No 727481 RESERVE

D2.6 v1.0

Drafting of Ancillary Services and Network codes definitions V1

The research leading to these results has received funding from the European Union's Horizon 2020 Research and Innovation Programme, under Grant Agreement no 727481.

Project Name	RESERVE
Contractual Delivery Date:	30.09.2018
Actual Delivery Date:	29.09.2018
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Workpackage:	WP2 – Frequency Stability by Design
Security:	PU
Nature:	R
Version:	1.0
Total number of pages:	73

Abstract:

The objectives of this deliverable are twofold. On one hand, white papers and existing network codes for primary and secondary frequency control are reviewed. With this regard, ENTSO-E and Transelectrica current practices are discussed. On the other hand, recommendations for ancillary services and new network code definitions for frequency control of networks with high penetration of non-synchronous, converter-based generation are drafted. The topics considered for network codes are frequency estimation, RoCoF and fast frequency control with converter interfaced generations and microgrids; and primary and secondary frequency control with renewables and energy storage systems. Both low inertia and 100% non-synchronous scenarios are considered. For the 100% non-synchronous scenario the concept of linear-swing virtual synchronous generator is discussed. Several case studies duly illustrate the need for new ancillary services and network codes and discuss the performance of proposed solutions.

Keyword list: Frequency control, ancillary services, network codes, transmission and distribution networks, frequency estimation, RoCoF, wind energy conversion system, solar photo-voltaic generation, microgrids, energy storage systems, virtual synchronous generator, HVDC systems, transient

Executive Summary

This deliverable is the first major output of Task T2.6, which is part of the Work Package WP2. The main goal of Task 2.6 is to collect the output of the research performed in WP2 and provide input for the work in the WP6 with regard to the ancillary services and network code recommendations related to frequency stability and control in transmission and distribution systems.

This deliverable reviews existing white papers and network codes and discusses, through case studies the motivations and rationales for the proposal of new ancillary services and network code definitions, or, when possible, the modification of existing ones. The conclusions of this deliverable constitute a preliminary draft of recommendations to be evaluated, harmonized and promoted for international adoption by WP6.

The main objectives of this deliverable are twofold:

- To review existing white papers and network code definitions for frequency estimations and for the provision of the rate of change of frequency (RoCoF). With this regard, ENTSO-E and Transelectrica current regulatory framworks are considered and discussed.
- To draft recommendations for new network codes or modifications of existing ones. The topics considered are frequency estimation, RoCoF and fast frequency control with converter interfaced generations and microgrids; primary and secondary frequency control with renewables, energy storage systems. Low inertia and 100% non-synchronous scenarios are considered. For the 100% non-synchronous scenario the concept of linear-swing virtual synchronous generator is discussed.

With regard to ENTSO-E existing network codes and white papers, ENTSO-E recognizes the relevance of the fast response of non-synchronous generation as well as HVDC connections. The codes indicate the ranges for the RoCoF that such devices have to withstand, but do not indicate a specific control strategies. Moreover, ENTSO-E does not currently provide a regulation that covers clear frequency control requirements for energy storage systems. As a member of ENTSO-E, Transelectrica has to comply with the ENTSO-E existing regulation. Transelectrica is particularly concerned about the regulation of wind power plants connected to the Romanian system.

Based on the review of ENTSO-E and Transelectrica regulation, the deliverable identifies a set of priority areas to improve existing practices. Specific estimation and control issues that are discussed in this deliverable are summarized below.

The measure and estimation of the frequency appears as a relevant area of research with also interesting regulatory implications. It is in fact important for transmission and distribution system operators to be able to identify whether distributed resources and/or loads that provide demand response services are regulating the frequency and, if so, the amount of regulation provided. The deliverable discusses a technique to estimate, through a simple yet accurate linear expression, the participation of the aforementioned agents to frequency and RoCoF control based on PMU measurements. This technique is based on the “frequency divider” concept duly discussed in Deliverable D2.1.

Another aspect of the measurement of frequency is the “quality” of the signal to be measured. This appears to be particularly critical in distribution networks. The deliverable discusses a variety of techniques to measure frequency variations aimed at the frequency control through distributed energy resources in distribution networks. Local, centralized and distributed approaches are compared. The trade-off between accuracy (centralized approach) and the need to minimize communication delays is identified.

The impact of the frequency control of energy storage devices in transmission networks appears relevant. The conclusion, based on preliminary simulation results, is that energy storage devices are an effective solution and should be commissioned whenever possible.

The impact of a high penetration of grid-connected microgrids on frequency stability is also studied. The main conclusions are that the microgrids have to provide frequency control and that their energy storage devices are crucial for such a control. The study carried out for this deliverable illustrates a stochastic control technique that, if adopted by all microgrids, is able to

maximize their revenues while providing a proper frequency support to the grid. The results identify that the microgrids are incentivized to increase the capacity of their energy storage to increase their revenues and, at the same time, the energy storage allows better tools for regulating the frequency.

With regard to network codes on primary frequency control, it is advisable to develop recommendations for the coordination between inverters considering their characteristics for frequency control and droop values. This is important to achieve coherence in the interconnected power system. Standardized operation characteristics should be provided for those units that respond to both inertial and primary control. This is essential because both control schemes are linked in time, and the power provided as frequency control service is set by the same controller

With regard to network codes on secondary frequency control, two types of control procedures appear relevant: the decentralized control specific to the primary frequency control, and the centralized control specific to the secondary frequency control. In the future, a diversity of control procedures may be required. For example, the distributed control is introduced. The distributed control refers to the coordinated control within a regional network, including both generation sources and loads, as a low-level control in the centralized scheme. This control strategy refers to the VPP and microgrid concepts.

The 100% non-synchronous scenario is considered. Assuming that the main converter-based power generation/supply is provided by non-synchronous RES and HVDC systems, implies fully rethinking the active power control strategy for the electric grid. In this deliverable a solution based on the Linear Swing Dynamic (LSD) concepts described in Deliverable D2.3 is discussed and tested through proof-of-concept tests. Results shows that the LSD is effective and has the potential to maintain the power balance under dynamic conditions in high-voltage transmission systems.

Simulation results and recommendation for network codes discussed in this deliverable will be expanded and consolidated in Deliverable 2.7.

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1. Introduction

1.1 Task 2.6

This deliverable is the first major output of Task T2.6 in the Work Package WP2. The main goal of T2.6 is to collect the output of the research performed in WP2 and provide input for the work to be carried out by WP6 with regard to the ancillary services and network code definition concerning frequency control. These inputs from WP2, which take the form of recommendations for the aforementioned services and definitions, will be later evaluated, harmonized and promoted for international adoption by WP6. It is thus crucial for T2.6 to provide a solid foundation of such recommendations, by extending the research carried out in WP2 from the illustrative case studies so far presented, to a broad variety of real-world scenarios.

1.2 Objectives and Outline of the Deliverable

The outputs of T2.6 are collected in two main deliverables, namely D2.6 and D2.7. With regard to this document, D2.6 aims at the following objectives. First, a comprehensive overview of the current status of existing European Network Codes (NCs) and other regulatory documents and recommendations under review is presented, where we identify the areas that, based on the results of the research carried out in WP2, need to be updated or, in some scenarios, created. Second, the frequency control strategies studied in WP2 are adequately identified and classified. These are: Rate of Change of Frequency (RoCoF) and Primary Frequency Control (PFC) of low-inertia systems; Secondary Frequency Control (SFC) of low-inertia systems; and RoCoF and PFC of zero-inertia systems. The methodologies to be applied during the last year of the project for each of these categories is described in detail, as well as the case studies that will be considered. Finally, preliminary results of these studies are presented and discussed.

1.3 How to Read this Document

This deliverable must be read after all previous deliverables of WP2, namely D2.1, D2.2, D2.3 and D2.4. In particular, D2.1, D2.2 and D2.3 are strictly related to Chapters 3, 4 and 5 of this document, respectively, while D2.4 gives an understanding of all issues related to the telecommunication area that affect, to a greater or lesser extent, all aforementioned chapters.

Additional dependencies and links of D2.6 with other deliverables, tasks and work packages from the RESERVE project are summarized below (see Figure 1.1).

- The case studies proposed have been defined based on the different Scenarios on the Frequency defined in D1.1 (T1.1, WP1).
- The research concepts presented in this deliverable that will be studied during the last year of the project will be tested and validated by T5.3 (WP5) in D5.4 and D5.5.
- We recommend the interested reader to read D3.8 from Task T3.7 of WP3 in parallel to D2.6. The rationale is that T3.7 is responsible of defining the recommendations of ancillary services and NC definitions concerning voltage control, mirroring the objectives of Task 2.6 for frequency control concepts. Therefore, the structures of D2.6 and D3.8 are analogous.

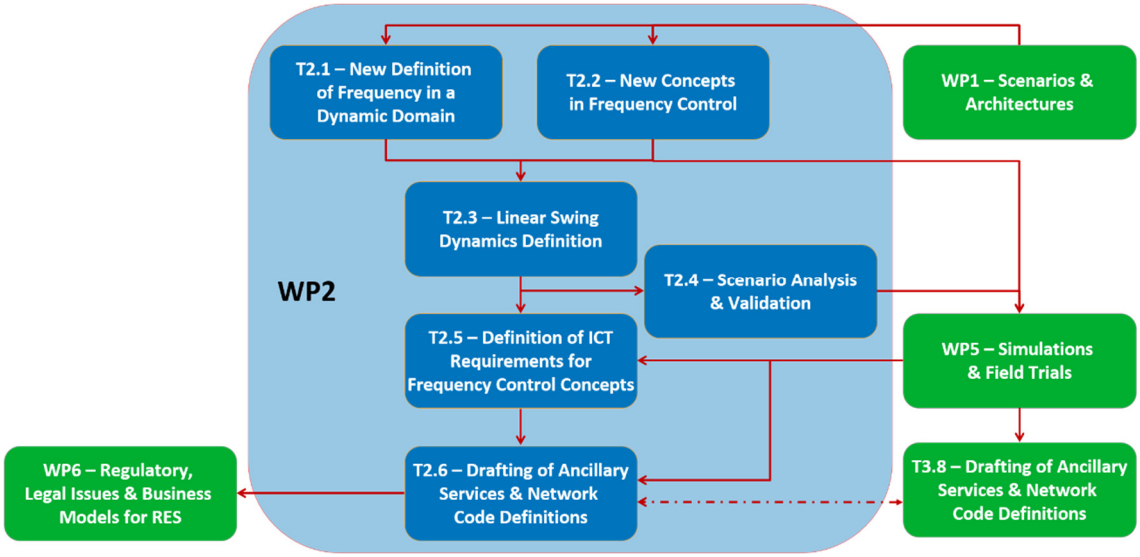

Figure 1.1 Relations between Tasks in WP2 and other Work Packages.

1.4 Structure of the Deliverable

This deliverable is the result of the collection of contributions from the different partners that participate to WP2. This deliverable has thus been organized to maximize the coherency of the subtasks performed by each partner, while optimizing the flow of the overall content. To this aim, each chapter spanning from 2 to 5 has been authored by a different institution, as indicated below.

- Chapter 2 – Transelectrica;
- Chapter 3 – UCD;
- Chapter 4 – UPB;
- Chapter 5 – RWTH.

The remainder of this document is organized as follows. Chapter 2 provides a thorough review of the existing NCs defined by the European Network of Transmission System Operators for Electricity (ENTSO-E), as well as the white papers that recommend updating such codes and that are currently under review by different ISOs such as Transelectrica from Romania. The chapter also collects the areas that, based on the results of the previous works of WP2, have been identified for needing to be updated and/or created. These areas have been categorized based on the scenarios defined in D1.1. The detailed methodology and the description of the case studies that will be applied to study the different concepts identified in Chapter 2 are provided in Chapter 3 to 5. In particular, Chapters 3 and 4 focus on the RoCoF/PFC and SFC of low-inertia systems, respectively, whereas Chapter 5 tackles the issues related to zero-inertia systems. Chapter 6 draws concluding remarks of the preliminary results obtained so far, and outlines the future work directions of T2.6 with regard to the preparation of D2.7.

2. Review of White Papers and Existing Recommendations under Review by ISOs

2.1 ENTSO-E

Each country's electricity network is governed by internal codes and regulations in order to ensure system stability, security of supply and safe operation. However, in Europe, increased number of interconnections between countries and high flows dictated by a regional/pan-European market, determined the need for EU-wide rules to manage electricity flows. These rules, known as Network Codes (NCs) or guidelines, are European Commission (EC) regulations containing legally binding rules for all member states. They govern all cross-border electricity market transactions and system operations alongside the EU regulation on conditions for accessing the network for cross-border electricity exchanges. [1]

The European NCs are prepared by the ENTSO-E based on a set of principles, called framework guidelines, developed by the Agency for the Cooperation of Energy Regulators (ACER). The codes are submitted back to ACER for its opinion. If ACER deems that the code fulfils its framework guidelines and the EU's internal market objectives, and is fair and balanced, it recommends the European Commission to adopt the code. The Commission studies it and then sends it to an Electricity Cross-Border Committee, made up of energy specialists from member countries, for an opinion. Once the Committee accepts the draft of the NC, it is adopted with the approval of the Council of the EU and the European Parliament.

At the date of this document, there are eight codes and guidelines that have been published in the Official Journal of the European Union [2] as listed below.

Connection Code Family

- Network code on Requirements for grid connection of high-voltage direct current system and direct current-connected power park modules - NC HVDC (in force since September 28th 2016) - Commission Regulation (EU) 2016/1447 (of August 26th 2016);
- Network code on demand connection - NC DCC (in force since September 7th 2016) - Commission Regulation (EU) 2016/1388 (of August 17th 2016);
- Network code on requirements for grid connection of generators - NC RfG (in force since May 17th 2016) - Commission Regulation (EU) 2016/631 (of April 14th 2016).

Operations Code Family

- Guideline on electricity transmission system operation (in force since September 14th 2017) - Commission Regulation (EU) 2017/1485 (of August 2nd 2017);
- Network code on electricity emergency and restoration (in force since December 18th 2017) - Commission Regulation (EU) 2017/2196 (of November 24th 2017).

Market Code Family

- Guideline on capacity allocation and congestion management (in force since August 15th 2015) - Commission Regulation (EU) 2015/1222 (of July 24th 2015);
- Guideline on electricity balancing (in force since December 17th 2017) - Commission Regulation (EU) 2017/2195 (of November 23rd 2017);
- Guideline on forward capacity allocation (in force since October 17th 2016) - Commission Regulation (EU) 2016/1719 (of September 26th 2016).

The technical aspects studied in the RESERVE project, mainly for providing innovative solutions for frequency and voltage control in a European grid with 100% Renewable Energy Sources (RES) and thus with increasing shares of converter-interfaced sources, have a positive impact on the present NCs in terms of improving them, while also allowing for the creation of new NCs altogether.

2.1.1 Frequency Control

The NCs and guidelines that currently cover frequency control are listed in Table 2-1.

Table 2-1: ENTSO-E NCs and Guidelines with references to frequency definition and control.

Connection Codes	*Operations Codes*	*Market Codes*
NC RfG	System Operation Guideline [1]	Balancing Guideline [3]
NC DCC	Network code on emergency and restoration [4]	
NC HVDC		

The Connection Codes provide technical requirements for generators, demand and HVDC, which represent the tools necessary for Operations and Market.

2.1.1.1 Network Code on Requirements for Grid Connection of Generators

NC RfG [3] contains requirements for new synchronous generators, for power-generating modules and for power park modules. The requirements for power-generating modules are presented below for exemplification. Power-generating modules within the following categories shall be considered as significant:

- **Type A**: Connection point below 110 kV and maximum capacity of 0.8 kW or more;
- **Type B**: Connection point below 110 kV and maximum capacity at or above a threshold proposed by each relevant TSO in accordance with the procedure laid out in Table 2-2;
- **Type C**: Connection point below 110 kV and maximum capacity at or above a threshold specified by each relevant TSO in accordance with Table 2-2. This threshold shall not be above the limits for type D power-generating modules contained in Table 2-2; or
- **Type D**: Connection point at 110 kV or above. A power-generating module is also of type D if its connection point is below 110 kV and its maximum capacity is at or above a threshold specified in accordance withTable 2-2.

Table 2-2: Limits for maximum capacity threshold for different types of power generating modules.

Limit for max. capacity / *Synchronous areas*	*Type B*	*Type C*	*Type D*
Continental Europe	1 MW	50 MW	75 MW
Great Britain	1 MW	50 MW	75 MW
Nordic	1.5 MW	10 MW	30 MW
Ireland and Northern Ireland	0.1 MW	5 MW	10 MW
Baltic	0.5 MW	10 MW	15 MW

Clear requirements for all type of generators (A, B, C, D) are laid out in terms of frequency stability and control.

Type A power-generating modules have to fulfil the following requirements relating to frequency stability:

- With regard to **frequency range**, a power-generating module shall be capable of remaining connected to the network and operate within the frequency ranges and time periods specified in Figure 2.1.

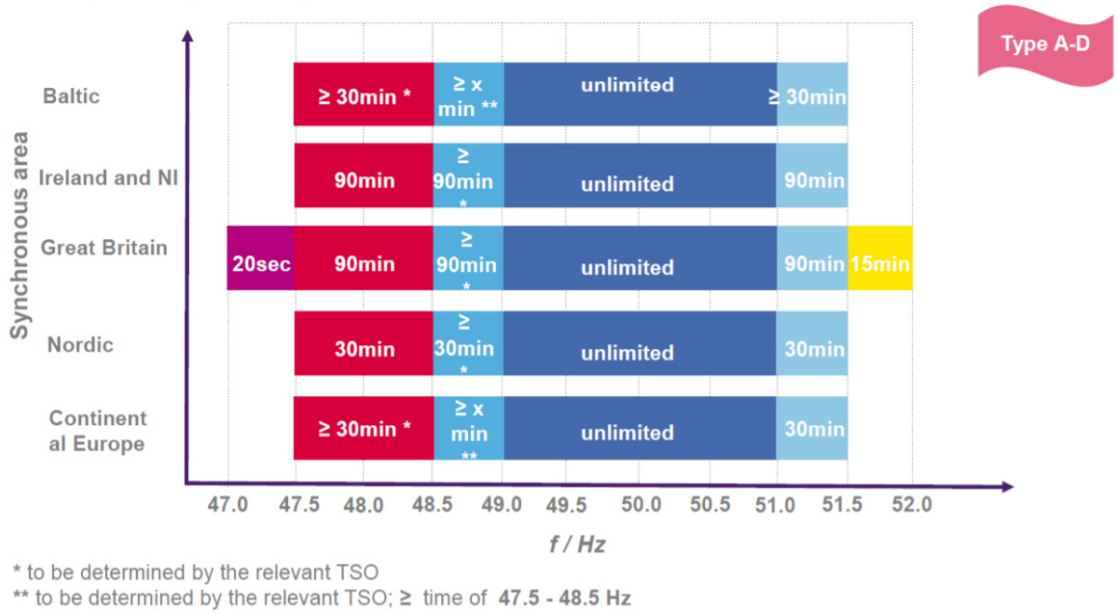

Figure 2.1 Frequency ranges and time periods for all types of generators

- With regard to the **rate of change of frequency** (RoCoF) withstand capability, a power-generating module shall be capable of staying connected to the network and operate at RoCoFs up to a value specified by the relevant TSO, unless disconnection was triggered by RoCoF-type loss of mains protection. The relevant system operator, in coordination with the relevant TSO, shall specify this RoCoF-type loss of mains protection. According to ENTSO-E [5], RoCoF is the time derivative of the power system frequency.
- With regard to the **limited frequency sensitive mode-overfrequency** (LFSM-O), the power-generating module shall be capable of activating the provision of active power frequency response according to Figure 2.2 at a frequency threshold and droop settings specified by the relevant TSO, or the relevant TSO may choose to allow within its control area automatic disconnection and reconnection of power-generating modules of Type A at randomised frequencies, ideally uniformly distributed, above a frequency threshold, as determined by the relevant TSO where it is able to demonstrate to the relevant regulatory authority, and with the cooperation of power-generating facility owners, that this has a limited cross-border impact and maintains the same level of operational security in all system states;
    - the frequency threshold shall be between 50.2 Hz and 50.5 Hz inclusive;
    - the droop settings shall be between 2% and 12%;
    - the power-generating module shall be capable of activating a power frequency response with an initial delay that is as short as possible. If that delay is greater than two seconds, the power-generating facility owner shall justify the delay, providing technical evidence to the relevant TSO;
    - the relevant TSO may require that upon reaching minimum regulating level, the power-generating module be capable of either: continuing operation at this level or further decreasing active power output;
    - the power-generating module shall be capable of operating stably during LFSM-O operation. When LFSM-O is active, the LFSM-O setpoint will prevail over any other active power setpoints.

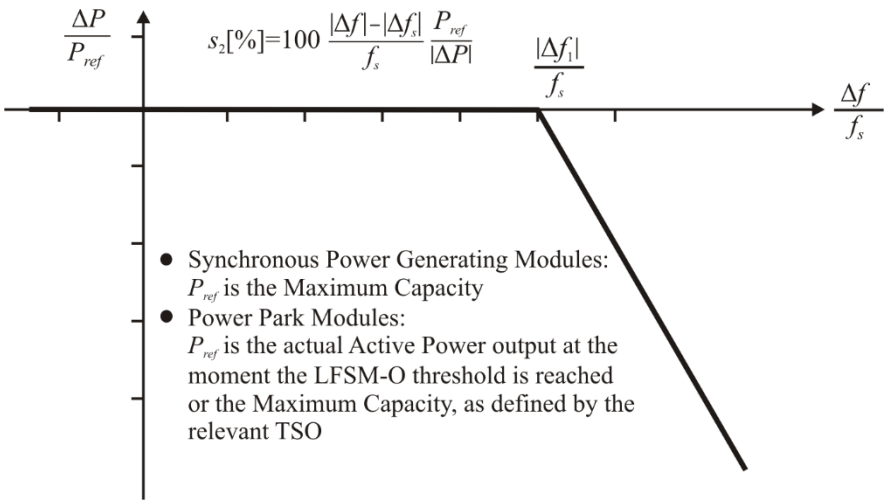

Figure 2.2: Active power frequency response capability of power-generating modules in LFSM-O

- The power-generating module shall be capable of **maintaining constant output at its target active power value** regardless of changes in frequency, except where output follows the changes specified in the context of previous paragraphs and the next one.
- The relevant TSO shall specify **admissible active power reduction from maximum output** with falling frequency in its control area as a rate of reduction falling within the boundaries, illustrated by the full lines in Figure 2.3: (a) below 49 Hz falling by a reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop; (b) below 49.5 Hz falling by a reduction rate of 10% of the maximum capacity at 50 Hz per 1 Hz frequency drop. The admissible active power reduction from maximum output shall: (a) clearly specify the ambient conditions applicable; (b) take account of the technical capabilities of power-generating modules.

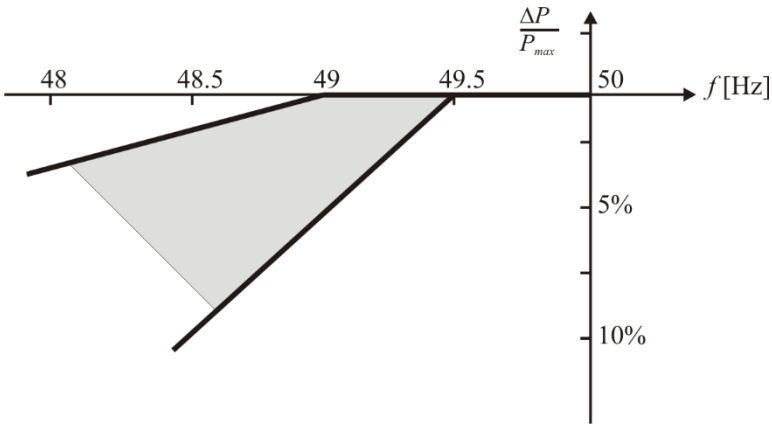

Figure 2.3: Maximum power capability reduction with falling frequency. The boundaries are specified by the relevant TSO.

- The power-generating module shall be equipped with a logic interface (input port) in order to **cease active power output within five seconds following an instruction** being received at the input port. The relevant system operator shall have the right to specify requirements for equipment to make this facility operable remotely.
- The relevant TSO shall specify the conditions under which a power-generating module is **capable of connecting automatically to the network**. Those conditions shall include: (a) frequency ranges within which an automatic connection is admissible, and a corresponding delay time; and (b) maximum admissible gradient of increase in active power output. Automatic connection is allowed unless specified otherwise by the relevant system operator in coordination with the relevant TSO.

Type B power-generating modules have to fulfil the same requirements as type A but the relevant TSO may not choose to allow within its control area automatic disconnection and reconnection of power-generating modules of Type B at randomized frequencies, above a frequency threshold, as determined by the relevant TSO. Type B power-generating modules shall fulfil the following requirements in relation to frequency stability:

- to control active power output, the power-generating module shall be equipped with an interface (input port) in order to be able to reduce active power output following an instruction at the input port; and
- the relevant system operator shall have the right to specify the requirements for further equipment to allow active power output to be remotely operated.

Type C power-generating modules shall fulfil the following requirements relating to frequency stability:

- with regard to active power controllability and control range, the power-generating module control system shall be capable of adjusting an active power setpoint in line with instructions given to the power-generating facility owner by the relevant system operator or the relevant TSO. The relevant system operator or the relevant TSO shall establish the period within which the adjusted active power setpoint must be reached. The relevant TSO shall specify a tolerance (subject to the availability of the prime mover resource) applying to the new setpoint and the time within which it must be reached;
- manual local measures shall be allowed in cases where the automatic remote control devices are out of service. The relevant system operator or the relevant TSO shall notify the regulatory authority of the time required to reach the setpoint together with the tolerance for the active power;
- the following requirements shall apply to type C power-generating modules with regard to limited frequency sensitive mode — underfrequency (LFSM-U):
    - the power-generating module shall be capable of activating the provision of active power frequency response at a frequency threshold and with a droop specified by the relevant TSO in coordination with the TSOs of the same synchronous area as follows:
        - the frequency threshold specified by the TSO shall be between 49.8 Hz and 49.5 Hz inclusive,
        - the droop settings specified by the TSO shall be in the range 2 – 12%.

    This is represented graphically in Figure 2.4;

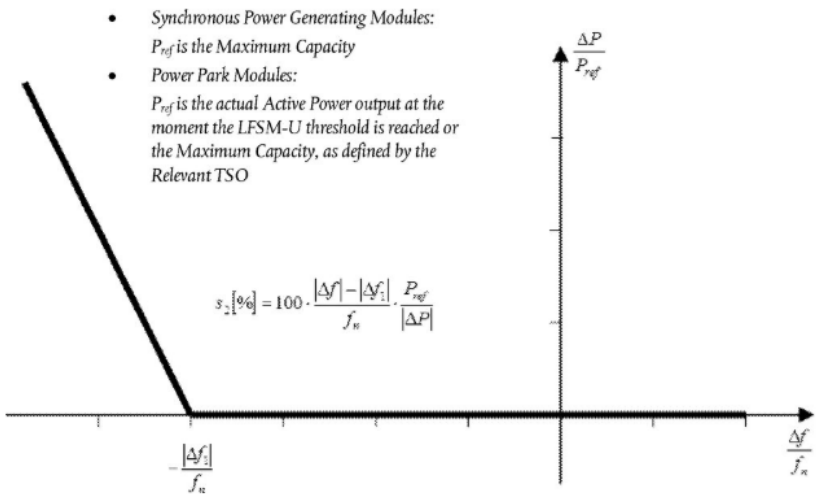

Figure 2.4 Active power frequency response capability of power-generating modules in LFSM-U.

    - the actual delivery of active power frequency response in LFSM-U mode shall take into account:
        - ambient conditions when the response is to be triggered,

        - the operating conditions of the power-generating module, in particular limitations on operation near maximum capacity at low frequencies and the respective impact of ambient conditions, and
        - the availability of the primary energy sources.
    - the activation of active power frequency response by the power-generating module shall not be unduly delayed. In the event of any delay greater than two seconds, the power-generating facility owner shall justify it to the relevant TSO;
    - in LFSM-U mode the power-generating module shall be capable of providing a power increase up to its maximum capacity;
    - stable operation of the power-generating module during LFSM-U operation shall be ensured;
- with regard to frequency restoration control, the power-generating module shall provide functionalities complying with specifications specified by the relevant TSO, aiming at restoring frequency to its nominal value or maintaining power exchange flows between control areas at their scheduled values;
- with regard to disconnection due to underfrequency, power-generating facilities capable of acting as a load, including hydro pump-storage power-generating facilities, shall be capable of disconnecting their load in case of underfrequency. The requirement referred to in this point does not extend to auxiliary supply;
- with regard to real-time monitoring of FSM:
    - to monitor the operation of active power frequency response, the communication interface shall be equipped to transfer in real time and in a secured manner from the power-generating facility to the network control centre of the relevant system operator or the relevant TSO, at the request of the relevant system operator or the relevant TSO, at least the following signals:
        - status signal of FSM (on/off),
        - scheduled active power output,
        - actual value of the active power output,
        - actual parameter settings for active power frequency response,
        - droop and deadband;
    - the relevant system operator and the relevant TSO shall specify additional signals to be provided by the power- generating facility by monitoring and recording devices in order to verify the performance of the active power frequency response provision of participating power-generating modules;
- "*synthetic inertia*" means the facility provided by a power park module or HVDC system to replace the effect of real inertia of a synchronous power-generating module to a prescribed level of performance. Type C power park modules shall fulfil the following additional requirements in relation to frequency stability:
    - the relevant TSO shall have the right to specify that power park modules be capable of providing synthetic inertia during very fast frequency deviations;
    - the operating principle of control systems installed to provide synthetic inertia and the associated performance parameters shall be specified by the relevant TSO.

Type D power-generating modules have to fulfil the same requirements as type C but automatically connection to the network is not allowed.

2.1.1.2 Network Code on Demand Connection

The NC DCC [6] applies to all new transmission-connected demand and distribution facilities, closed distribution systems[1] and new demand units used by a demand facility or a closed distribution system to provide demand response services to relevant system operators and relevant TSOs.

Frequency stability-wise, the code offers:

[1] The definition of "closed distribution system" can be found in [4].

- Clear frequency ranges and time periods at which transmission-connected demand and distribution facilities and distribution systems are to remain connected to the network, as listed in Table 2-3.

Table 2-3 Frequency ranges and time periods for demand

Synchronous area	*Frequency range*	*Time period for operation*
Continental Europe	47.5 Hz – 48.5 Hz	To be specified by each TSO, but not less than 30 minutes
	48.5 Hz – 49.0 Hz	To be specified by each TSO, but not less than the period for 47.5 Hz – 48.5 Hz
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	30 minutes
Nordic	47.5 Hz – 48.5 Hz	30 minutes
	48.5 Hz – 49.0 Hz	To be specified by each TSO, but not less than 30 minutes
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	30 minutes
Great Britain	47.0 Hz – 47.5 Hz	20 seconds
	47.5 Hz – 48.5 Hz	90 minutes
	48.5 Hz – 49.0 Hz	To be specified by each TSO, but not less than 90 minutes
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	90 minutes
	51.5 Hz – 52.0 Hz	15 minutes
Ireland and Northern Ireland	47.5 Hz – 48.5 Hz	90 minutes
	48.5 Hz – 49.0 Hz	To be specified by each TSO, but not less than 90 minutes
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	90 minutes
Baltic	47.5 Hz – 48.5 Hz	To be specified by each TSO, but not less than 30 minutes
	48.5 Hz – 49.0 Hz	To be specified by each TSO, but not less than the period for 47.5 Hz – 48.5 Hz
	49.0 Hz – 51.0 Hz	Unlimited
	51.0 Hz – 51.5 Hz	To be specified by each TSO, but not less than 30 minutes

2.1.1.3 Network Code on Requirements of Grid Connection of High-Voltage Direct Current Systems and Direct Current-Connected Power Park Modules

NC HVDC [7] applies to HVDC systems connecting synchronous areas or control areas, including back-to-back schemes or those connecting power park modules to a transmission network or a distribution network, while also applying to embedded HVDC systems within one control area and connected to the transmission network or embedded HVDC systems within one control area and connected to the distribution network when a cross-border impact is demonstrated by the relevant TSO.

Related to frequency stability and active power control, the code presents the following requirements:

- Clear frequency ranges and time periods at which HVDC systems are to remain connected to the network, which are listed in Table 2-4.

Table 2-4 Frequency ranges and time periods for HVDC systems

Frequency range	*Time period for operation*
47.0 Hz – 47.5 Hz	60 seconds
47.5 Hz – 48.5 Hz	To be specified by each relevant TSO, but longer than established times for generation and demand according to Regulation (EU) 2016/631 and Regulation (EU) 2016/1388 respectively
48.5 Hz – 49.0 Hz	To be specified by each relevant TSO, but longer than established times for generation and demand according to Regulation (EU) 2016/631 and Regulation (EU) 2016/1388 respectively, and longer than for DC-connected power park modules (PPMs)
49.0 Hz – 51.0 Hz	Unlimited
51.0 Hz – 51.5 Hz	To be specified by each relevant TSO, but longer than established times for generation and demand according to Regulation (EU) 2016/631 and Regulation (EU) 2016/1388 respectively, and longer than for DC-connected PPMs
51.5 Hz – 52.0 Hz	To be specified by each relevant TSO, but longer than for DC-connected PPMs

- Capability response to the limited frequency sensitive modes (over- and under-frequency), as depicted in Figure 2.5 and Figure 2.6.

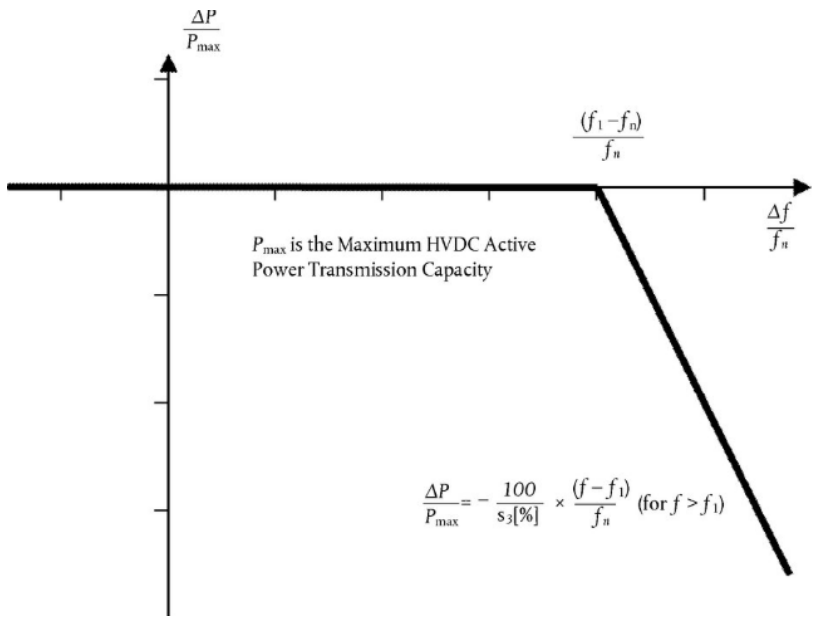

Figure 2.5 Active power frequency response capability of HVDC systems in LFSM-O

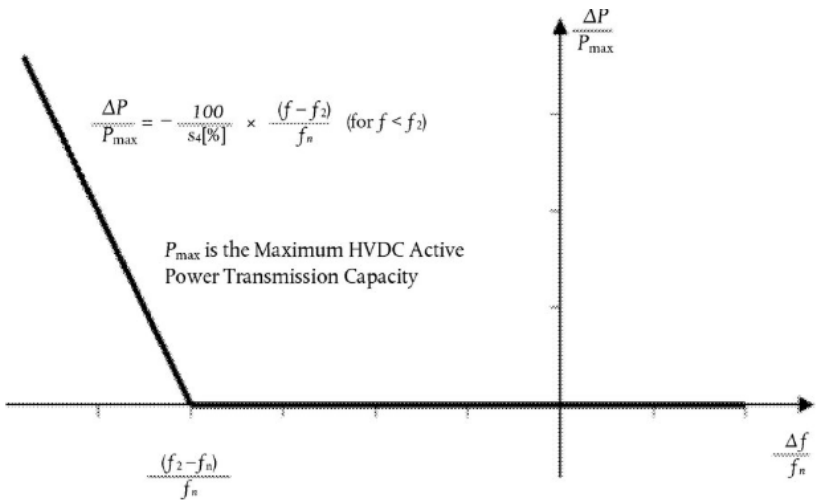

Figure 2.6 Active power frequency response capability of HVDC systems in LFSM-U

- Active power frequency response capability as shown in Figure 2.7.

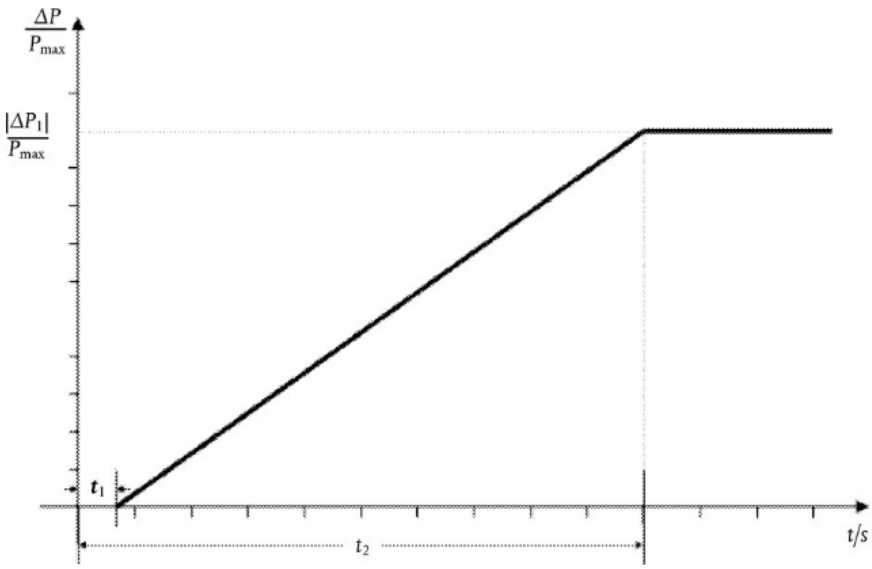

Figure 2.7 Active power frequency response capability of an HVDC system

- RoCoF withstand capability: An HVDC system shall be capable of staying connected to the network and operable if the network frequency changes at a rate between -2.5 and +2.5 Hz/s (measured at any point in time as an average of the rate of change of frequency for the previous 1 sec), while a DC-connected PPM shall be capable of staying connected to the remote-end HVDC converter station network and operable if the system frequency changes at a rate up to ±2 Hz/s (measured at any point in time as an average of the rate of change of frequency for the previous 1 second) at the HVDC interface point of the DC-connected power park module at the remote end HVDC converter station for the 50 Hz nominal system.
- Synthetic inertia: In low and/or high frequency regimes, HVDC systems have to rapidly adjust the active power injected to or withdrawn from the AC network in order to limit the RoCoF.

2.1.1.4 Storage

In both NC RfG and NC DCC, it is clearly specified that the regulation does not apply to storage devices, aside from pump-storage power-generating modules. Also, the balancing guideline requires each TSO to lay down the terms for storage facilities to become balancing service providers [3]. In the NC on emergency and restoration, it is required for each TSO to establish in

its system defense plan the frequency thresholds at which the automatic switching or disconnection of energy storage units shall occur [4].

Therefore, there is no adopted regulation that covers clear frequency control requirements for energy storage systems. As for regulation that is pending approval, the balancing guideline and the NC on emergency and restoration impose that frequency control requirements for storage facilities are not to be established at ENTSO-E level, but by each TSO for its own system.

An EU level code for electricity storage systems could be established based on the experience of all TSOs.

2.2 Transelectrica

In the Romanian power system, from the point of view of the primary energy source, the following types of generating groups are in operation: hydroelectric, classical thermoelectric (with and without combined production of electricity and heat) based on coal or gas, nuclear, wind, photovoltaic and thermoelectric based on biomass.

The total power generation installed in the Romanian power system on January 1st 2018 was 24,738 MW with 24 MW higher than that installed on January 1st 2017, a very small increase, mainly due to the evolution of the power installed in renewable sources.

- The largest groups in the system are the 707 MW nuclear units from Cernavoda (the second unit was commissioned in August 2007);
- the installed power of the hydroelectric groups ranges from less than 1 MW to 194.4MW (the power installed after the rehabilitation of the CHE Portile de Fier groups);
- the classical thermoelectric groups have a wide variation in the installed unit power: from several MW for some groups of prosumers, to 330 MW the unitary capacity of the lignite condensation groups in the Rovinari and Turceni power plants;
- wind power units with unit powers of less than 1 – 3 MW have been installed, but aggregating a large number of such groups results in wind power plants (CEE) that can reach hundreds of MW. At the 400 kV Tariverde station is connected and operates a wind power plant with an installed capacity of 600 MW, ranked as the largest terrestrial wind power plant in Europe at the time of completion;
- the total electricity installed in wind at the end of 2017 was 3,030 MW and in solar reached 1,375 MW;
- finally, biomass power plants totals 130 MW at the end of 2017;

Starting with 2014, the average gross domestic consumption registered a positive trend, increasing compared to the previous years, with average values ranging from 0.7% to 1.9%.

The maximum consumption (winter peak) was registered on January 22nd 2018, and was about 9,541MW. In the Table 2-6 it can be seen how this consumption was covered.

Table 2-5: Installed capacities in the Romanian transmission system. January 1st, 2018.

Source of energy	***Installed Capacity (MW)***
Coal	6,240.27
Hydrocarbon	5,788.94
Hydro	6,761.19
Nuclear	1,413.00
Wind	3,029.74
Biomas/Biogas	130.44
Solar	1,374.64
Geothermal	0.05

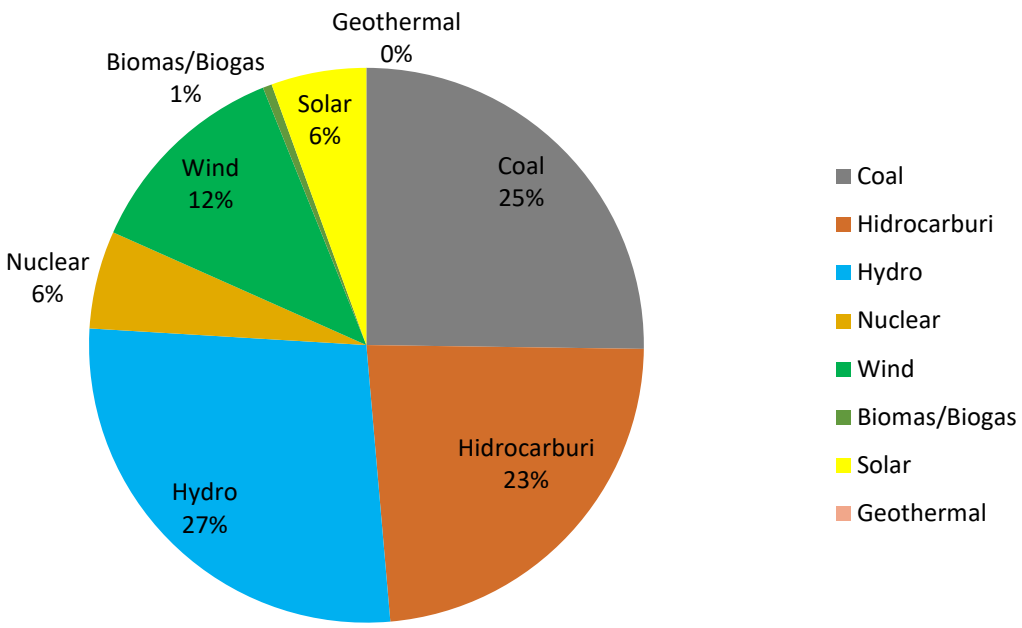

Figure 2.8: Installed capacities in the Romanian transmission system. January 1st, 2018.

Table 2-6: Coverage of maximum instantaneous consumption

Date	***22-01-2018 18:25:07***
Consumption [MW]	**9541**
Production [MW]	**10484**
Coal [MW]	2632
Hydrocarbons [MW]	1774
Hydro [MW]	1985
Nuclear [MW]	1388
Wind [MW]	2648
Solar [MW]	-1
Biomas [MW]	57
Export [MW]	**-943**

Transmission network owned by Transelectrica comprises 154 overhead lines (400 and 220kV, and 7 on 110kV), 81 substations and 216 transformers and autotransformers.

In force contracts for connecting new power plants to the power transmission grid is presented in Table 2-7 below.

Table 2-7: In force contracts for connecting new power plants to the power transmission grid

Source of energy	***Installed Capacity (MW)***
Wind	**5,400**
Solar	**2,300**
Hydro	650
Biomas/Biogas	160
Geothermal	0.05

Prior to the approval of NCs on European Union level, the legislation that covered technical requirements for equipment connected to the Romanian transmission grid was:

- The Technical Transmission Grid Code of the Romanian Power System (of August 27th 2004);
- The “Technical conditions for the connection to the public electricity networks for wind power plants” Technical Norm (of April 3rd 2009, modified in May 29th 2013 in order to be in line with the Photovoltaic Technical Requirements);
- The “Technical conditions for the connection to the public electricity networks for photovoltaic power plants” Technical Norm (of May 30th 2013).

However, as an ENTSO-E member, Transelectrica has the obligation of implementing the European NCs. The process involves the drafting of the NCs, workshops with stakeholders (DSOs, generation companies, large consumers, ANRE - the Romanian National Regulatory Agency, other TSOs), public consultation, and approval by ANRE.

The implementation timeline agreed upon by Transelectrica and ANRE highlights the fact that all connection codes shall be drafted by May 17th 2018.

ENTSO-E Connection Code	***Transelectrica Technical Specification***	***Status***	***Changes made to existing Romanian codes***
NC RfG	Technical Norm "Technical conditions for the connection to the public electricity networks for synchronous generators"	Approved August 2017	The articles of the Technical Transmission Grid Code of the Romanian Power System dealing with technical requirements of synchronous generators will be abrogated
	Technical Norm "Technical conditions for the connection to the public electricity networks for generating modules"	Public consultation	The technical norms for the connection of wind and photovoltaic power plants will be abrogated
NC DCC		Public consultation	The articles of the Technical Transmission Grid Code of the Romanian Power System dealing with technical requirements of demand will be abrogated
NC HVDC		Public consultation	New code

3. Drafting of Ancillary Services and Network Code Definitions for Frequency Estimation and for the Provision of RoCoF and Fast Frequency Control

3.1 List of Recommendations of Ancillary Services and NC Definitions to be Added and/or Modified and Rationales Behind

This chapter considers the ancillary services and NCs described in Chapter 2 that are related to the RoCoF and primary frequency control (PFC) in low-inertia systems. In particular, the chapter focuses on the codes that need to be updated and, more often than not, created in order to account for the new agents that are expected to participate, to a large extent, to these frequency control categories in the near future. Examples of these agents are converter-interfaced Energy Storage Systems (ESSs), Distributed Energy Resources (DERs) operated by Distribution System Operators (DSOs), and grid-connected microgrids.

As a first step towards this task, Deliverable D2.1 proposes a new definition of ***frequency*** in the context of very high penetration of RESs to replace that proposed by the ENTSO-E in [8]. The main rationale behind the proposal is that, in this new scenario where non-synchronous, inertia-less generation will surpass the conventional synchronous one, larger frequency variations are expected following transients, which will also consistently vary from point to point in the network. Therefore, the usual assumption that *the frequency is the same everywhere in the network* is not acceptable in low-inertia power systems.

As stated at the beginning of Chapter 2, updating the definition of ***frequency*** in the ENTSO-E NCs is an ambitious goal, due to the high number of agents involved. Nevertheless, updating this definition is a necessary step towards the regulation of the different agents that will participate in the scenario described above, that implies changing consistently the vision we have today on power systems. However, this is just the first step, and many more should follow if the final goal is to have a secure and reliable power system in the not-so-far horizon. This is one of the objectives that have been set in Task 2.6 of the RESERVE project.

To achieve the aforementioned objective, two main obstacles must be overcome. First, one needs to cope with the problem of estimating the frequency at every relevant location of the network, as the commonly-used approach of just measuring the frequency at a single pilot bus of the network will not suffice. Moreover, with the exponential increase of computational power, together with the development of new ICTs such as 5G which allow transmitting signals with latencies in the order of few milliseconds with minimal loss of information, the so long pursued desire from TSOs of knowing all relevant states of the system (including the “confidential” rotor speeds of the synchronous machines of the system) in “real-time” can become a reality. The problem of the frequency estimation is further discussed in Section 3.1.1.

The second obstacle regards the reduction of the inherent inertial response of synchronous machines in the event of contingencies that naturally compensates such transients. The most obvious solution is to be able to provide an equivalent response from non-synchronous DERs (i.e., RESs and ESSs), taking advantage of the very fast dynamics of the power converter that acts as interface between the DER and the rest of the system. However, this solution is not trivial, and poses a number of problems. For example, the number of agents that will provide inertial or fast frequency control and that will be required to be coordinated, will considerably increase over time. Sections 3.1.2 to 3.1.4 provide a description of a number of these new agents, namely RESs, ESSs and microgrids, for which new requirements and regulations for their connection and operation will be required.

3.1.1 Frequency Estimation: Frequency Takers and Frequency Makers

The series of publications [9, 10, 11] focus on the estimation of the frequency based on the concept of the frequency divider formula (FDF) proposed in D2.1. These papers constitute a corpus of works that are aimed at the on-line definition of rotor speed frequencies, local bus frequencies and the frequency of the centre of inertia. The ultimate goal of the on-line dynamic state estimation of the frequency is to improve the monitoring of the system by system operators and, hence, to provide a preventive control tool (see Figure 3.1).

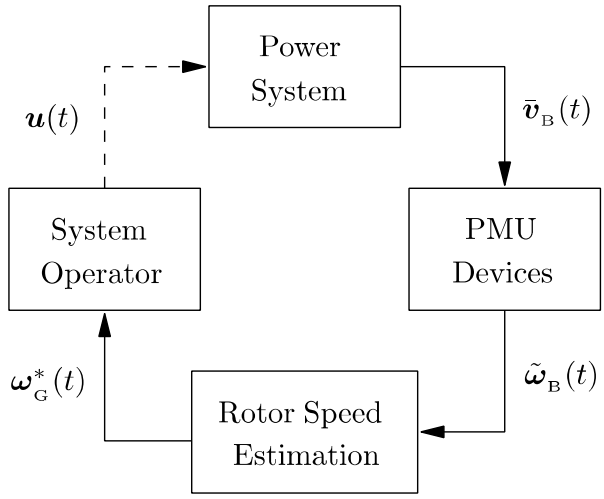

Figure 3.1: Scheme of corrective control by system operators based on frequency rotor speed estimation.

In the context of the RESERVE project, in particular of Task 2.6, the estimation of the frequency is particularly relevant not only to be able to communicate the right signals to the non-synchronous converter-interfaced generators but also to be able to identify whether these devices are providing frequency control or not. An anticipated extension of the work carried out so far in [9, 10, 11] is, in fact, the ability to distinguish, based on frequency measurements, between DERs that are "frequency makers" (i.e., provide RoCoF control support) and those that are frequency takers (i.e., do not provide RoCoF control).

In Subsections 3.2.1 and 3.2.2 we describe first the work carried out in [9, 10, 11] and then we outline that concept of frequency makers/takers in Subsection 3.2.3, that will be fully developed and tested in D2.7.

3.1.2 Frequency Control of Distributed Energy Resources in Distribution Networks

Until recent years, frequency regulation from DERs was not available, as they were operated with the aim of supplying their maximum feasible power according to meteorological conditions by means of the maximum power point tracking (MPPT) control [12, 13]. However, this scenario is rapidly changing. In fact, as the penetration of DERs increases, there is the urgent need to maintain the system frequency regulation capability while the system inertia is being reduced. A crucial problem is that, while active power curtailment is generally always available for DERs in case of over-frequencies, they usually cannot guarantee a power reserve in case of under-frequencies. To overcome this issue, energy storage systems ESSs become apparent, thanks to their capability to supply/absorb large amounts of active and reactive power simultaneously in very short time frames [14].

While the provision of frequency control through DERs is considered to be inevitable, there is still no clear understanding on what is the best approach to control such devices [15, 16, 17, 13]. In particular, there are several concerns for DERs with "small" capacity, which are typically connected to the distribution (medium voltage) level. The main issues that are anticipated for the control of these DERs are: (i) large number of small devices; (ii) relatively high noise in the distribution network due to the proximity to loads.

Conventional primary frequency control from synchronous power plants has been implemented in a decentralized (i.e., local) way, also because these power plants have a "good" local estimation of the frequency which is the rotor speed of the synchronous machines. Since DERs are typically non-synchronous as they are coupled to the grid by means of power converters, the frequency has to be estimated based on voltage/current phasors at the point of connection of the DER. This is done typically with a phase-locked loop (PLL) device, which unfortunately introduces errors, e.g., due to the calculation of the numerical derivative of phasor components. Reference [14] shows that the impact of PLLs on the frequency regulation of non-synchronous generation at the high-voltage transmission system level can create instabilities. Similar issues have to be anticipated for the frequency estimation of PLLs at the medium-voltage distribution system level.

Moreover, while there exist a large variety of PLL implementations, there is no solution that optimizes simultaneously accuracy, sensitivity to noises and speed of frequency tracking, as discussed in [18].

The goal of this study is to provide comprehensive analysis on the impact of the frequency control of distribution-level DERs on the overall transient behavior of transmission systems. Three strategies to generate the signal used as input of the DER frequency regulators are proposed and compared: (i) decentralized, where each DER estimates its local frequency through a PLL; (ii) centralized, where the DERs connected to the same distribution system receive a common signal from a PLL installed at the point of contact of the distribution network with the transmission system; and (iii) average, where the frequency estimations of the DERs are collected at the distribution system level and then a common, average signal is sent back to each DER. The case study also duly discusses the effect of noise, delay in the transmission of the signals and loss of information in the communication system.

Results of this study will be later used to define the best frequency signal retrieval strategy for DERs in distribution systems, as well as the recommendations for maximum acceptable levels of latencies and noises of the input signal of the DER frequency regulators to guarantee the stability of the grid in scenarios with very high penetration of DERs. Requirements for the ICT used to transmit the different signals will be also defined from this work.

3.1.3 Frequency Control of Converter-Interfaced Energy Storage Systems in Transmission Grids

In D2.1 and D2.2, we have demonstrated why converter-interfaced ESSs are seen as a key element to cope with the issues related to the increasing penetration of non-dispatchable generation based on RESs. These issues, which threaten the stability of the power system, are due to the uncertain and volatile nature of the RESs, as well as the reduction of the overall system inertia that is related to the replacement of synchronous power plants with this type of non-synchronous, power converter-interfaced generation. In particular, ESSs can help regulate the active power supplied by RESs, provide fast frequency and voltage regulation, contribute to the secondary frequency regulation, etc.

As stated in Chapter 2, no existing NC provides the required regulation for the connection of ESSs in the transmission system. This is mainly due to the fact that, to date, the number of studies that test the performance of large ESSs connected to transmission systems is very limited. With this regard, this deliverable, and the subsequent D2.7, provides comprehensive studies of ESSs connected to real-world transmission networks when providing fast frequency control. To this aim, this deliverable considers the all-island Irish system as test example, while D2.7 will focus on the interconnected model of the Romanian transmission grid.

Apart from the variety of ancillary services that converter-interfaced ESSs can provide to a transmission grid – which include flattening the power provided by RESs, active power regulation in a transmission line, local and/or global frequency regulation, RoCoF mitigation, etc. – a relevant by-product of ESSs is their capability of improving the transient stability of such a grid. In fact, the fast responses associated with ESSs, together with their inherent ability to control both active and reactive powers independently, can increase the critical clearing times (CCTs) associated with a fault. This service is illustrated in this deliverable considering the Irish transmission grid as test system, where an analysis that quantifies the impact of ESS technologies on the transient stability of the grid, taking into account different locations and initial loading conditions.

The recommendations of ancillary services and requirements for ESSs in transmission grids for fast frequency control and transient stability that are expected to be defined in D2.7 are as follows:

- Total energy and power capacities of ESSs required in a given system for different shares of RESs.
- Effect of system topology and ESS location on the overall system performance and stability.
- Identification of the best ESS technology and fast frequency control strategy for each scenario.

3.1.4 Frequency Control of Grid-Connected Microgrids

The concept of microgrid (MG) has received particular attention from the scientific community as it is generally considered the building block of the smart grid [19]. The MG can be defined as an electrical entity that facilitates a high depth penetration of DERs and relies on advanced control strategies. A less abstract definition is provided by the U.S. Department of Energy: A MG is a group of interconnected loads and DERs with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can connect and disconnect from the grid to enable it to operate in both grid-connected or island mode [20].

This new paradigm combined with the recent trend of the energy market deregulation, that will allow a MG to apply new policies of Demand Response, is expected to bring economic advantages to the users and to increase the efficiency of the power grid as a whole. Nevertheless, the electrical system nowadays still heavily relies on centralized generation from traditional rotating machines. It is highly unlikely that a transition to a fully distributed transmission system will happen in the near future. Furthermore, due to the MGs ability to conduct policies of Demand & Response, a reliable and secure penetration of these units might prove to be a challenge to attain [21].

While there has been a considerable amount of research carried out on the control of single, often islanded, MGs and on the investigation of the penetration level of DERs, the literature on the interaction between MGs, the market and its effect on the grid is limited. A relevant review on the impact of low rotational inertia in the power system frequency has been presented in [22]. In [23], angle and voltage stability is analysed as the MG penetration level increases and, in [24] and [25], the influence of high penetration of wind based DERs is assessed. In the aforementioned works, the ability of a MG to conduct policies of Demand & Response and its effect on the frequency control of the transmission system is not taken into consideration. Frequency deviations, in fact, are a measure of the active power imbalance and should remain within the operational limits in order to avoid transmission line overloads and the triggering of protection devices [26].

The MGs interaction with the electricity market is a crucial element that cannot be neglected: a MG adopts a greedy behaviour with respect to the electrical grid, selling or buying energy whenever it is convenient from an economical and operational point of view not necessarily taking into consideration the effects on the stability of the system. This behaviour is acceptable only if the penetration of MGs is small with respect to the total system capacity and, due to their small size, MGs can be reasonably modelled as price takers. This situation, however, might not be acceptable if such a penetration increases.

In this study, we merge together the electricity market model proposed in [27] with a hybrid dynamic and event-driven MG representation as well as a detailed electromechanical model of the system. The goal is to provide a dynamic model to study the coupling between the dynamics of the MGs, the power system and the energy market, with an emphasis on frequency regulation.

In this deliverable, we discuss the following points.

- A microgrid model that includes main elements (loads, DER, and storage) as well as a mechanism to take into account both electricity markets and freqeuncy control.
- An analysis of the dynamic impact of an increasing penetration level of MGs on power systems, coupled with market dynamics.
- A realistic time-domain analysis of the power system that takes into account detailed nonlinear electro-mechanical models, MGs, storage units and DERs.
- An analysis of the effects of different storage capacity sizes and different granularity of MGs on the stability of the power system.
- An application the Additive Increase Multiplicative Decrease (AIMD) technique, which has been successfully applied in the past to communication systems and that appears as a promising solution for the control of the MGs.

All results that are discussed in this section are based on the following works [28, 29, 30, 31, 32]. For the sake of compactness and clarity, the details on the mathematical formulation and modelling of the MGs, their energy management system and control are not given in this document. The interested reader can find all details in the five references above.

3.2 Methodology and Case Studies to be Done to Support the Recommendations

This section lists and describes the methodologies that are proposed in Task 2.6 to investigate the different concepts that have been presented in the previous section. The case studies that will be used in Task 5.3 to validate the recommendations proposed above by applying these methodologies are also highlighted. A number of preliminary results considering small IEEE benchmark networks, as well as a real-world test system are provided in Appendix A.1.

3.2.1 Estimation of Local Bus Frequencies based on Synchronous Machine Rotor Speeds

Reference [9] discusses a robust state estimator that, starting from the measurements of the rotor speeds of synchronous machines allows to estimate the frequencies at every bus of the system. The whole estimation problem is based on the direct application of the FDF. The idea is intriguing as the number of synchronous machines in the system is generally very small with respect of the total number of high-voltage buses over 110 kV (typically about 1 over 10 in real-world systems). The results of [9] can be further enhanced if considering that, in large systems, the vast majority of the participation factors of the synchronous machines to a given bus frequency are negligible. This is the major result of the work carried out in [10].

On the other hand, the state estimation proposed in [9] shows two possible issues:

- the measures of the rotor speeds are not always available to system operators;
- the physical distances between machines, especially in large interconnected systems, may lead to consistent delays in the measures that have to be collected in the control centre of the system operators.

It appears, thus, that the technique implemented in [9] can be utilized effectively only in small systems (e.g., ac microgrids or small islands) where both the number of machines and distances are small. While we do not anticipate that this technique can be substantially improved for large transmission systems (mainly due to large communication delays when distances are big), this technique can be applied in small islanded systems.

3.2.2 Estimation of Synchronous Machine Rotor Speeds based on Local Bus Frequency Measurements

Reference [11] considers the complementary problem that is solved in [9]. The starting point in this case are the measurements of local bus frequencies. These are potentially available to the system operators as they can install Phasor Measurement Units (PMUs) at any bus of the system. Then, utilizing the inverse of the FDF, one can determine the instantaneous values of the rotor speeds of the synchronous machines connected to the system.

The starting point of [11] may appear unrealistic as the number of buses of real-world transmission systems tends to be high. For example, in the model of the Irish system utilized in [11], the number of buses is 1,479, compared to the number of machines which are only 22 in the case study considered in the paper.

Nevertheless, the study of the structure of the pseudo-inverse of the matrix that appears in the FDF leads to draw some very interesting conclusions, as follows[2]:

- the minimum number of measurements required to estimate each rotor speed is equal to the number of buses directly connected to the terminal bus of the machine itself plus 1. This number is typically very low (2 or 3) as indicated in Figure 3.2;
- the FDF includes the information on the buses where the minimum number of frequency measurements have to be placed;
- if more than the minimum number of measurements are utilized, the state estimation is more robust and can cope with noise and bad data, as expected;

[2] A number of results of the Irish test system presented in [11] are provided and discussed in Appendix A.1.1.

- typical measurement delays do not impact significantly in the state estimation.

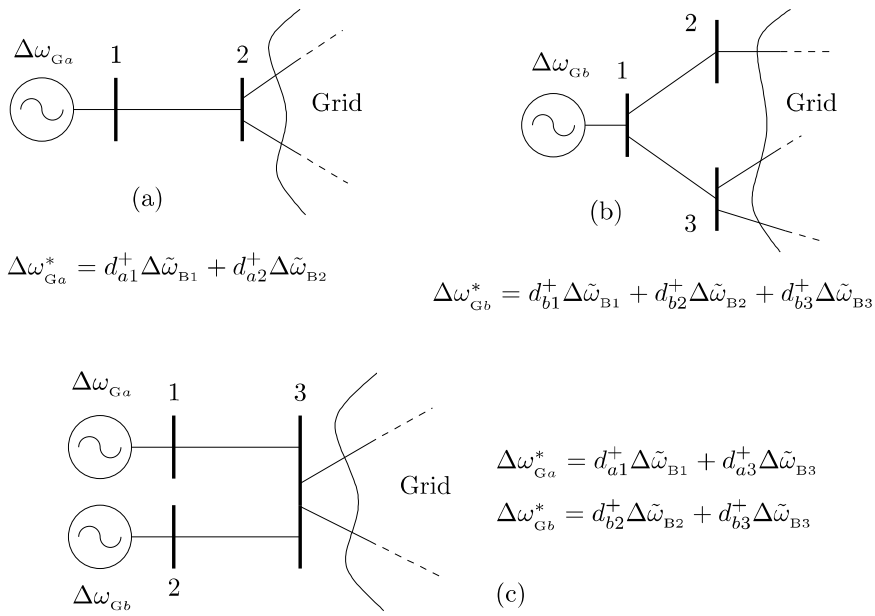

Figure 3.2: Minimum number of bus frequency measurements required to estimate the rotor speed of synchronous machines [11].

The methodology presented above will be applied to the Romanian transmission system model, and results and conclusions will be presented in D5.5 and D2.7, respectively.

3.2.3 Frequency Maker vs. Frequency Taker

The work carried out in [9, 10, 11, 33] paves the way to a further, relevant step in the frequency estimation, namely the ability to determine whether a non-synchronous generator (typically renewable converter-interfaced power plant based on wind or solar radiation, but also MGs, energy storage systems and frequency-controlled loads) do actually provide frequency control or not.

The FDF suggests that in the same way we can determine the rotor speed variations of a synchronous generator with known inertia, we can determine, based on frequency variations the "equivalent" inertia of a non-synchronous device. Since the FDF is able to capture only frequency deviations, the estimation of the equivalent inertia can be done only during transients, i.e., in dynamics conditions during which the bus frequencies at the buses are different.

At the time of writing this report, the most promising approach in this direction is the following formula:

$$y_{Gi} = \sum_{k \in \Omega_i} b_{ik} \Delta\omega_k \tag{2.1}$$

Where Ω_i is the set of buses connected to the non-synchronous generator i, b_{ik} are the elements of the matrix of the FDF that relates bus frequencies with rotor speeds (see [34] for details), $\Delta\omega_k$ is the bus frequency deviations with respect to the reference speed at the bus k, and y_{Gi} is the index that characterizes the frequency maker/taker.

The index y_{Gi} has the following properties:

- y_{Gi} is zero if the generator connected at bus i is not regulating the frequency and does not respond to frequency variations (e.g., does not include a virtual inertia controller);
- y_{Gi} is not null during the transient if the generator connected to bus i provides either frequency or RoCoF control.

By definition, y_{Gi} is null in steady-state conditions when all bus frequency deviations are null. During a transient, if the non-synchronous machine does not regulate the frequency the variations

between neighboring buses tend to be small, and even null if the generator is connected in antenna to the rest of the system. If the generator is synchronous, on the other hand, or even if it is non-synchronous but regulates the frequency, the variations of the frequency at neighboring buses are expected to be significant.

Some preliminary results of a case study based on the WSCC 9-bus test systems are shown in Appendix A.1.2 to prove the concept of the frequency maker/taker index. This concept will be later study considering the Romanian transmission system model, and results will be discussed in D2.7.

3.2.4 Frequency Control and Stability of Converter-Interfaced Energy Storage Systems in Transmission Grids

The scheme of the converter-interfaced ESS and its frequency controller have been duly described in Appendix D.3 of deliverable D2.1, where its performance was illustrated considering the IEEE 14-bus benchmark system. As the ultimate goal of WP2 is to provide specific and accurate recommendations for ancillary services, to be later revised and drafted by WP6, more comprehensive studies must be carried out with regard to converter-interfaced ESSs. With this aim, the following requirements must be met:

- Implementation of detailed dynamic models of real-world transmission grids.
- Development of techniques based on stochastic calculus to properly take into account system uncertainties. These techniques are aimed at substituting the deterministic, overly conservative N-1 (N-2) criteria that is used today.
- Study of a variety of topologies to account for different ESS locations, uncertainties in system faults, etc.
- Simulation of a variety of contingencies for different conditions to cover a wider spectrum of scenarios.

In order to meet all requirements above, a detailed model of the Romanian transmission grid based on sets of Stochastic Differential Algebraic Equations (SDAEs) is being implemented in the simulation tool Dome [35]. The steady-state and dynamic data of this grid has been provided by the Romanian TSO, Transelectrica. Thousands of simulations will be performed taking into account stochastic variations of loads and RESs generation, different initial loading conditions and ESS locations and technologies. Randomization of contingencies, as well as the impact of power and energy saturations of the storage device will be also taken into account. The interested reader can find the detailed description of this methodology in [36] and [37].

As a result of the case studies described above, and which results and conclusions will be included in deliverable D5.5, a list of duly justified recommendations of ancillary services and regulatory aspects of ESSs will be provided in D2.7.

To illustrate the capability of these ESSs to provide fast frequency control and to improve the transient stability of a real-world transmission grid modelled as a set of SDAEs, this deliverable includes a number of tests carried out considering the all-island Irish transmission system, which have been collected in Appendix A.1.3.

3.2.5 Frequency Control of Distributed Energy Resources in Distribution Networks

The goal of this study, which complete description and discussion is provided in [38], is to compare three different strategies to generate the input signal of the frequency controllers of DERs, namely centralized, decentralized, and average. The three strategies are illustrated in Figure 3.3. Note that we do not use the terms *centralized* and *decentralized* with the conventional meaning that they have in control applications. In this paper, the frequency controllers of DERs are local. *Centralized, decentralized* and *average* refer only to the strategy to define the input signals of such controllers.

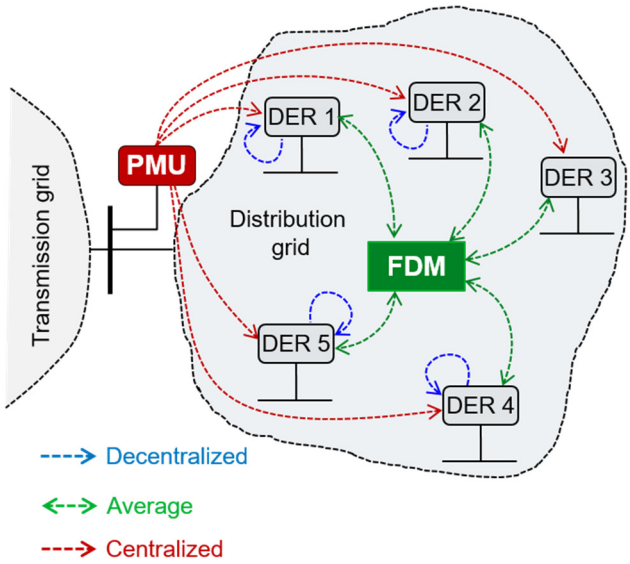

Figure 3.3: Illustration of the three strategies to retrieve the frequency control input signal.

Centralized: In this strategy, the frequency at the point of common coupling (PCC) between the transmission (TG) and distribution grids (DG) is measured, for example, by means of a PMU, and then the signal is sent to every DER installed. As all DERs use the same frequency signal in their regulators, a good overall control performance can be expected from this strategy. However, it is also characterized by a certain communication delay related to the measure and dispatch of the frequency signal that can deteriorate such a performance. Moreover, as the overall frequency control relies on only one measure, it is desirable to have a redundancy by means of, e.g., a second PMU connected at the PCC, to avoid the loss of all regulation capability in case of possible PMU malfunctions.

Decentralized: The second strategy considers that all DERs measure the frequency at their own bus of connection, by means of the PLLs included in their power electronic converters, in a decentralized manner. The main advantage of this strategy is that it does not include any communication delay in the process, as measurement and control is done locally. On the other hand, this strategy does not provide any form of coordination between DERs. Moreover, while the frequency variations estimated at every DER bus of a DG should be the same, this estimation can significantly differ from bus to bus during transients due mainly to the numerical issues that derive from the numerical derivation of the bus voltage phase angle.

Average: In the last strategy described in this Section, the PLL frequency estimations from every DER bus are sent and collected by a Data Management System (DMS) located generally within the DG. The DMS then computes the average value of all the signals, and then this average is sent back to every DER. This strategy shares its main advantage with the centralized approach, as all DERs regulate the frequency using the same signal. Moreover, averaging process of such a signal can allow reducing the impact of the spikes and other numerical issues present in the measured signals, as well as that of losing one or more of the measurements. However, as this strategy is based on a bidirectional communication channel, one must carefully consider the related delays.

Relevant results from [38], which considers the WSCC 9-bus test system with inclusion of the model of an Irish MV distribution network, are shown in Appendix A.1.4. A relevant conclusion from [38] is that, if the overall delay exceeds few tens of milliseconds, the performance of the frequency controllers, and thus of the overall system, can be compromised. Note that this latency is of the same order as that of existing ICTs. This case study is being implemented in the real-time simulator, with hardware-in-the-loop for the measurement devices and the communication system. If results from this set-up match those obtained from the offline simulations performed in the software tool Dome, then a new set of strict requirements for ICTs must be defined if either the *centralized* or the *average* strategy are to be implemented. These requirements, as well as a number of recommendations for DERs providing frequency control in MV distribution systems, will be verified by means of simulations (both offline and with real-time and hardware-in-the-loop) considering the Romanian transmission system model, and results will be provided in D2.7.

3.2.6 Frequency Control of Grid-connected Microgrids

3.2.6.1 Microgrid Model

The model of the microgrid that is considered in this section is thoroughly discussed in [28]. Each microgrid is modelled assuming that it includes a load, a DER and a storage device. The latter is crucial for the frequency control. The behavior of a microgrid without storage, in fact, is constrained to the availability of energy from the DER, which in general is not dispatchable as it is based on some kind of stochastic source (e.g., wind or solar). The main assumptions on which the dynamic model of the MG is based are the following [28]:

- The dynamics of the MG internal generation units and loads are neglected. This is not a strong assumption as the time constants of the internal MG dynamics are small compared to the ones of the high voltage transmission system.
- The storage units, the DERs and the loads of each MG are grouped into an aggregated model. This assumption allows reducing the computational burden of the proposed MG model.
- Due to their relatively small capacity, MGs are assumed to be price takers. Moreover, MG active power set- points depend on the electricity price. This assumption is consistent with the MG paradigm usually considered in the literature.

Finally, the microgrid includes an energy management system (EMS), which is the key element of the control. This is basically a set of “if-then” rules that decide, based on current information on DER power production, load power consumption, state of charge of the storage device, energy price at the point of connection of the microgrid whether the MG has to operate islanded mode (i.e., disconnected from the grid) or not and, if connected, whether it should behave as a consumer or as a producer. The number of parameters and scenarios to take into account is high and, hence, typically the EMS is defined as a lookup table (see [28] of an example of set of rules for the EMS). Note that typical EMS do not take into account ancillary services such as frequency control. This has been the common approach so far, as the number and total capacity of MGs with respect to distribution and transmission systems is small. This situation is expected to change substantially in the next decade or two and thus it appears timely to study the effect ancillary services, in particular, frequency control on distribution and transmission systems.

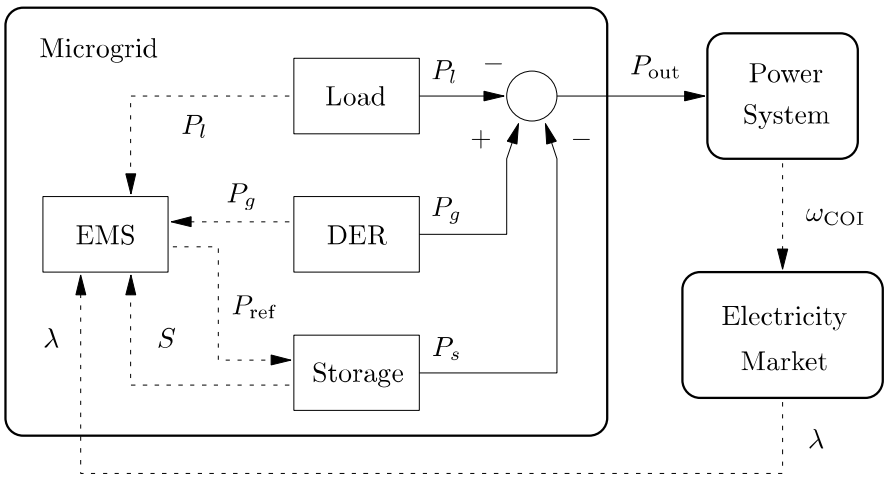

Figure 3.4: Scheme of a microgrid, its main components and connection to the grid and electricity market.

The scheme of principle on which the microgrid is based in shown in Figure 3.4. Note that the link between the power system and the electricity market is the frequency of the centre of inertia (COI). This is an indirect measure of the power imbalance in the system. The variations of the frequency of the centre of inertia are also a good indicator of the impact of the control (or the lack of it) of the MGs on the dynamic of the system. The higher the variations of the frequency, in fact, the more “negative” is the impact of the MGs.

Appendix A.1.5 shows simulation results based on the IEEE New England 39-bus system and considering different number and sizes of MGs (from 2 to 108).

3.2.6.2 Analysis of the Dynamic Impact of "Greedy" Microgrids

First of all, the case for which the MGs aim exclusively at maximizing their economical profit ("market mode") when connected to the grid is considered. The rules of the EMS are relatively simple but have to take into account a variety of scenarios. There are clearly several possible setups and we have defined a specific set of rules in our work [28].

From the simulation results presented in [28], which are briefly summarized in Appendix A.1.5.1, it is interesting to note that the impact on the system of the same DERs and stochastic loads of the MGs but without considering the EMS in "market mode" is less aggressive with respect to the frequency stability of the system. A detailed comparison of DERs and MGs is given in [28]. In other words, it is the EMS and their energy storage of the MGs that mostly impact of the dynamics and this has, hence, to be properly regulated.

From the results and discussions provided, it is clear that a proper regulation and code have to be put in place if the penetration of MG in the system increases above a certain threshold. The value of this threshold varies from network to network and on the maximum allowed variations of the frequency that the system operator allows in normal operation. Once the network parameters and the frequency threshold are given, a set of simulations such as those carried out in [28, 29, 30] allows defining the maximum allowed penetration of MG in "market mode".

3.2.6.3 Analysis of the Dynamic Impact of Microgrids with Stochastic Frequency Control

The previous subsection discussed how a high number of "greedy" MG can have a negative impact on the dynamic frequency response of an interconnected system, especially if their storage capacity is high.

This subsection discusses how this situation can be effectively solved through a smart control of the MGs. The key aspect is the EMS, which should be operated in such a way that the MG can still obtain an economical benefit while not affecting the dynamic response of the system.

Various solutions to this problem have been explored in [29, 30, 31, 32][3]. The conclusion is that it is possible to solve the problem satisfactorily for both the grid and the individual MG, provided that the MGs implement a decentralized stochastic control. The principle of this control is that each MG measures, at given intervals (e.g., 5 minutes) both the electricity price and the frequency deviation at its point of connection. Then, each MG assign a probability to regulate the frequency or not. The higher the frequency deviation measured by the MG, the higher the probability that MG still controls the frequency instead of maximizing its profit. Then each MG decides whether to regulate the frequency or not using a random number whose probability to be true is the one defined at the step above. The process is then repeated at regular time intervals.

It is important to note that the stochastic control above is effective only if the number of MG is big and all MGs agree on the function that returns the probability to regulate the frequency based on the actual frequency deviation at the point of connection. If the number of MG is high, in fact, statistically, the percentage of MG that will regulate the frequency at a given time will be always consistent with the frequency deviation of the system and, thus, the amount of frequency control provided to the system will adapt to the current transient behavior of the system itself.

It is also important to note that, given the stochastic nature of the control, each MG might not be guaranteed to maximize its profit in a given (short) period. It is possible, however, to guarantee that the profit is maximize on a long term if the proper stochastic control is implemented. This has been studied in our work [31], that is based on a well-known algorithm in communication systems that proved to be effective in networks with limited communication resources, namely the AIMD algorithm [39].

3.2.6.4 Impact of Storage Size on Microgrids with Stochastic Frequency Control

In [15], we have extended the analysis carried out in [31] to determine the impact of the size of energy storage devices when the MGs are operated with a stochastic frequency control, and key results are shown in Appendix A.1.5.3. The question is whether there is an "optimal" value for the capacity of the MGs for:

[3] Refer to Appendix A.1.5.2 for a discussion of relevant results from these studies.

- the minimization of frequency deviations in the system; and
- the maximization of the profit of the MGs themselves.

The analysis also aimed at understanding if the optimum for the system stability is higher or lower than the optimum for the MG profit. The understanding of this point is crucial because if the MG are imposed by the system operator to do frequency control but their revenues are not improved, they are going to provide the minimum frequency support possible. On the other hand, if the frequency control is a by-product of the maximization of the MG profit, the MG will have a strong incentive to provide a frequency control beyond the minimum level required by the system operator.

4. Drafting of Ancillary Services and Network Code Definitions for the Provision of Primary and Secondary Frequency Control

This section aims at identifying and explain the main technical implications on the power system operation, as regards the primary and secondary frequency control levels, under increasing share of generation from power electronic interfaced energy sources.

4.1 List of Recommendations of Ancillary Services and NC Definitions to be Added and/or Modified and Rationales Behind

4.1.1 Primary Frequency Control

The primary frequency control (PFC) is designed to restore (stabilize) the power system frequency at about a quasi-steady state value after a significant power unbalance occurring into the power system that leads to variations of the frequency that exceed a predefined threshold. This control is provided independently by every generation units, based on frequency input only. A frequency containment reserve, calculated by the national power system operator, should be ensured by each generation unit for this purpose [40, 41, 42, 43, 44, 7].

As specified in deliverable D2.2, on the continental Europe, the primary frequency control should be activated immediately after the disturbance occurrence, and the power required should be fully available within 30 seconds and maintained for at least 15 minutes [40, 41, 42, 43, 44, 7]. These characteristics have been defined based on a long experience within the traditional power systems, driven exclusively by synchronous generators. However, these specifications are about to be changed because the mechanical inertia installed in large synchronous machines is rapidly decreasing as the naturally synchronous generators are replaced by inertia-less power sources.

Based on the results of simulations presented in deliverables D2.1 and D2.2, two directions for further analysis have been identified, in view of providing recommendations for new or adapted network code requirements, and they are highlighted below.

4.1.1.1 NC.1: Requirements for power converter-based Energy Storage Systems (ESSs) connected to the transmission grid in a new network code

The first direction regards the provision of stabilizing controls provided by multiple systems already in commercial operation. In this vein, in the RESERVE project the focus is on converter-based ESS. As previously stated in Section 2.1, ENTSO-E's requirements on the installation and operation of power converter-based ESSs have not been provided. In this regard, the provision of recommendations on such requirements considering the variety of ESS technologies, capacities, locations, control, etc. are studied in Work Package WP2 of the RESERVE project. Moreover, in systems with 100% RES, i.e. no fossil fuel power plant is in operation, the current procedures for primary and secondary frequency control may not be valid. It is important to investigate the need for storage systems (besides the pumped storage plants) as support for frequency control. The results of this work will complement those outlined in Section 3.1.3.

4.1.1.2 NC.2: Recommended settings for the controlled units

The second direction of analysis deals with adapted settings for synchronous generators. In this regard, it is advisable to develop recommendations for the coordination between inverters considering their characteristics for frequency control and droop values. This is important to achieve coherence in the interconnected power system. Finally, standardized operation characteristics should be provided for those units that respond to both inertial and primary control. This is essential because both control schemes are linked in time, and the power provided as frequency control service is set by the same controller.

4.1.2 Secondary Frequency Control

The ENTSO-E interconnected network of the Continental Europe is operated by 24 TSO as a single large synchronous network. The frequency in one system is strongly related to the frequency in all the other power systems. Maintained steady-state average frequency deviation is caused by power unbalances in the whole power system, although when analysing closer within very short time frames the frequency is firstly influenced by local dynamic behaviour of the power system components.

The secondary frequency control (SFC), called also automatic generation control (AGC), is a coordinated action, and has both technical and economic purposes:

- From *technical point of view*, it is designed to restore the frequency to the reference value, and at the same time to replace the frequency containment reserve. In order to avoid overlapping with the primary control actions, the deployment time of the secondary frequency control reserve, called also automatic Frequency Restoration Reserve (aFRR), is greater than that specific to the frequency containment reserve [42].
- From *economic point of view*, the SFC aims at cancelling the power mismatches on the interconnection lines, thus reducing the contribution of the neighbor power system on longer term to the frequency control and power balancing inside a certain power system.

The power plants included in the secondary frequency control are selected based on qualification tests, during which the units must be capable of deploying power reserve within a minimum ramp, expressed in MW/min, for an unlimited period. Considering the two characteristics, the best generation units are selected; usually, the hydraulic power plants and the gas-fired combined-cycle power plants are the most appropriate to provide this service. However, nuclear power plants and classical thermal power plants are also used in power systems with small hydro-potential.

In Romania, for instance, aFRR is a symmetrical band about the notified power, designed for both the upward and downward regulation (refer to deliverable D2.2 for further details). Additionally, in order to maximize the available reserve, the notified power should be positioned at the mid-point of the generator's capacity. This requires high predictability of the reserve scheduled for this purpose, which means that the reserve is of deterministic type.

The strategy for replacing the classical power plants, which are characterized by a deterministic behaviour, by RES-based systems (mainly wind and photovoltaic), which are characterized by a stochastic behaviour, is about to jeopardize the security of the entire power system if appropriate measures are not taken. Both wind and photovoltaic systems are not capable of maintaining deterministic symmetrical bands, but can only provide downward regulation service, which is usually less necessary than the upward regulation service, while maintaining unused power can be very costly from the investment point of view.

On the other hand, large power plants are replaced by small and very small generation units. In order to schedule appropriate aFRR, integration of a large number of small units requires a very complex communication infrastructure. A direct connection between the central control centre and each generation source could be highly inefficient from both investment and reserve predictability point of view. One solution would be to aggregate the converter-based DERs, including storage systems, within so-called virtual power plants (VPPs). In RESERVE we are planning to analyse the effectiveness of employing such solutions in the view of proposing new network codes. For this purpose, the following objective has been formulated.

4.1.2.1 NC.3: Expanding the frequency control strategy to allow using small-sized and/or intermittent energy resources

Two types of control procedures are currently defined: the decentralized control specific to the primary frequency control, and the centralized control specific to the secondary frequency control. In the future, a diversity of control procedures may be required. For example, the distributed control is introduced. The distributed control refers to the coordinated control within a regional network, including both generation sources and loads, as a low-level control in the centralized scheme. This control strategy refers to the VPP and Microgrid concepts.

4.2 Methodology and Case Studies to be Done to Support the Recommendations

The simulations of the two control levels in the view of analysing the proposed network codes adaptations, for which technical recommendations will be drawn, have been performed in Eurostag on the Romanian power system database.

This database, projected for the year 2050, consists in the network buses, transmission lines, and the corresponding transformers that operate at 220 kV and 400 kV voltage level. In order to consider the converter-based DERs, the distribution voltage levels (including lines and transformers) are considered. Dynamic models of the electrical machines from the Romanian power system, together with their governors and automatic voltage regulators are also considered.

The reader is advised to read the deliverable D5.4, already released for public information, for brief presentation of the Romanian power system, and D5.5, scheduled for Month 36 of the project, for detailed presentation.

4.2.1 Primary Frequency Control

The main reason for this research resides in the fact that while the classical power plants are replaced by converter-based generation units, there are less and less units capable of providing frequency containment reserve without being affected from economic point of view. In order to provide primary frequency control service, both wind and photovoltaic generation units needs to maintain unused the primary reserve. Additionally, the intermittency of the primary resource makes the availability of the generation sources to be unpredictable for the primary frequency control, which increases the risk of frequency instability in the case of large and sudden unbalances. Therefore, **predictable frequency containment reserves are required in order to ensure frequency stability.**

For this reason, in the RESERVE project, we are focusing on using battery energy storage systems (BESS) as the main equipment for providing appropriate frequency control within the primary level, considering that they are already commercially in operation. However, considering the high share of generation from hydraulic power plants in Romania (~28%), the support from such generation units is also analysed. Under these conditions, this chapter aims at providing some recommendations for future power systems, characterized by share of generation from renewables of up to 100%, based on simulation scenarios created.

The characteristics of a BESS, of importance for frequency control, are:

- total energy (E_{BESS}, in MWh), represents the maximum energy that can be stored in the battery;
- installed/rated power (P_{BESS}, in MW), represents the maximum instantaneous power that can be delivered by the battery in steady state;
- available energy ($E_{BESS,av}$, in MWh) represents the energy available in the battery at the time of initiation of the primary frequency control; this is usually expressed as the state of charge (SoC, in %) and denoted the percentage of the total energy;
- reaction time (T_{BESS}, in seconds) represents the time necessary to the BESS system to reach the required instantaneous power as a response for frequency control, starting from the triggering time.

A dynamic model of a BESS developed by EPRI and WECC has been implemented in Eurostag, considering also the above-mentioned characteristics. The simulations performed for frequency control are also intended to evaluate the robustness of this model, in view of expanding its utilization also for other types of simulations, such as transient stability.

During one day, the average frequency may experience uneven positive and negative deviations with respect to the nominal value. In the case of negative deviations (real frequency is smaller than the nominal value), the battery injects energy into the power system, while during negative deviations, the battery absorbs power from power system. For RoCoF and primary frequency control, the power capacity is more important than the energy capacity. Therefore, if the frequency is maintained bellow the nominal value for a longer time period, the battery will discharge and can become unavailable to the frequency control. Figure 4.1 shows the frequency recorded in

Romania for 24 hours, with one second granularity, during which the frequency variation was in the range between 49.9 and 50.07 Hz, while the average value for the entire day was 49.9947 Hz. Figure 4.2 shows the effect on the BESS's available energy with and without control strategy.

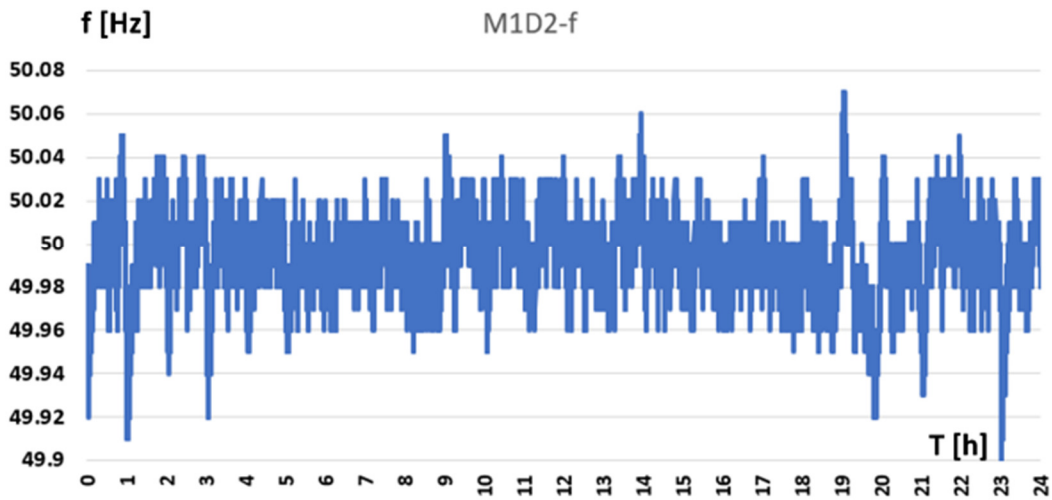

Figure 4.1: Frequency measured in Romania during one day.

The frequency deviation in a power system, at a certain time instant *t*, is simply calculated as:

$$\Delta f(t) = f_{ref} - f_{real}(t) \tag{4.1}$$

where and f_{ref} is the reference value, i.e. 50 Hz in Europe, $f_{real}(t)$ is the measured frequency at the time instant t, and t represents in fast one second.

The participation power of the BESS required to restore the frequency at the time instant t is:

$$\Delta P_{bat}(t) = -\Delta f(t)\frac{P_{max,bat}}{\Delta f_{max}} \tag{4.2}$$

where $P_{max,bat}$ is the rating power of the battery, and is the maximum frequency deviation within which the battery will respond, thus resulting in a participation factor [MW/Hz].

The total energy available in the battery is calculated at every time instant t (the simulation time step is 1 second) by [45]:

$$E_{bat}(t) = E_{bat}(t-1) + \frac{\Delta P_{bat}}{3600} \tag{4.3}$$

When the battery state of charge (SoC) decreases below a threshold (e.g. 20 to 25 %) or is above a similar threshold (e.g. 75 to 80 %), an additional charging/discharging power of constant value $P_{lt,ch}$ (subscript lt, ch denotes the long-term charging/discharging) is added to the power required by the primary frequency control, expressed in (4.4), i.e.:

$$\Delta P_{bat}(t) = -\Delta f(t)\frac{P_{max,bat}}{\Delta f_{max}} \pm P_{it,ch} \tag{4.4}$$

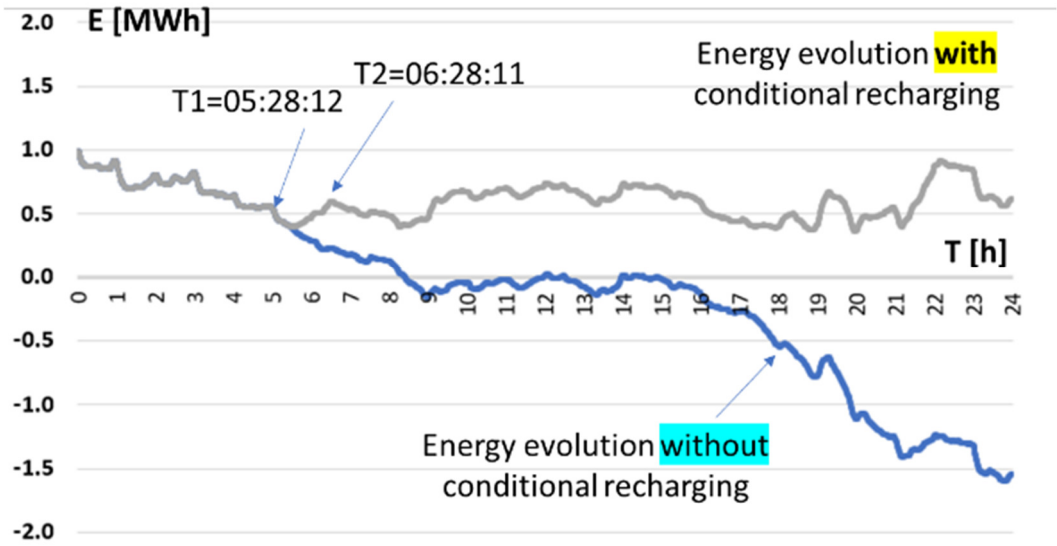

Figure 4.2: Available energy of the battery over the entire day, with/without charging compensation [45].

Figure 4.2 shows that without compensation, in this particular day the battery is completely discharged after around 8 hours because the average frequency was smaller than the nominal value. The blue line shows that, as a need for primary frequency control, in the last part of the day the SoC is mostly negative, which is not physically possible (BESS can discharge until zero only). For a charging compensation if SoC reaches a value below 20%, the SoC remains in the control region over the whole day.

The charging function is triggered when SoC falls below 20%. The charging power $P_{lt,ch}$ has been chosen to be only 5.8% of the total power and maintained constant for an entire hour after activation. In these conditions the battery is seen as a load, not as a frequency control entity. The charging orders of the BESS over the whole day are presented in Figure 4.3.

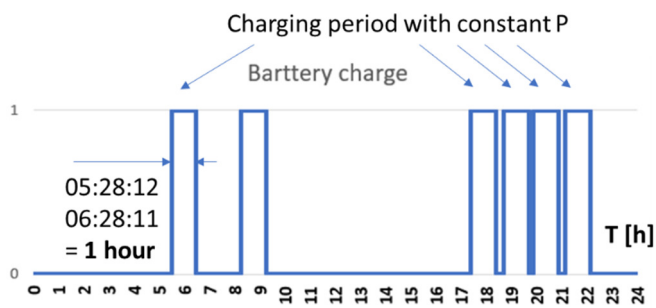

Figure 4.3: BESS SoC charging orders for DT1.

Since the primary frequency control is an independent and automatic action, both the individual response and the global influence of the power frequency is analysed. For this purpose, the primary frequency control simulations have been focused on the following aspects:

i) Analyzing the effect of the total mechanical inertia.

   This analysis is done based on dynamic simulations in several scenarios, characterized by different percentages of the share of generation. The first scenario considers a high share of synchronous generators. Then, the classical power plants are progressively replaced by converter-based generation units. A sensitivity analysis is performed in order to identify the measure in which the total mechanical inertia is influencing the frequency variations.

ii) Analyzing the importance of the BESS for the primary frequency control

Similar to the previous analysis, several scenarios are developed, by considering different share of generation from both the synchronous generators and from the converter-based units (wind and photovoltaic). The analysis focuses on determining the performances in terms of power-frequency control of the model, as well as on identifying the minimum reaction time.

iii) Effect of changing the droop settings

The requited frequency response characteristic of the generation units is defined by the so-called droop characteristic. The droop characteristic defines change in the rotor speed in the case of synchronous generators, for both upward and downward control, which is equivalent to a certain change in the active power. On the other hand, the droop control is a measure of load sharing. So, the bigger the droop value the bigger the participation power. The aim of this analysis it to identify the importance of the droop value to ensure the system stability from frequency point of view.

4.2.2 Secondary Frequency Control

Currently, in interconnected power systems, there is only one AGC regulator, which calculates the required power to be deployed in order to restore the average value of the frequency to the reference value, based on the input data from the whole power system. This is represented in Figure 4.4 by EMS (AGC).

As stated before, while replacing large power plants with small RES units, a very larger number of small units is needed to provide the same regulation reserve. Using the AGC from the national control center might not be effective. For this reason, we propose using an aggregator, represented by the VPP Control Center in Figure 4.4.

Two types of control architectures are tested:

- The classical secondary control scheme, with contribution of hydraulic power plants only;
- two-level secondary control scheme, by contribution of a virtual power plant. The control architecture is of cascading type. In the first step, the central AGC is calculating the control order of the VPP based on the characteristics provided in advance by the VPP owner. Then, in the second step, the VPP controller calculates the control orders to be sent to each DER from the VPP, based on their real-time available control reserves.

The VPP is seen as any other power plant by the AGC controller, which means that a control signal is sent to the VPP controller. The VPP consists of any type of intermittent sources, BESS and hydro units. Basically, the intermittent sources are not involved in providing secondary frequency control because their stochastic behaviour. Only hydro units and BESS provide. A VPP is created to cancel the fluctuations in power generation of the intermittent sources. The main idea is to use deterministic type sources to balance the intermittent sources. When included in the secondary frequency control loop, the control units are controlled in such a way to both balance the VPP internal unbalances created by the intermittent sources and to produce the required power ordered by the AGC as a participation share to the secondary control level. The details of the controller will be presented in deliverable D5.5.

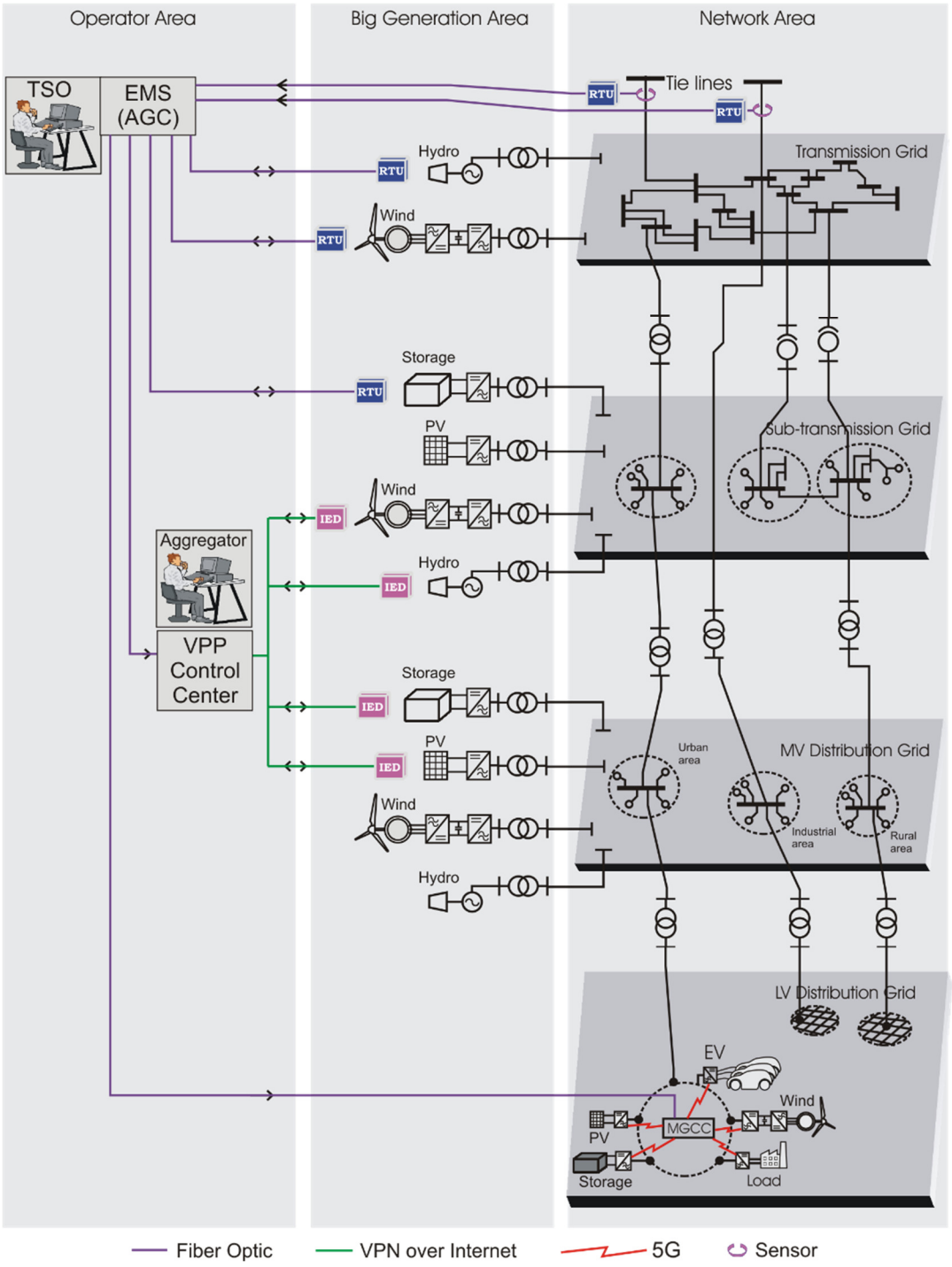

Figure 4.4: Operative hierarchical coordination in a power system.

5. Drafting of Ancillary Services and Network Code Definitions for the Provision of Inverter-based Frequency Control in 100% Non-synchronous Systems

The power electronics (converters) are expected to constitute the backbone of future power grids due to the steadily increase in RES integration, HVDC connections, and BESS installation. Hence, the power systems will undergo radical changes in terms of system dynamic behaviour, control, and operation.

The integration of converter-based RES will displace the existing Synchronous Generators (SGs), resulting in systems with significantly reduced/zero inertia. This represents a futuristic scenario of some European countries like Germany where there is no classical SG or hydro power plant installed, and the entire power generation is from converter-based RES, e.g. wind and solar power plants. Note that classical SGs offer significant advantages such as inherent inertial response, system synchronization, and primary power reserve. However, the main downside of these SGs is the nonlinear swing dynamics, which is caused by the inherent nonlinear electromechanical oscillations. This is in contrast with the converter-based RESs, which are integrated into power systems via static converters, as these converters do not have the problem of inherent electromechanical oscillations. Hence, new concepts should be developed to define system dynamics and behaviour in future converter-based power systems. In this regard, the Linear Swing Dynamics (LSD) concept is proposed to achieve uniform and linear system swing dynamics. Also, to exploit the fast dynamics, smartness, and controllability of these converters to shape freely system dynamic behaviour. This Chapter discusses briefly the proposed solutions for systems with up to 100% converter-based RES, and provides new forms of ancillary services provision with highlighting the need for new system requirements.

5.1 List of Recommendations of Ancillary Services and NC Definitions to be Added and/or Modified and Rationales Behind

5.1.1 Frequency Control of RES-tied Converters in Zero Inertia Power Grids

The transition to 100% converter-based RES represents one of the main challenging scenarios in RESERVE, where all the classical SGs are displaced with converter-based RES. In this scenario, extensive research work being carried out to study system dynamics and control from frequency stability perspective. Also, to define new roles and behavior of RES-tied converters to move from grid supporting to grid forming operation mode.

One of the main advantages of SG is the inherent (mechanical) inertial response that participate in arresting frequency deviation in case of disturbances. Note that system frequency is linked to the mechanical speed of SGs. However, the absence of these SGs and replacing them with RES-tied converters will result in a different form/definition of system frequency and dynamics. In zero inertia power grids, i.e. with 100% converter-based generation, system frequency will be an artificial signal driven/ decided by the connected RES-tied converters. Hence, the frequency is no more a natural balancing signal as in current power systems.

To preserve the advantages of SGs in zero inertia power grids, new solutions are proposed in the literature like Virtual Synchronous Generator (VSG) and Synchronverter. The aim is to enable the RES-tied converters to emulate classical SGs and provide virtual/ artificial inertia and frequency stabilization. Also, to maintain the synchronization between RES-tied converters and the power grid. Thanks to the power electronics for their features and smartness in providing such new solutions.

The frequency control categories of today's power systems are defined by the ENTSO-E [42] to have a hierarchical architecture including primary, secondary, and tertiary frequency control. The inertial response is naturally released by the SG, and hence, it is executed implicitly within the first seconds of primary frequency response. However, this is not applicable in the presented scenario with up to 100% converter-based RES due to the absence of SGs and very fast system dynamics. Therefore, this task proposes a new form of frequency control categories with a new (reduced) time frame. The new hierarchical frequency control categories include inertial, primary, secondary, and tertiary frequency control. However, this research work focuses on the first three control layers, and hence, does not consider the tertiary frequency control. Preliminary results are

presented in Section 5.2.1 to show the expected/estimated time response. With the work progress, more coherent and precise results will be reported to with regard to frequency control categories and their exact time response.

Note that the up-to-date solutions for SG emulation, e.g. VSG, are based on the classical representation of swing equation of a SG, which is not meaningful in the presented scenario. Hence, the LSD concept has been introduced and adopted in the development of SG emulation.

5.1.2 Linear Swing Dynamics for Converter-Based Power Grids

The LSD concept is introduced and embedded in the RES-tied converters to enable the future converter-based power grids operating in a linear dynamical behavior. The LSD concept allows the linearization of the nonlinear swing equation over almost the entire state space, thereby enabling the use of the small-signal stability analysis technique for large signal stability investigations. By properly choosing the controller parameters, the dynamics of the large number of converters expected in the system can be made unified and predictable. This in turn, can achieve uniform eigenvalues and oscillation-free dynamics for all the deployed converters, and hence, estimate system stability margins and transient behaviour. The conducted research work on this innovative concept has resulted in several publications [46, 47, 48, 49].

5.1.3 Frequency Control of HVDC Systems Connecting Low/ Zero Inertia Power Grids

The HVDC transmission technology has been proposed for efficient and controllable power delivery over long distances. This technology is receiving a major interest with the integration and feasibility of on/off shore RES and international power exchange, respectively. This lead to a HVDC proliferation worldwide. According to the ENTSO-E [7], the HVDC systems are expected to participate in system frequency support. However, there is no a clear methodology that defines the way of involving HVDC systems in providing system frequency support. This becomes crucial with the consideration of different transition forms in the international power grids, in terms of RES integration level and technology utilized. For example, a country with 100% RES including high percentage of hydro power plants will have higher inertia and stiffer grid than a county with 100% converter-based RES, e.g. wind and solar power generation. Such a scenario will result in different technical characteristics, constraints, power generation and demand in the HVDC-connected AC grids [50, 51, 52]. In this regard, new roles and requirements should be defined and fulfilled by the HVDC systems. The aim is to think globally, attending the technical specifications and constraints of all the HVDC-connected AC grids, and act locally to provide frequency support without compromising the local grid stability and dynamic performance. This is achieved by the proposed Multi Agent-based Intelligent Frequency Control (MA-IFC) scheme [53].

Also, in future power systems, the main converter-based power generation/supply will be from RES and HVDC systems. Hence, to achieve the LSD characteristics in a systematic way, the LSD concept is introduced in the grid-tied HVDC converters. The aim is to define new role and behavior for HVDC systems in their participation to frequency support of converter-based power grids. In this regard, the LSD-based improved VSG has been proposed [48].

5.2 Methodology and Case Studies to be Done to Support the Recommendations

5.2.1 Frequency Control of Multi-VSG in Zero Inertia Power Grid

The multi-converter system is developed based on the WSCC 9-bus system as shown in Figure 5.1. This is done by displacing the three SGs with three converter-based RES (VSGs). The role of these VSGs is to emulate the classical SG to provide virtual inertia and stabilise system frequency in case of disturbances. This study allows for studying system dynamic behaviour, operational characteristics, and performance. Different test scenarios are considered, including power disturbances (increase in load) and uncertain conditions: noise and delay in frequency measurements. The aim is to analyse and study system capabilities in maintaining a stable operation under wide range of operating conditions. Also, to define an acceptable level for the induced noise and delay in the frequency measurements, for which the system can overcome these uncertainties and preserve stable operation/ frequency profile.

5.2.2 LSD-Based Frequency Control in Multi-Converter Power Grid

The LSD concept has been extended by conducting the following research works:

5.2.2.1 LSD-based Virtual Synchronous Generator with Variable Moment of Inertia

Unlike a classical (real) SG, the parameters of the swing equation of the VSG can be controlled to enhance the fast response of the VSG in tracking the steady-state frequency. In this regard, the LSD-based VSG is designed with variable moment of inertia (M). The M value is changed based on the relative virtual angular velocity of VSG and its rate of change. The derivation of angular velocity of VSG indicates the rate of acceleration or deceleration during disturbances. This relation has a reverse relation to the M. Based on this fact, the M value is selected to have large/small value in case of acceleration/deceleration phase. This resulted in a better damped power oscillations and enhanced system dynamic performance. This also has an enhancement in the LSD characteristics as shown in Figure A.24 in the Annex A.2.2.1.

5.2.2.2 LSD Concept for Distribution Systems

This work derives the LSD concept for a more general system, where the grid is represented by a resistive-inductive series impedance, instead of a pure reactive impedance that was done in previous works [46, 47, 48]. The preliminary analytical results are provided in the Annex A.2.2.2.

5.2.2.3 Extending LSD Concept from Single Machine to Multi-machine Power System

The development and application of LSD concept has been extended from Single Machine Infinite Bus (SMIB) to multi-machine power system. As a first phase of this work, a centralised approach has been used to derive the control rules and analyse their behaviour in a multi-machine system. It is assumed that all busses voltages and angles are known, which makes it more suitable for theoretical analysis. The LSD concept has been tested and verified in four machine power system, and the results are provided in the Annex A.2.2.3.

5.2.2.4 LSD-based Frequency Control in HVDC Systems

The LSD concept has been introduced in the grid-tied HVDC converters to define new role and behaviour of HVDC systems in their participation to system frequency stabilisation of future low/zero inertia power systems. The LSD-based VSG has been implemented in the grid-tied HVDC converter as shown in Figure 5.2. So, the HVDC system is able to provide frequency support based on LSD concept, alongside with preserving a stable HVDC system operation. Results of two terminals HVDC system is provided in the Annex A.2.3.2.

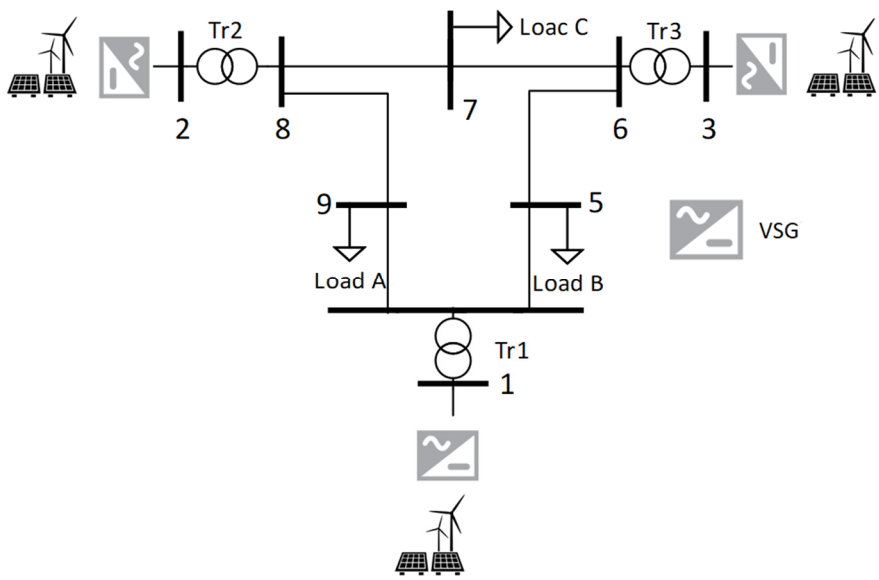

Figure 5.1: Futuristic multi-converter power system.

5.2.3 Frequency Control of Grid-tied HVDC Converters for System Frequency Support

A case study is considered to include HVDC grid connecting multiple AC grids for the purpose of wind power delivery. The AC grids are defined to have different technical characteristics, power generation and demand. Hence, two (three) weak (stiff) AC grids are considered with low (high) inertia and power reserve. The weak (stiff) grids are AC 3 and AC4 (AC1, AC2, and AC5). Large disturbance scenario is applied to AC grid1, and a comparative study has been performed between the classical Frequency Droop Control (FDC) and proposed MA-IFC as shown in Figure A.28 [53]. Both FDC and MA-IFC schemes are implemented in the grid-tied HVDC converters to participate in supporting the disturbed AC grid (AC1 in this scenario).

Also, the LSD-based VSG has been developed for and implemented in the grid-tied HVDC converter. The aim is to provide frequency support based on LSD concept while maintaining a stable HVDC system operation. To verify the proposed solution, two terminal HVDC system is considered to deliver the offshore wind farm power to the onshore AC grid. The LSD-VSG is implemented in the Voltage Source Converter (VSC1) as depicted in Figure 5.2. Note that the offshore wind farm could be also an AC grid delivering the power to the onshore AC grid.

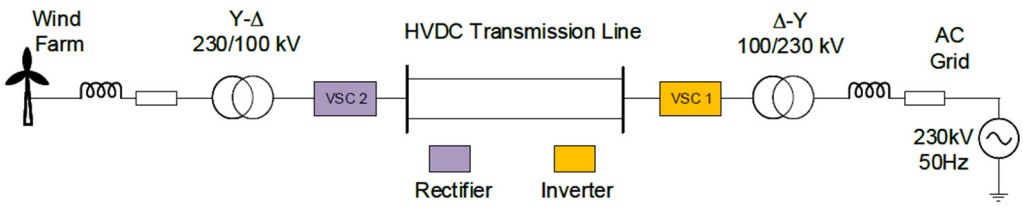

Figure 5.2: Two terminal HVDC system.

6. Concluding Remarks and Future Work

This deliverable presents the foundations of the recommendations for updates and creation of ancillary services and network code definitions concerning frequency control that will be proposed in D2.7 as a conclusion of Task 2.6.

After a thorough review of the existing network codes and white papers that are currently under review at European level, and based on the results of the studies carried out in WP2 since the beginning of this project, we have identified a number of concepts that need to be carefully revised in such existing codes in order to take into account the participation of new agents into the different layers of the frequency control. These areas have been collected and sent to WP6 for evaluation, which has resulted on a unified and coherent list of concepts to be investigated by WP2 and WP5. This list, which items have been arranged in order of prioritization in terms of relative importance, can be found in Table 2 of D6.1.

This deliverable has also carefully categorized the aforementioned research concepts into three main groups based on their belonging frequency control layer (RoCoF, primary and secondary frequency control) and on the inertia present in the power system (low- or zero-inertia). The rationales behind each concept, and the methodologies and case studies that will be considered for their investigation have been duly provided. Preliminary, illustrative results have been also presented to support the mathematical formulations and technical descriptions of the problems. Finally, additional, less urgent concepts not included in the list provided in D6.1 that, based on our judgment and experience, are also relevant to be studied in view of allowing very high RES penetrations, have also been introduced. If time is available after completing the list of D6.1, these problems will also be studied thoroughly.

The methodologies to investigate the research concepts presented in this deliverable will be applied and tested by means of time domain simulations performed in the different laboratories of the project as part of WP5, and the results of these simulations will be included in D5.5. These simulation results will be the base of the definitive recommendations of ancillary services and network code definitions concerning frequency control that will be presented in D2.7.

7. List of Figures

8. List of Tables

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10. List of Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserve
AGC	Automatic Generation Control
AIMD	Additive Increase Multiplicative Decrease
ANRE	Romanian National Regulatory Agency
BESS	Battery Energy Storage System
CCT	Critical Clearing Time
COI	Centre of Inertia
CT	Clearing Time
DER	Distributed Energy Resource
DG	Distribution Grid
DMS	Data Management System
DSO	Distribution System Operator
EC	European Comission
EMS	Energy Management System
ENTSO-E	European Network of Transmission System Operators for Electricity
EPRI	Electric Power Research Institute
ESS	Energy Storage System
FDC	Frequency Droop Control
FDF	Frequency Divider Formula
FESS	Flywheel Energy Storage System
FSM	Frequency Sensitive Mode
HESS	Hybrid Energy Storage System
HV	High-Voltage
HVDC	High-Voltage Direct-Current
ICT	Information and Communication Technologies
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
LFSM-O	Limited Frequency Sensitive Mode – Overfrequency
LFSM-U	Limited Frequency Sensitive Mode – Underfrequency
LSD	Linear Swing Dynamics
MA-IFC	Multi Agent-based Intelligent Frequency Control
MG	Microgrid
MV	Medium-Voltage
MPPT	Maximum Power Point Tracking
NC	Network Code
PCC	Point of Common Coupling
PDF	Probability Density Function

PFC	Primary Frequency Control
PLL	Phase-Locked Loop
PMU	Phasor Measurement Unit
PPM	Power Park Module
RES	Renewable Energy Sources
RoCoF	Rate of Change of Frequency
SDAE	Stochastic Differential Algebraic Equations
SFC	Secondary Frequency Control
SG	Synchronous Generator
STATCOM	Static Synchronous Compensator
TG	Transmission Grid
TSO	Transmission System Operator
VSC	Voltage Sourced Converter
VPP	Virtual Power Plant
VSG	Virtual Synchronous Generator
WECC	Western Electricity Coordinating Council
WLS	Weighted Least Square
WSCC	Western Systems Coordinating Council

A. Preliminary Results

A.1 Frequency Estimation and Fast Frequency Control

A.1.1 Estimation of Synchronous Machine Rotor Speeds – The Irish test case.

The study carried out in [11] based on the all-island Irish system compares both a conventional Weighted Least Square (WLS) state estimation approach and a robust formulation based on a convex optimization problem (OPT). Some relevant results are shown in Figure A.1, Figure A.2 and Figure A.3, while a detailed numerical appraisal is presented in [19]. In Figures 2.10-2.12 $\hat{\omega}_G$ is the actual (simulated) rotor speed frequency.

All results discussed in [11] indicate that the OPT state estimation approach is robust and reliable and can cope, generally better than the conventional WLS, with noise, bad data and measurement delays.

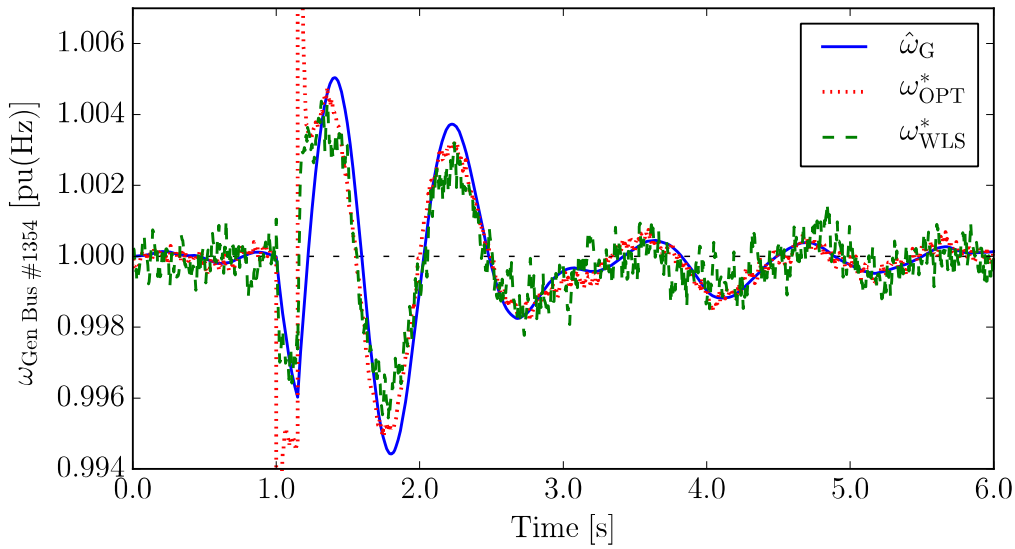


Figure A.1: Effect of noise on the estimation of the rotor speed of synchronous machines [11].

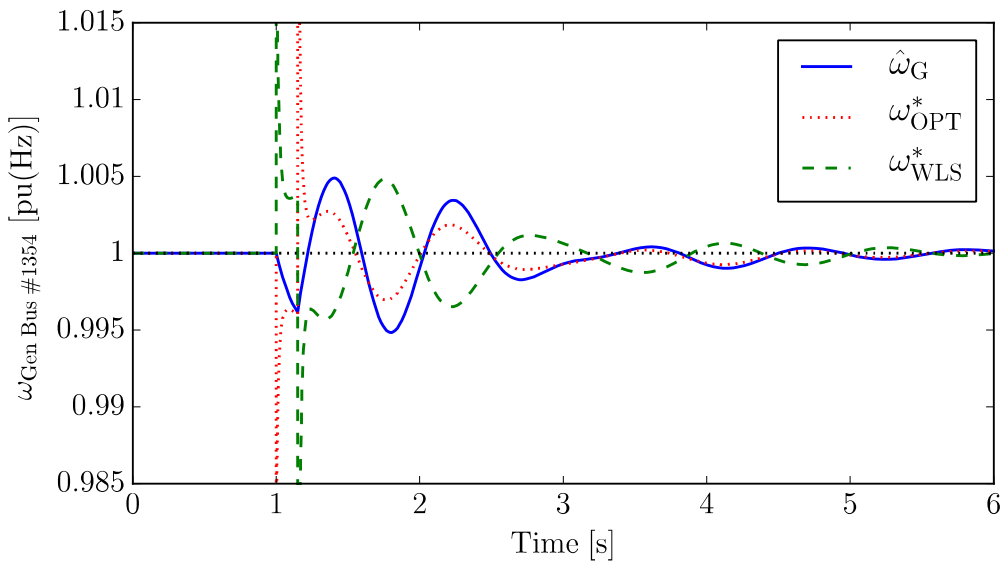


Figure A.2: Effect of bad data on the estimation of the rotor speed of synchronous machines [11].

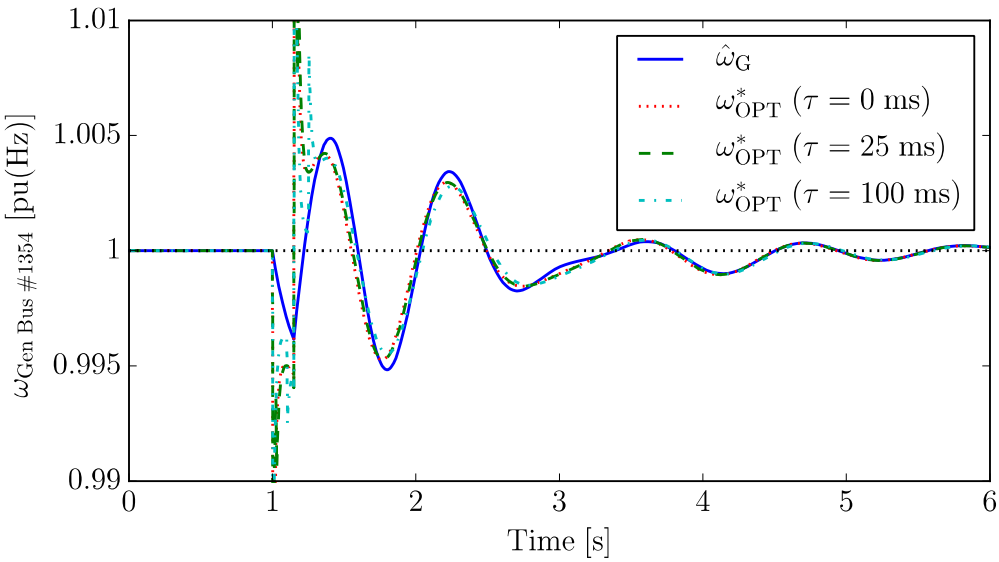


Figure A.3: Effect of delays on the estimation of the rotor speed of synchronous machines [11].

A.1.1.1 Estimation of the Frequency of the COI

A relevant by-product of the state estimation technique proposed in [11] is the fact that, with a very reduced number of bus frequency measurements, it is possible to estimate the frequency of the centre of inertia of the system. The details on this technique are provided in [33]. For system operators, the ability of measuring the COI, rather than the frequency of a pilot bus of the system is a useful advance as this signal can improve the primary and secondary control implemented in the system. It is also relevant to note that so far, system operators were not able to measure the frequency of the COI.

Figure A.4 shows simulation results based on the all-island Irish system as presented in [33].

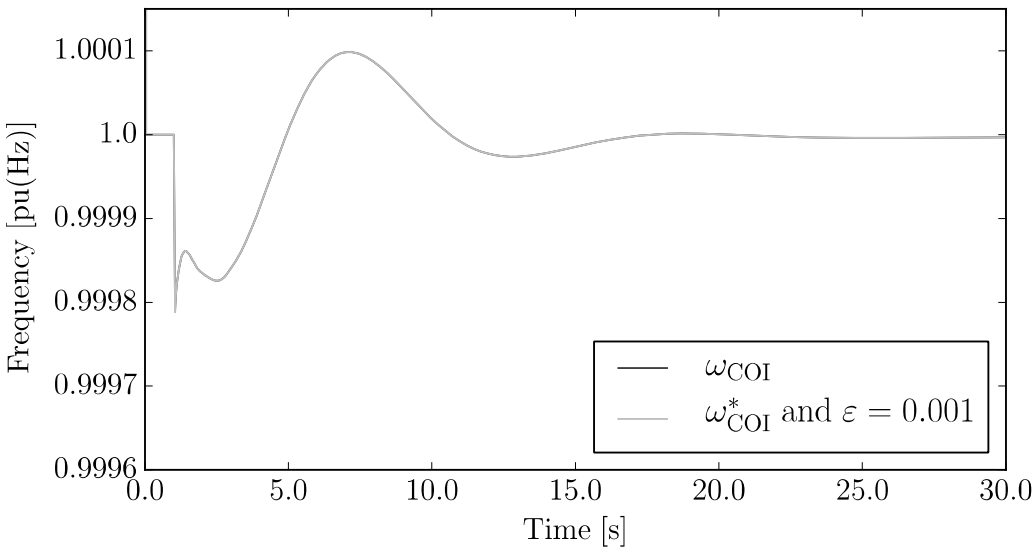


Figure A.4: Actual and estimated frequency of the COI for the all-island Irish system [20].

As it can be observed, the match between the ideal and estimated frequency of the COI is very good. The total number of measured required to estimate the COI is 42. Considering that the number of synchronous machines in the system is 22 and that the total number of buses is 1,479,

the computational burden of the proposed technique is very low. Of course, noise and delays can lower the quality of the estimation and again, for large systems the need to collect the bus measures in a single control centre might be an issue. We thus consider that this technique is particularly appropriate for the estimation of the frequency of the COI for relatively small islanded systems or ac microgrids with synchronous generation.

A.1.2 Frequency Makers vs Frequency Takers

A preliminary test of the approach proposed in Section 3.2.3 based on the WSCC 9-bus 3-machine test system that was also extensively utilized in D2.1 for testing the FDF has been reported here. For the sake of test, the synchronous generator connected to bus 3 has been replaced with a wind power plant of same capacity. Then the outage of the line connecting buses 7 and 5 is simulated for two scenarios: with and without frequency control of the wind power plant. The results are shown in Figure A.5 and Figure A.6.

Figure A.5, shows the trajectory of the frequency of the COI of the system in the two cases. As expected, the frequency of the COI varies less when the wind power plant includes the frequency control than in the case when the wind power plant does not provide frequency support. On the other hand, Figure A.6 shows the time evolution of the index proposed in equation (2.1). When the wind power plant provides frequency control the index is not null during the transient and it is zero otherwise. Note that the value of the index is independent from the actual total variation of the frequencies of the buses. It depends exclusively on the relative variations at neighboring buses. The index is thus able to separate the global effect of the frequency control present in the system from the local frequency control of the monitored generator.

We trust that this approach is promising and we will further investigate the features and the properties of (2.1). More study is in fact required to test the effectiveness and robustness of the proposed index with respect to noise, measurements delays and network topology. This extensive study will be completed for D2.7. We notice since now, however, that such an index, if proven to be reliable enough, can be a useful tool for distribution and transmission system operators as it would allow identifying and, possibly, quantify, the amount of frequency control provided by each participant of the grid, regardless if it synchronous or non-synchronous.

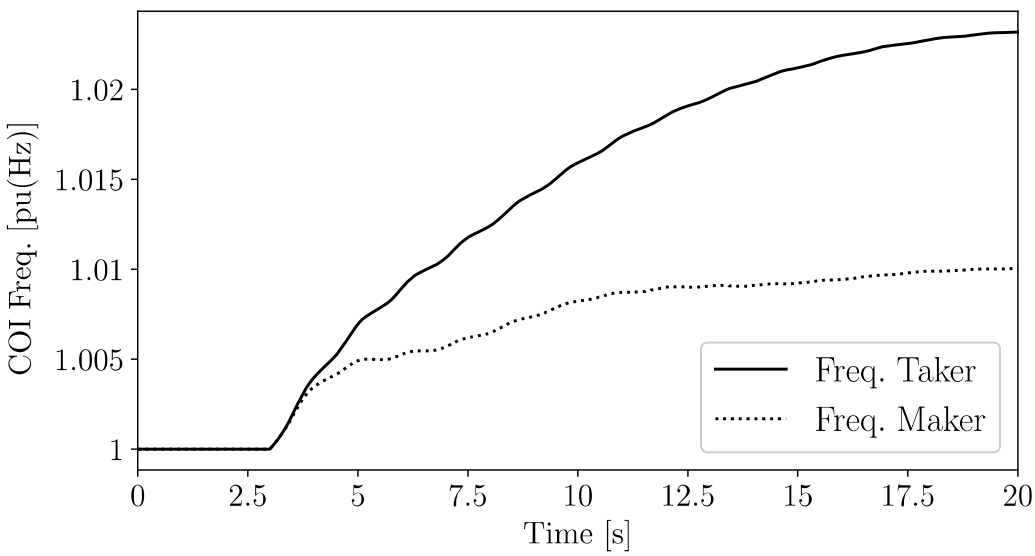


Figure A.5: Trajectory of the frequency of the COI for the WSCC 9-bus system with inclusion of a wind power plant with (maker) and without (taker) frequency control.

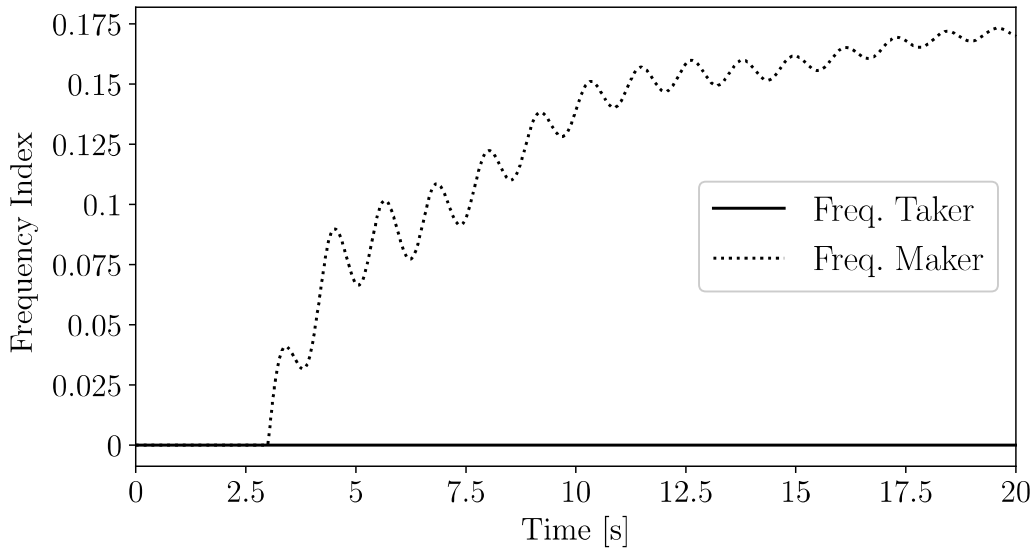


Figure A.6: Trajectory of the proposed index to identify frequency makers/takers for the WSCC 9-bus system with inclusion of a wind power plant with (maker) and without (taker) frequency control.

A.1.3 Frequency Control and Stability of Energy Storage Systems in Transmission Systems

For the purpose of this case study, a hybrid ESS (HESS) composed of a Flywheel ESS (FESS) and a Battery ESS (BESS) is installed in the 1,479-bus dynamic model of the all-island Irish transmission grid. Different stochastic processes are applied to the loads, and to the wind for each wind power plant. Two scenarios are shown below. First, fast frequency control provided by the HESS is studied in Subsection A.1.3.1, while the capability of the HESS to increase the CCT of a fault is demonstrated in Subsection A.1.3.2.

A.1.3.1 Frequency Control

In this scenario, the system variable regulated by the HESS is the frequency of the bus at which the storage device is connected to. The contingency considered is the disconnection of one of the synchronous machines of the system that is generating 50 MW prior the contingency. 1,000 simulations are performed for each case, namely with and without HESS, and results are shown in Figure A.7 to Figure A.10, where the histograms of the frequency of the bus of connection ω_{Bus}, as well as its probability density function (PDF) are represented for two conditions, namely at the frequency nadir, and 10 s after the generation unit outage. In the figures, μ_ω represents the mean of the PDF, while σ_ω stands for the standard deviations of the bus frequency.

It can be seen that installing the HESS improves the performance of the system for both the frequency nadir and 10 seconds after the machine outage, as μ_ω is closer to 1 pu (i.e., 50 Hz), and σ_ω is closer to zero, which implies smaller frequency deviations with respect to the mean. A detailed description of the methodology and the case study considered in this analysis is provided in [36].

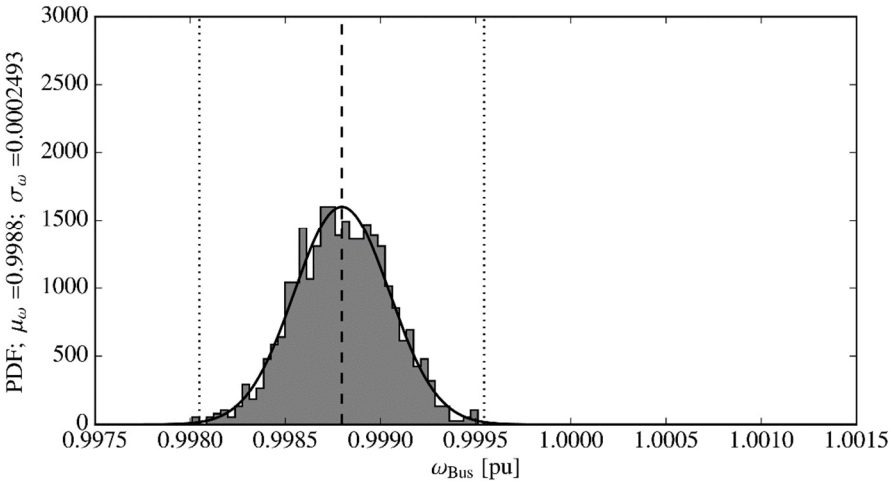


Figure A.7: Irish system without HESS facing the outage of a generating unit – frequency nadir. Dashed line: μ_ω; dotted lines: $\mu_\omega \pm 3\sigma_\omega$.

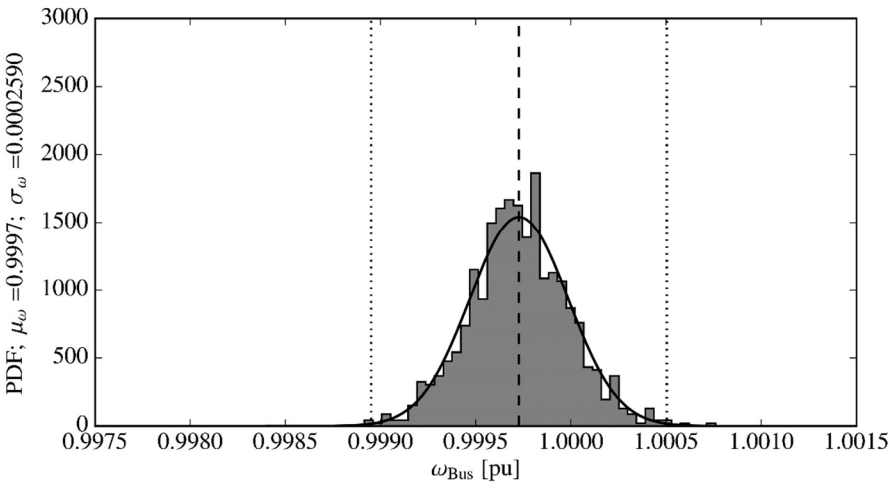


Figure A.8: Irish system without HESS facing the outage of a generating unit – 10 s after contingency. Dashed line: μ_ω; dotted lines: $\mu_\omega \pm 3\sigma_\omega$.

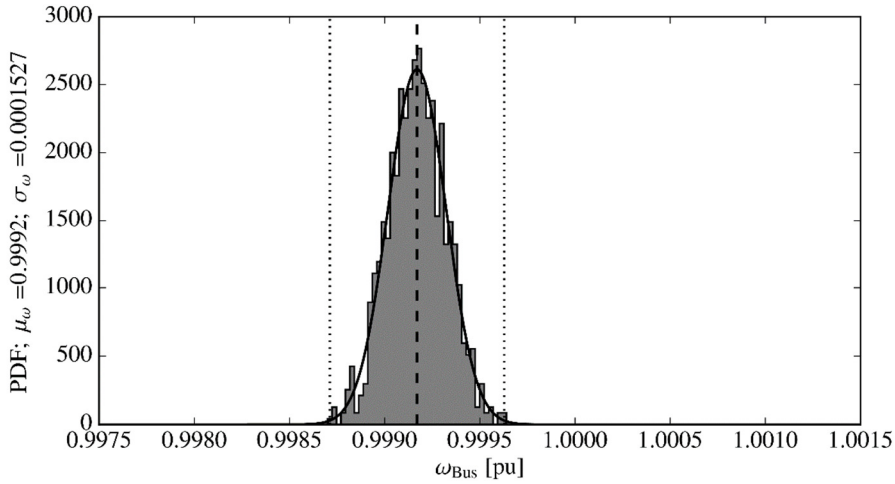


Figure A.9: Irish system with HESS facing the outage of a generating unit – frequency nadir. Dashed line: μ_ω; dotted lines: $\mu_\omega \pm 3\sigma_\omega$.

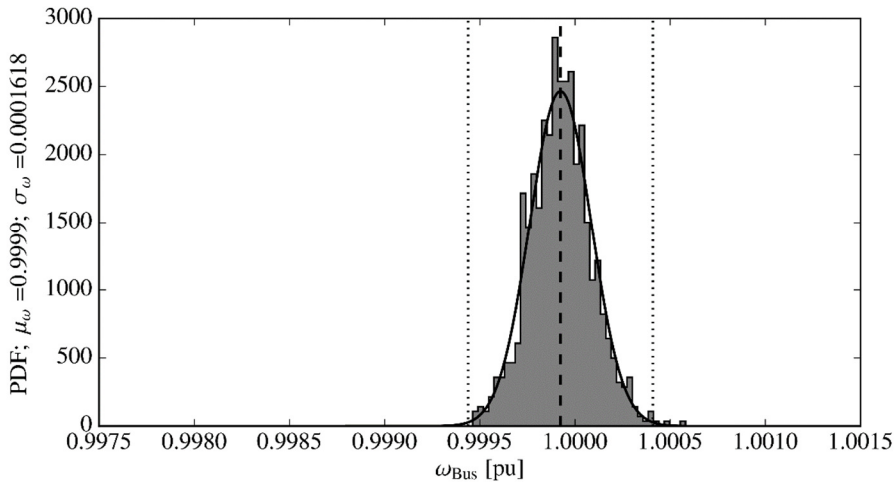


Figure A.10: Irish system with HESS facing the outage of a generating unit – 10 s after contingency. Dashed line: μ_ω; dotted lines: $\mu_\omega \pm 3\sigma_\omega$.

A.1.3.2 Transient Stability

In this scenario, the area where the ESS (FESS/BESS) is installed includes a synchronous machine that provides 139 MW and 15 MVAr as well as several wind power plants and loads. The controllers of both FESS and BESS devices can be designed to regulate the frequency of the bus of connection (ω_{Bus}) or the center of inertia (ω_{COI}). For the sake of comparison, the analysis also considers a 100 MVar STATCOM device which provides exclusively reactive power regulation [54]. Apart from the stochastic variations of the wind speeds, random initial loading levels have been considered to account for load uncertainty. Same control parameters have been chosen for the reactive power control of the ESS and the STATCOM.

The analysis is based on the results of stochastic time domain simulations (1,000 simulations per scenario, 60 scenarios). The contingency is a three-phase fault, and two different locations of the fault are considered in order to represent two possible system topologies according to the relative position of the fault and the ESS with respect to the synchronous machine, as depicted in Figure A.11. The percentage of simulations that are unstable due to the loss of synchronism of the machine is then computed for different clearing times (CTs), and shown in Table A.1 and Table A.2, for each of the following scenarios:

- Irish system without ESSs.

- One FESS/BESS providing local ω_{COI} control.
- One FESS/BESS ω_{Bus} providing control.
- One STATCOM device providing local bus voltage, v_{ac}, control.

Figure A.11: Topologies of a power system facing a fault. (a) Topology 1: The ESS and the synchronous machines are on the same side with respect to the fault; (b) Topology 2: The fault occurs between the synchronous machine and the ESS.

The concluding remarks from this study are summarized below.

- The reactive power support of the ESS plays the major role in transient stability enhancement.
- Regulating the frequency of the COI provides fairly similar results than controlling a local bus frequency.
- If the fault occurs between the synchronous machine and the ESS, the support provided by the latter is substantially diminished.
- The STATCOM device outperforms the ESS in some scenarios.

Should the reader desire a more detailed description of the methodology and case study presented in this appendix, we refer to our work in [37].

Table A.1: Percentage of unstable simulations after a three-phase fault in the Irish system for different CTs – ESS between synchronous machine and fault.

CT [ms]	105	110	115	120	125
NO ESS	25.3	44.4	65.6	83.1	99.9
ω_{Bus} CONTROL					
FESS	3.0	26.2	46.5	65.0	85.1
BESS	8.9	31.8	50.4	71.1	88.0
ω_{COI} CONTROL					
FESS	1.5	24.1	43.5	63.6	81.9
BESS	2.4	25.4	43.9	64.2	82.1
v_{ac} CONTROL					
STATCOM	5.8	28.9	47.0	67.5	84.7

Table A.2: Percentage of unstable simulations after a three-phase fault in the Irish system for different CTs – Fault between synchronous machine and ESS.

CT [ms]	105	110	115	120	125

NO ESS	29.8	48.7	69.4	86.5	100.0
ω_{Bus} CONTROL					
FESS	19.2	41.0	57.0	80.2	97.7
BESS	22.9	43.3	62.4	81.8	100.0
ω_{COI} CONTROL					
FESS	17.5	39.7	58.2	78.1	96.2
BESS	17.8	39.8	59.1	78.2	96.6
v_{ac} CONTROL					
STATCOM	16.7	39.1	57.4	76.9	95.5

A.1.4 Frequency Control of Distributed Energy Resources in Distribution Networks

The impact of the generation of the input signal of the DERs controllers in a distribution system on the overall system frequency regulation is studied considering the well-known WSCC 9-bus, 3-machine test system [55]. To this aim, the load at one of the buses of the system has been replaced with an 8-bus, 38 kV distribution system [56]. This modified version of a small Irish DG includes both radial and meshed configurations, and is composed of eight buses and lines, six loads, two wind power plants, one solar PV plant, and one ESS.

Two main scenarios have been considered. First, Figure A.12 and Figure A.13 show a comparison of the impact of noises and delays of the frequency signals for the three strategies described in Subsection 3.2.5, namely centralized, decentralized and average. Finally, Figure A.14 compares the robustness of each strategy against the loss of one of the measurements. For both scenarios, a three-phase fault is simulated, cleared after 150 ms by means of the disconnection of the affected line.

Remarks from these preliminary simulation results are the following:

- The centralized strategy shows a fairly good performance. However it shows a signifficant sensitivity to the associated signal communication delays. Moreover, to avoid the loss of all regulation capability in case of malfunctions of the measurement device, a redundancy of such a measure is desirable.
- The decentralized strategy works reasonably well, and it does not include any form of communication delay. However, its overall performance can be highly deteriorated in case of loss of any of the frequency measures.
- The average strategy shows a good robustness against the loss of measurement signals without the need of redundant measures. It naturally filters out the largest spikes and other numerical issues of the measures during transients. Similarly to the centralized strategy, its performance highly depends on the communication delays.

Based on these results, future work will focus on the improvement of the average strategy by means of the identification of the areas within the distribution grid with high density of DERs installed, with the aim of minimizing the related communication delays.

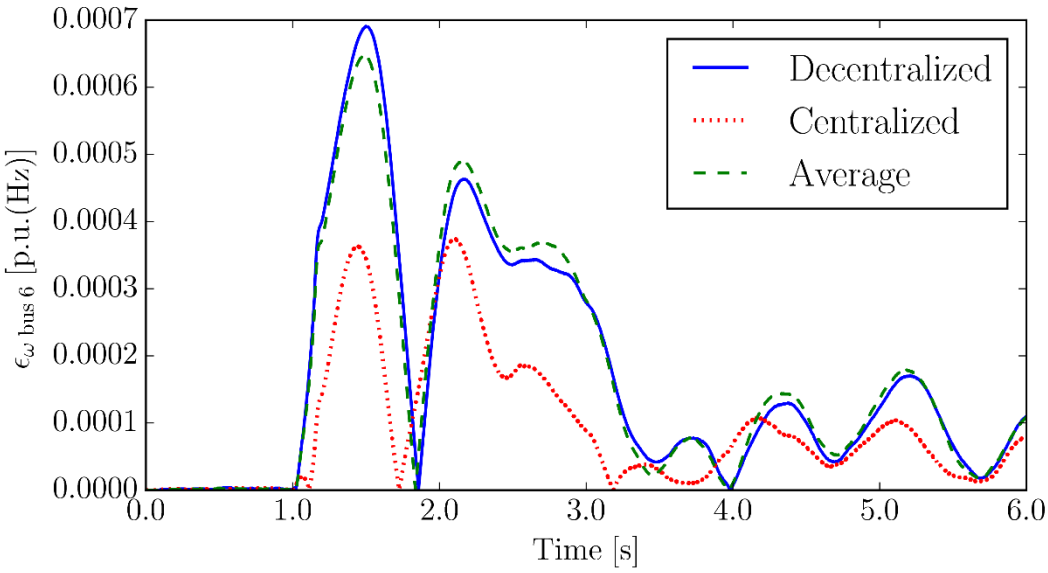


Figure A.12: Absolute error of the frequency at bus 6 after a three-phase fault. No communication delays are considered.

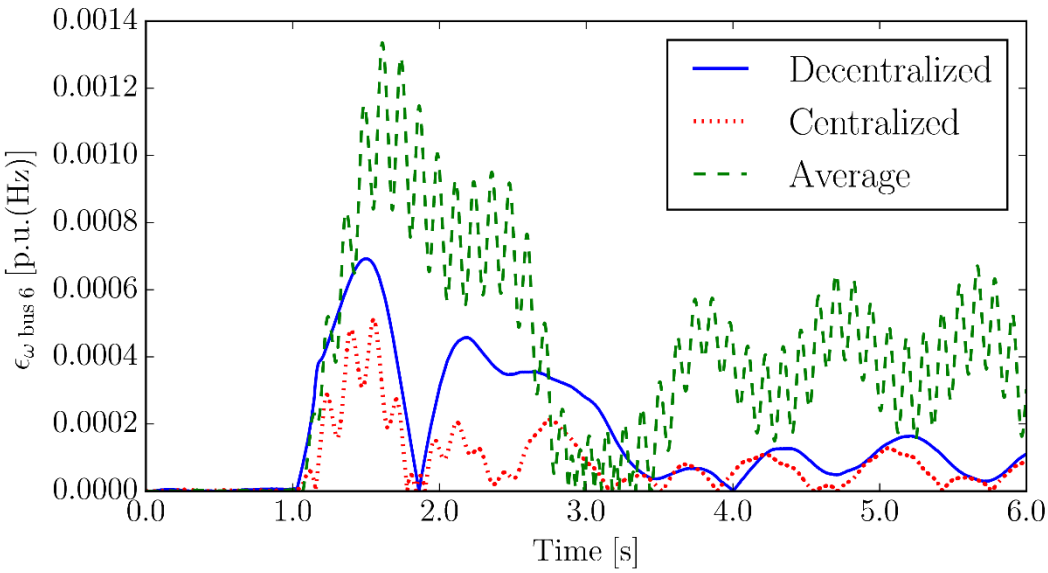


Figure A.13: Absolute error of the frequency at bus 6 after a three-phase fault. Communication delays are 35 and 55 ms for the average and centralized strategies, respectively.

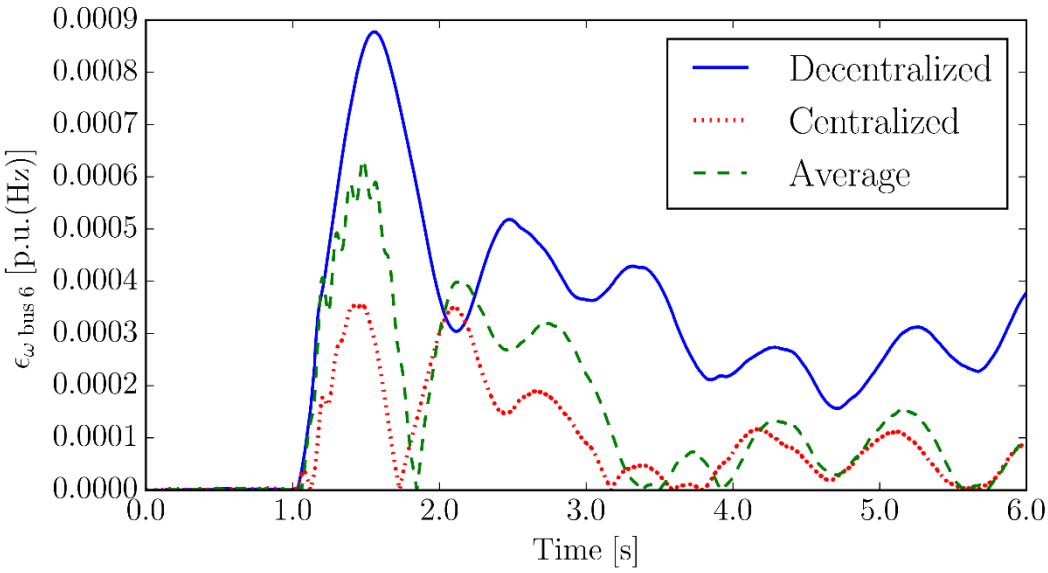


Figure A.14: Absolute error of the frequency at bus 6 after a three-phase fault. The frequency signal of bus D8 is lost for the average and decentralized strategies.

A.1.5 Frequency Control of Grid-connected Microgrids

A.1.5.1 Analysis of the Dynamic Impact of "Greedy" Microgrids

Figure A.15 and Figure A.16 show the effect of utilizing 2 and 12 MGs in the IEEE New England 39-bus system, respectively. From the observation of these figures, it is clear that the higher the penetration of the MGs operated in market mode, the higher the frequency variations.

Figure A.17 and Figure A.18 show the effect of different sizes of energy storage devices of MGs that are operated in "market mode". The fact that large storage capacity leads to a higher impact on the frequency deviations of the system is justified by the higher "flexibility" of the MGs. A large storage capacity, in fact, allows the MG to take more advantage of the current electricity price. For example, if the price is low, the MG can decide to buy electricity even if it energetically independent or could even sell its surplus energy to the grid. On the other hand, if the price is high, the MG can decide to sell the energy stored, even if its power balance is negative.

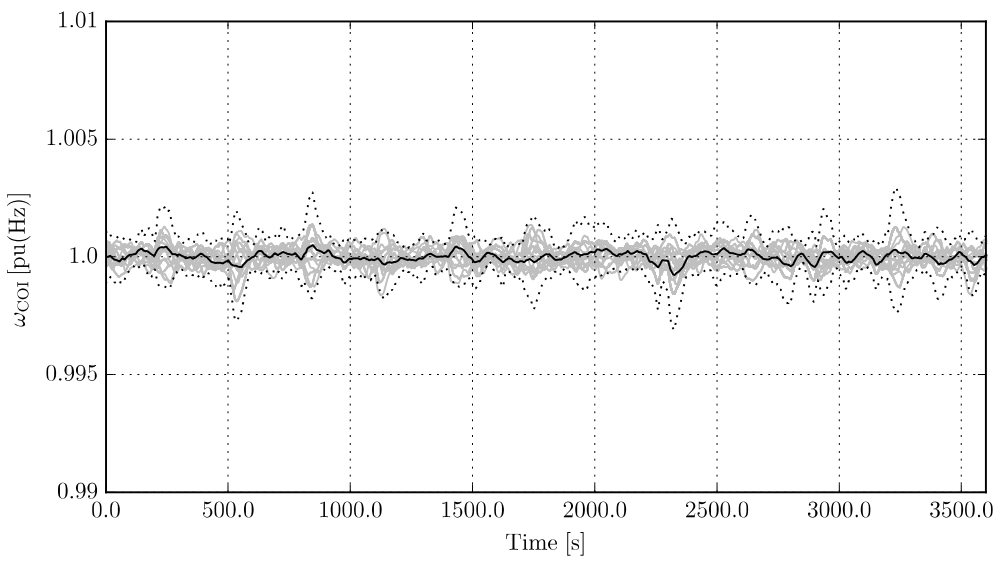


Figure A.15: Effect of 2 MG operated in "market mode" on the IEEE New England 39-bus system.

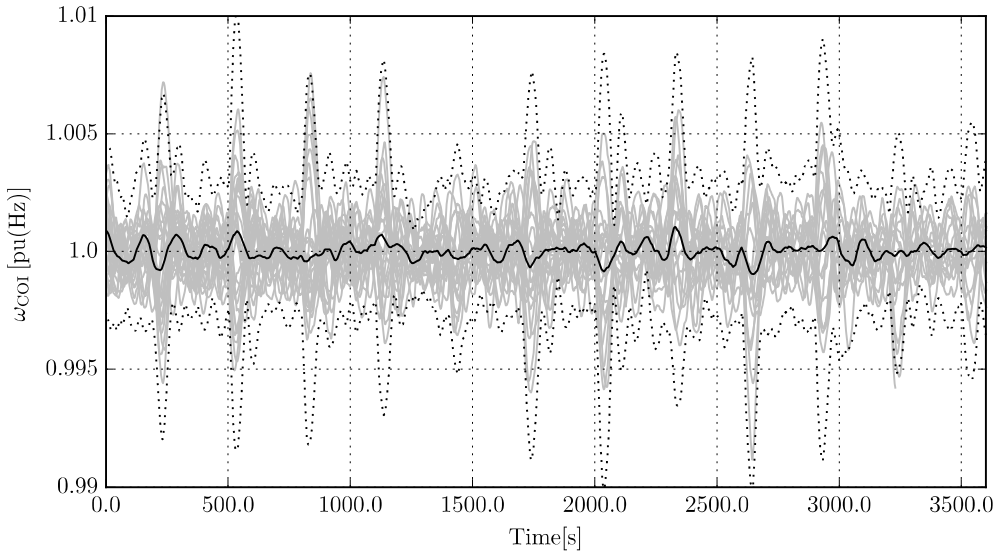


Figure A.16: Effect of 12 MG operated in "market mode" on the IEEE New England 39-bus system.

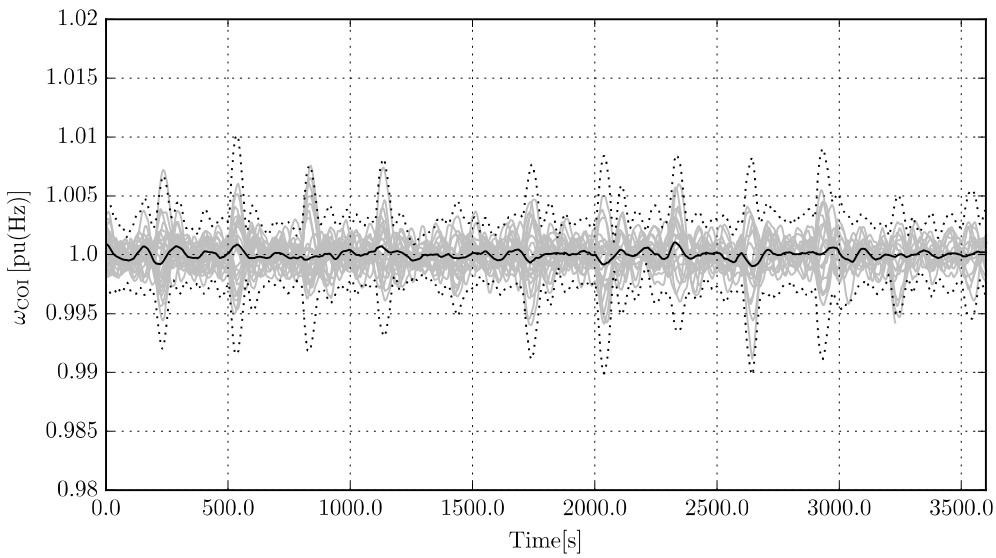


Figure A.17: Effect of 12 MG with small capacity energy storage operated in "market mode" on the IEEE New England 39-bus system.

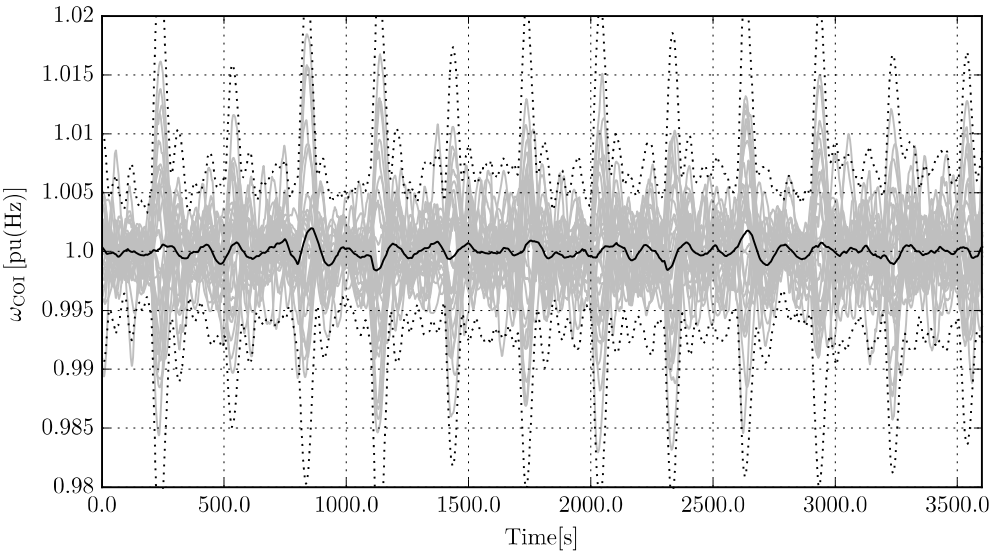


Figure A.18: Effect of 12 MG with large capacity energy storage operated in "market mode" on the IEEE New England 39-bus system.

A.1.5.2 Analysis of the Dynamic Impact of Microgrids with Stochastic Frequency Control – The IEEE New England 39-bus test case

Figure A.19 and Figure A.20 show the impact on the system of 12 MGs with and without the AIMD stochastic control for the IEEE New England 39-bus test system. The results clearly indicate that the AIMD is able to reduce the frequency deviations. Moreover, an economical appraisal indicates that the profit of the MG is not affected by the implementation of the AIMD control. More results are discussed in reference [32].

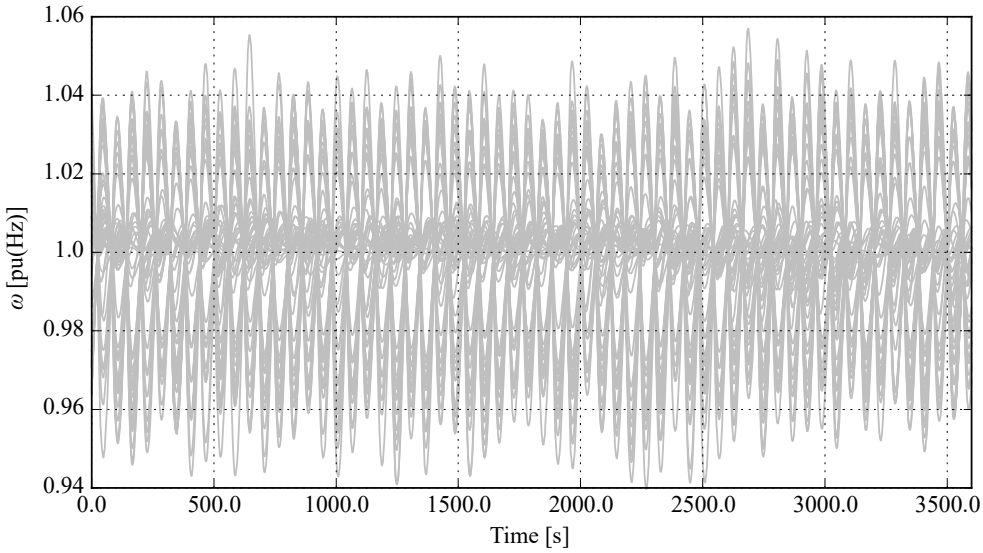


Figure A.19: Effect of MGs operated in "market mode" on the IEEE New England 39-bus system.

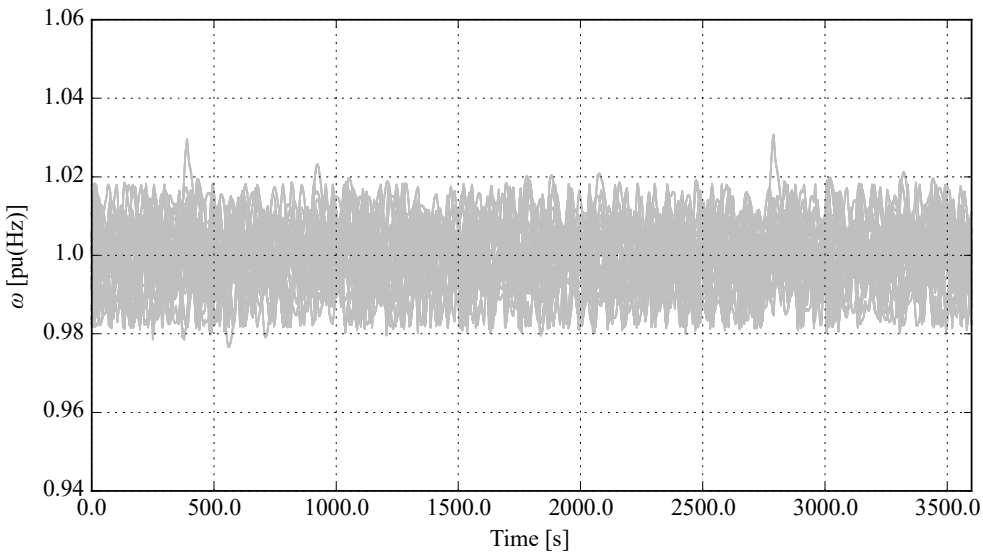


Figure A.20: Effect of MGs operated with the AIMD stochastic control that allows for both "market mode" and frequency control on the IEEE New England 39-bus system.

The AIMD appears as a promising solution for the control of several small resources as is scales very well (fully decentralized) and requires only local measurements. Moreover, the higher the number of devices that participate to the AIMD control, the more reliable (from the statistical point of view) is the control.

A critical aspect of the effectiveness of the AIMD control when applied to frequency regulation is the quality of the measurements of the local frequencies at the points of connection of the MGs. In the simulations we have utilized the frequency divider formula, which provides "ideal" frequency signals. In future work we will investigate the impact of noise and real-world frequency measurements (e.g., through PLLs) on the performance of the AIMD.

A.1.5.3 Impact of Storage Size on Microgrids with Stochastic Frequency Control – The IEEE New England 39-bus test case

The results of the simulation carried out in [32] are summarized in Table A.3. The results show that, at least for the considered scenarios, increasing the capacity of the storage beyond a certain value (i.e., 0.2 pu(MWh)) does not improve the dynamic response of the system. The reason for this results is that, beyond a certain capacity of the energy storage, the MGs cannot simultaneously internally balance the consumed and the generated energy, and at the same time provide ancillary frequency regulation services to the power grid.

Further increasing of the storage capacity, however, can increase the revenues of the MGs. This result is promising as it indicates that the MG are actually incentivized to increase their internal energy storage system and this is beneficial for both the MG and the grid.

Table A.3: Effect of different sizes of storage devices on system frequency deviation and GM revenue for stochastically controlled MGs and the IEEE New England 39-bus system.

Discharge Time [s]	Storage capacity [pu(MWh)]	Frequency sigma [pu(Hz)]	MG Revenue [pu(€)]
0	0	0.022	0.679
720	0.2	0.013	0.847
1340	0.4	0.006	0.902
2160	0.6	0.006	0.989
2880	0.8	0.006	1.000
3600	1.0	0.006	1.000

A.2 Provision of Inverter-based Frequency Control in 100% Non-synchronous Systems

A.2.1 New roles and requirements of PC in future converter-based power systems

The developed system shown in Figure 5.1 has been tested and simulated under different operating conditions. Small and large disturbance (load increase) has been applied at time 1 and 1.5 second, respectively. The results of active power, voltage and frequency at bus 2 are obtained as follow:

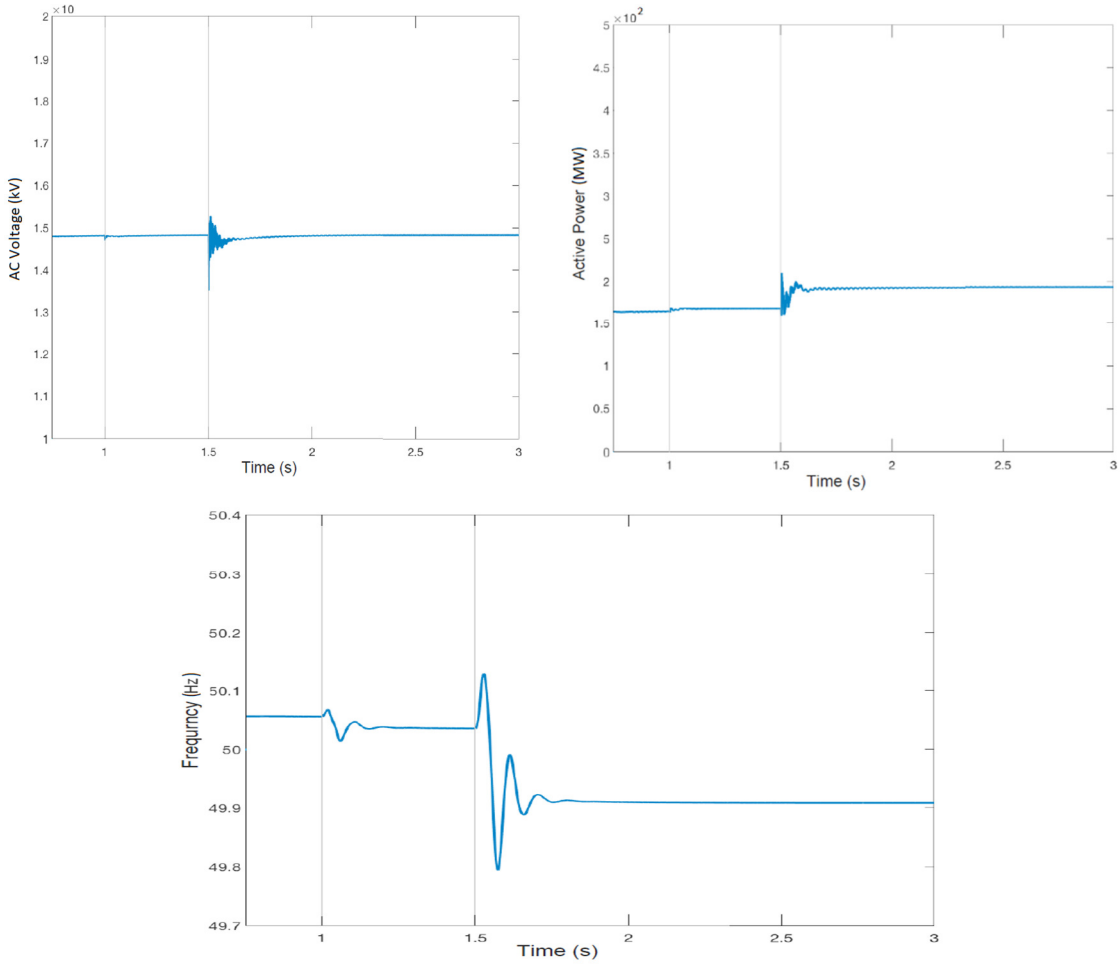


Figure A.21: System response at obtained at bus 2 under small and large disturbance

Also, uncertain conditions are considered by introducing a noise and delay in the frequency measurements. The aim is to study system capabilities and limits in overcoming such uncertain conditions and preserving a stable operation (stable frequency profile) as illustrated in Figure A.22 and Figure A.23.

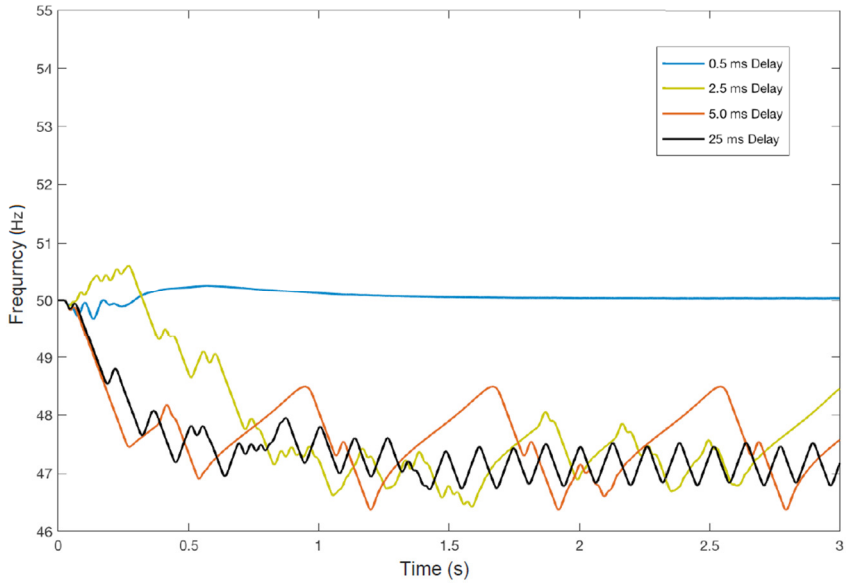


Figure A.22: Frequency profile under measurement delay

Due to the very fast dynamics of the presented converter-based WSCC system, the measurement delay has a significant influence on frequency stability and profile comparing with the measurement noises. The frequency stability is maintained within delay of 0.5 ms. While, longer delays with the range of milliseconds caused a significant drop in system frequency with a sustained oscillations. This event confirm the necessity for a very fast communication infrastructure in future converter-based power systems.

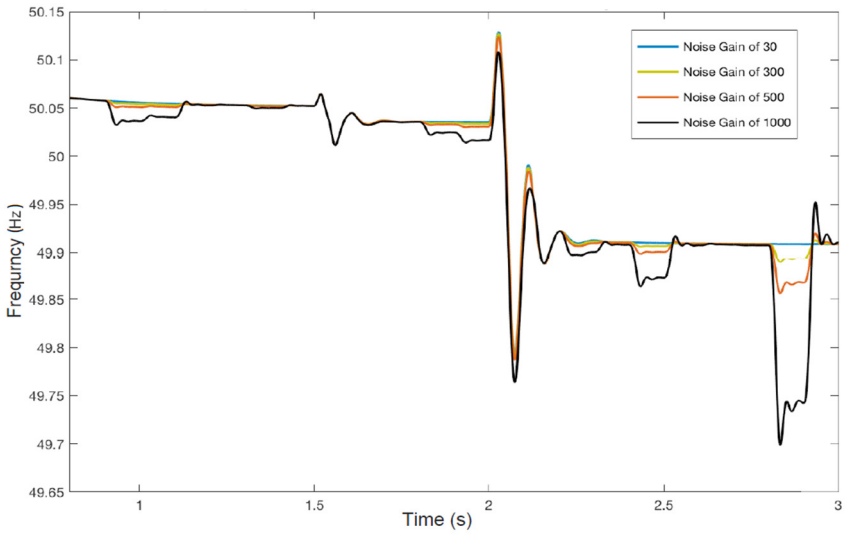
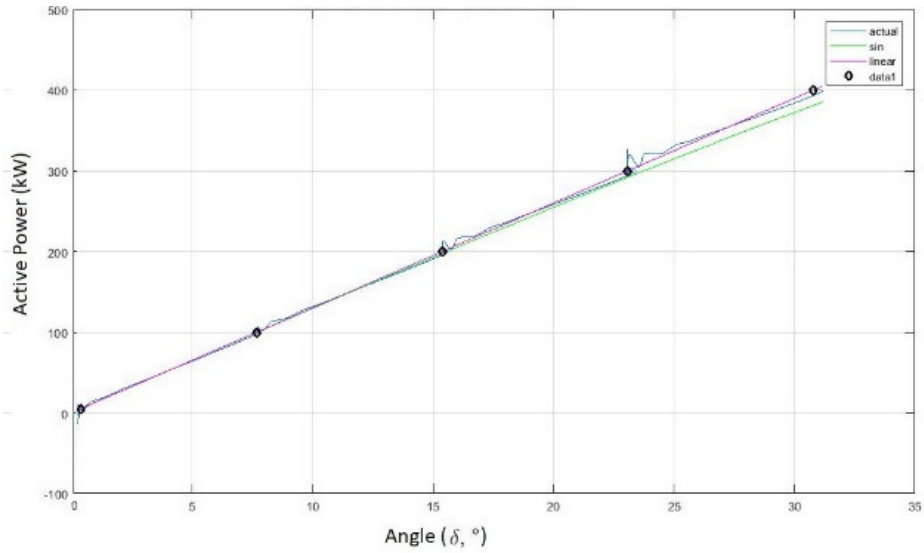


Figure A.23: Frequency profile in case of small and large disturbance, considering a noise in the frequency measurements

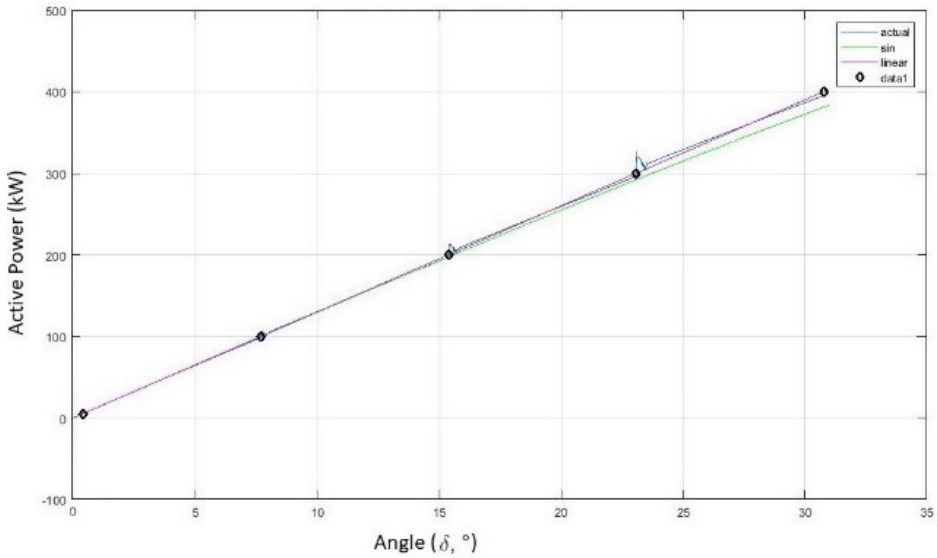
A.2.2 New form of Linear Swing Dynamics for future converter-based power systems

A.2.2.1 LSD with variable moment of inertia

The LSD-based VSG with variable moment of inertia is simulated and tested in a Single Machine Infinite Bus (SMIB). Two cases are considered and compared: LSD-VSG with fixed and variable M. The conducted test scenarios are represented by step increases in load active power. The system with variable M has better damped response and performance comparing with fixed M, as shown in Figure A.24.



(a) Fixed moment of inertia.



(b) Variable moment of inertia.

Figure A.24: Power-angle characteristics.

A.2.2.2 LSD for distribution systems

The LSD concept has been derived for a generic system, considering various R/X ratios, including pure inductive and resistive grid impedance. The same approach has been used, as in [46, 47, 48], by introducing a proper voltage control loop that is adjusting the AC voltage reference value continuously in a way to exploit the voltage tolerance (ε= +/- 10%) and achieve power-angle linear behaviour. There are some modifications in the concept and control formulation due to the changes in grid impedance representation, i.e. by substituting Z=X with Z=R+X. An analytical results are obtained as shown in Figure A.25.

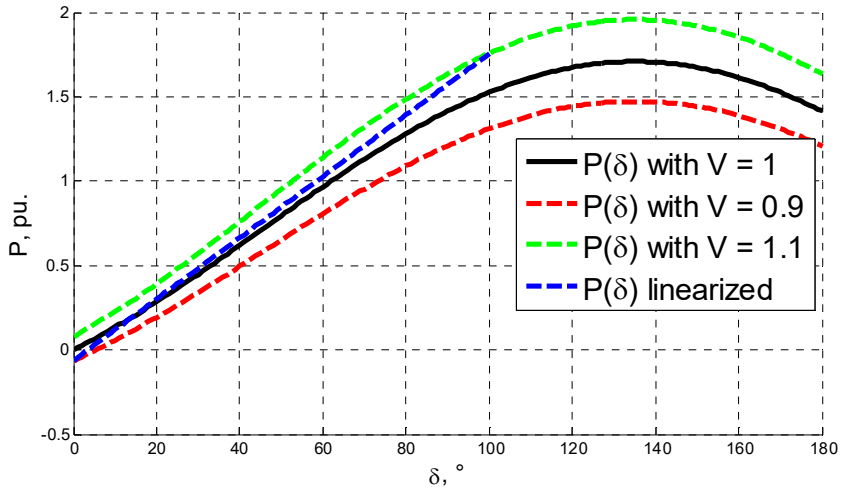


Figure A.25: Power-angle linearization, for R+X.

A.2.2.3 LSD for Multi-machine power systems

The LSD concept has been tested in four machines (converters) power system. Each converter is represented by LSD-based VSG. The reference and actual power outputs of the four converters are presented in Figure A.26.

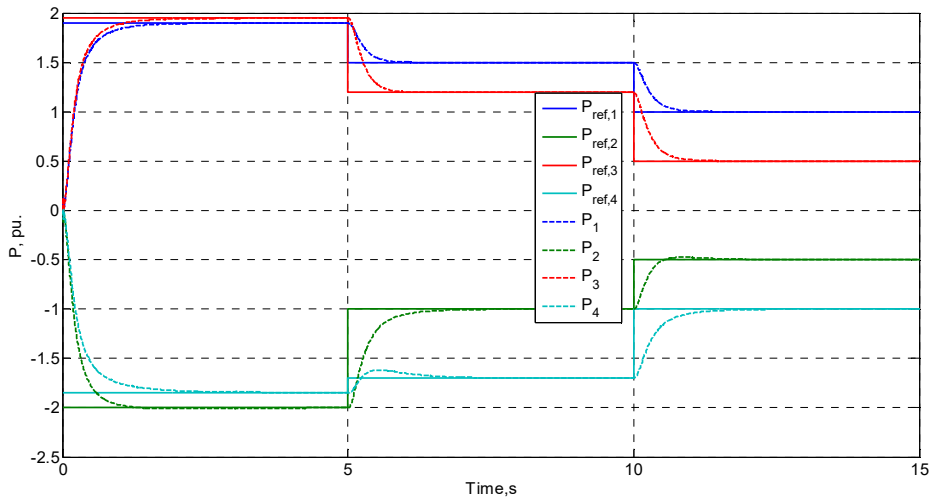


Figure A.26: Reference and actual active power outputs in the multi-machine system

In order to prove the linear P-δ linear behaviour, the calculated active power, $P_{calc,i}(t)$, that is ideally expected to be in a linear relation with the angle is compared with the actual output power of the converters, $P_i(t)$. By using the following expression

$$NL_i(t) = \frac{P_{calc,i}(t) - P_i(t)}{P_i(t)} \quad \text{(A.1)}$$

Which represents a measure for nonlinearity. The error between the calculated active power and actual output power is sufficiently small as shown in Figure A.27. It can be observed that $\boldsymbol{NL_i(t)}$ is close to zero in steady state, and below 2% during transients (except for the first 3 s start-up period).

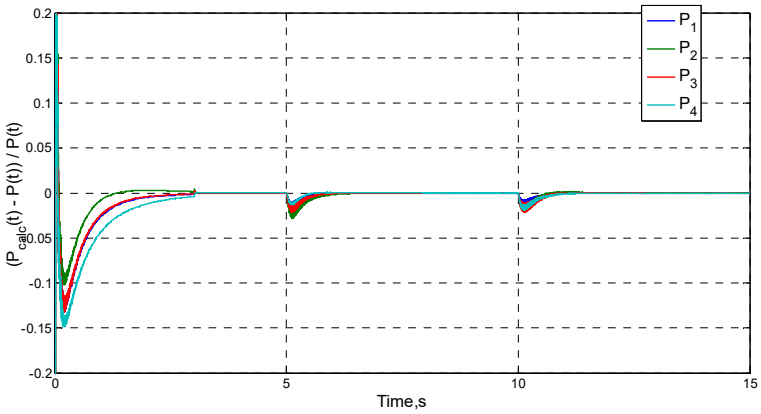


Figure A.27: Measure of $P(\delta)$ nonlinearity in the multi-machine system

A.2.3 New roles and operational characteristics of HVDC systems

A.2.3.1 Intelligent frequency support by HVDC systems

The developed control (MA-IFC) is tested and compared with the classical FDC in a hybrid AC/DC network to have five weak and stiff AC grids connected via HVDC system. The results show that with FDC, a fixed participation is done among all the healthy grids (AC2-5) in supporting the disturbed grid (AC1). On the other hand, the MA-IFC is shown to provide a different participations from each supporter grid (AC2-AC5) depending on their technical specification, constraints, power generation and demand. To conclude, the proposed control aims to achieve a systematic enhancement in frequency profile, in particular the weak and disturbed AC grids [53]. The minimum frequency undershoot (F_{nadir}) and Rate of Change of Frequency (RoCoF) are measured for all the grids, for both classical and proposed controllers as provided in Table A.4.

Table A.4: Frequency participation of AC grids: f_{nadir} (mHz) and RoCoF (mHz/s)

AC GRID	AC GRID STIFFNESS	CLASSICAL FDC		PROPOSED MA-IFC	
		f_{nadir}	RoCoF	f_{nadir}	RoCoF
AC1	Stiff (disturbed)	135	111.71	85	72.7
AC2	Stiff	16.5	5.11	48	20.67
AC3	Weak	51.5	21.8	15	10.08
AC4	Weak	48	20.77	11	3.79
AC5	stiff	38	3.59	12.5	16.39

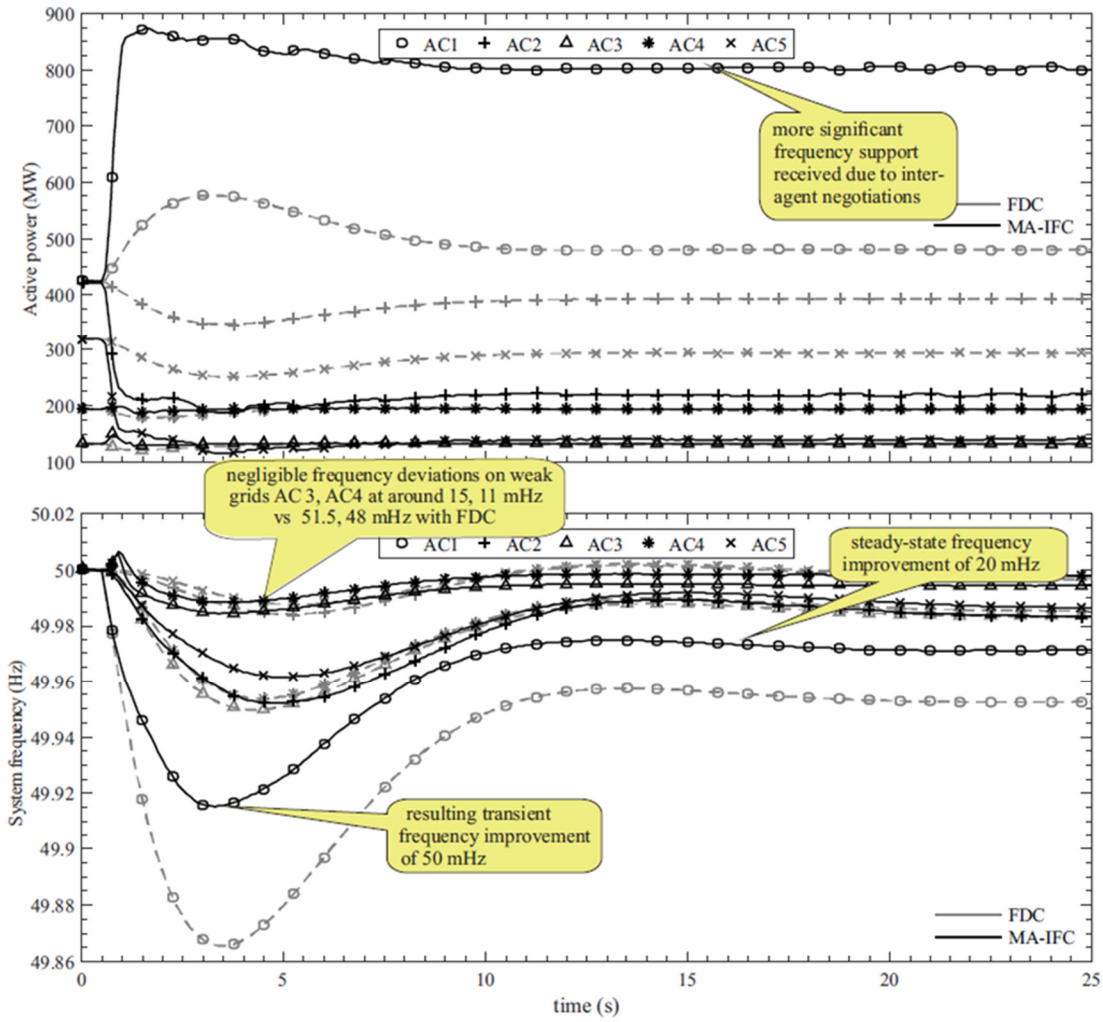


Figure A.28: Active power and frequency of AC grids under power disturbance at AC 1.

A.2.3.2 LSD-based frequency support by HVDC systems

To scrutinize the performance of the proposed LSD-VSG control scheme, the presented HVDC system has been tested and simulated in MATLAB Simulink. The test scenarios are applied to have a step increase in load active power on the AC grid side. The objective of these test scenarios is to verify the LSD-VSG feature of preserving a stable HVDC system operation, enabling the grid-tied HVDC converter (LSD-VSG) to operate with a linear dynamic behaviour to provide virtual inertia and frequency support. As shown in the results below, the LSD-VSG is able to achieve power-angle linear relation, provide frequency support to the AC grid, and maintain a stable DC voltage profile as illustrated in Figure A.29, Figure A.31 and , respectively. It is worth mentioning that the classical VSG and proposed LSD-VSG have almost similar performance in providing frequency support, except that the latter has unique characteristics in achieving power-angle linear behaviour and enhancing the DC voltage profile. Note that intermediate small oscillations are observed in the actual system response during transients as shown in Figure A.30. However, these could be further damped by introducing adaptive inertial control based on variable M.

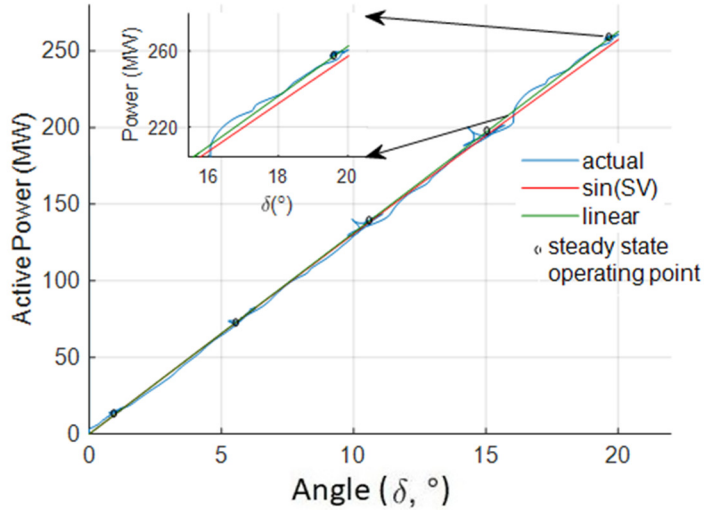


Figure A.29: Power-angle characteristics of grid-tied HVDC converter.

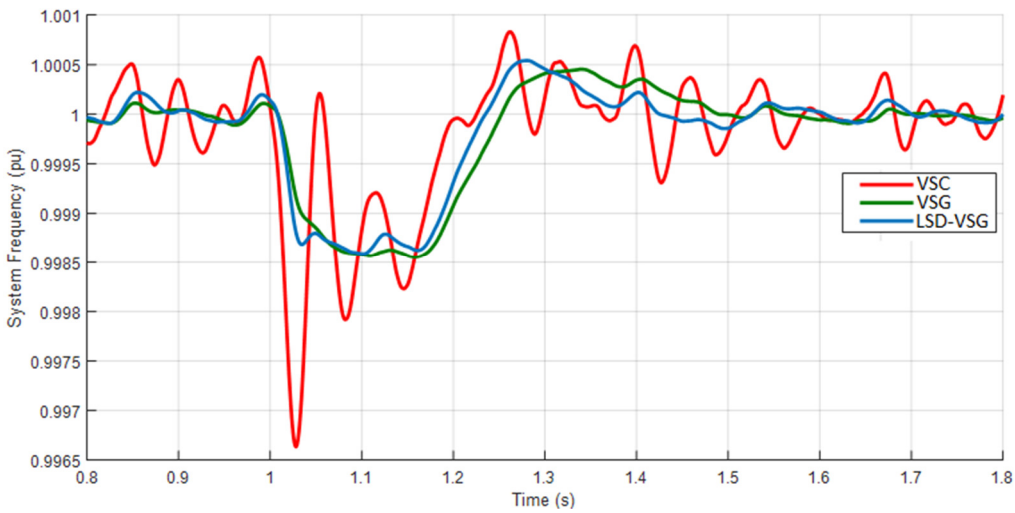


Figure A.30: Frequency profile of HVDC-connected AC grid.

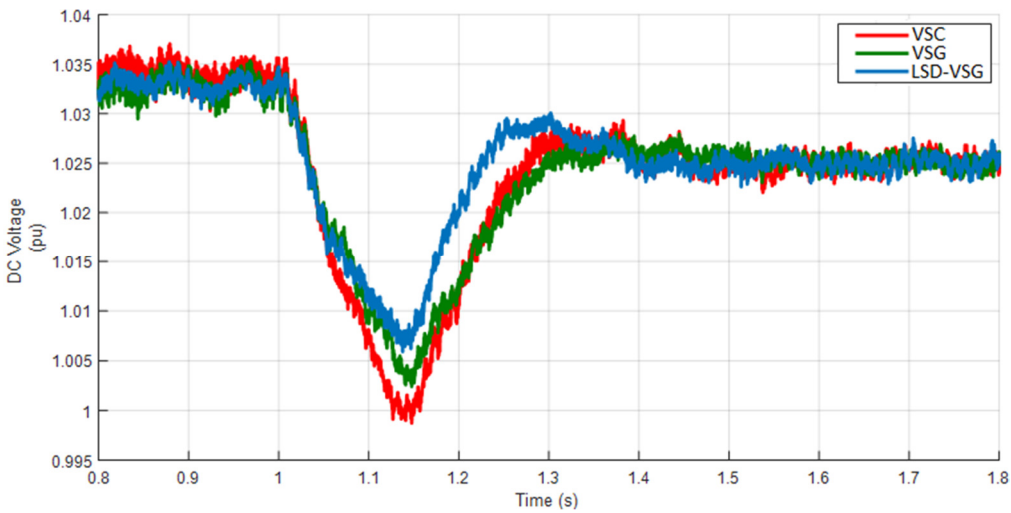


Figure A.31: DC voltage profile of HVDC system.