 (generation and demand) and 4.44 (voltage magnitudes and phases).

Table 4.43 – Generation and demand values for Case 1-1 and using Model 4.

Bus i	ΔPgi ajt	ΔPgi perd	Pgi	Qgi	ΔPci	Pci	Qci

	MW	MW	MW	Mvar	MW	MW	Mvar
13	0	0	0.4	0.5	0	0.9	0.436
14	-	-	-	-	0	0.838	0.275
15	-	-	-	-	0	0.838	0.275
16	-	-	-	-	0	0.419	0.138
17	-	-	-	-	0	0.419	0.138
18	-	-	-	-	0	0.838	0.275
19	-	-	-	-	0	0.838	0.275
20	-	-	-	-	0	0.419	0.138
36	-	-	-	-	0	0.216	0.105
37	-	-	-	-	0	0.135	0.065
38	-	-	-	-	0	0.135	0.065
39	-	-	-	-	0	0.086	0.042
40	-	-	-	-	0	0.216	0.105
41	-	-	-	-	0	0.135	0.065
42	-	-	-	-	0	0.086	0.042
43	0	0	1.5	0.299	-	-	-
44	-	-	-	-	0	0.135	0.065
45	-	-	-	-	0	0.086	0.042
46	0	0	0.7	-0.49	-	-	-
47	0	0.028	0.028	-0.009	-	-	-
48	0	0	0.8	-0.297	-	-	-
49	0	0	0.25	0.1	-	-	-
50	0	0	0.25	0.1	-	-	-
51	0	0	0.25	0.1	-	-	-
52	0	0	0.25	0.1	-	-	-
53	0	0	0.25	0.1	-	-	-
55	0	0	2.089	0.043	-	-	-

Table 4.44 – Voltage magnitude and phases for Case 1-1 and using Model 4.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	0.984	-1.050	29	0.999	-0.530
2	0.984	-1.060	30	0.997	-0.530
3	0.984	-1.070	31	0.996	-0.530
4	0.984	-1.080	32	0.996	-0.530
5	0.983	-1.090	33	1.004	-0.440
6	0.983	-1.090	34	0.996	-0.530
7	0.984	-1.060	35	0.996	-0.530
8	0.984	-1.070	36	0.973	-2.560
9	0.984	-1.070	37	0.975	-2.440

10	0.983	-1.080	38	0.978	-2.320
11	0.983	-1.080	39	0.977	-2.310
12	0.983	-1.090	40	0.982	-2.220
13	0.985	-1.830	41	0.982	-2.110
14	0.972	-3.050	42	0.982	-2.110
15	0.972	-3.070	43	1.011	1.670
16	0.972	-3.080	44	0.982	-2.110
17	0.971	-3.080	45	0.982	-2.110
18	0.972	-3.050	46	0.972	0.000
19	0.972	-3.060	47	0.985	-1.010
20	0.972	-3.070	48	0.982	-0.570
21	0.986	-0.940	49	0.996	0.750
22	0.989	-0.840	50	0.996	0.760
23	0.992	-0.730	51	0.995	0.750
24	0.992	-0.720	52	1.004	1.070
25	0.992	-0.730	53	1.011	1.250
26	0.991	-0.73	54	0.985	-0.43
27	0.995	-0.63	55	0.985	-0.42
28	0.999	-0.53	---	---	---

4.3.3.5 **Case 2-0**

In this simulation we used 0,074 €/h for the target value of the objective function and 0,100 €/h for its maximum value to formulate constraint (2.53). Using this model, we obtained the following general results:

- There are no demand adjustments indicating that all ΔPci variables are zero;
- There are no generation adjustments required to enforce system constraints, namely voltage limits or branch flow limits. This means that ΔPg_i^{ajt} variables are zero;
- The capacitor banks connected to nodes 1 and 5 inject 1,7 Mvar and 0,5 Mvar, respectively;
- Active power losses take the value of 0.02794 MW and are balanced in node 47 (distributed generation). This means that the ΔPg_i^{perd} variable associated to node 47 has a non zero value of 0.02794 MW;
- There are no branch congestions in the network in this case;
- The voltage magnitudes in all nodes is below the crisp limit of 1.03 pu;

- It was obtained a satisfaction degree of 0.728 that is associated to a value of the objective function of the crisp model of 0.084 €/h.

The detailed results are indicated in Tables 4.45 (generation and demand) and 4.46 (voltage magnitudes and phases).

Table 4.45 – Generation and demand values for Case 2-0 and using Model 4.

Bus i	ΔPgi ajt MW	ΔPgi perd MW	Pgi MW	Qgi Mvar	ΔPci MW	Pci MW	Qci Mvar
13	0	0	0.4	0.5	0	0.99	0.479
14	-	-	-	-	0	0.922	0.303
15	-	-	-	-	0	0.922	0.303
16	-	-	-	-	0	0.461	0.152
17	-	-	-	-	0	0.461	0.152
18	-	-	-	-	0	0.922	0.303
19	-	-	-	-	0	0.922	0.303
20	-	-	-	-	0	0.461	0.152
36	-	-	-	-	0	0.238	0.115
37	-	-	-	-	0	0.149	0.072
38	-	-	-	-	0	0.149	0.072
39	-	-	-	-	0	0.095	0.046
40	-	-	-	-	0	0.238	0.115
41	-	-	-	-	0	0.149	0.072
42	-	-	-	-	0	0.095	0.046
43	0	0	1.5	0.328	-	-	-
44	-	-	-	-	0	0.149	0.072
45	-	-	-	-	0	0.095	0.046
46	0	0	0.7	-0.052	-	-	-
47	0	0.028	0.028	-0.01	-	-	-
48	0	0	0.8	-0.299	-	-	-
49	0	0	0.25	0.1	-	-	-
50	0	0	0.25	0.1	-	-	-
51	0	0	0.25	0.1	-	-	-
52	0	0	0.25	0.1	-	-	-
53	0	0	0.25	0.1	-	-	-
55	0	0	2.768	-0.063	-	-	-

Table 4.46 – Voltage magnitude and phases for Case 2-0 and using Model 4.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	0.993	-1.020	29	1.006	-0.540
2	0.992	-1.040	30	1.004	-0.540
3	0.992	-1.060	31	1.003	-0.540
4	0.992	-1.070	32	1.003	-0.540
5	0.991	-1.090	33	1.011	-0.460
6	0.991	-1.090	34	1.003	-0.540
7	0.993	-1.030	35	1.003	-0.540
8	0.992	-1.030	36	0.979	-2.670
9	0.992	-1.030	37	0.982	-2.570
10	0.992	-1.030	38	0.984	-2.460
11	0.992	-1.030	39	0.983	-2.450
12	0.991	-1.100	40	0.988	-2.360
13	0.991	-1.960	41	0.988	-2.270
14	0.979	-3.200	42	0.988	-2.260
15	0.979	-3.220	43	1.019	1.620
16	0.978	-3.250	44	0.988	-2.270
17	0.978	-3.260	45	0.988	-2.260
18	0.980	-3.180	46	0.993	0.000
19	0.979	-3.190	47	0.993	-0.980
20	0.979	-3.190	48	0.990	-0.550
21	0.995	-0.920	49	1.004	0.730
22	0.997	-0.820	50	1.004	0.770
23	1.000	-0.730	51	1.004	0.770
24	1.000	-0.720	52	1.012	1.050
25	0.999	-0.720	53	1.017	1.210
26	0.998	-0.72	54	0.993	-0.21
27	1.003	-0.64	55	0.993	-0.2
28	1.007	-0.55	---	---	---

4.3.3.6 **Case 3-0**

In this simulation we used 0.074 €/h for the target value of the objective function and 0.100 €/h for its maximum value to formulate the constraint (2.53). Using this model, we obtained the following general results:

- There are no demand adjustments indicating that all ΔPci variables are zero;

- There are no generation adjustments required to enforce system constraints, namely voltage limits or branch flow limits. This means that ΔPg_i^{ajt} variables are zero;
- The capacitor banks connected to nodes 1 and 5 inject 1.6 Mvar and 0.5 Mvar, respectively;
- Active power losses take the value of 0.02726 MW and are balanced in node 47 (distributed generation). This means that the ΔPg_i^{perd} variable associated to node 47 has a non zero value of 0.02726 MW;
- Regarding congestions, the active, reactive and apparent flows in branch 1-2 are at 3.453 MW, 0.557 Mvar and 3.5 MVA. This value equals the branch crisp apparent power limit of 3.5 MVA, indicating that this branch is congested. However, it should be noticed that apparent power flows can assume values larger than 3.5 MVA, given that the corresponding limit constraints were formulated in a soft way using a tolerance as it was described in Section 2.7.1;
- The voltage magnitude in all nodes is below the crisp limit of 1.03 pu;
- It was obtained a satisfaction degree of 0.703 that is associated to a value of the objective function of the crisp model of 0.082 €/h.

The detailed results are indicated in Tables 4.47 (generation and demand) and 4.48 (voltage magnitudes and phases).

Table 4.47 – Generation and demand values for Case 3-0 and using Model 4.

Bus i	ΔPgi ajt MW	ΔPgi perd MW	Pgi MW	Qgi Mvar	ΔPci MW	Pci MW	Qci Mvar
13	0	0	0.4	0.5	0	1.08	0.523
14	-	-	-	-	0	1.006	0.331
15	-	-	-	-	0	1.006	0.331
16	-	-	-	-	0	0.503	0.165
17	-	-	-	-	0	0.503	0.165
18	-	-	-	-	0	1.006	0.331
19	-	-	-	-	0	1.006	0.331
20	-	-	-	-	0	0.503	0.165
36	-	-	-	-	0	0.259	0.125
37	-	-	-	-	0	0.162	0.078
38	-	-	-	-	0	0.162	0.078
39	-	-	-	-	0	0.103	0.05

40	-	-	-	-	0	0.259	0.125
41	-	-	-	-	0	0.162	0.078
42	-	-	-	-	0	0.103	0.05
43	0	0	1.5	0.344	-	-	-
44	-	-	-	-	0	0.162	0.078
45	-	-	-	-	0	0.103	0.05
46	0	0	0.7	0.2	-	-	-
47	0	0.027	0.027	-0.01	-	-	-
48	0	0	0.8	-0.238	-	-	-
49	0	0	0.25	0.1	-	-	-
50	0	0	0.25	0.1	-	-	-
51	0	0	0.25	0.1	-	-	-
52	0	0	0.25	0.1	-	-	-
53	0	0	0.25	0.1	-	-	-
55	0	0	3.438	0.038	-	-	-

Table 4.48 – Voltage magnitude and phases for Case 3-0 and using Model 4.

Bus i	Vi pu	θi degree	Bus i	Vi pu	θi degree
1	1.005	-0.990	29	1.016	-0.550
2	1.004	-1.010	30	1.014	-0.550
3	1.003	-1.030	31	1.013	-0.550
4	1.003	-1.040	32	1.012	-0.550
5	1.003	-1.060	33	1.022	-0.480
6	1.002	-1.070	34	1.013	-0.550
7	1.004	-1.000	35	1.012	-0.550
8	1.004	-1.000	36	0.989	-2.760
9	1.004	-1.000	37	0.991	-2.670
10	1.004	-1.000	38	0.993	-2.570
11	1.004	-1.000	39	0.993	-2.550
12	1.002	-1.070	40	0.997	-2.470
13	1.002	-2.040	41	0.996	-2.390
14	0.990	-3.310	42	0.996	-2.380
15	0.989	-3.330	43	1.030	1.570
16	0.989	-3.370	44	0.996	-2.390
17	0.988	-3.380	45	0.996	-2.380
18	0.990	-3.300	46	1.011	0.000
19	0.990	-3.300	47	1.004	-0.950
20	0.990	-3.300	48	1.004	-0.530
21	1.006	-0.900	49	1.015	0.720
22	1.008	-0.810	50	1.016	0.760
23	1.010	-0.720	51	1.016	0.760

24	1.010	-0.710	52	1.022	1.020
25	1.009	-0.710	53	1.027	1.170
26	1.009	-0.71	54	1.005	-0.01
27	1.013	-0.64	55	1.005	0
28	1.017	-0.55	---	---	---

5. Comments

Considering the results detailed in Section 4, we will now present some comments and conclusions:

- In the first place, the simulations conducted on both test networks (considering the 50 node and 55 node versions) indicate that this distribution network is very robust, since in general there are no load curtailment situations, branch overloads or voltage problems;
- Considering the crisp models, Models 1 and 2, the only situation in which there is load curtailment is associated with Case 3-0 using Model 1 (simulation detailed in Section 4.2.2.6). In this case, load curtailment occurs in node 13 and active losses inside the distribution network are balanced in node 55 (substation node). In this case the network operates in open loop and this together with the apparent power limit of branch 1-2 (3,5 MVA) determines the impossibility of supplying the entire load of this feeder because branch 1-2 gets congested;
- When using Model 2 in the same situation (microgrid sources connected, demand increased by 20% and operation in open loop) this load curtailment no longer occurs. This is because Model 2 considers for each generator two types of adjustment variables, the one to contribute to balance active losses and the one used to adjust active power required to enforce system constraints. As a result, active losses inside the distribution network are no longer balanced by the upper voltage network connected to the substation in node 55 but rather in node 47 (distributed source). This new strategy in balancing active power losses contributes to alleviate the apparent power flow constraint of branch 1-2 thus making room to supply the entire demand in node 13;
- This means that Model 2 is more flexible than Model 1, namely because it decouples the contribution to balance active losses and the active power adjustments required to enforce system constraints. As a result, Model 2 (or Model 4, the corresponding Fuzzy Linear Programming version) is more adjusted to model the operation of distribution networks allowing the development of the balancing of active losses ancillary service, namely because it incorporates a

transparent way of assigning active losses to the generators or other supply nodes;

- When using Models 1 and 2 there no voltage problems since the voltage profiles display values close to 1.0 pu;
- When using Models 3 and 4, one is allowing tolerances on the voltage limits and on the branch apparent power limits. This means turning the operation more flexible since we are admitting violations of the crisp original limits. This increased flexibility explains that when using Model 3 there are several nodes in the six simulations in which the voltage magnitude is above the crisp limit of 1.03 pu (value used in the simulations with Models 1 and 2) but below the soft limit of 1.05 pu (corresponding to the addition of the crisp limit and the specified tolerance of 0.02 pu). As an example, in Case 1-1 using Model 3 (detailed in Section 4.3.2.4, Tables 4.31 and 4.32) the voltage magnitude in nodes 33, 43, 52 and 53 are above 1.03 pu but below 1.05 pu. It should be mentioned that these nodes are associated with microgrid sources. The reactive power generation in these microgrid sources explain the elevation of the voltage magnitude in these nodes;
- When using Model 4 in the same cases, voltage magnitudes get below the crisp limit of 1.03 pu. This means that using Model 4 the flexibility given by the tolerance of 0.02 pu admitted for the voltage limit constraints was not used. This is explained given the fact that in Model 4 there is a decoupling of the generation adjustment variables in variables to contribute to compensate active losses and variables used to enforce system constraints. This allows generating active power to compensate active losses differently from what was obtained for Model 3. In case of Model 3, the active power to compensate active losses comes from the upper voltage level network through the HV/MV substation while when using Model 4 this power is generated in node 47, from a distributed generation source, turning it easier to control voltage through the network;
- Regarding the active losses in the distribution network, it should be mentioned that active losses display no significant reductions when closing the breaker between nodes NMVL5 and NMVL10, thus creating a loop;

- Comparing the situations in which the microgrids are not considered regarding the ones in which they are considered (for instance, comparing Case 0-0 to Case 1-0 and Case 0-1 to Case 1-1) the active power losses increase. This situation can be identified in Table 5.1 that details the values of active losses in the 6 studied cases for each of the four models.

Table 5.1 – Active losses in the analyzed Cases.

Case			Model 1	Model 2	Model 3	Model 4
0-0	open loop	without mg	0.0218	0.02168	0.0214	0.02199
0-1	closed loop	without mg	0.0212	0.02185	0.0210	0.02204
1-0	open loop	with mg	0.0281	0.02911	0.02768	0.02864
1-1	closed loop	with mg	0.02725	0.02921	0.02682	0.02835
2-0	open loop	with mg	0.02731	0.02853	0.0270	0.02794
3-0	open loop	with mg	0.05053	0.02735	0.04273	0.02726

The reason for this behaviour is related with the balance between the demand and the generation from the microsources in the left hand side feeder of the network and the right hand side feeder. It happens that the feeder on the right hand side has a generation from distributed sources that is larger than the demand connected to it. On the contrary, on the left feeder the demand is larger than the distributed generation. As a result of these profiles, there is a power flow (in fact, just an active power flow) from the right hand side feeder to the left hand side feeder. When the microsources are connected (in cases 0-1 and 1-1) the excess of generation on the right hand side feeder is even larger than when the microsources are disconnected (that is, in cases 0-0 and 1-0) and so the flow from the right side to the left increases. This leads to the increase of active losses namely in the branches closer to the microsources and also closer to the substation MV busbar. In order to illustrate this behaviour let us consider the following cases:

- Case 0-0 (open loop, without microsources): total generation, excluding losses, takes the value of 6.739 MW from which 3.739 MW are generated on the left side (including power injected in node 1 coming from the substation and also from nodes 46 and 48) and 3.0 MW generated at the right side. The demand is distributed by the two sides with the following values: 5.509 MW on the left side and 1.23 MW connected to the right side. As a result and excluding active losses, there is an active flow from the right side to the left side of 1.77 MW;

- Case 1-0 (open loop, with microsources): total generation, excluding losses, takes the value of 6.739 MW from which 3.239 MW are generated on the left side (including power injected in node 1 coming from the substation and also from nodes 46 and 48) and 3.5 MW generated at the right side. The demand has the same distribution as indicated in Case 0-0, that is 5.509 MW on the left side and 1.23 MW connected to the right side. As a result and excluding active losses, there is an active flow from the right side to the left side of 2.27 MW.

- As a final comment regarding the behaviour of active losses, it should be mentioned that, from this point of view, the connection and operation of microsources should be done carefully in terms of connecting nodes and maximum injected powers. Otherwise, one can face situations as the one illustrated above in which an imbalance between the distribution of the demand and distributed generation creates larger flows and so increases active losses in the networks under analysis;
- Regarding the transmission capacity of the network, the connection of the microgrid sources has a positive impact because it is responsible for the reduction of the power flows in several branches. As an example, when increasing the demand by 10% or 20% having the microgrid sources connected there are no congestion problems, with the exception of Case 3-0 using Model 1, due to the reasons already explained above. This confirms that the connection of sources closer to the loads has a positive impact in reducing the flows in several branches thus eventually turning it possible to postpone investments in transmission capacity.

6. References

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7. Annex I – Test Network Data

7.1 General Indications

The simulations were performed considering two networks derived from the test network presented in Section 3, as follows:

- Test network that does not include the microgrids. In this case, the network has 50 nodes and regarding the network in Figure 3.1 of Section 3 nodes 49 to 53 were eliminated and the nodes 54 and 55 were renumbered passing to nodes 49 and 50. The required changes were also made on the connectivity data of the branches;
- Test network that includes the microgrids and respective connection transformers. This network has 55 nodes and corresponds to the one depicted in Figure 3.1.

Both test networks include capacitors connected to nodes 1 and 5 with a rated power of 2.0 Mvar and 0.5 Mvar, respectively.

7.2 Test Network with 50 Nodes

Table 7.1 details the data for the generation/supply system for the 50 node network. It includes the minimum and maximum active and reactive powers used in the characterization of the capability diagrams of the generators and the maximum active power adjustment in % and the respective adjustment cost.

Table 7.1 – Data for the generation/supply system of the 50 node test network.

					adjustment data		
bus i	Pgmin MW	Pgmax MW	Qgmin MVar	Qgmax MVar	∆Pgi %	Cadj €/MWh	
13	0	0.4	-0.5	0.5	100	50	PD – CHP
43	0	1.5	-0.5	1	100	50	PD - Hydro; It includes a capacitor with 0,5 Mvar
46	0	0.7	-0.5	0.5	100	15	PD – Diesel
47	0	0.1	-0.01	0.01	100	35	PD – VSI
48	0	0.8	-0.3	0.3	100	10	PD – DFIM
50	0	7	-2.5	2.5	20	10	substation - NBASE

Table 7.2 details the active and reactive demand values. For each node it also indicates the corresponding power factor and the demand adjustment price. This cost is interpreted as the per unit remuneration each load wants to receive if it is curtailed.

Table 7.2 – Load data for the 50 node test network.

				adjustment cost
bus j	Pcj MW	Qcj MVar	cos φ	Ccajt €/MWh
13	0.9	0.436	0.9	100
14	0.838	0.275	0.95	100
15	0.838	0.275	0.95	100
16	0.419	0.138	0.95	100
17	0.419	0.138	0.95	100
18	0.838	0.275	0.95	100
19	0.838	0.275	0.95	100
20	0.419	0.138	0.95	100
36	0.216	0.105	0.9	100
37	0.135	0.065	0.9	100
38	0.135	0.065	0.9	100
39	0.086	0.042	0.9	100
40	0.216	0.105	0.9	100
41	0.135	0.065	0.9	100
42	0.086	0.042	0.9	100
44	0.135	0.065	0.9	100
45	0.086	0.042	0.9	100

Table 7.3 details the branch data, namely the resistance, reactance and susceptance of each branch, the apparent power limit and a general indication on the nature of the branch.

Table 7.3 – Branch data for the 50 node test network.

bus i	bus j	rij pu	xij pu	ysh pu	Sijmax MVA	
1	2	0.0204	0.01508	2.76E-05	3.5	
1	7	0.0204	0.01508	2.76E-05	3.5	
1	21	0.29236	0.1576	2.90E-06	2	
1	46	0	2.5	0	2	transformer
1	47	0	2.5	0	4	transformer

1	48	0	1	0	10	Transformer
1	49	0	0.5	0	7	transf. substation
2	3	0.0204	0.01508	2.76E-05	3	
2	14	0	3.968254	0	1.26	transformer
3	4	0.0204	0.01508	2.76E-05	2	
3	15	0	3.968254	0	1.26	transformer
4	5	0.0204	0.01508	2.76E-05	2	
5	6	0.0204	0.01508	2.76E-05	2	
5	16	0	7.936508	0	0.63	transformer
6	12	0.0204	0.01508	2.76E-05	2	
6	17	0	7.936508	0	0.63	transformer
7	8	0.0204	0.01508 2	7.60E-06	3	
7	18	0	3.968254	0	1.26	transformer
8	9	0.0204	0.01508 2	7.60E-06	2	
8	19	0	3.968254	0	1.26	transformer
9	10	0.0204	0.01508 2	7.60E-06	2	
10	11	0.0204	0.01508	2.76E-05	2	
10	20	0	7.936508	0	0.63	transformer
11	12	2 0.02	04 0.01508	2.76E-05	2	loop breaker
12	13	0	2.5	0	2	transformer
21	22	0.29236	0.1576	2.90E-06	2	
21	36	0	12.5	0	0.4	transformer
22	23	0.29236	0.1576	2.90E-06	2	
22	37	0	20	0	0.25	transformer
23	24	0.29236	0.1576	2.90E-06	2	
23	27	0.29236	0.1576	2.90E-06	2	
24	25	0.29236	0.1576	2.90E-06	2	
25	26	0.29236	0.1576	2.90E-06	2	
25	38	0	20	0	0.25	transformer
26	39	0	31.25	0	0.16	transformer
27	28	0.29236	0.1576	2.90E-06	2	
27	40	0	12.5	0	0.4	transformer
28	29	0.29236	0.1576	2.90E-06	2	
28	33	0.29236	0.1576	2.90E-06	2	
29	30	0.29236	0.1576	2.90E-06	2	
30	31	0.29236	0.1576	2.90E-06	2	
30	34	0.29236	0.1576	2.90E-06	2	
31	32	0.29236	0.1576	2.90E-06	2	
31	41	0	20	0	0.25	transformer
32	42	0	31.25	0	0.16	transformer
33	43	0	2.5	0	2	transformer
34	35	0.29236	0.1576	2.90E-06	2	
34	44	0	20	0	0.25	transformer

35	45	0	31.25	0	0.16	transformer
49	50	0.0017	0.0058	0.00095	7	substation – NBASE

7.3 Test Network with 55 Nodes

Tables 7.4, 7.5 and 7.6 include similar data as mentioned for Tables 7.1, 7.2 and 7.3 in Section 7.2 for the 50 node test network.

Table 7.4 – Data for the generation/supply system of the 55 node test network.

					adjustment data		
bus i	Pgmin MW	Pgmax MW	Qgmin MVar	Qgmax MVar	∆Pgi %	Cgajt €/MW.h	
13	0	0.4	-0.5	0.5	100	50	PD – CHP
43	0	1.5	-0.5	1	100	50	PD - Hydro; It includes a capacitor with 0.5 Mvar
46	0	0.7	-0.5	0.5	100	15	PD – Diesel
47	0	0.1	-0.01	0.01	100	35	PD – VSI
48	0	0.8	-0.3	0.3	100	10	PD – DFIM
49	0	0.25	-0.1	0.1	100	10	microgrid 1
50	0	0.25	-0.1	0.1	100	10	microgrid 2
51	0	0.25	-0.1	0.1	100	10	microgrid 3
52	0	0.25	-0.1	0.1	100	10	microgrid 4
53	0	0.25	-0.1	0.1	100	10	microgrid 5
55	0	7	-2.5	2.5	20	10	substation – NBASE

Table 7.5 – Load data for the 55 node test network.

				adjustment cost
bus j	Pcj MW	Qcj MVar	cos φ	Ccajt €/MWh
13	0.9	0.436	0.9	100
14	0.838	0.275	0.95	100
15	0.838	0.275	0.95	100
16	0.419	0.138	0.95	100
17	0.419	0.138	0.95	100
18	0.838	0.275	0.95	100
19	0.838	0.275	0.95	100
20	0.419	0.138	0.95	100
36	0.216	0.105	0.9	100
37	0.135	0.065	0.9	100

38	0.135	0.065	0.9	100
39	0.086	0.042	0.9	100
40	0.216	0.105	0.9	100
41	0.135	0.065	0.9	100
42	0.086	0.042	0.9	100
44	0.135	0.065	0.9	100
45	0.086	0.042	0.9	100

Table 7.6 – Branch data for the 55 node test network.

bus i	bus j	rij pu	xij pu	ysh pu	Sijmax MVA	
1	2	0.0204	0.01508	2.76E-05	3.5	
1	7	0.0204	0.01508	2.76E-05	3.5	
1	21	0.29236	0.1576	2.90E-06	2	
1	46	0	2.5	0	2	transformer
1	47	0	2.5	0	4	transformer
1	48	0	1	0	10	transformer
1	54	0	0.5	0	7	transf. substation
2	3	0.0204	0.01508	2.76E-05	3	
2	14	0	3.968254	0	1.26	transformer
3	4	0.0204	0.01508	2.76E-05	2	
3	15	0	3.968254	0	1.26	transformer
4	5	0.0204	0.01508	2.76E-05	2	
4	49	0	12.5	0	0.4	transformer
5	6	0.0204	0.01508	2.76E-05	2	
5	16	0	7.936508	0	0.63	transformer
6	12	0.0204	0.01508	2.76E-05	2	
6	17	0	7.936508	0	0.63	transformer
7	8	0.0204	0.01508 2	7.60E-06	3	
7	18	0	3.968254	0	1.26	transformer
8	9	0.0204	0.01508 2	7.60E-06	2	
8	19	0	3.968254	0	1.26	transformer
9	10	0.0204	0.01508 2	7.60E-06	2	
9	50	0	12.5	0	0.4	transformer
10	11	0.0204	0.01508	2.76E-05	2	
10	20	0	7.936508	0	0.63	transformer
11	12	2 0.02	04 0.01508	2.76E-05	2	loop breaker
11	51	0	12.5	0	0.4	transformer
12	13	0	2.5	0	2	transformer
21	22	0.29236	0.1576	2.90E-06	2	
21	36	0	12.5	0	0.4	transformer
22	23	0.29236	0.1576	2.90E-06	2	

22	37	0	20	0	0.25	T transformer
23	24	0.29236	0.1576	2.90E-06	2	
23	27	0.29236	0.1576	2.90E-06	2	
24	25	0.29236	0.1576	2.90E-06	2	
24	52	0	12.5	0	0.4	transformer
25	26	0.29236	0.1576	2.90E-06	2	
25	38	0	20	0	0.25	transformer
26	39	0	31.25	0	0.16	transformer
27	28	0.29236	0.1576	2.90E-06	2	
27	40	0	12.5	0	0.4	transformer
28	29	0.29236	0.1576	2.90E-06	2	
28	33	0.29236	0.1576	2.90E-06	2	

Table 7.6 – Branch data for the 55 node test network (cont.).

bus i	bus j	rij pu	xij pu	ysh pu	Sijmax MVA	
29	30	0.29236	0.1576	2.90E-06	2	
29	53	0	12.5	0	0.4	transformer
30	31	0.29236	0.1576	2.90E-06	2	
30	34	0.29236	0.1576	2.90E-06	2	
31	32	0.29236	0.1576	2.90E-06	2	
31	41	0	20	0	0.25	transformer
32	42	0	31.25	0	0.16	transformer
33	43	0	2.5	0	2	transformer
34	35	0.29236	0.1576	2.90E-06	2	
34	44	0	20	0	0.25	transformer
35	45	0	31.25	0	0.16	transformer
54	55	0.0017	0.0058	0.00095	7	substation – NBASE

Microgrid Solution for Future Provision of Energy and Ancillary Services

Table of Contents

Acronyms and Abbreviations

DER - Distributed Energy Resource

DG – Distributed Generation

DMS – Distribution Management System

DSM – Demand Side Management

DSO – Distribution System Operator

HV – High Voltage

LC – Load Controller

LV – Low Voltage

MC – Microsource Controller

MGCC – MicroGrid Central Controller

OLTC – On-Line Tap Changer

OPF – Optimal Power Flow

TSO - Transmission System Operator

VPP – Virtual Power Plant

1. Introduction

The main objective of this report is to demonstrate the ability of a microgrid system to contribute to both local and system support services particularly in the forms of reserve and voltage control while simultaneously optimising the portfolio of energy production in order to maximise the overall social welfare.

2. Background

According to the analysis previously conducted within the More Microgrid project and based on realistic scenarios from partners in different countries [1], a significant portion of our future energy consumption might be supplied by domestic or small scale Distributed Generation (DG). In this respect, Figure 1 shows one of plausible scenarios of future UK Low Carbon generation mixes, developed by the Environmental Change Institute, Oxford. According to this scenario, the growth of domestic DG will start in 2025 onwards and its installed capacity will be about 40% of the overall generating capacity in 2050. Similar trends can be expected throughout Europe. It is therefore crucial that DG, once reaching such significant capacity level, can displace capacity of central generation and to provide not only energy but ancillary services needed by the system.

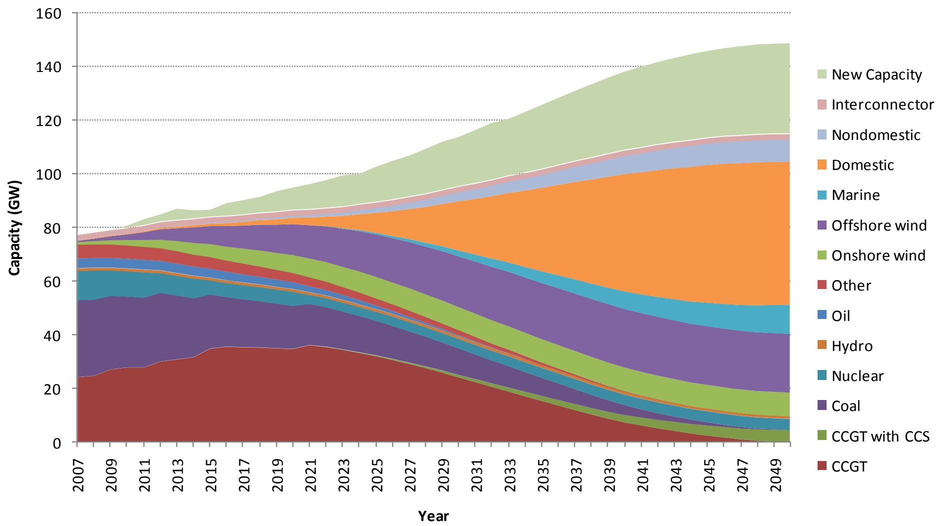

Figure 1: UK Low carbon scenario (source: ECI, Oxford)

Previous work in the Microgrids project has demonstrated that the implementation of a microgrid system will provide a solid framework for a full integration of DG and demand side into network operation as proposed in the "active future". DG and demand side will take the responsibility for delivery of system support services, taking over the role of central generation. In this context, DG will be able to displace not only energy produced by central generation but also its controllability, and, together with demand side, to reduce the system capacity requirements as illustrated in the Figure 2.

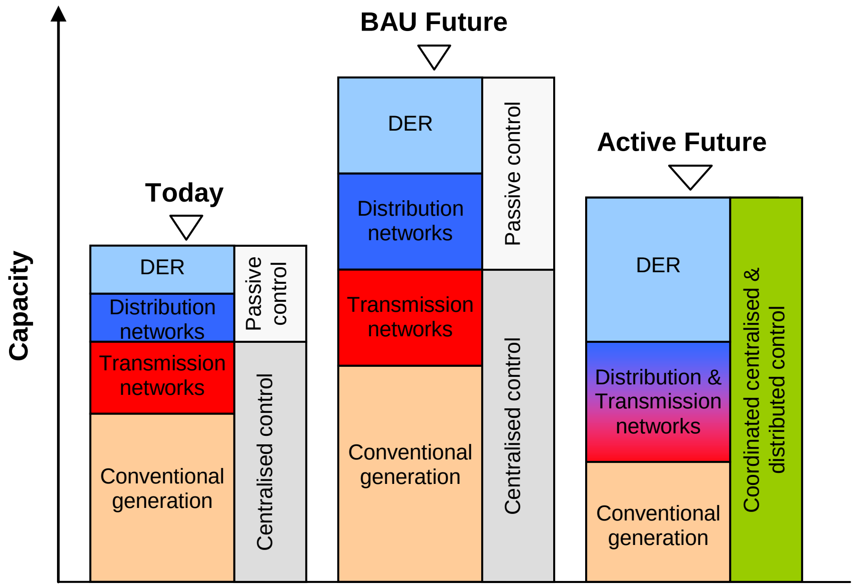

Figure 2: Relative levels of system capacity under centralised and distributed control strategies

This is contrast to the current practice whereby the policy of connecting DER is generally based on a "fit and forget" approach. Although this policy is consistent with historic passive distribution network operation, it is known to lead to inefficient and costly investment in distribution infrastructure. Under a "Business as Usual" approach (passive network), indeed, DER can only displace energy produced by central generation but cannot displace capacity, as lack of controllability of DER implies that system control and security must continue to be provided by central generation. Maintaining the traditional passive operation of these networks and the philosophy of centralized control will necessitate an increase in capacities of both transmission and distribution networks, as illustrated in Figure 2, leading to a very expensive and inefficient system.

Therefore, a shift from the traditional central control philosophy to a new control paradigm of coordinated centralized and distributed control such as the one offered by the microgrid philosophy is necessary to maintain efficient integration of DER into our electricity systems.

3. Enhancing visibility of DER to System Operators via VPP

Although historically the transmission system operator has been responsible for system security, integration of DER will require distribution system operators (DSOs) to develop active network management in distribution levels in order to participate in the provision of system security. This will present a radical shift from traditional central control philosophy towards a new and more distributed control paradigm, which should be applicable for operation of thousands (and potentially millions) of smaller generators and responsive loads. Using this highly distributed paradigm, systems can be decomposed into smaller autonomously operated systems, called “power system cells”.

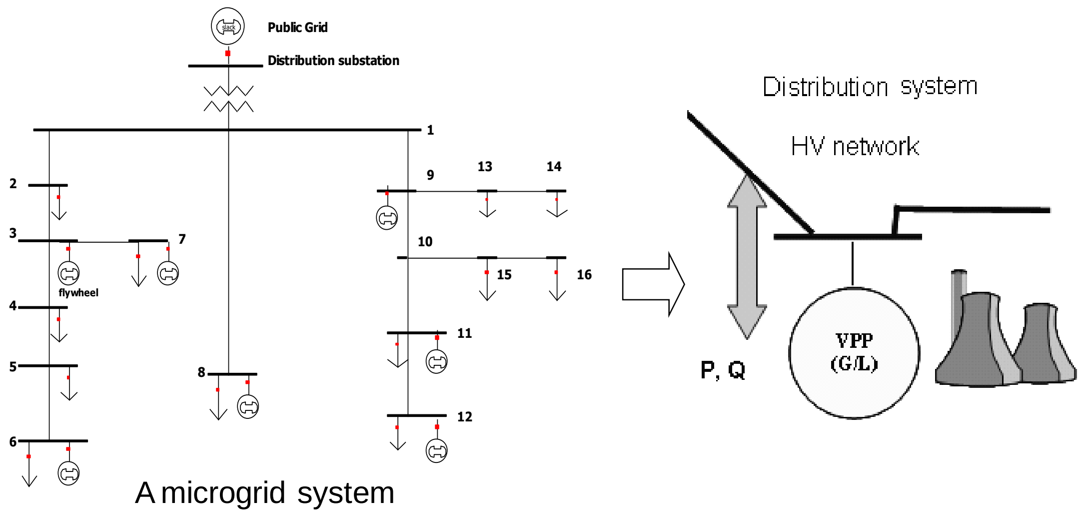

Figure 3: A microgrid system is presented in an aggregated form to the SO via VPP

Each cell is a microgrid which has a central system controller coordinating the operation of a manageable number of generators, loads and network devices. The controller is responsible for improving system performance within the cell. Using the Virtual Power Plant (VPP) concept each cell can then be presented as aggregated controllable groups, available for use in system management functions at higher network voltage levels. Interaction between generators, loads and network both intra and inter cells can be controlled by coordination among the Microgrid Central Controller (MGCC), the Distribution Management System (DMS) at distribution level and even the Energy Management System used by the TSO.

The specific objectives of this approach are to:

- Enhance the visibility of DER connected at distribution networks to the SO;

- Enable access of DER into external energy and ancillary service markets through aggregation; and
- Stimulate the use of the most economic sources.

4. Microgrid's solution on future reserve provision

Figure 4 shows different operating reserves commonly used nowadays. They are classified to three categories based on their operation time scales. The first category is "primary frequency control" (according to the UCTE terminology [4]), also called "frequency response" in the UK. The second category is “secondary frequency control” and the third category is “tertiary frequency control”.

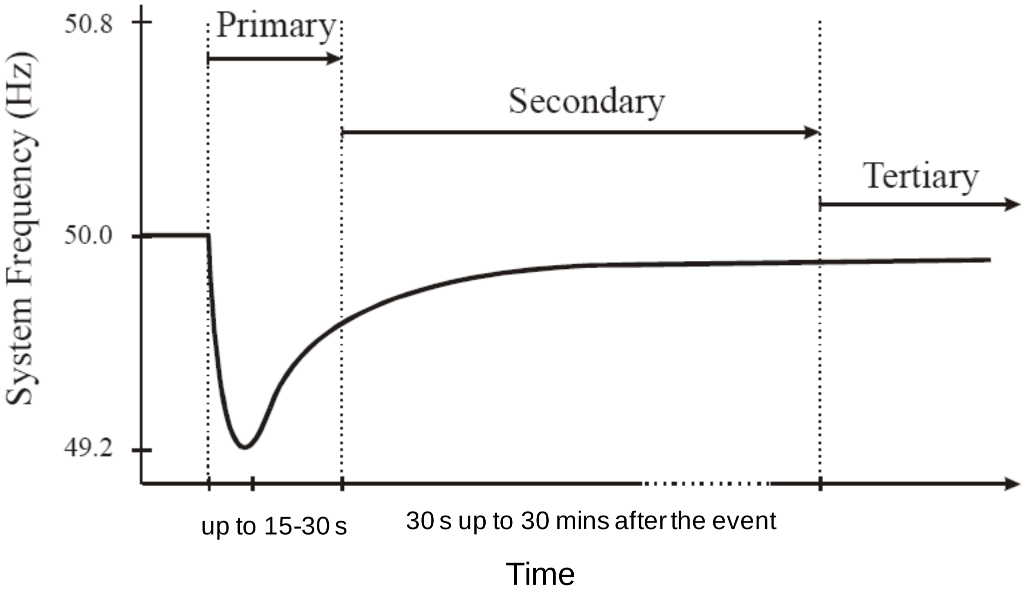

Figure 4: Operating reserves

Traditionally, primary frequency control or frequency response services are mandatory services provided by central generators to response quickly to the rapid change in frequency due to outages in generation or rapid increase/decrease in system loads. TSO can also use demand to provide this service by tripping the demand when the system frequency drops below a certain threshold. Due to the intrinsic nature of the requirements, this service has to be available immediately after a disturbance event in the system and to be hold (continuously available) for 15 s up to 30 s depending on system requirements. Because of the time scale associated with this service, this can only be provided by synchronised generators running part loaded. Enhanced capability to provide this response services can be offered to TSO on a commercial basis.

Secondary frequency control is also centralised automatic control with a function to restore the balance between supply and demand and, by doing so, to restore the frequency back to its target value. After a disturbance event, this service should be available within 30 s and continuously available up to 30 minutes, if required. Considering the time scale, this service is provided only by synchronised generators running part-loaded.

Tertiary frequency control can be classified as “slow reserve”. The TSO dispatches this service manually by increasing or decreasing central generation output to maintain the energy balance. This service can be provided by spinning or stand-by generators.

So far, the contribution of DERs on providing reserve services can be considered minimum. TSO treats DERs as negative loads and the balancing process occurring at distribution levels are treated the same as fluctuation in demand. Since the installed capacity of DERs at present is relatively low, this simple approach works well. However, for a system with high penetration of DERs, contribution of DERs should not be ignored, as discussed earlier.

As an alternative approach, DERs, depending on their capability, can also provide various frequency control services. This will bring benefits not only to the system by reducing primary and secondary control provided by central generators running part-loaded, but also to DER owners by providing another stream of revenues to them. The Micro source controller can decide the optimal usage of its DER capacity. The MC also determines the amount of energy it should produce together with the ancillary services (reserves and reactive power support) that can be offered to the system.

Another important benefit derived from the use of DERs to provide secondary frequency control is the reduction of the number of generators running part loaded. This is because small scale DERs can be started and the output can ramp up quite quickly. For instance, according to studies carried out at the Lawrence Berkeley National Laboratory, the fastest start up of a 30 kW Capstone micro turbine, including synchronisation time to the grid, can be less than 10 seconds. Such micro turbine would require only 120 seconds from start up to maximum output if operated in a stand-alone mode. This means that this unit, even in a stand-by mode, can be used to provide secondary frequency control. This is contrast to large scale generators that need to be synchronised (spinning) to provide the secondary control service. Figure 5 shows the response characteristics of a 30 kW Capstone micro turbine when it was shut down and started up. This shows the feasibility of using small DERs in a stand-by mode to provide secondary frequency control services.

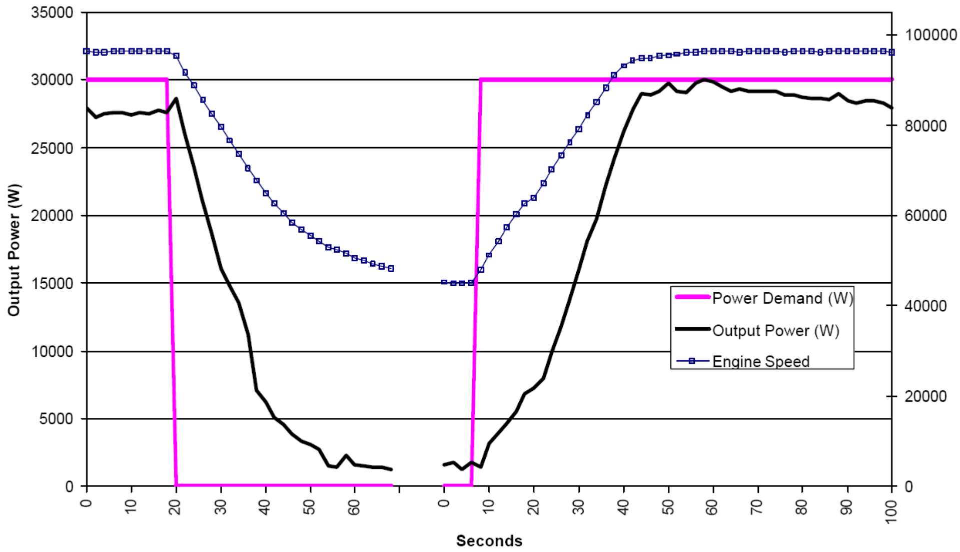

Figure 5: Capstone grid connect test (source: Lawrence Berkeley National Laboratory)

In order to facilitate and enable DERs to contribute actively in the provision of not only energy but also ancillary services in the most efficient and effective manner, the Microgrid Central Controller (MGCC) can be equipped with a smart control algorithm. The objectives are to:

- Optimise the use of DERs (including load) to minimise the overall costs ,i.e. Cost for providing energy and ancillary services and maximise the revenue stream to the microgrid , i.e., maximising value of energy and ancillary service production;
- Maintain system operation within its permissible operating limits and enhance its system reliability.

It is important to note that the MGCC is responsible to ensure that the microgrid system can deliver the scheduled energy production and ancillary services including the execution of response and reserve services in secured and efficient manner. Therefore the control coordination between the MGCC, MCs and LCs in a microgrid system (Figure 6) is critical.

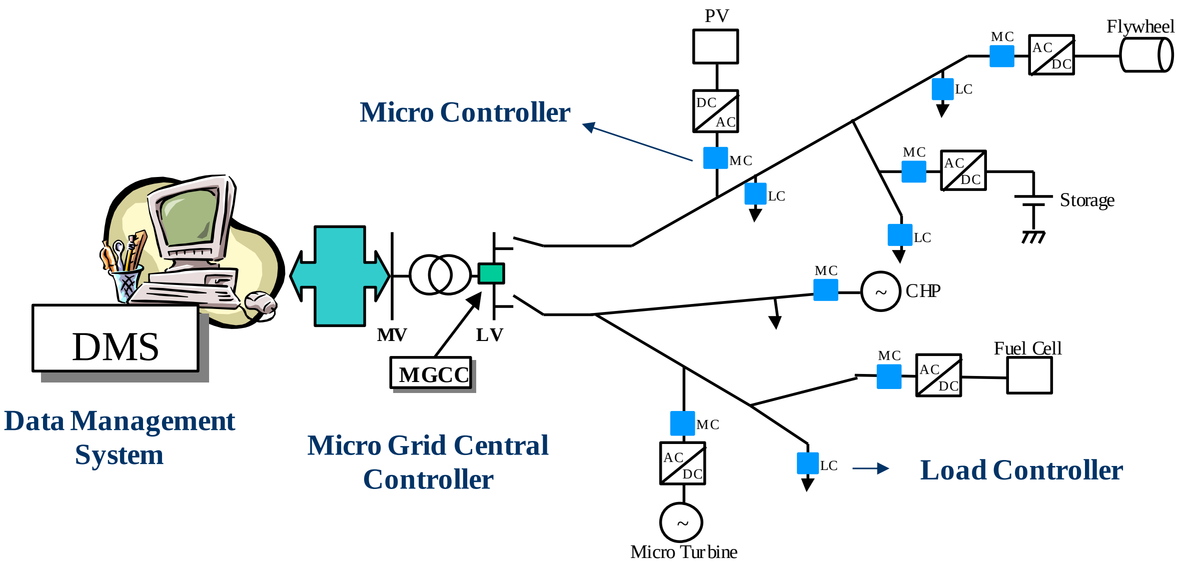

Figure 6: A microgrid system

5. Algorithm

Figure 7 shows the flowchart of a process that optimises *concurrently* the energy production and ancillary services offered to the system. There are a number of input data required for this process. These include:

- Market data that contain energy prices, prices of various ancillary services including prices for providing primary/secondary/tertiary frequency control, prices for reactive power supports, etc. The market data are normally time-dependent and could be location-specific too. The MGCC may need to have forecasting capability to predict the market prices based on certain parameters and historical data.
- Network data that contain network information including network topology and their electric parameters, network devices including tap changers, reactive compensators, and their operating limits.
- DER data. This includes the minimum stable generation output, power rating, ability to provide response and reserve services (taking into account the start up time and ramping up capability), DER operating cost data including fuel cost, no load cost, and start up cost.
- Demand data. This includes nodal active and reactive loads.
- Operating limits in this case include voltage and thermal limits.

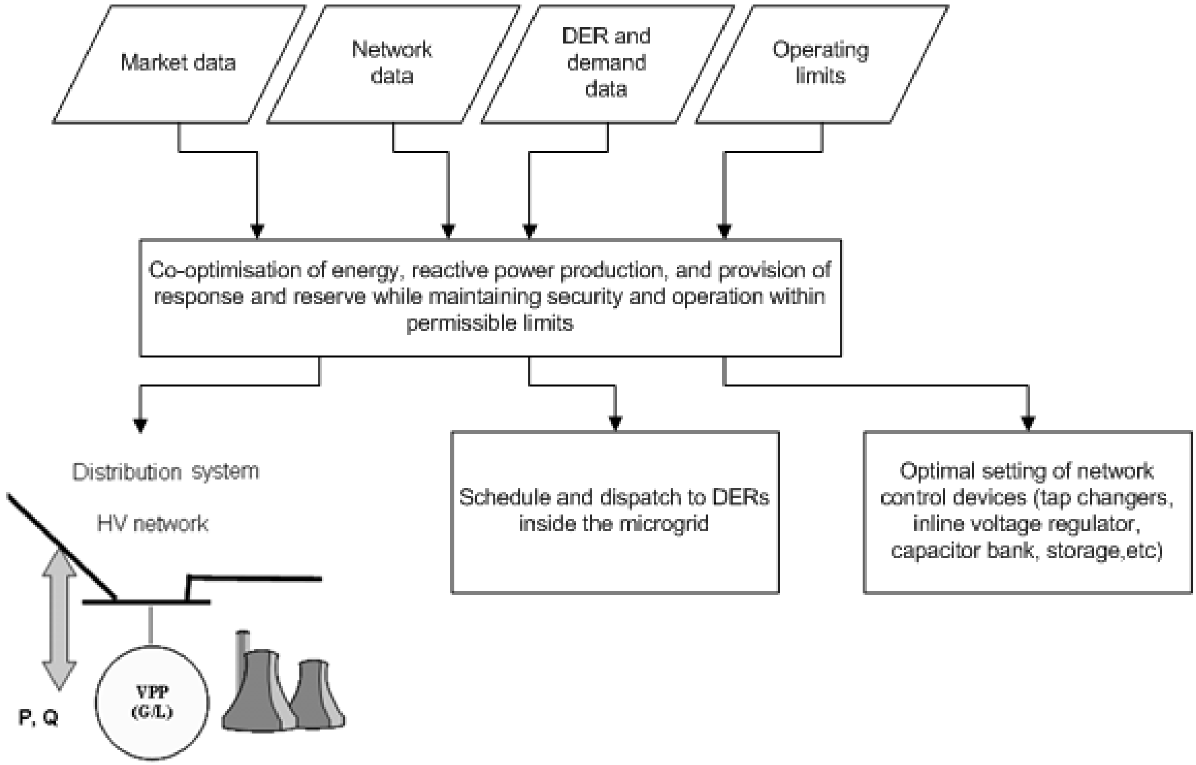

Figure 7: Process of co-optimising energy and ancillary services in the Microgrid

Data are processed by a multi state Optimal Power Flow algorithm that maximises the overall welfare of the Microgrid participants. The OPF will maximise the overall revenue from selling energy and ancillary services at the same time with minimising the overall operating costs. These include DER fuel cost, no-load cost and start up cost, and also the cost of importing electricity and reactive power from the grid.

The OPF is also run for the state where response and reserve services are executed to ensure that the system can still operate safely and within permissible operating limits while providing these services to the upstream grid.

6. Test network

The approach developed in our work was tested on the NTUA LV test system, illustrated in Figure 8. The test system contains seven micro sources. DER data were modified for the specific purpose of this analysis. All data for the studies are given in the Appendix.

The microgrid system in Figure 8 can be operated in two modes: (i) grid connected mode and (ii) islanded mode. Bus 17 belongs to the public grid and represents the slack bus. It is assumed that the voltage at the slack bus is maintained at 1.0 p.u. voltage. The higher voltage network beyond bus 17 is not modelled in this study. A tap changer connects the public grid (bus 17) to bus 1 in the microgrid.

The microgrid system has three feeders: (i) a residential feeder, (ii) an industrial feeder with an industrial customer connected at the end of the feeder and (iii) a commercial feeder. Demand data for each type of customer has been developed carefully to reflect different pattern of electricity consumption from different customer types. Demand data are given in the Appendix. The overall network demand profile is shown in Figure 9.

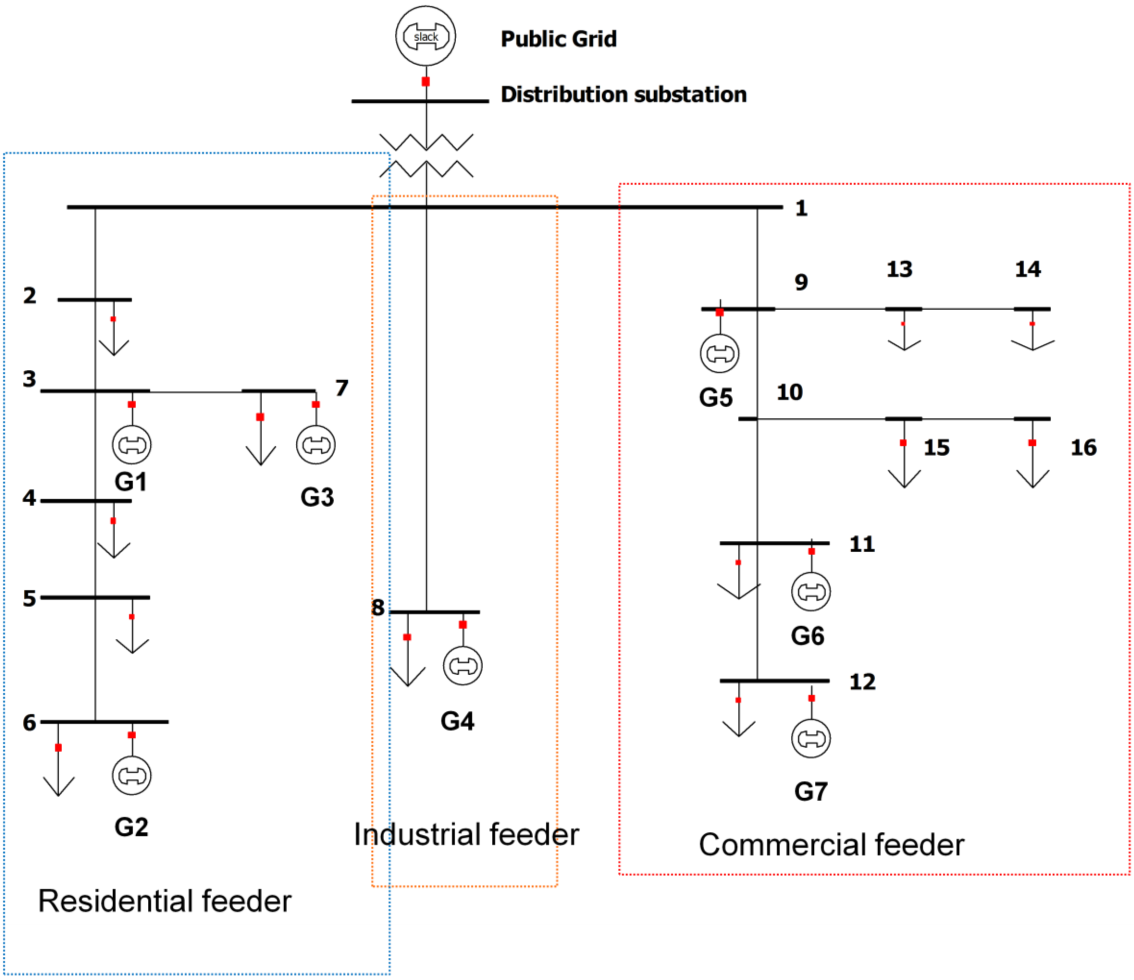

Figure 8: LV test system

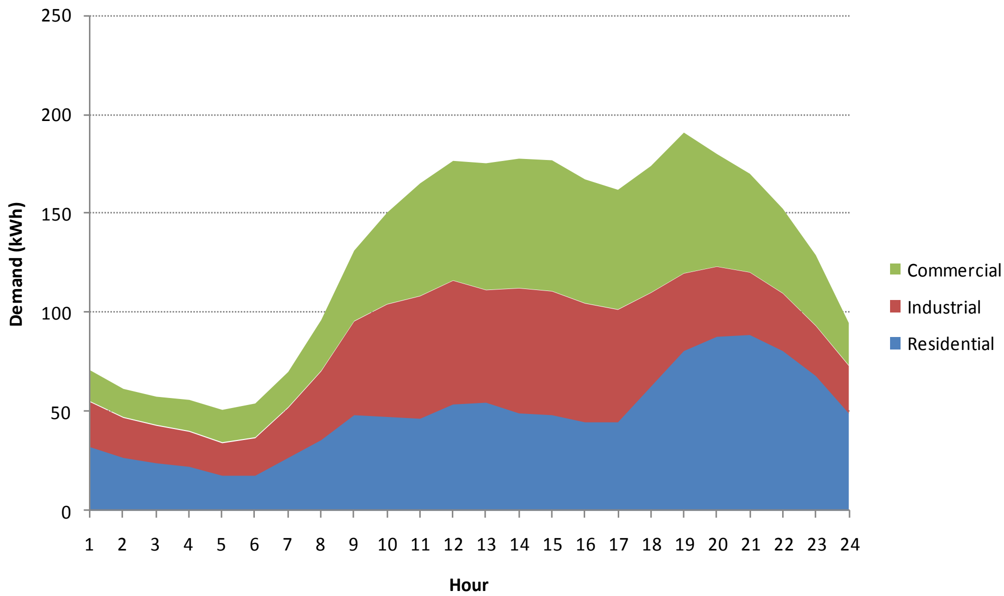

Figure 9: Demand profile

7. Simulation studies

A number of simulation studies have been developed to test and demonstrate the technical and commercial feasibility of the proposed Microgrid solution for providing energy and ancillary services.

7.1 Case study 1: when importing electricity from grid is cheap

In this case study, we simulated a period where demand in the microgrid was relatively low, *i.e.* 71 kW and 34 kVAr. This is associated with the 1st period of the 24 hour simulation horizon considered in this study. The electricity price was also low at this off peak demand period. Detailed market data can be found in the Appendix.

The scheduling of DER and the committed reserve services produced by the OPF algorithm are summarised in Figure 10. The results are in line with what one could expect, thus confirming the effectiveness pf the methodology developed. More specifically, only DER at bus 6 produces 10 kW of electricity (at its MSG) and sells the remaining 15 kW to provide primary frequency control services. This is the only DER which has a slightly lower marginal fuel cost compared with the grid's electricity price. Other DERs have higher marginal fuel costs and therefore it is not profitable for them to generate electricity. It is therefore expected that most of energy demand in the microgrid is supplied from importing electricity from the grid. About 60 kW is imported from node 17 (grid) as shown in Figure 10.

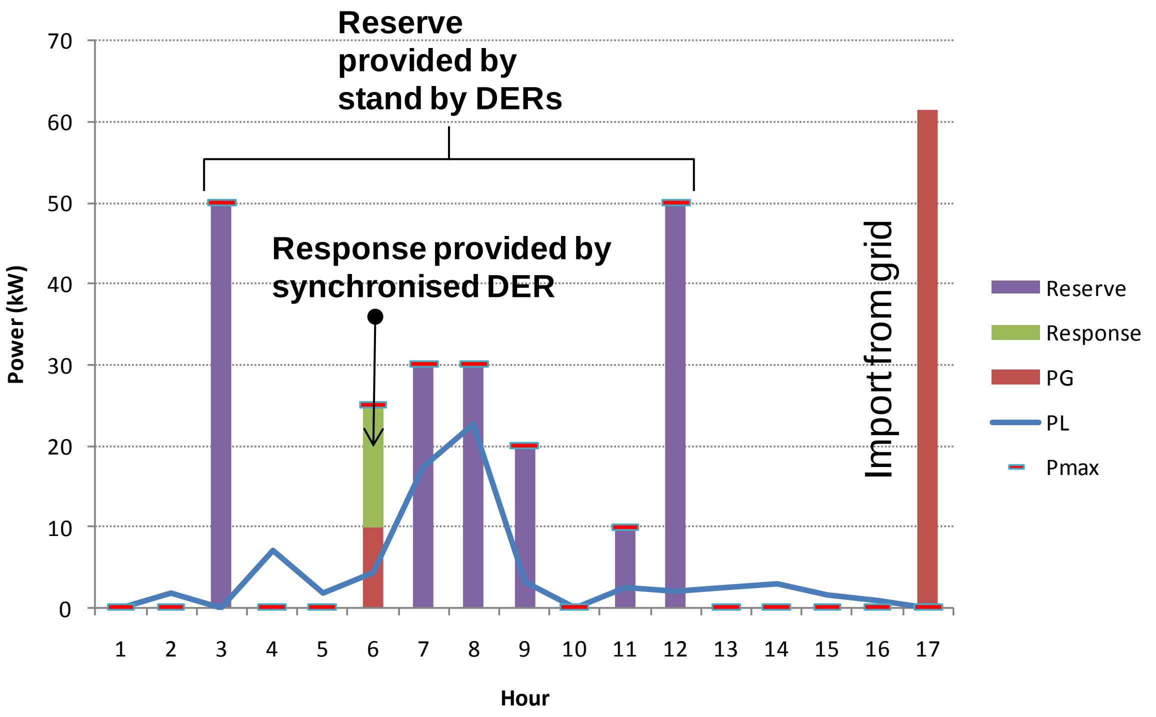

Figure 10: Energy production and committed reserve services during off peak period

In contrast to the current situation where the revenue for DER depends only on their energy production and in case feed-in tariffs, in this alternative approach off-line DERs can still deploy their capacity to provide secondary or tertiary frequency control to the grid. Considering that they are stand-by generators, there is very little cost for providing this service.

Further studies will need to be carried out to quantify accurately the benefits of this approach (see for instance Deliverable DH2 for such analyses). Qualitatively, the benefits can be expected since it will reduce the requirements of central generators running part loaded. Therefore, it will reduce the overall system operation cost and improve the overall system efficiency. Moreover, it is also known that part loaded central generators may also limit the system ability to utilise intermittent renewable output especially in the system with high level penetration of wind power. Therefore, the proposed microgrid solution is quite promising to solve this problem.

In order to ensure that the solution produced by the OPF is feasible, voltages and circuit's loading across the microgrid system were recorded for both states. The first state is the normal state where DER output is set according to the optimised schedule. The second state is the condition where DER output is set according to their schedule plus the amount of reserves they are committed. The objective of this exercise is to ensure that no voltage violation or thermal overloading will occur when the committed reserve services from DERs are exercised. The results are summarised in Figure 11 and Figure 12.

All circuit's loadings are well below 100%, so there is no thermal overloading in both states.

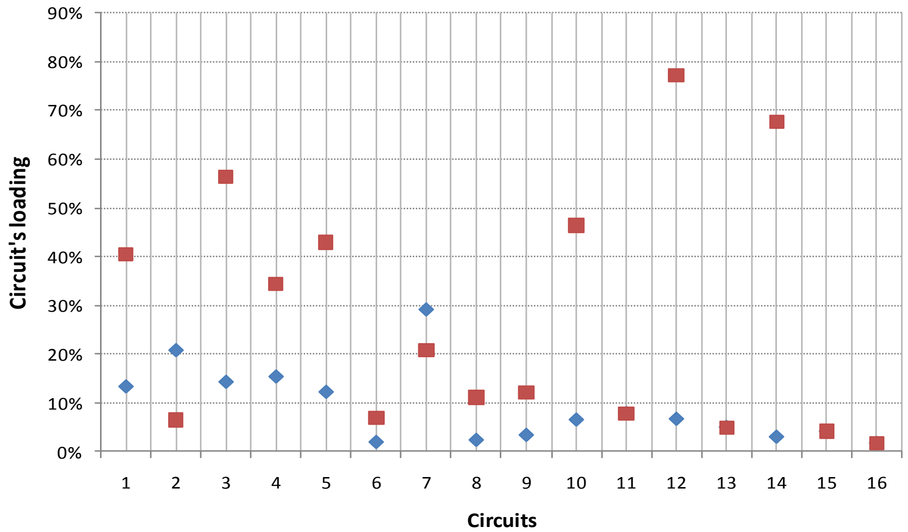

Figure 11: Circuit's loading assessment in case 1

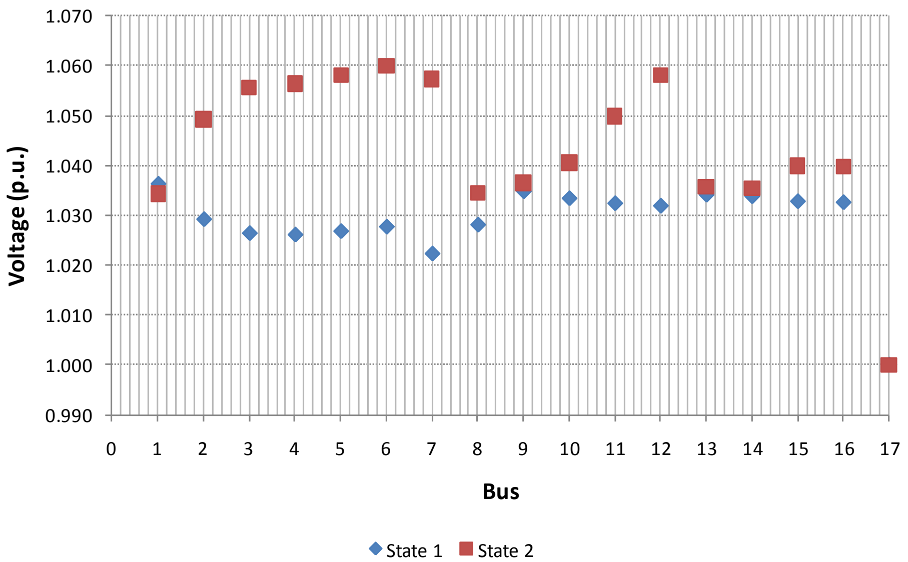

Figure 12: Voltage assessment in case 1

Voltages are also within the limits. The results in Figure 12 show voltage rise effect when the committed reserve services are executed. This is expected since the loading of the microgrid during that period is relatively low. However, the OPF algorithm within the MGCC has controlled successfully the voltages across the microgrid to be within the limits (±6%) although voltage at some buses (bus 6 and 7) reaches the maximum limit due to DG-inducted voltage rise effect.

7.2 Case study 2: when importing electricity from grid is expensive

In this case study, we simulated a period where demand in the microgrid was relatively high, i.e., 191 kW and 92 kVAr. This is associated with the 19th period of the 24 hour simulation horizon considered in this study. The electricity price was also high at this peak demand period. The price was higher than the marginal operating cost of all DERs in the microgrid.

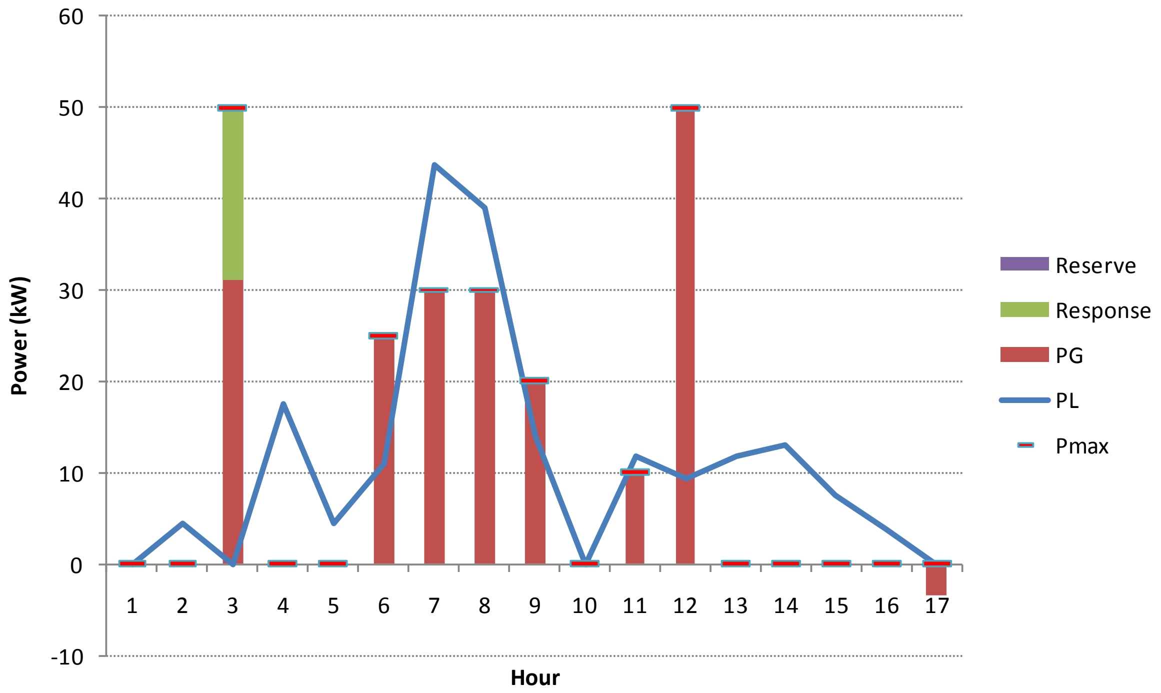

Figure 13: Energy production and committed reserve services during peak period

The results from the optimisation in the MGCC are summarised in Figure 13. Considering high energy price during this peak demand period, the results indicate that it is economical for DERs to produce energy to minimise import electricity from the grid. As the installed capacity is slightly higher than the peak demand, the microgrid can export power to the grid to get benefits from the high value of electricity. This is in contrast to the current situation where DERs may get only, for instance, a fixed feed-in tariff. Therefore, the commercial solution from this approach is quite attractive although further studies are needed to be carried out to quantify the system-level benefits.

Similar to case 1, circuit's loading and voltages across the microgrid system were assessed for both conditions (without and with reserves being exercised). The results are summarised in Figure 14 and Figure 15. There is no voltage violation or thermal overloading in any situation.

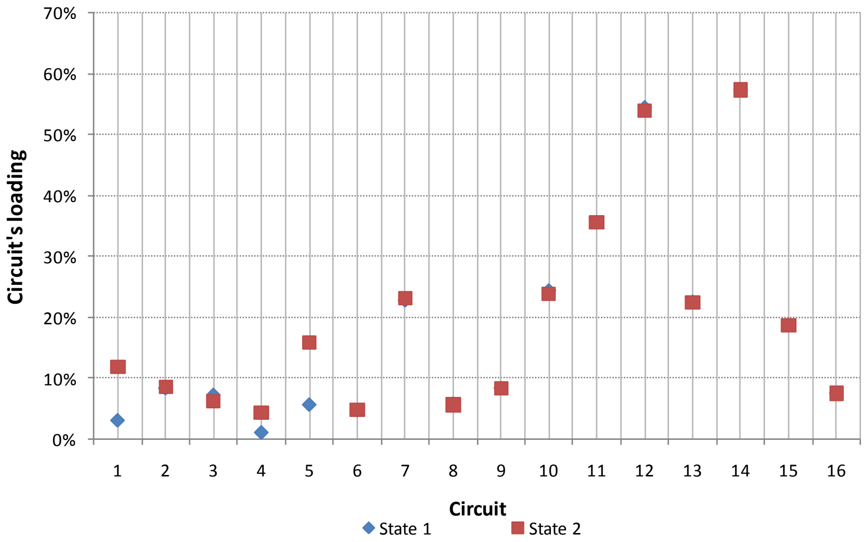

Figure 14: Circuit's loading assessment in case 2

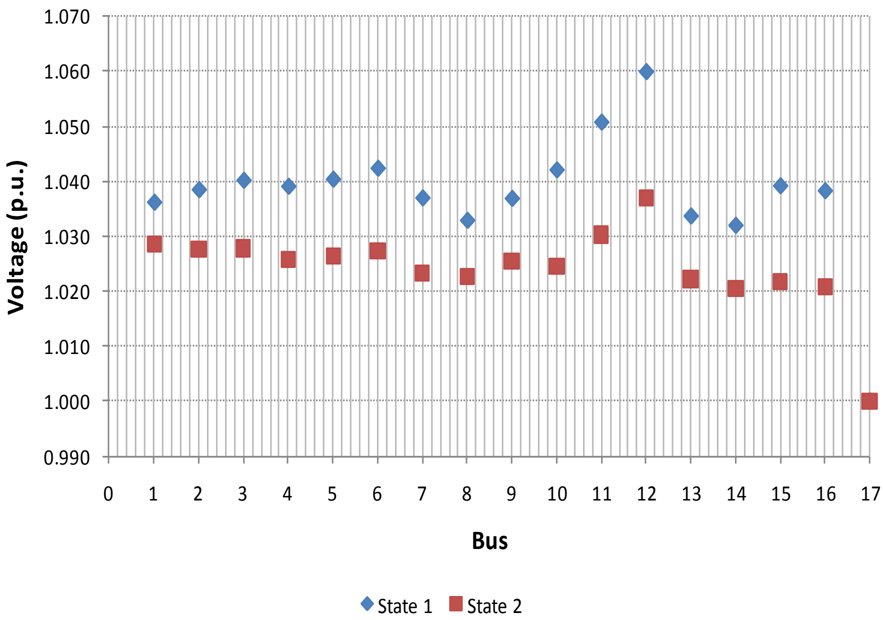

Figure 15: Voltage assessment in case 2

7.3 Optimising the utilisation of DER capacity

Figure 16 shows the utilisation of DER capacity for all simulation periods (24 h). It is very encouraging to see that the installed capacity of DERs is always optimally used, either to produce energy or to provide reserves to the system. This will maximise the value of DERs and increase the revenue to the DER owners. This is contrast to the current situation where DER revenues depend only on their energy production and, in case, the feed-in tariff.

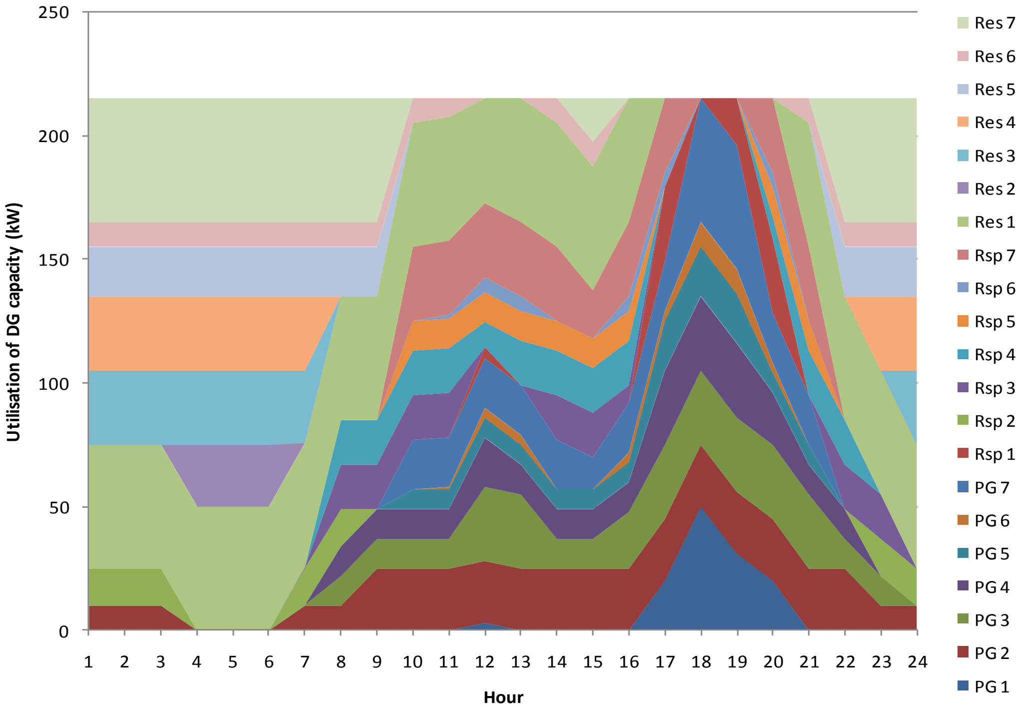

Figure 16: Utilisation of DER capacity across the 24 h simulation time horizon

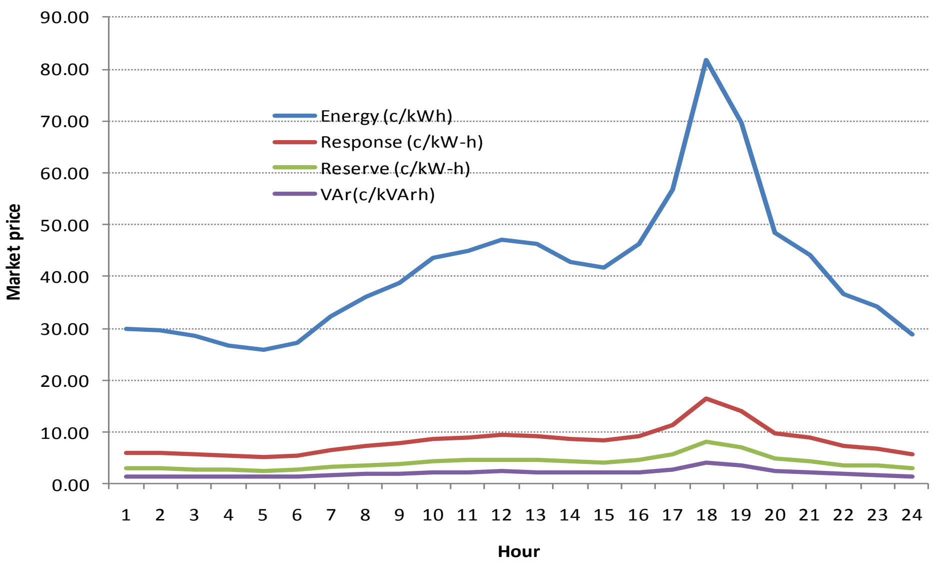

Figure 17: Price profiles for energy and ancillary services

The results in our studies indicate that the optimal strategy for using DER capacity is to use it to provide reserve services during off peak period where electricity price is cheap (see Figure 16) and therefore it is economical to import electricity from the grid. During peak demand period where electricity price is high (above the marginal operating cost of DERs), it is better to produce electricity locally to minimise the cost. Excess capacity can be used to export power from the grid or to provide system services.

7.4 Optimisation of VAr production

So far, the discussions have focused only on active power (energy) production and the provision of various reserve services by DERs facilitated by the microgrid. However, the OPF algorithm in the MGCC actually also optimises the reactive power production concurrently with the optimisation of energy and reserve services. Therefore the interaction between energy, reserve services and voltage control services is optimised to maximise the overall system efficiency and benefits to the microgrid users.

Figure 18 shows the reactive power dispatch for all DERs in the microgrid across the simulation period. The results indicate that during off peak demand it is adequate to use only the capacitor bank connected at node 1 to supply the reactive power requirements. This will minimise the operating cost of DERs and reduce the need for DERs to operate in spinning mode.

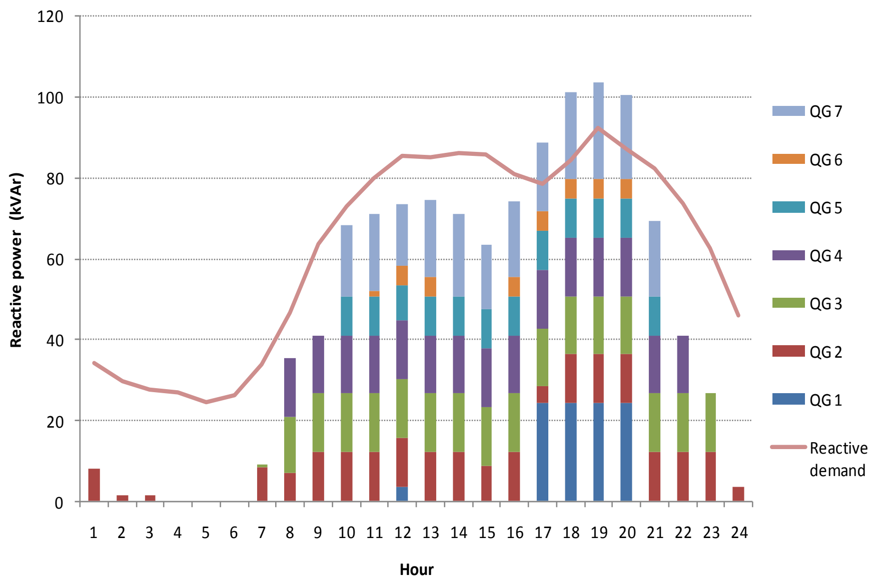

Figure 18: Reactive power output from DERs

7.5 Secured system operation

The optimisation function in the MGCC is subject to maintaining a secured system operation in the microgrid and respects the permissible operating limits. In order to ensure that this function works accordingly, voltages and thermal circuit's loading across the microgrid system were recorded for each operating snapshot across the simulation time period. The results showing the range of voltages and circuit loading are presented in Figure 19 and Figure 20 respectively. The results show that all operating limits are respected and neither voltage violations nor overloading occur.

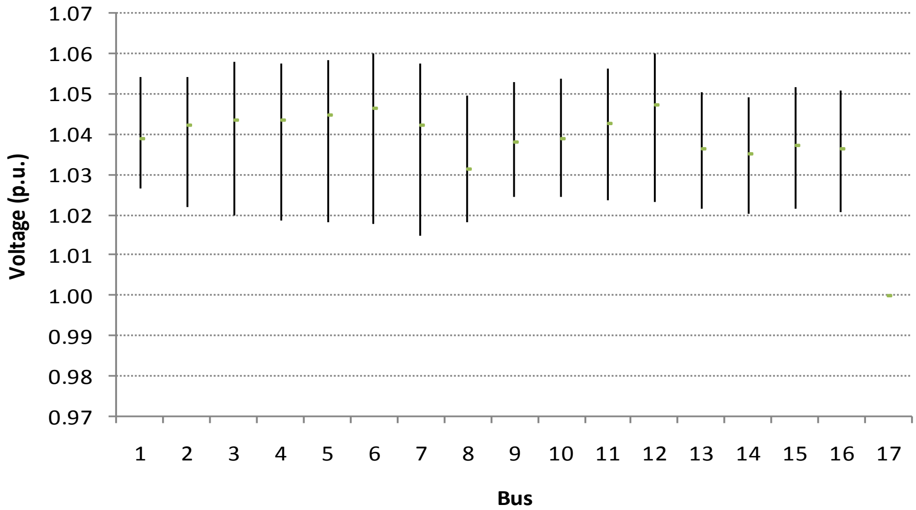

Figure 19: The range of voltage variation for each node across the simulation period

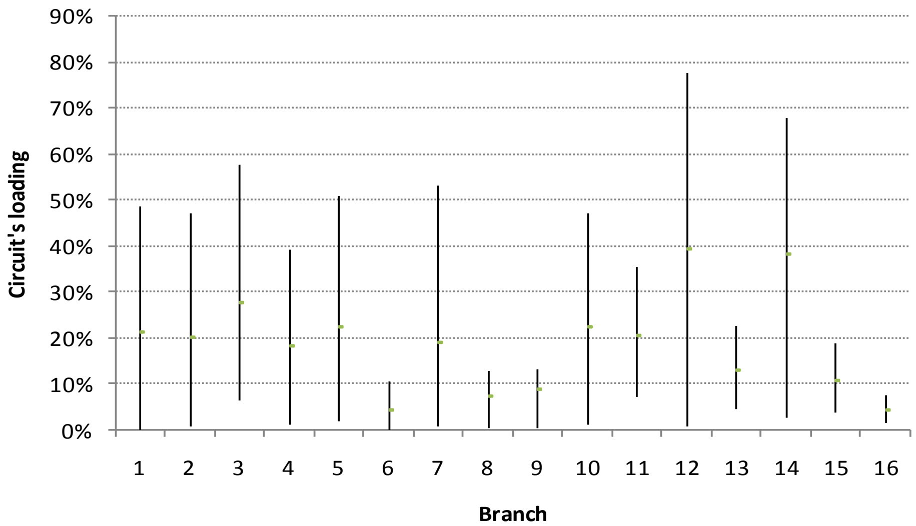

Figure 20: The range of circuit's loading for each branch across the simulation period

8. Summary

A number of studies have suggested that a significant portion of our future energy consumption will be supplied by domestic or small scale Distributed Generation. In order to mitigate excessive and under-utilised capacity, or, in other words, to maintain the efficiency of system, a radical shift from the Business as Usual "fit and forget" approach to coordinated centralised and decentralised control approach is required. DG and demand side have to take the responsibility for delivery of system support services, taking over the role of central generation. In this context, DG will be able to displace not only energy produced by central generation but also its controllability, and, together with demand side, to reduce the system capacity requirements.

In this context, the roles of microgrid are critical. Through microgrid coordinated centralised and decentralised control, the capacity of DERs (DG and controllable loads) can be used optimally to maximise their value to their owners or operators while respecting network security and operating constraints. Via the VPP concept, the microgrid capability to support system operation at higher voltage level can be facilitated.

In contrast to the traditional approach that relies on central generators to provide frequency control services, the implementation of the microgrid concept opens another alternative solution. DERs can be used also to provide response and reserve services in addition to produce energy and reactive power. There are a number of benefits. First, it improves the value of DERs by providing additional revenue streams, and second, it improves the overall system efficiency. DERs in stand-by mode can be used to provide secondary/tertiary frequency control and to reduce the requirements for generators running part loaded.

An OPF-based algorithm has been specifically developed to implement the proposed methodology for simultaneous optimisation of energy and reserve provision. The technical feasibility of this concept has been demonstrated through a number of numerical studies have been conducted on a microgrid system capable to contribute to both local and system support services particularly in the forms of reserve and voltage control while simultaneously optimising the portfolio of energy production in order to maximise the overall social welfare.

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Appendix A – Input Data for the MGCC's OPF

Market data

Time	Energy (c/kWh)	VAr(c/kV Arh)	Response (c/kW-h)	Reserve (c/kW-h)	Response utilisation (c/kWh)	Reserve utilisation(c/kWh)
1	29.87	1.49	5.97	2.99	45	36
2	29.62	1.48	5.92	2.96	44	36
3	28.53	1.43	5.71	2.85	43	34
4	26.70	1.33	5.34	2.67	40	32
5	25.90	1.30	5.18	2.59	39	31
6	27.26	1.36	5.45	2.73	41	33
7	32.35	1.62	6.47	3.24	49	39
8	36.02	1.80	7.20	3.60	54	43
9	38.66	1.93	7.73	3.87	58	46
10	43.61	2.18	8.72	4.36	65	52
11	45.01	2.25	9.00	4.50	68	54
12	47.11	2.36	9.42	4.71	71	57
13	46.29	2.31	9.26	4.63	69	56
14	42.67	2.13	8.53	4.27	64	51
15	41.66	2.08	8.33	4.17	62	50
16	46.17	2.31	9.23	4.62	69	55
17	56.80	2.84	11.36	5.68	85	68
18	81.78	4.09	16.36	8.18	123	98
19	69.73	3.49	13.95	6.97	105	84
20	48.47	2.42	9.69	4.85	73	58
21	44.12	2.21	8.82	4.41	66	53
22	36.62	1.83	7.32	3.66	55	44
23	34.23	1.71	6.85	3.42	51	41
24	28.72	1.44	5.74	2.87	43	34

Network data

Sending end busname	Receiving end busname	O	Area	Zone	Type	R (p.u.)	X (p.u.)	Rating (kVA)
1	2	1	1	0	0	0.030010	0.008010	170.0
1	8	1	1	0	0	0.033125	0.008750	110.0
1	9	1	1	0	0	0.007500	0.005000	110.0
17	1	1	1	0	2	0.001150	0.003830	400.0
2	3	1	1	0	0	0.012500	0.003750	170.0
3	4	1	1	0	0	0.012500	0.003750	170.0
3	7	1	1	0	0	0.021870	0.004380	60.0
4	5	1	1	0	0	0.012500	0.003750	170.0
5	6	1	1	0	0	0.012500	0.003750	170.0
9	10	1	1	0	0	0.015000	0.010630	110.0
9	13	1	1	0	0	0.010630	0.005630	70.0
10	11	1	1	0	0	0.021250	0.005630	70.0
10	15	1	1	0	0	0.023130	0.006250	50.0
11	12	1	1	0	0	0.021250	0.005630	70.0
13	14	1	1	0	0	0.010630	0.005630	70.0
15	16	1	1	0	0	0.023130	0.006250	50.0

Capacitor bank: 150 kVAr at node 1

Voltage limits : ±6%

DER data

Busname	Type	Pmin (kW)	Pmax (kW)	Qmin (kVAr)	Qmax (kVAr)	Marginal fuel cost (c/kWh)	Marginal cost of VAr (c/kVArh)	Start up cost (c/start-up)	No load cost (c/h in service)
3	Micro turbine	20.00	50.00	-24.22	24.22	45.00	1.50	100.00	30.0
6	Micro turbine	10.00	25.00	-12.11	12.11	25.00	1.50	100.00	30.0
7	Micro turbine	12.00	30.00	-14.53	14.53	30.00	1.50	100.00	30.0
8	Micro turbine	12.00	30.00	-14.53	14.53	32.00	1.50	100.00	30.0
9	Micro turbine	8.00	20.00	-9.69	9.69	35.00	1.50	100.00	30.0
11	Micro turbine	4.00	10.00	-4.84	4.84	37.00	1.50	100.00	30.0
12	Micro turbine	20.00	50.00	-24.22	24.22	40.00	1.50	100.00	30.0

Demand data (in kW)

	Bus												
Time	**2**	**4**	**5**	**6**	**7**	**8**	**9**	**11**	**12**	**13**	**14**	**15**	**16**
1	1.7	7.0	1.7	4.4	17.4	22.7	3.1	2.6	2.1	2.6	2.9	1.6	0.8
2	1.5	5.9	1.5	3.6	14.5	20.2	2.8	2.3	1.9	2.3	2.6	1.5	0.7
3	1.3	5.3	1.3	3.3	13.1	18.9	2.8	2.3	1.9	2.3	2.6	1.5	0.7
4	1.2	4.9	1.2	3.0	12.1	17.6	3.1	2.6	2.1	2.6	2.9	1.6	0.8
5	1.0	3.9	1.0	2.4	9.7	16.4	3.2	2.7	2.2	2.7	3.0	1.7	0.9
6	1.0	3.9	1.0	2.4	9.7	18.9	3.4	2.8	2.2	2.8	3.1	1.8	0.9
7	1.5	5.9	1.5	3.6	14.5	25.2	3.5	2.9	2.3	2.9	3.3	1.9	0.9
8	1.9	7.8	1.9	4.8	19.4	34.7	5.0	4.2	3.4	4.2	4.7	2.7	1.3
9	2.6	10.6	2.6	6.5	26.2	47.3	7.0	5.9	4.7	5.9	6.5	3.7	1.9
10	2.6	10.4	2.6	6.4	25.7	56.7	9.1	7.6	6.1	7.6	8.5	4.9	2.4
11	2.5	10.2	2.5	6.3	25.2	61.7	11.2	9.4	7.5	9.4	10.5	6.0	3.0
12	2.9	11.7	2.9	7.3	29.1	62.4	11.9	10.0	7.9	10.0	11.1	6.4	3.2
13	3.0	11.9	3.0	7.4	29.6	56.7	12.6	10.6	8.4	10.6	11.8	6.7	3.4
14	2.7	10.8	2.7	6.7	26.6	63.0	12.9	10.8	8.6	10.8	12.0	6.9	3.4
15	2.6	10.6	2.6	6.5	26.2	62.4	13.0	10.9	8.7	10.9	12.2	7.0	3.5
16	2.4	9.8	2.4	6.1	24.2	59.9	12.3	10.3	8.2	10.3	11.5	6.6	3.3
17	2.4	9.8	2.4	6.1	24.2	56.7	11.9	10.0	7.9	10.0	11.1	6.4	3.2
18	3.4	13.7	3.4	8.5	33.9	47.3	12.6	10.6	8.4	10.6	11.8	6.7	3.4
19	4.4	17.6	4.4	10.9	43.6	39.1	14.0	11.7	9.4	11.7	13.1	7.5	3.7
20	4.7	19.2	4.7	11.9	47.5	35.3	11.2	9.4	7.5	9.4	10.5	6.0	3.0
21	4.8	19.4	4.8	12.0	48.0	31.5	9.8	8.2	6.5	8.2	9.2	5.2	2.6
22	4.4	17.6	4.4	10.9	43.6	29.0	8.4	7.0	5.6	7.0	7.9	4.5	2.2
23	3.7	14.9	3.7	9.2	36.8	25.2	7.0	5.9	4.7	5.9	6.5	3.7	1.9
24	2.7	10.8	2.7	6.7	26.6	23.9	4.2	3.5	2.8	3.5	3.9	2.2	1.1

Power factor: 0.9

Demand at node 1, 3, 10 are zero for the simulation period.

Coordinating Power Exchange and Market Participation in Multi-Microgrids

Table of Contents

1. Introduction

One of the main objectives of WPD is to investigate ways of having multi-Microgrids and other DG participating in ancillary services (voltage support, service restoration and reserves) and short-term markets, involving the development of the specific tools for these purposes.

This report aims to provide the necessary inputs for short-term market participation and power exchange between Microgrids and upstream network in Multi-microgrids environment.

The elaborate description of the information exchange between the MGCC and the CAMC poses as an important factor not only in the successful integration of multi-MGs in the MV network, but also in facilitating the multi-MGs providing ancillary services. Furthermore, additional operations of the MGs need to be suggested so that the multi-Microgrids structure can participate in the short-term market. Such operations include demand side strategies, scheduling of DG units and DSB according to adequacy constraints within the Microgrid and estimation of voltage profile within a Microgrid.

The present report aims at two directions: 1) presentation of the necessary information exchange scheme between the MGCC and the CAMC, which facilitates the coordination of power exchange and 2) proposal of necessary modifications in the operation of Microgrids and the routines of MGCC, as suggested in WPB, so that Microgrids can adapt to the multi-Microgrids structure and participate in the short-term market and provide ancillary services.

Thus, first the operational framework of microgrids operation is described additionally to the functions that already have been considered for the MGCC. Then, the information exchange framework between MGCC and CAMC is provided. Moreover, a description of the additional functions to be incorporated in MGCC operation is provided while some results from application in a typical case study network are provided with emphasis to improving voltage profile and increasing local demand within a Microgrid after CAMC request.

2. Operational Framework and summary of functions of Microgrids as described in WPB and MICROGRIDS project

2.1 Operational Framework

The Microgrid during normal operation is assumed to operate as part of a Distribution network. Three hierarchical levels can be distinguished in this environment, as shown in Figure 1 [1]:

- Distribution Network Operator (DNO) and Market Operator (MO) which belong to the Demand Management System (DMS)
- Central Autonomous Management Controller (CAMC) which acts as an intermediate between the DMS and the MGCCs. In fact, the CAMC may be seen as one new DMS application that is in charge of one part of the network.
- Microgrid System Central Controller (MGCC) with its Local Controllers, which could be either Micro Source Controllers (MC) or Load Controllers (LC).

The Distribution Network Operator (DNO) is responsible for the operation of Medium and Low Voltage areas in which more than one Microgrid may exist. In addition, one or more Market Operators (MO) is responsible for the Market function of the specific area. These two entities do not belong to the Microgrid, but they are the delegates of the main grid.

As an intermediate between the DNO/MO and the rest of the MV network serves the CAMC. This exchanges information with each Microgrid using as a delegate the Microgrid Central Controller (MGCC). The MGCC may assume different roles ranging from the main responsibility for the maximization of the Microgrid value to simple coordination of the local controllers.

Control system for Microgrids can be either de-centralized or centralized. The differences and potential applications of these both control methods have been explicitly described [2]. Details on de-centralized control can be found in [3].

Each micro-source and load within the MG is equipped with a local controller designated as Micro-source Controller (MC) and Load Controller (LC), respectively.

The information exchange within a typical Microgrid is as follows: Every m minutes, e.g. 15 minutes, each DG source bids for production (active and reactive) for the next hour in m minutes intervals. These bids are based on the energy prices in the open market and the operating costs of the DG units plus the profit of the DG owner like the function described in (1).

$$actbid(x) = ax^2 + bx + c \qquad \textbf{(1)}$$

The MGCC optimizes the Microgrid operation according to the open market prices, the bids received by the DG sources and the forecasted loads and sends signals to the MCs of the DG sources to be committed and, if applicable, to determine the level of their production. In addition, consumers within the Microgrid might also bid for their loads supply for the next hour in m minutes intervals or might bid to curtail their loads. In this case, the MGCC optimizes operation based on DG sources and load bids and sends dispatch signals to both the MCs and LCs. Figure 2 shows the information exchange flow in a typical Microgrid operating under such conditions.

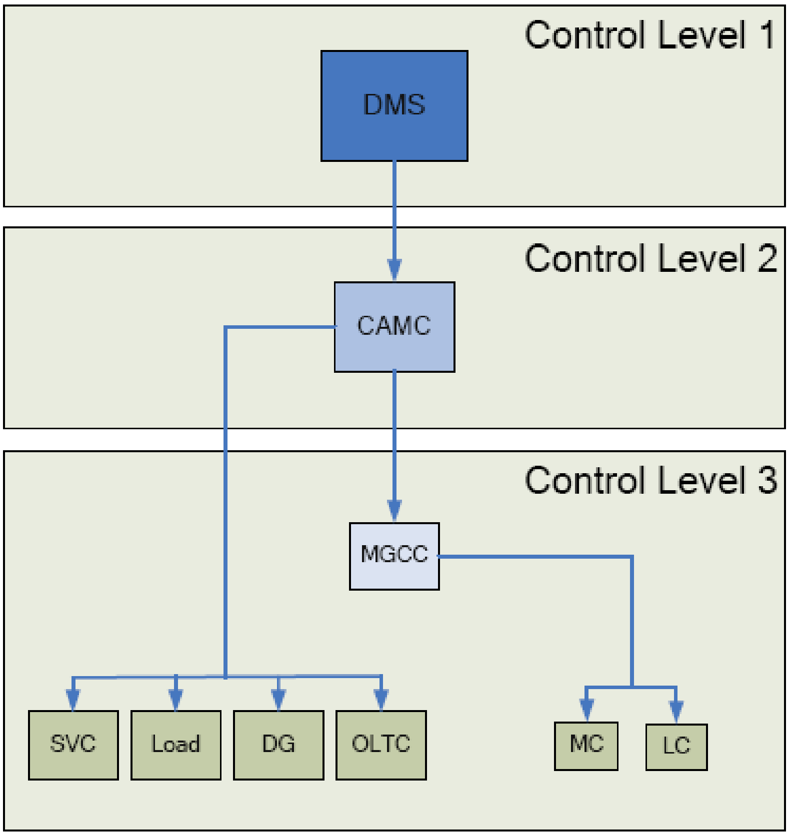

Figure 1: Hierarchical Control Structure

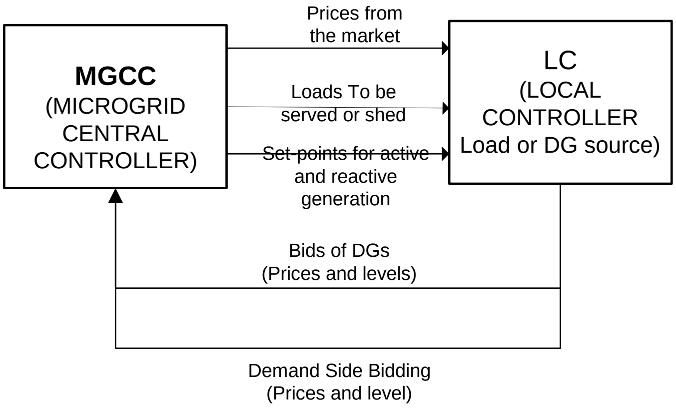

Figure 2: Information Exchange Diagram within a Microgrid

The two following market policies have been proposed for the operation of the Microgrid, described in more details in [2]:

- Market Policy 1 where the MGCC aims to minimize the cost of energy for the end-users without selling energy to the grid.
- Market Policy 2, where the MGCC aims to maximize the value of the Distributed Generators (DG) by selling excess energy to the upstream network.

2.2 Functions already incorporated in MGCC

2.2.1 Demand Side Bidding Strategies

It is assumed that each consumer has low and high priority loads allowing him to send separate bids to the MGCC for each type of them. In our application, it is assumed that each consumer places bids in two levels reflecting his priorities. “Low” priority loads can be satisfied in periods of lower prices (shift) or not be served at all (curtailment). Similar approach can be used for more than two bid levels reflecting more precisely the consumer’s priorities. Two options can be considered, the load shift option and the load curtailment option. In the shift option, load is satisfied, when the prices are considered beneficial while in the curtailment option, consumers offer to shed low priority loads in the next operating periods if remunerated at the fixed prices of their bids.

A typical formulation of demand side bid is provided in Figure 3. For the shift option, the consumer accepts service of 2.5 kW, if the price is below 8 €ct/kWh, and of another 3 kW, if the price is less than 10.1 €ct/kWh. In the curtailment option, the consumer with this bid states that he accepts shedding of 2.5 kW for 8 €ct/kWh, and 3 more kW for 10.1 €ct/kWh.

In the Shift Option, the MGCC sums up the DG sources bids in ascending order and the demand side bids in descending order in order to decide which DG sources will operate for the next hour and which loads will be served. This is shown schematically in Figure 4. Optimal operation is achieved at the intersection point of the producers' and consumers' bids. In the curtailment Option the MGCC has an estimation of the total demand of the Microgrid and sends interruption signals to the LCs, if this is considered financially beneficial.

In both options the MGCC:

- Informs consumers about the open market prices, in order for them to place their bids
- Accepts bids from the consumers every m minutes in m minutes intervals for the next hour.
- Runs the optimization routines
- Sends signals to the LCs according to the results of the optimization.

Even if these bids are not accepted or the loads are not finally disconnected, the information on "low" and "high" priority loads can be utilized for achieving higher adequacy levels in case of emergency.

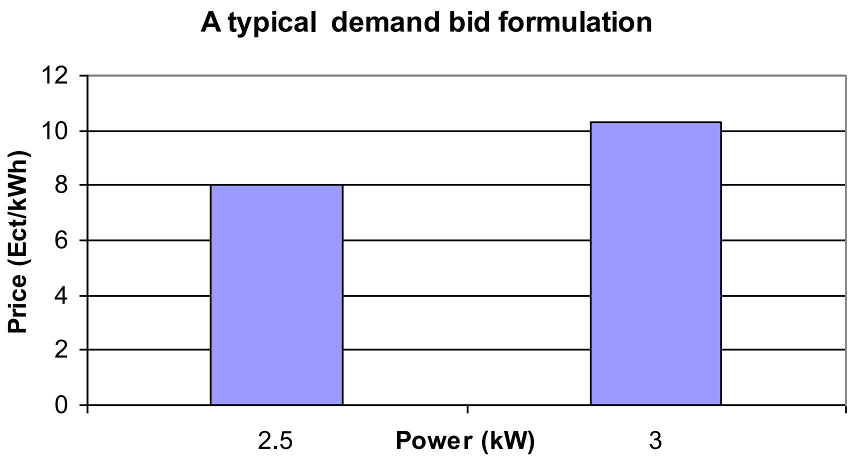

Figure 3: Typical Demand Side Bid Formulation

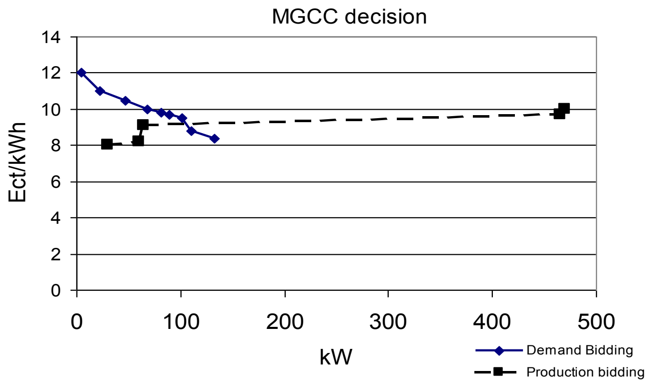

Figure 4: The decision made for the MGCC for shift option

2.2.2 Adequacy

For Microgrids, seamless transition between interconnected and islanded mode of operation is of particular importance. If a fault takes place in the grid, the survival of the Microgrid depends on the amount of the available spinning reserve, i.e. if it is sufficient to compensate for the loss of the power fed by the interconnection. Therefore, according to this constraint, it is essential that significant capacity of running units exists which can easily increase their production to meet the pre-determined demand. Thus the reaction time is smaller and the units can help to decrease the required size of the storage device that may be connected to face such an incident.

The approach followed is summarized in the flow chart of Figure 5. This approach may take also into account that the customer, under circumstances reflected by his bids, would accept disconnection of his low priority loads in order to maintain supply to his high priority loads in case of upstream fault. Thus, by reducing his requirements, this critical part of the demand can be more often served, since the total demand of the microgrid in such an event may be sufficiently met by the local units.

Therefore, after importing DSB from the loads, which can be totally high priority loads, the procedure is as follows:

If the micro-sources have enough capacity to meet a pre-determined amount of the load, then the microgrid can be adequate for this amount and the units to be committed or bids to be accepted should provide enough capacity to meet this part of the demand. In such a case, Micro-sources are committed according to their position in the priority list, until at least this predetermined demand is met. In this way the necessary spinning reserve to compensate grid disconnection will be maintained, although this might be clearly not the most economical solution. In the Economic Dispatch procedure, active power is dispatched to the micro-sources and if it is economically beneficial, active power is also bought from the grid as a typical economic dispatch process. In such case, there is sufficient running capacity of micro-sources to adequately meet the pre determined demand in the most economic way, in case of loss of interconnection.

During the hours the micro-sources are not sufficient to meet demand; they are committed according to their positions in the priority list, as long as they are cheaper than the open market prices, strictly economically. The rest of the demand is met by power bought from the grid. The Microgrid is then insecure in case of loss of the interconnection and the pre-determined demand will not be met, unless sufficient storage capacity exists.

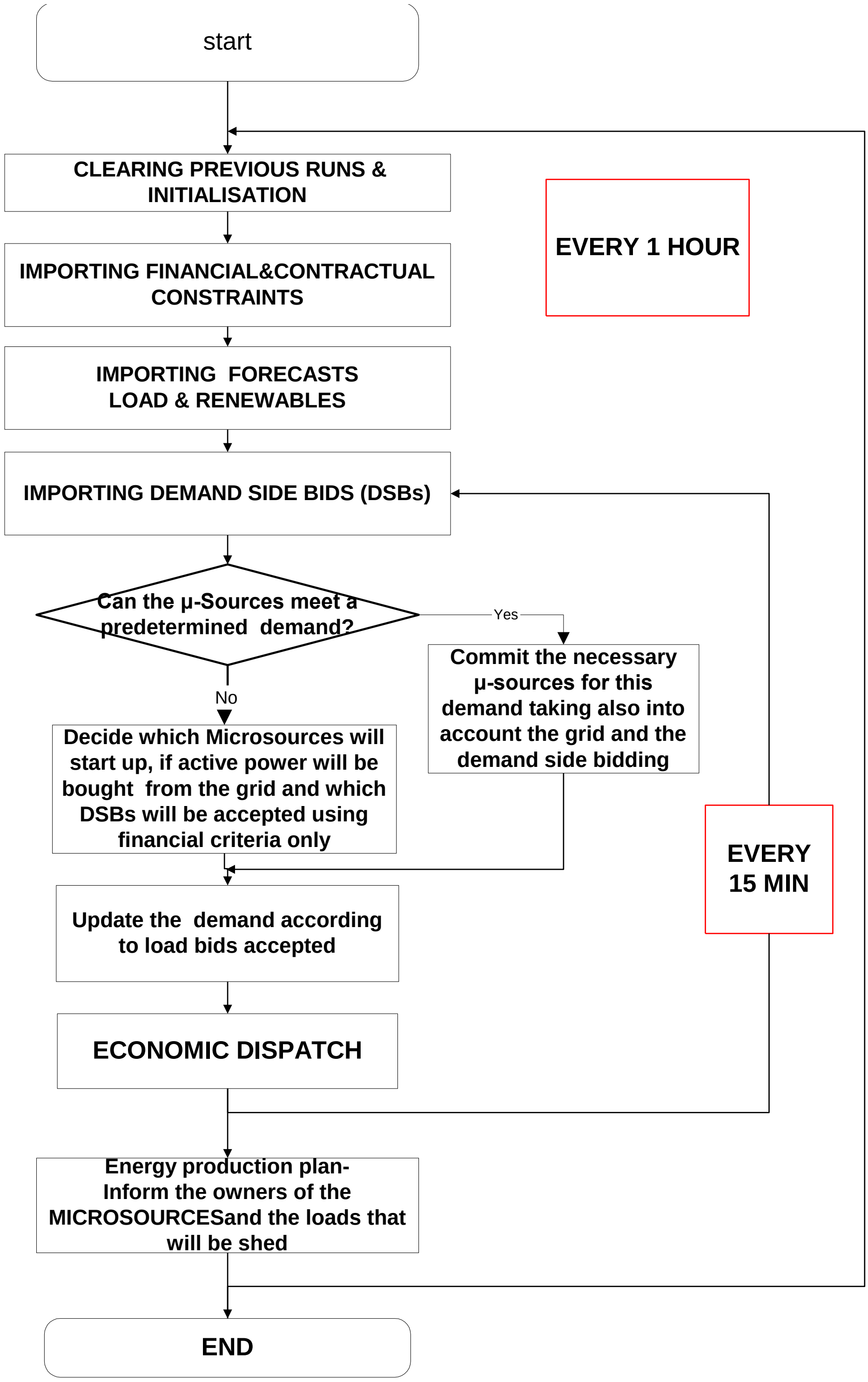

Figure 5: The flow chart of the proposed algorithm

A prototype software has been developed for the simulation for such an operation. With regards to adequacy of the Microgrid within the optimization horizon, the end-user can view a screen like the one shown in Figure 6 which displays how much load is possibly shed in case of grid disconnection in two cases.

- Bids for disconnection of low priority loads are accepted (marked with crosses)

- There are no priority loads (continuous line).

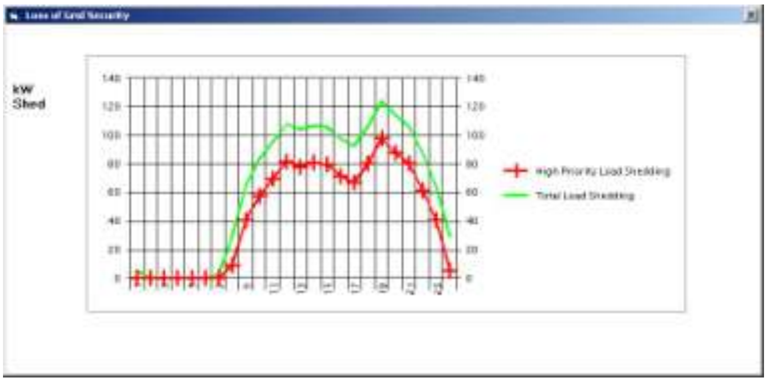

Figure 6: Load to be shed in case of grid disconnection (critical and non critical)

2.2.3 Participation in emissions markets

An additional function that can be incorporated in the MGCC operation is the ability of scheduling the dispatchable units in such a way that either the CO2 emissions are minimized or the economic benefits from participating in CO2 emission markets are maximized. The required information is a typical monthly 24-hour emissions curve of the upstream network.

More details on this proposed operation have been described in [4] and in Deliverable WPG [6]. The results from the application in the test network of Chapter 0 have shown that if sufficiently remunerated the DGs formulating a microgrid can further reduce the emissions of the upstream network with higher increase in their income compared to simply remunerating the emissions avoidance due to strictly economic operation of microgrids.

2.2.4 Economic scheduling functions

The forecasts provided the offers from the micro-sources, the demand side bidding values and the inputs for participating in emissions markets (if agreed within the microgrid) are used as inputs to the Economic Scheduling functions. These functions comprise Unit Commitment (UC) and Economic Dispatch (ED) Functions. The former decides on which units should be in operation, if active power will be bought from the grid and if any load bid is accepted. The latter decides on the set-points of the committed μ-sources.

The constraints of this economic scheduling problem is the adequacy of a predetermined demand of the microgrid and the fact that in steady state operation the total demand of the microgrid should be met. An additional constraint for Market policy 1 is the fact that the DG production cannot exceed the demand finally served in the microgrid.

The MGCC optimizes the Microgrid operation according to the bids of both DG and loads. For UC priority list method is utilized taking into account also DG bids while for the ED problem, the sequential quadratic programming method is used [7]. This is a generalization of the Newton's optimization method, which uses a quadratic approach of the non-linear objective function of fuel costs and linear approximations for the technical constraints. Other methods can be utilized as well, either purely mathematical [8] or based on artificial intelligence techniques [9], [10].

The final outcome of the Economic Scheduling functions is an Energy Production Plan consisting of the settings of the μ-sources and the load finally shed for the next hours of the simulation horizon.

3. Information exchange between MGCC and CAMC

In order to have much more active participation of a microgrid in multi-microgrids environment frequent exchange of information between each microgrid and CAMC is required. The frequency cannot be lower than 15 minutes for normal operation to comply with the MGCC circle of operation; it is recommended however this periodic information exchange to take place at least once per hour.

a. The data that should be sent from the MGCC to the CAMC are the following:
b. The expected demand exchange with the upstream network after the economic scheduling of the microgrid by the MGCC.
c. The total accepted bids from Intermittent RES (wind and PVs) so that CAMC can estimate production deviation useful for the control of the whole area.
d. Estimations for reactive power buy or sell from the upstream network based on the reactive power bids of the local units. Therefore, the MCs if they have the ability to increase reactive power should place their bids to the MGCC together with their active power bids.
e. The cost for decreasing demand within the Microgrid and the cost for increasing demand within the microgrid. Such information can help CAMC to select the most appropriate solution for facing emergency, either when energy is bought from the HV and there is disconnection, or when energy is sold to the HV network. Thus, the most economic solution for facing either lack or surplus of production can be identified for the CAMC. Then if the bids are accepted, the MGCC decides on what measures will take to decrease or increase production within the Microgrid it controls by informing the local controllers.
f. The minimum and maximum expected voltage within each microgrid. Thus, if there is voltage violation at any node the DMS should try to alleviate it. Moreover in this way the CAMC can calculate voltages only till MV/LV transformer of each microgrid, simplifying significantly the load flow calculations for multi-microgrids case.

Points d and e are explicitly described in chapter 4.

On the other hand, the CAMC should send to the MGCC information for normal operation regarding:

a. The market prices, if possible with some hours ahead, perhaps with running window technique. In this way the MGCC can inform the local controllers about these prices in order to prepare their bids more efficiently, according to the information diagram in Figure 2
b. If applicable for participation in the CO2 emissions market, the 24-hour emissions curve of the upstream network and the emission trading prices (expected to be constant for longer periods). This has been discussed also in WPG.
c. Request for hedging deviations in production in case of emergency, i.e. the suggested change in production/demand within the microgrid.
d. Deviations from suggested bids regarding reactive power.
e. The request for changing local production for providing voltage support, described in more detail in chapter 4.

3.1 Deviations in production in emergency and how CAMC will react

In the previous section the exchange of information between CAMC and MGCC was provided, here the reaction of both these stakeholders in case of emergency is described.

3.1.1 Request for Decreasing Local Demand

This may be the case when the HV network supplies power to the MV with the multi-microgrids. In case of emergency the CAMC should be able to reduce the demand within the MV network. This can be achieved by the following 3 ways:

a. By increasing DG production not belonging to any microgrid.
b. By disconnected large controllable loads outside the microgrid.
c. By asking from the MGCCs to reduce the demand they consume, according to the economic data sent to CAMC. The way of achieving that either by increasing DG production within the microgrids either by disconnecting loads is full

responsibility of each MGGC. Thus each Microgrid can be presented as one controlled entity as appears to the Distribution Network.

3.1.1.1 **DGs and controllable loads outside any microgrid**

This is for the case of larger DG units within the MV network not belonging to any of the microgrid within the specified area.

These units will not have to provide bids to CAMC for the normal operation and the CAMC will not interfere in their operation.

In order to participate within the “emergency” operation, DGs should indicate to CAMC how much they can increase their production if required and what should be the remuneration. This can be settled with longer term contract or with the DGs placing relatively frequent bids to CAMC for the additional production they can provide and the corresponding remuneration.

For controllable loads in case of emergency, they can reduce their demand or even not be supplied at all provided they are remunerated. This can be done with longer term contracts which will indicate the cost per disconnection (as a constant term) and a variable cost parameter which will define the cost for each kWh of demand not finally supplied. Another way that is more flexible and helps the owners of the controllable loads to adapt their remuneration to their actual needs is to provide more frequently bids for their disconnection providing the amount of load that can be disconnected and the corresponding remuneration.

3.1.1.2 **Microgrids within the area controlled by CAMC**

The MGCC will communicate to CAMC how much the additional reduction of the demand can be within the microgrid they control, if requested to as described in the beginning of the section. This reduction of the demand comes from two sources, the DG sources within the microgrid and the controlled loads. The CAMC is not interested on the source of this demand reduction but only for the reduction of the demand provided to the network.

The CAMC will use the most economic solution(s) among the 3 in order to meet the lack of production in local level just like any economic scheduling problem. CAMC will take into account the stated bids from MGCC for decreasing demand at Microgrid level, and the contract or bids of the local unit and the controllable loads.

3.1.2 Increase of the Demand

If there is flow from MV to HV and an emergency situation takes place (e.g. loss of connection with HV), then the production within the MV network should be decreased, or the load demand should be increased in order to maintain the frequency levels. 3 options exist:

a. The DG production is decreased
b. Some loads disconnected are brought back to operation
c. The Microgrids should increase the power that is delivered to them from the upstream network. This should be done either by decreasing DG production or by connecting some loads already disconnected within each microgrid.

Clearly CAMC tries to find the most economic solution in this problem, which is to choose the most expensive DG unit to reduce its output or the controllable load with either with the highest disconnection cost or with the lower service cost. The procedure is similar with the case of demand increase in case of emergency and if selected to increase the demand at a specific microgrid it is responsibility of the MGCC of the specific microgrid to identify the most profitable solution, e.g. to reduce the production of the most expensive DG unit within the microgrid.

4. Additional operations incorporated in MGCC for aid in provision of Ancillary services

The description of information exchange between MGCC and CAMC (chapter 3) and the functions that have been already developed as described in chapter 2 shows that some additional functions for the MGCC should be developed. The basic outlines of these functions are provided here.

First the functions for providing bids to CAMC for production change within the Microgrid are described.

In order to provide aid to voltage management to the CAMC, functions for calculating the expected voltage levels within the microgrid and the necessary change in local production that could help in improving voltage profile either within or even outside the microgrid should be incorporated in MGCC operation. First the methodology based on Probabilistic Load Flow (PLF) is described for estimating voltage profile, with emphasis to the expected minimum and maximum voltage level within the microgrid is described. Thus:

a. There is no need for the CAMC to run a load flow taking into account each node of the microgrid but each microgrid can be considered as a PQ bus concentrated at MV/LV. The voltage can be calculated at this point and based on the information provided by the MGCC can be calculated whether the voltage within each microgrid is expected to be outside the limits set by the standards. If there is expectation of voltage violation then corrective actions should be taken described in more detail in section 4.4.2.
b. Given the limits of increasing/decreasing local production without causing voltage violation inside the microgrid it can be calculated how much a microgrid could change its production for helping CAMC to face voltage violation.

4.1 Bids for offering change in local production to CAMC

The MGCC has received bids from the local DG units regarding their production and, if applicable, bids for Demand Side bidding as described in chapter 2. According to these bids and the market prices available formulates the bids to be placed to CAMC for changing local production.

4.1.1 Bids for increasing local production/decreasing local demand

The bids that have not been accepted are used as inputs for calculating the bids for the decrease of the demand asked by the upstream network. Increase of production will have as a benefit reduction of power bought from the upstream network. The following cases can be distinguished:

a. One of the units has not been fully dispatched and operates at dPg. This is clearly not the case for intermittent RES but for dispatchable units whose output is defined by wind or solar radiation. In such a case the additional cost for increasing production will be provided by a function like (2) with the constraints described in (3).

$$actbid(dPg + x) - mprice \cdot x - actbid(dPg) \qquad \textbf{(2)}$$

$$dPg \le x + dPg \le P^{MAX} \qquad \textbf{(3)}$$

b. There is a need for starting up one additional unit to offer additional change in demand to the CAMC. This unit should operate above its technical minimum and for bids above this value, the additional cost will be provided by (4) with constraints of (5).

$$actbid(x) - mprice \cdot x \qquad \textbf{(4)}$$

$$P^{\min} \le x \le P^{MAX} \qquad \textbf{(5)}$$

c. If the MGCC is willing to offer increase of the demand lower than the technical minimum of an additional unit, then the other dispatchable units should reduce their output to accommodate increase of local production. In such a case the cost increase that should be reflected in the bids is provided by (6) with index 1 denoting the inexpensive unit and index 2 the more expensive unit. The constraint for x is provided by (7). Pmin in such a case refers to the inexpensive unit and PMAX to the most expensive one.

$$actbid_2(P^{\min}) - mprice \cdot x + actbid_1(P^{MAX} - x) - actbid_1(P^{MAX}) \qquad \textbf{(6)}$$

$$P^{\min} \le x \le P^{MAX} \qquad \textbf{(7)}$$

d. If more than one unit requires changing their production to achieve a certain amount of capacity for increasing production, then an optimization problem like the one used for the case of economic scheduling is resolved.

In all cases, dividing by the increase of production required, the change in €ct/kWh can be calculated.

4.1.2 Reduction of production/increase of demand

On the other hand, when reduction of production is required, the bid for changing production reflects the loss of income due to this decision. The most inexpensive case is the reduction of production from the most expensive of the units dispatched already.

The bids that have not been accepted are used as inputs for calculating the bids for the increase of the demand asked by the upstream network. Decrease of production will have as a benefit reduction of cost as stated by the bids of the DG sources but increase of the power bought from the upstream network.

The following cases can be distinguished:

a. The production is reduced but no unit is de-committed. The cost in such a case is provided by (8) with constraints described in (9).

$$mprice \cdot x - actbid(dPg - x) \qquad \textbf{(8)}$$

$$P^{\min} \leq dPg - x \qquad \textbf{(9)}$$

If the unit is switched off then the cost will be $mprice \cdot dPg - actbid(dPg)$. For range of reduction $dPg \geq x \geq dPg - P^{\min}$ the MGCC cannot make an offer unless there is another unit that can decrease its production and the most expensive unit operates at its technical minimum. This however would increase the average cost. An example with two units, 1 the least expensive and 2 the most expensive, follows in (10) in terms of cost change and in (11) in terms of constraints required.

$$actbid_2\left(P_2^{\min}\right) + actbid_1\left(dPg_1 - x\right) + mprice \cdot (x + dPg_2 - P_2^{\min}) - actbid_2(dPg_2) + actbid_1\left(dPg_1\right) \qquad \textbf{(10)}$$

$$0 \leq x \leq dPg_1 - P_2^{\min} \qquad \textbf{(11)}$$

b. If the MGCC is willing and at the same time it is possible to further reduce production affecting more than one unit, then the bid offered is a result of an optimization problem for the various levels of production decrease willing to be submitted as bids.

4.2 Estimating voltage profile within a Microgrid

4.2.1 Introduction

During the operation of an LV network with RES, an estimation of both the total demand and the RES production using simple techniques like persistence methods or even more sophisticated load and wind forecasting tools can be obtained [11],[12]. Additionally, the topology of the network, the type of load and typical curves for each type are usually available to the DNO, who operates the network within its acceptable power flow and voltage limits.

In such networks, very rarely do other measurements exist at consumer nodes other than periodical, e.g. monthly energy consumption readings. Therefore, the demand at each node is not known and accurate estimation of voltage violation at the network nodes is not possible.

This uncertainty is increased if the stochastic and non-dispatchable production of RES installed in the network. The estimation of RES production has significant uncertainty even with sophisticated wind power forecasting tools co-operating with meteorological data presenting relatively small Mean Average Percentage Error (MAPE) [12],[13].

Taking into account the above uncertainties imposed in an LV network with RES, deterministic load flow cannot guarantee that there will be no voltage violation in any of the network nodes since specific value for each power injection is required. On the other hand, Probabilistic Load Flow (PLF) is a powerful tool for estimating the voltage profiles in power systems with significant uncertainty estimating how probable and where in the network, voltage or over-current violations exist [14].

Change in the production or even demand by accepting demand side bids within the microgrid can help in mitigating voltage violations especially inside it. Increase in local production can help in periods when low voltage occurs while decrease in local production can help when voltage exceeds the upper acceptable limit.

a. The methodology developed models, as described in Section 4.2.2:
b. The demand of each node when the total demand of the network is known and the uncertainty of the RES estimated production.

Then it applies PLF taking into account the special characteristics of LV networks as far as resistance to reactance ratio (R/X) is concerned using a modified load flow algorithm for LV networks as described in section 4.2.3.

4.2.2 Methodology for Estimating Voltage Profiles within a Microgrid

This methodology takes advantage of the special features of LV networks. The error when applied this is to MV networks as the ones assumed for multi-Microgrids environment, is higher as the R/X ratio becomes smaller. However, PLF methods can be applied as well, considering a probability density function for the power demanded or provided by the Microgrid.

4.2.2.1 Demand modelling

4.2.2.1.1 Representative Load Curves

In the attempt to acquire the representative load curves of the electricity consumers, two paths can be followed. The one involves the classification of electricity customers on the base of a priori indices, such as contracted power, type of activity etc, while the other is based on pattern recognition methods (k-means, hierarchical clustering, self-organizing maps etc). The result achieved by either of these two methods is the classification of the electricity customers into groups with similar characteristics. However, it should not be ignored the fact that similar as the results may be, there is an undeniable degradation in the accuracy of the achieved partitioning when the former method is preferred [15]-[17].

Following the formation of consumers' classes, the mean $m(t)$ and standard deviation $s(t)$ curves emerge, which are assumed to be representative for each different class. Assuming a normal distribution of the values, a daily load curve $f(t)$ with a certain probability of not being exceeded can be formed as follows [18]:

$$f(t) = m(t) + ks(t) \quad \textbf{(p.u.)} \qquad \textbf{(12)}$$

where k is the value in a Gaussian distribution table that establishes the probability pr (%).

Let us suppose one transformer with "p" consumers type "a" and "q" consumers type "b". The curves F_i, F_j of each consumer type are:

$$F_i = m_a P_i + k s_a P_i \qquad \textbf{(13)}$$

$$F_j = m_b P_j + k s_b P_j \qquad \textbf{(14)}$$

P_i, P_j are the power base for each consumer, m_a, m_b and s_a, s_b is the mean value and the standard deviation of consumers type "a" and "b" respectively (in per unit values).

The aggregation of "p" and "q" consumers will be given by the expressions:

$$M = \sum_{i=1}^{p} m_a P_i + \sum_{j=1}^{q} m_b P_j \Rightarrow M = \sum M_i \qquad \textbf{(15)}$$

$$S^2 = \sum_{i=1}^{p} (s_a P_i)^2 + \sum_{j=1}^{q} (s_b P_j)^2 \Rightarrow S^2 = \sum S_i^2 \qquad \textbf{(16)}$$

Thus, the total demand curve at every point of interest in the network is formed.

4.2.2.1.2 **Simplified Approach**

It is assumed that the total demand of the network is obtained for the next hour as output of a load forecasting algorithm. Additionally, a typical daily demand curve in hourly steps for each of the F load types in the network is known to the management system of the DNO. The demand of the network is then distributed to each type of loads using equation (17)

$$demand(f,t) = demand(t) \cdot \frac{perc(f,t) \cdot max_f}{\sum_{f=1}^{F} perc(f,t) \cdot max_f} \qquad \textbf{(17)}$$

where demand(f,t) is the total demand of the f type of load for the time interval t, perc(f,t) is the percentage at the specific time of the maximum demand, maxf, for the examined type of loads as specified by the typical demand curve. The parameter max_f for each type of customer corresponds to the coincidence maximum for the network.

Each load l belonging to the f type loads is assumed to follow a normal probability distribution function (pdf). The mean value of this pdf is derived by distributing demand(f,t) to each load of the same type according to its energy share, en_share(l,t) within the same type of loads as described by (18).

$$dem(l,t) = en\_share(l,t) \cdot demand(f,t) \qquad \textbf{(18)}$$

Such information can be easily obtained by the DNO from the energy readings for the same class of customers.

The standard deviation depends on the type of the load and typical values can be found in bibliography [19].

4.2.2.2 **RES modelling**

It is expected that one of the dominant DG to be installed in a LV network is (RES) like small wind Turbines or Built Integrated PVs (BIPV). These sources are characterized by uncertain production not only in long-term operation, i.e. the annual or monthly energy yield but also in the short-term operation. The modelling for each type of production is provided in the following sections.

4.2.2.2.1 **Wind power**

The pdf usually used for wind velocity for long-term operation of a network is the Weibull distribution [19]-[21].

In on-line operation, like the one considered here, usually there is an estimation of the wind power production or simply an estimation of the wind speed at the proximity of the studied network, for the next short term period.

In our case it is assumed that the wind speed v near the studied network is known for the previous hour and that will be the same for the current hour. Wind speed is considered as a random variable with mean value the known value and standard deviation equal to 11.03% of the mean value, which is the RMSE of a persistent forecasting model [11].

Knowing the wind speed probability density function (pdf) and the wind turbine wind velocity to power characteristic power curve, then the wind power production pdf can be derived using the following methodology:

The wind power production is a discrete pdf calculated at the following capacity points, at which the probabilities are calculated:

$$C_0 = 0$$
$$C_k = k \cdot \Delta P, k = 1..n \qquad \textbf{(19)}$$

where ΔP is considered equal to 5% of the nominal capacity therefore n in our case is equal to 20.

The possibilities of occurrence for each capacity point are given by the following set of equations:

$$p_0 = 1 + \Phi(Vcut\_in) - \Phi(Vcut\_off)$$
$$p_k = \Phi^{-1}((2k+1)\cdot\frac{\Delta P}{2}) - \Phi^{-1}((2k-1)\cdot\frac{\Delta P}{2}), k = 1..n-1 \qquad \textbf{(20)}$$
$$p_n = \Phi(Vnominal) - \Phi^{-1}((2n-1)\cdot\frac{\Delta P}{2})$$

where Φ(x) is the cdf of the expected wind speed, a Normal cdf in this case. Vcut_in is the velocity above which the WT starts producing active power and Vcut_off is the cut-off speed. Φ-1(x) represents the wind velocity at which the x wind power production is calculated.

4.2.2.2.2 Solar power

As far as PV is concerned, the maximum expected production of a PV at a specific time and installation place is easily determined. However, the actual output of a PV, for known temperature depends on the clearness index. It is assumed that the output of the PV depends linearly on the clearness index, and that the clearness index is a random variable.

This random variable follows a Normal pdf with mean value the clearness index (CI) of the previous hour, assumed to be equal with the CI of the current hour, as expressed by (21).

$$CI(t) = CI(t-1) = \frac{Measured\_PV(t-1)}{Max\_expect\_PV(t-1)} \qquad \textbf{(21)}$$

where Measured_PV(t-1) is the measured production during the previous hour and Max_expect_PV(t-1) is the maximum expected PV production for that hour.

The standard deviation of the Normal pdf is a function of the CI(t).More specifically, since CI(t) is among 0 and 1, the standard deviation should comply with equation (22)

$$\sigma = Min\{CI(t)/3.27,(1-CI(t))/3.27\} \qquad \textbf{(22)}$$

so that the possibility of the CI(t) to be within these limits will be 99.95%. Taking into account that

$$PV\_prod(t) = Max\_expect\_PV(t) \cdot CI(t) \qquad \textbf{(23)}$$

the production of the PV is also a random variable following also a Normal distribution with mean value

$$Max\_expect\_PV(t) \cdot CI(t) \qquad \textbf{(24)}$$

and standard deviation

$$\sigma \cdot Max\_expect\_PV(t) \qquad \textbf{(25)}$$

4.2.3 Probabilistic load flow

Unlike high voltage transmission lines, LV distribution networks are characterized by lines with rather high resistance to reactance ratio (R/X). If the reactance X is neglected, the error in calculating the voltage drop along a LV feeder is:

$$err\% = \frac{1}{\sqrt{1+\left(r/x\right)^2}} \cdot 100 \qquad \textbf{(26)}$$

where r is the resistance and x its reactance of the line in Ω/m. The higher the X/R ratio the higher this error is expected to be.

Taking only the resistances of the network into account the load flow for a LV network can be considered as a load flow for a DC system.

PLF has been widely used for estimating the voltage profile mainly in weak distribution networks with increased wind power penetration calculating the voltages at each node and suggesting reinforcement of the studied network [19], [21], [22]. Thus, taking into account the uncertainties described in section 4.2.2, the probabilistic load flow (PLF) technique can help in estimating the voltage profile at each node [19],[20],[22]. Due to the simplification allowed by the LV network conditions, the PLF is reduced to account only for the active power flows as the following equations (27)-(29) describe.

$$P = g(V) \qquad \textbf{(27)}$$

$$P_i = V_i \cdot \sum_{k=1}^{n} G_{ik} \cdot V_k \qquad \textbf{(28)}$$

$$V = J^{-1} \cdot (P - P^0) + V^0 = (V^0 - J^{-1} \cdot P^0) + J^{-1} P \qquad \textbf{(29)}$$

where P is the active power matrix given by the Normal distribution, V is the voltage matrix pdf sought for and g(V) is the linking equation between P and V. Gik is the conductance matrix of the network. P^0 is the matrix of the expected demand at each node and V^0 is the voltage matrix derived by a deterministic load flow and $J = \frac{\partial g}{\partial V}|V_0$. The final voltage matrix is derived by (29).

4.2.4 Voltage estimations in PLF

Using the above described methodology the voltage pdf at each node at specific time t, Vnode(t), the corresponding cumulative distribution function (cdf) can be derived. According to the risk that the DNO is willing to follow, p and q percentile points are found at each node voltage cdf corresponding to the minimum and maximum expected values for the specific node, respectively. Different values for the percentiles can be used.

In the following, perct(q,Vnode(t)) is defined as the solution of the following equation :

$$F_{Vnode(t)}(Vnode(t)) = q \qquad \textbf{(30)}$$

denoting the q percentile of the $F_{Vnode(t)}(Vnode(t))$ cumulative distribution function (cdf) of the Vnode(t) pdf.

If the node voltage pdf is following a Normal pdf then the p and q percentiles can be easily derived using the Normal cdf tables and the following set of equations (31) and (32).

$$perct(q, Vnode(t)) = \mu(t) + k\_q \cdot \sigma(t) \qquad \textbf{(31)}$$

$$perct(p, Vnode(t)) = \mu(t) - k\_p \cdot \sigma(t) \qquad \textbf{(32)}$$

where k_q and k_p are the percentile points corresponding to the standard normal pdf tables and μ(t) is the mean value of the Normal pdf of the node voltage.

If the pdf of the voltage at each node is not easily approximated via normal pdf, then percentile points are easier to be derived by discretization of the pdf. Having calculated the p and q percentile points, the minimum and maximum voltage of the network can be found and thus if in any node there is voltage violation, the magnitude of violation and at which nodes such violation exists can be easily identified.

4.3 The MG contribution to face voltage violations

Two separate cases are examined:

- When the voltage violation takes place in a node belonging to the MG.
- When the voltage violation takes place in a node outside any MG.

The general aspects of these cases and the solutions that a Microgrid can provide are described here whereas the functions that can be incorporated in the MGCC to help in this issue are described in more detail in section 4.4.

4.3.1 Voltage violation inside a specific MG

The solution in such a problem can be sought either solely inside or even outside the MG, by improving the voltage profile at another bus and as a result to improve the voltage profile within the microgrid.

In the former case, the MGCC decides which of the submitted bids will accept using the description of section 4.4 (favourably the most inexpensive solution) for changing production in such a case. Naturally, the cost for this service (offered by either loads or producers) must be paid. At this point, the problem that rises is summarized in the question: “Who pays?” The alterative answers are as follows:

1. The MGCC aggregator if such obligation is foreseen via an internal contract to improve voltage profiles within the microgrid. In such a case the customers may wish to have even more improved voltage profile compared to the corresponding standards.
2. The participants that belong to the specific MG, if they share the expenses and benefits from Microgrids operation.
3. The corresponding participant(s) facing the problem (voltage violation). This cost may be lower than installing a voltage support device that may be used for limited period.

4. The CAMC as much as the DSO holds this delegate responsible for maintaining the voltage levels inside the controlled area.

In the first three alternatives, the CAMC does not care on how the problem will be solved within the microgrid since there is no obligation from the MV network to provide compensation for resolving this issue. In this case the MGCC should solve an optimization problem so as to maintain voltage limits within desirable limits at the lowest cost.

In the latter case, i.e. when the solution can be sought both inside and outside the MG that faces the voltage violation, the optimal solution is a decision of the CAMC. The MGCC is obliged to provide the CAMC the remuneration of the suggested solution and the magnitude of active/reactive power change. The CAMC can calculate the cost of the various solutions at its disposal, e.g. cost of providing/absorbing active/reactive power at a bus outside the Microgrid compared to the cost that the MGCC provides that can solve the voltage violation problem. If the voltage violation solution is assigned to MGCC, then the MGCC applies the solution that complies with the suggested information to the CAMC.

4.3.2 Voltage violation outside a specific MG

The solution can be sought, as mentioned above, outside or less probable within a specific Microgrid. Each microgrid by changing its demand can change the losses of the MV lines and thus change the voltage drop on them.

The CAMC in the first case has to decide which is the most economic solution for solving the voltage violation problem based on DG units outside the microgrid or even on reactive power units, e.g. capacitor banks, based on which is the most economic solution. In the simplest approach the capacity of microgrids in changing their production is not taken into account and the MGCC has no other obligation.

If the CAMC is willing to take into account potential aid by the microgrids, then again the MGCC should provide his offer regarding change in the demand and the amount of change in active/reactive power. Then the CAMC takes also into account the MGCC to make the final selection of the way to combat voltage violation problem. If change in demand of microgrid is selected, the MGCC decides on the way to achieve the promised change in demand. In such a case it is rather indifferent which unit will change production since the topology inside the microgrid is not such an issue as in the case of voltage violation inside the microgrid. Therefore, the solution is based on economic criteria as described in 4.5.

4.4 Changes in local production due to voltage issues

Having calculated the voltage levels within the microgrid, if voltage violation is foreseen the required actions within the microgrid to solve this issue can be evaluated. Moreover, the limits for changing local production without causing voltage violations can also be evaluated. Thus, the MGCC can respond to the CAMC instructions if voltage support can be offered by the Microgrids.

In the following we define as "Last node" the last common node of the following two, a) and b), connecting lines.

a. The line connecting the slack node and the connection point for the under study DG unit and
b. The line connecting the slack node and the examined node.

First the solution of the problem in 4.3.1 when the MGCC is solely responsible for improving voltage profile within the microgrid is described. The case where the MGCC simply bids for solving voltage violation issue and is not the one providing the solution is described just afterwards.

4.4.1 Calculating required change in local production in case of voltage violation inside the microgrid

The following flow chart of Figure 7 presents the methodology for facing voltage violation.

The necessary injection or absorption ΔP in the microgrid to avoid voltage violation can be easily calculated and should account for the bus with the higher voltage violation. Thus, the ΔP is calculated taking into account the minimum and maximum voltage of the nodes with voltage violation according to equations (33) and

(34), the former for injecting to and the latter for absorbing power from the network. All values in both equations are expressed in per unit.

$$\Delta PI = \frac{V^{\lim it} - V^{\min}}{R} \cdot V_1 \qquad \textbf{(33)}$$

$$\Delta PS = \frac{V^{\lim it} - V^{MAX}}{R} \cdot V_1 \qquad \textbf{(34)}$$

where Vlimit is the voltage limit, Vmin is the minimum voltage of the network and V1 is the voltage at the slack node, the MV/LV connection point. R in both equations corresponds to the resistance between the slack node and the “last node”. VMAX is the maximum voltage of the network.

If there is only upper or only lower voltage limit violation then the procedure described in steps 1-3 is applied only for decrease or increase of the DG production, respectively. This means in the former case ΔPI=0 and in the latter ΔPS=0.

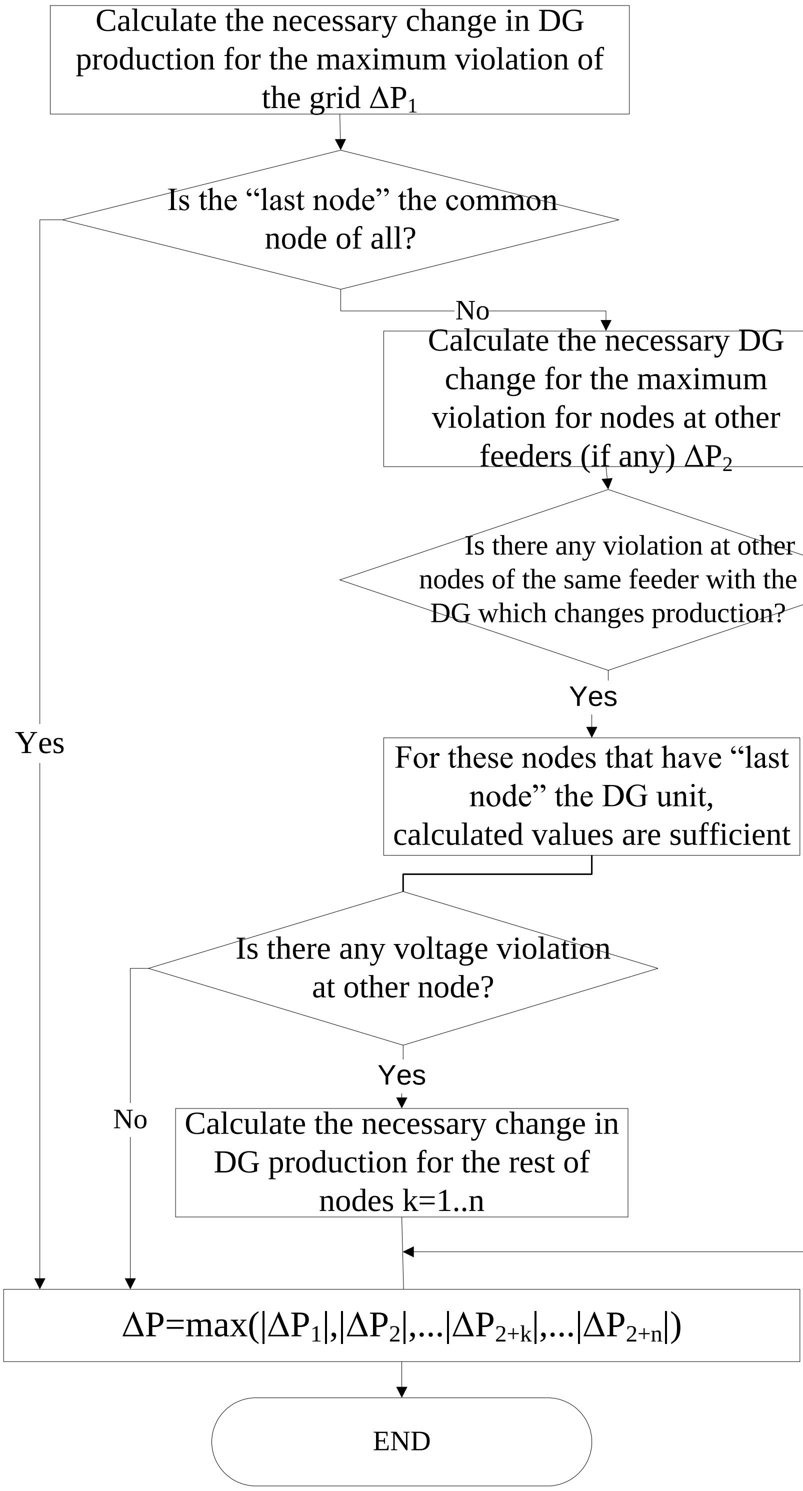

Figure 7: The flow chart for improving voltage violation as feedback to the CAMC instructions to the MGCC

Steps 1-4 described below are followed to calculate the necessary increase or decrease of the DG production in such a case:

1. Using equation (33) or (34) calculate the ΔP=ΔP1 requirements. If the "last node" is the starting point of all the feeders, ΔP1 is the maximum ΔP required. In such a

case in all the other nodes the voltages violation is lower and the calculated ΔP1 is sufficient to improve voltage profile at all nodes and thus the process is over moving to step 5.

2. Check for voltage violations at other feeders. If there is voltage violation at nodes of other feeders except the one with DG, ΔP1 might not be sufficient to meet the voltage violation at nodes belonging to these feeders even though it is lower than the maximum violation of the network. Thus either (33) or (34) are used to calculate the necessary ΔP=ΔP2 to avoid such a case. Vmin and VMAX at this step correspond to the minimum and maximum voltage of all the feeders except the one where the DG unit is connected to.
3. If there is voltage violation at nodes other than the ones studied at steps 1 and 2, there might still exist voltage violation even if ΔP1 or ΔP2 is used. The following steps i–ii are followed to calculate the necessary ΔP to avoid such a case.
   i. For the nodes that the “last node” coincides with “last node” of step 1, the larger of ΔP1 and ΔP2 calculated at steps 1 and 2, provides the necessary voltage change to overcome even greater voltage violation than the existing. Thus for these nodes no update for ΔP is foreseen and no other calculation is made.
   ii. If the “last node” does not coincide with the “last node” of step 1, then there might still exist voltage violation at the studied node. Then the necessary ΔP=ΔP(2+k) for this case is calculated using (33) or (34) and Vmin or VMAX are the minimum or maximum voltage for this node. The step is repeated until all the k=1 to n nodes of this type are examined.
4. If ΔP in any step is higher than the DG capacity to change production then the ΔP is considered equal to this and the calculations stop. Otherwise the ΔP requirements are calculated using (35):

$$\Delta P = max(|\Delta P_1|, |\Delta P_2|, \ldots, |\Delta P_{2+k}|, \ldots, |\Delta P_{2+n}|) \qquad \textbf{(35)}$$

4.4.2 Calculating acceptable change in local production without causing voltage violation within the Microgrid

The MGCC should be frequent aware of the limits of changing local production if requested by the CAMC. These limits are ΔPS and ΔPI respectively. If voltage violation exists then as in section 4.4.1 one of these values will be zero. Vmin and VMAX are the minimum and maximum voltages of the network as calculated in section 4.1. The maximum accepted ΔPS and ΔPI irrespectively of the node with the minimum voltage acceptance is calculated using methodology of section 4.4.1. In this case, unlike subsection 4.4.1 where the procedure was restricted to the nodes with voltage violations, here all the nodes are examined.

The steps for this purpose are the following:

1. Having calculated the p and q percentiles of the voltage at each node, the minimum accepted change in the voltage at the nodes of the network is calculated. Again Vmin and VMAX are the minimum and maximum voltages for the whole network.
2. For the nodes belonging to feeders different than the ones with DG units, the ΔP as calculated in section 4.4.1 will not lead to voltage violation; thus the ΔP limits are calculated similarly and are denoted as ΔPS1 and ΔPI1.
3. For the nodes with "last node" the DG unit connection point, Vmin and VMAX are the minimum and maximum voltage values of all these nodes and using (33) and (34), the ΔP limits ΔPS2 and ΔPI2 are calculated. If Vmin and VMAX coincide with the minimum and maximum voltage of the network then there is no need to check for the rest of the nodes since they will not have, in a radial network, any larger change. Otherwise proceed to step 4.
4. For the rest of the nodes that have minimum or maximum voltage lower than Vmin or higher than VMAX as calculated at step 3 respectively there might still be caused voltage violation if the lower of ΔPS1 and ΔPS2 or ΔPI1 and ΔPI2 is used. Thus, the necessary ΔPS=ΔPS2+k and ΔPI=ΔPI2+k should be calculated for all the k=1 to n nodes of this type. Vmin and VMAX are the minimum and maximum expected voltage at the node k and the values ΔPS and ΔPI for each node are calculated for each node using (33) and (34). This step is repeated until all the nodes are examined. R is the resistance of the "last node".

5. ΔP can neither exceed the current local production, pow, in case of request for decreasing local production nor the maximum quantity for increasing local production cap-pow, where cap the capacity of the DG unit. The values of ΔPS and ΔPI are calculated using equations (36) and (37) respectively.

$$\Delta PS = \min(pow, |\Delta PS_1|, |\Delta PS_2|, \ldots |\Delta PS_{2+k}| \ldots |\Delta PS_{2+n}|) \quad \textbf{(36)}$$

$$\Delta PI = \min(cap - pow, |\Delta PI_1|, |\Delta PI_2|, \ldots |\Delta PI_{2+k}| \ldots |\Delta PI_{2+n}|) \quad \textbf{(37)}$$

4.5 Economic evaluation of the changes in local production due to voltage change

In sub-section 4.4 the methodology for calculating either required or acceptable change in local production for voltage support issues has been presented. More than one solution regarding this type of change may be available. The MGCC should decide which is the most economic solution among the available ones. The comparison is based on absolute values (€/case) and not in terms of (€ct/kWh) which however is available by the bids of either the DG sources or the DSB since a DG unit with low required increase of production and high operational cost may be more economic than a unit with much lower operating cost but significant required increase on capacity.

Since the operation of the microgrid is optimized according to 2.2.4, any change in production will lead to loss of income, since there will be change in the energy exchanged between the Microgrid and the upstream network. The additional cost for this solution is the cost of the solution minus the cost of energy bought from the network if there is need for increasing local production.

The final cost for the change in local production is provided by (38), where x is the final change in the local production with positive value denoting increase of the local production and mprice is the market price for the period when the voltage change is required.

$$volt\cos t(x) = |x \cdot mprice - \cos t(x)| \quad \textbf{(38)}$$

For the case that there is no voltage violation within the Microgrid, the offer of MGCC to CAMC for changing the optimized operation for providing voltage support should reflect the additional cost similarly to (38). In such a case the cost may be even expressed in (€ct/kWh) or in bids format similar to the one of Figure 3. Ways of calculating these bids follow directly afterwards and are common with cases when CAMC requests production change from MGCC.

5. Study Case network

5.1 General description of the LV network

A typical, LV network which comprises three feeders, one serving a primarily residential area, one industrial feeder serving a small workshop, and one commercial feeder has been used [23], Figure 8. The typical demand pattern for each type of customer is shown in Figure 9. A variety of DER, such as one Micro Turbine (MT), one Fuel Cell (FC), one directly coupled Wind Turbine (WT) and several PVs are installed. It is assumed that all DER produce active power at unity power factor, i.e. neither requesting nor producing reactive power. Table 5-1 provides the capacity of the installed RES while Table 5-2 summarizes the characteristics of the fuel consuming units and their bids reflecting their fuel costs [24]-[26]. Both, Micro-Turbine and Fuel Cell are assumed to run on natural gas, whose efficiency is 8.8 kWh/m3 and price 10 c€/m3 [27]. For the MT the efficiency is assumed 26%, while the efficiency of the Fuel Cell (a PEM –Proton Exchange Membrane– unit) is assumed 40% [28], [29]. For RES the bids are considered as equal to zero reflecting their operating cost. The scope was to calculate the maximum potential savings for the customers in Market Policy 1.

Table 5-1: Data for the capacity of the RES DG units

Unit ID	Unit Name	Max. Capacity [kW]
3	WT	15
4	PV1	3
5-8	PV2-5	2.5

Table 5-2: Data for the bids considered for the fuel-fired DG unit

Unit ID	Unit Name	A [€ct/kWh^2]	B [€ct/kWh]	C [€ct/h]	Min. Capacity [kW]	Max. Capacity [kW]
1	MT	0.01	4.37	0.01	6	30
2	FC	0.033	2.41	0.841	3	30

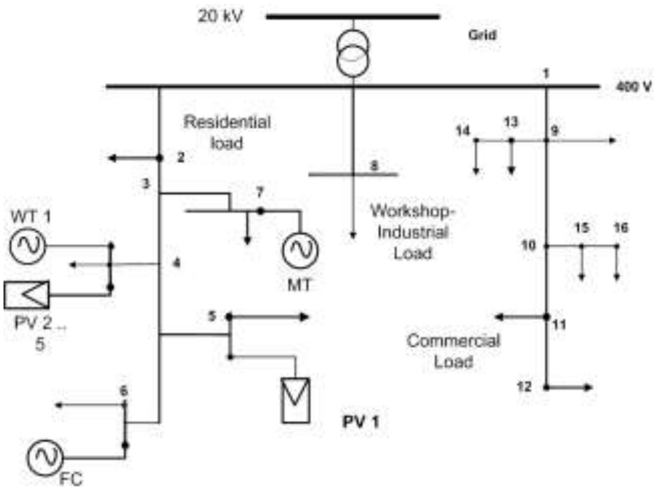

Figure 8: The case study LV network

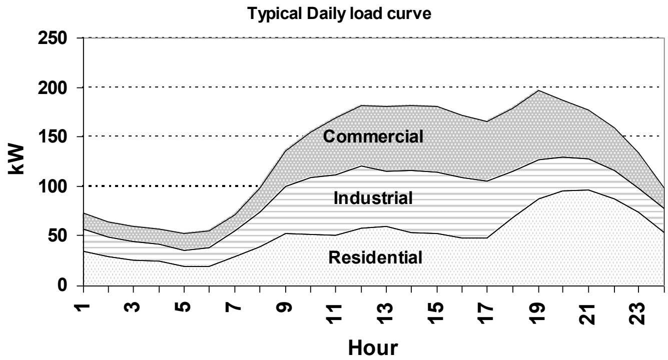

Figure 9: The typical demand curve for each type of customers of the Microgrid

5.2 Data used for extended period simulation - Adequacy constraint

In order to evaluate the proposed methodology under various combinations of RES production, demand and market prices the following assumptions have been made in order to enhance the one period data available in [23]. In specific, data coming from the wind velocity time-series of the island of Crete were used using a typical Wind Turbine of 15 kW, represented by a 3rd order polynomial [30]. For PVs, normalized hourly time-series from the PV installation (1.1 kW) in the campus of the NTUA are used [31]. Regarding demand for different seasons, the Reliability Test System (RTS) weekly variation [32] and the typical demand curve of the Microgrid (Figure 9) were combined providing the daily demand per season of Table 5-3.

Regarding energy market, prices from the Amsterdam Power Exchange (ApX) for 2003 [33] (Figure 10) have been used to represent realistically the open market in which the LV grid operates. In this figure, each 24 steps correspond to one season, with the following sequence, winter, Spring, Summer and Autumn at 3 levels: a) The highest per season and hour, b) The average per season and hour and c) the lowest per season and hour.

Table 5-3: Daily demand for the various seasons considered

Season	Daily Demand (kWh)
Winter (W)	3571
Spring(Sp)	3096
Summer(Su)	3402
Autumn(A)	3009

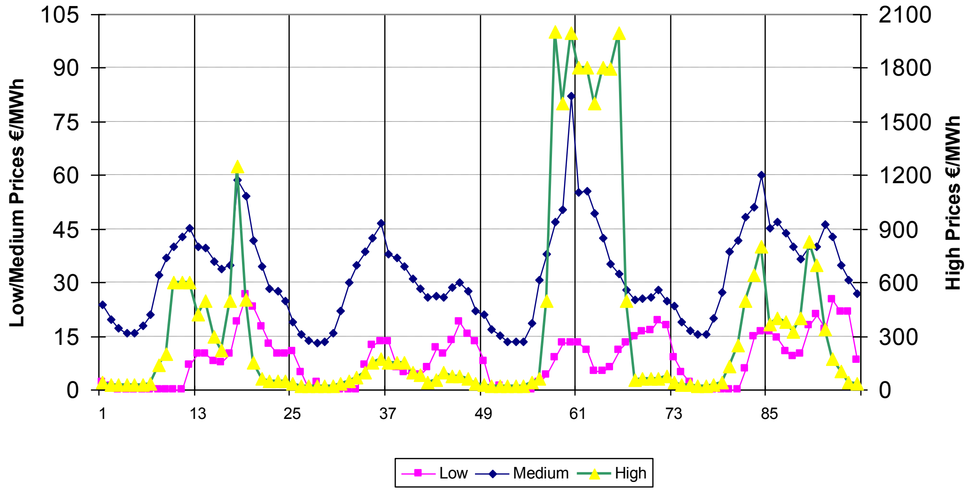

Figure 10: The market prices used. Season changes every 24 steps

Regarding demand side bids, the concept presented in Figure 3 was used. The lowest bid corresponds to 6.9 €ct/kWh, the lowest energy charge tariff for LV networks in Greece during 2006 [34]. The high priority load bids are considered as an "infinite" price. Each consumer is assumed to have low priority bids of 2kW if his demand is expected to be higher than this value. For simplicity in the provided results, the power magnitude and the bid price are considered constant throughout the period of study.

Regarding operation concept, the analysis is focused on Market Policy 1 and Demand Side Bid Option of shifting load. Since the production capacity is in the vast majority of cases lower than the demand, policy 2 will not change the results significantly.

5.3 Modifications for voltage violation

Some slight modifications for the case study network have been made for studying the voltage violation problem. Since the method can be generalized for energy storage devices, it is presented how this result can change.

5.3.1 Case study network modified

The network used is based on the one of Figure 8 but taking into account only RES units, as presented in Figure 11. Power base of 100 kVA has been considered.

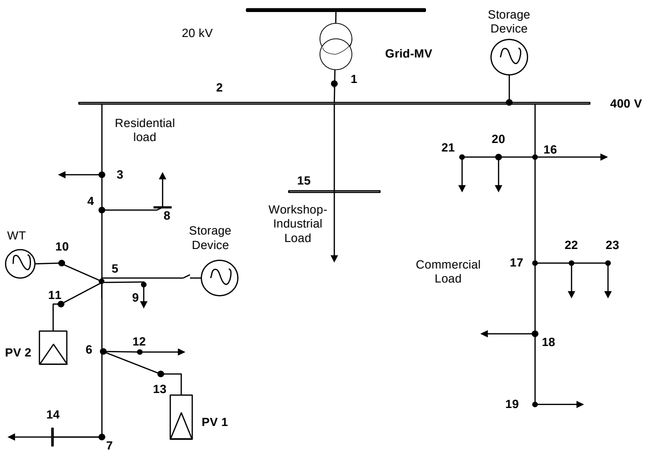

Figure 11: The case study network for the voltage violation study

The standard deviation of each type of load is a constant percentage of the mean value of the load for the whole period of study. According to [19] standard deviation is considered 10% for the first two load types and 8% for the third one of the expected mean value. There are 5 residential, 1 industrial and 7 commercial customers. The demand of each one of the 5 residential customers is considered coincident and so is for the 7 commercial customers.

Table 5-4 summarizes the energy share, the demand dispersion as percentage of the calculated mean value and the maximum demand for each group of customers.

Table 5-4: Load Characteristics

Customer Type	Energy Share	Dispersion	Max (p.u.)
Residential	37.62%	10%	1.18
Industrial	30.16%	8%	0.7
Commercial	32.22%	10%	0.84

The data about the lines and the typical demand power curves are described in [23]. The installed DG sources for the network are provided Table 5-5.

Table 5-5: Installed DG Sources

Unit ID	Unit Type	Max Power (p.u.)
1	WT	0.1
2	PV1	0.03
3	PV2	0.1

The power curve for WT is available in [35], and is also shown in Figure 12. This curve is represented by a 3rd order polynomial (39), where v is the wind velocity in m/s and pwr is the output in kW.

$$pwr(v)=\begin{cases}0, \ if\ 0 \le v < 4 or\ v > 54 \\ 0.0136\,v^3 + 0.3776\,v^2 - 2.176v + 3.732, \ if\ 4 \le v \le 14.07 \\ -2.39 \cdot v + 43.63, \ \ if\ 14.07 \le v \le 17 \\ 3, \ \ if\ 17 \le v \le 54\end{cases} \quad \textbf{(39)}$$

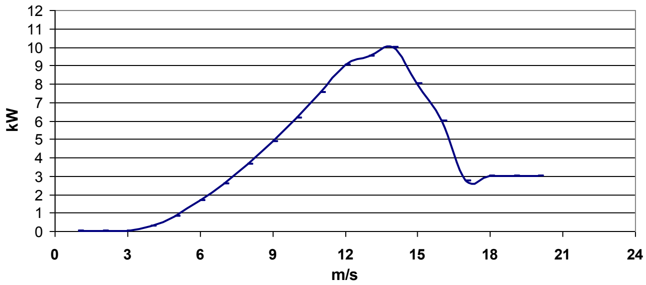

Figure 12: The power curve function of the typical 10 kW WT

5.3.2 Operation scenarios considered

For the studied network three characteristic cases a-c have been studied first for installing storage device at node 2, point of starting all the feeders and then installing a storage device at node 5 where significant DG capacity is going to be installed. The characteristic cases are the following.

a. High demand period without DG sources is studied. The demand is 2.7pu.
b. High load and high DG sources production expectation. Thus, the impact of the installed DG sources can be studied for high load and high production expectation.
c. Low load periods, with high RES penetration. The demand was 0.7pu.

In all the cases it was considered that no limitations of ΔP capacity exist in order to examine the magnitude of the voltage violation.

6. Results and discussion

Some initial results are presented here from the application of the above methodology into a single microgrid. First the results when applying the adequacy constraint are presented and then the results from an application for combating voltage violation are provided.

6.1 Adequacy and demand side bidding

Even though some initial results showing the benefits of this approach have been described in Microgrids deliverables of WPC, some additional results obtained this period of study are also provided here.

6.1.1 Overview

In order to evaluate the methodology described above in terms of DG penetration, the benefit for the customers and the adequacy either for the total Microgrid load or only for the summation of critical loads is calculated.

Various types of loads the following scenarios have been studied:

- Scenario 1: Current operation without DG
- Scenario 2: Operation with DG bids only without adequacy constraints
- Scenario 3: The same with scenario 2 but taking into account DSB
- Scenario 4: Operation when adequacy constraint is taken into account for the whole load
- Scenario 5 : Operation when adequacy constraint is taken into account for the critical loads

Scenario 1 is the reference scenario for studying the economic impact. For scenario 4, the pre-determined demand in Figure 5 becomes 100% while for scenario 5 is the summation of “High” priority loads, as stated by the DSB.

Regarding Prices High (H), Medium (M) and Low (L) prices have been used, as the ones shown in Figure 10. These have been combined with two levels, High (H) and Low (L), of RES production each of the 4 seasons studied. For High RES, the highest per hour type and season time-series has been produced while for the latter case, the lowest average per hour and season was used based on the assumptions of the Case Study section.

6.1.2 Operation without adequacy Constraints

DG penetration for both Scenarios 2 and 3 is shown for high prices in Figure 13. The maximum difference in DG penetration for these cases is lower than 10% during High prices and the highest penetration value reaches 46% from 41.7% without DSB. The impact of DSB in the operation cost for these periods is significantly higher as Figure 14 shows reaching 15% compared to Scenario 2.

Generally, for high prices the benefits for the operational cost are significant, either for scenario 2, 40%, or for scenario 3 56% for High RES, compared to Scenario 1. Reducing RES production causes 7-8% lower benefits. In all cases with high prices however, the minimum benefit for scenario 2 is 20% and for Scenario 3 is 33%.For medium prices only during summer some power is reduced for the load side and the cost difference is lower than 2%, thus, this value is not shown in this figure.

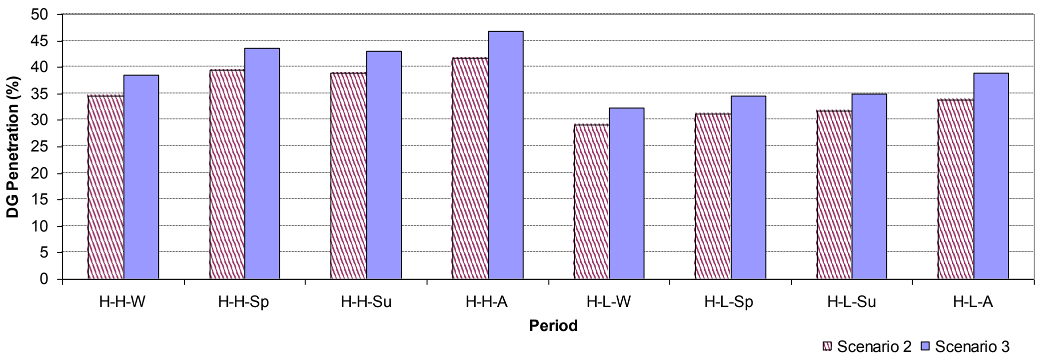

Figure 13: Change in DG penetration for High prices in ApX

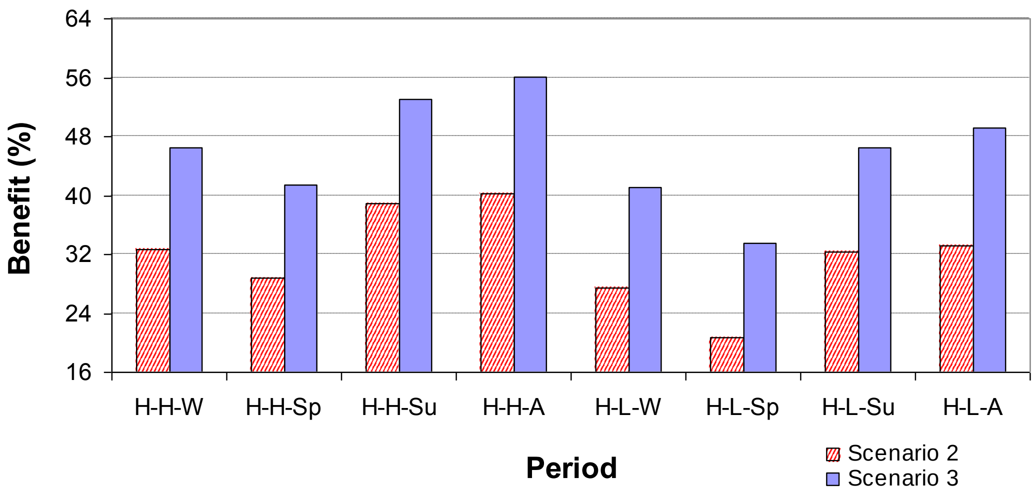

Figure 14: The benefits between with and without DSB.

Since energy bought from the upstream network during high prices periods is reduced, the Microgrid customers may have significant economic benefits as shown in Table 6-1, where the average cost of energy for them is shown. The maximum hourly cost reduction can reach 87.14 €ct/kWh, for the extreme case of ApX prices at 2000€/MWh that appear for few hours per year. The maximum difference in cost between scenario 2 and 3 is 39.9€ct/kWh and on 24 hour average value 13.69 €ct/kWh.

Table 6-1: Average 24-hour cost for the customers of the Microgrid

Prices	RES Production	Season	Scenario 1 (€ct/kWh)	Scenario 2 (€ct/kWh)	Scenario 3 (€ct/kWh)
High (H)	High(H)	Winter (W)	34.08	22.94	20.32
		Spring(Sp)	8.86	6.31	5.73
		Summer(Su)	97.55	59.54	50.6
		Autumn(A)	35.33	21.1	17.85
	Low(L)	Winter (W)	34.08	24.75	22.33
		Spring(Sp)	8.86	7.02	6.51
		Summer(Su)	97.55	65.97	57.68
		Autumn(A)	35.33	23.59	20.71
Medium (M)	High(H)	Winter (W)	3.66	3.36	3.36
		Spring(Sp)	3.04	2.74	2.74
		Summer(Su)	3.76	3.28	3.24
		Autumn(A)	3.91	3.42	3.42
	Low(L)	Winter (W)	3.66	3.55	3.55
		Spring(Sp)	3.04	2.99	2.99
		Summer(Su)	3.76	3.53	3.49
		Autumn(A)	3.91	3.77	3.77

6.1.3 Taking into account adequacy constraints

Then the impact of the adequacy constraint is presented either for the total load (Scenario 4) or for part of the load (Scenario 5).

The economic impact of the constraint may be low in actual values but in percentage terms is much higher for the case of the medium-low ApX prices case as Figure 15 shows. This is due to the fact that more units operate in order to meet adequacy constraints even if this is not the most economic option. This results in higher cost of Scenario 4 compared to Scenario 1 for low prices, a bit higher than 5%, but in actual values the additional daily cost is only by 1.42€ higher.

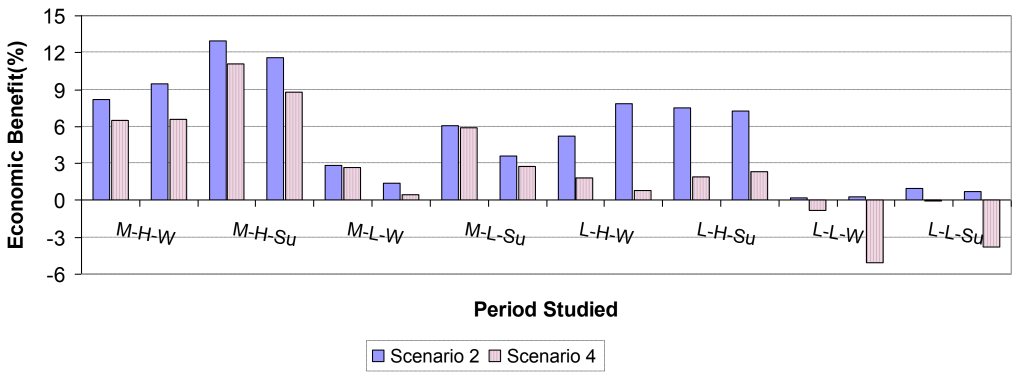

Figure 15: Impact in the economic for the adequacy constraint when no DSB is assumed compared to Scenario 1

Table 6-2 presents how often load disconnection is expected in case of the upstream network fault, as a percentage of the periods when this may happen. Even if the capacity of the DG sources is sufficient to meet the demand but is not committed, then for very short time there will be some load disconnection unless sufficient capacity of storage device is apparent. Such a case is also counted in this table. Obviously inadequate operating cases are reduced by up to 20% when comparing scenarios 2 and 4

The impact of classifying loads into critical and non-critical ones and the capability of disconnecting non-critical ones is studied next. The impact on DG penetration is shown in Figure 16. Increase in penetration during high market prices is mainly due to demand side bids acceptance. When DSB is taken into account the local units should be able to meet lower demand; thus they are more often committed increasing DG penetration even for low prices.

For high prices DSB helps so that the adequacy constraint is met at lower cost and mainly for the type of loads which have higher needs to be supplied in case of a fault in the upstream network. The maximum benefit for this categorization (scenario 4 vs. Scenario 5) can reach 39.9 €ct/kWh, and on 24 hour average value 13.69 €ct/kWh. Adequacy constraint increases the cost for the operation with accepting DSB only (Scenario 3 vs. scenario 5) by maximum 0.69 €ct/kWh, and on average 24 hour operation for 0.087 €ct/kWh.

For low market prices, DG penetration increases up to 30% for high RES combination. This however leads to cost increase compared to Scenario 1 even for high RES cases as Figure 17 shows. The percentage increase is the highest among the studied cases. However, the absolute value is rather small and the additional cost is maximum 0.562€ct/kWh, and on 24 hour average operation 0.059€ct/kWh (Table 6-4).

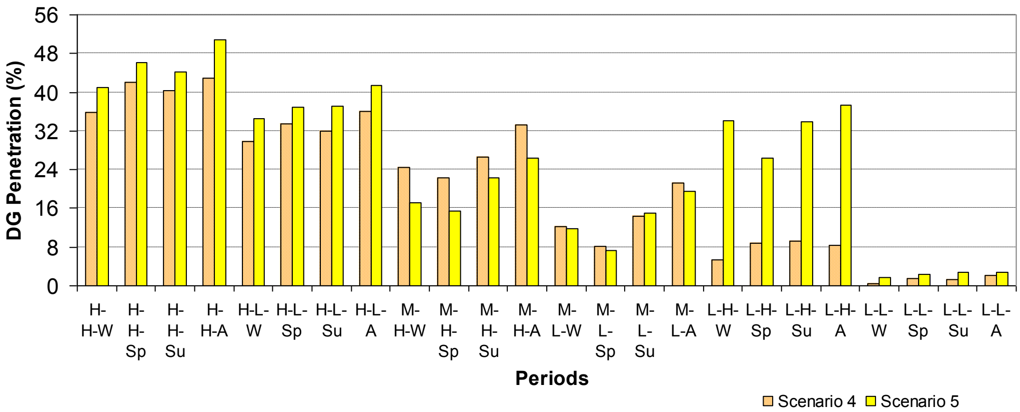

Figure 16: Comparison of DG penetration when adequacy constraint is taken into account. Scenario 4 vs. Scenario 5

The impact of how often critical loads will not be supplied in case of upstream network fault for all the cases studied is shown in Table 6-2. If 100% of the demand is taken as a criterion for the adequacy constraint, adequacy percentages for both the critical loads and the total load are the same (Scenarios 2 and 4). If the adequacy constraint takes into account only the critical loads these can be more often adequate than before. Inadequacy may happen for maximum 75% of the cases studied, which is lower than all the cases with 100% demand adequacy constraint. Moreover, the frequency of not supplying non-critical loads due to the critical load adequacy constraint is slightly increased.

Table 6-2: Adequacy results for the critical loads of the system for all the cases studied

Prices	RES Production	Season	Scenario 2	Scenario 4	Scenario 5
High (H)	High(H)	Winter (W)	100	87.5	70.8
		Spring(Sp)	100	79.2	70.8
		Summer(Su)	100	79.2	70.8
		Autumn(A)	100	79.2	70.8
	Low(L)	Winter (W)	100	95.8	70.8
		Spring(Sp)	100	83.3	70.8
		Summer(Su)	100	95.8	70.8
		Autumn(A)	100	79.2	75
Medium (M)	High(H)	Winter (W)	100	87.5	70.8
		Spring(Sp)	100	79.2	70.8
		Summer(Su)	100	79.2	70.8
		Autumn(A)	100	79.2	70.8
	Low(L)	Winter (W)	100	95.8	70.8
		Spring(Sp)	100	83.3	70.8
		Summer(Su)	100	95.8	70.8
		Autumn(A)	100	79.2	75
Low(L)	High(H)	Winter (W)	100	87.5	70.8
		Spring(Sp)	100	79.2	70.8
		Summer(Su)	100	79.2	70.8
		Autumn(A)	100	79.2	70.8
	Low(L)	Winter (W)	100	95.8	70.8
		Spring(Sp)	100	83.3	70.8
		Summer(Su)	100	95.8	70.8
		Autumn(A)	100	79.2	70.8

An additional benefit of the proposed method is that the critical loads are, in case of emergency, supplied more often and, especially for higher prices, at significantly lower cost.

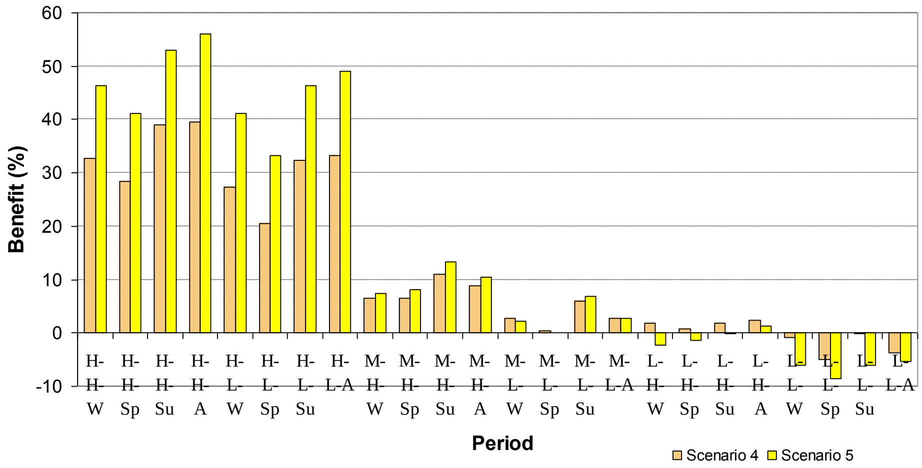

Figure 17: Comparison of economic impact when adequacy constraint is taken into account compared to scenario 1.

6.1.4 Discussion-Comparison when adequacy constraints are taken into account

Table 6-3 provides the maximum additional cost required to meet the adequacy constraint compared to fully economic operation with and without DSB. This is expressed in both hourly and average daily value for the demand. These values occur for high prices scenarios where small economic percentage reflects significant additional value. The daily average is higher for scenario 4. Thus, higher adequacy level for the critical loads of the microgrid is achieved at on average lower cost when the adequacy criterion is the summation of the critical loads only and not the one of the total load.

Table 6-3: Economic impact of adequacy constraint impact compared to only economic operation of the Microgrid

	Scenario 4 vs. Scenario 2	Scenario 5 vs. Scenario 3
Maximum additional hourly cost €ct/kWh	0.473	0.69
Maximum average 24-hour cost €ct/kWh	0.278	0.087

As the prices get lower, the additional percentage cost impact of the adequacy constraint is significant as the above diagrams have shown. For low prices, the cost may be even higher than the operation without DG sources, especially for Low RES scenario. The percentage cost increase may be high but the actual value is rather small especially compared to the benefits achieved. Table 6-4 makes a comparison of the maximum additional cost for low prices at average and hourly level. In such conditions considering only critical loads increases the cost.

Table 6-4: Comparison of maximum additional costs for low prices

	Scenario 5-Scenario 4	Scenario 5-Scenario 1	Scenario 4-Scenario 1
Maximum additional hourly cost €ct/kWh	0.562	0.681	0.688
Maximum average 24-hour cost €ct/kWh	0.059	0.071	0.047

6.2 Examples of Bids from MGCC to CAMC for changing demand

In this paragraph some simple examples from bids that the MGCC places to CAMC for changing the demand of the microgrid, if requested to, are provided. Two main cases are considered: a) Decreasing local demand or b) Increasing local demand. The results refer to one snapshot of operation of both Microgrids and multi-microgrids and the case of only affecting dispatchable units is studied. If non-dispatchable units are to be considered, these can be considered only for increasing local demand i.e. reduce their output which practically means switching off these units.

6.2.1 Decreasing local demand

For simplicity, decreasing local demand is considered as increase of local production.

For the case study network of Figure 8, four different cases are examined and the corresponding market prices considered:

a. None of the dispatchable units has been committed-market price 22€/MWh
b. Only the FC has been committed but is not dispatched at its technical maximum-29€/MWh
c. Only the FC has been committed and is dispatched at its technical maximum-35€/MWh

d. The MT has been committed and is not dispatched at its technical maximum-45€/MWh

The interesting points of change of the bids are:

i. power value that corresponds to operating FC at its technical maximum
ii. power value that corresponds to committing MT and operating it at its technical minimum. This means that even though this is not the most economic solution, the FC should reduce its output to accommodate the MT operation
iii. the sum of both MT and FC technical maximum values.

These are the limits for changing the bids range offered to CAMC.

For case a, the points of changing the bids are easily calculated at 30kW, 36kW and 60kW according only to technical minimum and maximum. The values of the bids are shown in Figure 18.

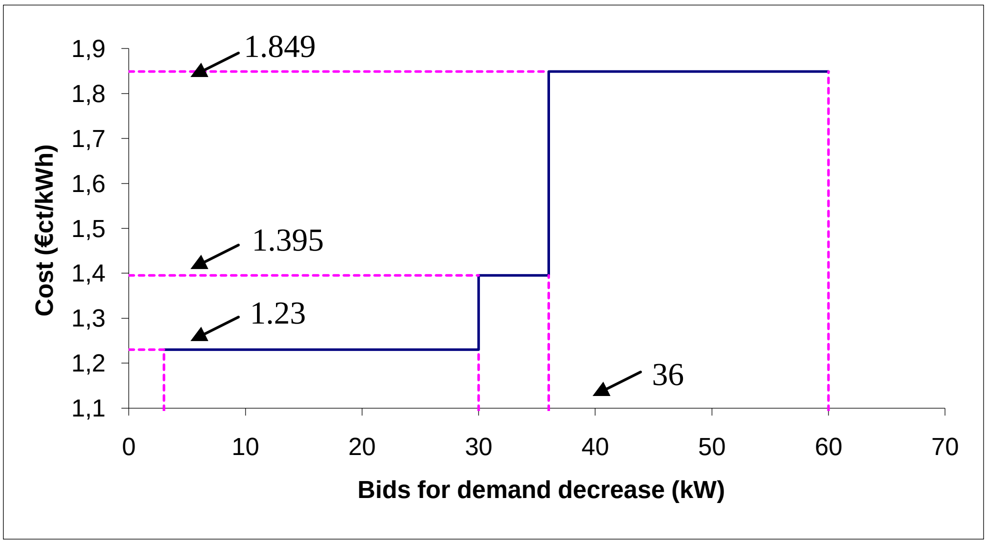

Figure 18: The bids to the CAMC for decreasing Microgrid Demand for case a)

For case b, the FC operating point derived from the optimization procedure run by the MGCC is 12.9kW. The first bid will be up to (30-12.9) kW = 17.1kW. Then the next 6kW up to the technical minimum of the MT and then at 47.1kW which is the maximum increase of the demand by the microgrid. Figure 19 describes the bids for this case.

In Figure 20 the bids for case c) are described. In this case there are two points of change, the one at the technical minimum of the MT and the other at its technical maximum. If the requested decrease of demand is lower than the technical limit of the MT, the FC should reduce its output in order to avoid technical minimum violation of the MT. This leads to a greater increase in the cost than having the MT increasing its production. This can occur above 6kW.

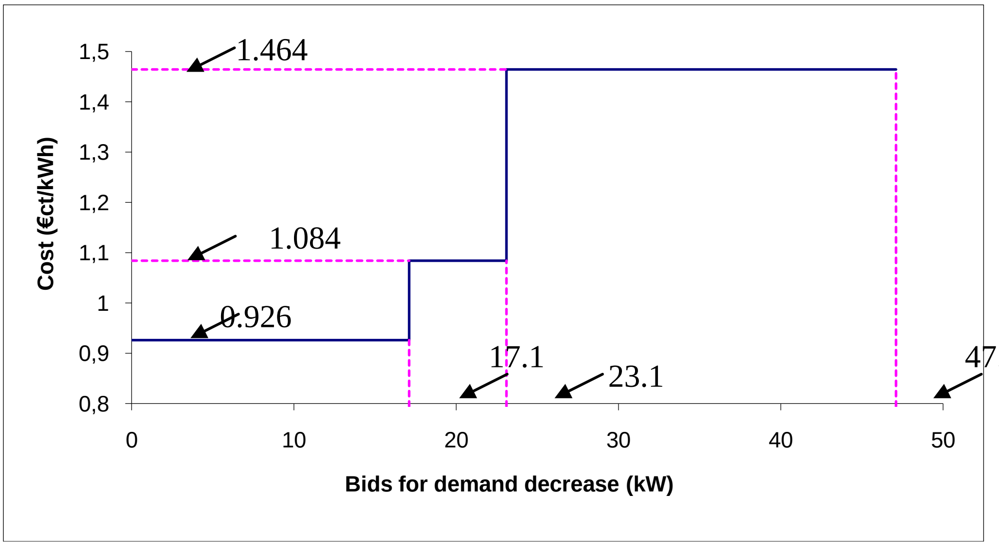

Figure 19: The bids to the CAMC for decreasing Microgrid Demand for case b)

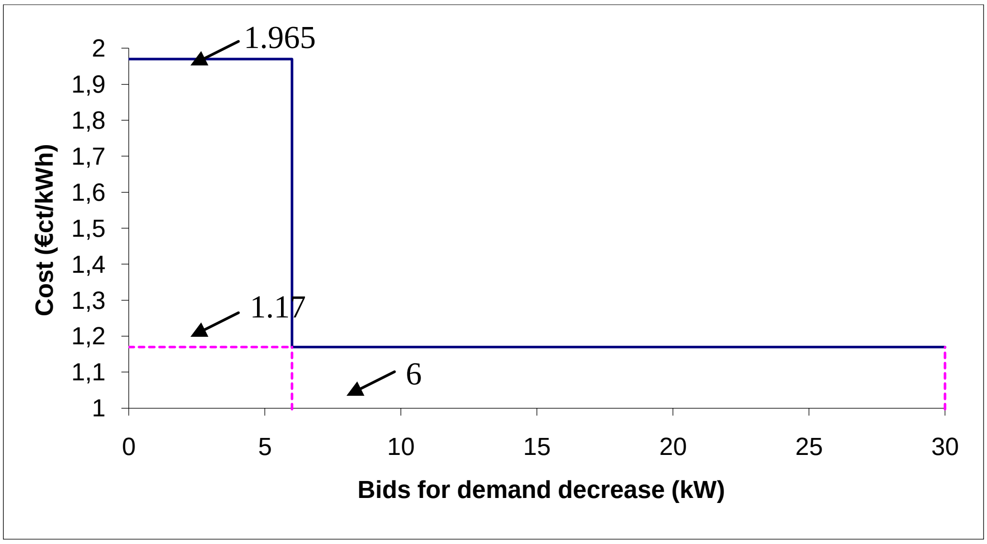

Figure 20: The bids to the CAMC for decreasing Microgrid Demand for case c)

For case d), the MT operating point is 13kW. Its production can be increased up to 17kW, and this is the only case studied. The bid in such a case is 0.3€ct/kWh which is the lowest between the cases studied.

6.2.2 Increasing local demand

This is the case of surplus of energy inside the Multi-microgrids area that is attributed to decrease of production or reconnecting loads. The following cases can be studied:

a. Both dispatchable units have been committed and dispatched at their technical maximum-market price 51€/MWh
b. Both dispatchable units have been committed but the MT operates at lower operating point-45€/MWh
c. Only the FC has been committed and is dispatched at its technical maximum-35€/MWh
d. Only the FC has been committed and is dispatched at a lower operating point-29€/MWh

The interesting points of change of the bids that correspond to the limits for changing the bids offered to the CAMC are:

i. The reduction up to the technical minimum of the MT
ii. Additional reduction up to quantity equal to the technical minimum of the MT. In such a case the MT operates at its technical minimum and the FC reduces its production to accommodate this change.
iii. The MT has been switched off and the production of the FC is reduced until it reaches its technical minimum
iv. Both MT and FC are switched off. The additional reduction in this case is just a single number, the dispatched units operating point and not a range of production related to the technical minimum of the MT.

Figure 21 shows the bids placed to CAMC in case a). An additional bid is made at exactly 60kW and 1.05€ct/kWh. The MG cannot offer increase of the demand between 57kW and 60kW because of the technical minimum of the FC unit. Either the Microgrid demand will be increased up to 57kW or only 60kW.

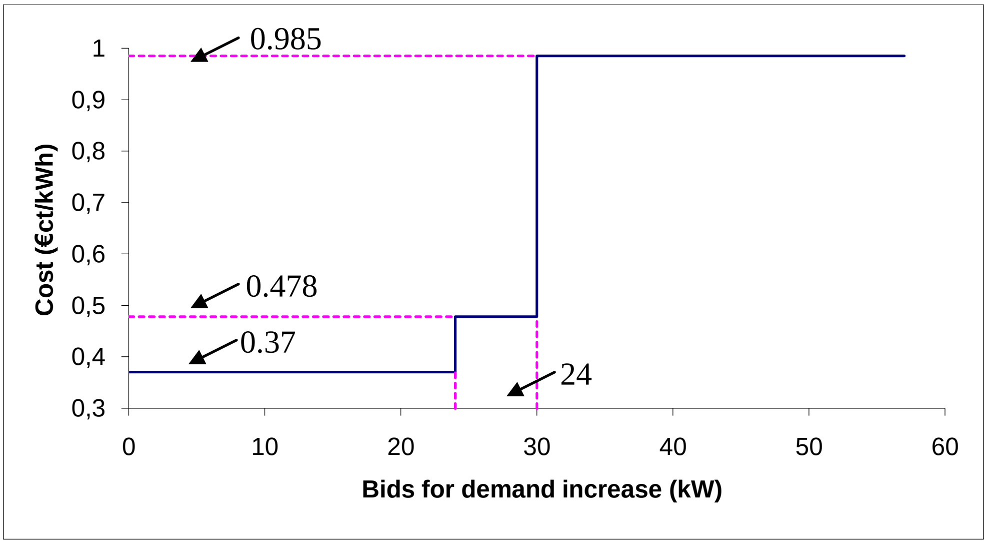

Figure 21: The bids to the CAMC for increasing Microgrid Demand for case c)

For the second case the operating point of the MT is 12.9kW. The bids in this case are shown in Figure 22. An additional bid at 43kW can be submitted at 0.758€ct/kWh. Range of 40-43 cannot be offered.

For case c) only FC operation is affected. The FC operates at its technical maximum and can reduce production up to 27kW. The bid in this case is as small as 0.01€ct/kWh. The FC may be de-committed and the reduction offered can be 30kW if the remuneration is 0.072€ct/kWh.

For case d) the FC operates at 12.9kW. A first step of production reduction can be up to 9.9kW so that the FC operates at least at its technical minimum. The bid in this case is as small as 0.01€ct/kWh. The FC may be de-committed and the reduction offered can be 12.9kW if the remuneration is 0.01€ct/kWh.

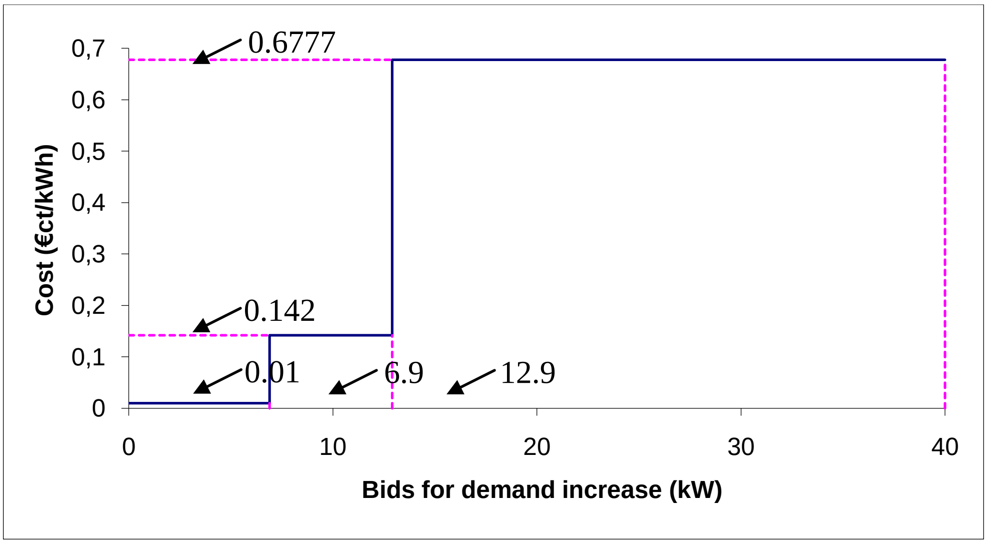

Figure 22: The bids to the CAMC for increasing Microgrid Demand for case b)

6.3 Voltage violation constraint

For the case study network of Figure 11, it was identified that for total demand 1.95pu and no RES production the node 8 has the lowest expected voltage value within the network, 0.956pu. According to the expected values there is no voltage violation at this node and thus there is no need of changing local production.

Applying the methodology described in Chapter 4, the voltage pdf at this node is shown in Figure 23. The 5% percentile of the voltage at node 8 is 0.945pu and this is Vmin. Therefore, there is 5% probability that the low voltage limit 0.95 p.u. will be violated.

From the analysis performed, it was identified that at nodes 8 and 14 there is voltage violation during high load and no DG operating (Scenario A). If RES are connected, producing about their technical maximum, then there is significantly lower voltage violation and only at node 8 at 0.949pu (Scenario B). During low load periods no voltage violation takes place.

Table 6-5 summarizes the results from the cases studied when the only available local production is installed at node 2. Compulsory increase stands for the minimum injection to compensate for voltage violation. Upper injection limits are the limits above which overvoltage violations take place.

Table 6-6 summarizes the results if a Dispatchable DG unit is installed at node 5.

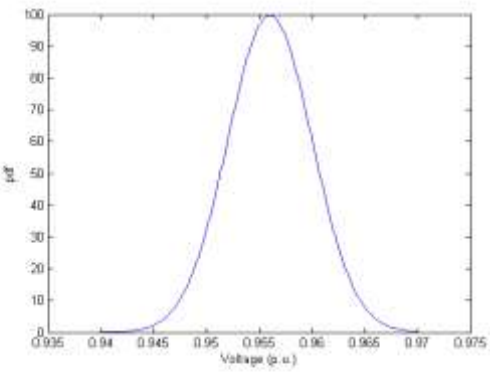

Figure 23: The voltage pdf at node 8 without RES and high load.

Table 6-5: Results from the Cases Studied-available production At Node 2

Case studied	Compulsory Increase	Upper local production decrease (ΔPS)	Upper local production increase

			(ΔPI)
A	5.28	0	52.28
B	0.92	0	52.07
c	0	45.48	45.82

Table 6-6 Results from the Cases Studied- available production At Node 5

Case studied	Compulsory Increase	Upper local production decrease (ΔPS)	Upper local production increase (ΔPI)
A	0.262	0	2.53
B	0.046	0	2.08
C	0	1.54	1.43

Required change at local production is significantly lower in Table 6-6 compared to the results of Table 6-5. As expected the results show that local production near the buses that usually have problems with voltage violations these problems are resolved using significantly lower capacity. Installation of a DG at the MV/LV bus bar would have been beneficial in terms of economics if the operational cost was 1/20th of the cost of a DG installed at Node 5.

7. Conclusion

The integration of multi-Microgrids in MV operation requires the definition of the ways in which multi-Microgrids participate in the power exchange. This requires extensive communication between the MGCC and CAMC, the two entities which represent one Microgrid and DNO or part of the network controlled by the DNO, respectively. The information exchanged between these two entities includes electrical as well as economic data that enable the MGs to participate in the short-term market and contribute to the reactive power control, in a multi-microgrids environment.

In this report, a summary of the functions incorporated within the MGCC has been provided. Moreover, the description of information exchange between CAMC and MGCC is provided with emphasis on ancillary services provision.

Some additional operations of the MGCC have also been defined in terms of providing change of Microgrids production/demand if requested by the CAMC. Furthermore, the contribution of the MGs to voltage violation management has been investigated. From the analysis performed it became clear that two cases should be examined, when the voltage violation occurs a) inside or b) outside the area each MGCC controls. The methods of calculating the necessary change in local production to face incidents like a) and the suggested change in production and costs submitted to CAMC to provide aid in cases like b) have been described based on probabilistic techniques.

Characteristic results from applications of these additional functions in a typical network have been provided in order to illustrate how these can provide solutions to ancillary services issues.

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Impact of the Horizon of the Short-term Market Participation

Table of Contents

1. Introduction

The impact of horizon of short term market operation is studied in this part of the report. Short term market operation is considerably affected by the forecasting accuracy of the various uncertain quantities in a Microgrid and Multi-Microgrids environment. The forecasting accuracy in turn is largely affected by the forecasting horizon since it is normally deteriorated as the forecasting horizon is increased. Therefore the scope of the report is to calculate the economic impact of various forecasting horizons for wind power, market prices and load forecast. Focus is given on the impact of forecasting uncertainty mainly in one Microgrid to show the span of the deviations that may be encountered if these differences are aggregated in Multi-Microgrids environment.

More specifically, wind power forecasting accuracy, which is directly linked to forecasting horizon, may lead to significant deviations in the expected reduction of demand caused by the wind power installed in the networks under study. This may lead to buying energy at the spot market at market prices higher than contracted or selling excess energy at significantly lower prices. Both cases lead to income loss.

Moreover, the price forecasting uncertainty may lead to erroneous decisions regarding the committing or not of some of the DG units and even of their operational point, if applicable. This affects Microgrids, independent DG sources as well as independent large loads placing Demand Side Bids (DSB) within a Multi-microgrids environment. Thus some units may be erroneously committed, even though this is not the most economic solution whereas some others may stay off-line because the market prices were erroneously predicted lower making these units seem more expensive than they really are.

Additionally, the uncertainties attributed to the forecasting error of the demand of the Microgrids and Multi-microgrids may lead to economic penalties ascribable to buying more electricity from the upstream network or selling lower amount of energy than promised to the upstream network. The greater the uncertainty, the higher the complexity of participating in short term market operation in an upstream network than in a microgrid or an aggregation of Microgrids in Multi-microgrids environment.

The forecasting models assumed in the present report are as simple as possible due to the nature of the application. Thus, the absolute numbers may be different if more sophisticated methods are used, but the differences among the forecasting horizons are not expected to be significant.

2. Case Study Network

Typical, LV network is used in our study, Figure 1. The network consists of three feeders, one serving a primarily residential area, one industrial feeder serving a small workshop, and one commercial feeder. A variety of DER, such as one Micro Turbine (MT), one Fuel Cell (FC), one directly coupled Wind Turbine (WT) and several PVs are installed in the residential feeder. It is assumed that all DER produce active power at unity power factor, i.e. neither requesting nor producing reactive power. Table 1 provides the capacity of the installed DG sources and their fuel costs. Both, Micro-Turbine and Fuel Cell are assumed to run on natural gas, whose efficiency is 8.8 kWh/m3 and price 10 c€/m3 [1]. For the MT the efficiency is assumed 26%, while the efficiency of the Fuel Cell is assumed 40% [2]. For RES the bids are considered as equal to zero reflecting their operating cost.

For the monthly demand data, annual demand is distributed to each month according to the Reliability Test System (RTS) weekly variation [3] and the typical demand curve of the Microgrid, is used [4], as described per feeder in Figure 2.

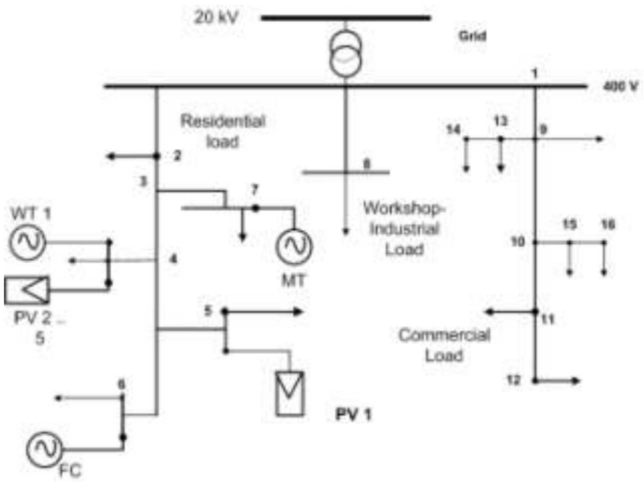

Figure 1: Case Study Network

Table 1: Data for the capacity of the installed DG units

Unit ID	Unit Name	Min. Capacity [kW]	Max. Capacity [kW]	B [Ect/kWh]
1	MT	6	30	4.37
2	FC	3	30	2.84
3	WT	0	15	0
4	PV1	0	3	0
5	PV2	0	2.5	0
6	PV3	0	2.5	0
7	PV4	0	2.5	0
8	PV5	0	2.5	

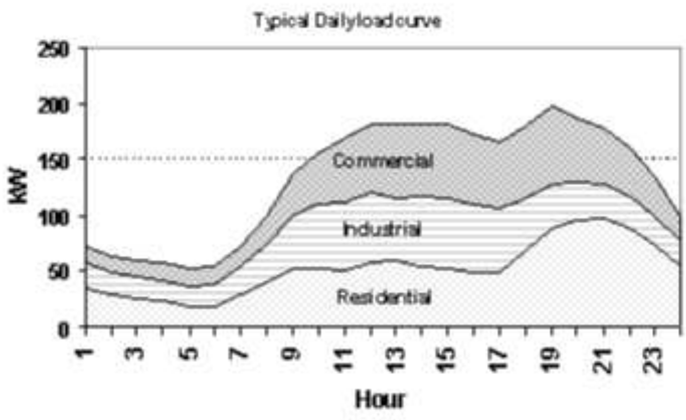

Figure 2: Distribution of demand among feeders.

3. Cases studied

3.1 Considering only uncertainties of wind power prediction

In this section it is assumed that the difference in the short term market operation comes from the deviation of wind power production from the forecasted one with the persistence method. An actual time-series from the Greek island of Ikaria was used and a 10kW wind turbine with power curve, as shown in Figure 3.

4 cases have been considered for the forecasting horizon a) 1 hour b) 2 hours c) 3 hours d) 4 hours ahead. The forecasting error was evaluated in both deterministic and probabilistic way using actual spot market prices from the Amsterdam Power Exchange (ApX) and marginal prices from the Hellenic Transmission System (HTS) [5]. For the deterministic evaluation, the wind power time-series as predicted by the persistence method was used combined with the market prices time-series.

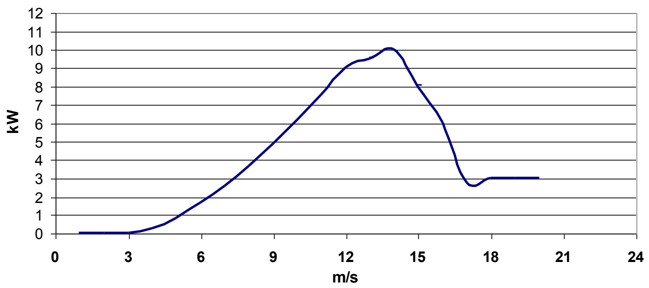

Figure 3: Velocity to power curve for a typical small wind turbine

In the probabilistic approach, the forecasting error distribution for each horizon is convoluted with the market prices distribution shown in Figure 4 for ApX and in Figure 5 for HTS respectively. Thus, the expected difference in cost can be evaluated irrespectively of the time-series followed.

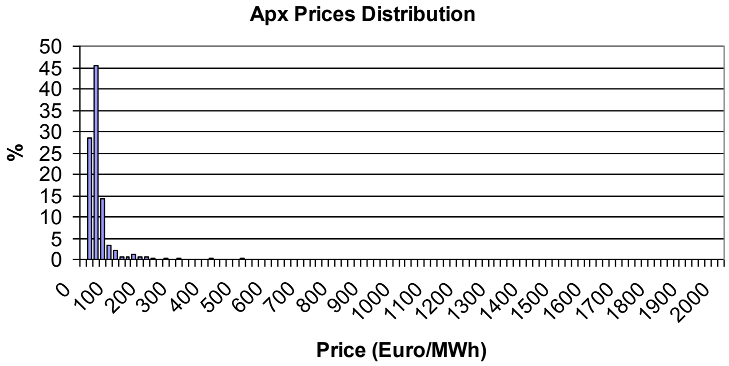

Figure 4: ApX market prices distribution

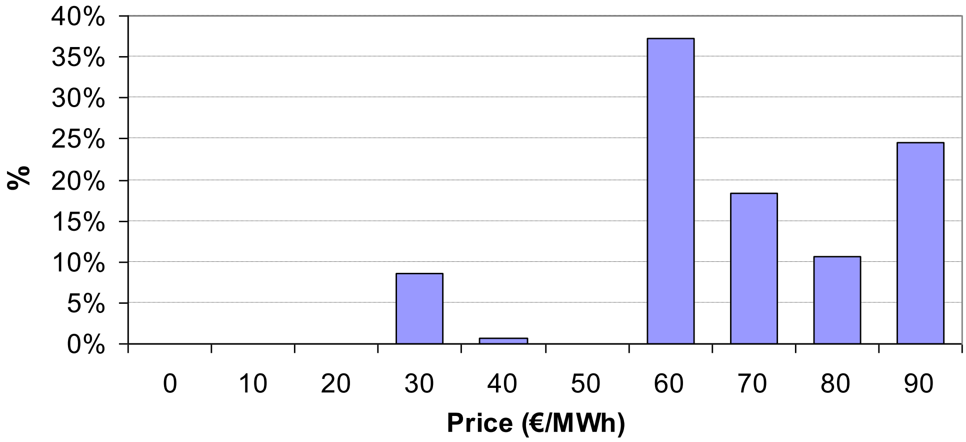

Figure 5: The HTS market prices distribution

3.1.1 Results

The actual production according to the time-series considered for one year was 38.85MWh or 44.3% Capacity Factor. According to ApX market time-series the income would have been 1893.36€ for the wind power time-series considered, while for the Greek market prices the income would have been 2529.2€.

Table 2 presents the estimations for the 4 short term intervals considered with regards to wind power produced, value in the ApX open market and the minimum or maximum production deviation in terms of confidence interval 2.5% -97.5%. In Table 3 the corresponding economic results for the Greek market are provided.

In all cases the results for the probabilistic approach are in line with the expected deviation of the annual production. In the deterministic case study the estimated value of wind power is always lower than the perfect forecasting and gets lower as the forecasting horizon is extended. Such an extension has as a result increase of the values that constitute the confidence interval of the forecasting error. This means that the wind power production will deviate much more in the 4-hour horizon than the 3-hour horizon. This case however will not create significant deviation in the long term, i.e. one year. It should be noted that the annual production difference for the 3 hour horizon interval is negligible. The impact is higher in the deterministic cost rather than in the probabilistic approach cost difference. Generally the deviations in the calculated values between deterministic and probabilistic approach are much lower for the Greek market prices rather than the ApX.

Table 2: Summary of the results for ApX

Forecasting horizon	Annual production difference (kWh)	Confidence Interval [2.5%,97.5%]	Estimated value with persistence(€)	Difference in estimated value (€)	Probabilistic cost difference estimation (€)
1 hour	-1.656	[-2.7,2.8]	1872.4	21.95	-0.25
2 hours	128.29	[-3.5,3.5]	1866.8	27.51	6.18
3 hours	-0.05	[-3.875,4]	1859.2	35.18	-0.4648
4 hours	295.67	[-4.25,4.25]	1844.6	49.76	13.99
6 hours	271.69	[-4.9,5.4]	1803.2	91.16	15.34

Table 3: Summary of the results for HTS market prices

Forecasting horizon	Estimated value with persistence (€)	Difference in estimated value (€)	Probabilistic cost difference estimation (€)
1 hour	2529.6	-0.4	-0.346
2 hours	2520.8	8.4	8.642
3 hours	2530.8	-1.6	-0.65
4 hours	2510.4	18.8	19.568
6 hours	2513.5	15.73	18.75

3.2 Considering Market prices uncertainty

3.2.1 Basic Assumptions for forecasting market prices

In order to study this uncertainty, a simplified prediction method of market prices was developed. First of all, the average market prices per month, hour type grouped into weekdays and weekends were calculated based on the market prices from both ApX in 2003 and HTS in 2006.

Then for each day type, weekend or weekday, the following equation (1) has been used to derive the forecasted prices. The idea is to use the ratio of actual price some hours before, (t-1-k) to the average price for that hour type as was calculated by historic data.

$$price(t) = avprice(t) \cdot \frac{price(t-1-k)}{avprice(t-1-k)} \qquad \textbf{(1)}$$

avprice stands for the average price for the specify month, different for weekday and weekends. k is smaller than the persistence step t0 and is provided by $k = \mathrm{mod}(\frac{t}{t_0})$.

The operating costs for the MT and the FC of

Table 1 are used as base for the comparisons to be made.

3.2.2 Results from ApX

If the prices were perfectly predicted, the savings from the FC operation would have been 6081€ and the operating hours 4270. For the MT the operating hours would have been 1932 leading to savings equal to 4731.5€.

For FC, the annual operating hours with 1 hour persistence will be reduced to 4121 with corresponding savings 5998.5€. For 269 hours market prices were erroneously predicted higher than the FC operation cost leading to operation of the FC without being actually less expensive. This increased the cost by 22.56€. Moreover, for 411 hours the market prices were erroneously predicted lower than the operational cost of the FC, leading to non operation of the FC although this would have been beneficial. The loss of income would have been 59.89€ for that case.

For the case of 4 hour persistence, the FC operating hours will drop to 4021 with savings 5956€. For 344 Hours the predicted market prices were erroneously predicted higher than the FC operation cost leading to operation of the FC without being actually less expensive. This increased cost by 35.23€. Moreover, for 586 hours the market prices were erroneously predicted lower than the operational cost of the FC, leading to non operation of the FC although this would have been beneficial. The loss of income would have been 89.67€ for that case or 1.47% of the expected income.

For the case of 6 hour persistence, the FC operating hours will drop to 3892 with savings 5865.7€. For 382 Hours the predicted market prices were erroneously predicted higher than the FC operation cost leading to operation of the FC without being actually less expensive. This increased cost by 45.09€. Moreover, for 753 hours the market prices were erroneously predicted lower than the operational cost of the FC, leading to non operation of the FC although this would have been beneficial. The loss of income would have been 170.19€ for that case or 1.47% of the expected income.

Regarding the case for the MT for 1 hour persistence the operating hours are increased to 2073 and the savings will be 4623.8 €. For 374 hours the market prices were erroneously predicted higher than the MT operating cost leading to operation of the MT without being actually less expensive than the market prices. This increased the cost by 61.97€. Moreover, for 233 hours the market prices were erroneously predicted lower than the operational cost of the MT, leading to non operation of the MT although this would have been beneficial. The loss of income would have been 45.69€ in that case.

For the case of 4 hours persistence the operating hours are 2291. The savings due to MT operation will be even lower at 4574.8€. For 559 Hours the market prices were erroneously predicted higher than the MT operation cost leading to operation of the MT without being actually less expensive. This increased cost by 109.38€. Moreover, for 200 hours the market prices were erroneously predicted lower than the operational cost of the MT, leading to nom operation of the MT although this would have been beneficial. The loss of income would have been 47.29€ in that case.

For the case of 6 hours persistence the operating hours are 2244. The savings due to MT operation will be even lower at 4491.5€. For 607 Hours the market prices were erroneously predicted higher than the MT operation cost leading to operation of the MT without being actually less expensive. This increased cost by 136.11€. Moreover, for 295 hours the market prices were erroneously predicted lower than the operational cost of the MT, leading to nom operation of the MT although this would have been beneficial. The loss of income would have been 103.86€ in that case.

3.2.3 Greek market-HTS prices

For HTS market prices, the average price is higher than ApX (64.13€/MWh vs. 46.37€/MWh) but much less volatile. However, they can often allow operation of the MT and FC, for 7950 and 8453 hours respectively. If the prices were perfectly predicted the savings would have been 5740.8€ and 9401.3€, respectively.

For 1 hour persistence the FC hours will marginally change to 8452 and the savings achieved are 9395.6€. For 111 Hours market prices were erroneously predicted higher than the FC operation cost leading to operation of the FC without being actually less expensive. This increased the cost by 2.85€. Moreover, for 112 hours the market prices were erroneously predicted lower than the operational cost of the FC, leading to non-operation of the FC although this would have been beneficial. The loss of income would have been 2.86€ for that case.

For the case of 4 hour persistence, the number of operating hours is the same but for some hours the operating state of the FC will be different reducing somewhat the benefits to 9386,7€. More precisely, for 130 Hours market prices were erroneously predicted higher than the FC operation cost leading to operation of the FC without being actually less expensive. This increased the cost by 3€. Moreover, for 130 hours the market prices were erroneously predicted lower than the operational cost of the FC, leading to non operation of the FC although this would have been beneficial. The loss of income would have been 11.6€ for that case.

For the case of 6 hour persistence, the number of operating hours is 2586 and the benefits are reduced to 9381.7€. More precisely, for 196 Hours market prices were erroneously predicted higher than the FC operation cost leading to operation of the FC without being actually less expensive. This increased the cost by 5.18€. Moreover, for 63 hours the market prices were erroneously predicted lower than the operational cost of the FC, leading to non operation of the FC although this would have been beneficial. The loss of income would have been 14.44€ for that case.

Regarding the case for the Microturbine, the operating hours for 1 hour persistence change from 7950 hours to 7940 hours. The savings will be 5623.3€. For 139 hours market prices were erroneously predicted higher than the MT operation cost leading to operation of the MT without being actually less expensive. This increased the cost by 61.28€. Moreover, for 149 hours the market prices were erroneously predicted lower than the operational cost of the MT, leading to non operation of the MT although this would have been beneficial. The loss of income would have been 56.29€ in that case.

For the case of 4 hours persistence the operating hours are 7885. The savings due to MT operation will be even lower at 5559.6€. For 181 hours market prices were erroneously predicted higher than the MT operation cost leading to operation of the MT without being actually less expensive. This increased the cost by 80.11€. Moreover, for 246 hours the market prices were erroneously predicted lower than the operational cost of the MT, leading to non operation of the MT although this would have been beneficial. The loss of income would have been 101.08€ in that case.

For the case of 6 hours persistence the operating hours are 7681. The savings due to MT operation will be even lower at 5398.9€. For 258 hours market prices were erroneously predicted higher than the MT operation cost leading to operation of the MT without being actually less expensive. This increased the cost by 116.12€. Moreover, for 527 hours the market prices were erroneously predicted lower than the operational cost of the MT, leading to non operation of the MT although this would have been beneficial. The loss of income would have been 225.80€ in that case.

Table 4 summarizes the above findings for both markets and the forecasting horizons considered for the dispatchable units whose output is affected by forecasting errors. The percentage difference from perfect forecasting is also provided. Clearly 4 hours horizon creates significantly higher economic loss. In both markets more significant is the difference in operation of the MT. For FC especially for HTS markets the impact of market prices forecasting is negligible. For more volatile market like ApX, the change in both absolute and percentage values are much higher.

Table 4: Summary of the savings achieved for both markets

	Savings Achieved (€)	
Case	**ApX**	**HTS**
Perfect forecasting	10813	15142
1 hour	10622 (-1.76%)	15019 (-0.81%)
4 hours	10531 (-2.6%)	14946 (-1.29%)
6 hours	10357 (-4.22%)	14781 (-2.38%)

3.3 Considering load forecast uncertainty

Taking into account the findings of [6] regarding the Normalized Mean Absolute Error (NMAE) a summary of the results is provided in Table 5. Since no other information is available it is assumed that the forecasting error follows a normal distribution with mean value μe equal to zero and standard deviation provided by (2), as proved in [7].

$$\sigma = \frac{NMAE}{2} \cdot \sqrt{2 \cdot \pi} \quad \text{and} \quad \mu_e = 0 \qquad \textbf{(2)}$$

Table 5: Summary of the results regarding Confidence intervals for various forecasting horizons

Forecasting Horizon	NMAE (%)	σ (%)	Forecast error within range		Confidence Intervals		
			±5%	±10%	85%	90%	95%
1 hour	2.43	3.05	89.9	99.9	[-4.39%,4.39%]	[-5.03%,5.03%]	[-5.98%,5.98%]
2 hours	3.43	4.3	75.5	98	[-6.19%,6.19%]	[-7.10%,7.10%]	[-8.43%,8.43%]
3 hours	3.86	4.84	69.8	96.1	[-6.97%,6.97%]	[-7.99%,7.99%]	[-9.49%,9.49%]
4 hours	4.00	5.01	68.2	95.4	[-7.21%.7.21%]	[-8.27%,8.27%]	[-9.82%,9.82%]
6 hours	4.12	5.16	66.7	94.7	[-7.43%,7.43%]	[-8.49%,8.49%]	[-10.1%,10.1%]

First the impact of load forecasting error when the deviation of forecasted value is met by exchange with the grid is studied. Then the impact of load forecasting error on potential reduction of the local production to comply as much as possible with Market Policy 1 constraints is studied. All the suggested forecasting horizons were used and two sets of market prices ApX and HTS were used.

3.3.1 Exchange with the grid to meet deviations in load forecasting.

For each forecasting horizon 8760 values of forecasting errors following Normal distribution with standard deviation σ equal to the numbers of Table 5 were produced.

Deviations in energy demand and the cost for both ApX and HTS markets are provided in Table 6. It is assumed that there is no penalty for the over-prediction or down prediction, i.e. energy is exchanged at market prices.

Table 6: Annual results for deviations due to short term forecasting error

Forecasting Horizon	Energy deviation (kWh)	ApX cost deviation (€)	HTS cost deviation (€)
1 hour	30.83	-25.70	-0.56
2 hours	-239.83	45.42	-26.10
3 hours	-905.12	51.50	-74.32
4 hours	-567.80	-70.87	-38.39
6 hours	557.4	-96.37	55.7

These values are not very high especially if considered for one year. Actually if the Normal distribution was taken into account and not as random numbers, the calculated expected deviation in energy should be zero (due to its symmetrical error) and similarly zero should have been the expected cost deviation provided that the charge for deviating the expected demand is the same.

If the charge for buying more than predicted from the upstream network is higher than the benefit of buying less than predicted, i.e. there is some kind of penalty for deviations in load forecasting, then there will be some cost deviation calculated by (3).

The penalties as a percentage of the hourly market price for the demand deviation are denoted as penh and penl. These values can even change with time but for the sake of simplicity they are assumed here as constant throughout the year. Load(t) is the forecasted load while σh is the deviation for each forecasting horizon. The percentage of deviation that is considered as free of charge is denoted as Limit.

$$\mathrm{cost\_dev} = \sum_{t=1}^{8760} \frac{\sigma_h \cdot load(t)}{\sqrt{2\pi}} \cdot \exp\left(\frac{-1}{2 \cdot (\sigma_h \cdot load(t))^2} \cdot \left(\frac{\mathrm{limit}}{\sigma_h} \right)^2 \right) (penh - penl) \cdot price(t) \quad \textbf{(3)}$$

Table 7 presents the cost deviation for penh=1.1, penl=0.9 for both ApX and HTS prices and two values of deviation limits, 0.5% and 1%. However, no significant economic difference is noticed between these cases and mainly for shorter forecasting horizon due to rather low σh. As the forecasting horizon increases, the economic impact increases.

The average market prices affect the results. ApX prices may be very volatile but the average price is lower than the HTS. This increases the cost by at least 35€. The difference between penh and penl is another parameter as well. For different values than the ones used for the calculations, the results will be in analogy with the ones presented in Table 7.

Table 7: Economic impact of deviation for the total demand of the Microgrid if deviation is penalized

Forecasting Horizon	Deviation limit	ApX prices (€)		HTS prices (€)	
		0.5%	1%	0.5%	1%
1 hour		160.41	160.12	194.57	194.07
2 hours		226.26	226.16	274.49	274.31
3 hours		254.69	254.62	308.99	308.86
4 hours		263.64	263.57	319.84	319.73
6 hours		271.54	271.48	329.43	329.32

3.3.2 Considering variations in the scheduling of the local units

Variations in the scheduling of the local units may exist when the forecasted demand is comparable to the installed capacity and Market Policy 1 [8] is applied. In such a case the demand may be forecasted lower than the actual and lead the MGCC to reduce the local production in order to restrict selling to the upstream network. The dispatchable units will be affected and will reduce their output even if it is not beneficial. Thus, the units will operate at lower operating point and the surplus of demand should be met by the upstream network. This will lead to additional income loss compared to the one of sub-section 3.3.1.

Since MT is more expensive than the FC, this is the regulated unit that is expected to be affected by changes in estimations of load forecast; underestimation may lead to lower operating points in order to maintain the expected demand.

The installed capacity of the Microgrid in Figure 1 is 88kW. Therefore for forecasted demand higher than 88kW (1+3σh) the Microgrid will always have to buy energy from the upstream network. This happens for the hours 9-23 all year round, even for the 4 hours forecasting horizon. Taking also into account the fact that the PVs cannot produce during the night hours, then the corresponding demand above which energy should be always bought by the microgrid is reduced to 75kW(1+3σh). Thus for hour 24, the Microgrid should always buy energy from the grid, irrespective of the forecasting error. Therefore, for these hours the possibility of leading to reduction of local production is zero.

For the rest hours there is some possibility that the MT operation may be affected. More specifically, for the hours when production from MT is expected, it is checked whether forecasting lower demand than the actual has as impact reduction of its production. If the forecasted demand minus RES production is lower than 60kW, the dispatchable units capacity, then the MT operating point should be reduced.

The forecasted demand Pfrc(t) provided that the actual demand is Pact(t) follows the same pdf with the forecasting error with mean value Pact(t) and standard deviation linked with the forecasting horizon as described in Table 5. Thus, having forecasted value Pfrc(t) is a random variable.

If the forecasted demand value minus RES production is lower than 60kW, then the MT production should be reduced accordingly. Three scenarios exist if the pricing is favourable for MT to be committed.

The actual demand Pact(t) minus RES production PRES(t) is below 60kW (Pact(t)-PRES(t)<60). In such a case any underestimation of the demand will lead to additional reduction of the MT. In such a case the reduction will be provided by the difference Pact(t)-Pfrc(t). The probability of having forecasted Pfrc(t) multiplied with the probability of having PRES(t) leading to lower demand is the probability of this production reduction.

(Pact(t)-PRES(t)>60). In such a case the MT should operate at its maximum, however, for some forecasted demand values may happen that Pfrc(t)-PRES(t)>60. In such a case the difference of the MT operating point from its nominal capacity is calculated and we are interested in the combination of probabilities that may lead to such an incidence.

(Pact(t)-PRES(t)>60) and for none of the forecasted demand values the demand to the dispatchable unit is lower than this. In such a case, the MT will operate at its nominal capacity.

For the ApX prices the MT is almost never scheduled during hours 1-7. Thus, no economic deviation is expected for these hours.

For HTS prices, the prices during these hours are higher. Thus for some hours of the year, there will be reduction in MT production compared to the operation point if perfect demand forecast was available. The expected reduction and the economic impact is summarized in Table 8, Compared to the economic impact in 3.3.1 the additional cost is in the order of 6% for all the cases studied.

Table 8: Impact on economics operation because of MT production reduction in the HTS

Forecasting Horizon	Energy deviation (kWh)	HTS cost deviation (€)
1 hour	765.56	11.63
2 hours	1129.76	17.21
3 hours	1238.23	18.73
4 hours	1345.37	20.53
6 hours	1385.11	21.28

4. Conclusions

The impact of wind power forecasting horizon in the economics is rather limited, mainly due to the relatively low capacity in the network considered. However, the difference in deviation in expected production is significant from 1 hour forecasting horizon to 6 hours.

Price forecasting errors may lead to erroneous decisions regarding mainly the operation of the dispatchable units. Since prices may be forecasted either lower than their operational cost or higher than this, in the former case their operation will be stopped even though it would have been beneficial to operate, while in the latter case these units would operate even though it is proven to be clearly not beneficial. Both these events reduce the savings that can be achieved by up to 4.22%. More volatile markets are more sensitive to erroneous forecasting and the shorter horizon helps in alleviating the economic impact.

The impact of short term horizon considered is significant in the deviation for load forecasting. However, since the forecasting error is symmetrical the annual deviation is very small or even zero. If the penalty for buying additional power from the grid is higher than the penalty for buying less, then the economic impact of using longer forecasting horizon periods is increased.

Moreover, short term forecasting errors for demand values comparable to the capacity of the microgrid can lead to reduction of production of the dispatchable units compared to the one of the actual demand value. Thus, the Microgrid is led to buy active power from the upstream network that otherwise would have been produced by dispatchable units at lower prices. This leads to little additional cost for the Microgrid.

Generally, shorter term operation horizon and more frequent updates of the available forecasts can reduce the operating cost significantly but more importantly the deviation in demand that the upstream network may face. It is suggested that the update of the forecast is made at least at equal time-periods with the foreseen short-term market horizons. More frequent update of the forecasts can help in better managing uncertainties and increasing short term market participation efficiency.

5. References

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