Advanced Architectures and Control Concepts for

MORE MICROGRIDS

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Strategies for Emergency Functions

Islanding with Several Microgrids

&

Blackstart

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Foreword

Coordination of frequency and voltage control in MV distribution networks with large presence of microgrids and distributed generation units, directly connected to the MV grid, is addressed here with the purpose of improving system operation conditions in emergency operation. These improvements can take several forms, e.g.:

- Minimizing frequency deviations and maximizing survivability following islanding;
- Allowing for multi-microgrid blackstart and minimizing the loss of supplied energy.

This can be done exploiting, in a combined way, the control capabilities of distributed generation units, microgrids (that can be regarded as active cells, including several different microgeneration units) and controllable loads. Specific physical and technical limitations of all these controllable devices are taken into account and this fact lead to the implementation and use of adequate detailed dynamic models for several of these devices.

INESC Porto developed a multi-microgrids simulation platform, exploiting EUROSTAG, to be used as a tool to evaluate the need for specific generation abilities or alternative control strategies (e.g., load curtailment) for the emergency operation of multi-microgrids. This simulation platform is also used to test blackstart sequences, identifying problematic issues.

ICCS/NTUA exploited EUROSTAG to test and develop emergency control procedures for the multi-microgrid. This includes under frequency load shedding schemes, a knowledge based system using Decision Trees and split of the MV network into several islands. This knowledge base system was used to control the multi-microgrid following islanding and its use was also suggested for the planning of blackstart sequences.

The contributions given by the partners INESC Porto and ICCS/NTUA, regarding the topics presented in “Task TD4 – Emergency Functions – Islanding with Several Microgrids and Blackstart” are presented in the next two parts of this deliverable. Since these contributions were built with an individual envelop it was decided to keep both contributions separate in order not to cause difficulties in the reading of this document.

INESC PORTO CONTRIBUTION

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Acronyms and Abbreviations

CAMC – Central Autonomous Management Controller

CHP – Combined Heat and Power

DFIM – Doubly-Fed Induction Machine

DG – Distributed Generation

DMS – Distribution Management System

DSM – Demand Side Management

DSO – Distribution System Operator

EMS – Energy Management System

HV – High Voltage

LC – Load Controller

LV – Low Voltage

MC – Microsource Controller

MGCC – MicroGrid Central Controller

MMG – Multi-MicroGrid

MV – Medium Voltage

OF – Objective Function

PF – Power Factor

PI – Proportional-Integral

RTU – Remote Terminal Unit

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.

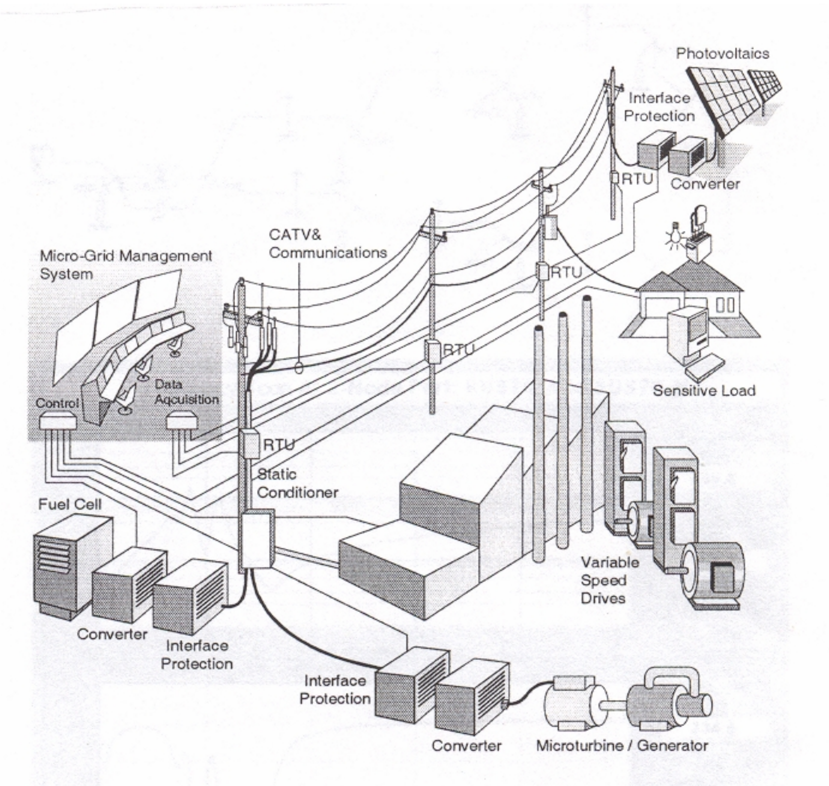


Figure 1: Typical MicroGrid System

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)

A multi-microgrids concerns 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.

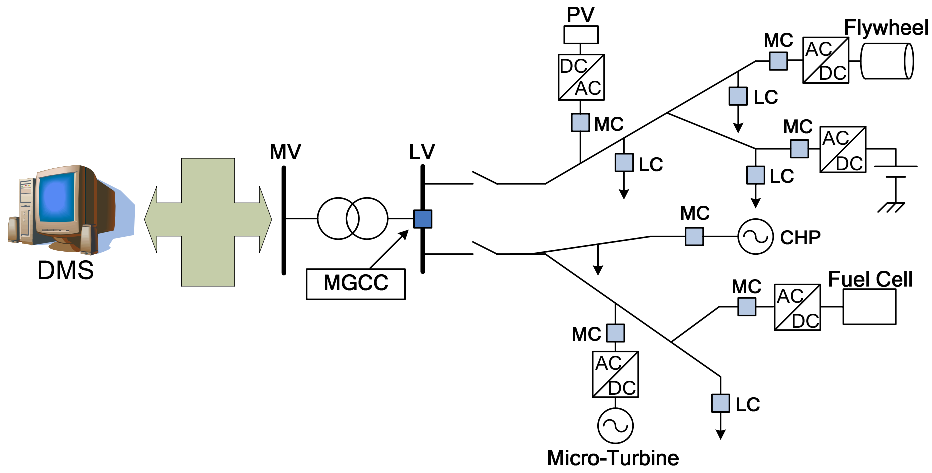


Figure 2: Microgrid Control Architecture

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 regards 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. The CAMC must then communicate with other “local” controllers such as MGCCs or with DG sources or loads connected to the MV network, serving as an interface for the DMS.

Therefore, the CAMC will be playing a key role in a multi-microgrid system: it will be responsible for the 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.

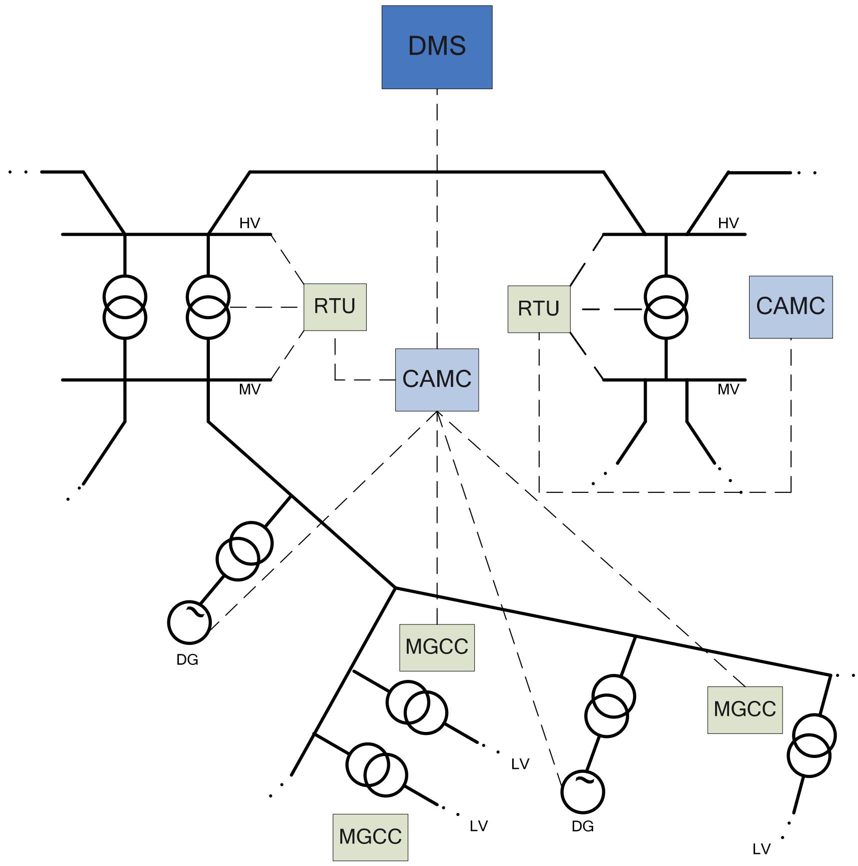


Figure 3: Control and Management Architecture of a Multi-MicroGrid System

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 RTUs located in the MV network and existing MGCCs. It will also have to deal with constraints and contracts to manage the multi-microgrid in both HV grid-connected operating mode and emergency operating mode. A first set of functionalities to integrate the CAMC can be seen in Figure 4.

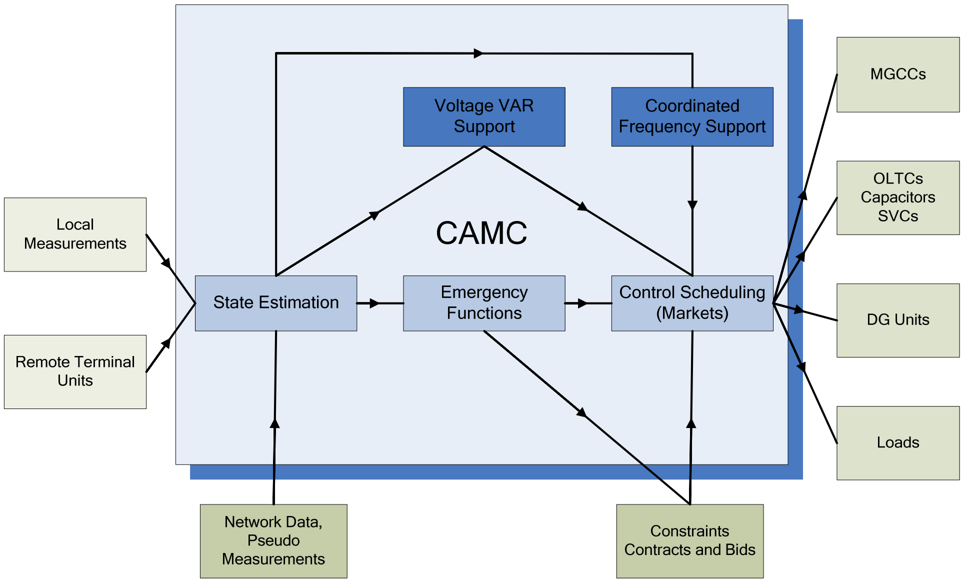


Figure 4: CAMC Functionalities

However, 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.

The Coordinated Frequency Support functionalities presented in Figure 4 will be described in detail in the following sections.

2. Introduction

Reliability and security has become a primary concern for power systems since network conditions are becoming more and more stressed. In order to increase reliability of supply, distributed generation can be used to partially fulfil the role of traditional active power reserve services. This is particularly true since the moment DG is showing up as a leading player in distribution system reorganization.

However, a problem remains: how to coordinate the efforts of multiple generation units, along with controllable loads, so that frequency control can be effectively achieved? The solution is based on the hierarchical system already described by Figure 3 and Figure 4, which depends heavily on the CAMC (at the MV network level) and on the various MGCCs (at the LV microgrid level).

Activation of reserve services for frequency control can be performed in either grid connected or emergency modes of operation. Islanded operation is considered to be possible, so load-following performance is important. However, another very important subject to tackle is the transition to islanded operation while substantial power flows exist between the Multi-MicroGrid and the upstream HV network. In this case the power imbalance that may take place inside the newly created island must be eliminated in the least amount of time possible, with the contribution of all the available MMG elements.

The implementation of controlled Load Curtailment programs (also known as Load-Shedding, Demand Response, Dispatchable DSM, etc.) was always thought as useful in this kind of scenarios. Loads that can be managed at the microgrid level are, for instance, normal customers that can be rewarded with special tariffs for allowing having their consumption partially curtailed if needed.

In order to study these control strategies, it was necessary to implement a simulation platform, already used in TD3.3 [3], capable of reproducing the way in which an intermediate managing control structure – the CAMC, capable of controlling the downstream agents depending from a MV bus of a HV/MV distribution substation – can be used to accomplish some management and control tasks in this kind of multi-microgrid system Such tool is particularly important to address frequency control in case of MV network islanding and also load-following in islanded operation. This dynamic simulation platform was built around *Eurostag* and *MATLAB* software packages. This combination was chosen due to the flexibility that their simultaneous use brings to the simulation. In fact, *Eurostag 4.2* is very strong in dynamic simulation but is left behind because of its lack of capabilities for algorithm implementation. *MATLAB*, on the other hand, is completely at ease regarding the implementation of complex algorithms and control procedures, just like most other programming languages.

This simulation approach requires having a procedure, under *MATLAB* environment, starting multiple Eurostag simulation runs that last for a predefined period of time. This *MATLAB* routine is used to emulate both CAMC and MGCC behaviours. Such behaviour requires the monitoring of system frequency variations and involves sending setpoints or load change commands to the *Eurostag* environment where the system dynamic simulation runs. The *MATLAB* routine will also acquire several measurements from *Eurostag*'s data files, corresponding to the real system, and use them in this process.

3. Test Network Description

The test network (Figure 5, page 13) has four clearly different areas: two with typically urban topologies (the loops) and two rural ones (radial structures).

This test network started with an initial proposal by ICCS/NTUA but has been developed since then. The main differences regarding this initial proposal were:

- the increase in size;
- the increase in the number of Microgrids;
- the addition of several capacitor banks to improve voltage profile (particularly in islanded operation);
- the inclusion of a diesel generator with a PI controller;
- the adjustment of the MV voltage value from 21 kV down to 15 kV (the value typically in use in distribution networks in Portugal).

The first two changes were particularly important because they were expected to enable the testing of larger MV networks with large proportions of distributed generation and MicroGrids and also make any possible limitations of the algorithm stand out.

Its first appearance in this form was in [3], where all the relevant parameters are listed.

The HV network to which this MV distribution network is connected is represented by an infinite bus (at the top of the diagram). The islanding operations are to be simulated by disconnecting one end of the branch connecting the HV and MV networks together.

A total of 13 MicroGrids can be seen in the diagram of Figure 5, shown in *Eurostag* display format [4]. They can be easily identified by the relatively large buses, each with 5 identical power injectors and a single load. The MicroGrids in use are almost identical, differing only in some details regarding if they are in a rural or urban area. All of the 13 MicroGrids are connected to 0.4 MVA transformers and their detailed structure is given in section 5.

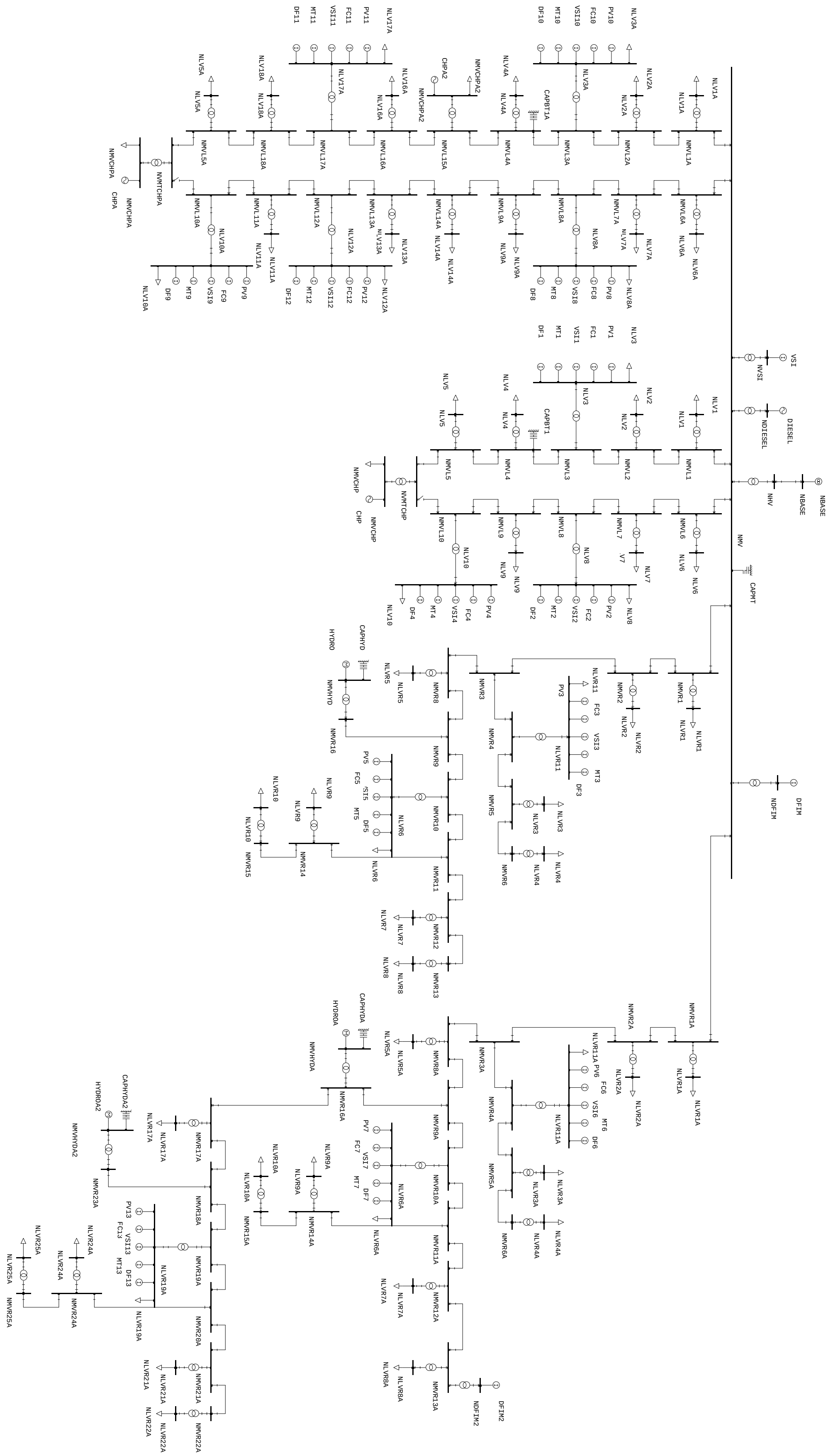


Figure 5: Final test network

4. Hierarchical Control System

The hierarchical control system can be represented by the block diagram in Figure 6. Only Control Levels 2 and 3 are implemented, as the simulation platform deals only with a single autonomous multi-microgrid (a single MV network) and does not perform any function related to the DMS that is dealing with several MV networks.

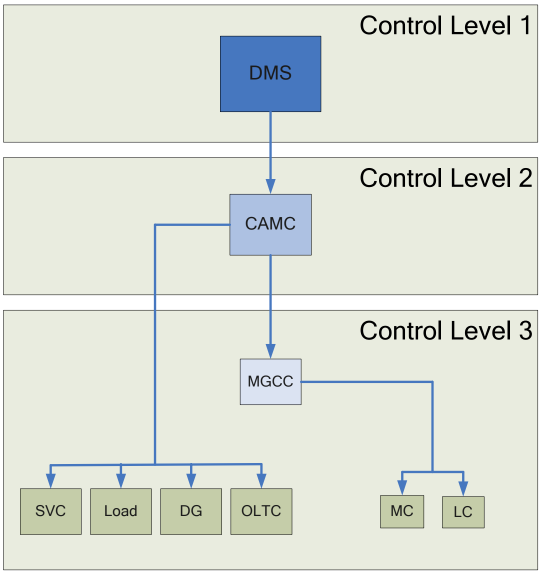


Figure 6: Hierarchical Control Scheme

The commands needed to modify generation and load are originated in the CAMC. These commands are sent to MGCCs, to independent DG units and also to controllable MV loads. MGCCs act as an interface between the CAMC and the internal active components of the microgrids, so that the CAMC does not need to have the details of the structure of each microgrid.

While connected to the upstream HV network, the MV CAMC limits its autonomous intervention to a minimum. However, in islanded operation, the CAMC will respond to power system frequency changes in a way similar to the one implemented in regular Automatic Generation Control (AGC) functionalities [5]. A PI controller is used to derive the requested global power change needed to restore system frequency. Then, an economical allocation algorithm will allocate contributions for this power change among all the power generation units, controllable MV loads and MGCCs under CAMC control but only if they are willing, at that point in time, to participate in frequency regulation.

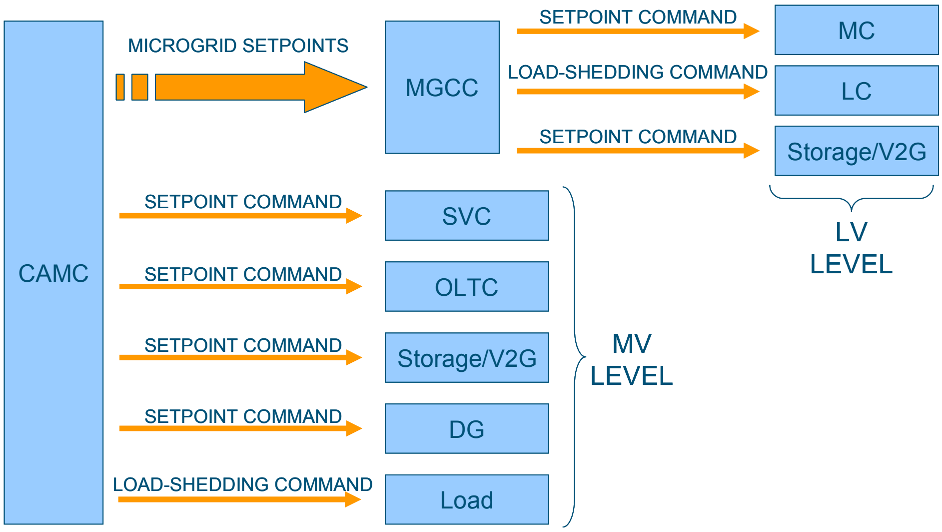


Figure 7: Relationships between elements inside a MMG.

Each of the MGCCs will also allocate the necessary power changes among its subordinate controllable loads and micro-generation units, through the Load Controllers (LC) and Microsource Controllers (MC). Some of these microsources do not usually have regulation capabilities (e.g., PV or wind generation, due to limitations in primary resource availability) and will not normally be asked to change power generation.

It should be noted that the CAMC will only act if strictly needed and will not try to globally change set-points in order to achieve a near optimum point of operation of the system. This justifies the choice of using power setpoint variations and not absolute power set-points in order to make it possible to have a higher order control system, either automatic or manual, that would independently adjust microsource or DG output to set-points other than the system optimal ones. One example of this “control system” could be the microsource individual owners who would adjust microturbines, for instance, according to their heating needs.

A cluster of several storage devices (e.g., flywheels and batteries) could, if integrated in the hierarchical control system, efficiently establish a storage reserve that would be of great help to the islanded operation of the network at the microgrid and multi-microgrid levels. On the other hand, these storage devices, assumed to have interface inverters of the Voltage Source Inverter (VSI) type, can also have their output power controlled on the basis of frequency droop.

Therefore, these storage devices can help in two possible ways: a) they can act autonomously, with their output power P_{VSI} responding to system frequency changes providing energy used to balance initially the system using a proportional control element as described by (1) or b) they can receive setpoints controlled from a central location, in a hierarchical way.

$$P_{VSI} = K_P \times \left(f_{rated} - f \right) \tag{1}$$

These two control methods are not mutually exclusive: while an autonomous response will undoubtedly improve the system's response to the initial frequency deviations following a disturbance, the hierarchical system can take over after that initial response and real-locate each source and storage element contributions according to some predefined criteria. This two-step approach can be justified by the intrinsically slow nature of the hierarchical control scheme, which suggests that grid connected storage devices under hierarchical control should be regarded as secondary reserve while, in order to be able to limit initial frequency excursions, storage devices must be capable of acting autonomously if necessary. However, these actions are only possible while enough energy is stored in the storage devices. From the simulation point of view, the implementation of such control capability required a step by step evaluation of the energy injected into the grid and a comparison with the available nominal storage values in each existing storage or cluster of storage devices.

4.1 Control Details

In the proposed approach system's frequency is continuously monitored by the CAMC (Figure 8). Every time interval T_s (sample time), if triggered by significant changes in frequency, the CAMC will send control setpoints to every MGCC, other DGs and controllable MV loads. This sample time T_s cannot be very small, mainly because of the constraints imposed by the communication system on which this control system depends.

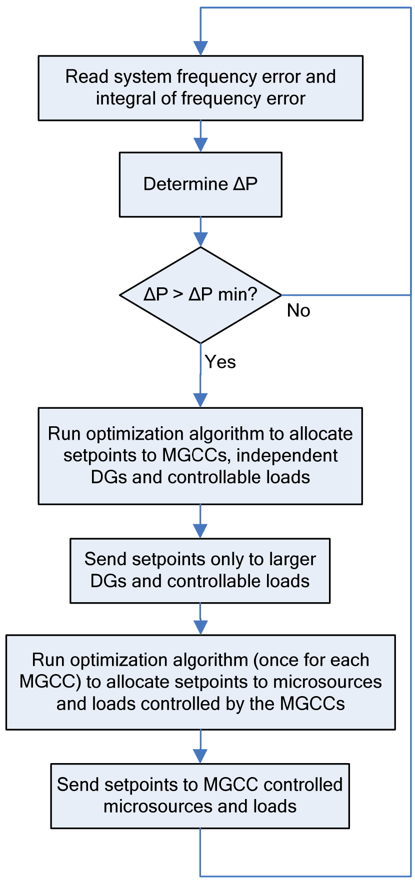


Figure 8: Implementation flowchart – this procedure runs once each period T_s

Therefore, the frequency error and the frequency error integral will be used to determine the additional power ΔP (2) to be requested to the available contributors under CAMC control: MGCCs, DGs and controllable loads.

$$\Delta P = K_C \times \left(K_P \times \Delta f + K_I \times \int \Delta f \right) \tag{2}$$

Where:

ΔP: desired power change (W)

Δf: frequency error (p.u.)

K_P: proportional gain

K_I: integral gain

K_C: network constant (proportional to the controllable power in the network under control) (W)

The purpose of K_C is to do nothing else than to convert the value between parenthesis in (2) to S.I. units and, simultaneously, scale the value adequately to the network under control. In this way the values of the other two gains become less dependent on the size of the network or the available machines.

It should be noted that this additional power can have negative values if the frequency rises over its rated value. In this way the CAMC can also respond to other disturbances, such as load loss while in islanded mode, commanding the distributed generation to reduce power output (including micro-generation curtailment, if necessary), eventually reconnecting some loads still disconnected at the moment.

If the required power variation ΔP is larger than a predefined threshold (related to a dead band), the control system will proceed to determine how to optimally distribute the power requests through the available sources. Unitary generation costs for each of the sources (MGCCs and other DGs) are used for this purpose.

The optimization is based on standard linear optimization techniques:

$$\begin{aligned} &\min_x z = c^T x \\ \text{subject to} \quad &\sum x = \Delta P \\ &x \geq b_1 \\ &x \leq b_2 \end{aligned} \tag{3}$$

Where the vectors represent:

c generation cost and load curtailment prices;

x generation or load setpoint variations;

b_1 smallest variations allowed (lower bounds);

b_2 largest variations allowed (upper bounds);

The set of restrictions (3) can also define which generators/loads participate in frequency regulation. This can be done by setting to zero the i[th] elements of both b_1 and b_2 corresponding to units that cannot be adjusted.

There can be some cases where the optimization algorithm might fail because, for instance, there is not enough reserve power to fulfil the first restriction (3) in case of a frequency drop. A failure of the optimization algorithm would cause no changes in power setpoints which, in most cases, would be worst than to simply increase the generation of all sources as much as possible, even if that wouldn't completely meet the hierarchical system control requirements.

In order to attain this behaviour, the following verification is performed:

$$\Delta P \geq \sum b_2 \tag{4}$$

Then, if the previous comparison (4) returns true, ΔP is enforced to be equal to the sum of the elements of b_2 (5):

$$\Delta P = \sum b_2 \tag{5}$$

In order to avoid globally changing setpoints (e.g., decreasing production from expensive microsources and replacing them with less expensive ones), it is necessary to adjust the lower and upper bounds in (3) according to the ΔP value:

$$\begin{cases} \Delta P > 0 \Rightarrow b_1 = 0 \\ \Delta P < 0 \Rightarrow b_2 = 0 \end{cases} \tag{6}$$

The enforcement of these conditions (6) assures that no microsource will decrease its production so that another can increase it (i.e., there will not be any unwanted power transfers between power sources).

A locking system is also set in place that avoids this kind of power transfers in subsequent instants in time (e.g., decreasing production from expensive microsources at t=t1 and replacing them with less expensive ones at t=t1+t2). This is accomplished through a scheme that prevents power changes from sources other than the ones that have just had their setpoints changed, except if these power changes are in the same course of those that have just happened. Therefore, if a source is used to compensate for a frequency drop through an increase in production, an immediate frequency overshoot which could require a power generation reduction drop would tend to be corrected using the same source and not another one, more expensive. course

The optimization step is performed each sample period T_s and will originate a vector representing the power generation changes to be requested to microgrids (MGCCs), independent DG units (e.g., CHP) and loads (MV load-shedding operations).

Each MGCC will now use the power change requested by the CAMC to establish the main restriction of a new optimization procedure (identical to the one used before by the CAMC) which will determine the power changes to be requested to microsources and controllable loads under MGCC control.

5. Islanding with Several MicroGrids

A Multi-MicroGrid can be operated in either normal or emergency mode, connected to the upstream HV network or isolated from it, respectively. In both operating modes, the hierarchical control described previously is exploited.

When the MMG is operated in interconnected mode, the hierarchical control requirements are limited to the minimum, being only concerned with attending the requests sent by the DMS to the CAMC regarding suitable values of the load flow on the MMG interconnection with the upstream HV system, without the need to control system frequency.

However, when the MMG is operated in islanded mode, the hierarchical control scheme implemented on the CAMC plays a key role. In this situation, the CAMC is responsible for managing the whole MMG as well as to control the system frequency autonomously, improving then the MMG continuity of service following a fault occurrence on the upstream HV network.

Thus, in this section, the hierarchical control application when the MMG is operated in islanded mode is addressed. The feasibility of the MMG islanding and its subsequent operation in islanded mode is demonstrated through numerical simulations. For this purpose, the test system presented on section 3 (previously described in detail in [3]) is used and several scenarios will be considered regarding different amounts of imported or exported active power as follows:

- **Scenario 1:** The MMG is importing a small amount of active power from the upstream HV system;
- **Scenario 2:** The MMG is exporting a small amount of active power to the upstream HV system;
- **Scenario 3:** The MMG is importing a large amount of active power from the upstream HV system.

The dynamic simulations are carried out taking into account that the MMG is operated in interconnected mode and at t=10 s the islanding occurs.

The control parameters are the same for all the scenarios. As described previously, in section 4.1, these control parameters comprise:

- The hierarchical control system gains (K_P and K_I);
- The grid constant (K_C);
- The threshold active power variation (ΔP_{min});
- The sample time (T_S).

The values used for these parameters are presented on Table 1.

Table 1: Parameters of the hierarchical control system

Parameter	Value
K_P	7
K_I	0.01
K_C	15 MW
ΔP_{min}	2% of K_C (0.3 MW)
T_s	5 s

The values of K_P and K_I were obtained through a trial and error approach. The grid constant depends on the installed capacity of generation regarding the controllable DG units and should take the same value for all the scenarios.

The control system response can be considerably influenced by the value of the threshold active power variation. Small values will increase the number of control actions, the convergence speed to the MMG nominal frequency and the accuracy of the frequency value under steady state conditions while large values will have the opposite effect. So the adopted value corresponds to a trade-off solution, which takes into account the minimization of needless efforts of controllable devices.

The sample time is also critical for the control system operation. As already mentioned previously, this time should be as small as possible in order to obtain a fast response. However, the minimum value can be limited for several reasons, namely the frequency required by the communication system, the computation time required by the CAMC and the stress of controllable devices to attend set points sent with high frequencies.

The test system to be used comprises thirteen MGs. Five of them are located on rural regions while the remaining eight are located on urban regions. Taking into account the MG location, they have different compositions. Therefore, two configurations were considered: The rural MG and the urban MG, being neglected some differences that can exist between MGs located at the same region. Thus, it was assumed that urban MGs do not comprise micro wind turbines and rural MGs do not comprise microturbines.

Based on these assumptions, the active power generation inside each one of the urban and rural MGs is presented on Table 2 and Table 3, respectively.

Table 2: Initial active power generation inside the urban MGs

Source	Output Power (kW)	Rated Power (kW)	Controllable
MTA e MTB	40	100	Yes
FC	16	40	Yes
VSI	0	150	–
PV	4	10	–
Total	100	400	(140 kW)

Table 3: Initial active power generation inside the rural MGs

Source	Output Power (kW)	Rated Power (kW)	Controllable
WGA e WGB	40	100	–
FC	16	40	Yes
VSI	0	150	–
PV	4	10	–
Total	100	400	(40 kW)

The remaining data that is needed for the simulation process, particularly regarding the optimization process described in section 4, can be found in the annex at the end of this document.

The results obtained from the study of each one of the scenarios considered are presented on the following three subsections.

5.1 Scenario 1: Small amount of imported power

In this scenario, the MMG is importing a small amount of active power from the upstream HV system. So the interconnection load flow adopted corresponds to 5% of the MMG load (1.12 MW of 19.89 MW), which is also equivalent to 4% of the MMG installed capacity. The active power supplied from each one of the DG units is presented on Table 4.

Table 4: Initial active power generation inside the MMG (Scenario 1)

Source	Generated Active Power (MW)	Rated Power (MVA)	Controllable
Diesel	0.9	1.5	–
VSI	0	1	–
DFIM	5.5	6	–
DFIM2	2.5	3	–
HYDRO	2	2.8	Yes
HYDROA	2	2.8	Yes
HYDROA2	0.8	1.4	Yes
CHP	1.8	2.2	Yes
CHPA	1.8	2.2	Yes
CHPA2	0.7	1.2	Yes
Microgrids (Urban) (1, 2, 4 and 8 to 12)	0.1	0.25 (+0.15 VSI)	Yes
Microgrids (Rural) (3, 5, 6, 7 and 13)	0.1	0.25 (+0.15 VSI)	Yes
Total	19.3	27.35 (+1.95 VSI)	(15.85 MW)

The results obtained are presented on the following figures. Figure 9 presents the frequency behaviour following the MMG islanding at *t*=10s.

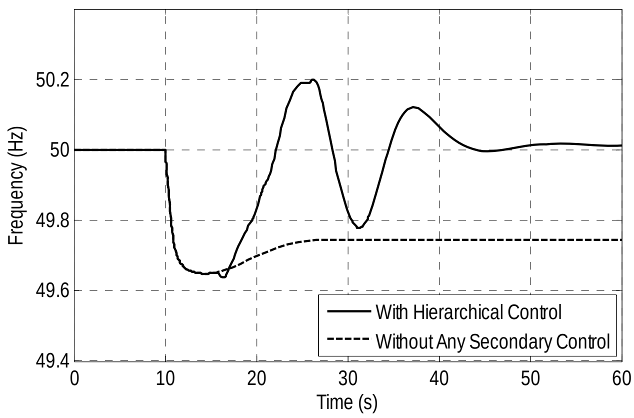


Figure 9: Frequency behaviour following MMG islanding (Scenario 1)

As it can be observed from Figure 9, the small amount of active power imported from the HV network causes a small impact on the MMG system frequency, leading with frequency deviations around 0.5 Hz. At *t*=15 s the hierarchical control system implemented on the CAMC starts to recover the MMG system frequency, which after the transient period stabilizes near its nominal value. Without hierarchical control the Diesel group is responsible for the secondary frequency control and the frequency behaviour, in this situation, is also presented on Figure 9.

The frequency recover procedure, guided by the hierarchical control system, is based on active power set points sent by the CAMC to the hydro units. The response of this one connected to the bus NMVHYD following the CAMC active power request is depicted on Figure 10.

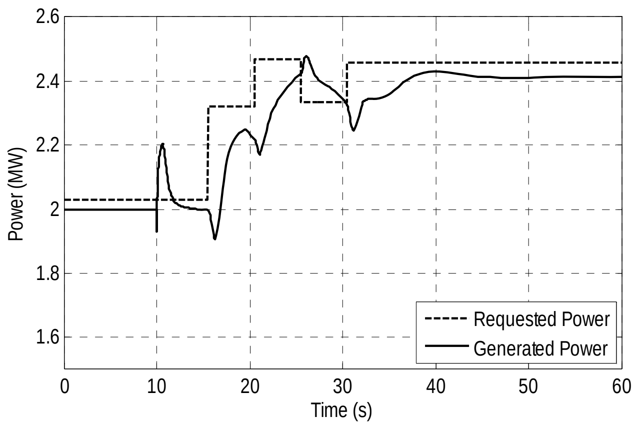


Figure 10: Active power output from the hydro unit connected to bus NMVHYD following the CAMC set points (Scenario 1)

As it was already mentioned previously, the hydro units are the first DG units to be asked for the increase of their active power generation because they are considered the least expensive ones. Since the increase of power generation provided by the hydro units is enough to recover the MMG system frequency to acceptable values, the CAMC did not send requests to other DG units. This fact can be observed from Figure 11, where the active power output of the CHP unit connected to the bus NMVCHP is presented.

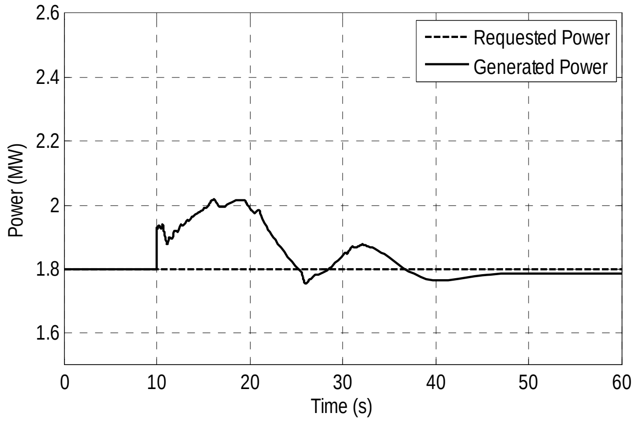


Figure 11: Active power requested and generated by the CHP unit connected to bus NMVCHP (Scenario 1)

It should be noted that the active power variations are due to the proportional control implemented on the CHP unit frequency governor.

Since the hierarchical control system behaves like a slowly secondary frequency control, autonomous DG units with fast response play a key role concerning frequency recover to its nominal value. This can be observed from Figure 12, where the active power output of both the Diesel group equipped with a P-I controller and the main storage device connected to the MV network through a VSI equipped with a proportional controller is presented. These controllers allow the active power injection into the grid autonomously while the system frequency is less than its nominal value.

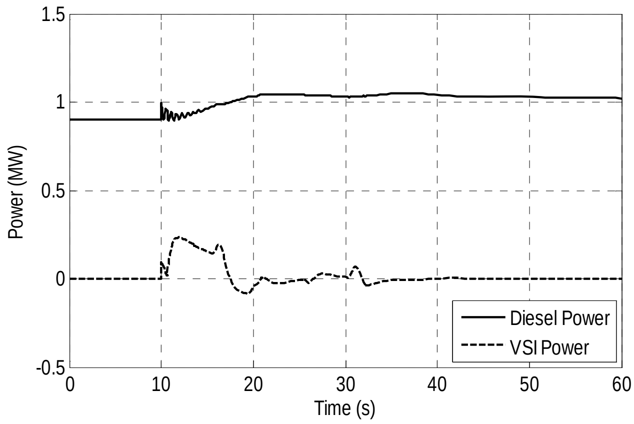


Figure 12: Active power contributions from both the Diesel group and the main storage device connected to the MV network (Scenario 1)

Although the contributions are modest, it should be noted that the main storage device responds immediately after a system frequency deviation from its nominal value, while the Diesel group allows obtaining a more accurate value concerning the system frequency after the transient period.

5.2 Scenario 2: Small amount of exported power

In this scenario the MMG is exporting a small amount of active power to the HV system. Although it is expected that this situation will not be frequent, its study can be interesting since it allows understanding the MMG system response following its islanding.

The load flow on the interconnection with the upstream HV network corresponds to around 11% of the MMG load (2.11 MW of 19.89 MW), which is equivalent to 7% of the total installed capacity of the MMG. In order to obtain this interconnection load flow, the active power generation and consumption is distributed for the several DG units and loads, respectively, as presented on Table 5 and Table 6 (modification regarding the scenario set in [3]).

Table 5: Initial active power generation inside the MMG (Scenario 2)

Source	Generated Active Power (MW)	Rated Power (MVA)	Controllable
Diesel	0.9	1.5	–
VSI	0	1	–
DFIM	5.5	6	–
DFIM2	2.5	3	–
HYDRO	2	2.8	Yes
HYDROA	2	2.8	Yes
HYDROA2	0.8	1.4	Yes
CHP	1.8	2.2	Yes
CHPA	1.8	2.2	Yes
CHPA2	1	1.2	Yes
Microgrids (Urban) (1, 2, 4 and 8 to 12)	0.1	0.25 (+0.15 VSI)	Yes
Microgrids (Rural) (3, 5, 6, 7 and 13)	0.1	0.25 (+0.15 VSI)	Yes
Total	19.6	27.35 (+1.95 VSI)	(15.85 MW)

Table 6: Initial active power consumption inside the MMG (Scenario 2)

Nodes	Active Power (MW)	Reactive Power (MVAr)	Modification
NLV1 and NLV1A	0.838	0.275	Disconnected
NLV9 and NLV9A	0.419	0.138	Disconnected
NLVR22A and NLVR25A	0.086	0.042	Disconnected
NLVR21A and NLVR24A	0.135	0.065	Disconnected

Figure 13 presents the frequency behaviour following MMG islanding.

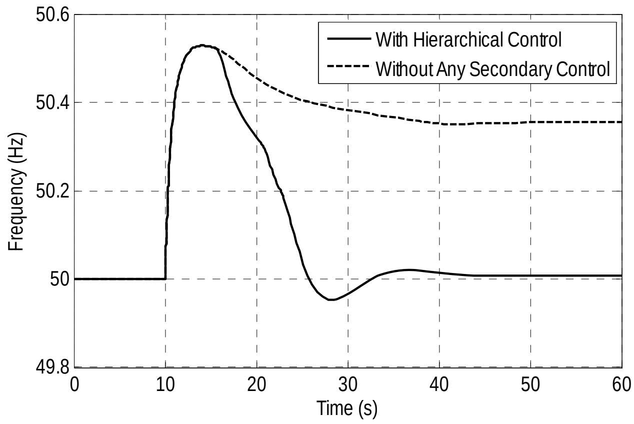


Figure 13: Frequency behaviour following MMG islanding (Scenario 2)

Due to the imbalance between generation and demand after the MMG islanding from the upstream HV network, the system frequency increases and presents a deviation from its nominal value around 0.5 Hz, as it can be observed from Figure 13. Due to this frequency deviation the DG units equipped with frequency control systems decrease their power generation, as depicted on Figure 14, in an attempt to balance demand and supply. However, without the hierarchical control system, it is not possible to restore the system frequency to its nominal value, as it can be observed from Figure 13.

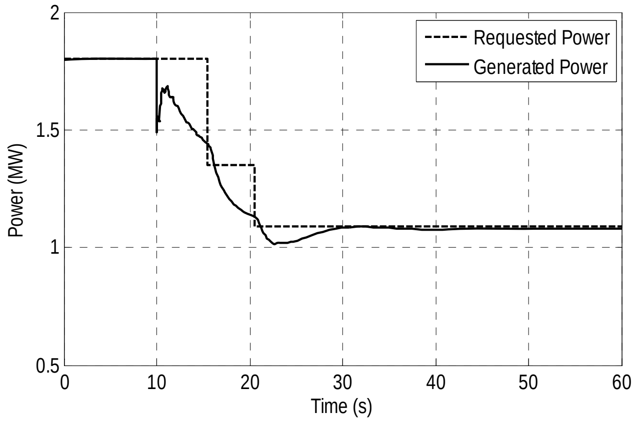


Figure 14: Active power output of both the Diesel group and the main storage device connected to the MV network (Scenario 2)

At *t*=15 s, the CAMC verifies the system frequency deviation and sends requests to the CHP units in order to decrease their active power generation, since they are the considered the most expensive DG units. Figure 15 shows the response of the CHP unit connected to the bus NMVCHP following the CAMC request together with the response of its proportional control.

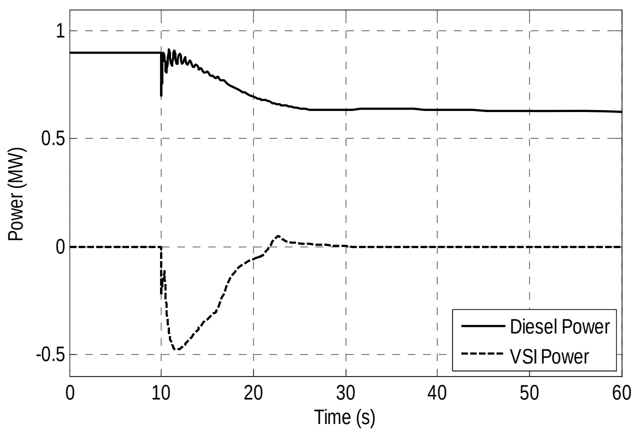


Figure 15: Active power output of the CHP connected to the bus NMVCHP following the CAMC request (Scenario 2)

Concerning the main storage device connected to the MV network through a VSI, it can be observed from Figure 6 that it absorbs some amount of active power while the system frequency is greater than its nominal value. Due to its P-I controller, the Diesel group decreases the active power output while the nominal value of the frequency is not restored.

5.3 Scenario 3: Large amount of imported power

In this scenario the MMG is importing a large amount of active power from the HV system. This situation is commonly considered for the purpose of simulation of an unintentional MMG islanding following a fault occurrence on the upstream HV network.

The initial interconnection load flow from the upstream HV network is around 26% of the MMG load (5.11 MW of 19.89 MW), which is equivalent to 17% of the total installed capacity inside the MMG. So, at the beginning of the simulation it was considered that the active power distribution among the several DG units including MG is presented on Table 7.

Table 7: Initial active power generation inside the MMG (Scenario 3)

Source	Generated Active Power (MW)	Rated Power (MVA)	Controllable
Diesel	0.9	1.5	–
VSI	0	1	–
DFIM	4	6	–
DFIM2	2	3	–
HYDRO	1.5	2.8	Yes
HYDROA	1.5	2.8	Yes
HYDROA2	0.8	1.4	Yes
CHP	1.2	2.2	Yes
CHPA	1.2	2.2	Yes
CHPA2	0.7	1.2	Yes
Microgrids (Urban) (1, 2, 4 and 8 to 12)	0.1	0.25 (+0.15 VSI)	Yes
Microgrids (Rural) (3, 5, 6, 7 and 13)	0.1	0.25 (+0.15 VSI)	Yes
Total	15.1	27.35 (+1.95 VSI)	(15.85 MW)

In order to highlight the hierarchical control capabilities, the Diesel group active power generation is near its maximum value (1 MW). In this way it is not possible for this unit to increase considerably its active power output in order to balance demand and supply after MMG islanding.

Although voltage control is out of the scope of the hierarchical control system, the MMG adequate operation requires that the bus voltages should be kept on acceptable values. For this purpose the reactive power production should also be kept on acceptable values. However, due to the resistive characteristics of distribution networks, bus voltage levels tend to increase with the amount of active power generation on these buses.

Considering a reactive power flow from the upstream HV network near 40% of the active power flow (2 MVAr), the distribution of reactive power among the MMG generation units is presented on Table 8. It was also considered a 5 MVAr capacitor battery connected to the MV side of the HV/MV substation.

Table 8: Initial reactive power generation inside the MMG (Scenario 3)

Source	Reactive Power (MVAr)
Diesel	0
CHP	0.5
CHPA	0.5
CHPA2	0.3
Capacitor Bank (HV-MV substation bus)	5

The simulation to be carried out comprises the MMG islanding at *t*=10s and load increase at *t*=90 s. For this purpose the following assumptions are taken into account:

- The distribution of both active and reactive power presented on Table 7 and Table 8 allow a frequency drop near to 48 Hz after MMG islanding;
- The under frequency protections are regulated to 47 Hz, as defined on the European power quality norms [6].

The load increase occurs simultaneously on several buses, as described on Table 9, and corresponds to an increase of 4% of each bus load per second during 10 seconds.

Table 9: Load increasing inside the MMG (Scenario 3)

Nodes	Initial Value (MW)	Final Value (MW)
NLV1A and NLV6A	0.838	1.173
NLV11A, NLV18A NLV4, NLV5 and NLV9	0.419	0.586
NLVR3A, NLVR7A NLVR21A, NLVR24A	0.135	0.189
NLVR17A	0.216	0.302
Total	4.53	6.34

The results of the simulations are presented on the following figures.

Figure 16 presents the MMG system frequency. After MMG islanding, the frequency drops from its nominal value to the minimum value, near 48 Hz.

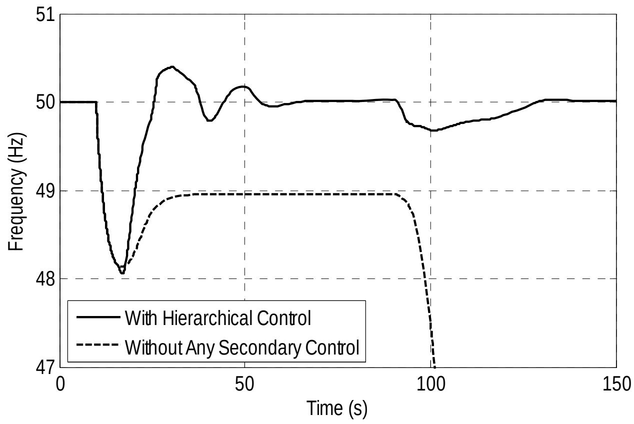


Figure 16: Frequency behaviour following MMG islanding (Scenario 3)

The behaviour of the MMG system frequency during its recovering is conditioned for several factors, namely:

- Dynamic response of proportional controllers of CHP units;
- Dynamic response of P-I controllers of storage devices connected to the MV network and connected to the LV networks of several MG;
- The hierarchical control system, which starts to help on frequency recover before *t*=20 s. in contrast

As it can be observed from Figure 16, the hierarchical control system together with the DG units equipped with proportional and P-I control systems allow the MMG operation following islanding, as well as during load following conditions. In both transient situations the MMG system frequency was restored to its nominal value. On the contrary, also from Figure 16 it can be observed that if no secondary frequency control systems are enabled (with the exception of the Diesel unit) the MMG collapses following the load increase at t=90 s. This happens because the system frequency drops to a value less than 47 Hz leading with the actuation of the under frequency protections of the synchronous machines.

Following the system disturbances considered for this scenario, the CAMC sends requests to several DG units connected to the MV network, such as CHP and hydro units as well as to MGs. The results obtained are presented on the following figures.

Figure 17 presents the active power output of the CHP unit connected to the bus NMVCHP following the CAMC requests.

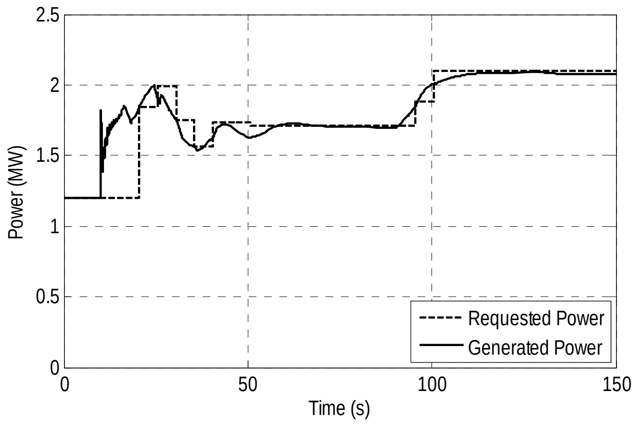


Figure 17: Output power of the CHP unit connected to the bus NMVCHP following the CAMC set points (Scenario 3)

As it can be observed from Figure 17, the output power of the CHP unit does not exactly match the target value. This is due to the dynamic response of the proportional control system of this DG unit frequency governor (following MMG system frequency deviations). As the CHP units are equipped with this kind of speed governors, with proportional controllers, they tend to respond to frequency deviations as soon as they occur and will not wait to receive setpoints from the slower CAMC or other management units.

The response of the hydro unit connected to the bus NMVHYD following the CAMC set points is depicted on Figure 18.

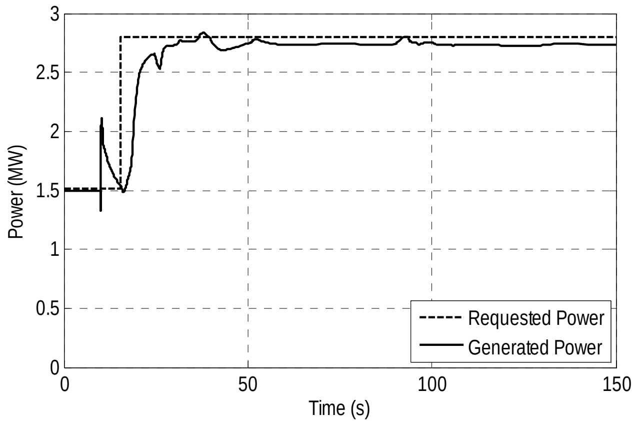


Figure 18: Output power of the hydro unit connected to the bus NMVHYD following the CAMC set points (Scenario 3)

As it was considered that the generation costs of hydro units are lower than these ones of the CHP units, the CAMC ordered to increase the output power of hydro units to its maximum value. Therefore, the CAMC did not send a new request when the MMG load is increased.

Finally, the CAMC send requests to the MGs. Figure 19 presents the output power of the MG connected to the bus NLV3 following the CAMC requests. It should be noted that the Microgrid MG1 output power concerns the total amount of active power generated by the several microsources inside the Microgrid MG1.

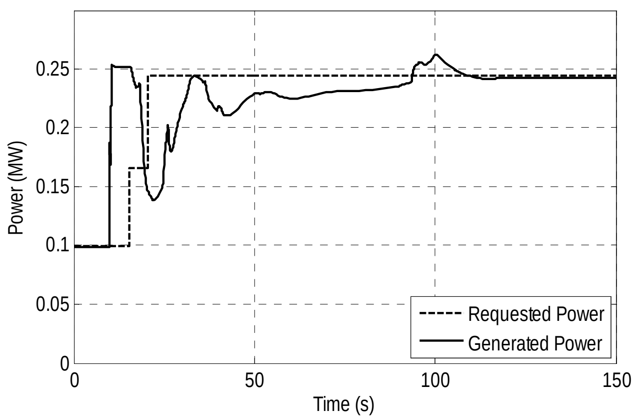


Figure 19: Output power of the MG1 connected to the bus NLV3 following the CAMC set points (Scenario 3)

As it can be observed from Figure 19, the MG1 increases its active power generation suddenly from 100 kW to 250 kW immediately after the MMG islanding and before receive the CAMC request. This is due to the MG1 main storage device connected to the LV grid through a VSI, which allows the active power injection while the system frequency deviates from its nominal value. In this case, the MG1 main storage device injects its rated power during some seconds, since the MMG system frequency drops considerably.

As it was assumed that the fuel cells and microturbines are controllable microsources, they are responsible to increase the MG1 output power following the CAMC request. In this context, the MGCC ordered both microturbine and fuel cell to increase their power generation also based on economical criteria. Figure 20 presents the microturbine output power following the MGCC set points.

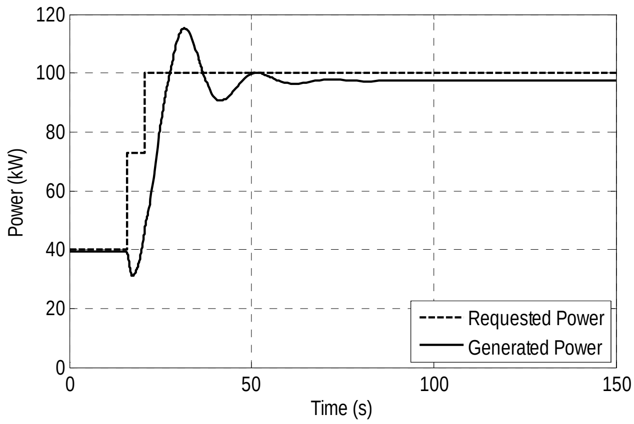


Figure 20: Output power of the microturbine of the MG1 following the MGCC set points (Scenario 3)

As it can be observed from Figure 20, the microturbine presents a fast response to the received set points.

As the power generation from fuel cells was considered more expensive, the MGCC sent a set point first to the microturbine. Since the first increase of active power was not enough to recover the MMG system frequency, as depicted in Figure 16, a second request was sent to the microturbine, as it can be observed from Figure 20. This second request occurred simultaneously to the first one sent to the fuel cell, as depicted on Figure 21, since the target value of the microturbine active power output corresponds to its maximum generation capacity. Thus, in order to meet the CAMC request concerning the MG1 generation, the MGCC requires also the increase of the fuel cell active power output.

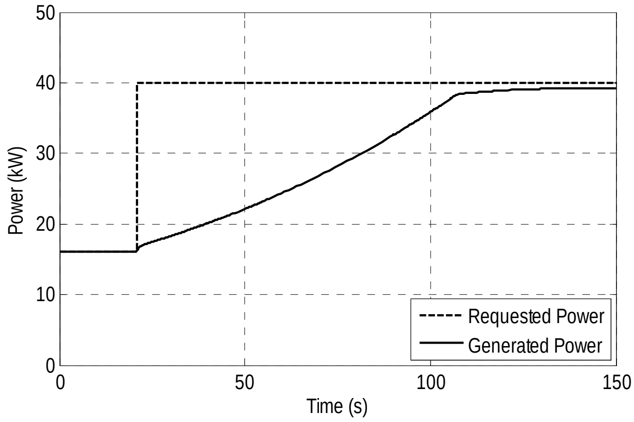


Figure 21: Output power of the fuel cell of the MG1 following the MGCC set points (Scenario 3)

As it can be observed from Figure 21, the fuel cell presents a very slow response to be helpful on the control of fast frequency variations. However, the continuous increase of the fuel cell generation can be useful to compensate the active power generated by other DG units with fast response but without economical advantages, which increase their active power output autonomously following system disturbances (MMG islanding and load increase), such as the Diesel group, as depicted on Figure 22.

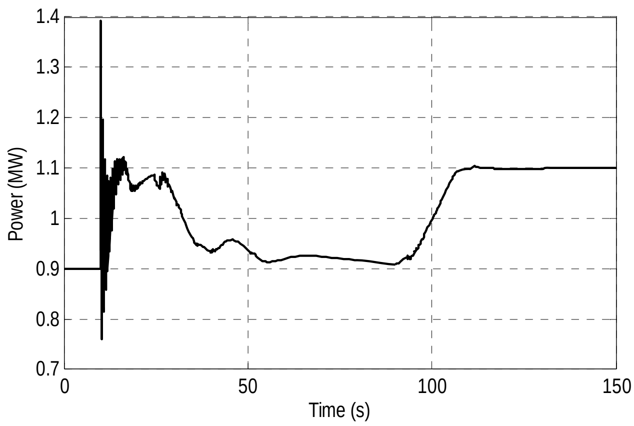


Figure 22: Active power output from the Diesel group (Scenario 3)

As it can be observed from Figure 22, between t=70 s and t=90 s, the output power of the Diesel group experiments a slowly reduction caused by the increase of the output power of all the fuel cells, since the other sources already stabilized their generated power.

5.4 Importance of Under-Frequency Load-Shedding

In this scenario the MMG is initially importing a very large amount of active power from the HV system: 6.54 MW. This situation is exceptionally hard for the generation system alone to be able to react and recover from the islanding of the MMG. As can be seen from the dashed line on Figure 23, without any help from the load-shedding system, the frequency would soon drop below 47 Hz, point where several of the synchronous machines would trip and trigger the grid collapse.

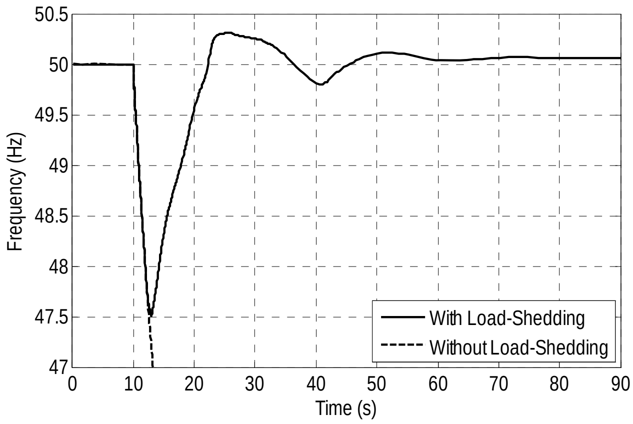


Figure 23: Frequency variation with and without load-shedding.

However, when load-shedding is enabled with the settings shown in Table 10 the frequency manages to recover back to the rated value, as shown by the solid line on Figure 23. The load-shedding is enabled on loads in nodes NLV1, NLV6, NLV7, NLV2, NLV2A, NLV7A, NLV16A and NLV13A.

Table 10: Load shedding frequency thresholds and coefficients

Power Shedding Coefficients	Load Shedding Frequency Thresholds (Hz)
25%	48.0
25%	47.6
25%	47.4
25%	47.3

In this particular case, two load-shedding events occurred at about 12.3 and 13 s (of approx. 1.67 MW each) which were of great help to keep the system under control. Figure 24 shows the total load available to load-shedding, the slight load reduction due to the voltage drop that follows the islanding operation and then the two load-shedding steps.

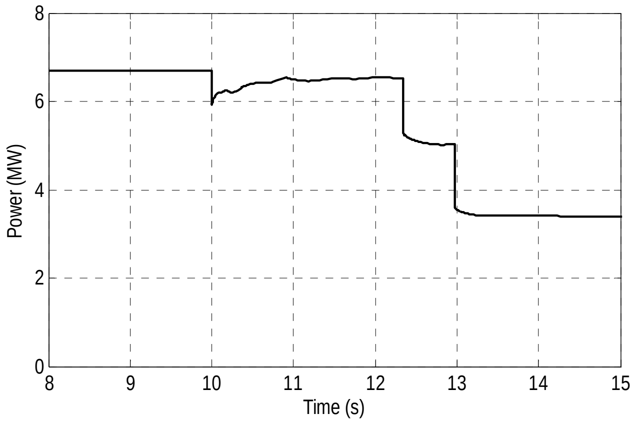


Figure 24: Total load available to load-shedding and actual shedding steps.

Although the hierarchical control system is rather slow to take the place of the load-shedding and guarantee the survival of the system, it still takes control of the system afterwards, as soon as it can, in order to ensure the secondary frequency control inside the MMG.

6. Multi-MicroGrids Black-Start

A Black-Start (BS) procedure is commonly defined as a sequence of actions to be carried out in order to provide system restoration after a general blackout occurs.

The service restoration of any power system is a very complicated procedure. The related restoration tasks are usually carried out manually, according to predefined guidelines and they have to be completed fast, in a minimum amount of time, under extreme stressed conditions. Since the power system is a dynamic system and the restoration procedure is carried out in a real time, it can be subjected to unforeseen disturbances which may put in cause the predefined guidelines. Therefore, a decision support tool would be a valuable resource to help power system operators during the system restoration procedure [7].

In what concerns to MMG, it is expected that the system restoration procedure would be simpler. Although the system complexity, it will be possible to fully automate the entire restoration procedure, which exploits the MMG hierarchical control and management systems presented previously, in section 4, and makes use of the MMG communication infrastructures.

Under this context, the CAMC plays a key role, being the main responsible to run specific network functionalities concerning the MMG black-start after a general system blackout. The BS software module to be implemented on the CAMC is responsible for controlling a set of rules and conditions to be checked during the restoration procedure, which should be identified in advance. These rules and conditions define a sequence of control actions to be carried during the MMG restoration procedure.

This section tackles the identification of special issues for fully automate the MMG service restoration procedure. Thus, section 6.1 provides a general overview of service restoration and, in section 6.2, the more specific issues related with MMG black-start are addressed. The results obtained through numerical simulations are presented and commented on section 6.3.

6.1 General overview of service restoration

Although power systems are designed to prevent a total system collapse, the operation of bulk power systems close to their technical limits and the uncertainty arising from liberalization is contributing to increase the risk of major blackouts. Following a general blackout, the system normal operation has to be restored as soon as possible, being the main objective the maximization of restored loads within the minimum elapsed time, satisfying also the required security and operating conditions.

Power system conventional restoration procedures are usually developed before any major disturbance occurs based on results obtained from different numerical simulations. In addition heuristic approaches, which reflect human operators' experience to deal with the problem, are adopted. Furthermore, the size and specific characteristics of each power system precludes the definition of a universal methodology [8]. Therefore, restoration plans are usually defined step by step, based on predefined guidelines and operating procedures, exploiting sometimes decision support tools to assist system operators [9, 10].

Network restoration procedures are focused on the plant preparation for restart, network energization and system rebuilding. However, depending on system characteristics, the restoration procedure must follow either a strategy of energizing the network, creating thus the global system skeleton, before synchronizing most of the generators and load pick-up or a strategy of restoring islands first [11]. In this case, when at least two islands are restored, they are usually synchronized in order to form a new one and so forth, being the load picked-up for the whole system.

Two common characteristics of both strategies are the choice of the initial power source – BS unit – and the power system control during the restoration procedure. BS units are usually gas or hydraulic turbines because of their ability to start up autonomously and to be coupled on the network in a short time. Concerning the control during the restoration procedure, it is usually divided into two global stages:

- The production restarting and network integration, wherein the main control concerns are about unit restart, voltage profile, switching operations and prime movers response to a sudden load pickup;

- The stage of load supply, where more attention is paid to the real and reactive power balance, overloads and load uncertainty.

However the voltages must be kept within acceptable limits during the load supply stage and the power balance must be respected during the first restoration stage.

Although DG has been increasing significantly in recent years, there is a little work on the identification of its contribution for power systems restoration. The general policy for integration of DG in electrical power systems is based on the principle that DG should not jeopardize the power system to which it is connected and it should be quickly disconnected following any disturbance. Additionally, it is only reconnected when distribution circuits are energized and present stable values of both voltage and frequency.

It would be possible to develop a network restoration strategy that will run simultaneously in both the transmission and distribution systems. Such a strategy will exploit the conventional power system restoration strategy in the upstream transmission level, while the energization of some islands by means of DG units will allow expanding service restoration at the downstream distribution level based on the availability of DG units with BS capability. The coordination between the upstream and downstream restoration will allow an increase in reliability, increasing the amount of restored load and shortening the electrical power restoration times [12, 13]. The entire power system restoration procedure can then exploit a simultaneous bidirectional approach: a conventional top-down philosophy, starting from large plants restart and transmission energization and simultaneously a bottom-up strategy, starting from the distribution side and exploiting DG units and microgeneration capabilities. Synchronization of these areas follows afterwards. MMG black-start will contribute to improve the entire power system restoration procedure exploiting a simultaneously bidirectional approach.

6.2 Service restoration in MMG

The MMG restoration procedure will be triggered if a general or local blackout occurs or if major injuries affecting the HV upstream system do not allow feeding the MMG from the HV side after a pre-defined time interval. The CAMC should also receive information from the DMS about the service restoration status at the HV level in order to help deciding to launch the MMG black-start procedure.

As already mentioned previously, for MMG service restoration purposes the hierarchical control system of the MMG is exploited, which involves mainly the CAMC, the MGCC of each MG and the controllers of DG units connected to the MV network. The CAMC will guide the MMG service restoration based on information about the last MMG load scenario, which is stored in a data base, and on the set of rules identified in advance and embedded into the CAMC software.

Thus, MMG controllers and communication infrastructures are of utmost importance for the MMG restoration procedure success. Therefore, small auxiliary power units are required to power the communication network elements and controllers allowing the availability of bidirectional communication between the CAMC and both the MGCC of each MG and controllers of DG units.

Another basic requirement is the availability of DG units connected to the MV network with BS capability. Its restart procedure is carried out previously to network energization, so it is not reflected on the MV network. The same happens with the several MG with BS capability.

Beyond these essential conditions, a set of general assumptions should be taken into account in order to carry out a successfully MMG black-start procedure. These main assumptions are presented on subsection 6.2.1 and the sequence of actions to be performed is presented on subsection 6.2.2.

6.2.1 General assumptions

As the CAMC will try to restore the last MMG load scenario, it is assumed that there is availability for updated information, obtained before disturbance, about the status of load/generation in the MMG and about availability for DG units connected to the MV network to restart. During normal operation, the CAMC periodically receives information from the controllers of Control Level 3 (according to the MMG hierarchical control system previously described) about consumption levels and power generation, storing this information in a data base. It also stores information about technical characteristics of the different DG units in operation, such as active and reactive power limits. This information should be used to restore the loads of the consumption scenario before blackout occurrence.

In addition, it is also assumed that there is availability for preparing the network for energization. For this purpose, after the system collapse, the following requirements should be taken into account:

- The MMG is disconnected from the upstream HV network;
- The MMG feeders are fully sectionalized;
- MG are disconnected from the MV network;
- DG units and loads are disconnected from the MV network;
- The HV/MV transformer is disconnected from the HV and MV networks;
- All the MV/LV transformers are disconnected from the MV and LV networks;
- All the reactive power sources such as shunt capacitor banks are switched off.

During the MMG service restoration procedure it was assumed that all the MG inside the MMG have availability for BS (being able to create local LV islands) and the DG units connected to the MV network with BS capability are the Diesel group and the CHP units. It is also assumed that the automatic frequency control system embedded into the CAMC software is out of operation.

Concerning the MG concept [3] the reduction of LV consumers interruption time can be performed by allowing MG islanded operation, until MV network is available, and by exploiting MG generation and control capabilities to provide fast service restoration at the LV level. This first step will be afterwards followed by the MG synchronization with MV grid when it is available. Based on MG control strategies and making use of the MG communication infrastructures, special issues for MG service restoration were identified in order to totally automate the MG restoration procedure [12, 14]. Therefore, during MMG service restoration it was assumed that the MGCC of each MG is responsible for its service restoration and build-up the MG system autonomously.

6.2.2 Sequence of actions for MMG service restoration

The MMG restoration procedure is carried out with the aim of supplying the consumers as soon as possible satisfying the system operation conditions. So, after a general blackout the CAMC will perform service restoration in a MMG based on information stored in a data base about the last MMG load scenario, as described before, by performing the following sequence of actions:

1. **Disconnect all loads, sectionalize the corresponding MV/LV transformers and switch off the reactive power sources.** After a general blackout all the loads, transformers and shunt capacitor banks should be disconnected in order to avoid large frequency and voltage deviations when energizing the MV network.
2. **Sectionalizing the MMG around each MG and around each DG unit with BS capability.** These actions lead to the creation of small islands inside the MMG, since after MG black-start it is operated in islanded mode feeding some amount or its own entire load and both the Diesel group and CHP units are supplying its protected loads. These islands will be all synchronized later.
3. **Building the MV network.** The Diesel group is used to energize the initial part of the MV network, which comprises the unloaded LV/MV transformer downstream the Diesel group and some paths which allow to synchronize CHP islands (CHP units feeding its own loads) or to feed important loads. The energization of the initial part of the MV network is carried out step by step in order to avoid large voltage and frequency deviations. Thus the LV/MV transformer is energized first, some MV branches are energized afterwards and finally the MV/LV transformer is energized.
4. **Synchronization of CHP islands with the MV network.** Each one of the CHP islands can be synchronized with the MV network when the corresponding path is energized in order to strengthen the MMG system. The synchronization conditions (phase sequence, frequency and voltage differences) should be verified in order to avoid large transient currents.

5. **Connection of some amount of important load.** Connection of important loads is performed if the DG units connected to the MV network have the capability to supply these loads. The amount of power to be connected should take into account the generation capacity in order to avoid large frequency and voltage deviations during load connection.
6. **Energization of the remaining MV branches and the MV/LV transformers upstream the MG.** At this stage the CHP islands are already synchronized and the MMG is strength enough to energize the remaining branches of the MV network. However, as the MMG comprises a large number of MV/LV unloaded transformers, their energization should be carried out in several steps in order to avoid large inrush currents. Thus, the MV/LV transformers upstream the several MG are energized first in order to allow the MG synchronization with the MV network.
7. **Synchronization of MG with the MV network.** MG operated in islanded mode can then be synchronized with the MV network. For this purpose the synchronization conditions should be verified.
8. **Energization of the remaining MV/LV transformers.** In order to start restoring the load, the MV/LV unloaded transformers should be energized. They are divided into several groups which are energized in different timings in order to avoid large inrush currents. Afterwards the MV/LV transformers upstream the uncontrollable DG units are also energized.
9. **Load restoration.** At this stage the MV network is fully energized and some loads can be connected depending on the generation capacity.
10. **Connection of uncontrollable DG units connected to the MV network.** At this stage it is supposed that MMG becomes sufficiently strong to smooth voltage and frequency variations due to power fluctuations in non controllable DG units, allowing their connection to the MV network. MV paths are also created so that DG units without BS capability can absorb power from the grid in order to restart.
11. **Load increase.** In order to feed as much load as possible other loads can then be connected.
12. **Activation of the automatic frequency control.** The automatic frequency control is now activated in order to assure the MMG system frequency near its nominal value while the MMG is operated in islanded mode.

13. **MMG reconnection to the upstream HV network when it becomes available.** The synchronization conditions should be verified again, after the synchronization order is given by the CAMC. The HV/MV transformer should be previously energized from the HV side and the synchronization is performed through MV switches.

The feasibility of the proposed sequence of actions to carry out MMG service restoration is demonstrated in this section through numerical simulations. For this purpose the test system presented in section 3 is used.

According to this sequence of actions, the MMG system restoration procedure can be split into the next two main parts:

- MV network energization and synchronization of small islands;
- Load supply and integration of generation.

In what concerns the first part, the skeleton paths of the MV network are energized and DG units supplying their protected loads can be synchronized. Then, some load should be restored in order to balance generation and to stabilize voltage. In this stage the main problems to deal with concern mainly voltage profile and switching operations as a consequence of energizing unloaded MV paths and a large number of unloaded transformers.

In the second part load is restored according to generation requirements and MGs can be synchronized. Other DG units can also be connected to the MV network. Then, the main problems to deal with concern mainly active and reactive power balance, overloads and prime movers response to sudden load pick-up.

Therefore, in the following two subsections the results obtained through numerical simulations concerning each one of these parts are presented and discussed.

6.3 MV network energization and synchronization of small islands

In order to simulate the sequence of actions concerned with MV network energization and synchronization of small islands a simulation platform developed under *EMTP-RV®* environment was used. This allows analysing the fast transients that take place during the initial moments of the BS procedure. The test system implemented in this simulation platform is presented in Figure 25.

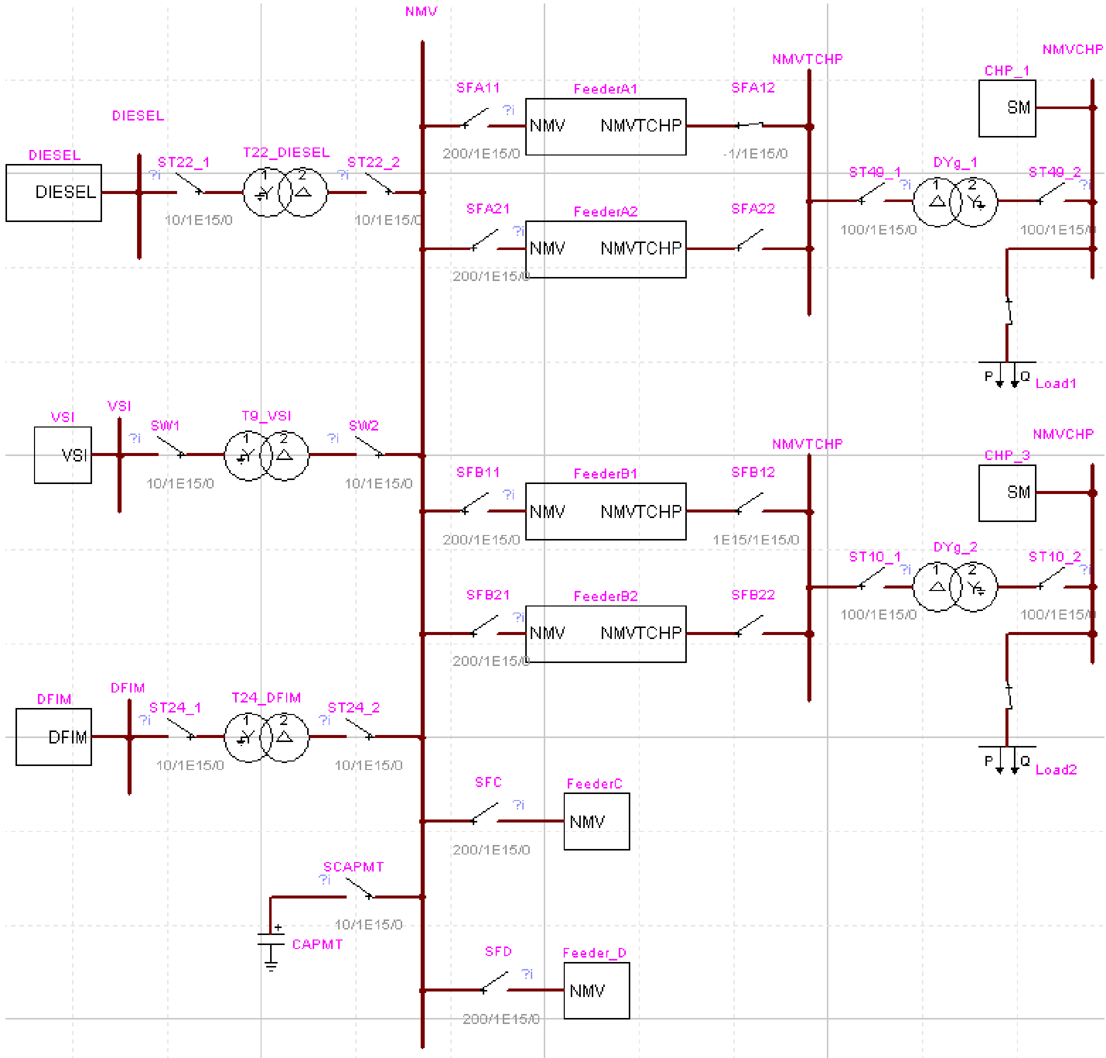


Figure 25: Test system implemented under EMTP-RV® environment

It was assumed that the Diesel group and the CHP units are already running and feeding their own loads. The Diesel group was selected to energize the initial part of the MV network in order to create paths to synchronize first the islands formed by CHP units. Then at *t*=10 s the LV/MV transformer downstream the Diesel group is energized. The FeederA1 of the test system is energized at *t*=16 s following the energization of the MV/LV transformer upstream the CHP1 unit at *t*=20s. The FeederA1 is presented in a more detailed way on Figure 26.

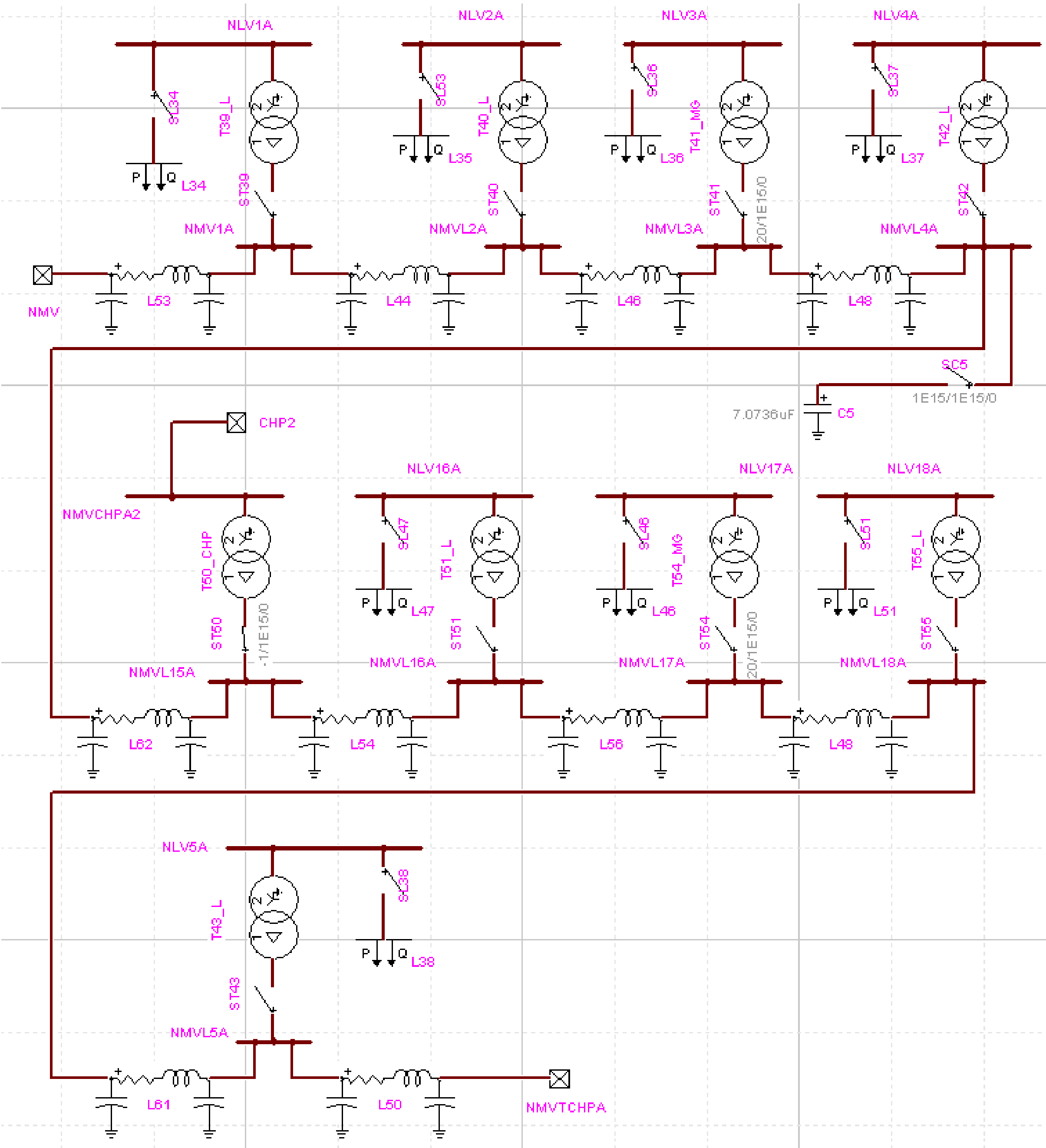


Figure 26: Detailed representation of FeederA1

The results obtained are presented on the following figures.

Figure 27 presents the rms values of voltages at several buses of the test system presented on Figure 25.

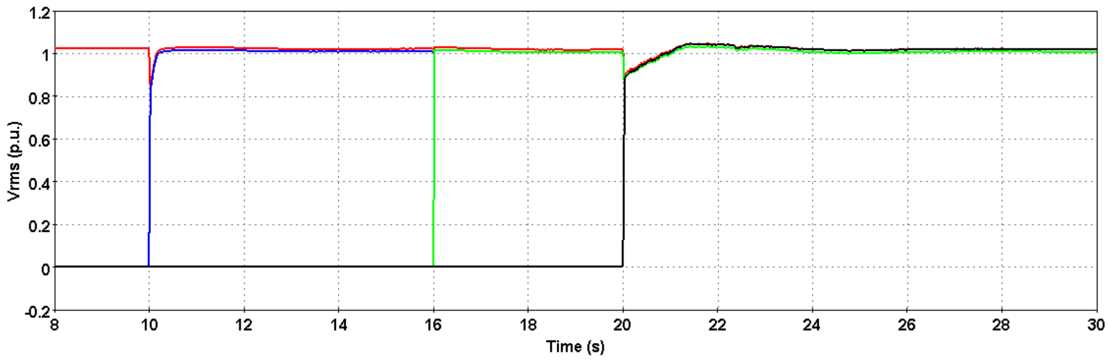


Figure 27: Buses voltages following the first steps of FeederA1 energization

As it can be observed from Figure 27, the bus voltages are kept within acceptable limits during both transformers energization and during the FeederA1 energization.

The frequency on the three islands formed by the Diesel group and by the two CHP units is presented on Figure 28.

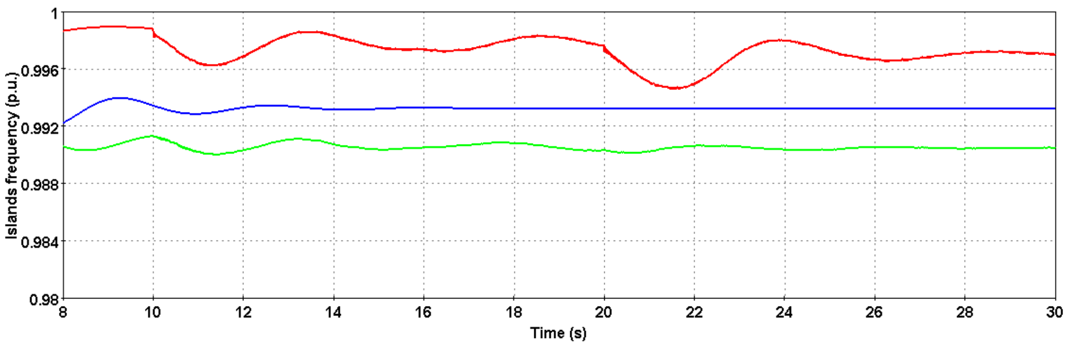


Figure 28: Islands frequency following the first steps of FeederA1 energization

The frequency variations observed from Figure 28 concerning the island formed by the Diesel group are provoked by unloaded transformers energization under the responsibility of the Diesel group. So the frequencies concerning the other two islands are kept near a constant value which depends on the supplied load.

The current supplied by the diesel group following the simulated actions is presented on Figure 29.

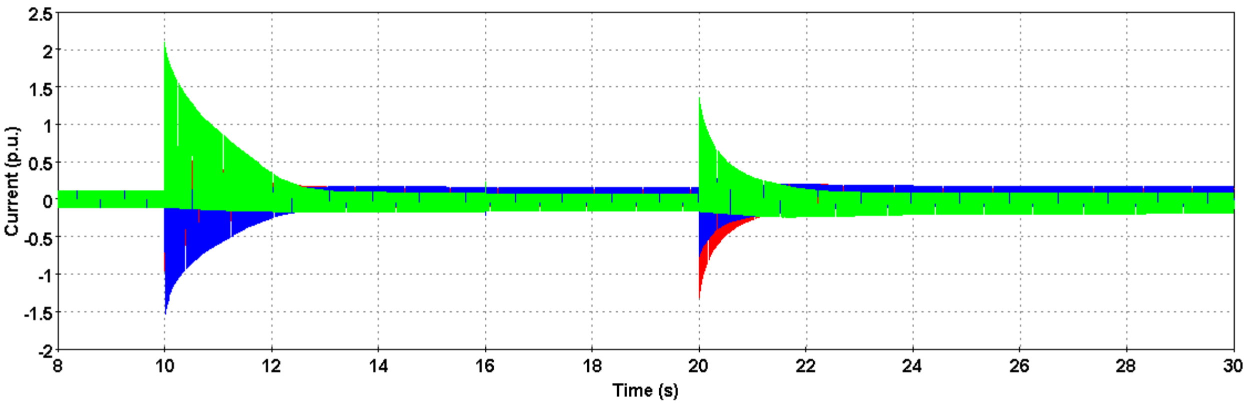


Figure 29: Current supplied by the Diesel group following the first steps of FeederA1 energization

As it can be observed from Figure 29, the energization of the unloaded transformer downstream the Diesel group requires a large inrush current.

In order to continue with the MV network energization the following sequence of actions was simulated:

- Synchronizing the CHP1 island with the MV network (*t*=11.2s);
- Synchronizing the CHP2 island with the MV network (*t*=15s);
- Energizing the MV/LV transformers upstream the MG (*t*=20s);
- Energizing the first group of MV/LV transformers upstream the loads (*t*=30s);
- Energizing the second group of MV/LV transformers upstream the loads (*t*=40s);

The results obtained are presented on the following figures.

As already mentioned previously, for simulation purposes, it was considered that both CHP units, CHP1 and CHP2, are successfully restarted, feeding their own loads with the operating frequency of each island close to the nominal value, as it can be observed from Figure 30.

The CAMC is responsible for sending the synchronization order to both the controllers of the CHP units. However, the synchronization conditions are checked locally by each DG unit controller. In this case voltage magnitudes are within acceptable limits, as it can be observed from Figure 31, so the synchronization conditions are verified in terms of the phase difference between the CHP units and MV network voltage.

In this simulation it was assumed that CHP1 units received from the CAMC the request in the first place so that it was synchronized first.

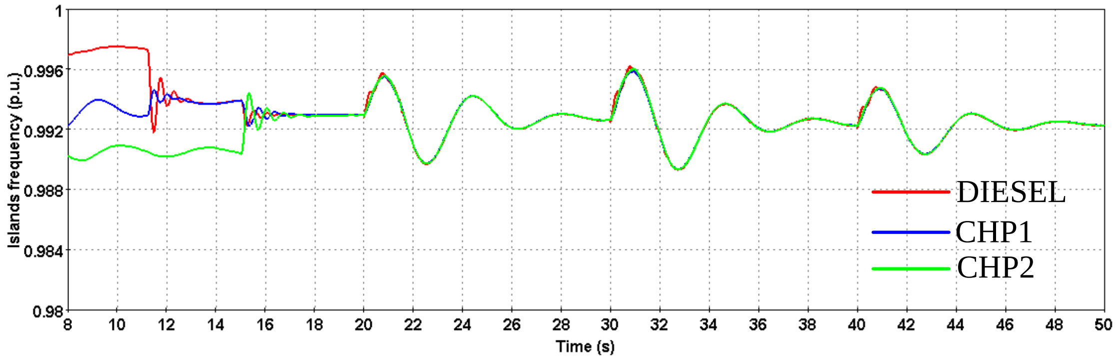


Figure 30: Islands frequency following the remaining steps of FeederA1 energization

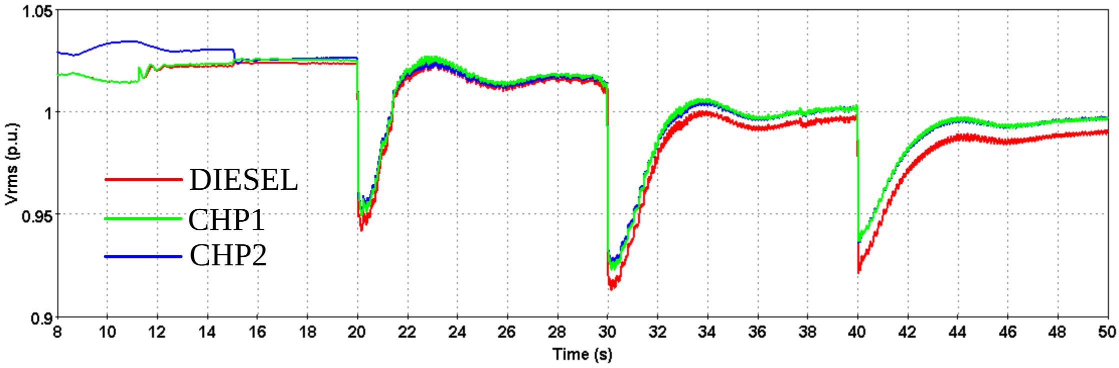


Figure 31: Terminal bus voltages of Diesel group and CHP units following the remaining steps of FeederA1 energization

The synchronization conditions concerning the CHP1 and CHP2 units are met at t=11.2 s and t=15 s, respectively. As it can be observed from Figure 30 and Figure 31, the impact on the MV network is negligible. This fact is also demonstrated through the active power exchange presented on Figure 32.

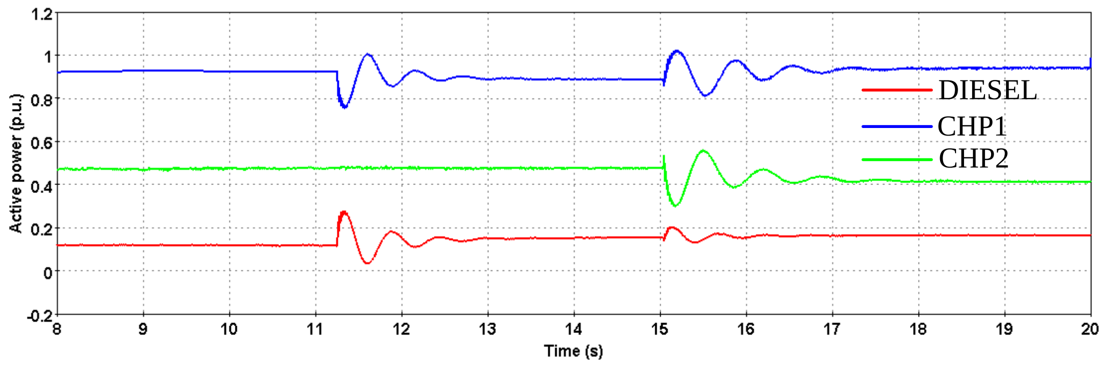


Figure 32: Active power supplied by the Diesel group and CHP units

After both islands synchronization several groups of unloaded MV/LV transformers are energized. The first group to be energized, at *t*=20 s, comprises the transformers located upstream the several MG, which are referred as T41_MG and T54_MG on Figure 26. The other two groups, energized at *t*=30 s and *t*=40 s comprise the transformers located upstream the loads. As it can be observed from Figure 30 and Figure 31, this procedure allows that the system frequency and bus voltages are kept within acceptable limits.

Figure 33 shows the voltage magnitude at the LV side of the MV/LV transformers located upstream the MG as well as voltages at some load buses, demonstrating that these voltage values are near its nominal value after energization.

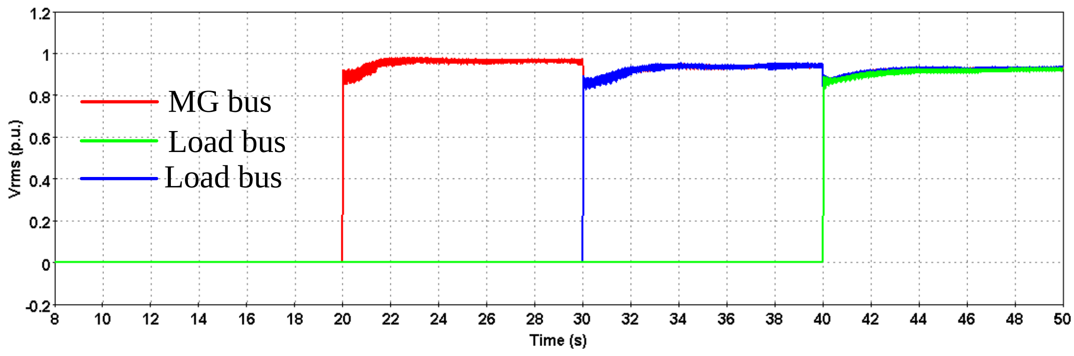


Figure 33: Voltage at the LV side of transformers located upstream the MG and loads

The current supplied by the Diesel group, following the simulated sequence of events is depicted on Figure 34. The Diesel unit is picking up the load with some initial transients.

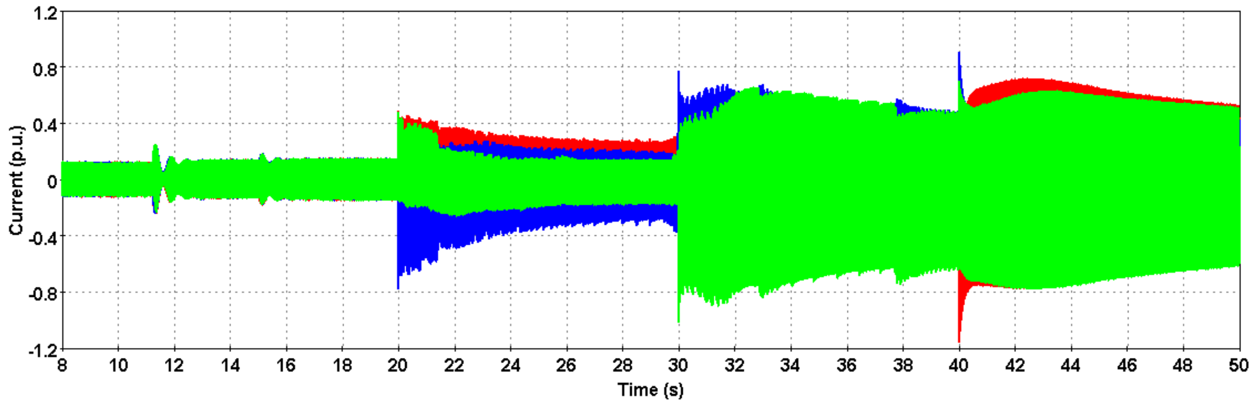


Figure 34: Current supplied by the Diesel group following the last steps of FeederA1 energization

The results obtained demonstrate the feasibility of the proposed sequence of actions for MV network energization in order to perform afterwards the entire MMG restoration procedure.

6.4 Load supply and integration of generation

Due to its duration, this part of the black start dynamic simulation in done in the *Eurostag* simulation environment and starts as close as possible from where *EMTP* left off. The MMG is thus considered to be almost completely energized and this starting point. This is also somewhat enforced by the fact that *Eurostag*, in this test network, seems incapable of dealing consistently with the frequent topology changes that arise from the multiple and sudden connection and disconnection of loads and associated transformers[1].

Each of the power production systems that have directly associated loads are considered to be generating just the necessary power to supply these loads. These power production systems include CHP units and also the Microgrids present in the test network. The net contribution of these units for the MMG is, consequently, zero. For this to be possible, each of the 13 MGs present on the MMG is considered to be able to blackstart on its own.

[1] The large amount of devices present in the test network and the complexity of their models seems to test to the limit the robustness of the numerical methods implemented in the simulation engine of *Eurostag*.

6.4.1 General Planning

In order to be able to make a general plan of the procedure to follow during the blackstart sequence, it is necessary to define what will be the target to reach. Therefore, it was decided that all the loads in the MMG should be properly supplied as in the data set shown in [3] which was also used as a base data set for the islanding scenario in section 5.3. In this scenario the load level is quite high, but the MMG has already shown to be able to ensure the transition to isolated mode of operation.

Starting from the mentioned initial conditions, the chosen sequence tried to limit the frequency excursions in the MMG, while still making available enough power to supply the loads that are going to be connected in the following instants. It is of great importance to make available as much of the power generating facilities as possible. As the mini-hydro generators are still disconnected from the MV network, these are on the top of the priority list. The asynchronous machines are first accelerated to nearly the synchronous speed and only then are connected to the grid, in order to minimize the initial adverse transients. The same procedure is followed for the three generators of this kind present on the test network and is done at different times with the purpose of minimizing the impact on the network and also to improve the visibility of each of the events on the behaviour of the system.

It was assumed that the secondary frequency control is not active in the MMG during all the blackstart sequence. This is to force the MMG to work in a worst case scenario and, again, to improve the visibility of the individual control actions on the figures that will be shown. The lack of secondary control makes it normal for the frequency to rapidly stabilize, but around values somewhat offset from the rated 50 Hz, depending of the volumes of load or generation just being connected or modified.

As soon as all the power production units are made available it is necessary to begin connecting chunks of load possible. The loads to be connected first will be the priority loads, followed by the smaller loads. Loads of very small size may be connected in groups, while large loads are connected individually. Even in cases where a group of small loads is going to be connected, it may be advantageous to spread the connection of the loads in this group over several seconds in order to reduce the dynamic impact on the network.

The loads that are being connected must be balanced by corresponding increases in power production. As all the power production units were already made available, all that is needed is to increase the setpoints of the power sources that allow such control. In this test network, the MV connected units which can have their setpoints significantly increased are the CHP and mini-hydro units.

The wind generators pose a different challenge. It was considered that the wind is blowing at a constant speed of 10 m/s in the areas where both wind parks of this MMG are placed (DFIM and DFIM2).

Connecting any of these wind parks all at once would not be feasible so it was decided to use the *deload* capabilities of the wind generators. These units will, therefore, initially inject a reduced power in the MMG. If the power requirements of the MMG increase, the *deload* value can be gradually changed, adjusting the production the system's actual needs.

The *deload* system is implemented exploiting the capabilities of the electronic and pitch control systems described in [15-18].

As the network load and power production levels change, the voltage values will also fluctuate. It is very important to keep these voltages inside acceptable ranges, preferably within 0.95-1.05 p.u., in steady-state. In order to ensure these values, it will be necessary to switch steps of the capacitor bank of the HV-MV substation bus. The system can also exploit the help of the wind park (DFIM) connected on this same bus, because the controller of these wind generators has a voltage control system [16] that enables them to behave in a way similar to a SVC device. The problem of voltage control deserves some more attention, so the next chapter will address this issue.

As the required target is based on the scenario defined in section 5.3, it is now necessary to increase the loads of the 13 MGs from 100 kW to 150 kW. The original load is 150 kW, but before starting the blackstart sequence it was changed (through load-shedding) to 100 kW so that it could be supplied by MG generation. With the MGs connected to the MMG, their loads can be increased since they can be fully supplied by the DG units connected to the MV grid.

At this point, the MMG is again with all the loads fully supplied and working in islanded mode, but the secondary frequency control is still disabled. The frequency will stabilize at a value ideally near the rated value, but to be able to consistently approach this value and follow it in case of load changes it is necessary to activate the hierarchical control system [3].

The hierarchical control system was kept disabled during the blackstart sequence to avoid undesirable interactions (and also to avoid masking the individual blackstart actions). Now this control system can be enabled in order to bring the frequency as close as possible to the nominal value and to increase the system's robustness.

In this test network there are several storage devices which are interfaced with the LV or MV network using VSI systems. These devices are programmed to injected power to the grid whenever the frequency deviates from the rated value more than a predefined threshold, according to the output of a proportional controller [19]. The VSIs are located on each of the 13 Microgrids (small 150 kW units) and on the HV-MV substation bus (one large 1 MW unit) and their help can be quite important to limit the frequency transients that occur during the blackstart sequence.

6.4.2 Voltage Control

Keeping voltage levels in an adequate range throughout a network like this can pose some challenges. This network has a not very large voltage regulating capability because the small number of conventional generation units (which have standard voltage regulator systems) cannot provide sufficient reactive power to supply all the test network loads.

Therefore, the steady increase of the load level during the blackout sequence must be accompanied with a corresponding increase of the production of reactive power originated in sources other than conventional synchronous machines. The most straightforward way is the use of capacitor banks and, as the installation of one of these banks is already planned for the HV-MV substation bus, the change of its steps is the approach of choice.

However, we have to pay some attention to the voltage transients that may occur when the capacitor bank steps are switched. If these voltage transients are of excessive amplitude or if the maximum voltage protection relays on the network are configured in a very conservative way, it is possible that some machine protections will be triggered, causing a sequence of disruptions.

As previously mentioned, also the wind parks are able to contribute with reactive power production, if necessary. In this actual example, the DFIM wind park, because it is connected directly to the HV-MV substation bus and thus have its power production more readily distributed through the entire network, is the prime candidate to have this reactive power production function enabled.

The machines in these wind parks are supposed to have capability for voltage control (see models [3, 16]) that can be turned on, enabling them to behave somewhat as SVC devices. This controller's behaviour was compared with the one of the model of the SVC supplied with *Eurostag* and was indeed found to be quite similar. As the help supplied by the DFIM wind park in this context cannot be neglected, the voltage controllers in this wind park were considered enabled.

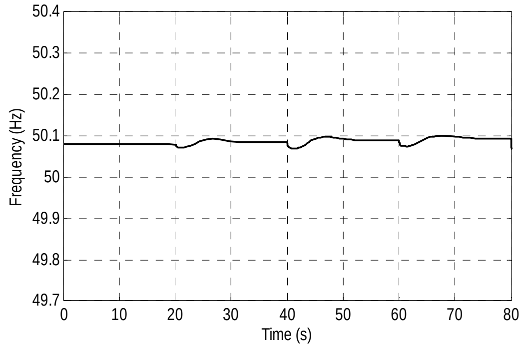
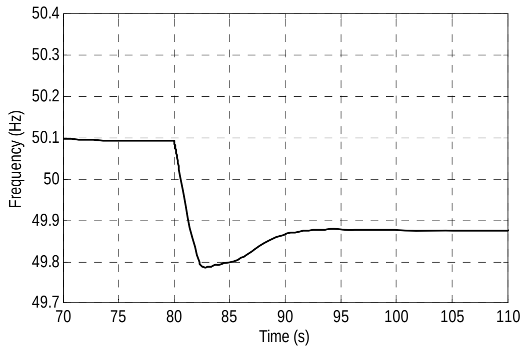
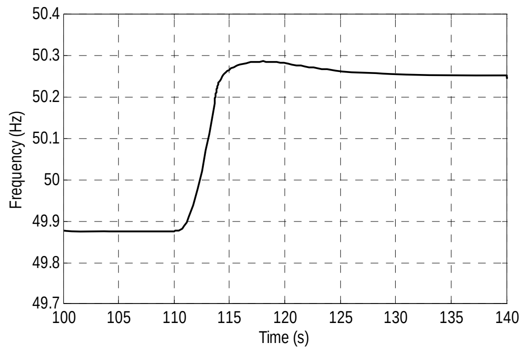
Regarding voltage problems in distribution networks with high levels of DG, another question can arise in a bit more obscure way. These networks, which are characterized by having very high resistive component to their parameters (e.g., when compared to HV networks), can cause active power flows to impact on voltage levels in a way that can severely limit power production from some units. The most affected units are those located at the weakest points of the test network, specifically the rural (radial) areas. An actual example is related to the DFIM2 wind park which, during the blackstart sequence, cannot have its output power increased as much as desirable because the voltage levels in nearby nodes would rise substantially over the 5% that was considered as the tolerance level over the steady state rated value.

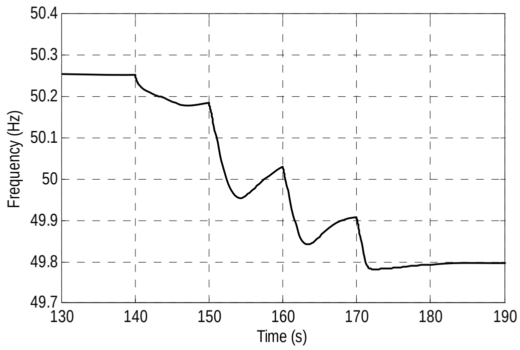
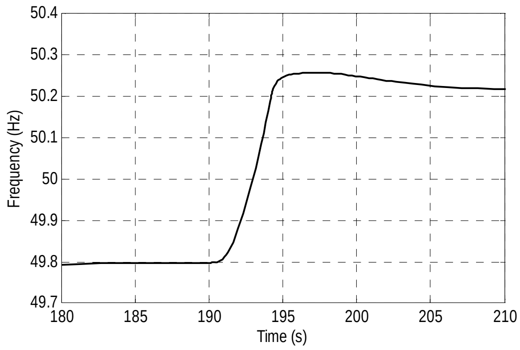
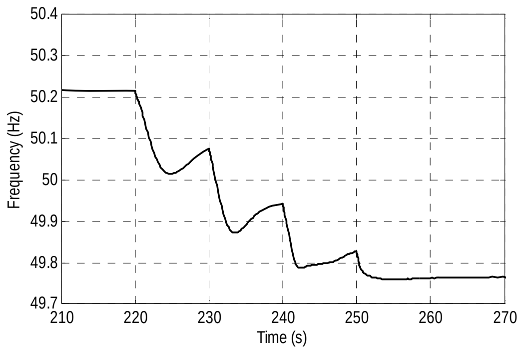
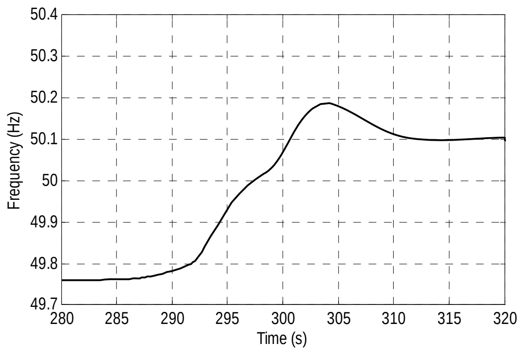
6.4.3 Control Sequence

An example of the application of the general planning considerations referred to in the previous chapter is shown below. The test network in use is the one previously mentioned with all the dynamic models earlier established.

The whole blackstart sequence is presented in a detailed way, with a particular attention to the impact on the frequency variations following each and every one of the switching or load/generation change operation. The one exception to this rule is the switching of the capacitor bank steps, due to the small effect they have on this kind of transient phenomena.

At the end of the blackstart sequence (t=900 s), with all loads connected to the MMG, the hierarchical control system is activated, enabling a kind of secondary frequency control. The frequency value recovers quite rapidly back to the rated value of 50 Hz and load changes that may occur will not cause long-term frequency deviations because the MMG load-following capabilities are already restored. It is thus possibly for the MMG to resume operation from this point in a robust way, while still in isolated mode, before being reconnected to the upstream HV grid.

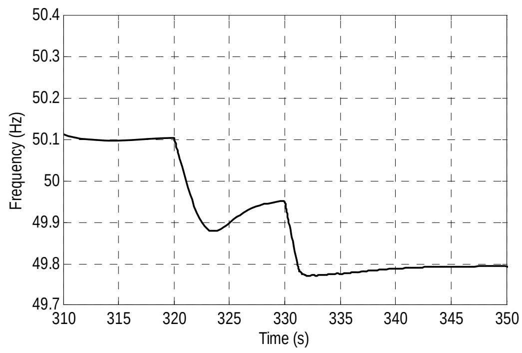
Parallel of mini-hydro generators The mini-hydro generators HYDROA2, HYDROA and HYDRO, are connected to the MV network at 20, 40 e 60 seconds into the simulation, respectively. These are asynchronous generators which are accelerated slightly above the synchronous speed before connection, in order to minimize the impact on the system.	
Connection of a group of small loads When 80 seconds into the simulation, 8 loads are connected simultaneously: NLVR4, NLVR8, NLVR10, NLVR4A, NLVR8A, NLVR10A, NLVR22A and NLVR25A. These are all alike: (0.086 MW, 0.042 MVAr). This simultaneous approach was chosen due to the loads' small size, which can be seen in the also small impact in the system frequency.	
Setpoint change of mini-hydro generator At t=110 s the power output of the HYDRO mini-hydro generator, which was nearly at zero, was increased to 50% of its rated power. The MMG now begins to get ready to sustain the next load increase operations.	

Non-simultaneous load connection Load in nodes NLV5, NLV9, NLV4 and NLV4A are connected when at 140, 150, 160 and 170 seconds into the simulation, respectively. Due to the larger size of these loads (0.419 MW, 0.138 MVAr), it was decided not to connect them all at the same time.	
Setpoint change of mini-hydro generator At t=190 s the power output of the HYDROA mini-hydro generator, which was nearly at zero, was increased to 50% of its rated power.	
Non-simultaneous load connection Loads in nodes NLV5A, NLV9A, NLV18A and NLV11A are connected when at 220, 230, 240 and 250 seconds into the simulation, respectively. Due to the larger size of these loads (0.419 MW, 0.138 MVAr), it was decided not to connect them all at the same time.	
Wind-park DFIM2 power injection start At t=280 s the DFIM2 wind park starts to inject its power production into the MMG. Although both the current network load and the current wind speed (10 m/s) allow for a larger power generation, this is limited to 50% in order to avoid an excessive voltage increase in this zone of the MMG test network.	

Loads are connected in two groups

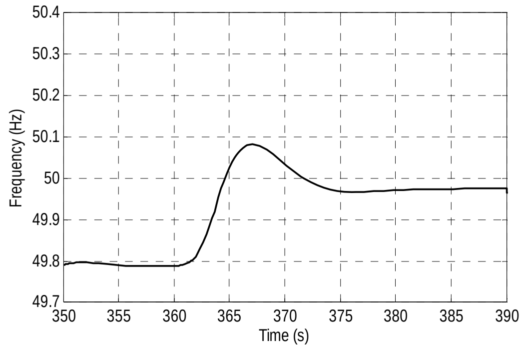
Loads in nodes NLVR1 and NLVR5 are connected at t=320 s, while loads in nodes NLVR1A, NLVR5A and NLVR17A are connected at t=330 s.

Due to the size of these loads (0.216 MW, 0.105 MVAr), it was decided not to connect them all at the same time, but it two groups.



Setpoint change of mini-hydro generator

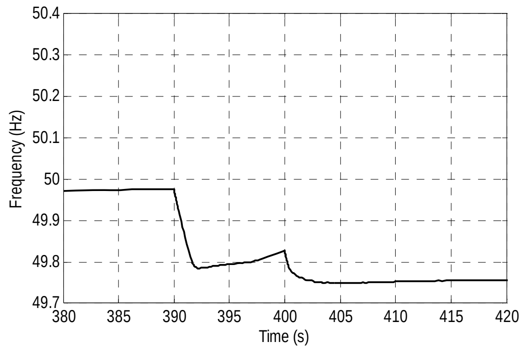
At t=360 s the power output of the HYDROA2 mini-hydro generator, which was nearly at zero, was increased to 50% of its rated power.



Loads are connected in two groups

Loads in nodes NLVR2, NLVR3, NLVR7 and NLVR9 are connected at t=390 s, while loads in nodes NLVR2A, NLVR3A, NLVR7A and NLVR9A are connected at t=400 s.

Due to the size of these loads (0.135 MW, 0.065 MVAr), it was decided not to connect them all at the same time, but it two groups.



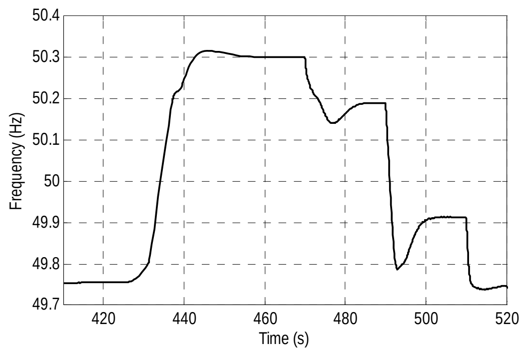
Wind-park DFIM power injection start

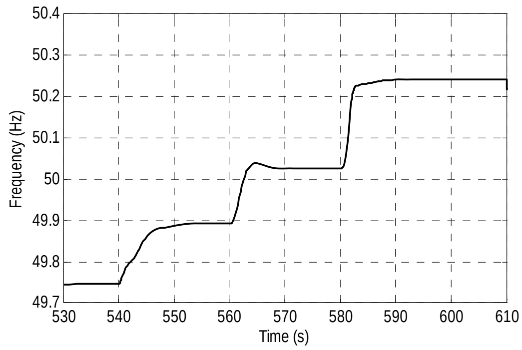
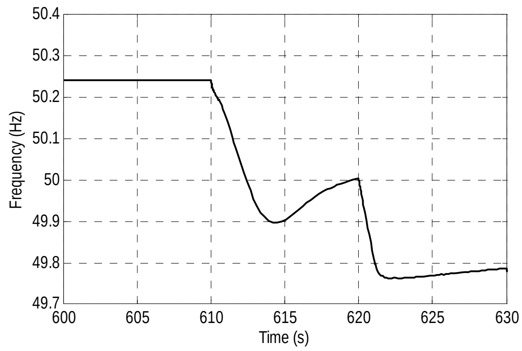
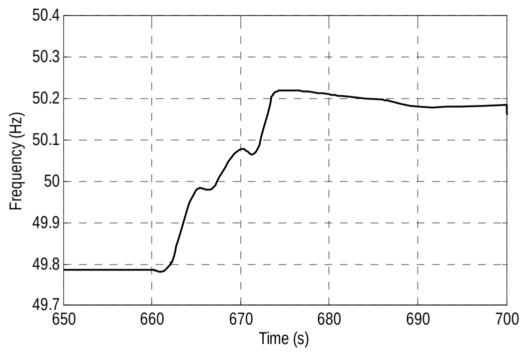
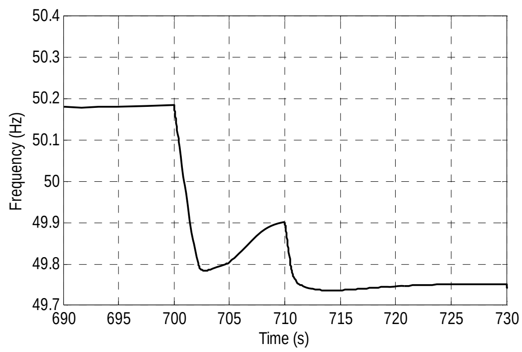
At t=420 s the DFIM wind park starts to inject its power production into the MMG. Although the current wind speed (10 m/s) allows for a larger power generation, this is for now limited to 40%.

Non-simultaneous large load connection

Loads in nodes NLV6, NLV7 and NLV1 are connected when at 470, 490 and 510 seconds into the simulation, respectively.

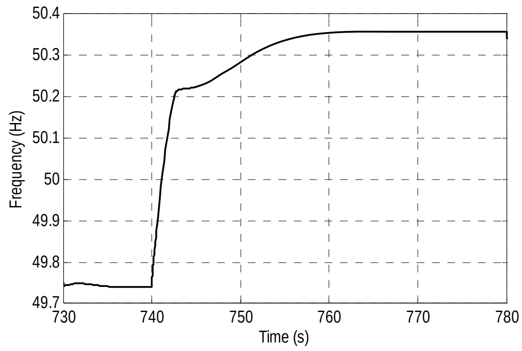
Due to the large size of these loads (0.838 MW, 0.275 MVAr), it was decided not to connect them all at the same time.



Setpoint change of CHP units When at 540, 560 and 580 seconds into the simulation, the power output of each of the mini-hydro generators (CHP, CHPA2 and CHPA, respectively) were increased one at a time to 80% of the rated power.	
Non-simultaneous large load connection Loads in nodes NLV2 and NLV1A are connected when at 610 and 620 seconds into the simulation, respectively. Due to the large size of these loads (0.838 MW, 0.275 MVAr), it was decided not to connect them all at the same time.	
Setpoint change of mini-hydro generators When at 660, 665 and 670 seconds into the simulation, the power output of each of the mini-hydro generators (HYDRO, HYDROA2 and HYDROA, respectively) were increased one at a time to 70% of the rated power.	
Non-simultaneous large load connection Loads in nodes NLV2A and NLV6A are connected when at 700 and 710 seconds into the simulation, respectively. Due to the large size of these loads (0.838 MW, 0.275 MVAr), it was decided not to connect them all at the same time.	

Setpoint change of DFIM wind park

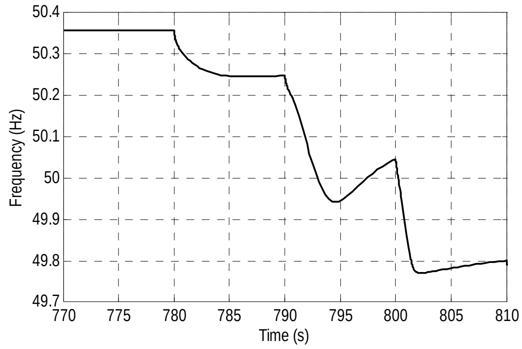
At t=740 s the power output of the DFIM wind park is increased in order to completely utilize the wind speed at the moment (10 m/s). This is done removing the *deload* restriction that was being applied.



Non-simultaneous large load connection

Loads in nodes NLV7A, NLV16A and NLV14A are connected when at 780, 790 and 800 seconds into the simulation, respectively.

Due to the large size of these loads (0.838 MW, 0.275 MVAr), it was decided not to connect them all at the same time.

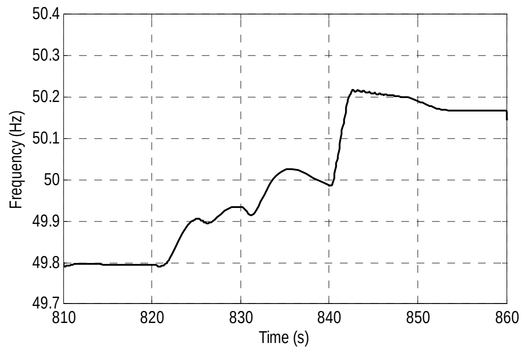


Setpoint change of mini-hydro generators

When at 820, 825 and 830 seconds into the simulation, the power output of each of the mini-hydro generators (HYDRO, HYDROA2 and HYDROA, respectively) were increased one at a time to 80% of the rated power.

Setpoint change of Diesel unit

At t=840 s the Diesel unit output power is also increased to 80% of the rated power.

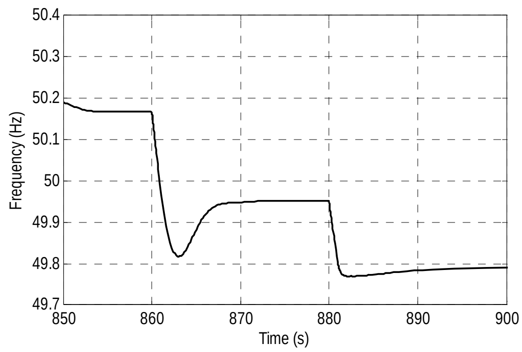


Large load connection

Although small, these increases allow for a bit more support allowing the connection of the last load at t=860 s, located at bus NLV13A (0.838 MW, 0.275 MVAr).

Microgrid load increase

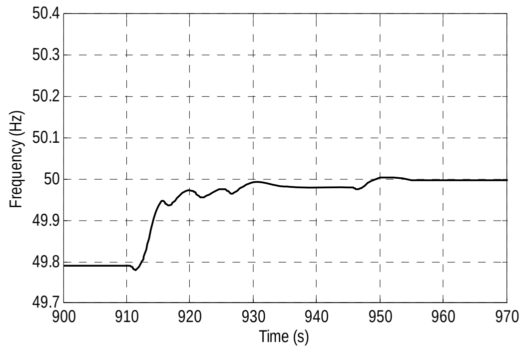
At t=880 s, the loads in all the 13 microgrids are increased by 50 kW (a total of 650 kW) all at once.



Hierarchical Control System activation

At t=900 s the Hierarchical Control System is activated and the CAMC takes charge of the secondary frequency control inside the MMG. Therefore, some adjustments are made so that the frequency can be brought as close as possible to the rated 50 Hz. These adjustments will be made upon the setpoints of the mini-hydro units as follows:

TIME	SETPOINT	UNIT
t=950.5 s	90.81%	HYDRO
t=950.5 s	90.43%	HYDROA2
t=955.5 s	95.23%	HYDRO
t=955.5 s	93.32%	HYDROA2
t=960.5 s	97.02%	HYDRO
t=960.5 s	95.78%	HYDROA2
t=965.5 s	98.48%	HYDRO
t=965.5 s	98.53%	HYDROA2
t=985.5 s	100.0%	HYDRO
t=985.5 s	100.0%	HYDROA2



The frequency variation in the Multi-Microgrid during the complete blackstart sequence can be seen in Figure 35. The maximum frequency deviations never surpass 0.5 Hz, which is a consequence of the careful choice of the steps taken throughout the full blackstart sequence.

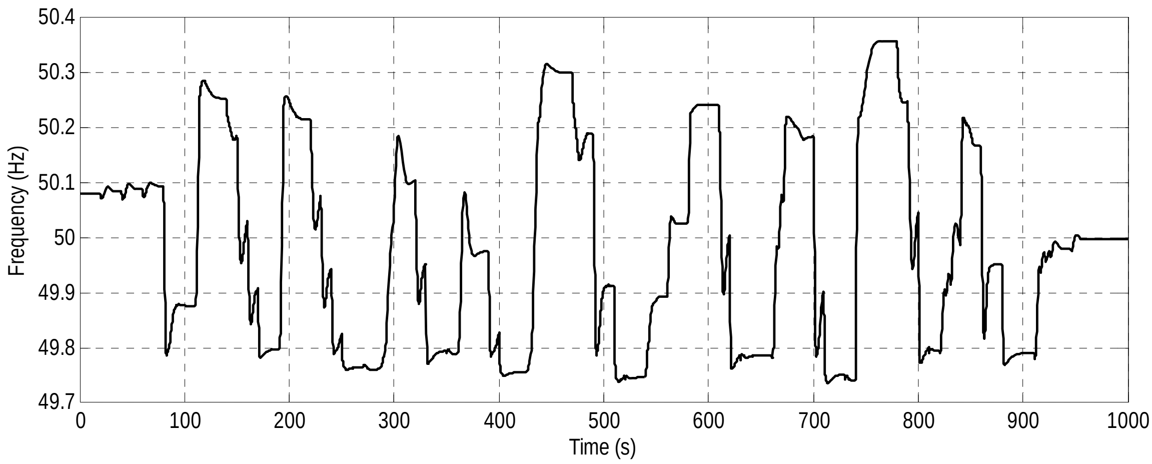


Figure 35: Frequency variation during the blackstart sequence

It can also be seen that the whole sequence could be made much shorter. In fact, much time was spent waiting for the frequency to stabilize in order to better visualize the individual contributions of the several sources and the frequency drops originated by each of the loads being connected.

Figure 36 shows how the VSI connected on the MV level contributes to frequency control. It is clearly visible the effect the threshold has on the VSI power output, because it hovers around zero for large periods of time even when the frequency is clearly far from the rated value. However, this is necessary to prevent the storage element to completely discharge or fully charge, which would stop it from carry out its job correctly. All the other 13 VSIs on the Microgrids behave in a similar way.

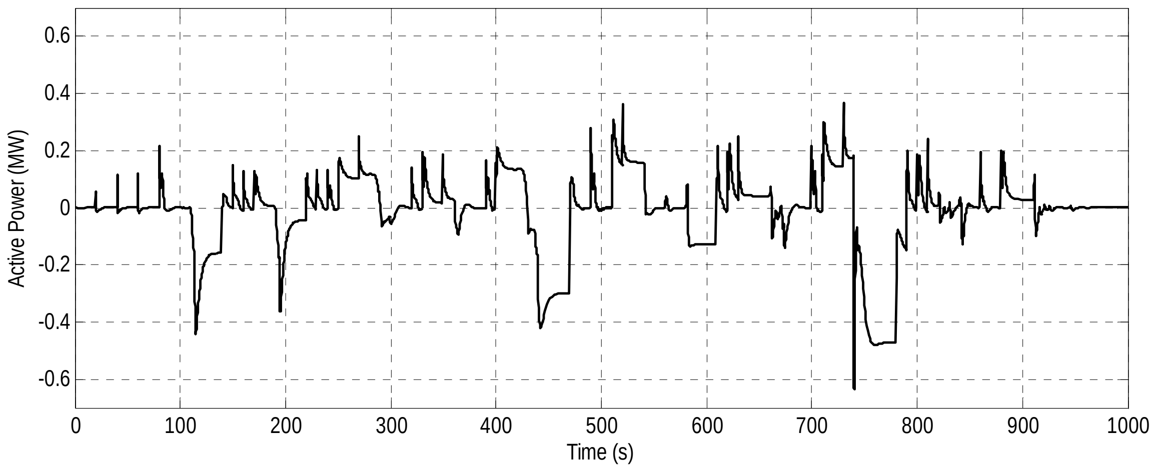


Figure 36: Contribution of the MV connected VSI for frequency control

It should perhaps be noted that the rated power of this VSI is 1 MW so from Figure 36 it can be inferred that it is capable of reacting to larger disturbances than those experienced in this example.

6.4.4 Voltage Levels

As previously mentioned in section 6.4, voltage levels can easily become problematic in distribution networks. To illustrate this statement, Figure 37 presents the voltage values in two of the network MV nodes during all the blackstart sequence.

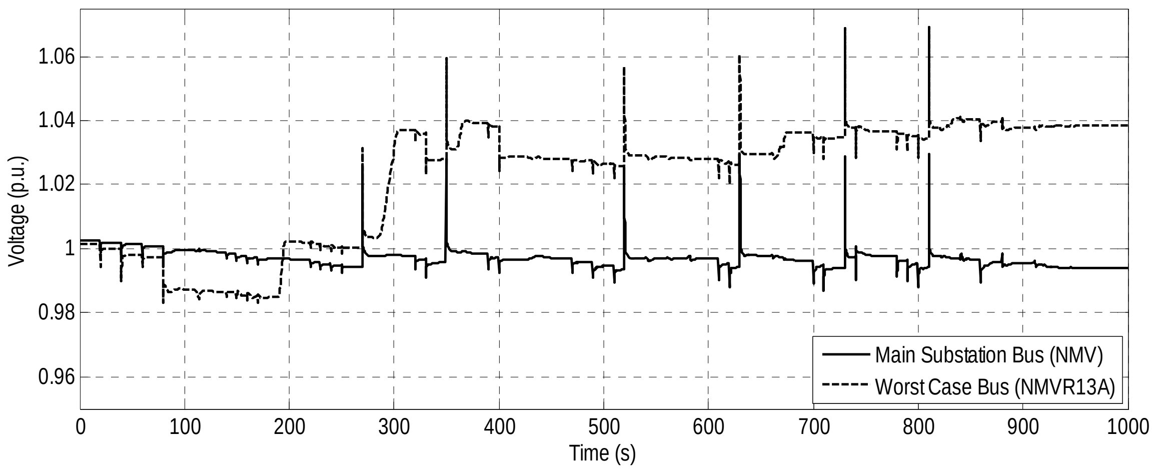


Figure 37: Voltage variation during the blackstart sequence

The NMVR13A bus is located in a weak sector of the network, near the DFIM2 wind park (3 MW). The radial nature of the network at this point clearly poses difficulties towards letting the active power flow to other areas of the network. This problem can be perceived by the sudden increase in the bus voltage of NMVR13A, which follows the increase of the production of the DFIM2 wind park, at around t=300 s.

The NMV bus is located in a strong part of the test network, where the active power has a lot of pathways and can easily reach the loads that require it. The problem here is more related to the lack of reactive power and the corresponding drop in the voltage value. This can be corrected in several already mentioned ways: standard synchronous generators with voltage regulators, capacitor banks and the DFIM wind park with activated voltage regulators.

In this case, the synchronous generators cannot take care of the problem on their own. They are completely overpowered because of their small number and must have the help of other different units. Therefore, it was necessary to use the capacitor bank connected to the HV-MV substation bus, switching its steps whenever necessary to keep the voltage as stable as possible. It is, however, necessary to be careful with the voltage transients that occur when these steps are switched on and these transients might need to be taken into account when setting network protections.

SVC devices can be of great help in this kind of application, particularly because they allow the synchronous machines to generate less reactive power. Their application in this kind of scenario can be difficult to justify. However, the DFIM wind park has in its controller the necessary capabilities to perform this kind of function.

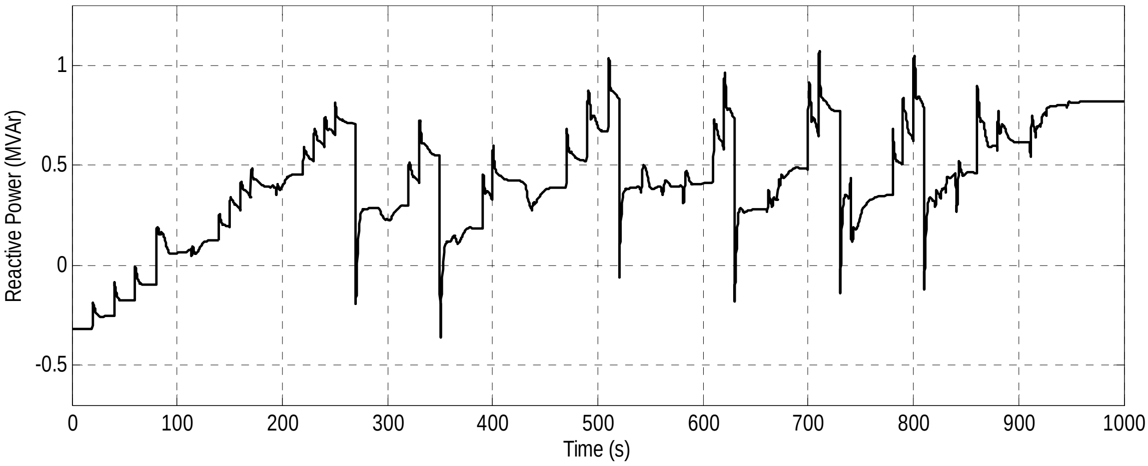


Figure 38: Contribution of the MV connected DFIM (wind park) for voltage control

Figure 38 shows the reactive power that the DFIM wind park injects on the network in order to keep the voltage on its connection node at the rated value. Taking into account that were talking about a 6 MW wind park, the contribution is not disproportionate and is sufficient to keep other HV-MV bus generators (e.g., the Diesel unit) from working excessively near their thermal limit.

7. Conclusions

The feasibility of MMG islanded operation and black-start was demonstrated provided that specific control strategies are adopted.

From the simulations performed, it was possible to conclude that the Multi-MicroGrid was able to survive the transition to islanded operation in several kinds of scenarios with increasing levels of stress.

The hierarchical control system played a key role in islanded mode, as the absence of any other kind of secondary frequency control or other controllable sources would have made it impossible for the MMG to respond to the disturbance in an adequate way.

Very large disturbances (e.g., islanding when importing extremely large amounts of power) can be overcome resorting to load-shedding schemes.

If a system disturbance provokes a general blackout at the upstream HV network, such that the MMG is not able to automatically separate and be operated in islanded mode, the results obtained demonstrate that the DG units and the existing MG can provide fast black-start functionalities in the entire MMG, which are guided by a black-start software module housed on the CAMC.

Based on the MMG control strategies and making use of the MMG communication infrastructures, a sequence of actions was identified in order to perform a fully automate MMG service restoration procedure. The black-start software module includes this sequence of control actions to be carried out during the MMG restoration procedure, which were evaluated through numerical simulations in this work, allowing the CAMC to control the entire MMG black-start procedure.

The results obtained demonstrate the feasibility of such black-start procedure. The degree of success of this procedure is very much dependent on the following issues:

- The formation of small islands contribute to reduce restoration times concerning both LV and MV loads, which is an important issue concerning system restoration, improving thus the reliability. However, these small islands will be synchronized later requiring then capability to check locally the synchronization conditions as well as the existence of synchronization devices.

- The availability of, at least, one DG unit connected with the MV network with black-start capability to be used as the grid forming unit. This DG unit plays a key role on the first stages of the MMG service restoration and should have capability to provide both voltage and frequency regulation autonomously.
- In order to avoid large inrush currents and therefore large voltage drops inside the MMG during the building MV network stage, the energization of the large amount of unloaded MV/LV transformers have to be carried out in several steps.

Regarding voltage control during blackstart in this kind of Multi-MicroGrids, it should be noted that when the electrical distance between generation and load is very large, which can happen frequently in this kind of weak distribution networks, the voltage levels near the generation sites can raise to exceptionally high values.

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Annex – Hierarchical Control Parameters

The data listed in the following tables is used in the hierarchical control system described in section 4 (mainly in the optimization process). All the results presented in section 5 were obtained using this specific set of values.

Table 11: Data for CAMC simulation

ID	Min Limit	Max Limit	Rated Power (MW)	Cost	Type
MGCC01	–	–	–	15	MGCC
MGCC02	–	–	–	15	MGCC
MGCC03	–	–	–	14	MGCC
MGCC04	–	–	–	15	MGCC
MGCC05	–	–	–	14	MGCC
MGCC06	–	–	–	14	MGCC
MGCC07	–	–	–	14	MGCC
MGCC08	–	–	–	15	MGCC
MGCC09	–	–	–	15	MGCC
MGCC10	–	–	–	15	MGCC
MGCC11	–	–	–	15	MGCC
MGCC12	–	–	–	15	MGCC
MGCC13	–	–	–	14	MGCC
HYDRO	0	1	2.8	10	DG
HYDROA	0	1	2.8	10	DG
HYDROA2	0	1	1.4	10	DG
CHP	0.1	1	2.2	20	DG
CHPA	0.1	1	2.2	25	DG
CHPA2	0.1	1	1.2	25	DG

ID	Adjustable	Minimum Variation ↑	Maximum Variation ↓
MGCC01	1	0.01	0.01
MGCC02	1	0.01	0.01
MGCC03	1	0.01	0.01
MGCC04	1	0.01	0.01
MGCC05	1	0.01	0.01
MGCC06	1	0.01	0.01
MGCC07	1	0.01	0.01
MGCC08	1	0.01	0.01
MGCC09	1	0.01	0.01
MGCC10	1	0.01	0.01
MGCC11	1	0.01	0.01
MGCC12	1	0.01	0.01
MGCC13	1	0.01	0.01
HYDRO	1	0.01	0.01
HYDROA	1	0.01	0.01
HYDROA2	1	0.01	0.01
CHP	1	0.01	0.01
CHPA	1	0.01	0.01
CHPA2	1	0.01	0.01

Table 12: Data for urban MGCC simulation

ID	Min Limit	Max Limit	Rated Power (MW)	Cost	Type
PV	–	–	10	10	DG
MTA	0.1	1	100	10	DG
VSI	–	–	150	12	DG
FC	0.1	1	40	11	DG
MTB	0.1	1	100	10	DG

ID	Adjustable	Minimum Variation ↑	Maximum Variation ↓
PV	0	0.01	0.01
MTA	1	0.01	0.01
VSI	0	0.01	0.01
FC	1	0.01	0.01
MTB	1	0.01	0.01

Table 13: Data for rural MGCC simulation (MGCCs 3, 5, 6, 7 and 13)

ID	Min Limit	Max Limit	Rated Power (MW)	Cost	Type
PV	–	–	10	10	DG
DFA	–	–	100	10	DG
VSI	–	–	150	12	DG
FC	0.1	1	40	11	DG
DFB	–	–	100	10	DG

ID	Adjustable	Minimum Variation ↑	Maximum Variation ↓
PV	0	0.01	0.01
DFA	0	0.01	0.01
VSI	0	0.01	0.01
FC	1	0.01	0.01
DFB	0	0.01	0.01

ICCS/NTUA CONTRIBUTION

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Acronyms and Abbreviations

CAMC - Central Autonomous Management Controller

DT - Decision Trees

DG - Distributed Generator

DFIM – Doubly Fed Induction Machine

GRA - Generic Restoration Actions

MG - MicroGrid

MMG - Multi-MicroGrid

OP - Operating Point

UFLS - Under Frequency Load Shedding

1. Introduction

The operating states of an Multi MicroGrid are described by Figure 1.

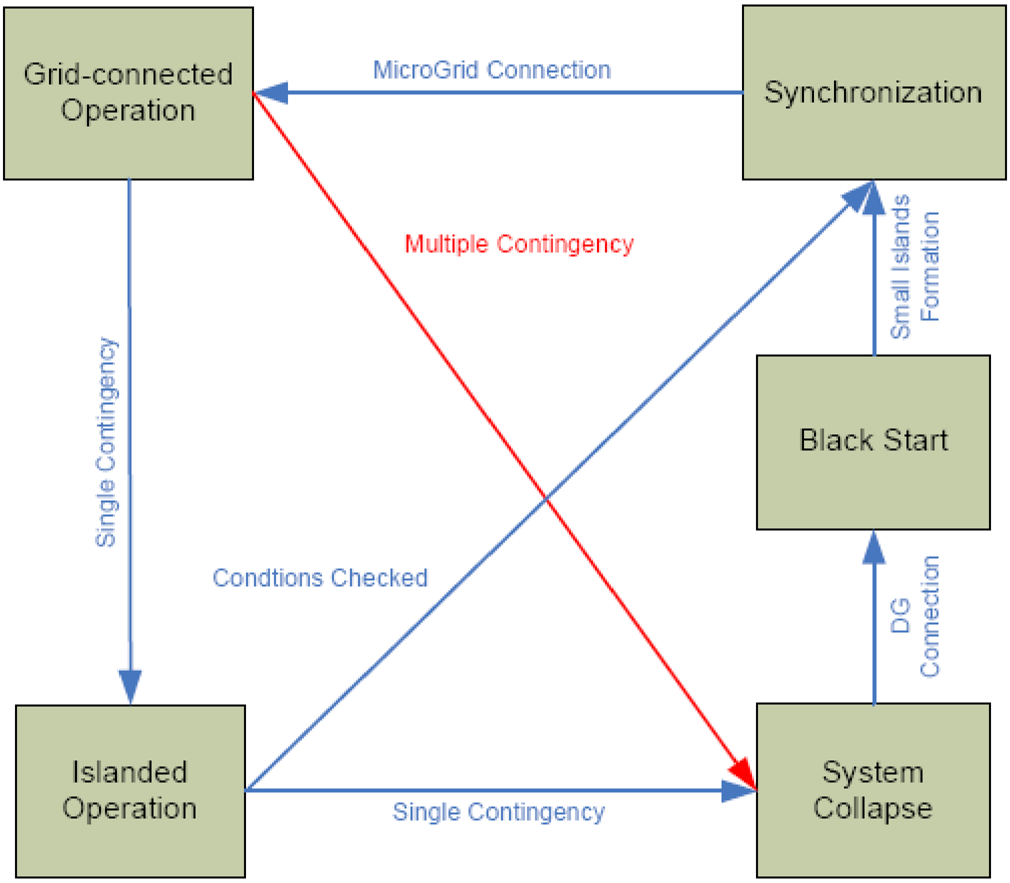

Figure 1: MMG Operating States

In grid-connected operation the MMG is electrically connected to the upstream HV network either injecting or absorbing power from it. In case there is a failure in the main network, the MMG transposes to the islanded operation. This will lead to a frequency and voltage drop or rise depending on the amount of power imported from the upstream network. Depending on the ability of MGs and DGs, to provide fast frequency and voltage control and the emergency control actions executed after islanding, the MMG will either survive the isolation or it will collapse. Control actions, like load shedding or controlled system separation are used for saving as much of the system as possible from a widespread blackout. In the black start operation, the

CAMC performs control actions in order to reconnect all the generating units and to restore the load.

The transition to islanding operation mode and the operation of the network in this mode requires that DGs participate in active power/frequency control, so that the generation can match the load. Storage devices contribute also to the frequency control during the transient period of islanding. CAMC coordinates the frequency control in a way similar to the one implemented in regular Automatic Generation Control (AGC) functionalities [1]. This way, the CAMC can respond to other disturbances, such as load loss while in islanded mode, commanding the distributed generation to change power output [2] as defined by the following equation.

$$\Delta P = \left(K_P + \frac{K_I}{s} \right) \Delta f$$

A reactive power/voltage control is also required fro voltage stability. To maintain the voltage between acceptable limits, the inverter of the DGs injects reactive power if the voltage falls below the nominal value and will absorb reactive power if the voltage rises above its nominal value.

The emergency control actions considered are:

- Under frequency load shedding (UFLS) schemes. A three steps load shedding is implemented, with each step corresponding to a certain deviation in the system's frequency. Table 1 shows the parameters of UFLS.

Table 1: Under-Frequency Load Shedding

Frequency Deviation	Load Shedding (% of total load)
49	10%
48.5	10%
48	15%

- Knowledge Base System for Emergency Control. A Knowledge Base comprising instances of MMG islanding, under various operating conditions is created and an intelligent system is constructed

- Controlled islanding of local system into separate areas with matching generation and load, where each area must have at least one controllable unit

2. Study Case Network

The network defined in [3] was used in the analysis below. Figure 2 illustrates the diagram of the MMG.

The following microgeneration sources were included in the simulation platform for each of the 13 MG:

- Photovoltaics (PV)
- Split-shaft and Single-shaft Microturbines
- Fuel cell
- Wind generator
- Storage Devices

The Distributed Generators of the MMG are:

- 1 Diesel Generator
- 1 Storage Device
- 3 CHP Units
- 3 Small Hydro Generators
- 3 Wind Parks

The models used for the above generating units are mainly based on Eurostag library and [3].

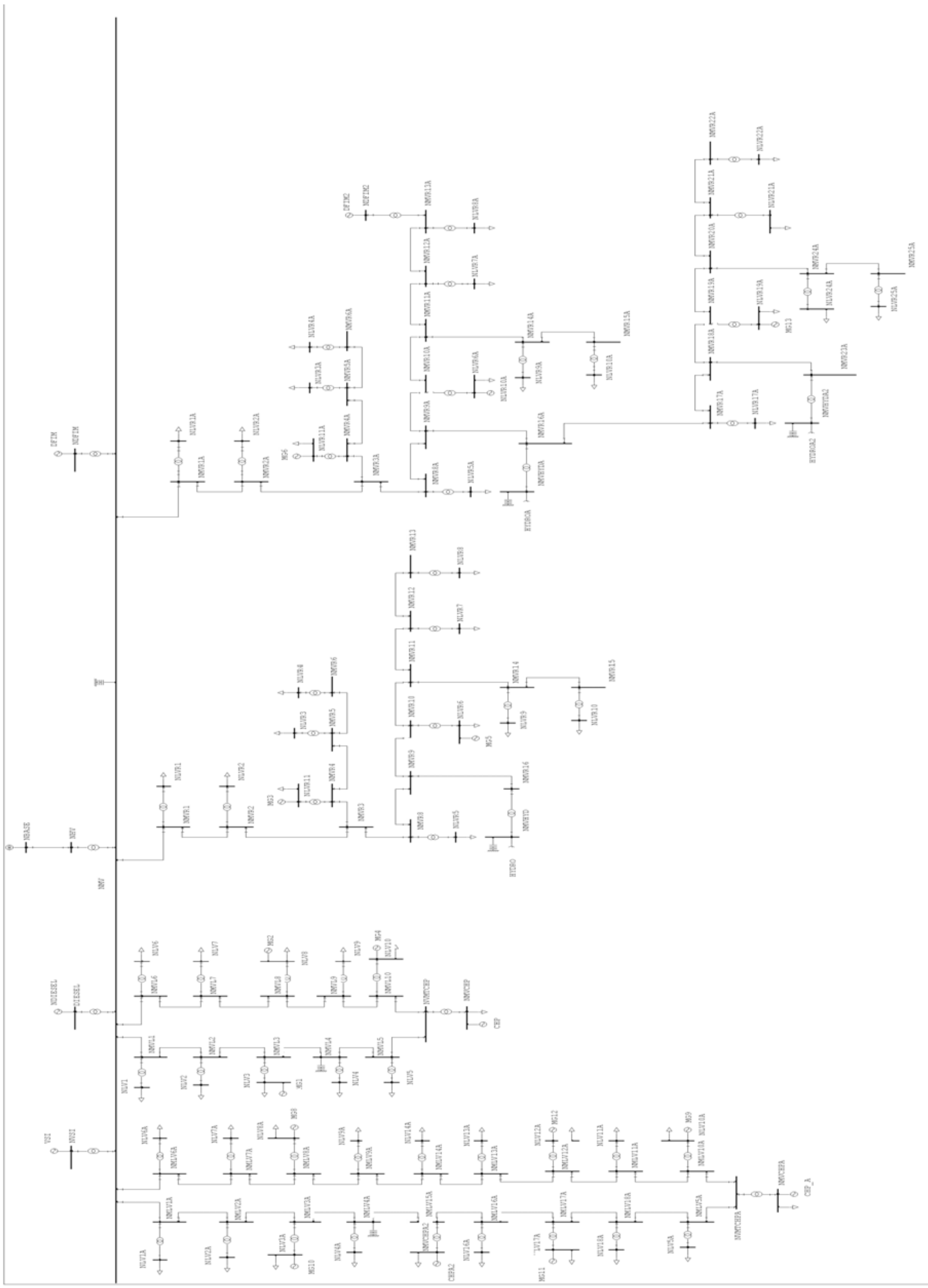

Figure 2: Multi MicroGrid Under Study

3. A Knowledge Base System for the Emergency Control of the MMG

In order to investigate the dynamic behavior of the MMG a data set comprising 6800 operating points (OPs) are created by the method of Monte-Carlo simulation. Each operating point is characterized by a vector of MGs and DGs productions. Table 2 illustrates the variables used to produce the data set and their range of values.

Table 2: Value Range of Random Variables

Variable	Value range (kW)
MG Fuel Cell	0-10
MG PV	0-40
MG MT	100
MG DFIM	100
CHP	0-2100
CHPA	0-2100
CHPA2	0-1100
HYDRO	0-1500
HYDROA	0-1500
HYDROA2	0-1500
DIESEL PRODUCTION	0-1200
Total Load	20%-120%

Load flow is performed for each OP and the islanding of the MMG is simulated using EUROSTAG. Figure 3 illustrates the histogram of absorbed active power of each MG, and Figure 4 the active power imported from the upstream network.

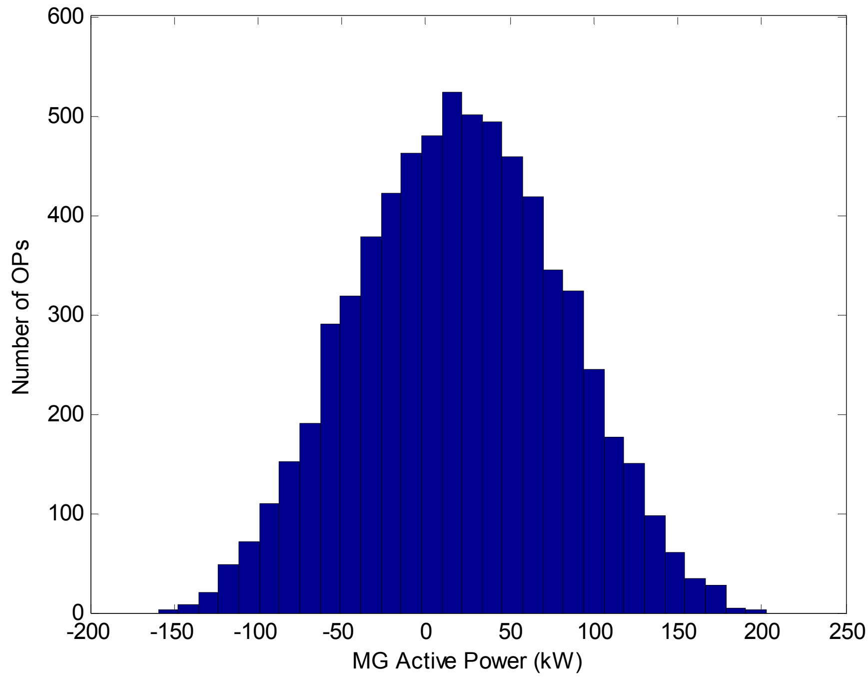

Figure 3: Active Power absorbed by each MG to the MMG

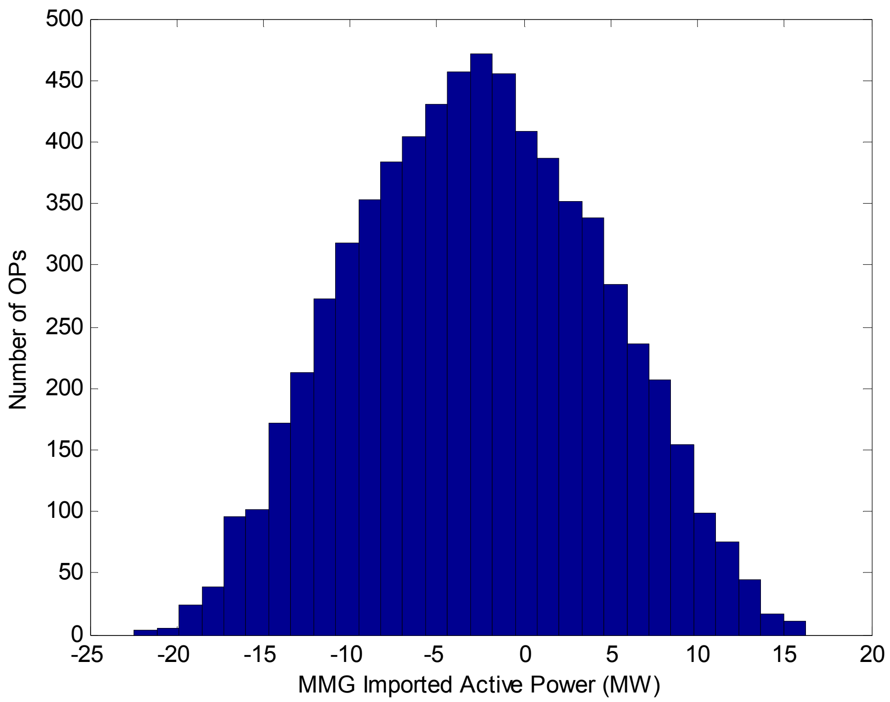

Figure 4: Active Power imported from the upstream network

The post-disturbance frequency and voltages are recorder and the operating point is classified as secure or insecure, regarding its ability to operate in islanded mode.

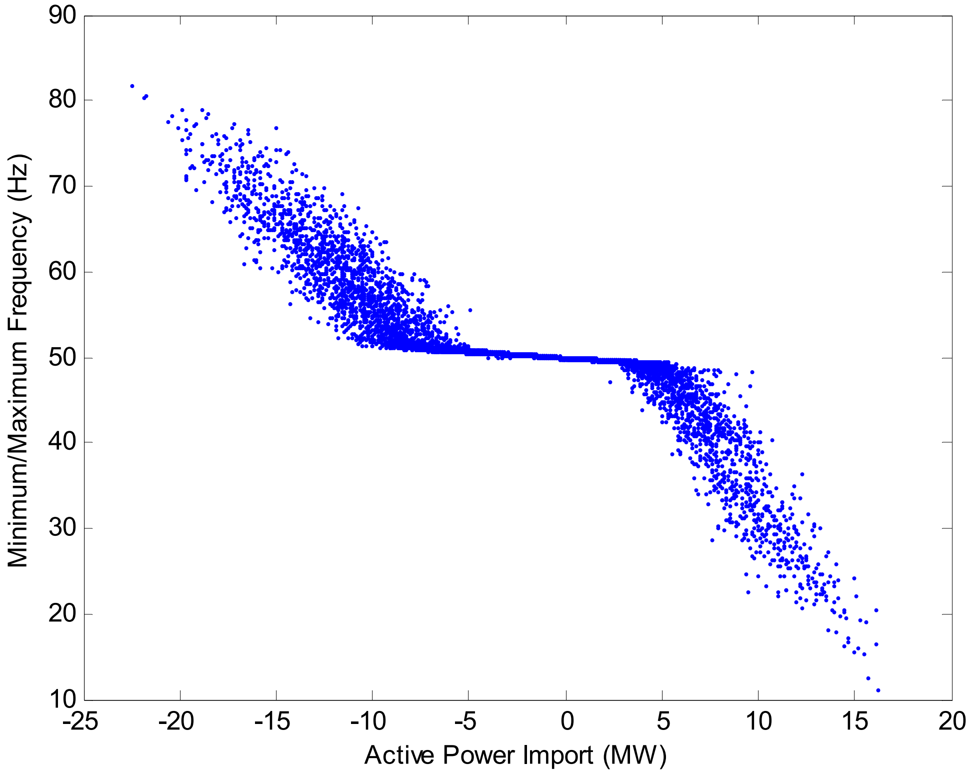

Figure 5: Post disturbance frequency with regard to active power import of the MMG

The data set is then split into a Learning Set, used to construct a classifier (here a Decision Tree) and the Test Set to evaluate its performance Table 3.

Table 3: Data Set

	Number of OPs	Secure OPs	Insecure OPs
Learning Set	3400	1736	1664
Testing Set	3400	1758	1642

A Decision Tree is constructed on the basis of the Learning Set, in order to provide rules that determine the conditions under which the MMG is able to transpose to the islanded mode.

The inputs for the construction of the DT are:

- Total Load of the MMG
- Active Power import from the upgrid (MW)
- Total Production of MGs
- Active Power import from the upgrid (MW) / Total Load
- Spinning Reserves from the DG units

Figure 6 illustrates the Decision Tree for developed. The nodes of the D.T. have the following scheme: In the upper right side is the number of OPs, which belong to the node. In the upper left side is the label of the node. In the middle is the safety index. Finally in the bottom is the dichotomy test of the node or the characterization of the node as dead-end or leaf. In case there is a separation criterion, if it is true the left path is chosen, otherwise the right one.

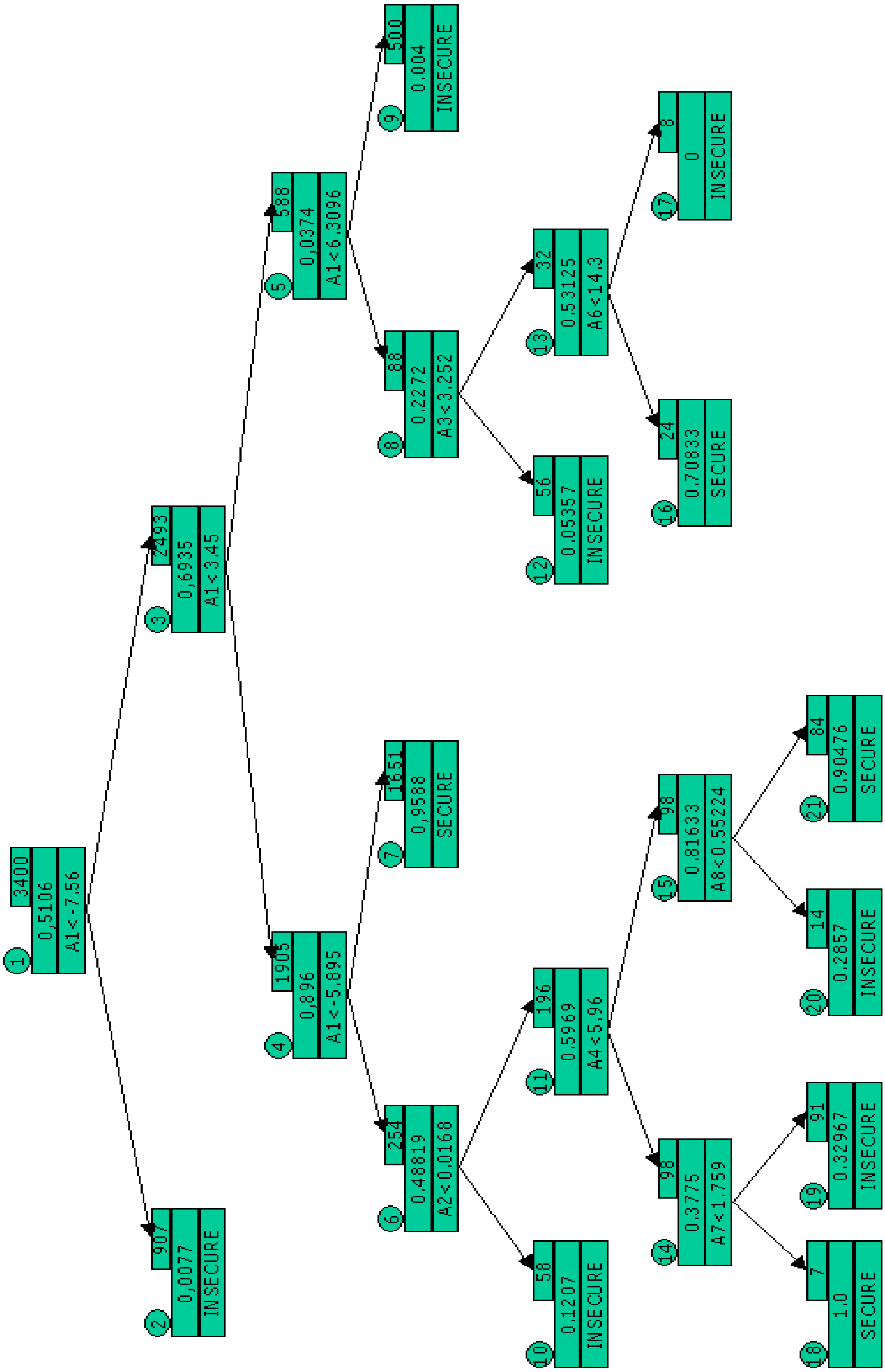

Figure 6: Decision Tree

Table 4 shows the attributes selected by the DT.

Table 4: Attributes Selected by the DT

A1	Imported Active Power
A2	Spinning Reserve of CHP unit
A3	Total Spinning Reserve of DGs and MG microsources
A4	Active production of wind parks and hydro units
A5	Spinning Reserve of DGs
A6	Total active power generation of DGs
A7	Active production of dfim
A8	Active production of chp
A9	Active production of diesel

The DT is evaluated using the Testing Set. The most important evaluator of the DT reliability and performance is the rate of successful classifications, defined as the ration of successfully classified OPs to the number of OPs tested. Two types of error, depending on the actual class of the misclassified OP are distinguished: False Alarms Rate (ratio of secure OPs misclassified by the DT as insecure to the total number of OPs in the test set) and Missed Alarms Rate (ratio of insecure OPs misclassified by the DT as secure to the total number of OPs in the test set). The performance indices of the DT are illustrated in Table 5.

Table 5: Evaluation of classification Performance

FOR TS = 3400 OPS	SECURE 1758	INSECURE 1642
Secure (1758)	1681	77
Insecure (1642)	111	1531
Performance Indices		
SR	94.47% (3212/4000)	
FA	6.31% (111/1758)	
MA	4.69% (77/1642)	

A Load or generation scheme is derived by crossing backwards the DT. A set of constraints for the secure operation of the MMG is derived by the DT.

Table 6: Security Constraint Sets extracted by the DT

Load Zone 1	
CS1 (Leaf 18)	(A7<1,759) ∩ (A4<4,96) ∩ (A2>0,0.168) ∩ (A1<-5,895) ∩ (A1>-7.56)
CS2 (Leaf 21)	(A8>0.552) ∩ (A4>4,96) ∩ (A2>0,0.168) ∩ (A1<-5,895) ∩ (A1>-7.56)
CS3 (Leaf 7)	(A1<3,65) ∩ (A1>-5,895)
CS4 (Leaf 16)	(A1>3,65) ∩ (A1<6,3) ∩ (A3>3,25) ∩ (A6<14,3)

4. Scenarios Under Study

A set of simulation scenarios, characterized by different load and generation levels was defined and simulated using Eurostag.

Initially 6 representative operating scenarios are investigated

- Scenario A: High Load
    - Scenario A1: The MMG imports power from the main grid
    - Scenario A2: The MMG export power to the main grid
- Scenario B: Mean Load
    - Scenario B1: The MMG imports power from the main grid
    - Scenario B2: The MMG export power to the main grid
- Scenario C
    - Scenario C1: The MMG imports power from the main grid
    - Scenario C2: The MMG export power to the main grid

The emergency control actions are simulated for the under study scenarios and the frequency and voltage control of the MMG during its islanded operation is also investigated. Table 7 gives detailed information of the scenarios under study.

Table 7: Operating Scenarios

Generation	SCENARIO A1	SCENARIO A2	SCENARIO B1	SCENARIO B2	SCENARIO C1	SCENARIO C2
MGs	1.60	2.44	1.56	1.30	0.78	1.56
CHPA2	0.98	0.95	1.80	0.98	0.00	0.80
CHPA	1.58	2.06	0.61	0.49	0.00	2.08
CHP	0.50	1.47	1.40	0.63	0.89	1.25
HYDRO	0.79	0.89	0.73	1.00	0.87	0.81
HYDROA	0.49	0.84	0.58	0.66	1.52	1.99
HYDROA2	0.18	0.11	0.36	7.59	0.21	1.00
dfim2	1.29	8.46	0.43	0.69	0.09	3.13
diesel	0.61	1.09	0.83	7.82	0.84	0.41
dfim	3.62	8.46	0.75	0.98	2.31	3.01
TOTAL LOAD	23.30	22.16	14.24	14.42	7.75	6.95
Losses	0.38	1.16	0.19	1.47	0.15	0.51
IMPORTS FROM UPSTREAM	12.03	-3.45	5.38	-6.25	0.39	-8.58
Decision Tree Attributes						
A1	12.03	-3.45	5.38	-6.25	0.39	-8.58
A2	1.60	0.63	0.70	1.47	1.21	0.85
A3	3.61	0.84	2.69	-2.67	5.57	2.20
A4	6.37	18.77	2.85	10.92	5.00	9.94
A6	10.05	24.34	7.49	20.84	6.73	14.48
A7	3.62	8.46	0.75	0.98	2.31	3.01
A8	0.50	1.47	1.40	0.63	0.89	1.25
DT Leaf	9	7	12	18	7	2

Simulation results concerning the MMG behaviour subsequent to islanding are presented below. The system frequency, the NMV bus voltage and the active and reactive power outputs of the DGs are illustrated in the figures below.

4.1 Scenario A1

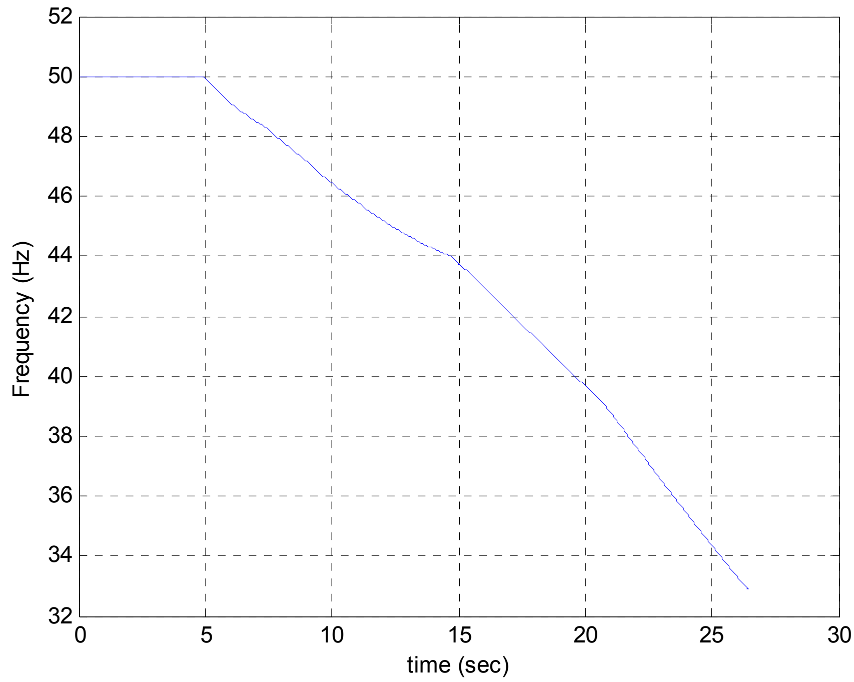

Figure 7: Frequency (Scenario A1)

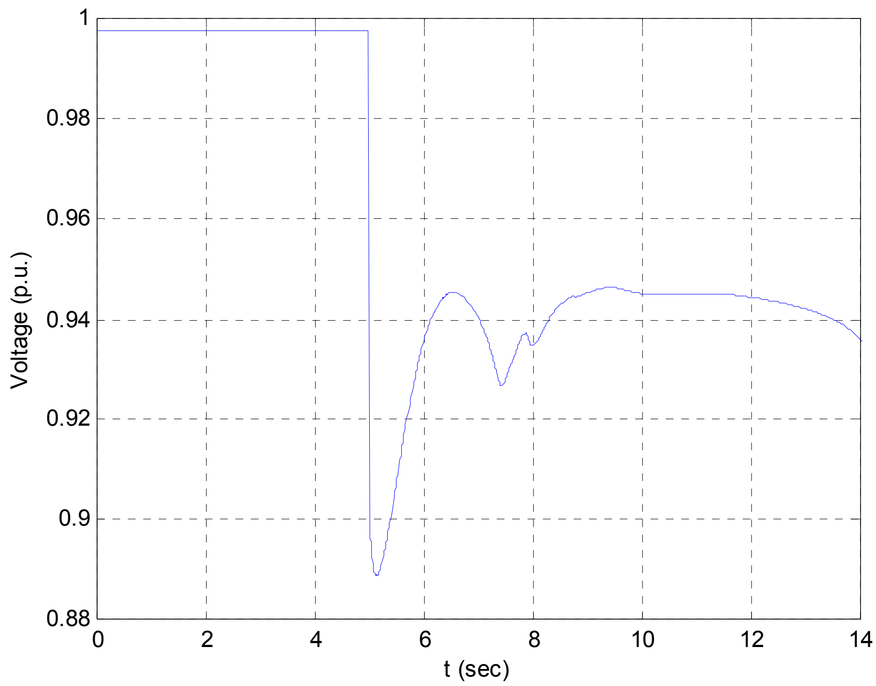

Figure 8: Voltage of NMV bus (Scenario A1)

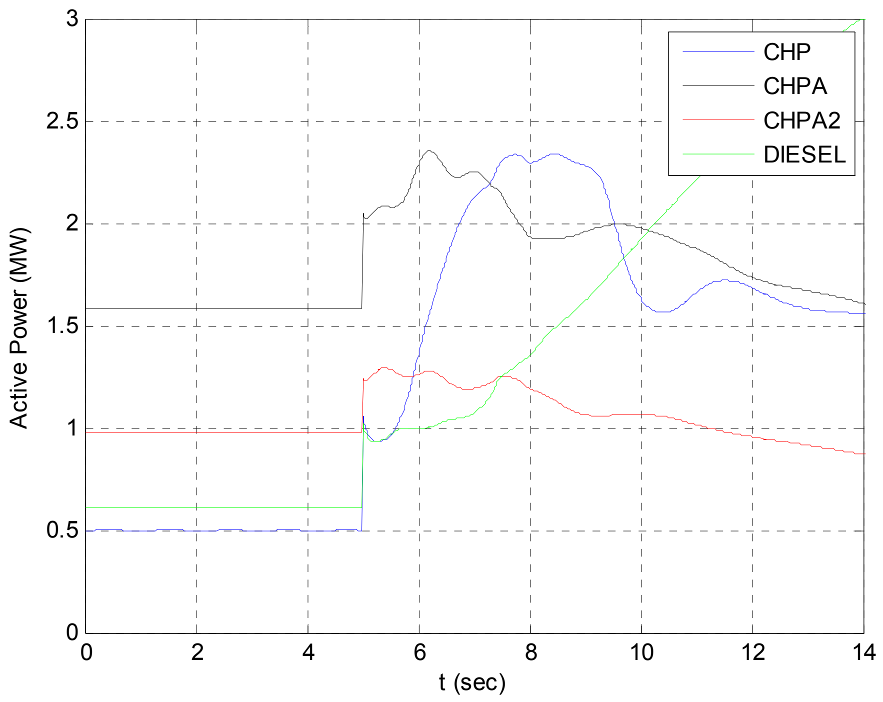

Figure 9: Active Power of Diesel and CHP units (Scenario A1)

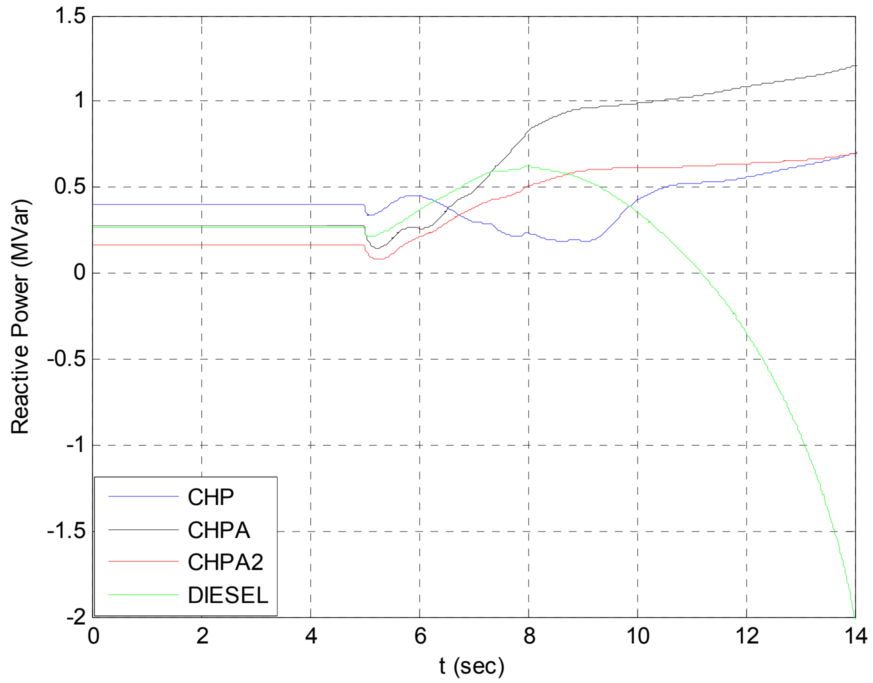

Figure 10: Reactive Power of Diesel and CHP units (Scenario A1)

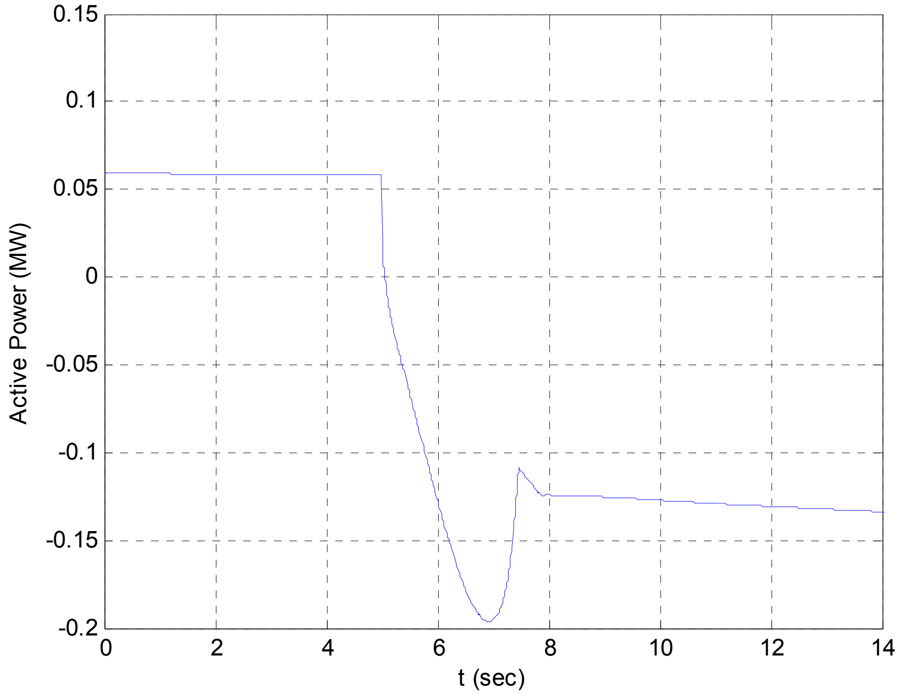

Figure 11: Active Power absorbed by MG (Scenario A1)

Load and Generation imbalance after islanding leads to a large frequency deviation as illustrated in Figure 7. The response of the distributed generators, the storage and the sources of the MG is inadequate to control frequency and this leads to diesel generator tripping a few seconds after the islanding.

Emergency strategies are applied to control the MMG and to avoid a total black out.

4.1.1 Under Frequency Load Shedding

Figure 12 and Figure 13 illustrate frequency and voltage at the NMV bus with and without UFLS. UFLS manages to keep frequency above 47.5Hz and to stabilize voltage.

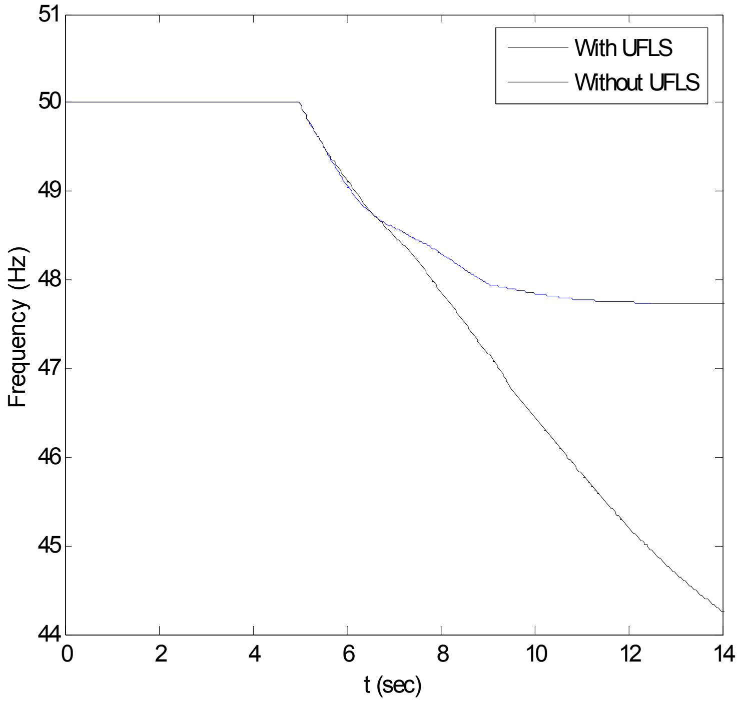

Figure 12: Frequency (Scenario A1-UFLS Automaton)

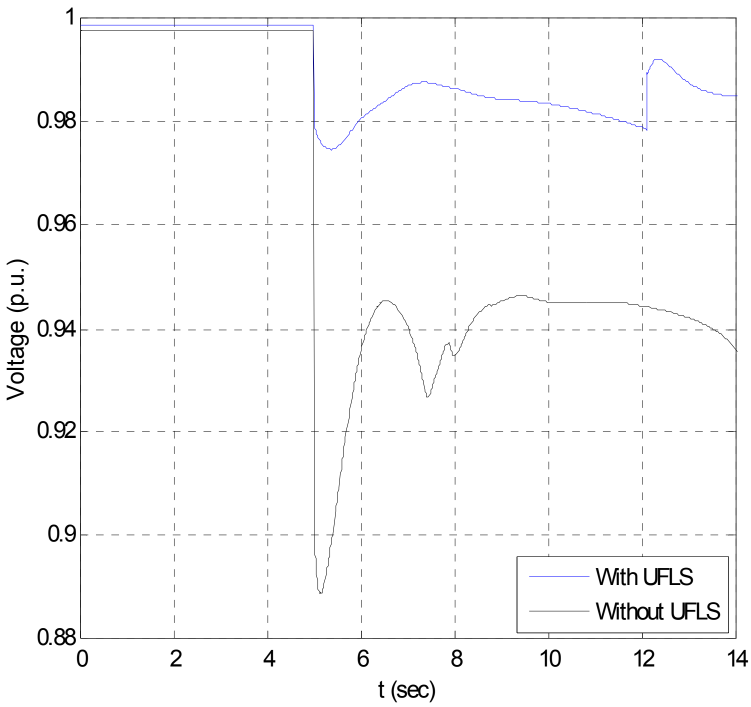

Figure 13: Voltage at NMV Bus (Scenario A1-UFLS Automaton)

4.1.2 DT proposed Load Shedding

Scenario A1 belongs to Leaf 9 of the DT. For a secure islanded operation it must transposes to one of the secure leafs of the DT, i.e. Leaf 7, 16, 18, 21. Transposition to Leaf 7 requires 7.58 MW of Load Shedding, while transposition to Leaf 16 requires 5.73 MW of Load Shedding. Transposition to Leafs 18 and 21 is not possible due to the high DFIM production. The transposition to Leaf 7 is preferred due to its higher security index. Figure 14 and Figure 15 illustrate frequency and Voltage with and without the DT proposed load shedding.

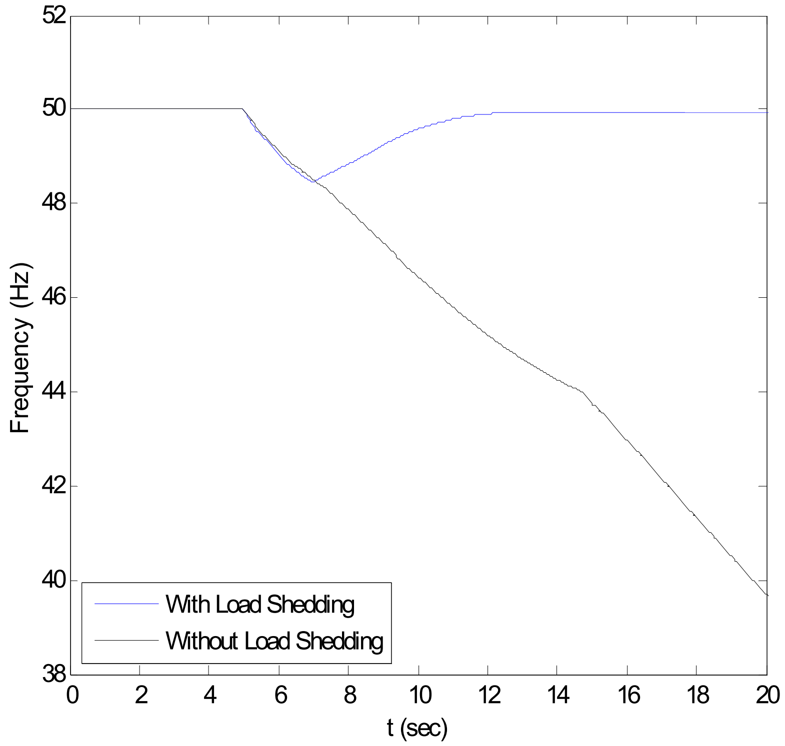

Figure 14: Frequency (Scenario A1- DT proposed load shedding)

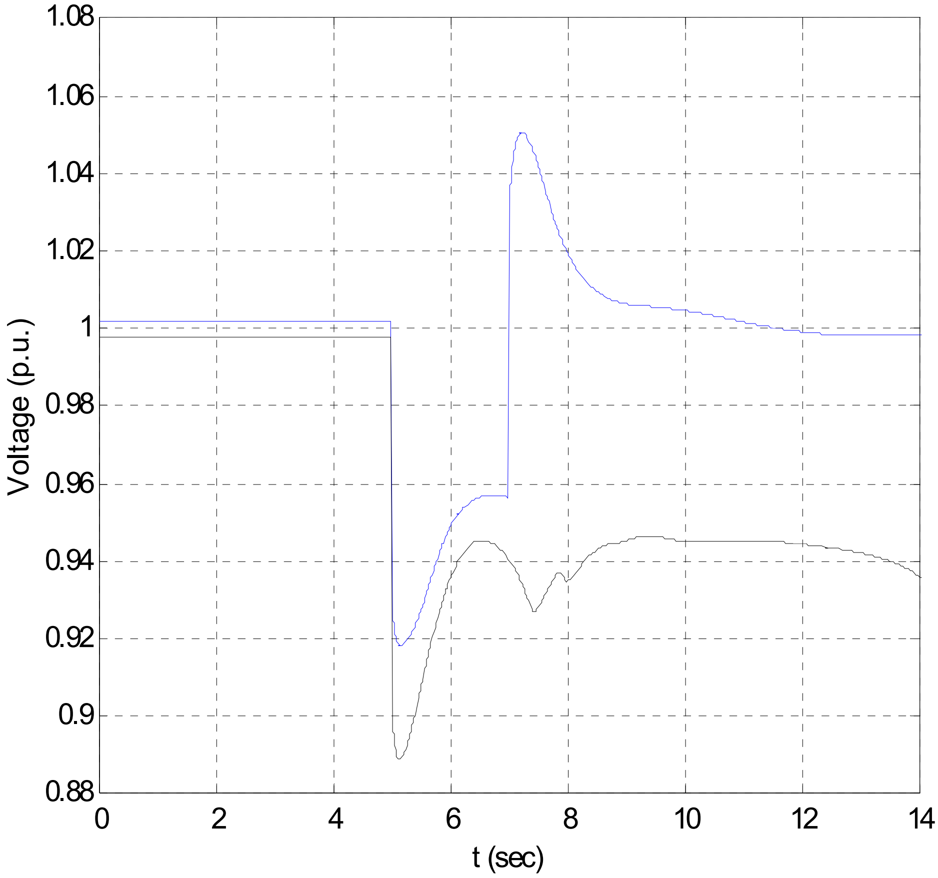

Figure 15: Voltage at NMV bus (Scenario A1 – DT proposed load shedding)

4.1.3 MMG Separation.

The MMG is separated into 3 islands as illustrated in Figure 16 order to avoid a major black-out. In addition all MGs are disconnected in order to avoid cascading collapse.

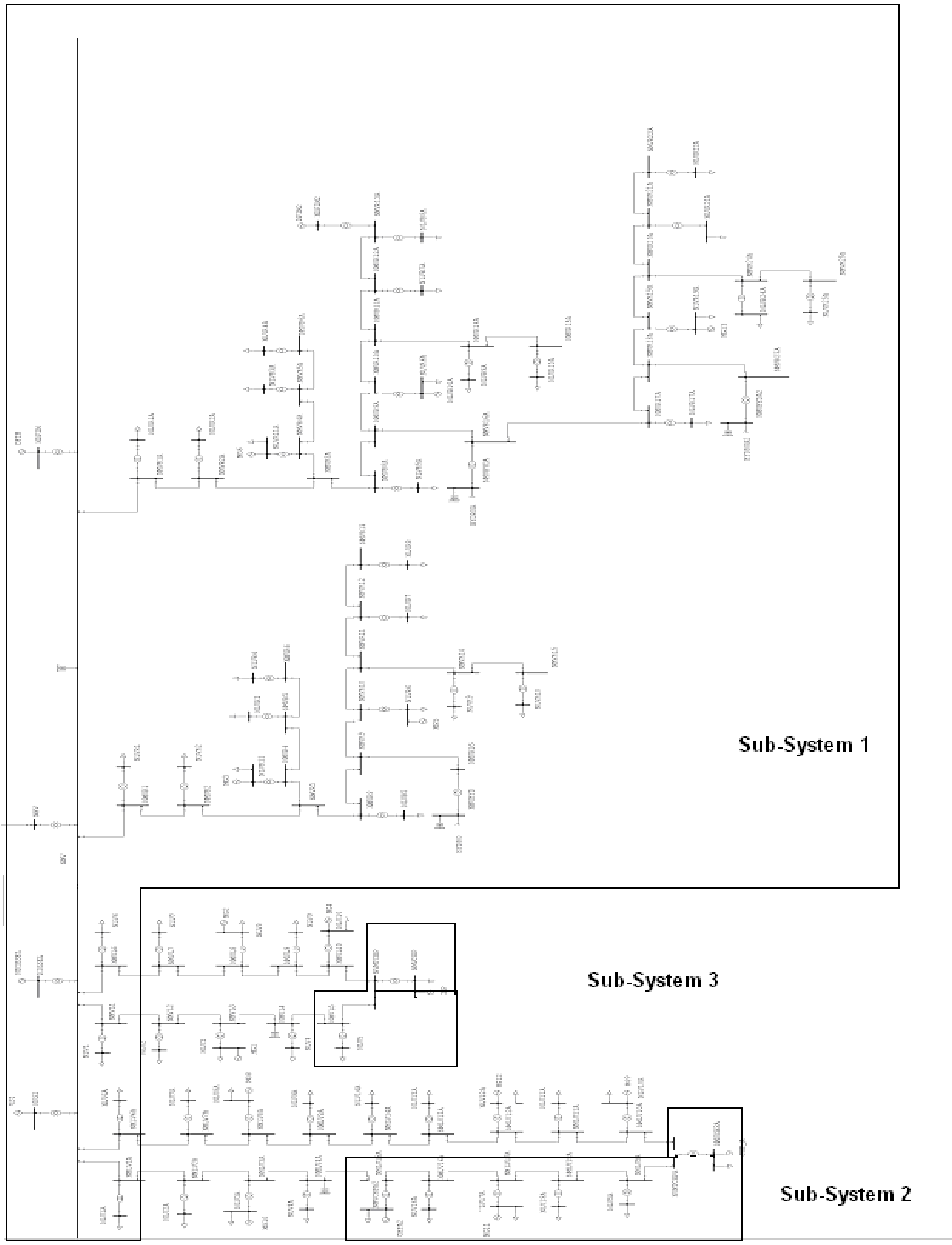

Figure 16: MMG SubSystems Creation

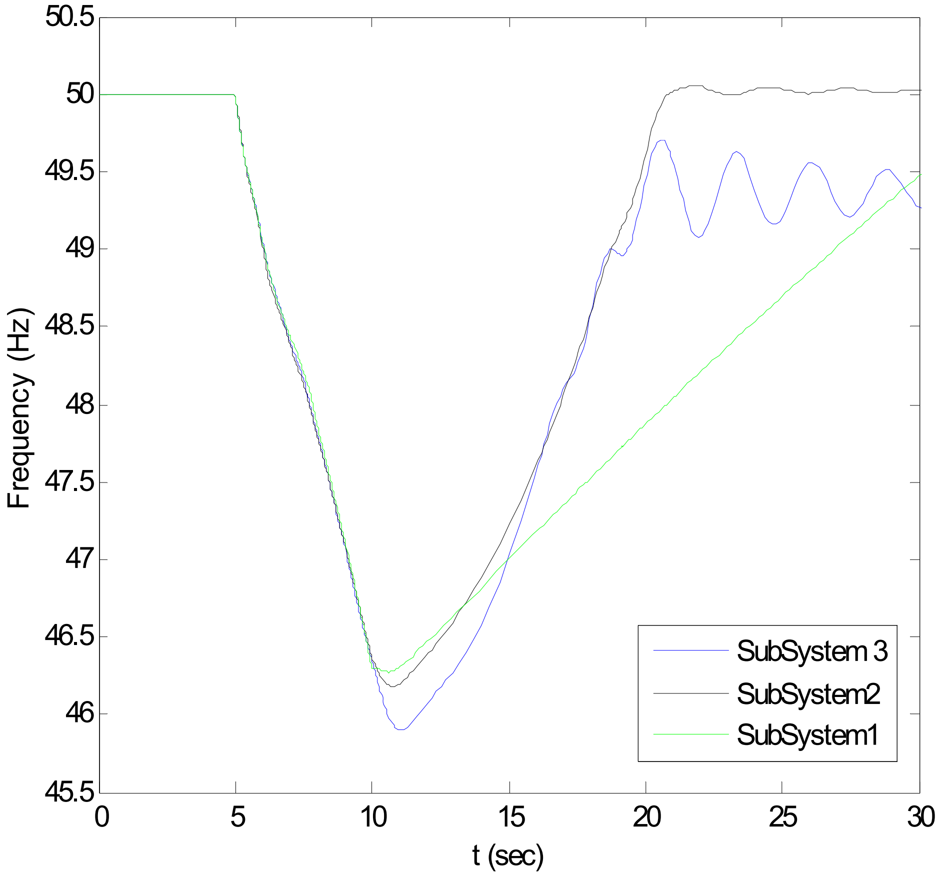

Figure 17: Frequency of Subsystems (Scenario A1 – MMG Separation)

4.2 Scenario A2

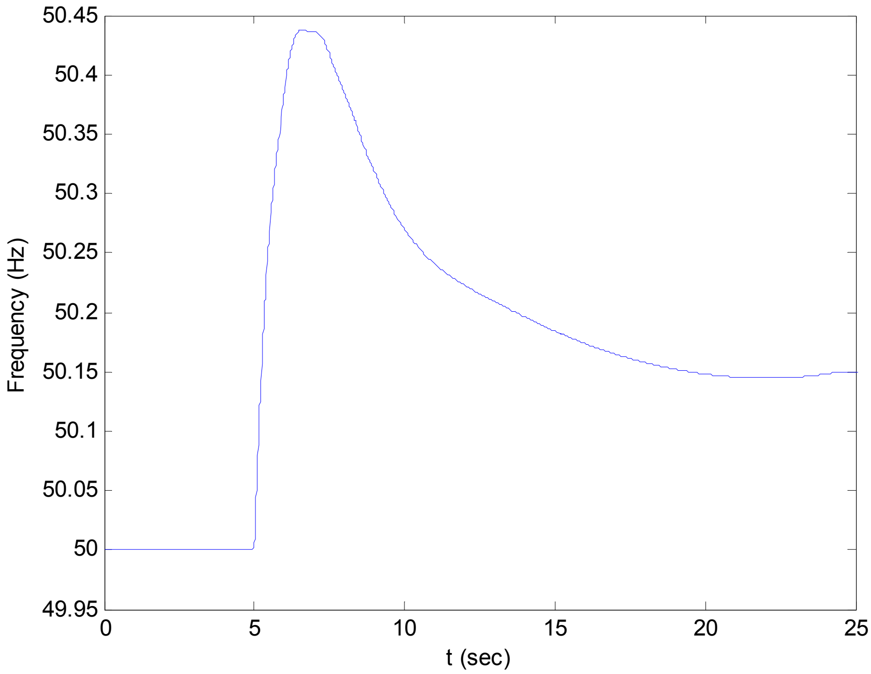

Figure 18: Frequency (Scenario A2)

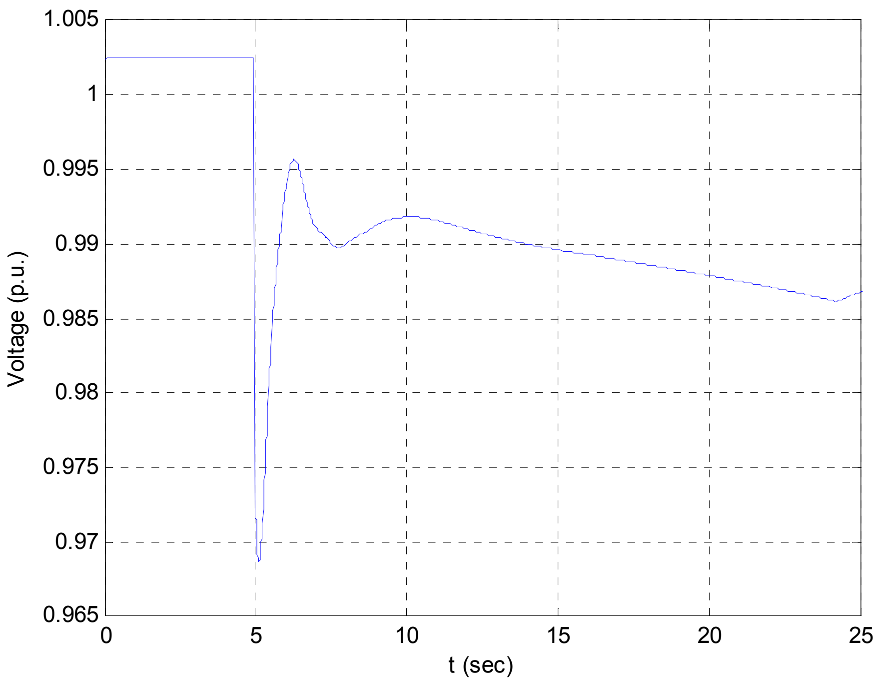

Figure 19: Voltage of NMV (Scenario A2)

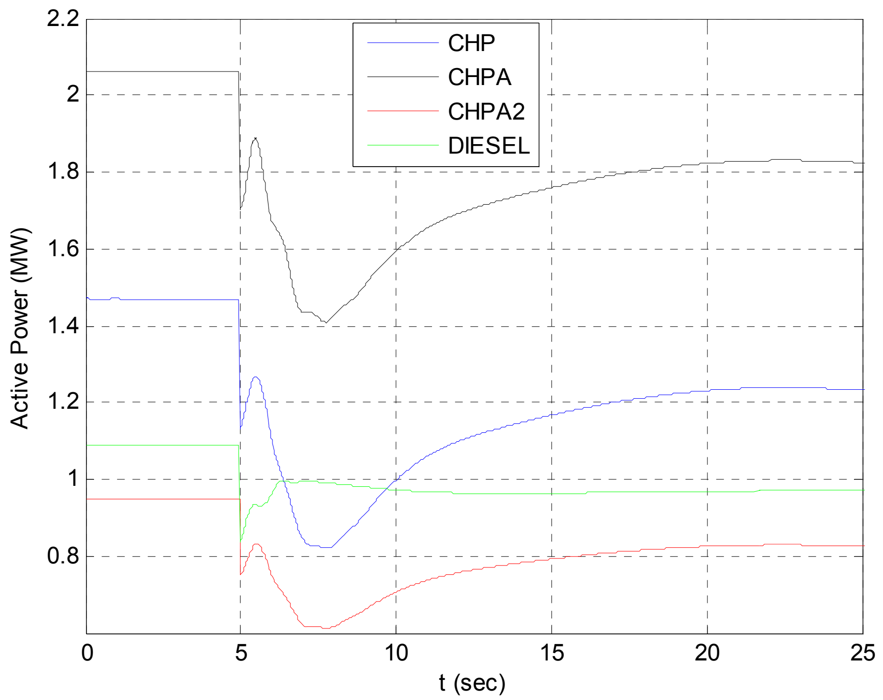

Figure 20: Active Power of Diesel and CHP units (Scenario A2)

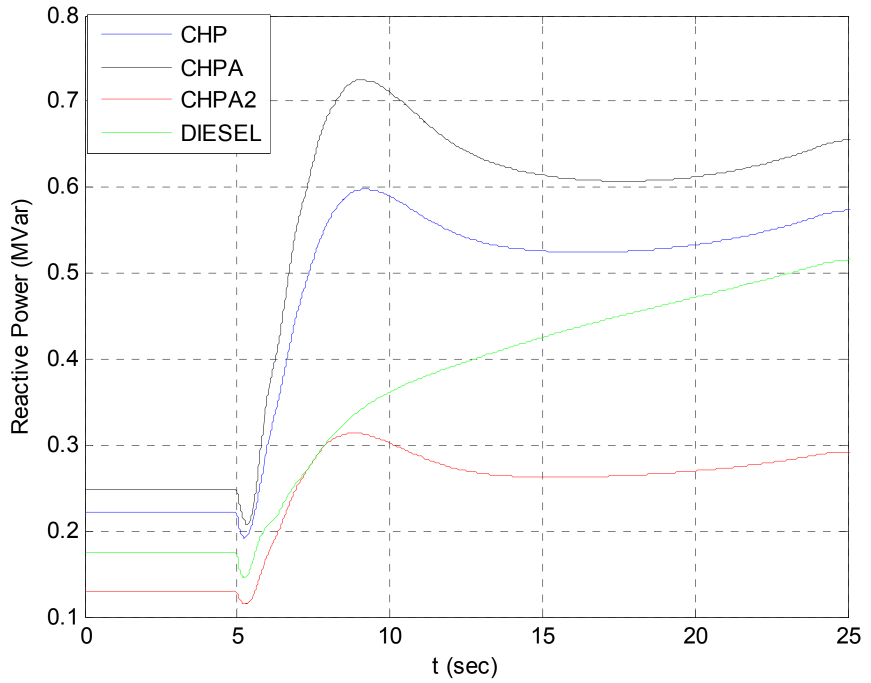

Figure 21: Reactive Power of Diesel and CHP units (Scenario A2)

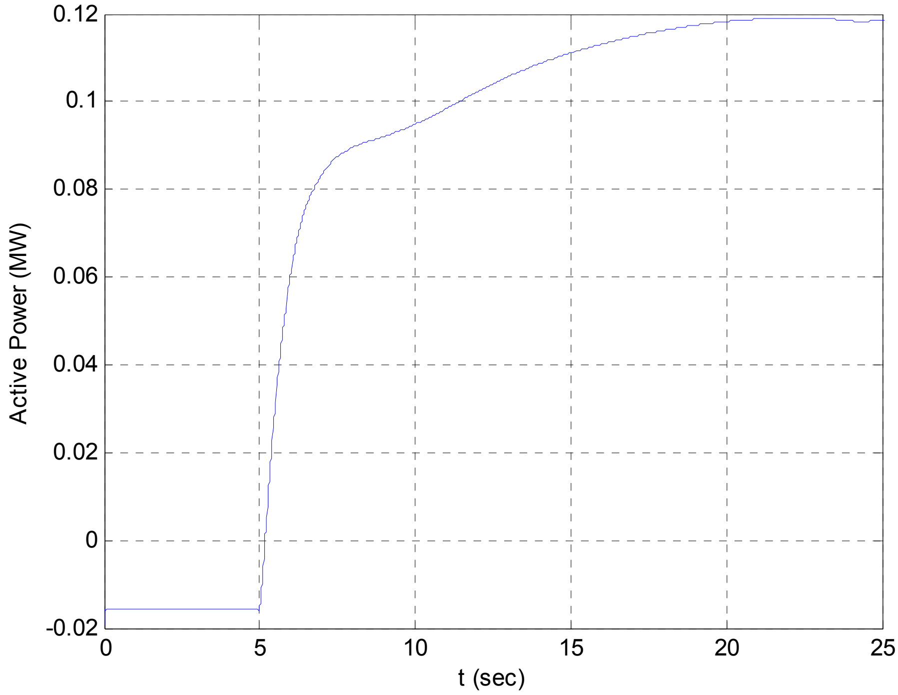

Figure 22: Active Power absorbed by each MG (Scenario A2)

Scenario A2 belongs to Leaf 7 of the DT, it is thus a secure scenario and it can operate isolated without any emergency control action, such as load or generation shedding. The generating units reduce their active power output in order to compensate for the surplus of production after the MMG islanding. The frequency rise is within certain bounds that do not jeopardize the stability of the MMG. Voltage is also kept close to its nominal, due to the immediate response of DGs.

A 10% increase of load during the islanded operation of the MMG is simulated and results are presented in Figure 23 and Figure 24. MMG manages to control frequency within acceptable bounds after the disturbance.

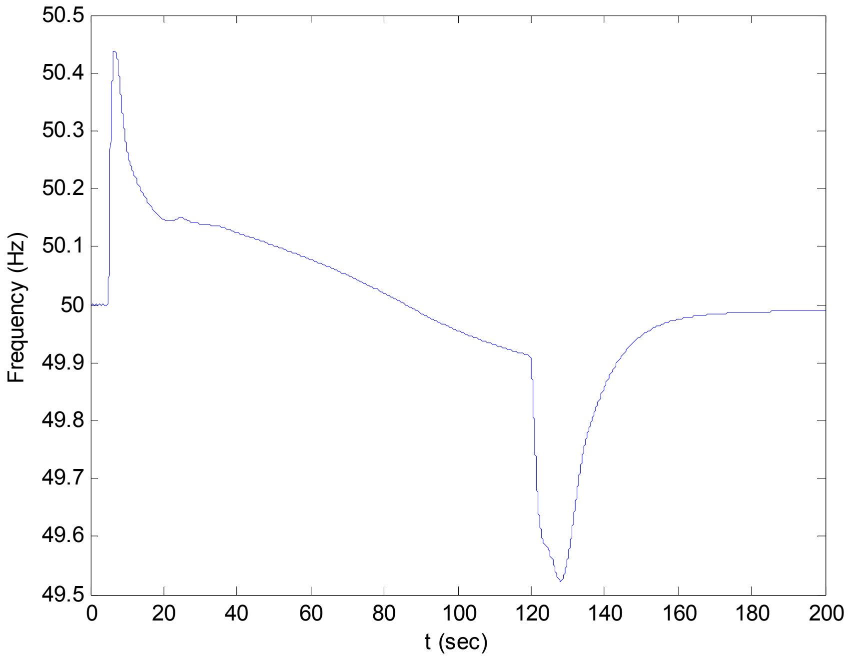

Figure 23: Frequency (Scenario A2)

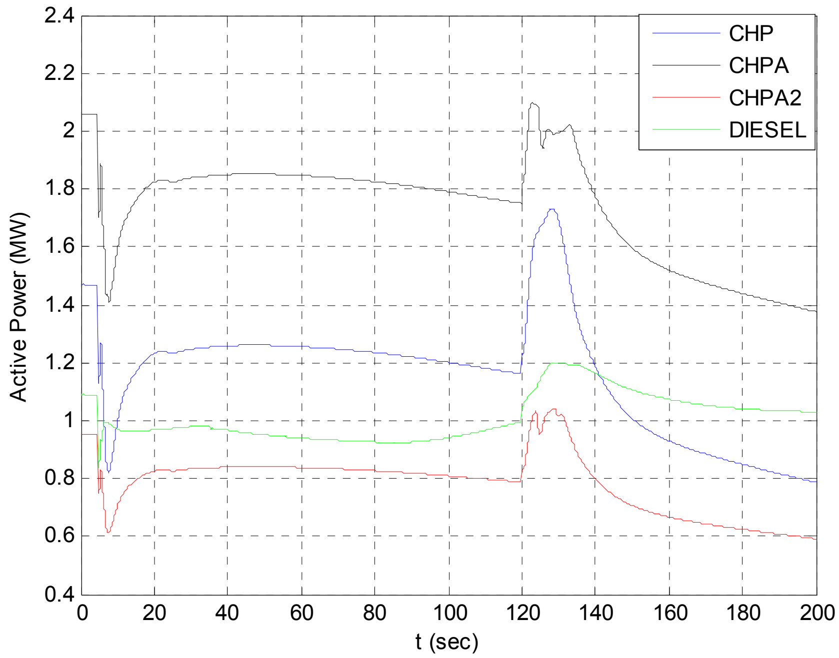

Figure 24: Active Power (Scenario A2)

4.3 Scenario B1

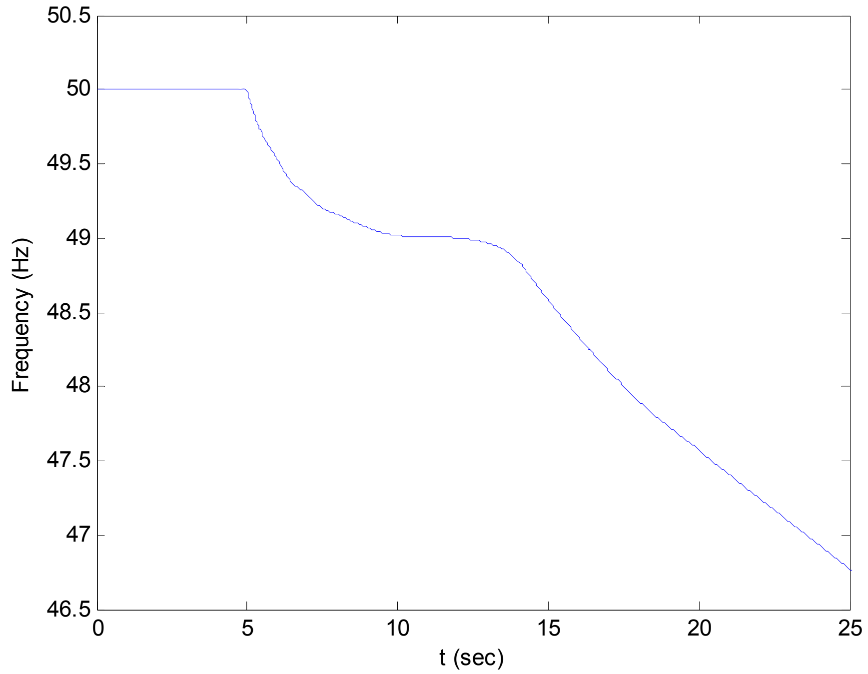

Figure 25: Frequency (Scenario B1)

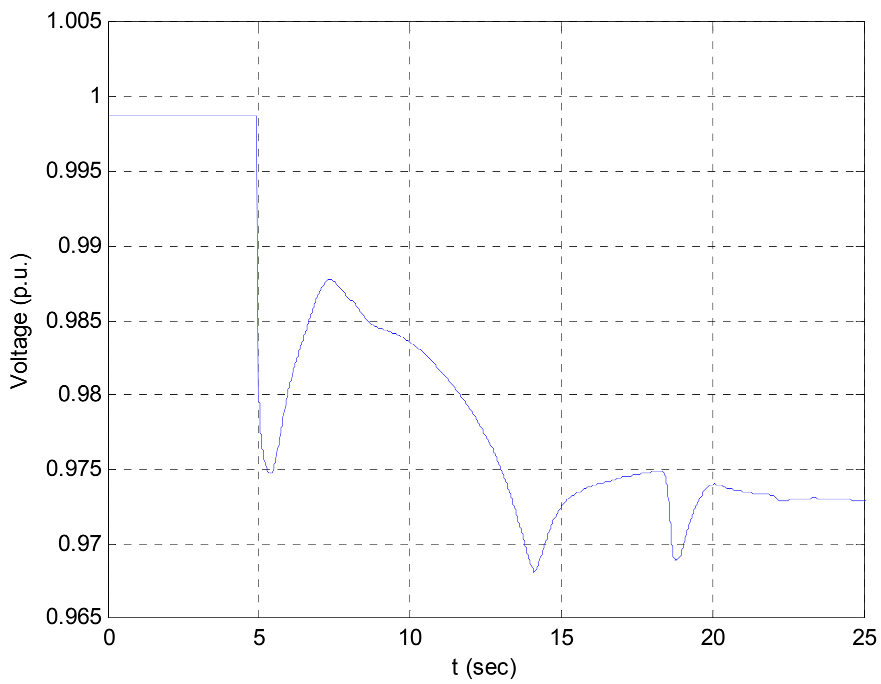

Figure 26: Voltage of NMV (Scenario B1)

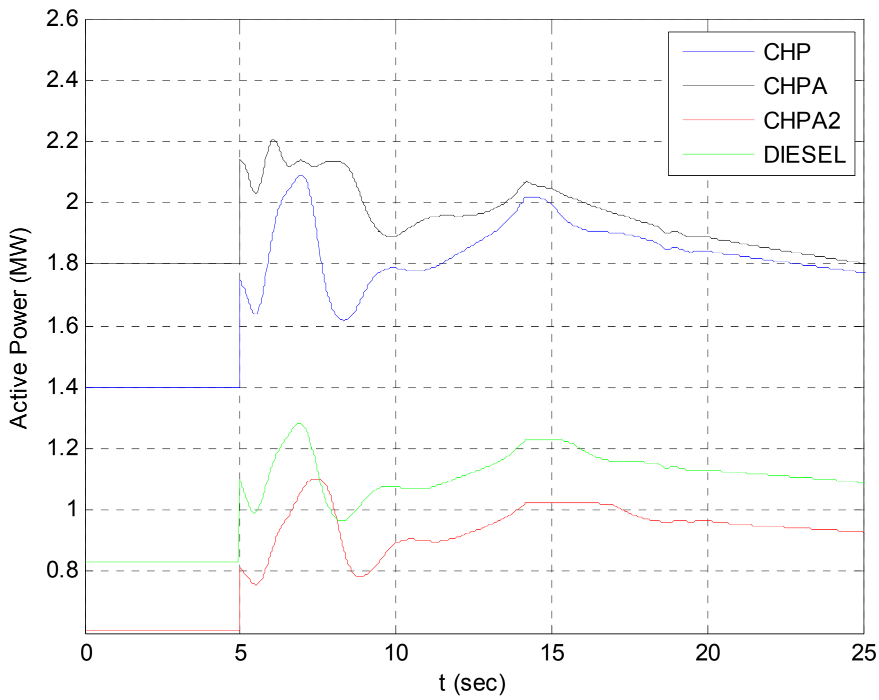

Figure 27: Active Power of Diesel and CHP units (Scenario B1)

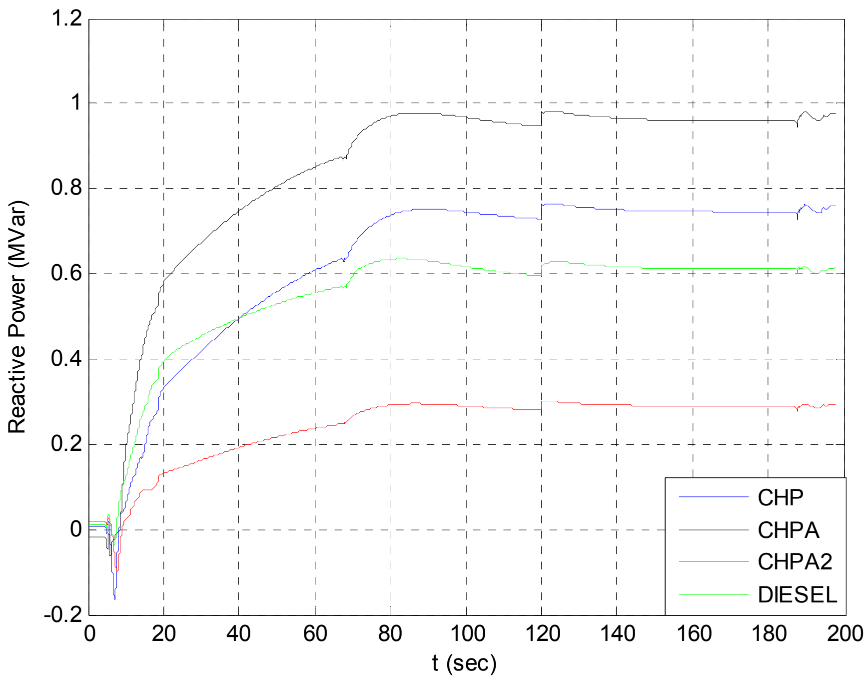

Figure 28: Reactive Power of Diesel and CHP units (Scenario B1)

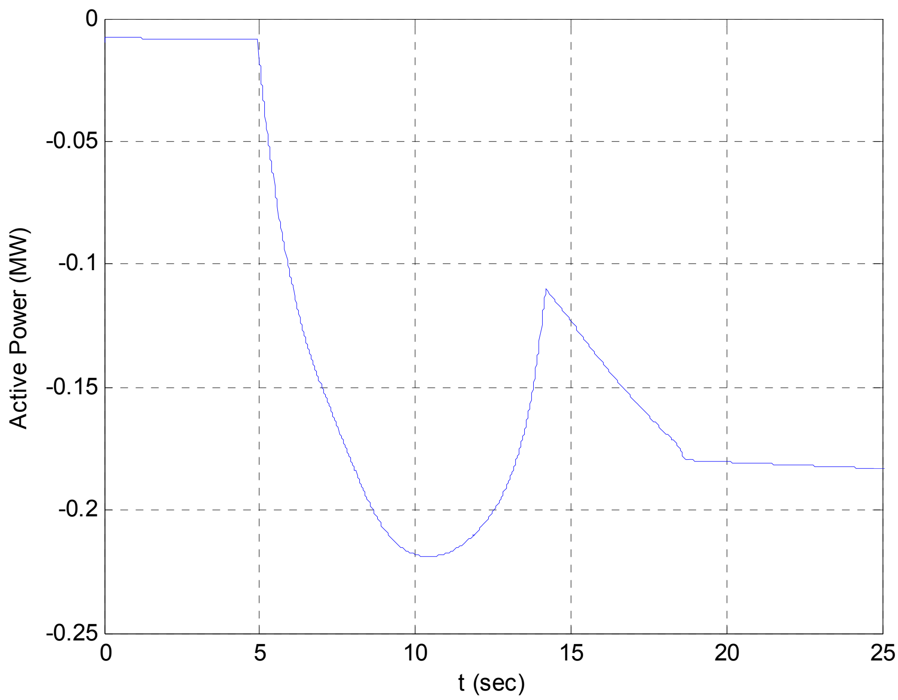

Figure 29: Active Power absorbed by MG (Scenario B1)

Load and Generation imbalance after islanding leads to a large frequency deviation as illustrated in Figure 25. The response of the distributed generators, the storage and the sources of the MG is inadequate to control frequency. Under frequency load shedding automatons and DT proposed load shedding are simulated and results are presented to the figures below.

4.3.1 Under Frequency Load Shedding

Figure 12 and Figure 13 illustrate frequency and voltage at the NMV bus with and without UFLS. UFLS manages to keep frequency above 47.5Hz and to stabilize voltage.

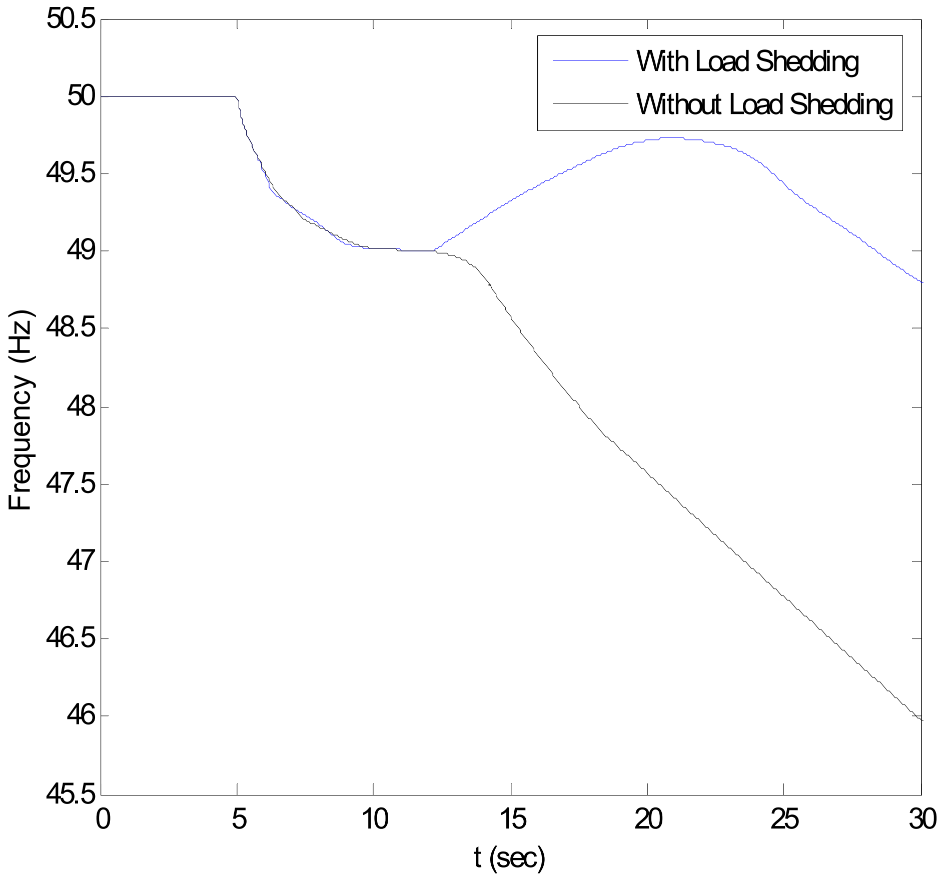

Figure 30: Frequency (Scenario B1- UFLS)

4.3.2 DT proposed Load Shedding

Scenario B1 belongs to Leaf 12 of the DT, it is thus an insecure scenario. For a secure islanded operation it must transposes to one of the secure leafs of the DT, i.e. Leaf 7, 16, 18, 21. Transposition to Leaf 7 requires 1.93 MW of Load Shedding, while transposition to Leaf 16 is not feasible due to the low value of Spinning Reserve (Attribute A3 should be above 3.252). Transposition to Leafs 18 and 21 would require higher load shedding and is not investigated. Figure 31 illustrate frequency with and without the DT proposed load shedding.

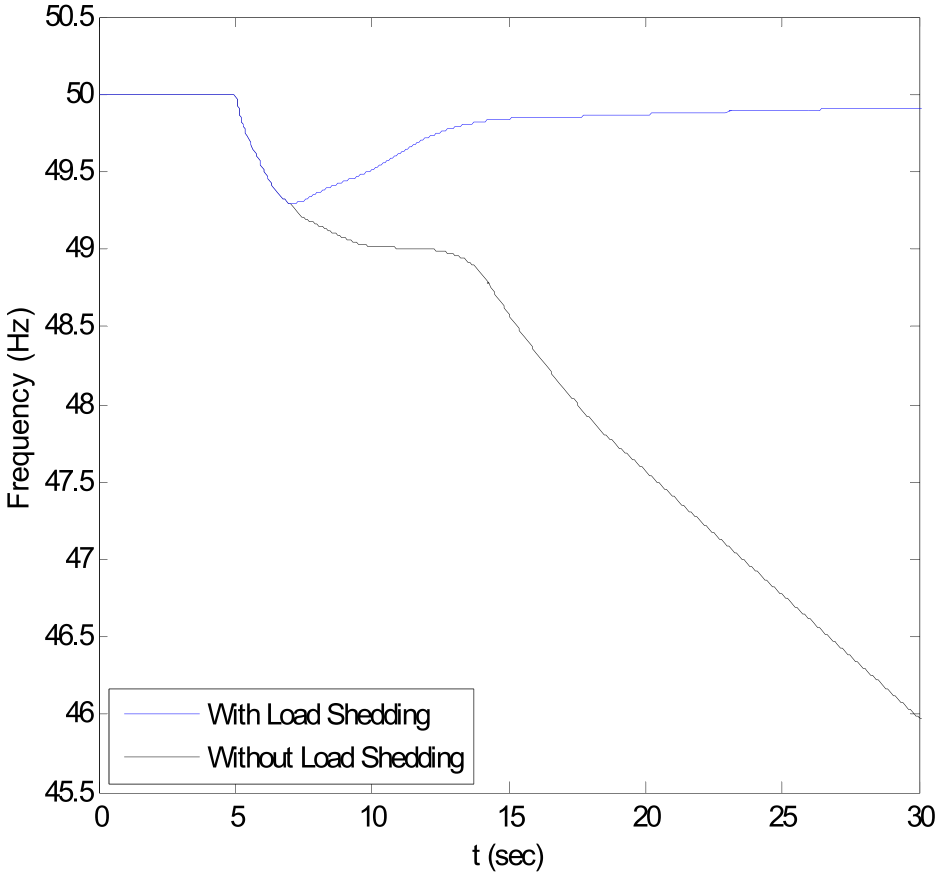

Figure 31: Frequency (Scenario B1-DT proposed load shedding)

An 10% increase in load at t=120sec for the three under study cases of the scenario (No load shedding, UFLS and DT proposed load shedding).

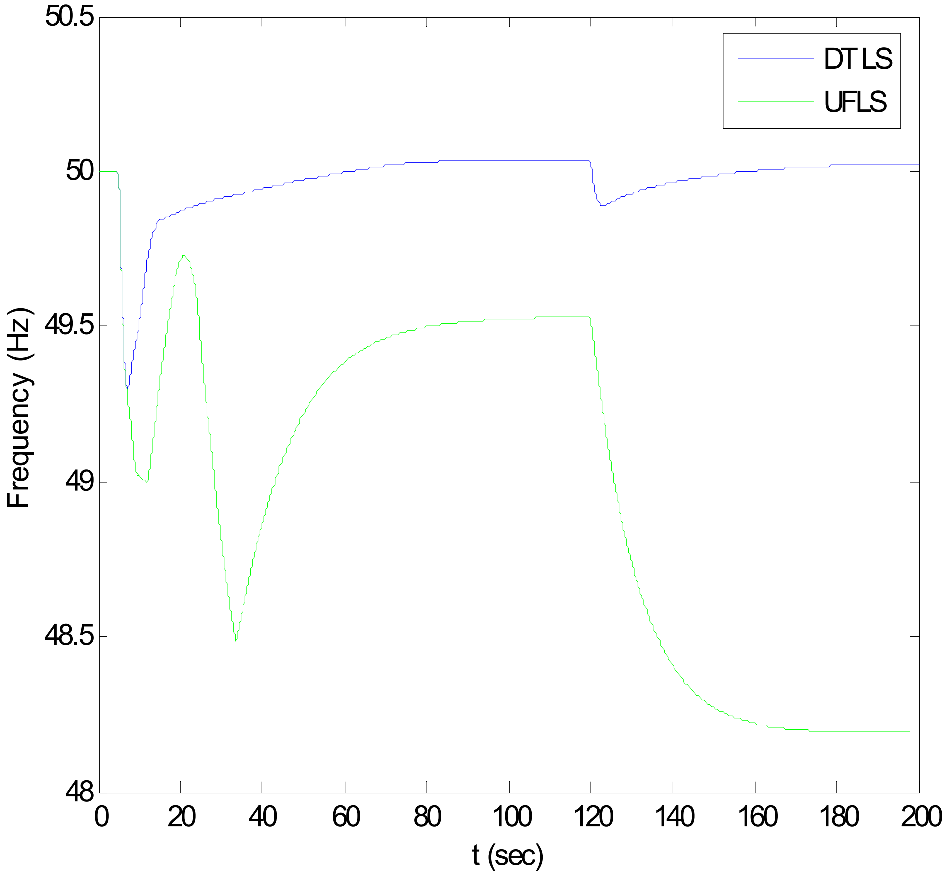

Figure 32: Frequency during islanded operation (Scenario B2)

4.4 Scenario B2

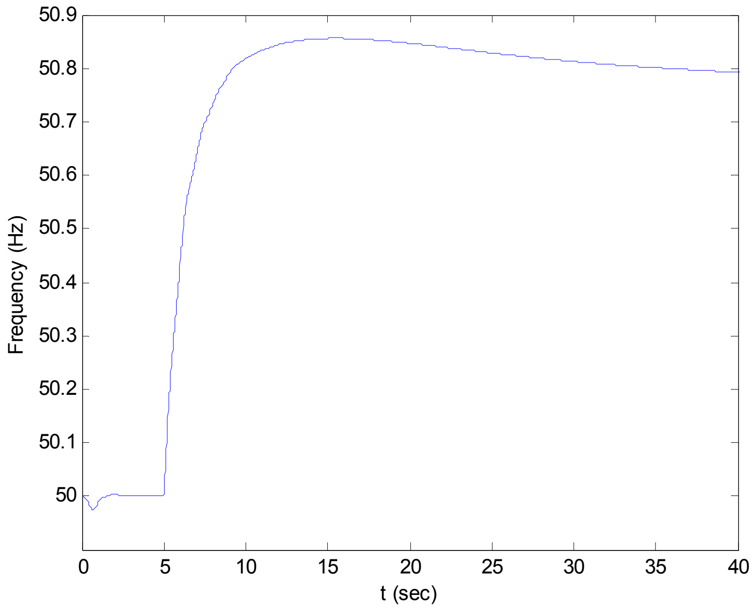

Figure 33: Frequency (Scenario B2)

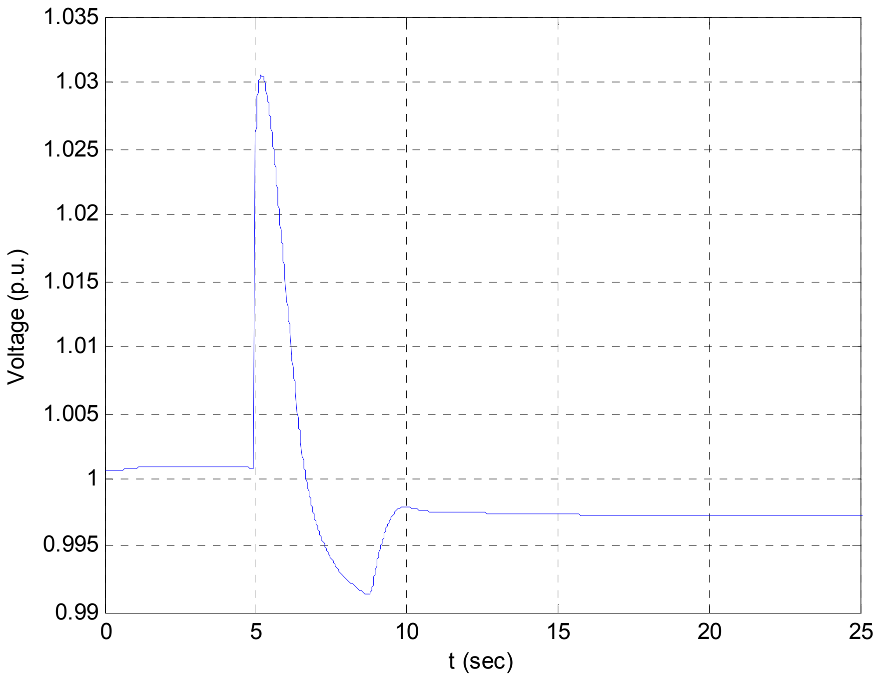

Figure 34: Voltage of NMV (Scenario B2)

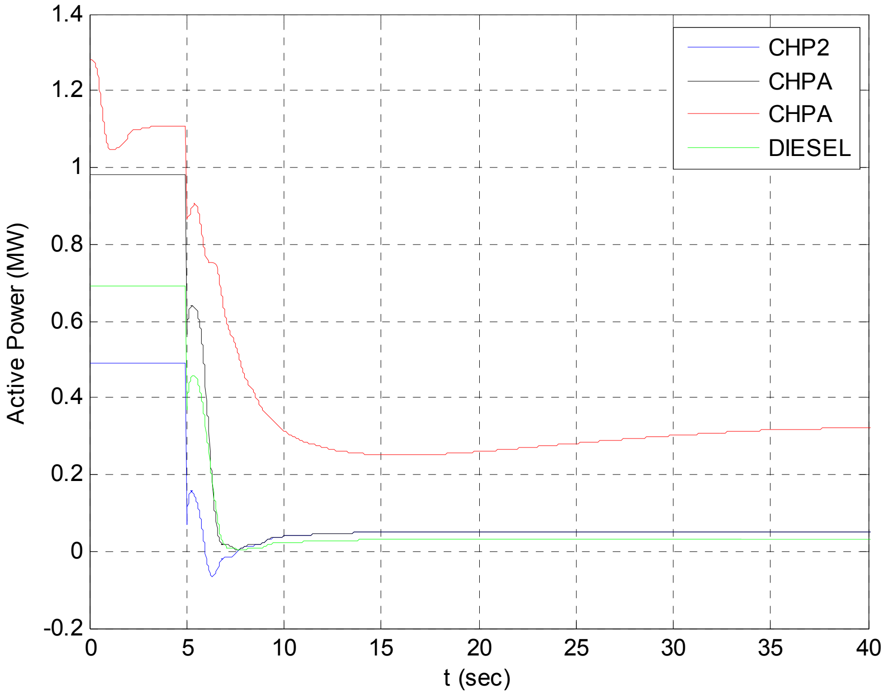

Figure 35: Active Power of Diesel and CHP units (Scenario B2)

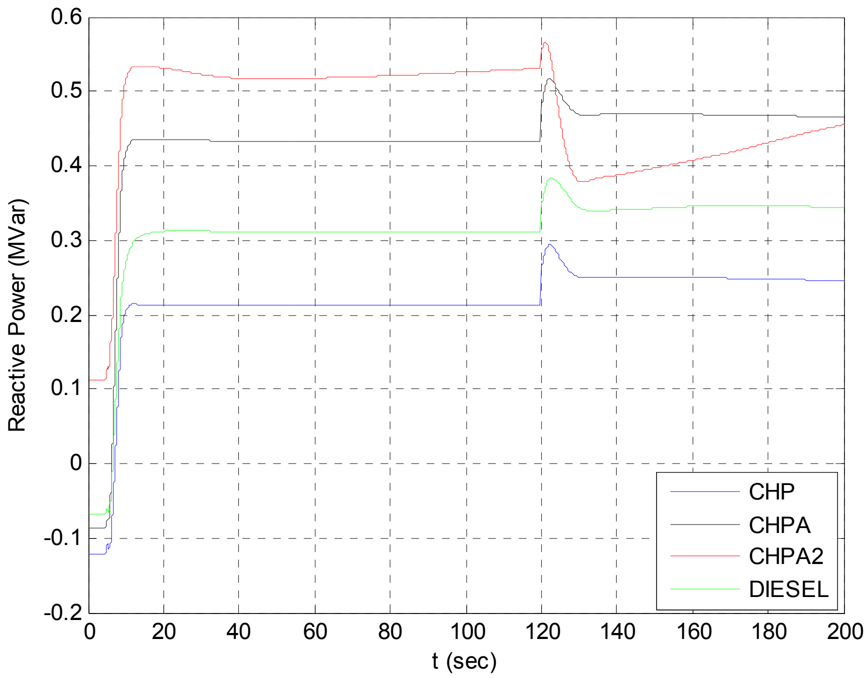

Figure 36: Reactive Power of Diesel and CHP units (Scenario B2)

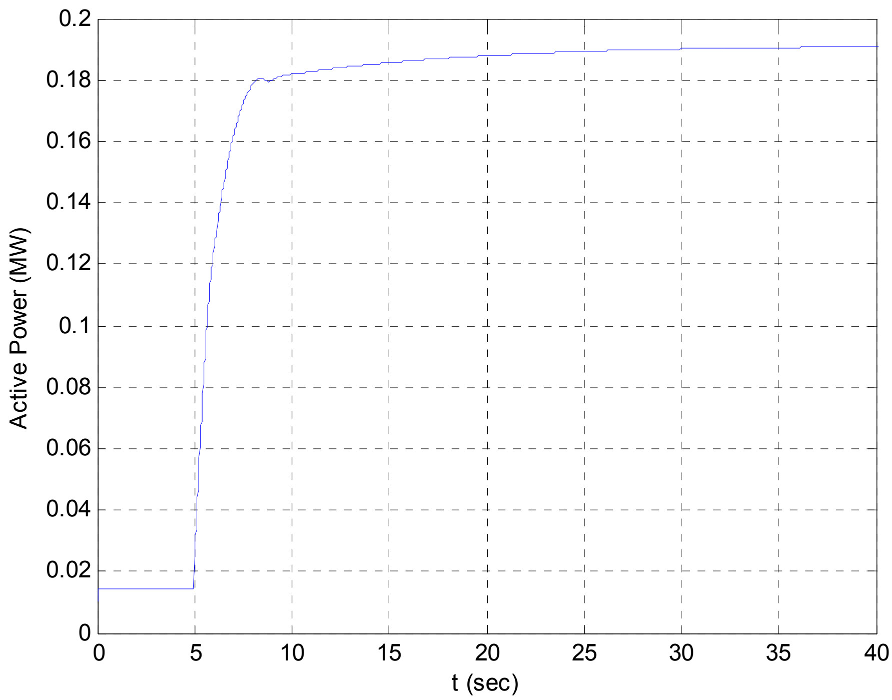

Figure 37: Active Power absorbed by each MG (Scenario B2)

Scenario b2 belongs to Leaf 18 of the DT, it is thus a secure scenario and it can operate isolated without any emergency control action, such as load or generation shedding. The generating units reduce their active power output in order to compensate for the surplus of production after the MMG islanding. The frequency rise is within certain bounds that do not jeopardize the stability of the MMG. Voltage is also kept close to its nominal, due to the immediate response of DGs.

4.5 Scenario C1

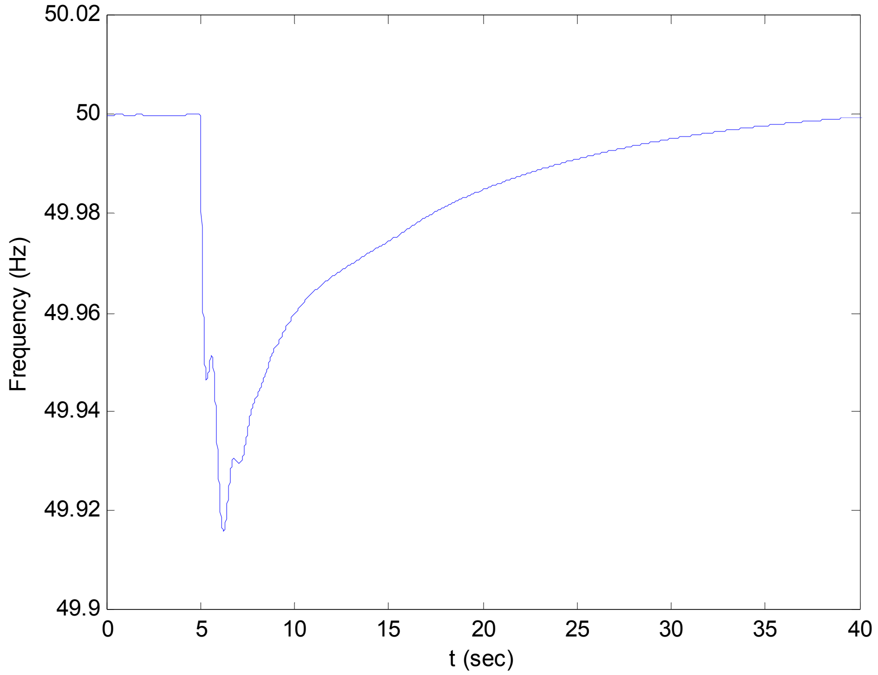

Figure 38: Frequency (Scenario C1)

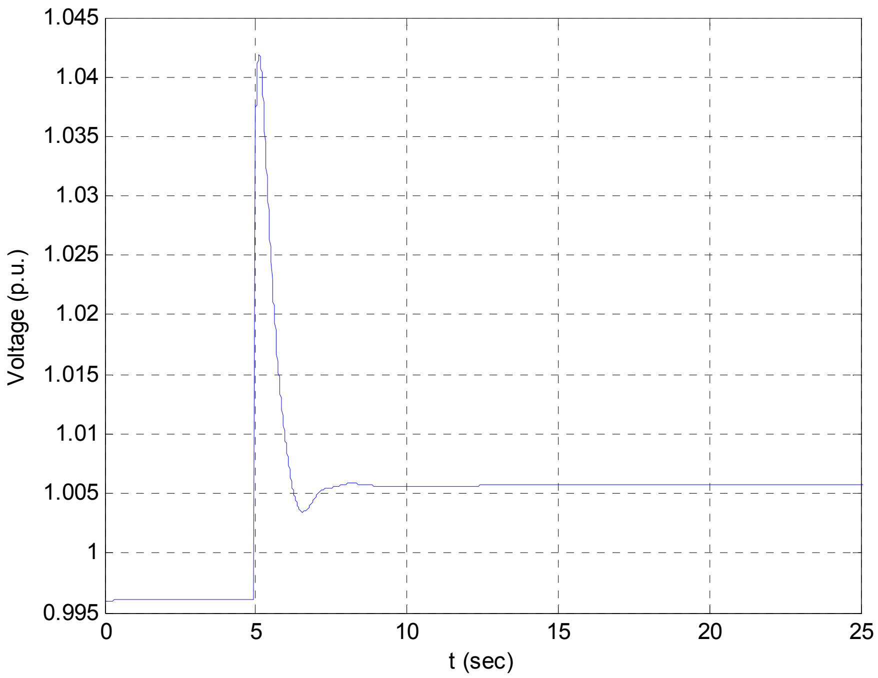

Figure 39: Voltage of NMV (Scenario C1)

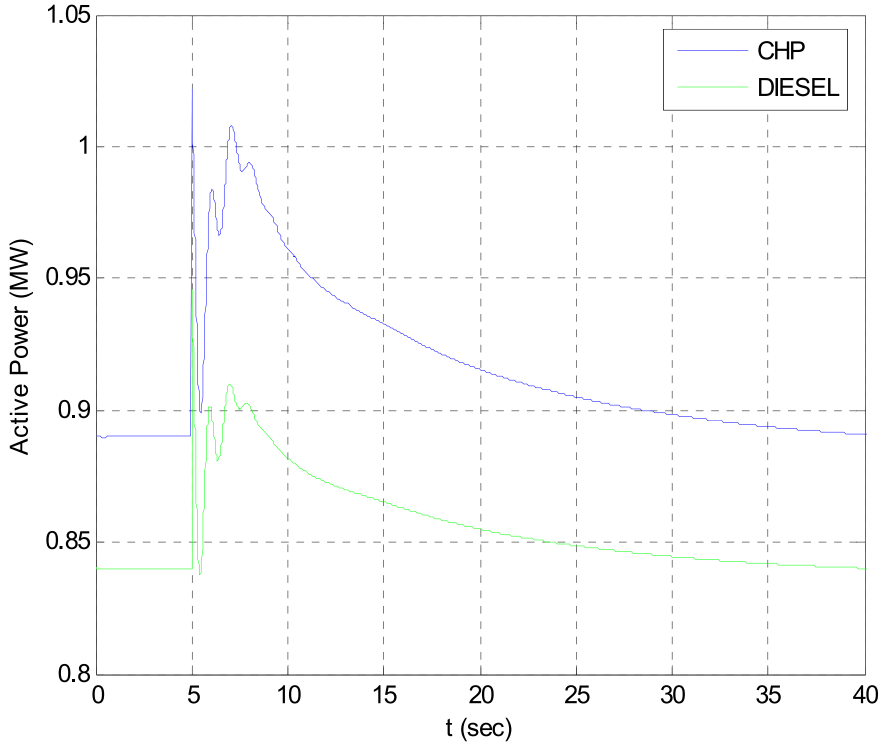

Figure 40: Active Power of Diesel and CHP units (Scenario C1)

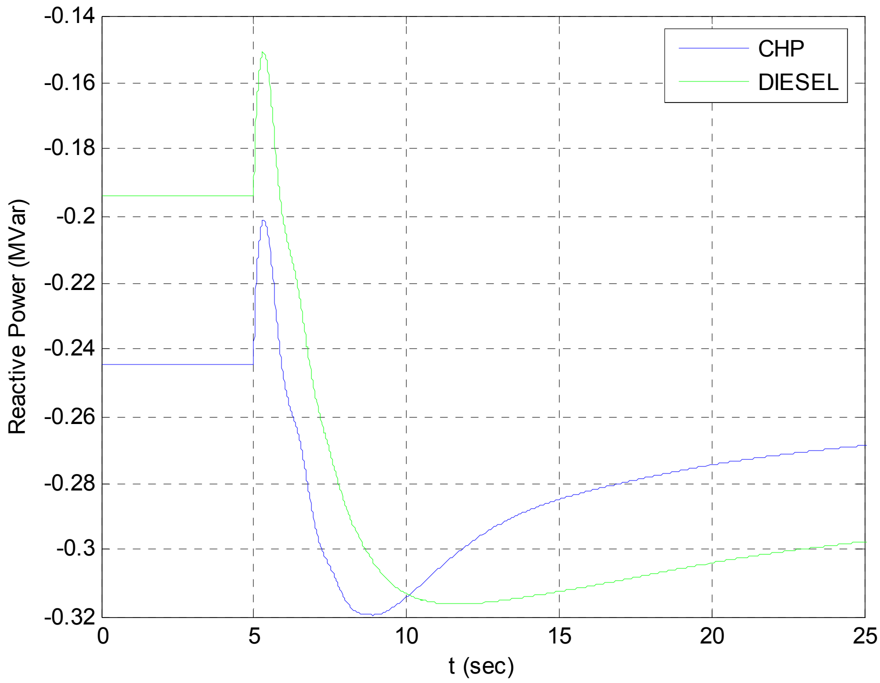

Figure 41: Reactive Power of Diesel and CHP units (Scenario C1)

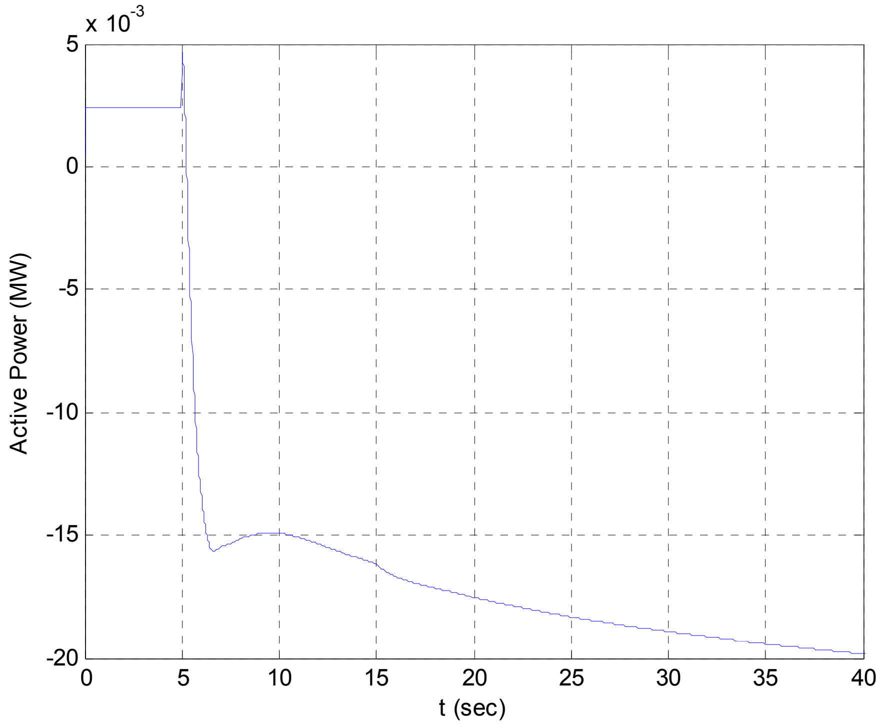

Figure 42: Active Power absorbed by each MG (Scenario C1)

Scenario C1 belongs to leaf 7, it is thus a secure scenario. As illustrated in the above figures it transits to the isolated mode of operation, maintaining the frequency and voltage within an acceptable range. Figure illustrates the dynamic response of the MMG at a load increase at time t=120 s, when it operates isolated.

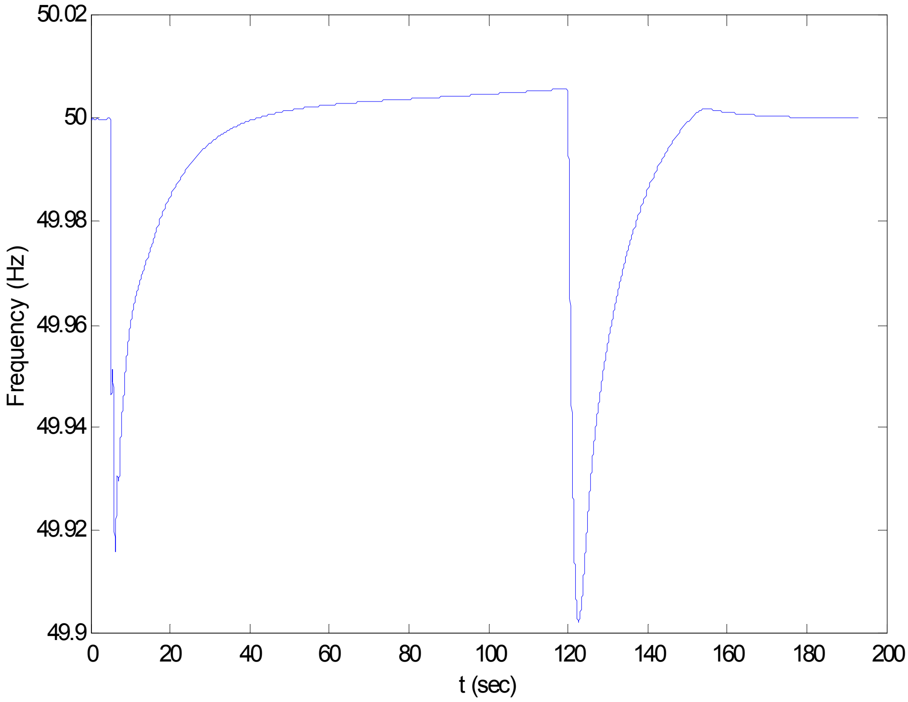

Figure 43: Frequency during isolated operation (Scenario C1)

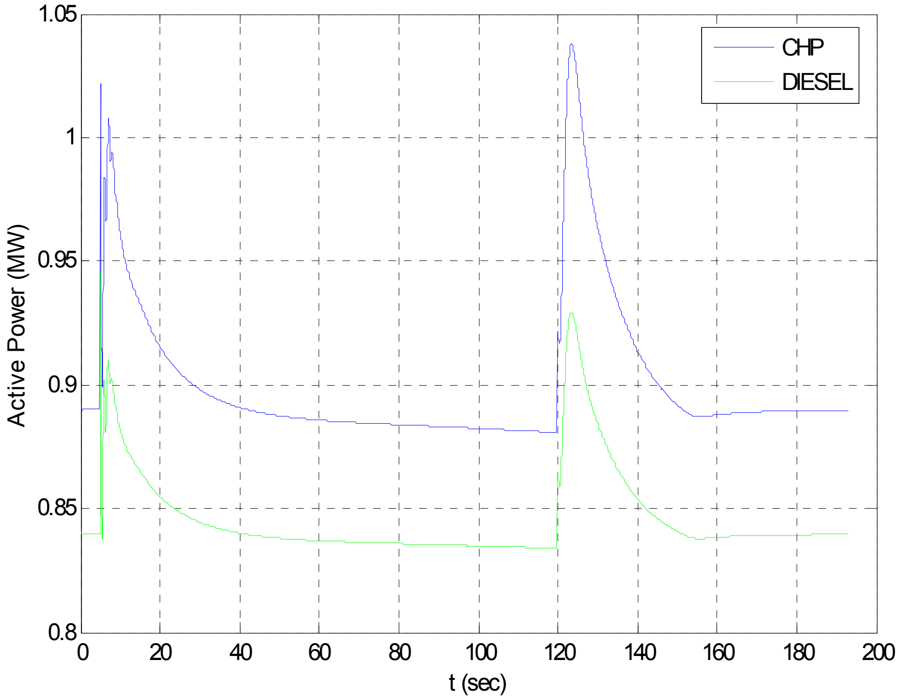

Figure 44: Active Power of Diesel and CHP units (Scenario C1 –load increase)

4.6 Scenario C2

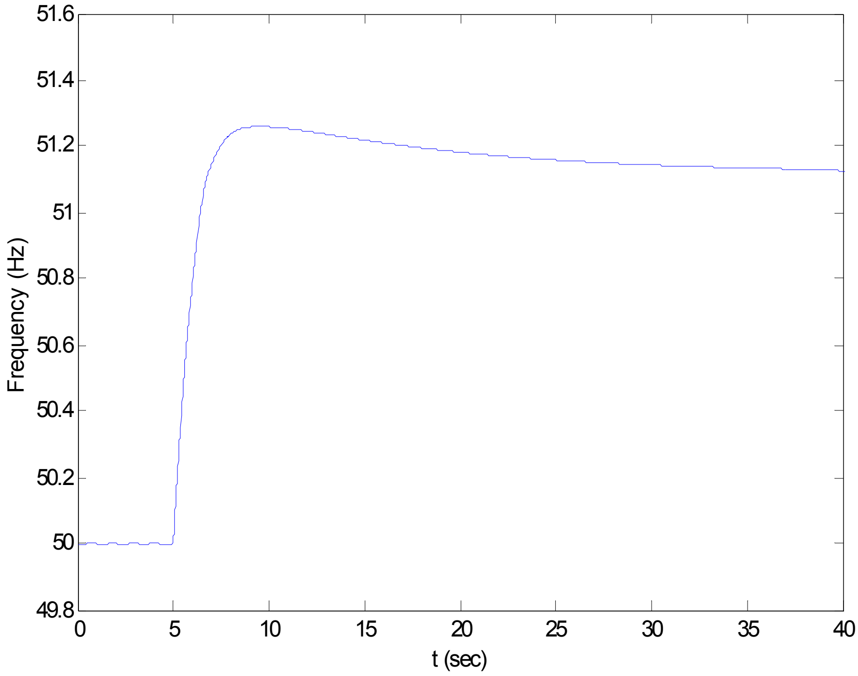

Figure 45: Frequency (Scenario C2)

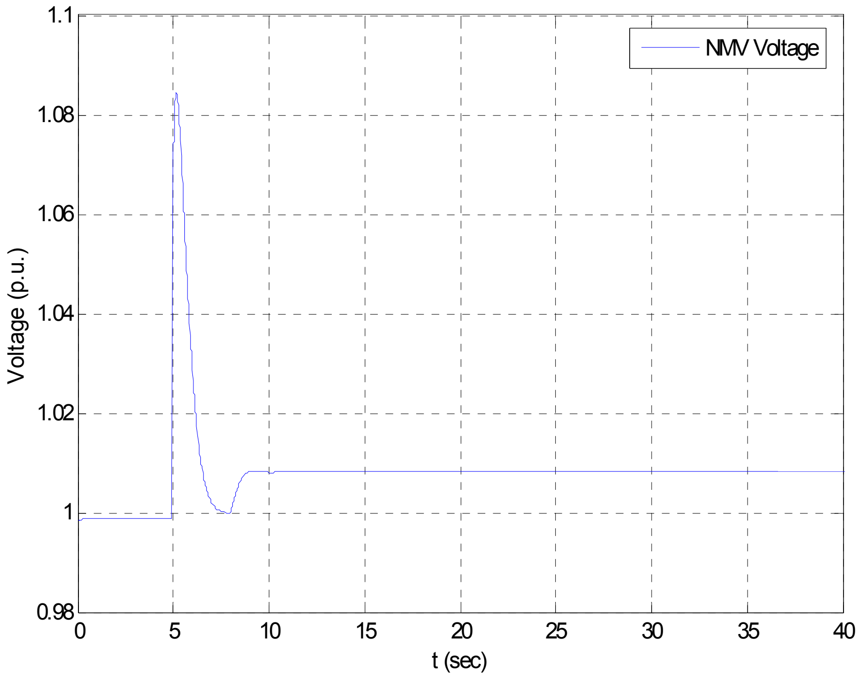

Figure 46: Voltage of NMV (Scenario C2)

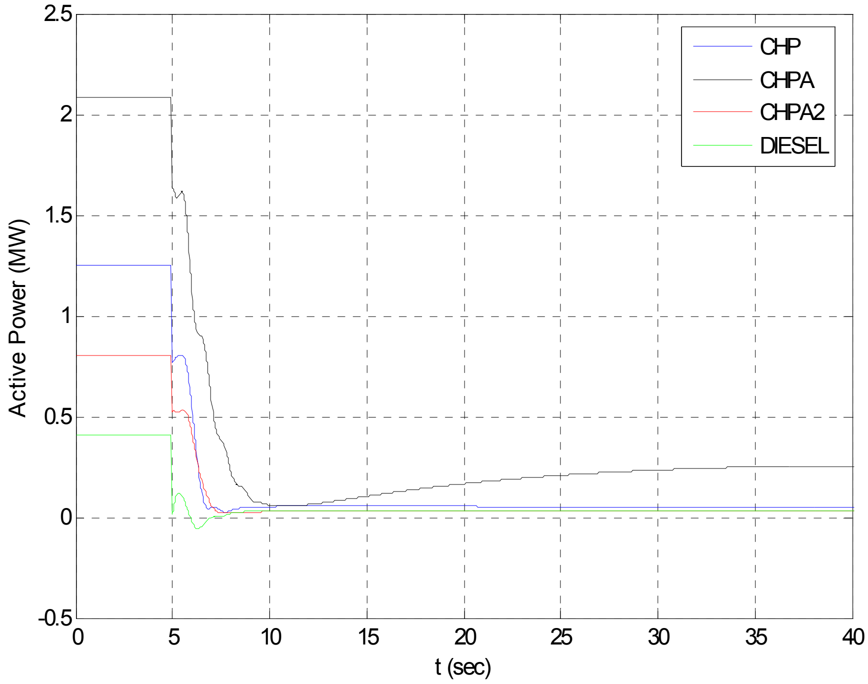

Figure 47: Active Power of Diesel and CHP units (Scenario C2)

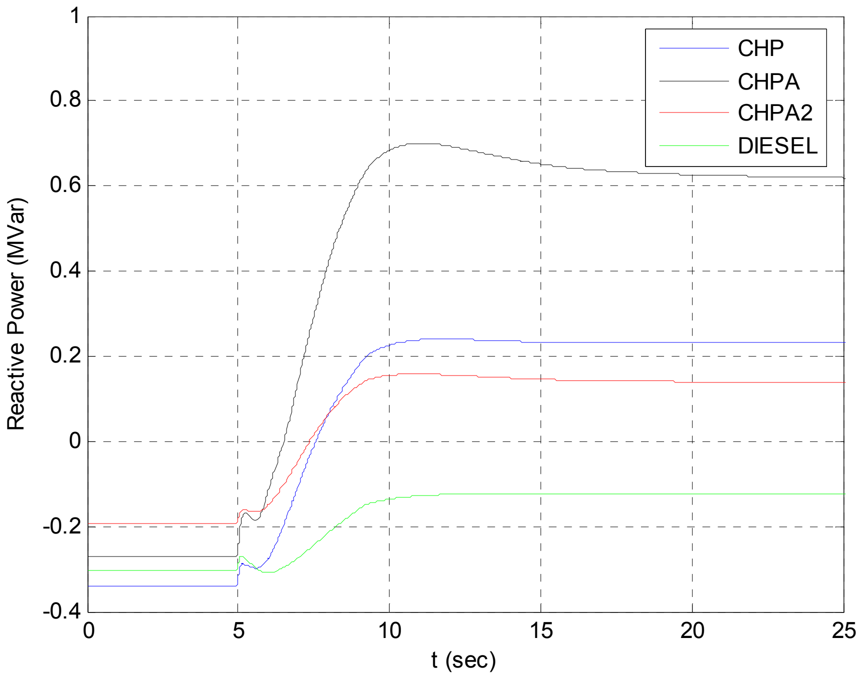

Figure 48: Reactive Power of Diesel and CHP units (Scenario C2)

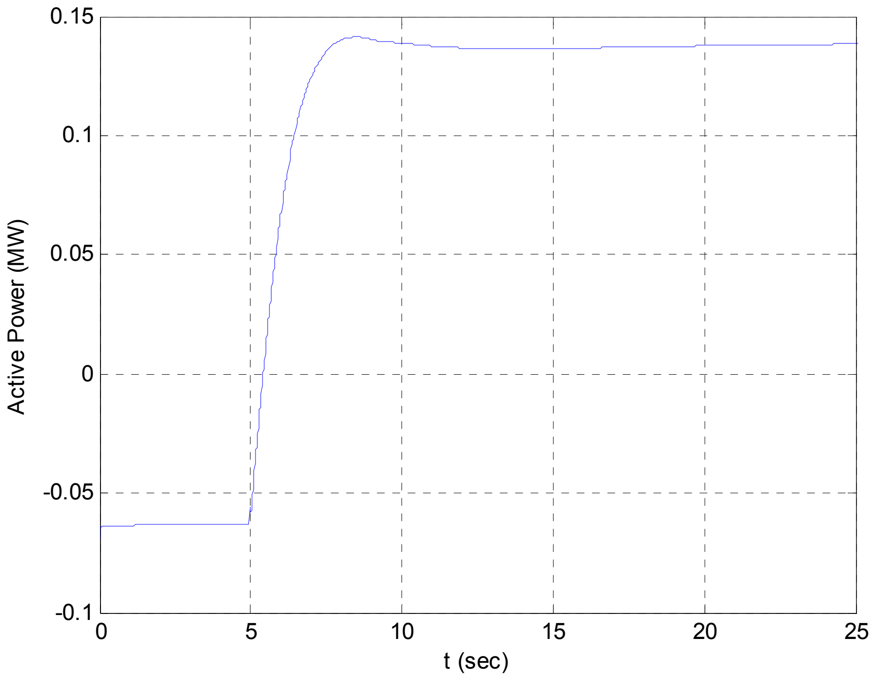

Figure 49: Active Power absorbed by each MG (Scenario C2)

Load and Generation imbalance after islanding leads to a large frequency deviation as illustrated in Figure 45. The active power output of diesel and CHP units falls below technical minimum, which means that tripping of the machines will follow if no emergency action is taken.

Scenario C2 belongs to leaf 2 of the DT (insecure).

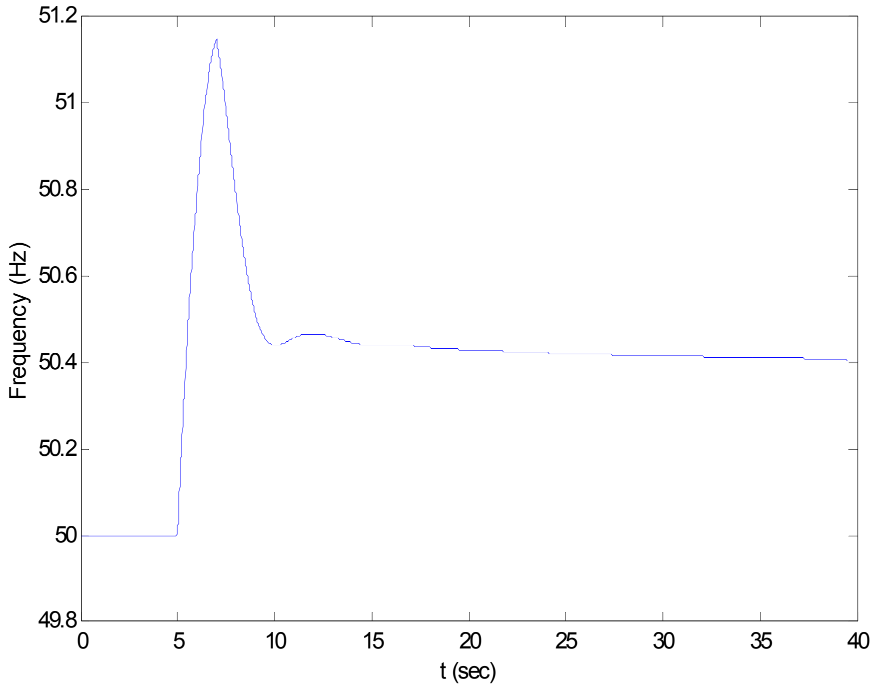

Figure 50: Frequency (Scenario C2- DT proposed Generation Shedding)

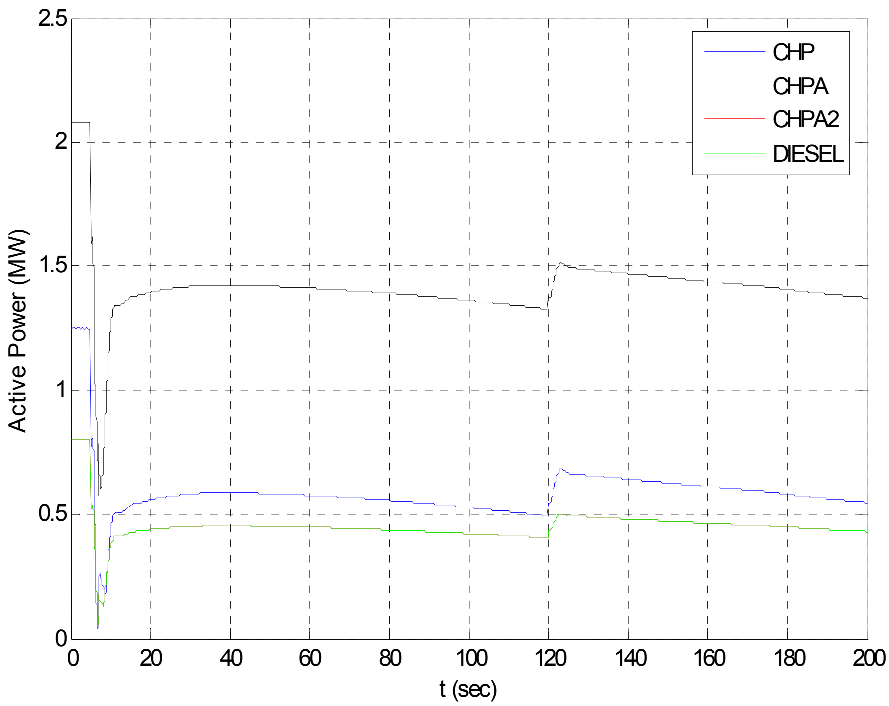

Figure 51: Active Power of DG units (Scenario C2- DT proposed Generation Shedding)

5. MMG Restoration

This chapter presents the strategies for the restoration of a MMG. Power system restoration problem can be divided into several stages [3], [6], [7].

1. Status reporting stage. During the status reporting stage the boundaries of energized areas and the status of generators are identified.
2. Restart stage. Black-start capable generators are restarted.
3. Network reconfiguration stage. Concurrently, system operator determine energizing network path in the network reconfiguration stage
4. Load restoration stage. loads are restored only when there is no risk during the load restoration stage

[8], [9], [10] propose a Knowledge Base System, to provide the appropriate sequence of actions for a power system restoration. The sequence of restoration process is represented by a set of Generic Restoration Actions as proposed in [6], [7]. The GRA have the following properties:

- GRAs are a limited set of actions executed during system restoration.
- A coordinated set of specified GRAs formulates a restoration plan.
- Different restoration plans can be built and simulate using different restoration actions. Thus a knowledge base of restoration plans can be built and the user can try the most effective.

For the coordination of the GRAs a modularized framework is used as illustrated in Figure 52. These modules serve to check the feasibility of a GRA.

The main modules coordinated by the CAMC are:

- MW and MVAR Management Module. This modules is used to before starting a machine or adding a static capacitor. A distinction between black start and non black start machines is made.

- Path Management. Path management module determines the branches to be switched for two nodes to be connected.
- Load Management. This module evaluates the active and reactive power balance of the MMG before connecting a load.
- Stability Inspection. The Stability Inspection module is invoked for a scenario which may cause stability problems

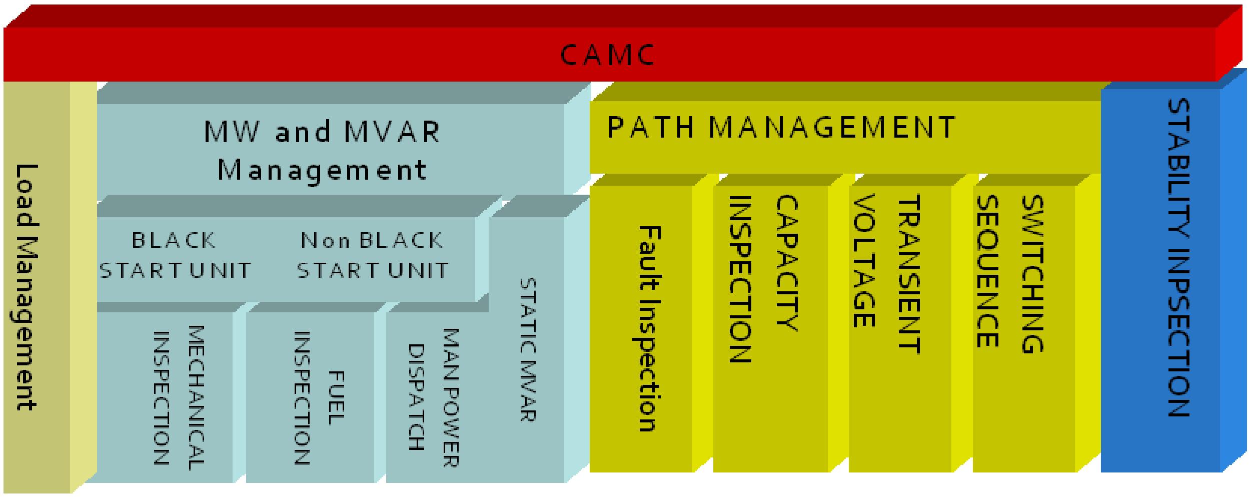

Figure 52: Modularized Framework for restoration

The set of GRA that can formulate a restoration plan is described below:

- Start of black start Unit (X). This GRA is to start a specified black-start unit X after checking its status by the Black-Start Unit Operation module.
- Find path (X,Y). This GRA is to used to find a path between two buses of the MMG. The path between X and Y will be searched and its availability and feasibility will be checked by the Path Management module.
- Energize Line (X) This GRA is to energize a line X. The status and capacity of the line is checked by path management module and its sub-modules.
- Pick up Load (X) This GRA is to pick up a specified load X as long as its power requirements can be satisfied and the switching actions do not cause any voltage or frequency violation.
- Synchronize (X,Y) This GRA is to synchronize two subsystems, X and Y, if the prerequisites of synchronization are satisfied.
- Connect unit (X). This GRA is to connect a specified non-blackstart unit X.

- Energize Busbar (X). This GRA is to energize a specified busbar X. The status and capacity of X and the loads connected to it must be checked.

Based on the above GRAs a library of restoration plans can be built, from which the restoration plan is selected.

5.1 Formulation of a Restoration plan

A restoration plan based on the sequence and procedures described above is illustrated in this paragraph.

1. **Identification that the system is in black out state.**
2. **Prepare the Network to start-up. Before launching the units for black start some** actions should be performed.
   - Disconnection from the upstream grid. If the MMG is connected to the upstream Grid then the black start will fail because the grid will absorb a high value current.
   - Shut down all the loads. This operation ensures that the system will not fail again because of increased demand and transient currents.

3. **Launch the black start units.** The GRA black_start is executed for each of the units with black start capability.
4. **Pick up the loads.** When the MW and MVAR management module indicates that there is available capacity for more load to be served, then loads are picked up one by one, starting from the critical loads. This procedure requires first to find a path (Path management) to energize the line and to energize the bus bar of the load.
5. **Connect non-controllable generators.** At this stage the system has controllable generators (chp and diesel) and loads capable of smoothing voltage and frequency variations due to power fluctuations in non-controllable units like hydro and wind turbines.
6. **Synchronize the MGs to the MV network.** MGs, which have a black start and are restored parallel to the MMG, are connected to the MMG when it is restored

Table 8 provides the restoration actions in chronological order.

Table 8: Sequence of restoration plan

Black Start of Diesel Unit
Connect Loads NLV1A, NLV1
Connect Loads NLVR1, NLVR2
Black Start CHPA
Connect Load NLVR1A, NLVR2A
Black Start CHP
Connect Load NLV5
Connect Load NLV5A
Black Start CHPA2
Connect Load NLV4A
Connect Load NLV9A
Start Hydro
Connect Load NLVR3, NLVR4, NLVR5
Connect Load NLVR7, NLVR8, NLVR9, NLVR10
Start HydroA
Connect Load NLVR3A, NLVR4A, NLVR5A, NLVR7A
Connect Load NLVR8A, NLVR9A, NLVR10A
Start HydroA2
Connect Load NLVR17A, NLVR21A, NLVR22A, NLVR24A
Connect DFIM (25% of windturbines)
Connect Load NLV1A
Connect NLV1,NLV6A, NLV6
Connect DFIM (50% of windturbines)
Conect Load NLV2A, NLV2
Connect DFIM (75% of windturbines)
Connect Load NLV7, NLV7A,
Connect DFIM (100% of windturbines)
Connect Load NLV4, NLV9
Connect Load NLV14A
Start DFIM2 (25% of windturbines)
Connect Load NLV13A,
Start DFIM2 (50% of windturbines)
Connect Load NLV16A
Start DFIM2 (75% of windturbines)
Connect Load NLV11A
Start DFIM2 (100% of windturbines)
Connect Load NLV18A
Synchronize MGs to the MV network one by one

The frequency and voltage at bus NMV deviations, are illustrated in Figure 53 and Figure 54.

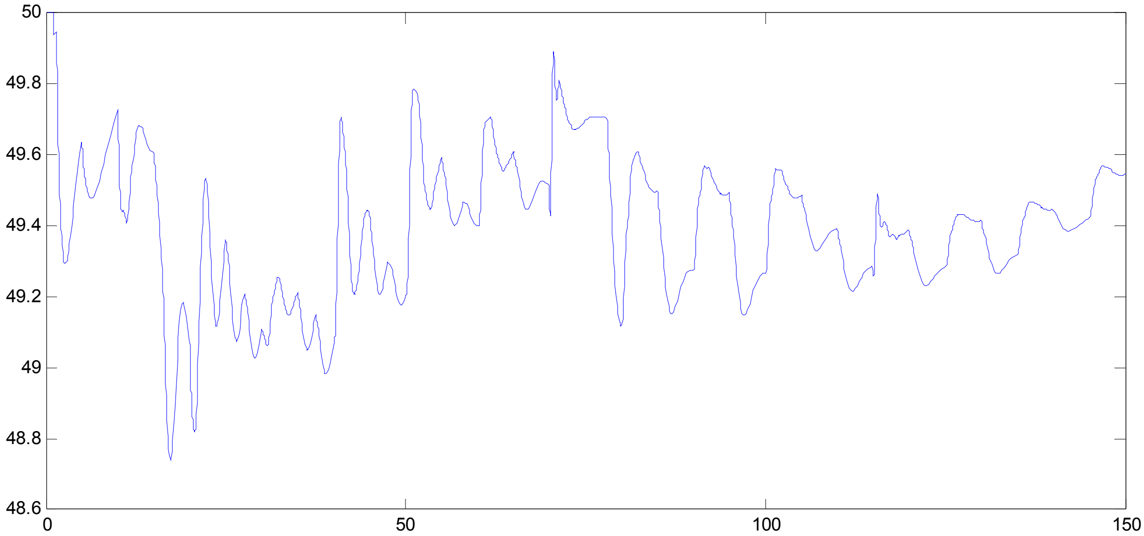

Figure 53: Frequency deviation during restoration

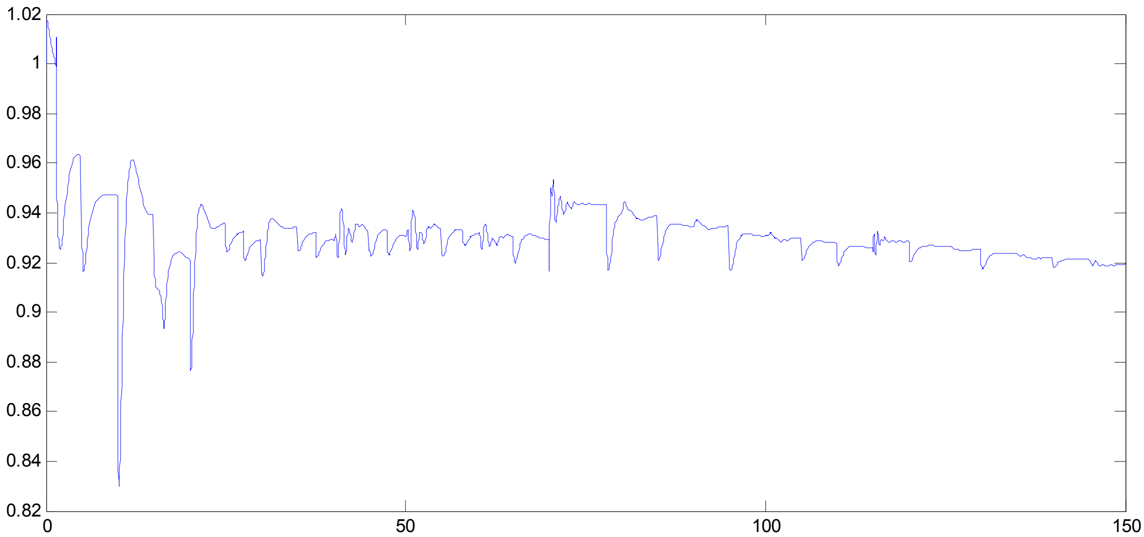

Figure 54: Voltage at bus NMV, during restoration

A parallel restoration sequence could be also applied, as an alternative to the above sequential restoration plan. The MMG is sectionalized to subsystems according to the following criteria.

- Each subsystem must have blackstart capability.
- Each subsystem should have the ability to match generation and load to within prescribed frequency limits.
- Each subsystem should have adequate voltage controls to maintain a suitable voltage profile. This would include the ability to pick up load, underexcite generating units, change taps on tie transformers or operate synchronous condensers.

6. References

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