# Advanced Architectures and Control Concepts for More Microgrids

**Contract No: SES6-019864**

## WORK PACKAGE E

## DE3: Specification of Management System Operation and Control requirements for Microgrids and multi-Microgrids

Final Version

April 2008

# Advanced Architectures and Control Concepts for More Microgrids

**Contract No: SES6-019864**

## WORK PACKAGE E

## DE3: Specification of Management System Operation and Control requirements for Microgrids

Final Version

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| | | |
|---|---|---|
| **Coordination:** | J. Oyarzabal[1] | joseoyar@labein.es |
| **Authors:** | I. Papadogoula[2] | ipapadog@anco.gr |
| | J. Oyarzabal[1] | joseoyar@labein.es |
| | N. Hatziargyriou[3] | nh@corfu.power.ece.ntua.gr |
| | C. Schwaegerl[5] | christine.schwaegerl@siemens.com |
| | | [1]LABEIN, [2]ANCO, [3]MVV, [4]NTUA, [5]Siemens |

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# Contents

# List of Figures

# List of Tables

# 1. Introduction

The progressive liberalization of the electricity sector and the subsequent transition to a decentralised system benefits the emerging of new options for planning, managing and operating distribution networks. In this context, customers can have the opportunity of participating actively in the electricity system through the operation of their micro-generators or the management of their controllable loads, following the criteria for this purpose of maximising their revenues or contributing to supply-demand balance of the system. This challenge can be accomplished through the employment of the Microgrid concept that consists in an aggregation of small generation systems (micro-CHP, photovoltaic, micro-wind…), storage devices and controllable loads that have local coordinated functions. These systems can be operated in a non-autonomous way, if interconnected to the grid, or in an autonomous way, if disconnected from the main grid.

The operation of the Microgrid requires three different control levels:

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

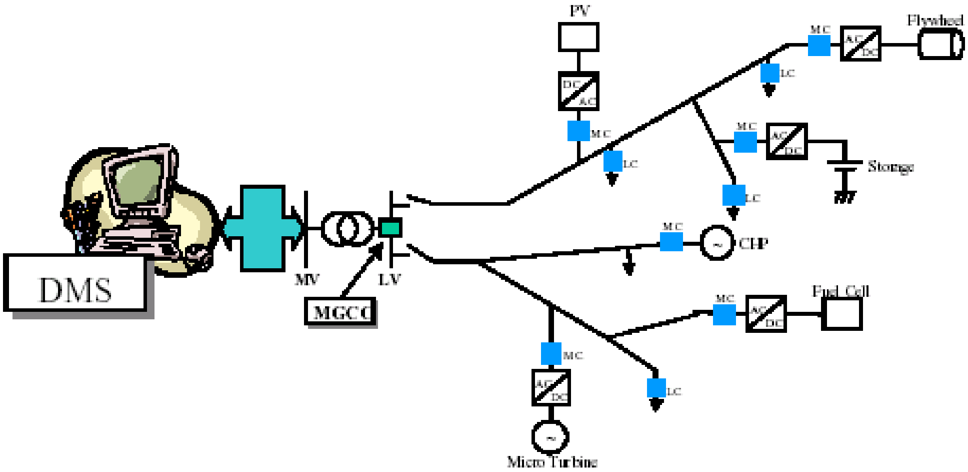

**Figure 1-1: Microgrid Control architecture**

The MicroGrid Central Controller (MGCC) is in charge of managing the Microgrid and its functions can range from monitoring the actual active and reactive power of the distributed resources to assuming full responsibility of optimizing the Microgrid operation by sending control signal settings to the distributed resources and controllable loads.

Micro-Source Controllers (MC) are installed at micro-generators and storage devices and are the responsible of making a local control of the active and reactive power generated by them. Local Load Controllers (LC) provide load control capabilities.

The Distribution Management Systems (DMS) manages the whole distribution network.

These controllers interact among themselves exchanging the required information for achieving their objectives.

# 2. Victoria advanced metering study case

In this chapter, a detailed analysis of the costs incurred for providing the Microgrid with a communication infrastructure that allows the mentioned information exchange is reported.

For this purpose, a study carried out by the consulting firm “CRA International” regarding a massive implementation of advanced interval meters in Victoria City, Australia, is taken as reference ([Ref-1]). Such work investigates whether or not it would be cost-effective to add communications to the meters and what communication technology would be better from the economical point of view. The study is focused on four different types of communication technologies: Wireless Networks (GPRS or CDMA), Distribution Line Carrier (DCL), Mesh radio and Power Line Carrier (PLC), providing a cost-benefit analysis for each of them. The methodology employed in the study and the main extracted conclusions can be extrapolated to the Microgrid case although there will be some differences that will be noted when needed.

This chapter is structured as follows: section 2.1 describes the general approach of the study; in section 2.2 the economical analysis of different communication technologies is provided; section 2.3 describes the main benefits that could be achieved with the deployment of an advanced interval metering infrastructure; section 2.4 contains information regarding technology trials; finally, section 2.5 summarises the main extracted conclusions from the study.

## 2.1. Methodology

### 2.1.1. Introduction

The communication requirements may vary from one Microgrid to other as a function of the characteristics of its components and the criteria followed for its operation. Sometimes it will be necessary an information exchange in real-time that allows to know the current status of the different devices connected to the Microgrid in order to send them the appropriate control signals, and other times, it will be possible a more deferred information flow. In general, the costs of communications will depend on the communication technology employed, the volume of data exchanged and the frequency of communications. An important factor that will influence the selection of one technology is the location of the Microgrid (rural or urban) because not all technology types are available anywhere.

In this work, a scenario based on the study “Advanced Interval Meter Communications Study” prepared by the consultancy “CRA International” is considered ([Ref-1]). In July 2004, the Essential Services Commission (ESC)[1] of Victoria City in Australia published a decision for the Interval Meter Rollout (IMRO) according to a specified schedule starting in 2008 and finalising in 2013 ([Ref-4]). By this year, all customers with new and replacement installation commencing in 2006 would have an interval meter. However, this decision did not establish a date by which all customers had to own interval meters. In addition to this, the IMRO decision did not include the requirement of installing communication equipment as part of the rollout. The mentioned document investigates the economical viability to add communications to the IMRO meters and analyses the benefits of accelerating the rollout so that all meters are converted to IMRO meters with communication capabilities in four years (from 209 to 2012). It is focused on customers consuming less that 160 MWh per annum. The evaluated technologies for advanced meter communications were the following ones:

a) Wireless networks (cellular radio networks: GPRS/CDMA)
b) Distribution Line Carrier (DLC)
c) Mesh radio
d) Power Line Carrier (PLC)

The communication infrastructure to be installed in a Microgrid is similar to the required one by interval meters. Smart meters are comparable to the local controllers of the Microgrid (MC/LC) and the Network Management System (NMS), which is in charge of aggregating and processing the measured data, is equivalent to the MGCC. Obviously, the local controllers of the Microgrid will require additional functionalities that allow them a more frequent data recording and the management of the power set-points received from the MGCC. The MGCC must be able to process the information in real-time as well as determine the generation and consumption schedules that will be sent to the MCs and LCs respectively. This will suppose an extra cost in relation to the smart meters infrastructure. However, the

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[1] The Essential Services Commission (ESC) is the independent regulator of the energy industry in Victoria. Its role is to regulate the distributors’ prices and monitor service standards, manage licence arrangements for the distribution and sale of gas and electricity in Victoria and ensure compliance by the licensees with codes and guidelines concerning service standards and appropriate conduct ([www-1])

general methodology of the “Advanced Interval Meter Communications Study” and the extracted main conclusions can be applied to the Microgrid case due to the high number of similarities that exist between them. Taking as basis the information provided in such document, it is possible to estimate the magnitude order of the different costs related to the deployment of a communication system based on different technology alternatives and evaluate consequently the most appropriate one from the economical point of view.

### 2.1.2. Overview of the approach

This section provides an overview of the approach of the study ([Ref-1]). It includes a description of the considered scenarios, the technology options, the specifications of the equipment as well as a general description of the costs and benefits analyses.

#### 2.1.2.1. Scenarios

As it was said previously, the ESC of Victoria City in Australia published in 2004 a decision for the IMRO according to a schedule starting in 2008 and finalising in 2013. The consultancy firm “CRA International” analysed the feasibility of postponing the beginning of such deployment until the year 2009 in exchange for accelerating the process so that it would only last four years (from 2009 to 2012). The reasons that justified this delay were related to the required time to solve many important issues such as:

- Making of the necessary policy and business decisions for a rollout to proceed,
- Functionality specification of the meters,
- Running trials of systems,
- Installation of new meters,
- Building the communication network.

In the study, two different scenarios are considered:

- Scenario 1: Slow deployment of the communication infrastructure.
- Scenario 2: Accelerated deployment of the communication infrastructure.

In the first scenario, it is considered that the deployment is carried out during seven years. However, in the second one it lasts only four. These scenarios try to analyse the impact of scale effects.

#### 2.1.2.2. Technology options

Nowadays, multiple types of communication technologies exist. These can be grouped into two different categories: wireless technologies and cable technologies.

Wireless technologies transfer the information without the use of electrical conductors. They comprise cellular radio networks (GSM, GPRS, CDMA, UMTS…), radio paging systems, trunked radio services, WiMAX, satellite… ([Ref-5])

Cable technologies require a physical cable connection between the sending and the receiving units. They include Power Line Carrier (PLC), fibre optics, Asymmetric Digital Subscriber Line (ADSL)… ([Ref-5])

This work is focused on a) Cellular radio networks and b) Power Line Carrier (PLC) because they represent the most likely communication technologies for being employed in a Microgrid.

a) Cellular radio networks

Cellular radio networks make use of public wireless communication links on the basis of services offered by third parties. They comprise several technologies such as GSM (Global System for Mobile Communications), GPRS (General Packet Radio Systems), and CDMA (Code Division Multiple Access). UMTS (Universal Mobile Telecommunications System) is also included in this group. Although it has a small geographic coverage nowadays, this third-generation technology is expected to replace the previous ones in the future because it is an extremely powerful digital mobile telephony system that allows higher data transmission rates than GSM/GPRS/CDMA ([Ref-1],[Ref-5]).

Cellular radio networks can be easily implemented because they do not require the installation of a wiring system. Due to this reason, they are appropriate for providing coverage to rural areas. They also allow a very fast, reliable and safe bi-directional data transmission ([Ref-5]). Some disadvantages are their range limitations, as well as the interferences that might be caused under adverse weather conditions.

b) Power Line Carrier (PLC)

PLC technology makes use of electric power lines for communication purpose. It can be employed over high, medium and low voltage lines and can be limited to one specific level or cross between two different voltage levels. This technology is not new because it has already been used by electricity utilities mainly for protection signalling on transmission lines. There exist different types of PLC as a function of the frequency bands employed that can offer a broadband or a narrowband communication.

The main advantage of PLC technology is that it makes use of the existing infrastructure for transferring information along the power lines. For this reason, it allows a simple implementation not only in urban areas but also in rural ones. PLC can be employed for providing a bi-directional high-speed transmission of large quantities of data for multimedia and internet purpose (broadband Power Line Communications). Regarding the transmission of energy related data, PLC has been applied for different purposes such as collecting measuring data from customers or transferring energy data and operation parameters to a central computer supervising the state of a photovoltaic system. However, this technology has not a widely diffusion nowadays. Besides, it has low reliability and speed of transmission and there can be some technical problems as a function of the frequency bands employed ([Ref-1],[Ref-5]).

In this work, three different deployment/technology combinations have been considered taking as reference for this purpose the “Advanced Interval Meter Communications Study”:

- 1a: Slow deployment, cellular radio networks technology (public wireless network)
- 2a: Accelerated deployment, cellular radio networks technology (public wireless network)
- 2b: Accelerated deployment, PLC technology (private network)

The mentioned study does not analyse the combination 1b that would correspond to a slow deployment of the communications infrastructure based on PLC due to the unavailability of cost information.

Deployment/technology combinations 1a and 2a consider GPRS networks for urban areas and CDMA networks for rural ones when GPRS is not available. Combination 2b assumes an architecture based on PLC for performing communication between the local controllers of the Microgrid and the PLC transceivers at each zone substation and GPRS technology for the communication between the MGCC and the PLC transceivers.

As it was mentioned previously, the current radio cellular network technologies (GPRS/CDMA) are expected to be replaced by third-generation ones such as UMTS in a few years. This change will require the modification of the installed modems that will represent an additional cost that has been taken into account in this analysis.

### 2.1.2.3. Specification of the Local Controllers of the Microgrid

The majority of the meters installed nowadays are single-phase electro-mechanical meters with a single register or multiple registers that are manually read. An advanced interval meter has additional functionalities and communication capacities that allow it exchange information with the utility.

The Australian study establishes the following minimum requirements for AMI (Advanced Metering Infrastructure) Meters ([Ref-2]):

1) Metering: record active energy for export and import (when there is local generation capability at premises) in 30 minutes intervals, record total accumulated consumption per interval channel and store a minimum of 35 days per channel of 30 minute interval energy data.
2) Remote and local reading of interval data. When they are remotely read they must provide the collected data at least once every 24 hours.
3) Remote connection and disconnection capability: they must include a connect/disconnect contactor.
4) Load control capabilities: they must be able to respond to load control commands.
5) Meter loss of supply detection and outage detection.
6) Quality of Supply and other event recording.
7) Supply capacity control: they must have two supply limit settings, a normal limit and an emergency limit.
8) Interface to Home Area Network (HAN).

There are two possibilities for obtaining meters fulfilling the previous specifications. The first one consists in retrofitting the existing electro-mechanical meters with modules that perform the previously mentioned functions. The second one consists in replacing the existing meters by new ones. According to [Ref-1], the last approach is the most cost-effective one for massive deployment. The main reason that justifies this fact is related to the large variety of meter configurations that can be found among the installed meters that would difficult the development of retrofitting modules.

Looking at the previous information it can be concluded that the functionalities of the local controllers of the Microgrid will not differ very much from the mentioned ones for the advanced interval meters. The most important differences might be on the frequency of the records of some specific micro-sources or loads that might be required close to real-time instead of every 30 minutes so as to operate them.

#### 2.1.2.4. Analytical approach to costs and benefits

Taking as reference ([Ref-1]) it can be stated that there are eight different costs categories related to the deployment of a communication system in a Microgrid:

**Table 2-1: Costs related to the deployment of a communication system in a Microgrid**

| Communication system costs |
|---|
| Costs of local controllers (MC/LC) |
| Local controllers (MC/LC) installation costs |
| Project management costs |
| Private network capital costs |
| Private network operating costs |
| Public network communication costs |
| MGCC capital costs |
| MGCC operating costs |

These costs will be different as a function of the communication technology employed and the considered scenario. A detailed analysis of each of them is provided in section 2.2.

The benefits of implementing an advanced interval metering infrastructure are constant for all technologies varying only between scenarios. The most important ones are presented in the following table:

**Table 2-2: Benefits related to the deployment of and advanced metering infrastructure**

| Communication system benefits |
|---|
| Avoided cost of manually read |
| Avoided Battery Replacement |
| Storage capacity reduction |
| Demand Side Management |

Section 2.3 includes a description of each of them.

## 2.2. Costs analysis

### 2.2.1. Introduction

This section presents a detailed description of the main incurred costs for deploying a communication system in a Microgrid. Specifically, an assessment of the costs presented in Table 2-1 for the three deployment/technology combinations considered in the study (see section 2.1.2.2) is performed. For this purpose, the main conclusions extracted from [Ref-1] are taken as reference and extrapolated to the Microgrid case. The results will provide an overview of what the most cost-effective approach is.

### 2.2.2. Costs of local controllers (MC/LC)

They represent the costs of the LC and MC devices installed at controllable loads and micro-sources respectively. These costs will vary as a function of the generator or customer type they are connected to and the functions they have to perform.

Focusing on the metering module, they can be ([Ref-1]):

- 1 phase non-off-peak meters: single register meters for whole premise loads with single-phase supply.
- 1 phase off-peak: meters for premises with single-phase supply, which contain two registers, one for dedicated circuit for off-peak water or space heating and the other for the rest of the premise.
- 3 phase direct connected: meters used for some large households and for small to medium businesses with three-phase supply where the meter is directly connected in series with the load.
- 3 phase CT connected: accumulation meters for large businesses with three-phase supply, where the meter is connected with current transformers to measure the energy usage at the premise.

The addition of communication modules to these devices will represent a different cost as a function of the considered scenario and the employed technology. The following table provides a comparison between indicative incremental unit costs for each scenario and communication technology. These costs represent the additional costs that would be incurred if communication modules were incorporated to the meters [Ref-1]:

**Table 2-3: Incremental costs of the meters**

| Device type | Incremental Unit cost (€) | | |
|---|---|---|---|
| | 1a (Slow deployment;GPRS/CDMA) | 2a (Accelerated deployment;GPRS/CDMA) | 2b (Slow deployment;PLC) |
| 1 phase – non off peak | 83 | 66 | 37 |
| 1 phase- off peak | 70 | 58 | 40 |
| 3 phase direct connected | 98 | 86 | 58 |
| 3 phase CT connected | 175 | 162 | 115 |

Looking at the previous table two main conclusions can be extracted. The first one is related to the lower unit incremental cost of scenario 2. This is due to the economics of scale that allow the manufacturers sell the equipment at a more competitive price.

The second one is that the integration of GPRS/CDMA modems into local controllers is more expensive than integrating PLC modules.

### 2.2.3. LC/MC installation costs

These costs are related to the installation of the local controllers and include labour, travel time, “site“ costs (rewiring, meter board replacement and asbestos issues) and back office operations to support the installations.

The following table shows estimations of these costs for the AMI meters ([Ref-1]):

**Table 2-4: Installation cost estimates**

| Device type | Installation cost estimates (€) | |
|---|---|---|
| | Scenario 1 (Slow deployment) | Scenario 2 (Accelerated deployment) |
| 3 phase CT connected | 80 | 77 |
| 3 phase direct connected | 117 | 144 |
| 1 phase- off peak | 143 | 140 |
| 1 phase – non off peak | 346 | 343 |

It can be observed that installation costs are practically the same for both scenarios. However, there exists a small difference between them that represents the higher efficiency on the installation process that can be achieved in the second scenario in relation to the first one. This is due to the optimisation of the travel time of the installers that occurs in an accelerated deployment and the elimination of other inefficiencies associated with a fragmented deployment approach.

It has to be noted that the installation costs of a local controller sited in a micro-generator (MC) could be higher than the corresponding ones to a local controller sited in a load (LC) due to the higher installation complexity.

Regarding the different technologies, the cost of installing a local controller with a GPRS/CDMA modem is the same as the corresponding one to a local controller with a PLC communication module. However, in the study it is considered that cellular radio technologies will be replaced in a near future (ten years) by UMTS, requiring consequently the change of the current modems. Due to this reason, the installation costs of local controllers based on cellular radio network communications will be higher.

### 2.2.4. Project management costs

This category is related to the incurred project management costs. Due to the higher complexity of a project involving an accelerated deployment, the costs corresponding to scenario 2 will be higher than the corresponding ones to the scenario 1.

Regarding the different communication technologies, cellular radio networks will have some additional project management costs to cover the replacement of GPRS/CDMA systems for other third-generation digital mobile telephony systems such as UMTS that will have a high diffusion in a few years.

### 2.2.5. Private network capital costs

These costs are only applicable to the deployment/technology combination 2b that makes use of a private communication network. They are associated with the costs of the PLC transceivers installed at each zone substation that collect data from the local controllers and transmit it via GPRS to the MGCC.

According to ([Ref-1]) it can be stated that the cost of each PLC transceiver is approximately 20200 €.

### 2.2.6. Private network operating costs

This category includes the costs of operating and maintaining a private network. The same as previously it is only applicable to the deployment/technology combination 2b. In this case, they cover the repair and replacement of failed components of PLC transceivers. According to [Ref-1] they take an average value of 67€/year per transceiver.

### 2.2.7. Public network communication costs

These costs are related to the usage charges that must be paid to public network service suppliers. In deployment/combinations 1a and 2a these costs cover the usage of public wireless networks for communication between the MGCC and the local controllers. In scenario 2b, they cover the cost for connections between the MGCC and PLC transceivers.

These costs have been estimated by [Ref-1] to take a value of 3€/year per local controller in scenarios 1a and 2a and 49€/year per PLC transceiver in scenario 2b.

### 2.2.8. MGCC capital costs

This category includes the costs related to the required equipment for managing and controlling the Microgrid. It represents the cost of the MGCC that is in charge of optimizing Microgrid operation and whose main functions are data processing and storage, power generation and consumption schedules definition and sending to the local controllers, billing and settlement…

These costs are the same for both scenarios but vary as a function of the employed technology. They include the costs of:

- all hardware
- all software
- database of meters
- systems integration
- implementation costs including project management, change management,…

According to the meter study [Ref-1], the employment of systems based on PLC is more economical than the employment of systems based on cellular radio networks. This difference is about the 13%.

### 2.2.9. MGCC operating costs

Finally, these costs cover the operation of the MGCC as well as additional costs of any ongoing incremental hardware maintenance and software licensing. Again, the more costly technology is radio cellular networks which costs a 15% more than PLC based systems.

## 2.3. Benefits analysis

There are several benefits associated with the deployment of an advanced interval metering infrastructure. These, are constant across the various technologies ([Ref-1]).

The most important one is the avoided cost of manual meter reads. Nowadays, the majority of domestic meters are manually read. The costs related to this process can be very high if the meters are randomly distributed along the geography. The addition of communication capabilities to the meters contributes no only to avoid the mentioned costs but also to facilitate the billing and eliminate the profiling for settlement.

Manually interval meters need a battery to maintain the real time clock during power outages. However, meters with advanced communication systems do not require it because they can be reset immediately after a power failure. This way, the costs related to batteries and batteries replacement are saved. Such replacement is estimated to be necessary every ten years.

When meters are enhanced with communication capabilities, the required storage capacity is reduced because the measures are expected to be read more frequently. However, this fact does not represent a significant price reduction because memory is not expensive.

Other benefits related to the deployment of a communication infrastructure in the Microgrid are provided next:

- Information display on consumption or generation.
- Demand Side Management: the customers equipped with a LC can actively participate in the Microgrid operation through the management of their power consumption as a function of the control signals sent by the MGCC.

## 2.4. Technology trials

A fundamental step for evaluating the convenience of a communication technology is the conducting of trials in order to allow better understanding of its behaviour and to check if the necessary requirements are met.

In May 2006, the “Trials Working Group (TWG)” was formed in Victoria, being its main functions:

- Develop a project plan for the AMI technology trials.
- Design and specify the trials.
- Coordinate the implementation and conduct of the trials.
- Provide a forum for the discussion of trial operations, progress and results, and resolution of issues.

The trials were focused on assessing the performance of the AMI communications systems. The intention was not to compare technologies, but to evaluate independently their suitability for further investigation for implementation in Victoria.

The following table shows the assessment criteria considered in the trials:

**Table 2-5: Assessment criteria of the technology trials**

| | Criteria |
|---|---|
| Communications (NMS to meters and return) | Bandwidth: to meet current and future data throughput requirements |
| | Latency: to meet response times and meter time synchronisation accuracy requirements |
| | Reliability: bit error rata, redundant components, time to repair, auto reconfiguration of network |
| | Availability: the effect of interference |
| | Data integrity: no corruption of data sent from meter to NMS |
| | Security: message privacy, access control and user authentication |
| AMI System Architecture | Ease of setup and operation of AMI system |
| | Ability to meet configuration requirements |
| | Ability to recover from equipment failures |
| | Ability to recover from power outages |
| | Ability to scale to the size required for the rollout, identify bottlenecks |
| | Network coverage/environmental limits |
| | Software deployment |
| | Network management |
| | System limits: maximum meters per concentrator, maximum meters per NMS, maximum concentrators per NMS, maximum and minimum meter density. |
| | Communications network resilience: ability to recover from network and equipment failures. |
| | Backend systems integration |
| | Ability to reliably acquire meter data end to end |
| Vendor capability | Technical and logistical support |
| | Quality/reliability of equipment |
| | Supply of equipment |
| | Ability to tailor AMI system to meet Victorian functionality, performance and service level requirements |
| | Maturity of solution, proven deployments |
| | Longevity of the technology |
| | Open architecture |

The followed approach in the trials, which were carried out in August 2007, and the main extracted conclusions are reported in the document "Advanced Metering Infrastructure-Technology Trials Report" developed by the Department of Primary Industries of Victoria ([Ref-3]).

An overview of the main findings for each communication technology is presented next.

The GPRS technology trial consisted of 100 sites and was undertaken with the purpose of testing the communications technology as well as end-to-end business processes. The results showed that GPRS has enough bandwidth to meet the necessary requirements.

Regarding PLC, the TWG concluded that there are available PLC technologies suitable for further investigation. Some concerns were related to the potential margin to support future bandwidth requirements that are expected to increase significantly in the future. In addition to this, some technical issues such as voltage flicker and harmonics should be further investigated and solved.

In general, the results of the trials showed that there are suitable communication technologies for being deployed in Victoria city. However, not all of them are at their full maturity requiring consequently further development. Most of the vendors involved in the trials showed their interested in the AMI project and expressed their intention of improving the performance of their products in order to comply the minimum AMI functionality specification ([Ref-2]) or even exceed it. In this process, the sharing of information and experiences among the implicated parts (suppliers, vendors…) is of great importance in order to reach a common agreement.

## 2.5. Conclusions

In this work, an economical assessment of different available communication technologies applied to AMI are reported in order to determine a suitable one for being employed in a Microgrid. Specifically, the study is focused on cellular radio networks (GPRS/CDMA) and PLC systems representing a wireless technology and a cable technology respectively.

For this purpose, the "Advanced Interval Meter Communication Study" carried out by the consulting firm "CRA International" is taken as reference. Such work is focused on evaluating the convenience of adding communications to the meters to be installed in Victoria City in Australia and determining what communication technology would be better from the economical point of view. The methodology employed in that study and the main extracted conclusions are applicable to the Microgrid case due to the high number of similarities that exist between both systems.

As a result, eight different categories of costs related to the deployment of a communication infrastructure in a Microgrid are identified: costs of MC/LC, MC/LC installation costs, project management costs, private network capital costs, private network operating costs, public network communication costs, MGCC capital costs and MGCC operating costs.

In addition to this, some benefits obtained from the establishment of an advanced interval metering infrastructure are defined. These most important ones are: avoided cost of manual meter reads, avoided battery replacement and demand side management.

The main extracted conclusions show that the costs of implementing a system based on cellular radio networks are higher than the corresponding ones to a system based on PLC. This is mainly due to two reasons. The first one is related to the usage charges that have to be paid to public network service suppliers. In a PLC system, the utility is the proprietary of the communication channel and consequently, these payments are avoided. The second one is due to the expected obsolescence of the current digital mobile systems (GPRS/CDMA) that will be substituted by third-generation technologies such as UMTS. This fact will require the change of the modems installed nowadays.

In the analysis, two different scenarios have been considered. The first one corresponds to a slow deployment of the communication infrastructure and the second one to an accelerated one. Due to the impact of scale effects, the costs in scenario 2 are lower than in scenario 1.

However, not only the economical point of view is important for determining the convenience of a communication technology. Trials play a fundamental role for better understanding of the technology behaviour in order to check that the technical requirements are also met. [Ref-3] describes the conditions of the trials that were carried out during August 2007 in Victoria City for testing the AMI communication technologies. The obtained results show that both technologies, GPRS and PLC, can be suitable for the implementation in Victoria City.

Finally, it can be noted that the communication infrastructure could be designed to allow remote reading not only of electric consumptions but also gas and water ones. This is called multi-utility metering and in this situation, the mentioned costs would be shared among electricity, gas and water supply companies diminishing consequently, the required investment and operating costs for the utility.

# 3. References

[Ref-1] CRA International “Advanced Interval Meter Communications Study”, Department of Infrastructure – Energy and Security Division, Melbourne, December 2005.

[Ref-2] Department of Primary Industries “Advanced Metering Infrastructure- Minimum AMI Functionality Specification”, Victoria, October 2007.

[Ref-3] Department of Primary Industries “Advanced Metering Infrastructure - Technology Trials Report, Victoria, November 2007.

[Ref-4] Essential Services Commission “Mandatory Rollout of Interval Meters for Electricity Customers: Final Decision” Victoria, Melbourne, July 2004.

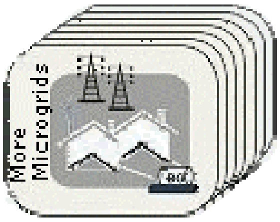
[Ref-5] Erge, Th. “Inventory of Relevant ICT technologies: Role of Communication Technologies for the Development of DG Networks”, DISPOWER, May 2006.

# 4. Web Sites

[www-1] http://www.esc.vic.gov.au./pulic/Energy
Essential Services Commission - Energy

# 5. Glossary

| Term | Stands for |
|---|---|
| ADSL | Asymmetric Digital Subscriber Line |
| AMI | Advanced Metering Infrastructure |
| CDMA | Code Division Multiple Access |
| CHP | Combined Heat and Power |
| DLC | Distribution Line Carrier |
| DMS | Distributed Management System |
| ESC | Essential Services Commission |
| GPRS | General Packet Radio Systems |
| GSM | Global System for Mobile Communications |
| HAN | Home Area Network |
| IMRO | Interval Meter Rollout |
| LC | Load Controller |
| MC | MicroGenerator Controller |
| MGCC | MicroGrid Central Controller |
| NMS | Network Management System |
| PLC | Power Line Carrier |
| TWG | Trials Working Group |
| UMTS | Universal Mobile Telecommunication System |
| WiMAX | Worldwide Interoperability for Microwave Access |



# Advanced Architectures and Control Concepts for More Microgrids

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**DE3:** Specification of Management System Operation and Control requirements for multi-Microgrids

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|---|---|---|
| **Coordination:** | João Abel Peças Lopes | jpl@fe.up.pt |
| **Authors:** | João Abel Peças Lopes | jpl@fe.up.pt |
| | André Madureira | agm@inescporto.pt |
| | José Ruela | jruela@inescporto.pt |

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# Contents

# List of Figures

# List of Tables

# 1. Introduction

A microgrid ([Ref-1]) 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 1-1.

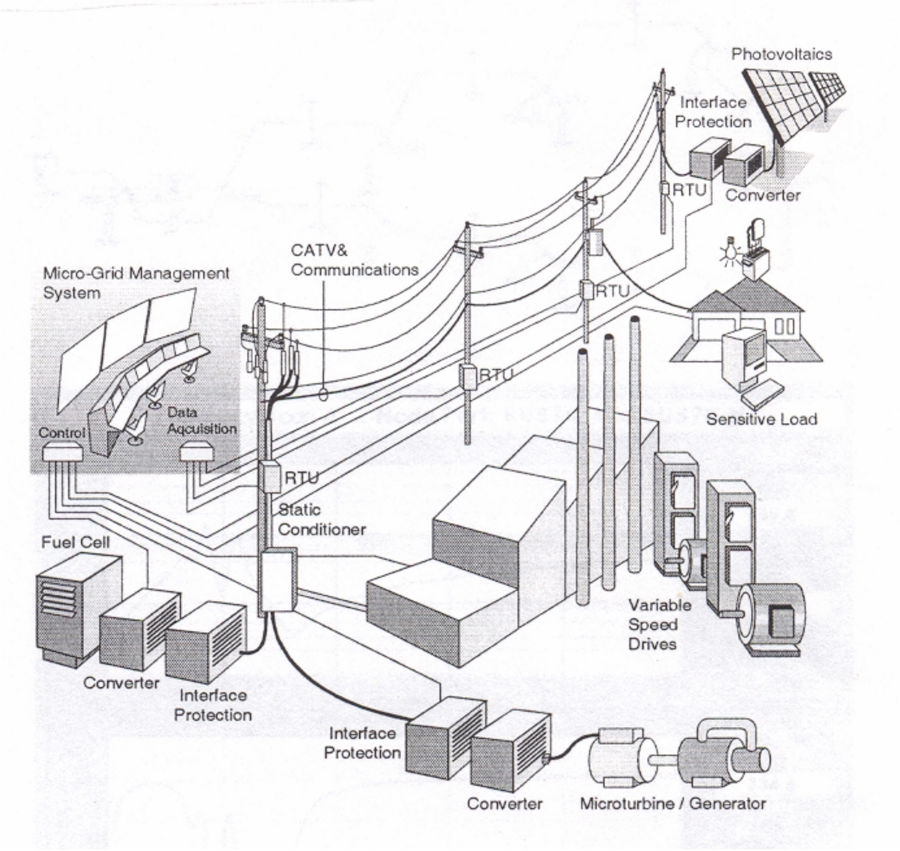

Figure 1-1: Typical MicroGrid System

A control scheme for microgrid operation requires three different control levels that can be seen in Figure 1-2:

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

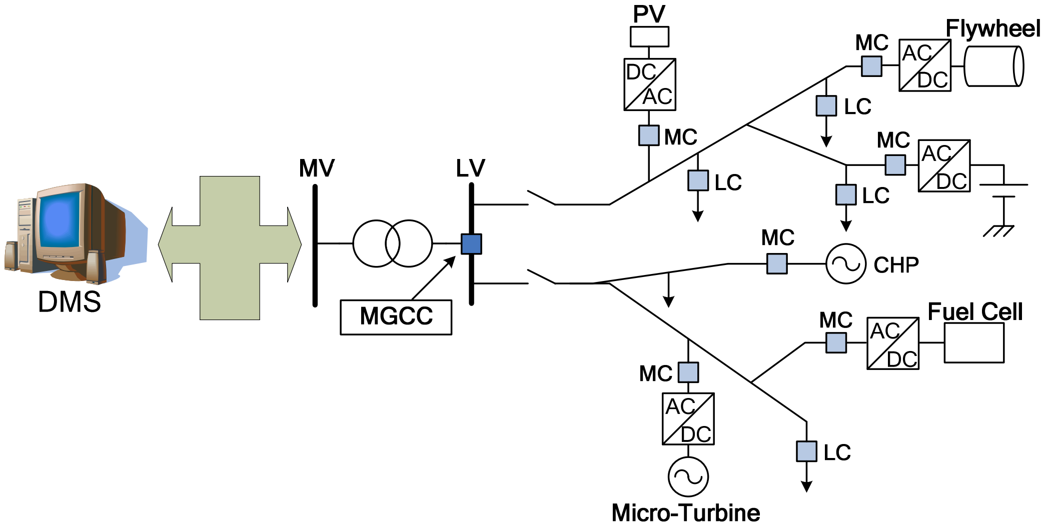

**Figure 1-2: Microgrid Control Architecture ([Ref-1])**

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

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

# 2. Control and Management Architecture

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

Nevertheless, decision making using decentralized control strategies must still hold a hierarchical structure ([Ref-2]). A central controller should collect data from multiple agents and establish rules for low-rank individual agents. These rules for each controller must be set by the high level central controller (DMS) which may delegate some tasks to other lower level controllers (CAMC or MGCC). This is due to the fact that a central management would not be effective enough because of the large amount of data to be processed and treated, and therefore would not ensure an autonomous management namely during islanded mode of operation. The CAMC must then communicate with other "local" controllers such as MGCCs or with DG sources or loads connected to the MV network, serving as an interface for the DMS.

Therefore, the CAMC will be playing a key role in a multi-microgrid system: it will be responsible for the data acquisition process, for enabling the dialogue with the DMS upstream, for running specific network functionalities and for scheduling the different agents in the downstream network. In general terms, this new management and control architecture is described in Figure 2-1.

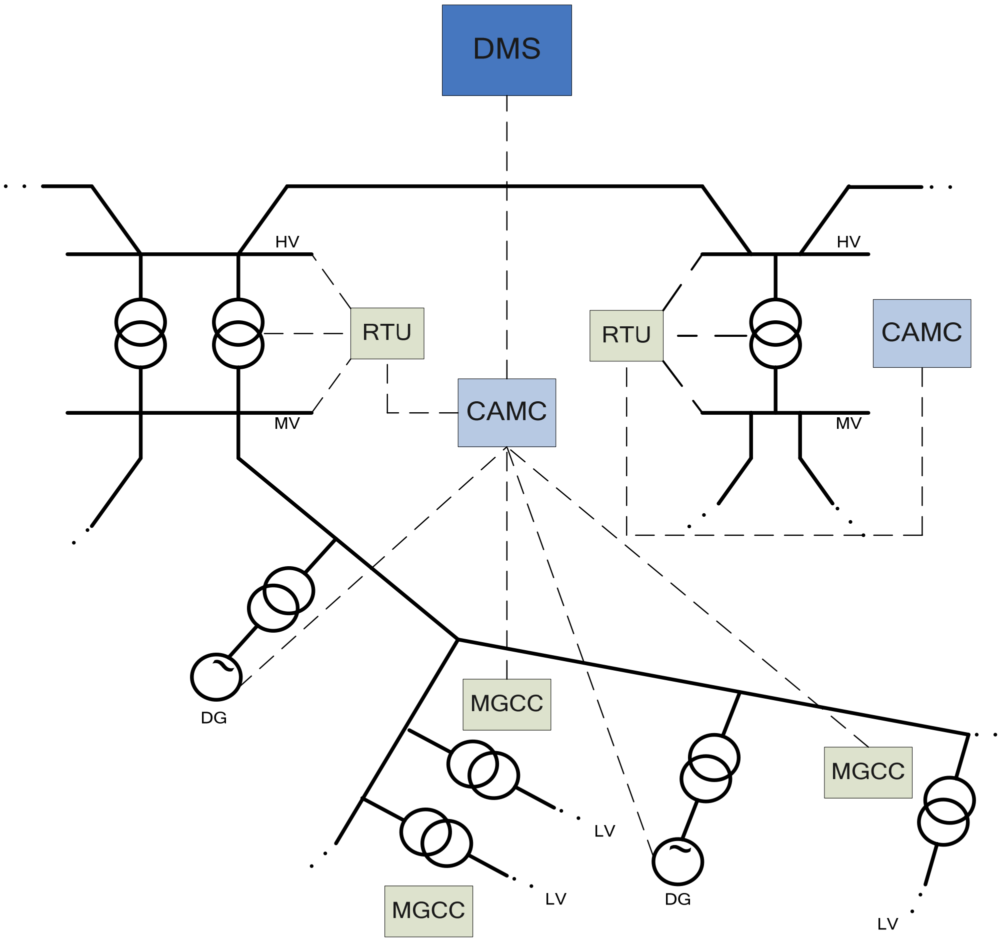

**Figure 2-1: Control and Management Architecture of a Multi-MicroGrid System**

A hierarchical scheme is required for both communication and for control. Figure 2-2 illustrates the decentralized hierarchical communication scheme for a multi-microgrid system, including the expected interactions between agents. Figure 2-3 presents the decentralized hierarchical control scheme for a multi-microgrid system.

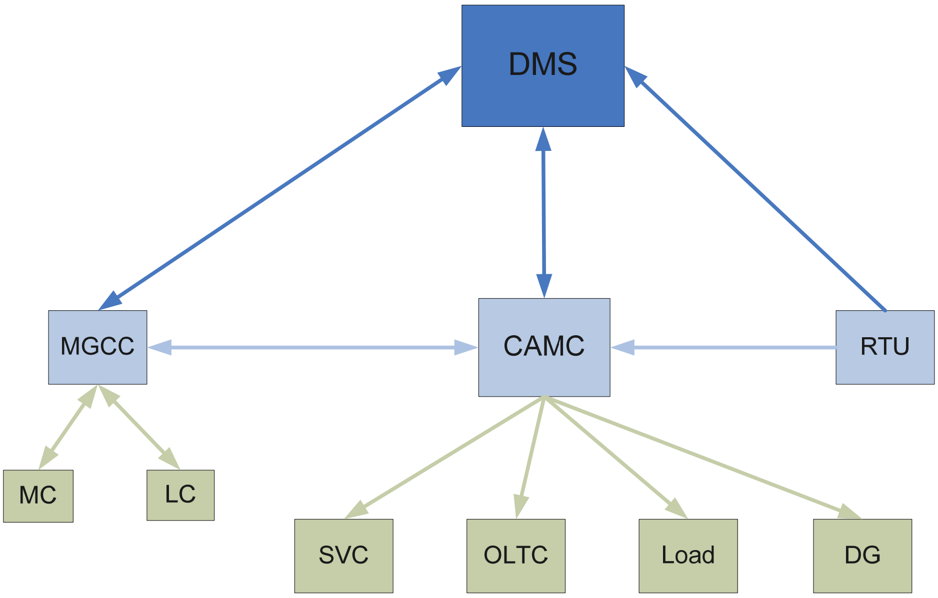

**Figure 2-2: Communication Scheme of a Multi-MicroGrid System**

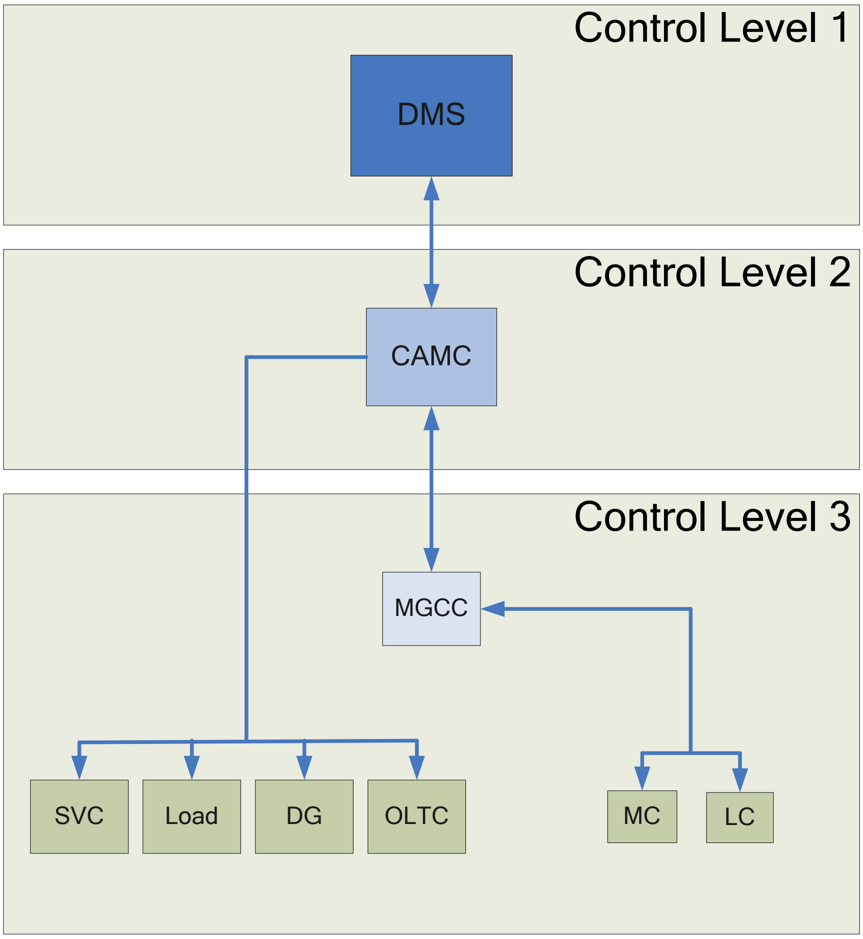

**Figure 2-3: Control Scheme of a Multi-MicroGrid System**

Concerning the communication scheme in Figure 2-2, the importance of decentralized control in the system architecture is related to the fact that, especially in emergency mode of operation, the communication between controllers (or agents) may be compromised. It is therefore most important that multi-microgrid operation should not be jeopardized by failures in communications.

The communications between controllers may be bidirectional or unidirectional depending on the type of controllers involved.

Still, a hierarchical structure may be observed in communication flows, somewhat similar to the control structure hierarchy presented in Figure 2-3.

Concerning the control scheme in Figure 2-3, there will be basically three control levels in order to profit from the advantages of hierarchical decentralized control. Several tasks of the various controllers may be autonomous or may work in a coordinated way and these functionalities must also be clearly defined. Still, some redundancy must exist in order to overcome situations where some control actions may be inhibited and there is a need for a higher-rank controller to step into action.

The most important interactions occur between the three “main” controllers, i.e. the DMS, the CAMC and the MGCC. As previously stated, the CAMC provides an interface between the microgrids (via corresponding MGCCs) and the DMS. Also, the correct specification of DMS and CAMC functions is one of the main objectives for efficient multi-microgrid system control.

## 2.1. Interactions among Controllers

As it was stated, the most important interactions concern high-level controllers such as the DMS, the CAMC and the MGCC. The communication among these three managing agents is addressed in this section. The communication flow will differ significantly according to the operating mode considered, as will be seen in the next chapter.

### 2.1.1. DMS-CAMC

The DMS and the CAMC are at the head of the communication scheme for a multi-microgrid system. Many traditional DMS functionalities have been transposed to the CAMC, as will be seen later in this report. This means that some of these functionalities may even be duplicated. The CAMC will act as an interface to the LV side of the multi-microgrid system and will have a considerable degree of autonomy. The interaction between these two controllers will form the basis for multi-microgrid operation especially concerning islanded operation.

The main information flow involving the DMS and the CAMC concerns mainly:

Data relating to local state estimation;

- Data relating to local state estimation;
- Data relating to market operation.

### 2.1.2. DMS-MGCC

The DMS may acquire some information directly from the MGCCs without having to use the CAMC as an interface.

The main information flow corresponding to DMS and MGCCs involves namely:

- Data relating to local state estimation;
- Data relating to forecasting;
- Data relating to DSM.

### 2.1.3. CAMC-MGCC

An efficient communication between the CAMC and the MGCC will be crucial for an efficient multi-microgrid system operation.

The MGCC is responsible for the control of an individual microgrid cell. Each microgrid must be considered as a fully controllable, flexible and active cell. The MGCC should operate the corresponding microgrid according to the requests coming from the CAMC.

Basically, the CAMC should specify the levels for active and reactive power for the MGCC to be provided by the corresponding microgrid cell. The active and reactive power levels may consider import or export conditions. The MGCC must then dispatch orders to both MC and LC in order to raise/lower generation or consumption.

In this case, the information flow between the CAMC and the MGCC will be significantly large. Also, different volumes of information are required according to the operating mode considered. An extensive collection of the information exchange needed between these two controllers is required.

# 3. Operating Modes and State Diagrams

Considering multi-microgrid systems, different modes of operation and operating state may be identified.

The two possible operating modes considered for a multi-microgrid system have been studied and are presented next:

- Normal operating mode;
- Emergency operating mode.

It is considered that the normal mode of the multi-microgrid system corresponds to grid-connected operation and that the emergency mode corresponds to islanded operation and to the black start procedure (service restoration).

Multi-microgrid operation also comprises several different states, and the corresponding transitions between states, due to different causes that may be divided in two categories: planned and unplanned. The proposed transition schemes can then be divided as follows:

- Transition scheme concerning planned events (scheduled/planned islanding of the multi-microgrid system);
- Transition scheme concerning unplanned events (forced/unplanned islanding of the multi-microgrid system).

The state diagrams for the multi-microgrid system are presented in Figure 3-1 (for planned events) and in Figure 3-2 (for unplanned events).

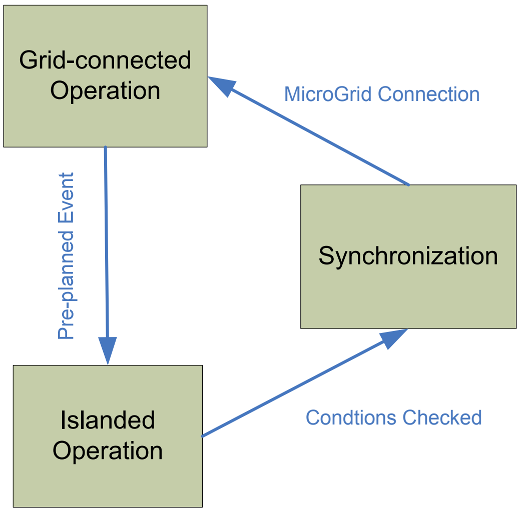

**Figure 3-1: State Diagram for Planned Events**

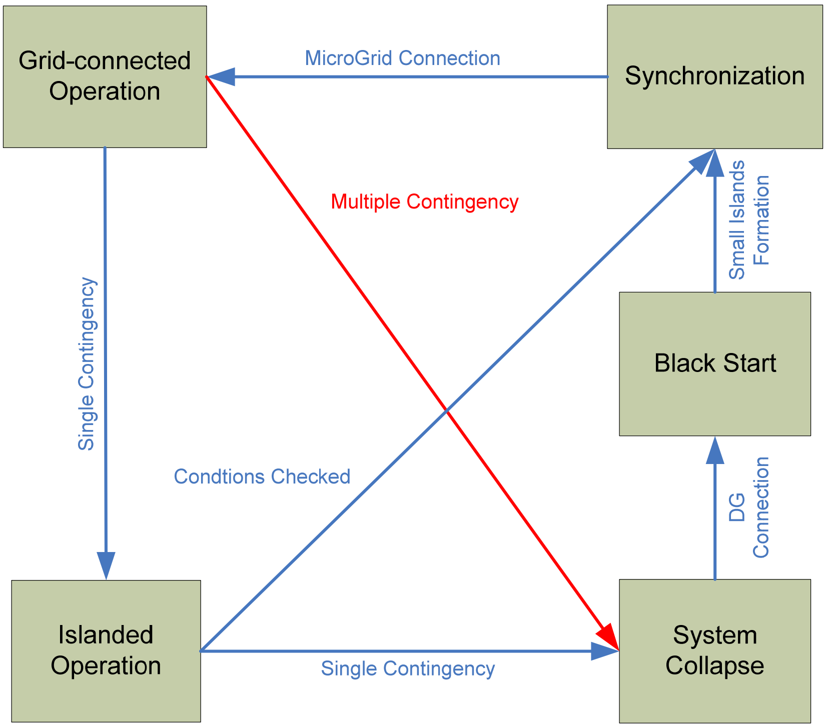

**Figure 3-2: State Diagram for Unplanned Events**

In Figure 3-1, three states may be observed: Grid-connected operation where the multi-microgrid system is connected to the main distribution network, participating in control scheduling (market operation), but also voltage/VAR control; Islanded Operation where the multi-microgrid operates autonomously controlling both voltage and frequency; and

Synchronization where the microgrid is being synchronized with the main MV network (checking the conditions on phase sequence, frequency and voltage) and after that the CAMC will authorize the reconnection.

In Figure 3-2, two additional states may be observed: System collapse, where a blackout occurred following a contingency or a series of contingencies; and Black start where the restoration procedure is initiated with the connection of DG sources followed by the formation of small islands.

The next chapters introduce several functions associated with each operating state, namely concerning emergency operating mode.

# 4. CAMC Functionalities

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 that may integrate the CAMC can be seen in Figure 4-1.

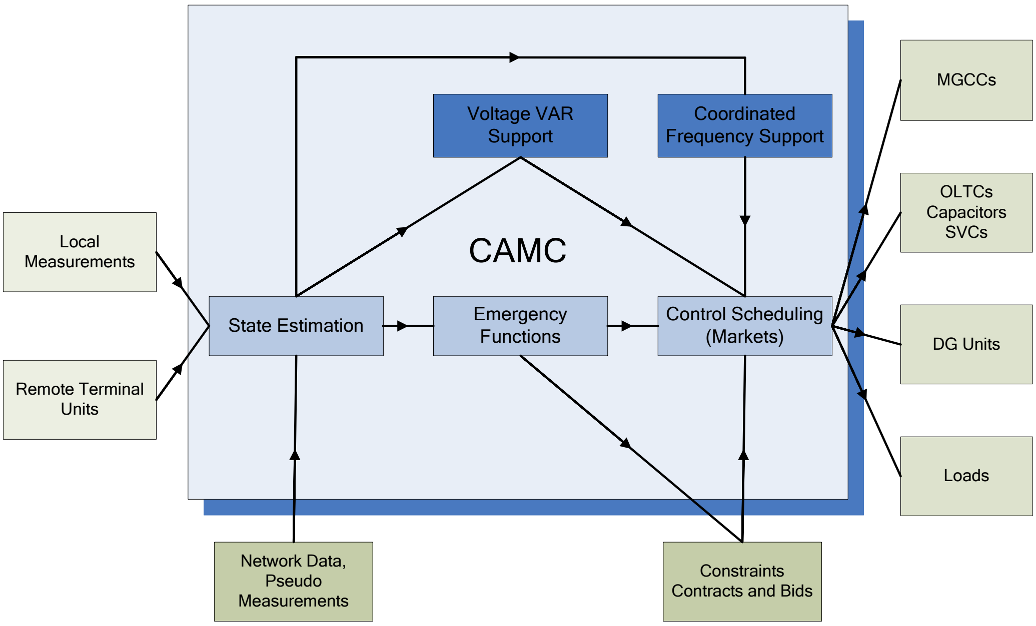

**Figure 4-1: CAMC Functionalities**

However, not all these functionalities will be available in any multi-microgrid system. Their availability will depend on the characteristics of local DG units present.

The functionalities presented in Figure 4-1 will be described in detail in the following sections.

## 4.1. State Estimation

A state estimation routine provides a complete and consistent model of the power system operating conditions. This is a routine that includes a procedure where system measurements are used to calculate values of unknown parameters.

A state estimation routine is typically a DMS function. Nevertheless, a local state estimation function will be included in the CAMC that will eventually provide results to a global state estimation functionality of the DMS.

Local state estimation is one of the most important features of the CAMC. It requires the collection of measurements that may be affected by errors. This information is processed together with additional pseudo-measurements and commercial information that will allow obtaining a clear “picture” of the local grid operating conditions, which is to be used in other control and managing functions. Functions such as voltage/VAR support or coordinated frequency control require information on the network operational conditions.

The advent of multi-microgrid systems constitutes an important opportunity to improve state estimation quality in MV distribution networks, since the MGCCs are able to provide a large set of information to the CAMC and to the DMS. At the same time, it is important to remember that during black start a good “picture” of the network is required in order to proceed adequately with the restoration sequence.

The MGCC of each microgrid has measurements regarding the LV feeder it is connected to, meaning that there are new measurements to turn networks more observable, to facilitate running a state estimation algorithm and to make it less dependent on load allocation procedures given that these algorithms can produce less accurate input data for state estimation. On the other hand, there are several issues to be dealt with including:

- The measurements available in the MGCC in general will not be synchronized with the remaining measurements available from the MV network. This means they ultimately refer to different system states, thus possibly making the results less accurate. This issue will have to be addressed either to guarantee this synchronization or to reduce the impact of its absence;
- The possibility of operating the multi-microgrid system in an isolated operating mode means that the topology of the network may not always be the same. Some traditional state estimation algorithms assume that the topology is fully known and that it will remain

the same. If there are topology changes, it will be interesting to enlarge the state vector including the state variables in order to consider also topology variables. This ultimately means that, in a complete state estimation algorithm, topology will also be estimated according to the available measurements; hence the need for a Topology Processor;

- During emergency operation, partial lack of communication may occur between the CAMC and the several MGCCs and this should be carefully accounted for;
- Finally, the possibility of operating the system divided into several islands, resulting from islanded operating mode of microgrids, presents several numerical problems when implementing simulation codes. The most challenging one is the requirement for a phase reference in each island, if there are more than one, and the presence of only one phase reference if the network is fully connected. Also, the phase references in each island should be set within a tight interval in order to facilitate reconnection.

## 4.2. Voltage/VAR Support

Hierarchical control should be established for voltage control, similarly to what happens in frequency control (described in the next section).

A hierarchical voltage control scheme can be divided into three control levels, according to areas of action and deployment time ([Ref-3]). These three levels are presented next:

- Primary Voltage Control – It keeps the voltage within specified limits of the reference values. Automatic Voltage Regulators (AVRs) are used to control voltage in primary control and their action takes effect in a few seconds;
- Secondary Voltage Control – It has the main goal of adjusting, and maintaining, voltage profiles within an area and of minimizing reactive power flows. Its action can take up to a few minutes. The control actions associated with secondary control include modifying reference values for AVRs, switching Static VAR Compensators (SVCs) and adjusting On-Line Tap Changing (OLTC) transformers. Usually a reference bus is used to represent the voltage profile of a certain area in order to define the reference for secondary control;
- Tertiary Voltage Control – It has the goal of achieving an optimal voltage profile and of coordinating the secondary control in accordance with both technical and economical criteria. It uses an algorithm of Optimal Power Flow (OPF). The time-frame of this control

action is around some tens of minutes. The control variables used are generator voltage references, reference bus voltages and state of operation of reactive power compensators.

In Figure 4-2, a scheme of the hierarchical voltage control architecture is presented.

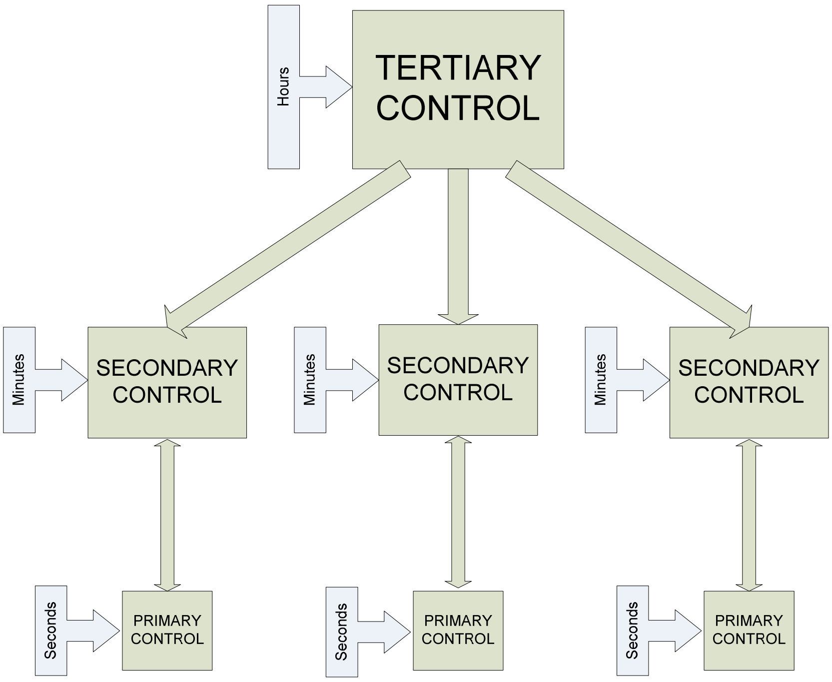

**Figure 4-2: Hierarchical Voltage Control**

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

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

Secondary Voltage services in multi-microgrids may be provided in either grid-connected or emergency modes of operation. Tertiary Voltage services, however, may be provided but only in grid-connected mode.

The CAMC will have a key role in this task since it will have the ability to control the power flows of the several microgrids (through the corresponding MGCCs) and optimize global system operation of multi-microgrid systems in order to minimize reactive power flows and improve voltage profiles.

One of the most common strategies to deal with voltage services in multi-microgrid systems involves the definition of voltage control areas each one with a reference bus for voltage regulation purposes.

The strategy used for the definition of voltage control areas is subject to discussion. Several methods can be found in the available scientific literature such as the method based on the definition of electrical distance ([Ref-4],[Ref-5]). This method has been used successfully by EDF (Electricité de France) for quite some time [Ref-5]. Nevertheless, other methods may also be used. The definition of a voltage control area per feeder is also an interesting possibility, given the expected structure of multi-microgrid system and corresponding configuration.

The main objective for solving the voltage/reactive power problem for a multi-microgrid system will be to optimize operating conditions by using control capabilities of power electronic interfaces from DG sources, OLTCs, SVCs and microgrids (that can be regarded as active cells).

Voltage control in multi-microgrids is an optimization problem, non-linear, discrete and with a strong hierarchical structure. This fact will imply dealing with voltage control sub-areas for each microgrid. Once a solution has been found to the global problem, the sub-solutions for individual microgrids will be tested in order to evaluate their feasibility, given the characteristics of their microgenerators. The optimization procedure will require a sequence of local sub-problem solutions and global problem solutions in order to converge to a near-optimum solution.

## 4.3. Coordinated Frequency Support

Frequency control functions may be defined for normal operating mode since some DG will be able to participate in global system frequency control, meaning that primary frequency control will be possible using distributed energy sources connected to the MV network. Also, frequency control functions may be defined for emergency operating mode, where several possibilities are considered. These possibilities are presented next.

Frequency control in emergency mode may be divided in two parts: active power generation control and load control ([Ref-6]). In Figure 4-3 the various control actions related to frequency control are presented. The first three control actions (Governor Control, Automatic Generation Control and Fast Unit Generator Loading) correspond to active power generation control and the last one (Load Shedding) corresponds to load control. It is considered that Fast Unit Generator Loading is the ability of DG to provide power from stand-still mode in order to respond to frequency deviations within a time-frame of around 5 minutes. An example of a fast unit generator may be a small hydro system.

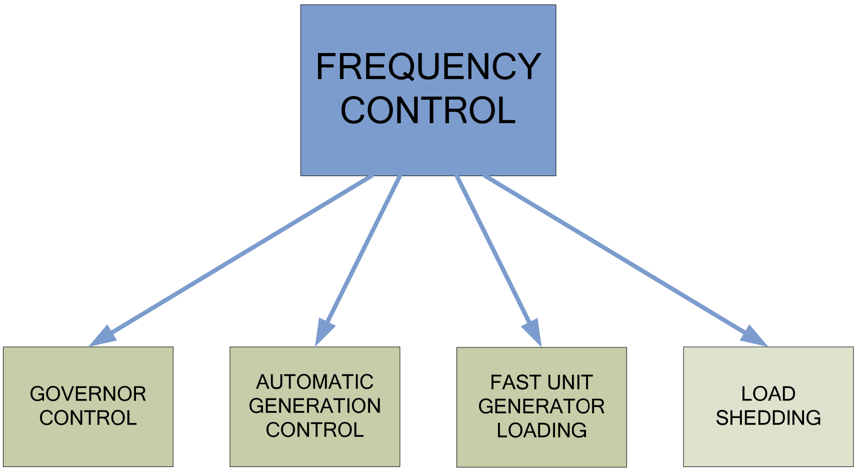

**Figure 4-3: Actions for Frequency Control**

It was seen within the MicroGrids project ([Ref-7]) that it is possible to control frequency in a single microgrid in islanded operating mode. For that purpose, the use of a Voltage Source Inverter (VSI), coupled to a storage device or other fast-acting power source, provides the frequency reference for the remaining units and guarantees a smooth transition to islanded mode and also secures load-following services. In grid-connected mode, this reference is externally imposed. However, in a multi-microgrid scenario, it is important to have a broader view of this situation. The main issue will be the re-synchronization of individual microgrids to enable a reconnection with the main grid or maybe even to each other. For that reason, it is interesting to explore the possibility of having the several microgrids operating in phase, within tight limits, when in emergency operating mode, in order to ease the reconnection of the islanded systems. Thus, a general approach for frequency control should be found.

### 4.3.1. Active Power Generation Control

Considering power system operation, it is inevitable that loads are continuously being connected and disconnected, generators coming online or going offline, switches being operated, etc., so that deviations between the generated power and the consumed power will occur. These imbalances lead to changes in the system's frequency because generators trade their rotating kinetic energy for electrical power. This action corresponds to a first level of frequency control (primary control) that responds immediately to these deviations keeping the system frequency within specified limits. With primary control, the system reaches a new state of equilibrium but at a frequency different from the nominal one since the generators maintain their droop characteristics. As most microsources operate similarly to conventional synchronous machines by means of droop control (proportional to frequency), a secondary control action is required in order to correct the frequency deviation and should take effect within a few seconds (typically 15-30 seconds). The correction of the frequency offset is especially important in the case of microgrid systems since the storage devices present operate with a control strategy proportional to frequency deviation and if frequency is not restored to the nominal value there is a great risk of depleting the capacity of these devices, jeopardizing global system operation.

Fig. 11 illustrates the traditional frequency control scheme and the types of control used that may be applicable for multi-microgrid systems.

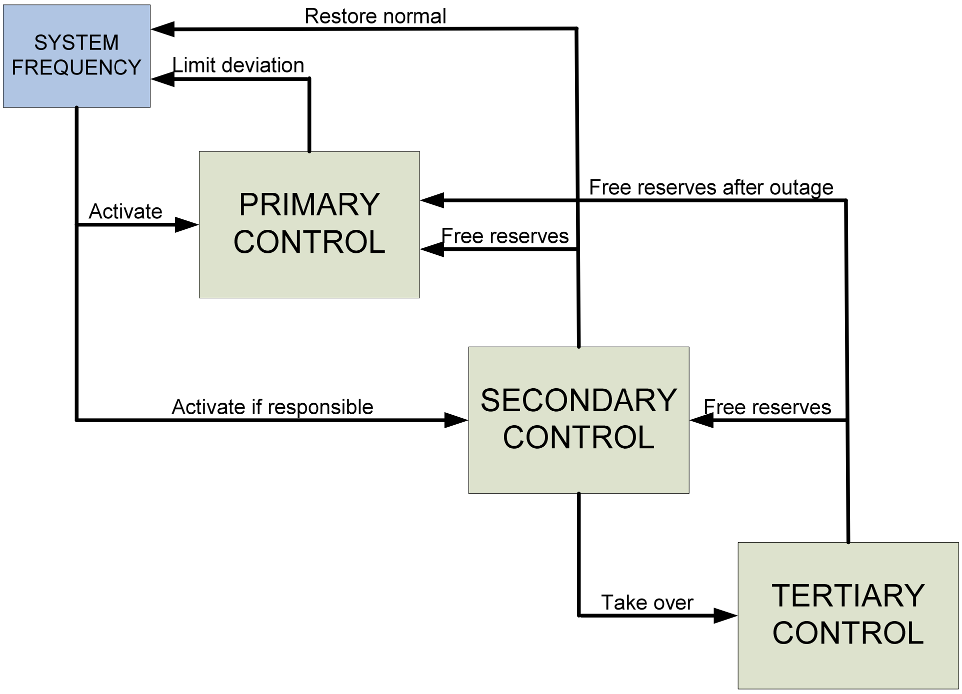

Figure 4-4: Frequency Control Scheme ([Ref-8])

In order to apply these control actions, minimum levels for primary and secondary reserve must be set, as it is performed in large power systems. A third level of reserve must also be considered in order to guarantee security of operation at all times.

Definitions for primary, secondary and tertiary reserve [Ref-8] must be revised for the multi-microgrid case. Essentially this means establishing the reserve margin and time for action for each type of reserve. The classic definitions are summarized in the following paragraphs.

In short, primary reserve concerns the action of speed regulators, operating in a time-frame of around 15-30 seconds. The primary reserve should be sufficient to compensate for load/generation imbalances without the need for load shedding action. This is the current view of the situation; however, since load control is expected to play an important part in frequency control, this criterion ought to be reviewed. Secondary reserve should be sufficient so as to eliminate the steady state frequency deviation, with an operating time of around 15 minutes. Tertiary reserve should be sufficient to cover secondary reserve in an adequate time period, in face of security of supply needs set by the System Operator (SO).

Frequency reserve services in multi-microgrids may be performed in either grid-connected or emergency modes of operation.

Concerning primary frequency control, upon a request of the SO, a reserve margin may be set considering a deload of some DG for primary control in grid-connected mode. In emergency mode, the additional primary reserve may be provided by the storage devices present.

Also, according to the control architecture in multi-microgrids, the CAMC is the controller who will be in charge of managing secondary frequency reserve. As previously mentioned, these tasks will be performed in a decentralized way. The CAMC will have the ability to communicate with other controllers, namely MGCCs, in order to guarantee that an adequate amount of secondary reserve can be supplied. MGCCs will be responsible for managing the secondary reserves at the microgrid level.

Secondary reserve may be provided by increasing generation levels or by reducing the demand. The latter option refers to load curtailment strategies that may also be exploited, if necessary, in order to compensate for renewable generation that may not be available at the time (e.g. PV or wind generators).

In order to guarantee security of supply, a security criterion must be used. The traditional security criterion is known as the n-1 criterion, where a component of the system may fail without compromising the security of operation of the global system. This criterion must be reviewed for the special case of multi-microgrid systems since there are a number of differences between this case and the classic view of power systems, namely:

- There will be a high number of units participating in ancillary services in multi-microgrid systems compared to classic power systems;
- The nominal powers of the microgenerators are very similar and up to a few tens of kilowatts, hence the failure of a single component (being a generator) will most likely not endanger global system operation;
- The massive presence of storage devices and the fast ramp-up rates and start-up times of some microgenerators will enable a fast recovery from a component failure;
- The structure of the multi-microgrid system is designed to be bidirectional, therefore allowing reconfiguration of the network and changes in power flows in order to overcome a component failure by reconfiguring feeders or even to island parts of the system.

It must be not be forgotten that, apart from microgrids that are operated as single active cells (controllable in terms of generation and consumption by the CAMC) there is also DG, some with an inverter-interfaced type, connected to the MV network (also controlled by the CAMC).

The subject of establishing criteria for setting spinning reserve margins must also be carefully addressed and evaluated.

One possible criterion for spinning reserve definition could be:

$$SR \geq \alpha \cdot P_{LOAD} + \beta \cdot P_{RENEW} - P_{SHED}$$

where SR is the spinning reserve, PLOAD is the total load of the system, PRENEW is the generation from renewable sources (such as PV or wind generation), PSHED is the load available for curtailment in the first stage of a curtailment scheme (concerning responsive loads), α (≥1) is a security load margin and β (≤1) is a coefficient for primary power source unavailability. In this criterion, the use of load control to define the reserve margin is extremely important. Load control is detailed in the next section. Obviously, an adequate specification for of α and β is one of the crucial issues of this strategy. One interesting possibility would be to consider α and β to be represented by fuzzy sets, thus considering the uncertainty in load and renewable generation prediction.

### 4.3.2. Load Control

Load control is expected to be one of the key features for coordinated frequency support in multi-microgrid systems.

Concerning load control, a load shedding action scheme following high generation/consumption imbalances is one emergency procedure that may be used in order to overcome situations where a significant frequency drop occur. This control strategy is extremely important for improving power system stability, provided that smooth load relief is guaranteed.

Such a method requires keeping track of the actual load available for curtailment. This strategy also implicates specifications on a series of parameters ([Ref-9]), such as:

- Location where the problem (frequency or voltage instability) occurred;
- Load curtailment steps;
- Time requirements for action;
- Cost for action.

Load control will be market-oriented just like active power generation control. It will give costumers the opportunity to act in the market structure as sellers instead of just buyers. This fact will be detailed ahead in this report.

## 4.4. Emergency Functions

Two main types of emergency operation are considered: islanded operating mode and black start. Some functions in emergency operation are common to normal operation (i.e. grid-connected mode with the MV network) but may hold some differences in implementation.

In case of disturbances in the upstream network that do not allow a fast reconfiguration in order to re-establish operation, the CAMC may decide to “isolate” several local microgrids, which will temporarily run in islanded operating mode controlled by the CAMC and their MGCCs. After the fault is cleared the CAMC will initiate network restoration.

Regarding islanded operation, a coordinated voltage and frequency control needs to be investigated. The activation of the provision of primary and secondary reserve needs to be studied in a coordinated way, having in mind that other MV connected DG units may be in operation and that each microgrid will have specific operational limitations. Central activation of secondary reserves should be defined by the CAMC controller. This includes also load shedding strategies, which can be connected with market rules related to the willingness to participate in the control in emergency situations.

For black start, the identification of a sequence that minimizes loss of supplied energy requires considerable investigation, namely considering the controllability characteristics of DG units and having in mind microsource characteristics and existing type of control. Coordination mechanisms of the global black start procedure with the internal microgrid procedures should be implemented.

These sequences should involve the synchronization of microgrids at MV level, assuming that a black start in the LV was well succeeded (here, results from the Microgrids project will be exploited).

## 4.5. Control Scheduling (Markets)

From an economic point of view, the operation of multi-microgrids regarding scheduling and dispatching requires an intensive activity of adjustment energy markets in order to deal with changes in generation or consumption. The adjustment models referred to previously can be considered as a market design aiming at integrating information on generation and loads with some degree of elasticity in the system. However, these adjustment models still have some deficiencies due to the fact that they consider a single objective function aiming at minimizing the overall adjustment cost. This objective can be achieved by admitting a large adjustment for a reduced number of agents, thus penalizing them strongly from an economic point of view. Taking this fact into consideration, it is important to study alternative models to consider individual objectives of each agent related to the minimization of their respective adjustment or each microgrid in view of the existence of multiple ones. From a traditional point of view, this will lead to a multi-objective optimization problem.

In order to ensure incentives for the widespread deployment of microgrids and DG, a market structure to include the services provided by these units must be developed. With the development of this new market structure, major institutional changes will have to take place and some of them have already begun. However, some service markets are at a relatively immature stage and a lot of reforming will have to be done ([Ref-10]).

Open competitive markets for generation for both energy and ancillary services should be encouraged, which should improve efficiency and hopefully lower electricity bills. This structure, mainly concerning ancillary services provision, will surpass generation level by having load participation in several services. In particular, ancillary service markets will be a great opportunity for DG and microgrids, as will be seen later in this report.

Electricity markets and ancillary service markets will be implemented for multi-microgrid systems. The several microgrids would sell services according to global system needs, with prices rising in emergency conditions, giving a clear sign of the desired response for the system. The microgrids or other DG that cannot respond to system requirements would continue to operate in order to satisfy their own necessities, but those who can respond will receive an economic signal (benefit). This strategy implies that both generators and consumers will see the electricity or service price according to the conditions of the system ([Ref-11]). Concerning energy markets, two separate markets should be considered: a day-ahead market and a spot market.

The main issue concerning market operation is related to the two operating modes for microgrid systems (islanded and grid-connected). One of the basic assumptions of an energy market is that power supplied from any generator can be delivered to any costumer. This would be valid if the system was not split into several different islands, as may happen. This problem ought to be solved, especially since islanding will many times result from unplanned events.

Also, the existence of bilateral contracts is a possibility for ensuring microgrid participation in ancillary services, namely in islanded operation. In emergency operating mode, full market operation will be difficult to implement given the urgency and variety of services to be provided. So, an independent market structure will be built for emergency operation and for normal operation. In order to ensure security of supply in emergency mode, a scheme based on bilateral contracts for some key services will be implemented.

# 5. DMS Functions

A Distribution Management System is a control system in a distribution network control centre containing the traditional Supervisory Control and Data Acquisition (SCADA) functions but incorporating several other functions to analyze the distribution system and support operations at present and future conditions ([Ref-12],[Ref-13]). The DMS concept is an extension of the Energy Management System (EMS) to the distribution level. The main difference between EMS and DMS is related to the characteristics of the distribution system. The DMS provides real-time monitoring capabilities, along with a comprehensive set of power applications, in order to support operation and planning activities in distribution networks.

Several functions of the DMS must be adapted and some new ones may be added for the case of multi-microgrid systems. Some of these modules from traditional DMS are presented next:

- Load Allocation;
- Reconfiguring Feeders;
- Topology Processor;
- Short-Circuits;
- Power Flow;
- Renewable Generation Forecasting;
- Load Forecasting.

Other functions such as state estimation and voltage/VAR control, which are primarily DMS functionalities, are to be transferred to the CAMC in order to avoid an overload to the DMS centre. These functions will be detailed ahead in this report.

# 6. Ancillary Services Provision

One of the most promising features of a multi-microgrid system is its potential ability to provide a variety of ancillary services, profiting from the characteristics of the various microsources present since DG is more suitable for providing some ancillary services than conventional central generators because many of these services are more efficient if provided locally (e.g. voltage support) ([Ref-14]). This ability will be fully applied once a market structure is built to operate such a system. Both loads and microgenerators may supply these services. Additionally, the usage of storage devices with considerable capacity and fast response to load/generation imbalances will play an important role in multi-microgrid systems. These devices, combined with power electronics may help sustaining voltage sags and dips and their interface will enable the provision of ancillary services such as frequency regulation or voltage regulation.

Ancillary services to be provided in a multi-microgrid system may be divided in two different categories: ancillary services for normal operation and for emergency operation. The main ancillary services for multi-microgrids are presented next.

- Normal Operation – Primary Frequency Regulation (if the primary energy source and technology allow), Voltage/VAR Control and Reconfiguring Feeders.

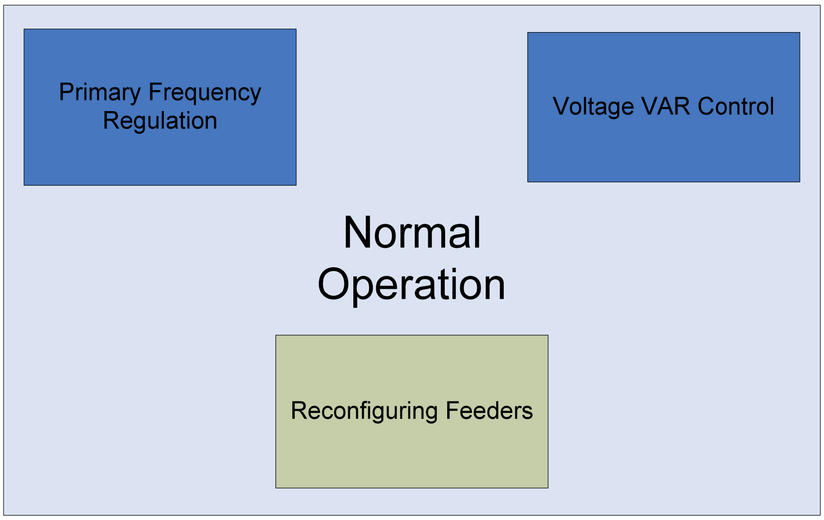

**Figure 6-1: Ancillary Services in Normal Operation**

- Emergency Operation – Frequency Regulation, Voltage/VAR Control, Reserves, Black Start, Load Following and Reconfiguring Feeders.

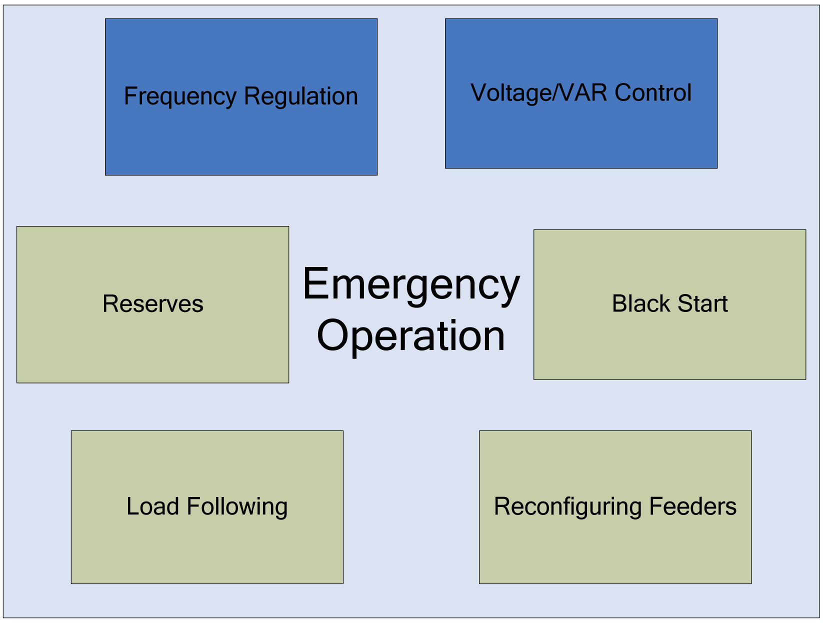

**Figure 6-2: Ancillary Services in Emergency Operation**

A brief description of the main ancillary services ([Ref-11],[Ref-15],[Ref-16]) considered for multi-microgrid systems is presented next.

Frequency Regulation is the use of operating generators that are equipped with load-frequency control and that can change output quickly in order to follow load or generation fluctuations. Hence, regulation will help to maintain interconnection frequency, minimize differences between actual and scheduled power flows between control areas, and match generation to load within the control area.

Voltage/VAR Control concerns the injection and absorption of reactive power in order to control voltage. In addition, supplying reactive power and real power locally will reduce losses on feeders and make the entire distribution circuit more efficient and less vulnerable to voltage collapse. Voltage control is generally accomplished by sending the generator a set-point for voltage. In this case, the set-point signal would be sent by the CAMC to MGCCs, which would then dispatch local microgrids through the corresponding MCs. Voltage/VAR control is one of the most promising ancillary services to be provided by microgrids given the local characteristic of voltage control.

Supply of Reserves is required to maintain bulk power system reliability and may be opened to competitive market participation. These services include Spinning Reserve and Supplemental Reserve and deal with restoring the balance between generation and load. The first requires an immediate response time (in the order of seconds) whereas the second requires only a response time of a few minutes. Backup supply may also be included for generation capacity available within one hour.

Black start is the capability to start generation without outside power and restore a portion of the power system to service after a total system collapse. Black start is a service that microgrids and some other DG units appear to be qualified to provide since microgrids are expected to be inherently capable of operating independently of the power system. Microgrids may be able to participate in the black start procedure by aggregating and forming larger islands, which would then enhance the stability of the grid as it is being restored.

Load Following concerns the use of generation in order to meet the hour-to-hour and daily variations in system load.

Reconfiguring feeders is a function that involves the reconfiguration of the network in order to reduce losses and optimize global system operation. This function will be most important especially considering the operating mode and scenario after faults.

Table 6-1 presents the availability of ancillary services provision for microgrid operation by the technology available per power source type.

**Table 6-1: Ancillary Services for Different Types of Power Sources**

**Power Source Type**

| Power Source Type | Frequency Regulation | Volt/VAR Control | Reserves | Black Start | Load Following |
|---|---|---|---|---|---|
| Conventional Power Plant | YES | YES | YES | YES | YES |
| CHP | YES | YES | YES | YES | YES |
| Diesel | YES | YES | YES | YES | YES |
| Wind Energy (IM directly connected) | NO | NO | NO | NO | NO |
| Wind Energy (DFIG) | YES | YES | YES | NO | YES[*] |
| Wind Energy<br>(SM + Converter) | YES | YES | YES | NO | YES* |
| PV | YES | YES | NO | NO | NO |
| Micro-Turbine | YES | YES | YES | YES | YES |
| Fuel-Cell | YES | YES | YES | YES | YES |

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[*] Special control approach required

| Power Source Type | Frequency Regulation | Volt/VAR Control | Reserves | Black Start | Load Following |
|---|---|---|---|---|---|
| Hydro Plant | YES | YES | YES | YES | YES |

# 7. Response Time Requirements

Communication requirements for classical power systems include a SCADA system with signals being sent at intervals of 2-8 seconds. However, in the case of a multi-microgrid system, it is expected that communications for bidding, dispatching and monitoring need only to be accomplished in the range of 1-2 minutes ([Ref-14]).

The fast times for classical system operation are not required since the consequences of a failure to respond are less serious, i.e. the failure of a small generator will not jeopardize the security of the control area. It is therefore expected that communication requirements can be relaxed to some extent without compromising global system reliability ([Ref-14]).

## 7.1. Voltage/VAR Support

Normally, as voltage has an implicit local characteristic, the system may be controlled without the need for a complex, high-speed communication system. However, for implementing a centralized voltage/VAR support tool for a multi-microgrid system, the requirements for the communication system will have to be reviewed.

Concerning voltage regulating components, such as SVCs and Synchronous Capacitors, these are controlled by adjusting their set-points and the response after the set-point has been received happens very fast, in a few cycles. Typically, other devices such as Static Capacitors and OLTCs can respond in a few minutes. Conventional generators may also aid in voltage control, making use of their power electronic interfaces, producing or absorbing reactive power according to system needs.

## 7.2. Coordinated Frequency Support

Concerning secondary frequency control, conventional AGC systems can send raise/lower pulses every 2-4 seconds but usually generators do not follow such fluctuations. Generation typically follows load at 1-2 minutes intervals.

Considering DG, depending on the rated power levels, the response time is generally considered in the range of minutes with ramp-up rates of around 5% per minute. Depending on the machine characteristics, some small generators may reach the rated power in about 1 minute.

## 7.3. Reserve Provision

### 7.3.1. Spinning Reserve

Spinning reserve is the generating capacity synchronized to the grid that begins to respond or ramp-up immediately and is fully available within 10 minutes, responding to frequency deviations. It is usually a high-price service and one that requires faster communication systems in the range of 5-10 seconds. Given the characteristics of DG, these are excellent candidates for the provision of spinning reserve. Especially small generators with fast ramp-up rates and low rated powers may be interesting for these services, since they would not need to remain online and just start-up when required. The grouping of these devices could be a smart option to ease communication.

### 7.3.2. Supplemental Reserve

Supplemental reserve is the generating capacity that can be fully available within 10 minutes in order to correct load/generation imbalances. Immediate response is therefore not required. A response time requirement in the area of 10-15 minutes is typical and most small DG is a good candidate since it can start fast and there is no need for an immediate ramp-up.

## 7.4. Load-Following

Load-following is similar to frequency regulation but occurs over longer time periods (at an hourly rate) to meet demand variations. It is measured in terms of real power capacity required over each hour. Shorter time periods (5-10 minutes intervals) may be used, thus eliminating the need for this specific service. Communication times of the order of 3-4 minutes are perfectly adequate for an hourly dispatched service.

## 7.5. Control Scheduling (Markets)

DG may also change its real and reactive power output, similarly to what happens for load-following, regarding the participation in energy markets. The response speed, however, may be different for load-following and for market participation. Usually, market signals may take longer than those for load-following, but the interaction between these two services should be tested and the delay time studied for multi-microgrid systems.

## 7.6. System Black Start

Black Start is the ability of starting up a generating unit autonomously (i.e. without grid assistance) and energizing the grid following a blackout situation. System Black Start involves a number of special concerns for communication and the restoration procedure differs greatly from system to system. Hence, a broad study for a particular case, or for a base-case, is in order.

# 8. Multi-Microgrid System Functions – Inputs and Outputs

The amount of information concerning multi-microgrid system operation is extremely vast and includes different types of data ranging from technical parameters to economical indices. While some of this data is relatively straightforward to acquire some other may be difficult or even impossible to obtain. This is a crucial issue since the global system optimization would normally require the whole amount of data. On the other hand, handling a huge volume of information could be technically infeasible and, if not, cost prohibitive. Consequently, several important choices must be made considering the entire set of data. This will imply the possibility of using approximate assumptions regarding some of the information required.

The use of hierarchical and decentralized control architecture is essential in order to implement an efficient scheme for multi-microgrid operation. The control strategy to implement considers the use of individual devices (agents) which have the ability to communicate with other agents in order to make decisions. Each of these agents must have a certain degree of autonomy for performing specific tasks and should report its actions to a higher-rank agent. The principle of decentralized control prevents one agent having to deal with an excessive volume of data while the principle of hierarchy builds a chain of command with decreasing complexity from the top to the bottom level.

The information flow for each function, characterized by the main inputs and outputs to the several management functions for the CAMC and the DMS, was estimated and is presented in the following sections. It must be stressed that some functions may share input data, which is common to the tasks to be performed. Also, the outputs for some functions may be used as inputs for those same functions (recursively) or for other functions.

## 8.1. Voltage/VAR Support

The Voltage/VAR Control System is a control function designed to optimize voltage profiles and reactive power flows in order to achieve some predefined goals such as loss reduction, etc. A centralized voltage/VAR control enables the optimization procedure at a global level rather than at a local level. The voltage/VAR control scheme uses topology structures available from the **Topology Processor**, functions from the **Power Flow** module and even data from the State Estimator. It supports both meshed and radial networks. This function is preceded by an Island Identification function to determine whether there are islands in the system and if they all are subject to voltage/VAR control.

**Inputs**

- Elements of the network and their characteristics:
    - generation, consumption and other power injections;
    - minimum and maximum values for node voltages and maximum branch current flows;
- Network topology;
- List of equipment on which to run the Voltage/VAR Control application (part of network or whole network).

**Outputs**

- Global results considering all islands where the optimization procedure was run:
    - active and reactive power losses;
    - maximum and minimum voltage magnitude deviations;
    - maximum line current deviation;
    - maximum transformer current deviation;
    - real and reactive power generations and consumptions;
- For each analysed island:
    - real and reactive power generation and consumption;
    - current (magnitude and angle) in all circuit elements;
    - voltage magnitude and phase at all buses;
    - active and reactive power losses;
    - real and reactive, line and transformer power losses;
    - tap positions for load tap changer transformers.

**Controls**

- Reactive power limits can be specified.

## 8.2. State Estimation

The State Estimation module is a real-time function designed to provide a complete voltage (magnitude and phase) solution for the network under analysis.

The state estimator provides complete model estimation for all observable and unobservable islands of the network.

Some of the measurements used in state estimation will be provided by the MGCCs to the CAMC.

**Inputs**

- Topology of the network;
- Set of input data (telemetered or pseudo-measurements) used in the previous run of the algorithm;
- Any available measurements (power application inputs) such as:
    - manually entered information used to update the network model:
        - status of circuit breakers and disconnect switches;
        - position of transformer taps;
        - reactive generation of capacitor banks;
    - telemetered:
        - measurement of real and reactive branch power flows;
        - measurement of branch current flows;
        - measurement of real and reactive loads;
        - measurements of real and reactive generations;
        - measurements of real and reactive injection powers, namely reactive powers from capacitor banks;
        - measurements of bus voltage magnitudes;
        - status of switching devices;
        - position of transformer taps;
    - pseudo-measurements of:

        - real and reactive branch power flows;
        - branch current flows;
        - real and reactive loads;
        - real and reactive generations;
        - real and reactive injection powers, namely reactive powers from capacitor banks;
        - bus voltage magnitudes.

**Outputs**

- Voltage magnitudes and phase angles of the network model buses;
- Transformer tap estimates;
- Bus real and reactive power injections;
- Capacitor banks reactive power injections;
- Branch real, reactive and apparent power flows;
- Magnitude and phase branch currents;
- Voltage magnitudes and phase angles at the open end of open-ended branches;
- Confidence interval of input data and of estimated values.

## 8.3. Coordinated Frequency Support

Coordinated Frequency Control involves all levels of generation and load control presented in this report. This module will focus especially on primary frequency control and secondary frequency control, by implementing an AGC-like scheme. Tertiary control is, for the time being, out of the scope. As it happens for **Voltage/VAR Support**, this function is preceded by an Island Identification function to determine how many islands there are in the system.

**Inputs**

- Elements of the network and their characteristics:
    - generation, consumption and other power injections;
    - generators participating in frequency regulation;

  - minimum and maximum values active power generation;
  - start-up and shutdown times for generators;
  - up-rate and down-rate for generators;
  - nominal capacity and state of charge of storage devices;
  - loads available for curtailment (capacity, time-frame, etc.);
- Network topology.

**Outputs**

- Global results considering all islands:
  - real and reactive power generations and consumptions;
  - active and reactive flows in lines and transformers.

**Controls**

- Droop settings;
- Reserve margins;
- Active power limits can be specified;
- Load curtailment limits can be specified.

## 8.4. Control Scheduling (Markets)

From an economic point of view, the operation of multi-microgrids regarding scheduling and dispatching requires an intensive activity of adjustment energy markets in order to deal with changes in generation or consumption. This will lead to a multi-objective optimization problem. Adjustment models can be considered as a market design aiming at the integration of information on generation and loads, considering some degree of elasticity in the system.

**Inputs**

- Price signals from loads, DGs and MGCCs for:
  - active and reactive power;
  - other ancillary services (reserve provision, black start, etc.);
- Active and reactive power for all generation and consumption;

- Technical network constraints.

**Outputs**

- Final values for prices concerning active and reactive power generation, ancillary services provision, etc.;
- Active and reactive power set-points for loads and generators.

## 8.5. System Black Start

Following major fault conditions, the CAMC may determine to isolate several local microgrids which will be temporarily run in islanded mode in order to allow faster system recovery of the distribution network. Identifying the sequence of actions that exploits the local generation capabilities to minimize down times and energy not supplied requirements will be based on specific control characteristics of DG units installed in the MV and LV level, making efficient use of the type of control existing in each microgrid active cell. The sequence of actions involves microgrid black start and its synchronization in the MV network (as well as with other DG types installed at the MV level). Also, protection issues (regarding, for example, DG protection relay settings, under frequency load shedding relays settings) need to be considered during the restoration stages, by finding the most appropriate settings for the protection relays in each phase of the restoration stage, in order to avoid repeated DG blackouts.

**Inputs**

- Elements of the network and their characteristics:
    - o generation, consumption and power injections (prior to system blackout);
    - o critical loads to be restored;
    - o generator black start capability (yes or no);
    - o minimum and maximum values active power generation;
    - o start-up and shutdown times for generators;
    - o up-rate and down-rate for generators;
- Network topology (including protection scheme and relays settings).

**Outputs**

- Microgrid sequence of actions for the black start procedure, including the definition of the most suitable relay settings in each phase of the restoration procedure.

**Controls**

- Controlled DG active and reactive power limits;
- Voltage control;
- Frequency control (reserves, energy storage management).

## 8.6. Load Allocation

The Load Allocation function is necessary to the estimation of load to the several distribution substations (MV/LV) and to the different points of the network. This load allocation module allows accessing the instant power at different points of the network.

The load allocation module will use the on-line network scheme available from the **Topology Processor.**

The specification of this functionality is, however, out of the scope of this work.

## 8.7. Reconfiguring Feeders

The Reconfiguring Feeders function provides several reconfiguration schemes (sequence of switching operations) in order to reduce network power losses or to restore loads not supplied in a faulted scenario. The final network configurations are evaluated against overload of system elements and voltage levels.

**Inputs**

- Network topology;
- Network loads;
- Switching devices data (status, operability, etc.);
- Maximum current values or power rates in system components;
- Limits (buses voltage deviation) to analyze feasible configurations;
- Loads hierarchical level;
- List of switching used during isolation process.

**Outputs**

- Number of solutions;
- For loss minimization process (per solution):
    - initial power losses (before reconfiguration);
    - final power losses (after reconfiguration);
    - power losses gain;
    - number of switching operations;
    - switching operations list;
    - power flow results for final configuration;
- For service restoration (per solution):
    - initial non-supplied load:
        - total and by hierarchical level;
    - final non-supplied load:
        - total and by hierarchical level;
    - re-supplied load:
        - total and by hierarchical level;
    - number of switching operations;
    - switching operations list;
    - power flow results for final configuration;

## 8.8. Topology Processor

The Topology Processor function is responsible for building and maintaining the topology model scheme of the network. This module is essential as a basis for many other functions.

**Inputs**

- Data on system parameters:
    - connectivity of lines, cables and transformers;

  - protection devices (circuit breakers, switches, etc.);
  - series reactances;
  - generators;
  - loads;
- State of devices (breakers, switches, fuses, etc.);
- Interconnections with other systems;
- Type of earthing.

**Outputs**

- One-line scheme of the network;
- Positive-sequence, negative-sequence and zero-sequence schemes of the network.

## 8.9. Power Flow

The Power Flow is an important tool involving numerical analysis applied to a power system. The great importance of this module is in planning future expansions of power systems as well as in determining the best operating point of existing systems.

The power flow model uses the topology structures available from the **Topology Processor**.

The power flow routine is a well-known tool in power system analysis so that it does not demand a detailed specification of inputs, outputs and controls in this report.

## 8.10. Load Forecasting

The main goal of the Load Forecasting function is to estimate n-hours ahead of active power at substation transformers, substation feeders and large consumers. This module will use Artificial Neural Networks (ANN) or an equivalent tool.

**Inputs**

Forecasted values will be mainly based on a time series of active power values for transformers' substations, substation feeders and large consumers. Other data to be used is a time series of weather conditions (temperature), characterization of the day (weekday, day of the year, holidays), the prediction hour(s), information on electrical network topology.

- Information about network topology;
- The trained ANN structure and weights;
- Database containing historical behaviour of the last few hours (or days) for the specified feeder or substation:
    - power of the transformer installed;
    - and in a hourly base:
        - active power;
        - weather information (temperature);
        - any other material potentially related to load consumption (information about holidays, network configuration changes, etc.).

**Outputs**

- (Re)Training phase:
    - new ANN weights;
    - load forecasting performance;
    - termination error code;
- Forecast phase:
    - active power prediction for the next hour (1 hour, 2 hours … to a week in advance);
    - load forecasting/estimation errors.

## 8.11. Renewable Generation Forecasting

### 8.11.1. Wind and PV Forecasting

The Wind and PV Forecasting is a tool with the main goal of estimating n-hours ahead the active power generated by these two types of renewable generation sources.

**Inputs**

- Description of the Wind Farms:
    - number of wind farms;

  - number of wind turbines at each farm;
  - wind farms nominal power;
  - description of the location of the wind turbines (distance between them) – optional;
- Description of the PV Farms:
  - number of wind farms;
  - number of PV panels at each farm;
  - PV farm nominal power;
  - description of the location of the PV panels;
- Description of the Wind Turbines:
  - technical characteristics of the wind turbines as given by the manufacturer including hub-height, diameter of rotor, etc.;
- Description of the PV Panels:
  - technical characteristics of the PV panels as given by the manufacturer including module efficiency, connection to the electrical network etc.;
- Power Curves for Wind Turbines:
  - for each type of wind turbine, the machine's characteristic curve that gives the power output as a function of wind speed;
- I-V Curves for PV Panels:
  - for each type of PV panel, the characteristic I-V curve as a function of temperature;
- Online data for Wind Turbines:
  - description of the data available online from each wind farm and at what time step;
  - data that can be used by the model as input are mainly:
    - wind power and/or
    - wind speed and if available

        - wind direction;
    - All available measurements from the existing installation can be used.
- Online data for PV Panels:
    - description of the data available online from each PV farm and at what time step;
    - data that can be used by the model as input are mainly:
        - irradiation;
        - temperature;
    - all available measurements from the existing installation can be used;
- Measurements from other sites:
    - historic measurements from other sites (if available) can be used in parallel to the online measurements from the wind or PV farms;
    - several years of such measurements can be used.

**Outputs**

- Active power generated by:
    - wind turbine;
    - wind farm;
- Active power generated by:
    - PV panel;
    - PV farm.

# 9. Conclusions

The definition of an effective control scheme for multi-microgrid operation is a key issue. In particular, it is extremely important to specify the interactions among controllers namely including the new main controller – the CAMC – together with the several DMS modules. Also, the interaction between the CAMC and the MGCC is crucial for ensuring efficient multi-microgrid operation. CAMC functions should be adapted and/or duplicated from the DMS and clearly defined; these functions are: Coordinated Frequency Support, Voltage/VAR Support, State Estimation, Emergency Functions and Control Scheduling (Markets). These functionalities have been defined and discussed throughout this document.

State Estimation is one of the most interesting functions to be explored for multi-microgrid systems; however several issues were identified as possible difficulties facing the implementation of this functionality.

Voltage/VAR Support is a function with a hierarchical structure that comprises the formulation of a discrete optimization problem, which may be solved using the concept of voltage control areas or equivalent methods.

A Coordinated Frequency Support scheme was considered, including the expected microgrid participation in primary and secondary frequency control; it was also seen that the definition of a new security criterion to replace the traditional n-1 criterion is required and a specific spinning reserve criterion was proposed.

Emergency functions for multi-microgrids were also analysed; they include islanded operation (ancillary services offered, etc.) and service restoration (black start procedure).

Control Scheduling (Markets) is seen as a great opportunity for DG and microgrids despite the rather immature stage of electrical markets; in addition, markets shall be defined for normal and emergency operation and islanding is likely to raise several questions in market operation, presented in this document.

The control strategy proposed is based on a hierarchical and decentralized scheme, ensuring both autonomy and redundancy. A communication strategy for multi-microgrid systems is also important and must have the same characteristics of the control scheme due to the dimension and complexity of the system.

Furthermore, the control strategy must take into account the two possible operating modes in a multi-microgrid system: a) grid-connected and b) islanded mode. In addition, state diagrams comprising these operating modes were derived, exploring all possible operating scenarios and reviewing the main conditions for the transitions between states.

Participation in ancillary services provision is expected to be one of the most interesting prospects for multi-microgrid systems. The ancillary services to be provided by these systems were presented and detailed in this document, taking into consideration the operating mode of the system.

Finally, for the all the main CAMC functions and for some crucial DMS functions, the response time requirements were specified and the main inputs and outputs of each function have also been analysed and detailed.

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# 11. Web Sites

[www-1] http://www.iec.ch/
International Electrotechnical Commission – IEC

# 12. Glossary

| Term | Stands for |
|---|---|
| AGC | Automatic Generation Control |
| ANN | Artificial Neural Network |
| AVR | Automatic Voltage Regulator |
| CAMC | Central Autonomous Management Controller |
| CHP | Combined Heat and Power |
| DFIG | Doubly Fed Induction Generator |
| DG | Distributed Generation |
| DMS | Distribution Management System |
| DSM | Demand Side Management |
| DSO | Distribution System Operator |
| EMS | Energy Management System |
| HV | High Voltage |
| IM | Induction Machine |
| LC | Load Controller |
| LV | Low Voltage |
| MC | Microsource Controller |
| MGCC | MicroGrid Central Controller |
| MV | Medium Voltage |
| OLTC | On-Line Tap Changing |
| OPF | Optimum Power Flow |
| PF | Power Flow |
| PV | Photovoltaic |
| RTU | Remote Terminal Unit |
| SCADA | Supervisory Control and Data Acquisition |
| SM | Synchronous Machine |
| SO | System Operator |
| SVC | Static VAR Compensator |