RESERVE

D2.2 v1.0

Review of relevance of current techniques to advanced frequency control

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Abstract:

This deliverable provided overview of the actual frequency control techniques in power systems. It emphasizes the specific characteristics of the primary control level and explains the architecture and characteristics of the secondary control level. The implications at all control levels with the increasing share of generation from renewable energy sources are discussed in detail. These discussions refer to both frequency control procedures, power market implications, and ICT requirements.

A frequency analysis is provided for a set of data achieved for the Romanian power system, consisting in wind and PV power generation, as well as frequency and RoCoF measurements by means of PMUs available at UPB laboratory. This analysis has been done in order to identify the way in which the frequency of the power balance are affected.

A simulation scheme was created and simulations were done in order to identify the influence of each type of classical power plant on the frequency stabilization for various mechanical inertia values. Additionally, battery energy storage systems are proposed to provide fast response (virtual inertia) as a measure to frequency stability when low mechanical inertia is considered.

Together with the models and techniques developed in D2.1, frequency control simulations will be done on the Romanian power system database within D5.5. While preliminary conclusions have been drawn so far as proposals for future new or adapted network codes, the synergy with real situation (the case of the Romanian power system) will be provided based on results from D5.5. The simulations will be done in correlation with the techniques developed in WP4.

Keyword list:

Frequency control characteristics and procedures, network codes, generic models, power system interactions, power system frequency analysis

Disclaimer:

All information provided reflects the status of the RE-SERVE project at the time of writing and may be subject to change.

Executive Summary

This Deliverable D2.2 presents the work done within the Task 2.1 “New concepts in frequency control”, as a component of the research work within the Work Package 2 “Frequency stability by design”. In this context, the goals of this deliverable are:

- To review the actual procedures and characteristics of the frequency control in a power systems. The purpose is to identify the needs for adaptations or changes under increased generation from renewable energy sources (RES) towards 100% clean energy.
- To identify the actual network codes that govern the frequency control procedures, and the requirement for the network users in relation to the frequency control.
- To analyse the influence of renewable energy sources on the power system operation, from both frequency variations and stabilization and the performances for power balancing in interconnected operation of the power systems.
- To identify the solutions for frequency stability, in situations with reduced mechanical inertia. The solutions analysed in this deliverable is the integration of battery energy storage systems in the decentralized frequency control (can aim both inertial and primary control).
- To draft proposals for new or adapted network codes to be verified within Work Package 5 “Test-beds for validation of research results”, respectively within Deliverable 5.5 “Report on trial of frequency control in Laboratory and validation of initial network codes and ancillary service definitions, V2”, and subsequently to define final proposals for network codes within Work Package 6 “Regulatory, legal issues & business models for RES”.

Shifting dramatically the power generation from coal-based and natural gas- based power plants to 100% renewable energy is a big challenge especially for the power system operators. In order to provide the frequency control service (which is a system service), the system operator needs predictable power reserves. With the actual technology of **wind and photovoltaic power generation**, there is a concern related to power reserve available for frequency control. In order to perform frequency control, the two technologies **should keep unused up to 5% of the available energy**.

Therefore, **the actual RES technologies** may have the following impact:

- **RES cannot maintain predictable power reserve**. This can have negative implications on the power market.
- **More investments would be required** to cover the energy demand, while power reserve should be maintained.

In order to avoid economic losses, new network codes should focus on energy storage systems, e.g. batteries, flywheels, supercapacitors. The actual *frequency control related network codes* should be *changed* from technical point of view in order *to allow the development of the storage systems* from economic point of view. The simulations performed have shown that (please see Annex C):

- **The time reaction** (*virtual inertia*) is very important rather than energy for inertial frequency control. For this reason, high capacity – low energy systems are needed in low mechanical inertia power systems to provide frequency stabilization.
- A **minimum mechanical inertia** should be maintained in the power system to guarantee the power system stability.

The actual network codes recommend three levels of control: primary (automatic, time reaction in seconds), secondary (automatic, time reaction from seconds to minutes) and tertiary (automatic, time reaction from minutes to hours). While simple specifications about the rate-of-change-of-frequency (RoCoF) are included in codes, no clear requirements are provided. Therefore, in this project, we propose introducing an additional type of control:

- **Inertial control**, with time reaction from 1 to 5 seconds). A Frequency Divider tool has been proposed in Deliverable D2.1, capable of estimating the frequency locally. A local or regional controller can be implemented based on this tool to send control signals to small generation units or loads.

A frequency analysis was also performed in this deliverable to determine the impact of RES on the Romanian power system operation. The frequency data were collected with PMU devices installed in the UPB laboratory (please see Appendix B). The analysis has revealed the following:

- PMU devices can help identifying very fast dynamics by measuring RoCoF. The most dangerous event that can occur in a power system is a **short-circuit close to a power plant** followed by the disconnection of the power plant, which means loss of important generation. In such situations, important **RoCoF variations are observed**.
- Very high wind fluctuations can be experienced, which can have a big impact on the power reserves. Such situations must be avoided by local deployment of energy storage systems or controlled cross-border power exchange.

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1. Introduction

1.1 Aim of Task 2.1

This deliverable (D2.2) is the main output of Task 2.1 “New concepts in frequency control” of the Work Package WP2. The main goal of Task 2.1 is to review the actual network codes in terms of characteristics and procedures for frequency control and to identify the need for network codes or adapted ones. This task is needed because the actual network codes still rely on large mechanical inertia based control generation units, situation not valid in the 100% RES context. The task extends the concept of virtual inertia within the frequency reserves containment framework. This means that RoCoF measurements are necessary as additional input into the primary frequency control. Real-time information are also used to analyses the impact of RES on the power system operation, including both frequency measurements and active power exchanges. The research work done in this task aims at emphasizing the need to new control structures, ICT requirements, and power market adaptations.

1.2 Objectives and outline of the deliverable

The Deliverable D2.2, titled “Review of relevance of current techniques to advanced frequency control”, was introduce to analyse the need for new concepts in frequency control under generation from 100% RES. In particular, we have identified the need for inertial control, as an advanced strategy to advanced frequency control, either as an independent action or as an additional signal, besides the frequency variation, into the primary frequency controller. The technique has been studied by considering a battery energy storage system, which is characterized by very small time reaction. On the other hand, in order to determine the need for new control techniques, the use of real-time data collected from the Romanian power system has been planned. The conclusion drawn from the analysis of the real-time data were used to infer new network codes. One particular aspect of the Romanian power system is that it rely on power generation from hydraulic power plants. For this reason, two frequency scenarios were defined, namely SF_A (with hydro units) and SF_B (no hydro units).

1.3 How to read this document

This deliverable creates inputs for future work within the project. It explains the framework of frequency control in a power system, as input for other tasks and/or deliverables. It is also linked to deliverable D2.1, which provides details of the use of the frequency divider as a special tool for frequency and RoCoF-based signals at local regional levels.

A general relationship of deliverable D2.2 with other deliverables and work packages is illustrated in Figure 1.1. It emphasizes the following connections:

- It is coordinated with the WP 1, where general framework of scenarios and architectures were defined.
- Together with D2.1, it provide the input for the theories and simulation framework on Linear Swing Dynamics in D2.3.
- Together with D2.1, it provide the mathematical models and control architectures that will be considered for frequency control simulations on the Romanian power system in Task 5 (deliverable D5.5).
- It provides a first draft for network code proposals related to the frequency control in interconnected power systems, to be used at the business level in WP6. The results achieved in Task D5.3 will verify and/or propose adaptations for final network codes proposals.
- Together with D2.1, and based on the results provided by D5.5, new technical requirements for frequency control network codes will be defined within Task 2.6.

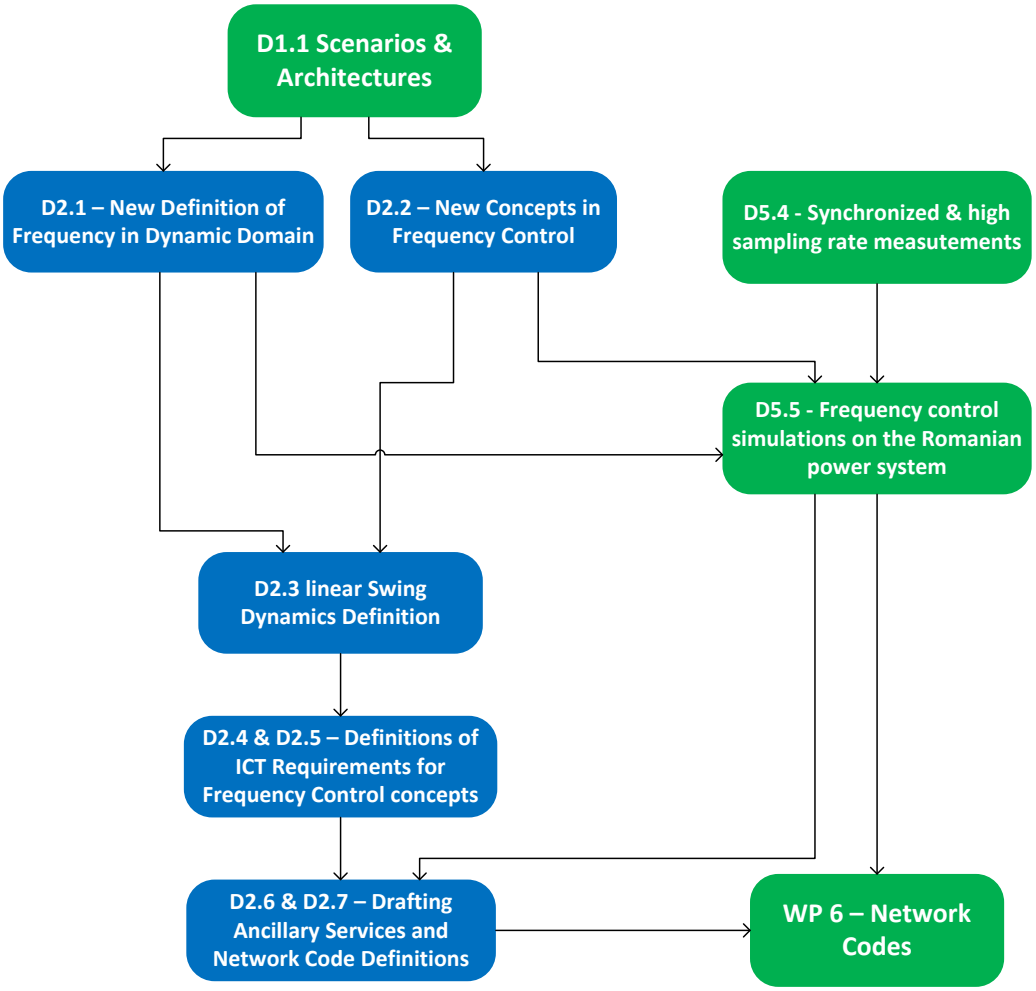

Figure 1.1 Relations of Deliverable D2.2 with other work packages and deliverables.

1.4 Structure of the deliverable

Most important results of this work are presented in Chapter 2. Chapter 2 also explains the motivation for the research work and provides the general framework of the frequency control characteristics and implications. These are supported by various appendices. Based on the discussion provided in Chapter 2, Chapter 3 outlines a first draft for future network codes on frequency control. Chapter 3 also discusses how to utilize the results presented in this deliverable for future work within the RESERVE project. Appendix A provides a review on current network codes, frequency control procedures, and power market implications. Appendix B provides and analysis on real-time data from the Romanian power system, as regards the influence of RES on the power system operation. Simulations and conclusions related to the importance of power electronic based storage systems for frequency stability are presented in Appendix C.

2. Implications of frequency control techniques for 100% RES in the context of working power networks

2.1 Introduction

2.1.1 Motivation

In the classical concept, the power system frequency is a global parameter that is maintained at the reference value by continuous balance between generation and load. Any imbalance between generation and load will result in positive or negative deviations of the system frequency with respect to reference value, depending on whether the generation is greater or smaller than the load. The system operator has the responsibility of ensuring the powers balance at any instant, according to the frequency regulation procedures.

In bulk interconnected power systems, characterized by large inertia in the rotational masses of the synchronous machines (turbo and hydro generators), the frequency variations following power unbalance are slow. The strategies for frequency control have been classically designed and implemented based on specific frequency phenomena. On the other hand, in the interconnected power system of ENTSO-E (more exactly, the continental power system), an unbalance considered large for a certain power system may not necessarily result in triggering frequency values (that will activate a specific control level), but in undesired power exchanges with the neighbour systems.

The last two decades have been characterized by important changes that affected the phenomena related to frequency variation and control. Among these changes we mention:

- Increasing the share of generation from sources connected to the power grid via electronic interface, such as the photovoltaic power plants, doubly fed induction generators and the permanent magnet synchronous generator based wind power plants. This is resulting in reducing the natural inertia of the generation sources, which result in sudden and fast frequency variations.
- The wind and solar power plants depend on an intermittent and sometimes unpredictable primary resource. For economic reasons, they are usually operated at the maximum power, thus resulting in intermittent generation. Under these conditions, the power unbalances are rapidly changing in time, thus causing fast frequency fluctuations.
- The increase in the share of generation from renewable energy sources results, under actual conditions, in reduced spinning balancing reserves in classical generators, which may affect the power system security.
- Significant evolution of the electronic based technology on both the load side and small generation side. The specific problem associated to these types of load is the instantaneous loading/unloading of a large power upon connection/disconnection of the load device, as well as the high disturbed current/voltage waveform. By contrast, in the past, most of the loads were characterized by slowly changing and near to sinusoidal operation.

For the reasons mentioned above, this projects aims at identifying the problems in the power systems operation caused by massive integration of renewable energy sources and to propose specific measures to adapt the frequency regulation strategy, from technical point of view and in accordance with the power market rules.

Power system security is very important, not only appropriate operation of the power system, but also for the economy of the European Union. Frequency instability can lead to an extended blackout at the ENTSO-E level. The history have shown that even if strict rules are defined at the ENTSO-E level, blackouts can occur for various reasons. To support this statement, let us consider the latest major blackouts that occurred in European Union.

A. The Major grid blackout of the Italian power system, on 28 September 2003 [51]

The sequence of events was triggered by a trip of the Swiss 380 kV line Mettlen-Lavorgo at 03:01 caused by tree flashover. Several attempts to automatically re-close the line were unsuccessful. A manual attempt at 03:08 also failed.
The following picture shows an overview of what happened with the frequency in Italy during the transition period which started with the disconnection of Italy from the UCTE grid at 03:25:34. So this blackout became a reality after about 2.5 minutes after the disconnection of Italy from the UCTE grid. Sardinia and a limited number of load islands were not involved in the blackout in Italy mentioned.

It is important to note that between 03:08 (the instant of the first event) and 03:25:34 (the instant of the separation of the Italian power system) the frequency was maintained by the UCTE system around the reference value. This shows that frequency stability can have many implications, at all decision levels.

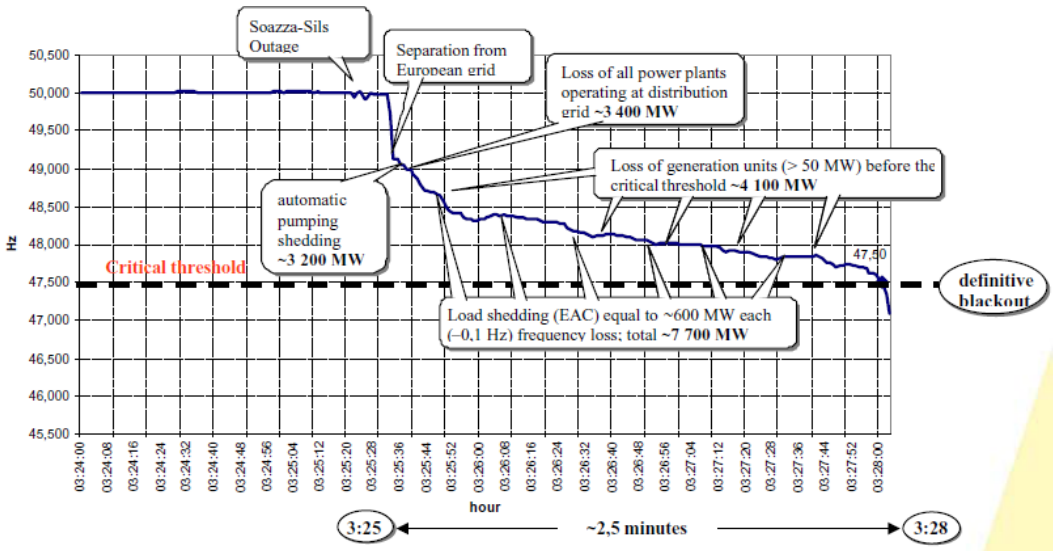

Figure 2.1 Frequency behaviour in Italy in the transitory period [51].

B. The desynchronization of the ENTSO-E Continental Europe, on 4 November 2006 [52]

On the evening of November 4th, 2006, there were significant East-West power flows as a result of international power trade and the obligatory exchange of wind feed-in inside Germany. These flows were interrupted during the event. The tripping of several high-voltage lines, which started in Northern Germany, split the UCTE grid into three separate areas (West, North-East and South-East) with significant power imbalances in each area. The power imbalance in the Western area induced a severe frequency drop that caused an interruption of supply for more than 15 million European households.

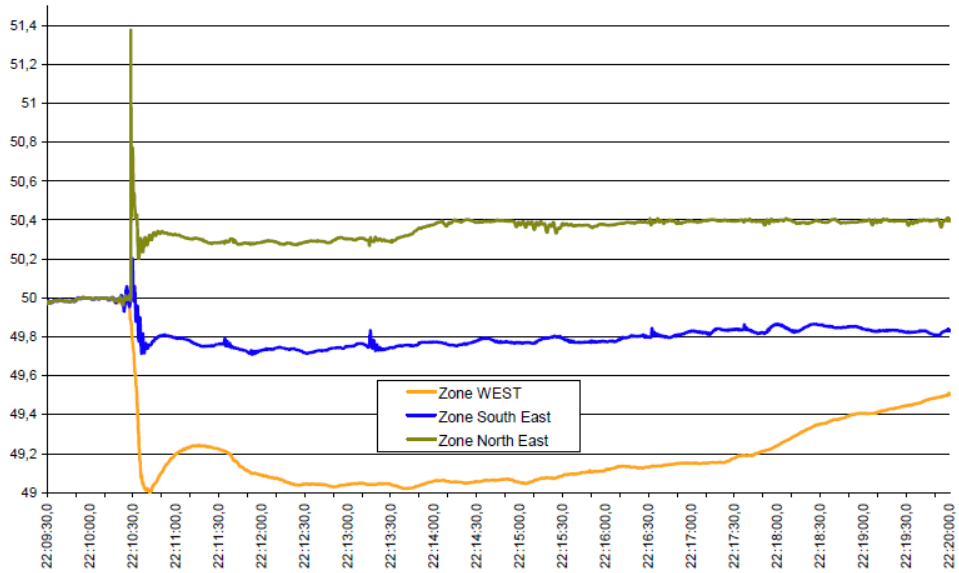

Figure 2.2 Frequency recording after the spit of the Continental Europe of ENTSO-E, on November 4th 2006 [52].

In both under-frequency areas (West and South-East), sufficient generation reserves and load shedding allowed to restore the normal frequency within about 20 minutes. The frequency recording after the split of the ENTSO-E power system of the Continental Europe is shown in Figure 2.2.

Both this event in 2006 and the Italian blackout in 2003, as well as many other local blackouts or loss of synchronization, are credible reasons for carefully situations that apparently seems harmless, but that can have large implications, including economic and social.

2.1.2 Introduction to the frequency control techniques for 100% RES

We are studying the impact of having 100% RES at three different time scales and proposing the tools needed to study the methodologies for frequency control specific for each of them.

In this report, we propose to use RoCoF for frequency control in scenarios for up to 100% RES. It relates to the times of reaction faster than currently used for frequency stabilization, and the need of new type of energy sources to provide balancing energy to the power network. Both existing and new control techniques could be applicable.

In one scenario, called SF_A in this project, we assume 100% RES with the inclusion of significant share of generation from hydro-electric power plants, which provides mechanical inertia. In the second scenario, called SF_B in this project, we assume 100% RES from wind and solar sources, but without the inclusion of hydro-electric power, so there is no mechanical inertia from synchronous generation in the system.

Changes needed at the three levels are examined in this project, in particular technical measures relating to three distinct timescales are proposed to enable frequency control with up to 100% RES:

2.1.3 Frequency control strategies for different timescales

In this project we focus mainly on the automatic frequency control levels. These are explained as follows [38], [39]:

1. **Inertial frequency control**, based on **RoCoF**, will provide frequency control within a timeframe less than 5 seconds. This control strategy, needed in order to counteract the fast and deep frequency variations, requires definition of a new control layer, specific for faster reactions than the actual primary frequency control. The timeframe can be different for the two frequency control scenarios defined within the project. For the scenario SF_A, the

timeframe can lay from 1 to 5 seconds, whereas for scenario SF_B, the timeframe should be resumed to 1 or 2 seconds (this will be decided later in this project, within Task 2.3 “Linear Swing Dynamic definition”). Architectures likely to be used are both decentralised and distributed control schemes.

2. **Primary frequency control** (mobilization of frequency containment reserve) provides control within a timeframe from 5 to 30 seconds; the exact appropriate timeframe for the two scenarios SF_A and SF_B will be decided later within Task 5.3 “Test-beds for validation of research results”. Additional layers may be added within the primary frequency control reducing the time window available for reaction due to the fast dynamics of the system (this point needs more study in the project). Two architectures for implementing primary control are possible. One is decentralised and the other is distributed. Distributed control can be provided by resources with a slower reaction. The dimensioning of the power reserves in the two primary control options is important and is the factor which enables the decision to be made on whether an energy resource is managed using decentralised or using distributed primary control.
3. **Secondary frequency control** (mobilization of automatic frequency restoration reserve) provides control within a timeframe from 30 seconds up to 15 minutes. Some countries have other definitions of secondary control timeframes. Common timeframes will be needed for deployment of common technical measures internationally. A key factor for improving secondary control is the creation of control loops covering several countries within geographic regions. Secondary control in different countries is currently organised within the country, with the exception of Spain and Portugal which have an organised collaboration for secondary frequency control. Architectures likely to be used to implement secondary control are coordinated control schemes.

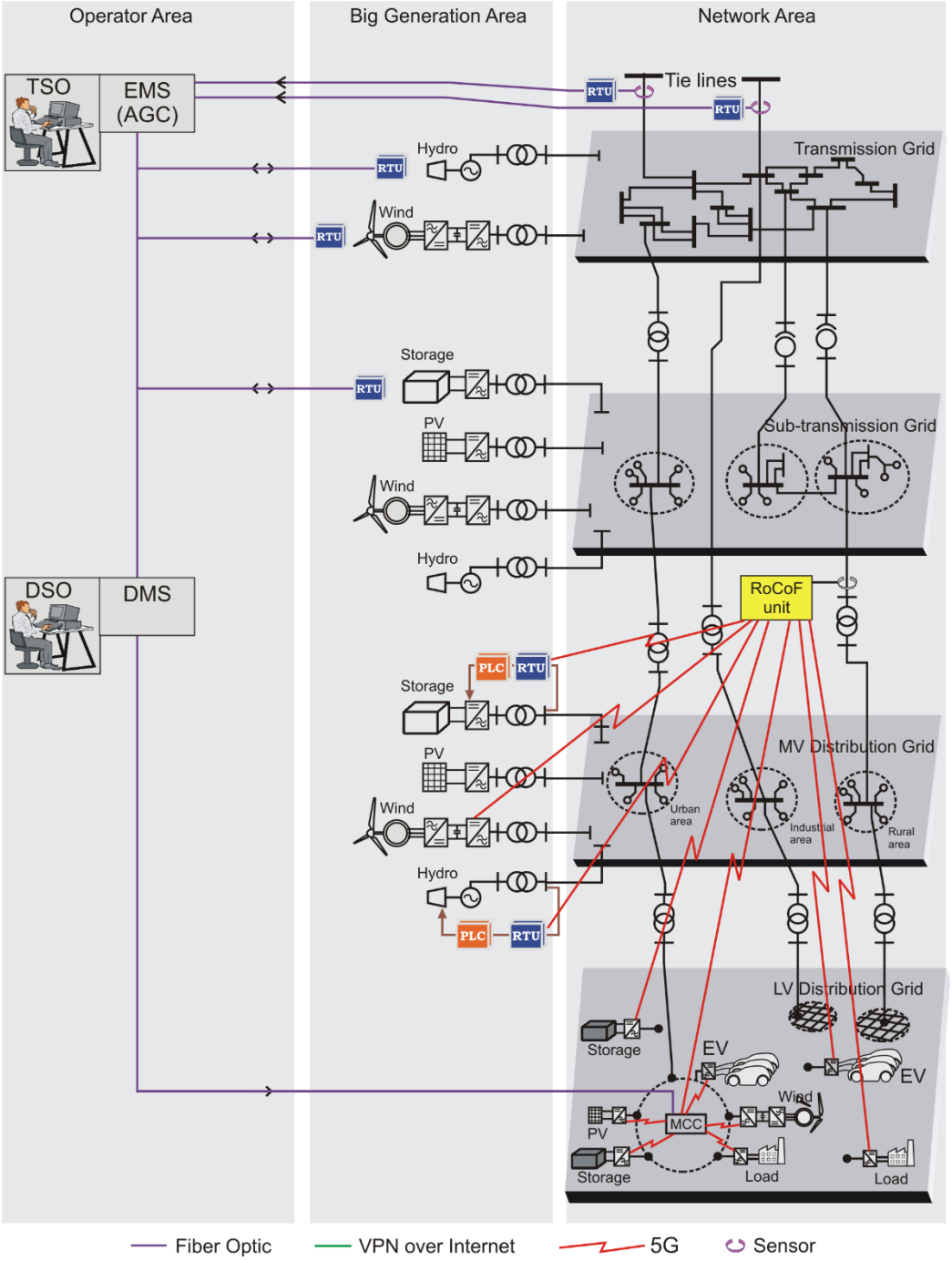

Figure 2.3 General representation of the automatic frequency control levels.

In order to have a clearer view on the frequency control architecture, let us consider the representation from Figure 2.3. The implications of the TSO and the DSO in coordinating or monitoring these control levels have also been explained in Deliverable D1.3. As shown in Figure 2.3, the responsibilities are assigned as follows [37]:

- The *inertial control*: the DSO can be involved if this level is distributed, while in the case of decentralised control, the TSO can be the only entity needed to qualify and monitor it; if the loads are involved, then the Energy Supplier can also be involved.
- The *primary control*: it normally falls within the responsibility of the TDO; however, if RoCoF signal is as control signal, besides the frequency variation signal, a close collaboration between TSO and DSO would be required
- The *secondary control*: this control level is coordinated by the AGC application, located within the Dispatching Centre of the TSO (or ISO), because it requires monitoring the frequency and the power exchanges on the interconnection lines; also if the cross-border

long-distance transmission is envisaged, in a distributed type control, the TSO remains the sole responsible entity.

The various characteristics of the frequency control levels are also presented in Table 2.1.

Table 2.1 . Basic characteristics of the automatic frequency control levels

	Inertial Control	**Primary Control**	**Secondary Control**
Coordination	Decentralized or Distributed	Decentralized	Coordinated
Control signal sent by	Local or regional controller	Local controller	AGC regulator
Purpose	Frequency stabilization	Frequency stabilization	Frequency correction
Time scale	1 to 5 seconds	5 to 30 seconds	30 seconds to minutes
Dependent on Telecommunication Infrastructure	No	No	Yes
Generation units involved	All	All	Qualified units / Balancing Market Merit Order

2.1.4 Providing balancing energy to enable a frequency control strategy

The **provision of balancing energy** is one of the key issues. We expect that in the future, as the classical power plants are decommissioned, it will be very difficult to provide system balancing in the high fluctuating conditions of renewable energy sources. Energy storage such as batteries is a typical example of a technology of the future for balancing energy [28], [35].

Under the current international regulations, in synchronous areas (countries), it is impossible to identify the source of the balancing energy cross-border provided for both primary and secondary frequency control. Current practice still includes mutual agreements, outside of the market rules.

Besides the actual AC Grid, a Su**pergrid is needed to enable the exchange of balancing power over longer distances**. The Supergrid, built by a community of interest, with financial support by the European Union, will be composed of long-distance, multi-terminal HVDC grids in Europe integrated into the AC networks as an energy hub [36].

An **energy hub** is a common connection point of AC network paths. The role of an energy hub can also be taken by HVDC networks, which are seen by the AC network as a simple point-to-point links for energy transfer. This allows the control of the power flows from the generation points to the load points through known paths. Currently, in AC networks, the contractual flows are ensured through multiple parallel flows, according to Kirchhoff's lows. The long-distance HVDC links will facilitate the development of agreements between remote areas to organise balancing power.

2.2 Enabling demand side control to enable frequency regulation

Currently, **demand side control** is not used to control the frequency. The best candidate loads for this purpose are: pump storage hydro units operating in motor mode, electric pumps in agriculture, climate control, electrical heating, lighting, and other non-essential load. The most effective are the first two as they have no social influence [30], [37].

For example, in Romania, demand control could be used in the scenario that **include hydro-electric power**, called SF_A, but today it is not yet used. In Romania, loads can participate in the market but, since 2005 when the balancing market was created, no load was used for balancing. No pump storage hydropower plants exist in Romania. Neither the electric pump used in agriculture can represent a significant candidate for load shading because these were destroyed following a change in the management of agriculture in Romania after 1990.

Smaller sized loads are currently less appropriate for demand side control because of problems with their coordination which require new ICT functionality, including security, to be deployed. Shedding street/highway light could have dangerous consequences for personal safety. However, as the ITC technology advances, and the small consumers are connected to the DSO (and eventually to the Energy Supplier) via the smart meter, climate control and electrical heating devices can be integrated into inertial or primary frequency control schemes. The effectiveness of such control was proven in Appendix D.4 of Deliverable 2.1.

For scenarios **with or without hydro-electric power**, the following applies to **demand side control**:

- Currently, the TSO in Romania hold its systems in closed loops without automatic interaction with external sources. If the TSO will open its systems to smaller loads, it could introduce new security risks (such as the risk that false signals could be injected).
- HVDC links will facilitate using pump storage power plants across European countries for frequency regulation. For efficient share of resources across Europe, multi-terminal systems must be used.
- If demand side control will be introduced in the future, then the corresponding secure communications systems will need to be developed and deployed as a pre-requisite to the operation of this technology. In the full-scale use of this technique, hundreds of thousands of loads or prosumers, some of them eventually being controlled within a micro-grid context, will need to be connected to the upper decision level through robust communication infrastructure. Because the number of loads is very big, a hierarchical communication organization is required. The TSO will not send control signals directly to the small loads/prosumers, but via their energy supplier or the DSO. The TSO sends a the control signal to the DSO/ Energy Supplier controller, which in turn may send signals to the loads/prosumers and to the micro-grid controllers. However, the interfacing with the loads/prosumers is through their smart meter, which in many cases is own by the DSO. For this reason, network grid codes should allocate a more active role to the DSOs to regulate frequency.

Demand side control is undertaken in many countries in LV networks for small loads but it does not provide the reliability required for large scale frequency regulation as described above.

Below, the authors provide an introduction to the options for frequency control at three different levels to transmission grids, and to some extent to distribution grids, at a full-scale commercial level. This is needed as the basis for the RE-SERVE project work on **network codes**, on ICT requirements and on CSR and sustainability issues.

2.3 Control strategies and architectures for frequency control

There are three distinct **architectures** for the automatic frequency control. Each architecture could be employs as appropriate in any of the three of the frequency control schemes described above (Inertial, Primary, and Secondary). They are described as follows.

2.3.1 Centralised control strategy

Centralised control of all RES sources and loads is needed to create awareness of the status of frequency control performances in the system as a whole but has the drawback that it operates in a slower timeframe as it requires communication to a central control centre which computes control orders and returns commands for control. In large networks, **communications latency** is the main latency factor. Communications links need to be installed between all RES sources and their private dispatching centre, which is in turn connected to the control centre of the TSO. Large-scale RES in HV networks are directly connected to the respective TSOs.

2.3.2 Decentralised control strategy

In frequency control, decentralised strategy assumes that no type of coordination exists between control units, as their actions are based on local measurements, while their performances depend on their technical characteristics. This type of control is currently applied in the primary frequency control [31], [32].

For the above mentioned reason, no communications is required in this architecture. However, for security purposes, each RES, each storage device, every prosumer or each VPP or microgrid controller may be connected to the central control room of the DSO in order to monitor their state parameters and provide corrective actions to ensure reliability (all state parameters of the network to be within admissible range). Smart meters could play the role of interface to the inverters of the loads or prosumers. The smart meters are already interfaced with communications to the dispatching centres.

2.3.3 Distributed control strategy

Definition: A distributed system is a model in which components located on networked computers communicate and coordinate their actions by passing messages. (Wiki), as shown in Figure 2.4.

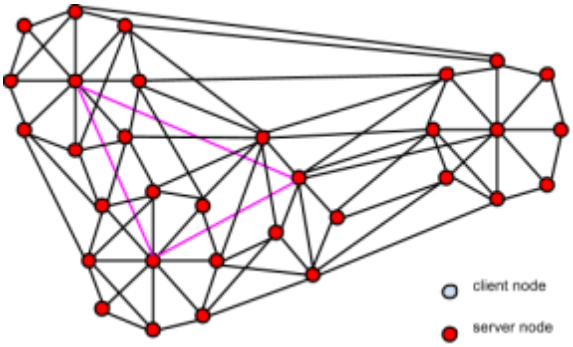

Figure 2.4 Generic representation of a distributed system

All that is needed is for each node to have multiple connections to as many other nodes as possible, and the ability to forward traffic on its way to some destination [40][41].

In a distributed control strategy, the actions of the local controllers are coordinated. An example of a local controller is the frequency divider. **The frequency divider tool needs to estimate the frequency very fast**, the time depends on the how fast depends on the application. Computation faster than the real-time speed is required. The frequency at all points in the network is computed and then **decisions** can be made on changes to make in the network and the appropriate signals are communicated to the individual RES sources or loads in the network. For a scenario in which synchronous generation is available, the algorithm will use either the information on the rotor speed of the synchronous machines or use the PMU measurements from the system. For the scenario of 100% RES without synchronous generation, this algorithm needs to be adjusted. It could potentially use the virtual speed of the connected virtual synchronous machines.

A reaction to RoCoF signals would involve the need for a common signal. This is because RoCoF is not the same all over the power system. Since the biggest problems in terms of RoCoF are created in the case of short-circuits near the generators, followed by loss of generation, the highest RoCoF will be observed at the location of the short-circuit; then, the longer the distance from the short-circuit location, the smaller the RoCoF is. For this reason, the fastest and biggest intervention will be from the sources closest to the short-circuit location. In order to have identical responses with the same RoCoF signal, there is need for **coordination**.

Depending on the control scheme, different communications links will be required. The geographical distances to be covered depend on the scale of the system using the distributed control strategy, which could be applied at TSO level or down to DSO or micro-grid levels. The number of devices (inverters of RES, battery storage, prosumers and microgrids) which need to be connected to DSO and TSO control centres is also variable and influence the choice of the communication channel. The relevant latency is defined by the use of the network architecture for either RoCoF or primary control. This coordination level is not likely to be used for secondary control, as this one is applied at the system level.

A further option for **top-down frequency** control could be to apply the frequency divider in **neighbouring regions** rather than for a whole network at once. Less information is available but the local control has an improved quality as it is based on the average values for the neighbouring regions and offers a good compromise between centralised and distributed control.

The actual primary control is independent and automatic, which means **decentralised** control. However, in the future, mixed signals, consisting of both RoCoF and Δf, can be used in primary control level to allow faster reserve deployment for better frequency stabilization. For this reason, the modified primary control level will require a regional coordination, in a distributed fashion. In order to identify the appropriate generation units for this type of control, a classification of the energy resources in terms of their technical capabilities is required.

2.4 Adopted strategies for frequency control at both TSO and DSO level

2.4.1 New assumptions for frequency control

In this context, we are using RoCoF with respect to a specific timeframe to refer to any type of frequency control or inertial response that happens in less than 5 seconds. As the share of non-synchronous generation increases, the ability to respond instantaneously is correspondingly reduced. In a 100% RES scenario without synchronous generation, storage systems participate in the system frequency regulation by providing virtual inertial. Other sources of balancing energy, for example the provision of virtual inertia from the convertor interfaced wind farms, must be available. The simulations presented in Deliverable D2.2 (Annex D) also who the behaviour of wind and PV plants when integrated to control the frequency based of RoCoF signals.

The measurement of the frequency is quite difficult and needs definition. None of the currently available techniques, such as the PMU or PLL measurements, fulfils all the requirements for a 100% RES scenario in which no synchronous generation at present. We propose a new technique in D2.1 for local frequency estimation, using a mathematical technique encapsulated in the **frequency divider formula**. This formula allows us to estimate frequency at every bus in the network. The signal provided by the formula is “ideal” in that it is free of the numerical issues associated with PMUs.

Data from thousands of devices will be needed. 1 hour of data from a single PMU equals 100 MB, one day of data is Gigabytes; for this information please refer to Deliverable 5.4. At present, Transelectrica stores data for 30 days only due to the volume of data storage required.

If the data would be collected from different PMU types, the data format could be different. A standard is needed which should be encapsulated in network codes for the communication of such data.

2.4.2 Frequency control strategies applied at transmission level

Centralised control. Due to latency issues, fibre-optic communications over long-distances is the only option. Links to RES sources within less than 1 km distance between each other or connections to fibre networks could be made with 5G mobile low latency communications. The latency may be so high that it is better to use a decentralised system as described below.

Decentralised control. It requires no remote communication as it is based on local metering and signal processing. For this reason it is a very fast control, and the reaction time depends of the technical characteristics of the generation unit. If economically feasible and necessary for the power system, any generation unit, located in both transmission and distribution networks, can use this type of control.

Distributed control: Communications links within a geographically limited region, i.e. distances of tens of kilometres and not hundreds of kilometres, are needed and computational power to run the frequency divider is needed. 5G low latency communications may be an option if the distances to be covered are within the order of magnitude of kilometres. For longer distances, station-to-station communication through the glass-fibre infrastructure of the DSO or TSO should be used.

2.4.3 Frequency control strategies applied at the distribution level

The ICT requirements are in common with the MV/LV networks. Because of the regional characteristics, distributed control could be an option.

In MV/LV distribution networks, where up to tens of kilometres are the maximum order of magnitude of distances, 5G communication can be successfully employed to reach to the many small sized RES units, storage and demand-side loads. The number of devices to be connected is of the order of magnitude of hundreds of thousands of end points. This communication links to all end points. The DSOs does not hold secure and fast (specific to the inertial control) wire communication in the LV distribution networks. At this time, power line communication is prohibitively expensive and unreliable to be employed. Only private Ethernet infrastructure exist [29], [33].

A regional controller with power data concentrator (PDC) needs to be installed to communicate with the small sized generation units and demand-side loads via 5G. For computation, local edge processing at the base station could be used to run the frequency divider. Network slicing could be used to ensure appropriate control of quality of service for the communications links and to enforce a strong security policy.

In MV networks, the glass-fibre infrastructure of the DSO can be also used for communication between the frequency divider device and the RES units.

2.4.4 General requirements of the introduction of new frequency control techniques

The needs of new frequency control strategies for 100% RES scenarios (including centralised, decentralised, and distributed control at all levels **including inertial, primary and secondary frequency control**) include:

- Collaborative forecasting of both load and generation is needed. New communications and new systems are needed in dispatching centres so that they can perform the forecasting. At present, a range of forecasting methods are used creating a diversity of values, which are then averaged to provide forecasts. The dispatching centres will need to work closely with meteorology institutes to coordinate the production of forecasts. New contracts will be needed to cover the new commercial conditions.
- Example: on 3 July 2017, a huge increase of 1000 MW occurred in Romania, and it had not been forecasted – such situations should be avoided in the future (please see Appendix B).
- The Forecasting obligations could be expressed as policies in new network codes or NORMs.
- Local network security in the sense of reliability – local conditions may depend on the meteorological conditions such as temperature and wind speeds. A uniform geographical distribution of power sources for primary frequency control is needed to increase the reliability of the system.
- Example: 10 small energy sources provide more reliability than one big source. Under market conditions, distributed resources increase reliability.
- The reference frequency for all synchronous power systems from the Continental Europe of ENTSO-E is set in the Laufenburg centre in Switzerland. A Pan-European supervision of the frequency in Europe would be required for historical observation in order to determine the RES influence on the frequency dynamics. ENTSO-E will need to monitor the dynamics of the entire system.
- Recently a Wide Area Measurement system was created in the Laufenburg centre (https://www.swissgrid.ch/swissgrid/en/home/reliability/wam.html). The frequency is not the same throughout the network as can be seen on the referenced web site. Monitoring of the frequencies by such a system is needed for wide area monitoring and control at the level of continental Europe. Currently, 9 PMUs from 8 ENTSO-E countries are integrated to monitor the frequency into a Wide Area Measurement System. 5 additional PMUs are planned for integration in the near future. The PMUs only are used because they attach the time stamp to the data. The data collected is sent to the centre in Switzerland and the data display is synchronised. Other systems in current use do not synchronise the data in this way (e.g. current SCADA systems). In this context, new recommendations or ICT codes for power system could be required.
- There is thus a need for new network codes to harmonize the technology employed in various power system for faster and effective correlation of the data.

2.5 The ICT requirements of introducing new techniques for frequency control

As we introduce new frequency control techniques, requirements for new communications systems, new generations of inverters and energy control systems are required

2.5.1 The Communications requirements of the new techniques

- The **volume of data** to be transmitted from the individual inverters to the SSAU is large (one hour of data from a PMU is 100 MB as an example of the volume of a simple device. More complex devices will generate larger volumes of data).
- The **latency** of the communications link is critical. Single measurements should be received within less than one second by the SSAU.
- **Ensuring System and Data security** is a critical requirement. Cyber-attacks on systems could have very serious consequence for power supplies. As a result, many power suppliers are reluctant to open their communications networks to enable the use of the needed techniques as we move towards 100% RES.
- **Data integrity** is critical. The importance receiving the messages as sent is high. The impact on the frequency stability of receiving incorrect data, due to wilful manipulation of the data, or to faults, would be high, potentially destabilising the power network and leading to blackout situations or fluctuations in the voltage.
- The **privacy of consumer data** from units in the distribution network has to be adequately protected.

2.5.2 Communication ports in inverters

The devices to be connected would need **communication ports** – this refers to the inverters in households, as well as for large loads such as factories, as they all need a connection to the energy management systems. These connections would need to be regulated by standards providing a common format for data interfaces and command structures. These common formats would be described in **Network codes or NORMs** which need to be adopted internationally.

Consequently, the manufacturers of devices and energy control systems need to adapt their products to conform to the new NORMs and network codes. In the next step, the **new generation of equipme**nt needs to be deployed in the power networks. After that, the **communications** equipment needs to be installed and connected. These are pre-conditions to the use of the new inertial control. Once the RoCoF measurements can be used, the potential to develop local markets for frequency control can be exploited.

2.5.3 The ICT consequences of introducing a new generation of invertors

Assuming such standards are put in place, new inverters (with communication ports) will be introduced to the market, RE-SERVE is investigating and defining the ICT functionality required to connect the controllers of the inverters to RTU (remote terminal unit) and PLC (programmable logic controller). In an advanced automation solution, they could be connected to an SSAU because the P-Q operating point of the inverter may need to meet some technical requirements.

The DSO will monitor the invertors for electrical network operation purposes, while the Energy Service Provider (generation units, prosumer, controllable load, aggregator or micro-grid) is intended to schedule the inverter control for providing energy services.

For both DSOs and Energy Service Provider (ESP), the following requirements may apply:

- The **number of new inverters** (with new controller software) that would need to be connected to the SSAUs is potentially very high – a typical household might have one inverter each and a distribution network would have hundreds of thousands of households. The number of inverters in the power system is equal to the number of power sources (PV panels, (not wind because it is not efficient at LV), EV's, batteries) and inverter connected load (DC load, air conditioning, lighting).
- The economic viability of using power line communication or other fixed line communications to the inverters is likely to be low. Wireless solutions are likely to be the most favourable option to connect the many new end points for communication. In urban areas, underground power cables may be used and a separate infrastructure is likely to be used for communications for economic reasons).

- The **inverters need an IP address** (as defined in IEC 61850) so that the SSAU nodes know which inverters are connected to it. The inverters are stationary. For frequency control, the location mapping of the devices in small scale systems is not important. In large scale systems, the physical location of the devices could be important for the distributed control or other control services. A common device would be used for both voltage and frequency control.

For Energy Service Provider, the following additional requirement applies:

- The **Energy Service Providers** are likely to need their own be-spoke connection to the inverters they control independent of other links from the same inverter to a neighbourhood DSO. This creates a need for secure, private communications network for aggregators.

RE-SERVE plans to undertake proof of concept studies using 4G- and 5G-based ICT hardware in the loop for simulations to investigate the performance of the latest mobile communication systems in supporting this scenario. We anticipate starting such simulations in the first half of 2018, within the Work Package 4. A preliminary description of the technical characteristics have been provided in Deliverable 4.5.

2.5.4 The ICT consequence of introducing a range of new energy control systems for larger loads

The energy control systems need to be adapted so that they have communications interfaces supporting the needed new network codes enabling frequency control schemes are described above.

2.6 The network codes and ancillary services implications of the new techniques

Based on the preliminary analysis on frequency control procedures to be developed and technology required, a set of additional codes are identified and summarized.

- **New Network Codes or NORMS** have to be developed and are needed to provide a common data format and command structure for implementation in the new devices and energy control systems.
- Adequate **security system** needs to be defined and implemented in the automation/control systems of the network. Security policies could be part of network codes or NORMS.
- The privacy of the **personal data** associated with loads needs to be protected via adequate policies encapsulated in network codes and implemented in systems.
- The **QoS of the energy services** needs to be assured. The compliance of the individual RES sources and power plants to the control signals sent by the TSO needs to be monitored. The QoS monitoring policies could be part of new network codes or NORMs.
- **Collaborative forecasting** of both load and generation is needed. New communications and new systems are needed in dispatching centres so that they can perform the forecasting. At present, a range of forecasting methods are used by owners of wind and PV power plants creating a diversity of values, which are then averaged to provide forecasts. The dispatching centres will need to work closely metrology institutes to improve the production of forecasts. New contracts will be needed to cover the new commercial conditions. (e.g. on 3 July, a big increase of 1000 MW happened in Romania and it had not been forecasted – such situations should be avoided in the future). The forecasting obligations could be expressed as policies in new network codes or NORMs.
- A **new standard for RoCoF computation** is needed as none exists at present. This would be encapsulated in a **new network code**. It means that **a new generation of PMUs** is needed which implements the new policies expressed in the network codes.
- New proposals for the **HVDC grid codes** will need to be developed to take frequency control needs into account.

2.7 Sustainability issues of the new techniques

Business relationships will change. Prosumers can play a more active role in energy markets through enabling control of their devices and energy systems for the control of frequency. Business opportunities for **larger load owners** should be better emphasized in the market codes to attract them participate in frequency control procedures. For example, a shopping centre of an offices building would not be connected through invertors but would receive direct signals to change power generation or consumption. This could be done through access to their thermostats or better, to their energy management systems.

New markets for frequency control would be very likely to emerge. Markets for frequency containment reserve (primary control) are about to be created in all ENTSO-E power systems to appropriately remunerate the service provided. These markets need eventually to be correlated for cross-border service provision. The use of RoCoF measurements and inclusion of the controllable loads in the frequency control procedures, eventually in a distributed control, will be the grounds for a new form of power market. While currently secondary and tertiary frequency controls are provided by large synchronous generators, in the future, as such generation units will be decommissioned, new schemes to aggregate inverter based small loads shall be encapsulated in the future network codes.

New **collaboration models between the TSOs and DSOs** will be needed so that DSO can support the provision of ancillary services for frequency control. The collaboration models will be encapsulated in policies standardised as Network Codes and Ancillary Service definitions.

For **primary reserves, ENTSO-E** will create a market for the acquisition of reserves. This creates a probability that reserves will be concentrated geographically because of the lower price. If the lowest price reserve always wins, geographic concentration is likely to result and this has a negative effect on the reliability of the system.

For **secondary frequency control and reserves**, inter-TSO trading should be allowed to share the available resources (such as hydro-electric power).

Aggregators could play a role, if regulators permit, in providing flexibility to counteract the intermittent generation of RES sources by aggregating the capacity of households and loads and providing it to markets. Aggregators could operate at the secondary control level. They could operate at system level with distances of thousands of kilometres between sources.

New collaboration models, contractual relationships (between traders, dispatching centres, power plant owners and aggregators) and tools **for forecasting** will emerge.

3. Concluding remarks

Following the different statements and observations, the following items are proposed for further analysis in the view of creating new network codes or adapted ones:

i. Two types of control procedures are currently defined: the centralized control specific to the primary frequency control, and the decentralized 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 centralization of the control actions within a regional network, including both generation sources and loads.

ii. The **network codes does not clearly explain the purpose of the DSO in the future frequency control procedures**. The DSO is the entity that have access to all meters (for both generation units and loads). It may be responsible for monitoring the operation of small sized units located in the distribution networks as related to the available reserve.

iii. The **Virtual Power Plants** and the **Microgrids** will play an active role in the secondary frequency control. Both concepts can be **classified as aggregators**. The Virtual Power Plants is a coordinated group of generation units and loads located in different parts of the national network. The Microgrid is a coordinated group of generation units and loads located in the same local network. Both types of aggregators **require standardization** of the operation in relation to the network operator in the grid cods, such as: **communication type**; **reserve monitoring**; **QoS monitoring**.

iv. **Harmonization of the remuneration rules for FCR across all ENTSO-E countries** in the Continental Europe is required. This is because it is hard to identify origin of the service provided from abroad. The principle of the in interconnected power systems is the inter-support in case of emergency situations. A survey has been conducted by ENTSO-E to identify all market aspects of the FCR and aFRR [49].

v. Under 100% RES, which means that no fossil fuel power plant is in operation, the actual procedures for primary and secondary frequency control may not be valid. This includes the classification done in the RfG, on the four types of generators (A, B, C, and D**). Consideration of the storage** (other than pumped storage) when providing frequency regulation services **should be carefully treated**.

vi. If the RfG document refers to both TSO and DSO, then the prosumer is neglected. **Specifications related to prosumers shall be introduced** in the grid codes.

vii. Currently, ENTSO-E recommends calculation of the FCR based on statistical data only [50]**Error! Reference source not found.**. Under 100% RES, it should be based on d ynamic simulations under various scenarios. These scenarios should be standardized into specific procedures. For this purpose, **a common complete database of the ENTSO-E system should be available for all system operators**.

viii. A Wide Area Measurement system is being developed at Laufenburg, in Switzerland [https://www.swissgrid.ch/swissgrid/en/home/reliability/wam.html]. It collects frequency data from various PMUs from CE and displays them on-line. More PMUs will be included in the platform. It is more important to develop Wide Area Monitoring focusing on angle oscillations across power systems to identify dangerous power flow oscillations. **Standardization of the PMU characteristics and the monitoring aspect should be include in a special recommendation report of ENTSO-E**.

ix. In the 100% RES, special circumstances from EU must be assigned to the hydro power plants in order to allow maintaining a higher inertia in operation. Some recommendations must be provided for other generation units of loads, with mechanical inertia. For the power system operator, **recommended practice for maintaining mechanical inertia into the system is advisable**.

x. Recommendation regarding the **coordination between inverters characteristics for frequency control and droop values** is advisable. This is important **to achieve coherency** into the interconnected power system.

xi. **Standardized operation** characteristics should be provided **for those units that respond to both inertial and primary control**. This is important because the two actions are linked in time, and the power provided as frequency control service is **set by the same controller**.

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5. List of Abbreviations

ACE Area Control Error
AC Alternative Current
aFRR automatic Frequency Restoration Reserve
AGC Automatic Generation Control
AFC Automatic Frequency Restoration
ARC Automatic Resources Control
BESS Battery Energy Storage System
CSR Corporate Social Responsibility
DC Direct Current
DER Distributed Energy Resources
DSO Distribution System Operator
EMS Decentralized energy management system
ENTSO-E European Network of Transmission System Operators for Electricity
ESO European Standardisation Organisations
FAT Full Activation Time
FCR Frequency Containment Reserve
aFRR automatic Frequency Restoration Reserve
FSM Frequency Sensitive Mode
HV High Voltage
HVDC High Voltage Direct Current
LFC Load-Frequency Controller
LFSM-U Limited frequency sensitive mode-underfrequency
LFSM-O Limited frequency sensitive mode-overfrequency
LV Low Voltage
ICT Information and Communication Technology
IEC International Electro-technical Commission
ISO Independent System Operator
NIST National Institute of Standards and Technology
mFRR manual Frequency Restoration Reserve
PDC Power Data Concentrator
PMU Phasor Measurement Unit
PLL Phase Locked Loop
PV Photovoltaic
RES Renewable Energy Sources
RoCoF Rate of Change of Frequency
SCADA Supervisory Control and Data Acquisition
SDH Synchronous Digital Hierarchy
SSAU Substation Automation Unit
SRB Secondary Regulation Band
TSO Transmission System Operator
UCTE Union for the Coordination of the Transmission of Electricity
VPP Virtual Power Plant

Annexes

Annex A Review of the frequency control procedures

A.1 Introduction

In order to maintain the power system frequency to a fixed value and equal to the nominal frequency, it is necessary that the total generated active power be equal to the total consumed active power at every instant of time. In reality, the balance between generation and load is permanently perturbed by load variations, by the imprecision of real time generation control or occasionally by the unscheduled / scheduled disconnection of a generator, a transmission line, etc. [8] The increase in the total generation to a value greater than the total load, including the exports / imports, causes a frequency increase above the nominal value, while a total generated active power smaller than the total load causes the frequency to decrease below the nominal value. The frequency variations denote a rapid process so that its correction requires high performances for generators. The power system perturbations leading to frequency variations occur at very short time intervals and therefore corrective actions for power balancing have to be taken continuously. Interconnected operation of power system represents an advantage regarding frequency control since the frequency variations are directly influenced by the power imbalance and the instantaneous load. Thus, the bigger the instantaneous generation / load is with respect to the produced imbalance, the smaller is the frequency variation. On the other hand, due to the physical laws that govern the current flow, any powers imbalance in a system has immediate consequence on the power flows on the interconnection lines. For this reason, besides frequency measurement, the frequency control involves power flow measurement on the interconnection lines.

A major imbalance involves the immediate response of a large number of devices and control systems within the interconnected power system while a minor imbalance could involve no response since the control systems are tuned to act only if the perturbation created a frequency variation greater than a certain value. Therefore, operation under power imbalances makes power system more vulnerable to contingencies.

In a synchronously interconnected power system, the frequency presents two main characteristics [7]:

- **uniformity**: in power systems based mainly on mechanical inertia, all generators swing together, in synchronism, at any instant, which makes the frequency be identical in all parts of the power system; however, while the classical power plants are replaced by inverter based generation units, this definition is no longer valid, leading to the need for a new definition, i.e.
- **coherency**: all generation units in the power system must be correlated in such a way that produced a synchronized voltage waveform.
- **quasi-stability**: the frequency must be maintained around the nominal value (50 Hz in Europe or 60 Hz in USA, Canada, etc.) because the power system components are designed to operate optimally at this value. Regarding the generating units, they are equipped with protection systems that disconnect them from the power grid to frequency deviations (Fig. A.1) that would lead to loss of synchronism of the others generators connected to the grid. On the other hand, maintaining the frequency to the nominal value is also important for the consumers. Their operation at a frequency different by the nominal value leads to productivity decrease, equipment ageing, erroneous operation of some electrical devices based on time measurement, misoperation of some protection systems, etc.

Since the frequency is a quantity characterizing the whole power system, its control falls within the responsibility of the system operator. The frequency is an inertial quantity, and an accurate control of it assumes its real time monitoring as well as of the power flow on the interconnection lines. Balancing between generation and load requires continuous availability of some power reserves that can be (un)loaded in due time. These reserves involves some costs, and for their minimization, taking into consideration the need for assurance of an appropriate security level of the system, within particular control areas, the system operator should formulate an optimization problem of a multi-objective function.

For short term planning / dispatching (usually one day ahead the dispatching day) the system operation performs load forecast calculations. These calculations are based on information regarding consumption, including export / import, from previous similar periods as well as information that could influence the load in the dispatching day, such as weather conditions (temperature, nebulosity, etc.). Performing the load forecast means tracking a theoretical load curve by the system operator (Figure A.2), usually on hourly intervals (in some cases of 30 minutes). Obtaining the smallest errors of the load forecast helps the operators to predict the requirements for each type and corresponding quantity of the power reserves, which will contribute to the minimization of costs.

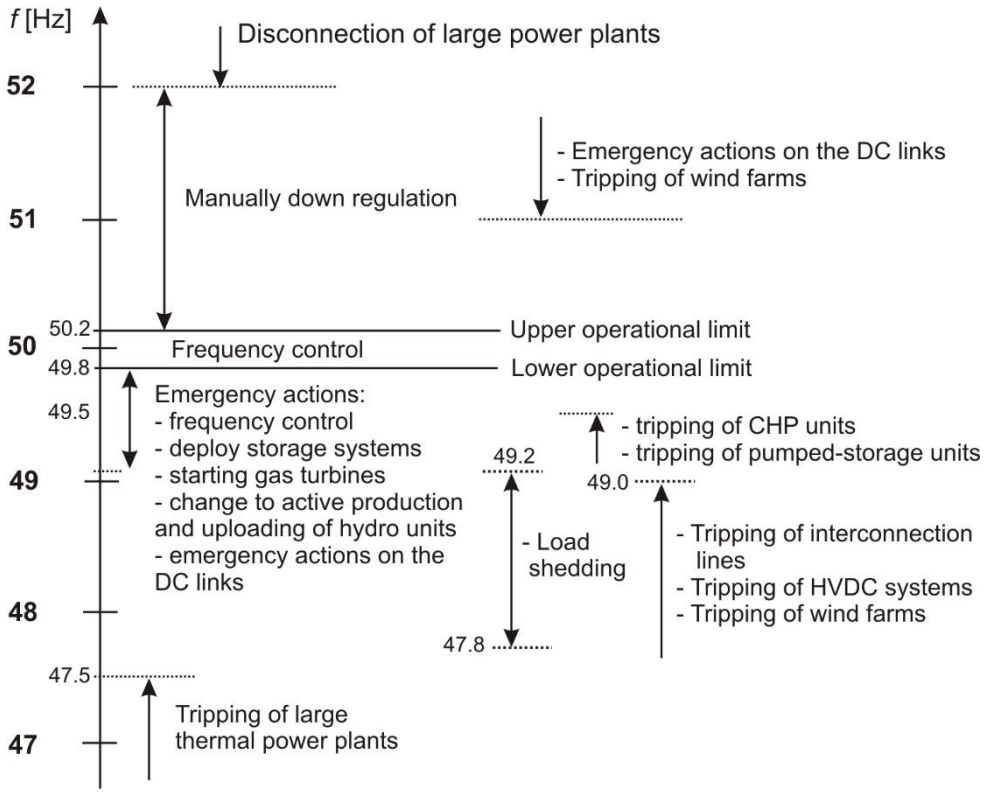


Figure A.1. Tripping thresholds to frequency variations [17][26][42][43].

Figure A.2 illustrates for comparative purposes the notified powers curve, the forecasted load curve made by the system operator and the real load curve. The notified powers curve is obtained by summing up the power amounts resulted from bilateral contracts, within a specific market or within the portfolio of a balance responsible party, as well as on the day ahead market of energy.

The smaller the difference between the notified powers curve and the real load curve is, the smaller is the power reserves amount necessary for (un)loading as ancillary service. However, obtaining a notified powers curve with small errors depends on the power markets flexibility and on the load forecast made by the balance responsible parties.

The real load consumption trend is one that can be predicted, the load curve having every day almost the same shape, excepting the holidays and special events (sportive, artistic, etc.). Analysing the load curve from Figure A.2 it can be seen that it presents two maximum values, the morning peak and the evening peak, as well as two minimum values, the night valley and the day valley. Based on the load evolution during a day, the operators can optimally use, economic and technical efficient, the power reserves in the balancing process. Therefore, during ascendant periods of the load curve the system operator will call upon generators to increase their generated power, while during descendant periods the generators are used to reduce their generated power.

The load curve shape is a reference for the system operators in establishing the generators dispatching strategy. This strategy is very important for the frequency control efficiency since the availability of high performance generators can, sometimes, be low.

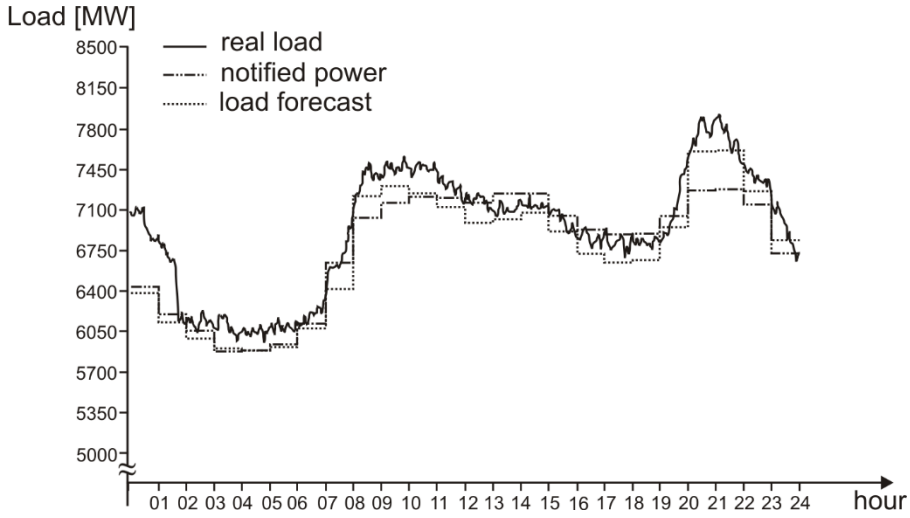


Figure A.2. Load curve of a particular power system.

The nuclear power plants that, for security reasons, do not support shut-downs, start-ups or power variations so as some thermal power plants, especially the ones running in cogeneration, which are continuously used to cover the base load. There are some periods of the load curve presenting sharp slopes, the two peaks, respectively, which, for technical and economic reasons, can be covered only by fast acting generators. The most appropriate generating units for peak regulation are the hydro power plants and the turbojet power plants. Establishing a strategy for the efficient use of the generating units will encourage the efficient use of the frequency control and minimization of the operating costs.

Other important issue that should be analyzed is the random behaviour of the load, experienced by the systems as rapid fluctuations. These fluctuations are corrected by means of speed governors or automatic generation control.

A.2 Network codes

Since the frequency control requires active participation of all synchronously interconnected power systems, harmonized network codes have been adopted at the European Union level. The entity that unify the Transmission and System Operators is ENTSO-E (European Network of Transmission System Operators for Electricity) [44]. The network codes are divided into three categories:

- Requirements for connection to the electrical network [17][45][43]
- Requirements for system operation [46]
- Market rules [47][48]

These codes have been adopted or will be adopted in national legislation. The first steps in the harmonization of the network codes was the adoption of the requirements for connection to the electrical network of the loads, generators, and HVDC systems. In August 2017, the EU Commission regulation on System Operation. It lays the ground for the next power system and for example makes regional coordination a legal obligation for grid operators.

The “Emergency and Restoration” and “Electricity Balancing” are currently under discussion.

Following the increased penetration of renewable energy sources and the distributed generation, a classification of the generation units was done into four types of generation units, called **power-generating modules**. They are classified as follows:

a) connection point below 110 kV and maximum capacity of 0.8 kW or more (type A);
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 paragraph 3 (type B).

This threshold shall not be above the limits for type B power-generating modules contained in **Table** A.1;

c) connection point below 110 kV and maximum capacity at or above a threshold specified by each relevant TSO in accordance with paragraph 3 (type C). This threshold shall not be above the limits for type C power-generating modules contained in **Table** A.1;

d) connection point at 110 kV or above (type D). 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 with paragraph 3. This threshold shall not be above the limit for type D power-generating modules contained in **Table** A.1.

Table A.1 . Limits for thresholds for type B, C and D power-generating modules

Synchronous areas	Limit for maximum capacity threshold from which a power-generating module is of type B	Limit for maximum capacity threshold from which a power-generating module is of type C	Limit for maximum capacity threshold from which a power-generating module is of 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

The frequency related characteristics of the four types of power-generating modules are presented as follows.

Table A.2. Frequency related network connection of power-generating units [17]

		Type A	**Type B**	**Type C**	**Type D**
Requirements relating to frequency stability	With regard to frequency ranges	• A power-generating module shall be capable of remaining connected to the network and operate within the frequency ranges and time periods specified in Table A.3 [17]. • The relevant system operator, in coordination with the relevant TSO, and the power-generating facility owner may agree on wider frequency ranges, longer minimum times for operation or specific requirements for combined frequency and voltage deviations to ensure the best use of the technical capabilities of a power- generating module, if it is required to preserve or to restore system security; • The power-generating facility owner shall not unreasonably withhold consent to apply wider frequency ranges or longer minimum times for operation, taking account of their economic and technical feasibility.			
	With regard to the rate of change of frequency withstand capability,	A power-generating module shall be capable of staying connected to the network and operate at rates of change of frequency up to a value specified by the relevant TSO, unless disconnection was triggered by rate-of-change-of-frequency-type loss of mains protection. The relevant system operator, in coordination with the relevant TSO, shall specify this rate-of-change-of-frequency-type loss of mains protection.			

		Type A	Type B	Type C	Type D
Requirements relating 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	-	
		-	The relevant system operator shall have the right to specify the requirements for further equipment to allow active power output to be remotely operated.	-	
		-		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.	
		-		Manual local measures shall be allowed in cases where the automatic remote control devices are out of service.	
	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 %.	
		-		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;	

		Type A	Type B	Type C	Type D
		-		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;	
	The following shall apply cumulatively when frequency sensitive mode ('FSM') is operating:	-		The power-generating module shall be capable of providing active power frequency response in accordance with the parameters specified by each relevant TSO within the ranges shown in Table A.4. In specifying those parameters, the relevant TSO shall take account of the following facts: • in the case of overfrequency, the active power frequency response is limited by the minimum regulating level • in the case of underfrequency, the active power frequency response is limited by maximum capacity, • the actual delivery of active power frequency response depends on the operating and ambient conditions of the power-generating module when this response is triggered, in particular limitations on operation near maximum capacity at low frequencies	
		-		The frequency response deadband of frequency deviation and droop must be able to be reselected repeatedly;	

		Type A	Type B	Type C	Type D
		-		In the event of a frequency step change, the power-generating module shall be capable of activating full active power frequency response, at or above the full line shown in Figure A.3 in accordance with the parameters specified by each TSO (which shall aim at avoiding active power oscillations for the power-generating module) within the ranges given in Table A.5. The combination of choice of the parameters specified by the TSO shall take possible technology-dependent limitations into account;	
		-		The initial activation of active power frequency response required shall not be unduly delayed.	
		-		The power-generating module shall be capable of providing full active power frequency response for a period of between 15 and 30 minutes as specified by the relevant TSO. In specifying the period, the TSO shall have regard to active power headroom and primary energy source of the power-generating module;	
		-		Within the time limits laid down in point (v) of paragraph 2(d) of [17], active power control must not have any adverse impact on the active power frequency response of power-generating modules;	
		-		The parameters specified by the relevant TSO in accordance with the above points shall be notified to the relevant regulatory authority. The modalities of that notification shall be specified in accordance with the applicable national regulatory framework;	

		Type A	Type B	Type C	Type D
Requirements relating to frequency stability	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;	
Requirements relating to frequency stability		-		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.	
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 A.4 at a frequency threshold and droop settings specified by the relevant TSO;			

	Type A	Type B	Type C	Type D
	Instead of the capability referred to in the first paragraph, 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	-		
	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 maintaining constant output at its target active power value regardless of changes in frequency			
	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 A.5: • below 49 Hz falling by a reduction rate of 2% of the maximum capacity at 50 Hz per 1 Hz frequency drop; • below 49,5 Hz falling by a reduction rate of 10% of the maximum capacity at 50 Hz per 1 Hz frequency drop.			
	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: • frequency ranges within which an automatic connection is admissible, and a corresponding delay time; • maximum admissible gradient of increase in active power output.			-

Table A.3 . Minimum time periods for which a power-generating module has to be capable of operating on different frequencies, deviating from a nominal value, without disconnecting from the network [17]

*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

Table A.4. Parameters for active power frequency response in frequency sensitive mode [17]

Parameters		Ranges
Active power range related to maximum capacity $\frac{\Delta P_1}{P_{max}}$		1,5-10 %
Frequency response insensitivity	$\lvert \Delta f_i \rvert$	10-30 mHz
	$\frac{\lvert \Delta f_i \rvert}{f_n}$	0,02-0,06 %
Frequency response deadband		0-500 mHz
Droop *s*		2-12 %

Table A.5. Parameters for full activation of active power frequency response resulting from frequency step change [17]

Parameters	Ranges or values
Active power range related to maximum capacity (frequency response range) $\frac{\Delta P_1}{P_{max}}$	1,5-10 %
For power-generating modules with inertia, the maximum admissible initial delay t^*	2 seconds
For power-generating modules without inertia, the maximum admissible initial delay t^*	as specified by the relevant TSO.
Maximum admissible choice of full activation time t_2, unless longer activation times are allowed by the relevant TSO for reasons of system stability	30 seconds

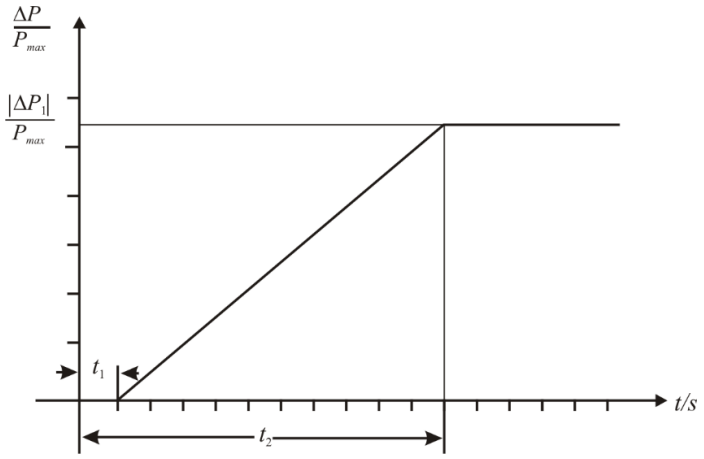


Figure A.3. Requirements grid connection regarding the active power frequency response capability Pmax [17].

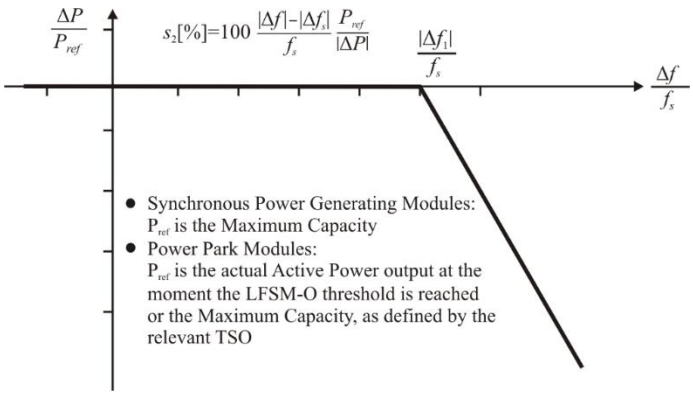


Figure A.4. Active power frequency response capability of power-generating modules in limited frequency sensitive mode – overfrequency [17].

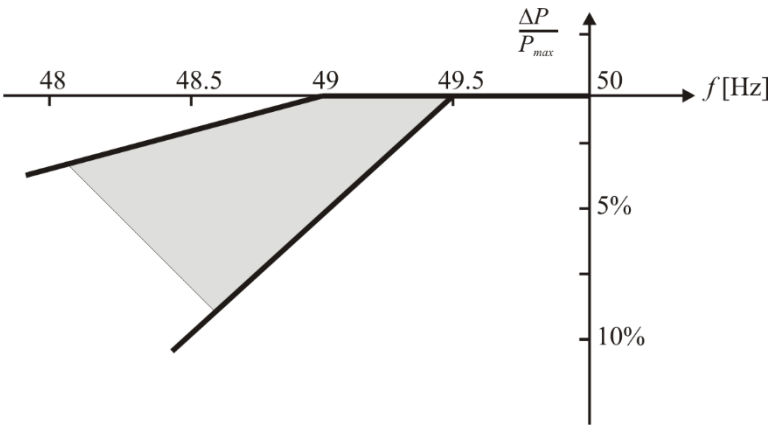


Figure A.5. Maximum power capability reduction with falling frequency [17].

A.3 Frequency control procedures

A.3.1 Hierarchical frequency control

The frequency control is a process performed by hierarchical or semi-hierarchical coordination, in time, of the regulation resources. This section presents a general overview on the utilization, coordinated or non-coordinated, automatic or manually, of the active power reserves when the frequency is subjected to variations caused by imbalances between generation and load [34].

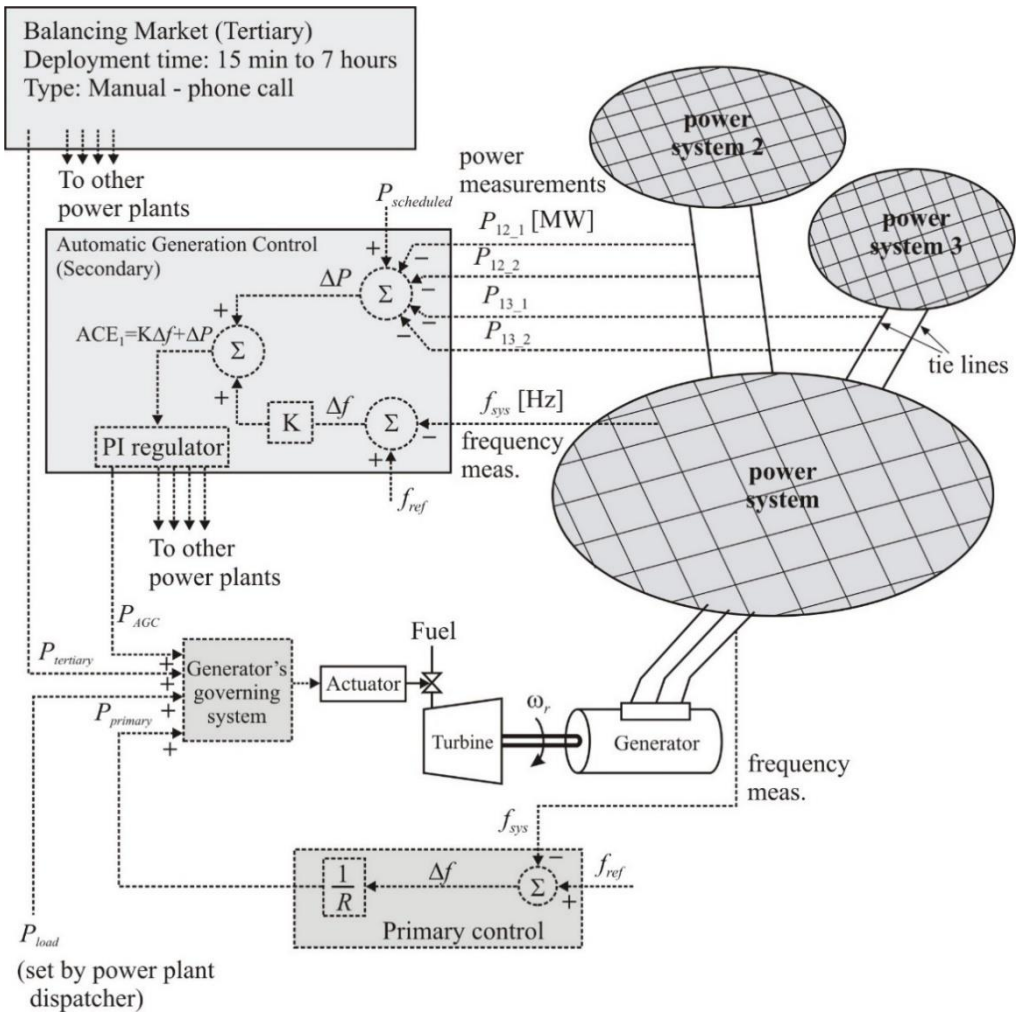


Figure A.6. The hierarchical frequency control scheme.

The terminology in the field of frequency control is reach in definitions in various countries, but they are often referring to the same procedures or functions. There are, however, some differences that are given by several peculiarities of the power systems, especially in geographically isolated countries or regions. The frequency control is performed mainly on three levels, that is: primary level (frequency containment), secondary level (automatic frequency restoration), and tertiary level (Figure A.6).

Figure A.6 illustrates the active power signals received by a classical generator from different frequency control levels, depending also on the frequency control service for which it is qualified. The active power produced by a generator consists of a load signal, P_{load}, which is the unit commitment of the owner, and the power signals resulted from participation to network ancillary services. Therefore, the generator, or more generally the energy resources, changes the power production slower or faster as a response to the frequency variations, by automatic or manual signal orders.

The interconnected operation assumes common support from all generators of a power system. For this reason, the policy for frequency control in the related interconnected areas contains common rules. These rules define the technical characteristics for operation of all energy resources connected to the grid and for the national automatic generation control (AGC).

There are mainly three types of power reserves defined in ENTSO-E that are deployed within various levels of the frequency control process: primary reserve (containment reserve), secondary reserve (restoration reserve) and tertiary reserve. Table A.6 shows a brief characterization of the three frequency control levels.

Table A.6. Characteristics of the three frequency control levels [11].

	Primary Control	***Secondary Control***	***Tertiary Control***
***Why** is this control used?*	To stabilize the frequency in case of any imbalance	To restore the frequency and the interchange programs to their target	To restore the secondary control reserve, to manage eventual congestions, and to bring back the frequency and the interchange programs to their target if the secondary control reserve is not sufficient
***How** is this control achieved?*	Automatically		Manually
***Where** is this control performed?*	Locally	Centrally (TSO)	
***Who** sends the control signal to the source of reserve?*	Local sensor	TSO	Gencos, Consumers or other TSOs (after receiving instructions from the TSO)
***When** is this control activated?*	Immediately	Immediately (seconds)	Depends on the system
***What** sources of reserves can be used?*	Depends on the system: partially loaded units, loads, fast/slow starting units, changes in exchange programs		

A.3.2 Primary frequency control / Frequency containment

Primary reserve, called also frequency containment reserve, is deployed automatically and independent, within the primary control level by the speed governor action in the immediate period succeeding some high and rapid frequency variations caused by the occurrence of a contingency or some imbalances between generation and load. The aim of the frequency control level is to stabilize the frequency around a quasi-steady state value, after a frequency variation greater than a predefined threshold. A sudden perturbation occurring within the ENTSO-E interconnected system will trigger all speed governors from all control areas affected by the perturbation according to their participation factor.

Frequency Response is provided by [1]:

Governor Action: Governors on generators are similar to cruise control on your car. They sense a change in speed and adjust the energy input into the generators' prime mover.

Load: The speed of motors in an Interconnection change in direct proportion to frequency. As frequency drops, motors will turn slower and draw less energy. Rapid reduction of system load may also be effected by automatic operation of under-frequency relays which interrupt pre-defined loads within fractions of seconds or within seconds of frequency reaching a predetermined value. Such reduction of load may be contractually represented as interruptible load or may be provided in the form of resources procured as reliability (or Ancillary) services. As a safety net, percentages of firm load may be dropped by under-frequency load shedding programs to ensure stabilization of the systems under severe disturbance scenarios. These load characteristics assist in stabilizing frequency following a disturbance.

The electromechanical model of a synchronous generator

When a disturbance occurs in the system and the system frequency deviates, each generator experiences an accelerating or decelerating torque T_a. The electromechanical model of a generator is given by the swing equations:

$$\begin{aligned} 2H\frac{d\omega}{dt} + D\omega &= T_m - T_e \approx P_m - P_e \\ \frac{d\delta}{dt} &= \omega_0\omega \end{aligned} \qquad \text{(A.1)}$$

where: T_m is the turbine mechanical torque;
T_e – electrical torque;
H – inertia constant, with $2H = M = T_a$;
T_a – acceleration torque;
M – mechanical starting time;
D – self-regulation of the load.

The term D in usually the same all synchronous areas, and assumed to be 1%/Hz, which means that a load decrease of 1% occurs in case of a frequency drop of 1 Hz. Hence *D*=1 in the equation if load damping is considered [19]. The block diagram of the system dynamics and load damping is shown in Figure A.7.

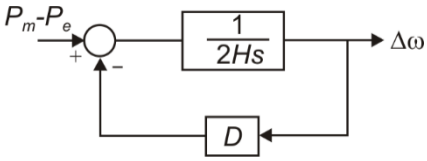


Figure A.7. Block diagram of the system dynamics, with load damping.

Simplifying the block diagram from Figure A.7, a single forward block is given by the function $1/(2Hs + D)$.

The primary frequency control function

The regulation of an energy resource is performed based on the “droop” control, given by:

$$R = \frac{\Delta\omega}{\Delta P} \tag{A.2}$$

and, thus, the resulted change in power is $\Delta P = \Delta\omega / R$. This power signal is added as reference power to the governor input, as shown in Figure A.8.

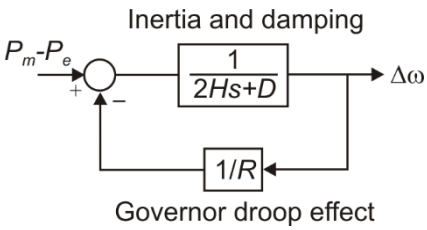


Figure A.8. Block diagram of the system dynamics, load damping and governor droop.

Expressed directly in terms of frequency and power, the droop is expressed as

$$s_G = \frac{-\Delta f / f_n}{\Delta P_G / P_{Gn}} \text{ in } \% \tag{A.3}$$

where $\Delta f = f_{meas} - f_n$, f_{meas} is the measured frequency, f_n is the reference/nominal frequency, ΔP_G is the quotient of the variation in power output of a generator, and P_{Gn} is the rated active power of the generator.

The “droop” is a straight-line function, with a certain speed reference for every fuel position, and provides the amount of speed (or frequency) change that is necessary to cause the main prime mover control mechanism to move from fully closed to fully open. In general, the percent movement of the main prime mover control mechanism can be calculated as the speed change (in percent) divided by the per unit droop [18]. The droop is usually set between 3% and 5%, depending on power system characteristics.

Let us consider the regulation of a unit with 4% droop, as shown in Figure A.9, the generation unit is loaded at 50%[1] of its rating, which the frequency is equal to the reference value, that is 1 p.u. (100%). This generation unit will then operate at zero load with a 2% over-frequency and at 100% load at 98% frequency or 2% under-frequency [18].

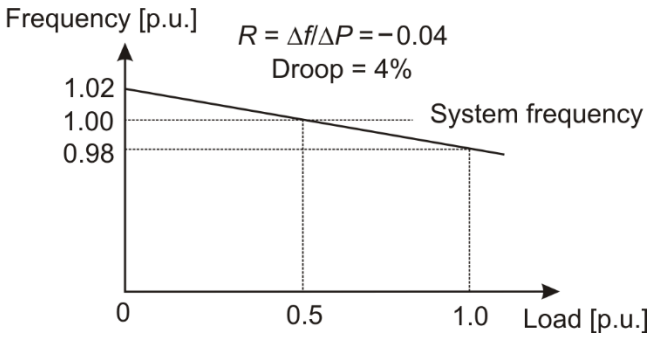


Figure A.9. Governor droop operation with 50% load at 100% frequency [18].

Technical characteristics

In continental Europe the primary frequency control is activated when the frequency deviation exceeds 20 mHz from the nominal value. Table A.7 shows the technical characteristics of the primary frequency control in various power systems.

Table A.7. Characteristics of the primary frequency control in various power systems [9].

	NERC	ENTSO-E	Germany	France	Spain	Netherlands	Belgium	Great Britain
Full availability	No rec.	≤ 30 s	≤ 30 s	≤ 30 s	≤ 30 s	≤ 30 s	≤ 30 s	Pr.: ≤ 30 s Sec.: ≤ 30 s Hi.: ≤ 30 s
Deployment end	No rec.	≥ 15 min	≥ 15 min	≥ 15 min	≥ 15 min	≥ 15 min	≥ 15 min	Pr.: ≥ 30 s Sec.: ≥ 30 min Hi.: ≥ as long as required
Frequency characteristic requirement	10% of the balancing authority's estimated yearly peak demand/Hz	20570 MW/Hz	4200 MW/Hz	4200 MW/Hz	1800 MW/Hz	740 MW/Hz	600 MW/Hz	variable 2000 MW/Hz
Droop of generators	5% in 2004; no rec. anymore			3-6%	≤7,5%	5-60 MW: 10% >60 MW: 4-20%		3-5%
Is an adjustable droop compulsory?	No rec.		YES	YES		5-60 MW: No rec. >60 MW: Yes	NO	YES
Accuracy of the frequency measurement	No rec.	± 10 mHz	± 10 mHz				± 10 mHz	
Full deployment for or before a deviation of:	No rec.	± 200 mHz	± 200 mHz	± 200 mHz	± 200 mHz	5-60 MW: 30% for ± 150-200 mHz >60 MW: 70% for 50-100 mHz	± 200 mHz	Pr.: -800 mHz Sec.: -500 mHz Hi.: +500 mHz

* Pr., Sec. or Hi.: primary, secondary or high frequency response
** No rec.: No recommendation

The services, respectively the energy used within the primary control, is seen in different ways in ENTSO-E. In many countries, this service is mandatory and is not financially remunerated, while in other countries it is the object of bilateral agreements between producers and the system operator [10].

A.3.3 Secondary frequency control / Automatic Frequency Restoration

Secondary reserve, called also automatic frequency restoration reserve (FRR), is activated in automatic and coordinated manner within few seconds (typically 30 minutes) and is fully available

[1] Note the range 50% from a practical standpoint is on the low side and is illustrative only.

within several minutes (from 2 minutes in Nordic countries up to 15 minutes in Romania and Slovak Republic) after detecting a frequency variation above a threshold or a change in net interchange power flows on the interconnection lines. This control level involves only those generators that are connected to the central regulator (Automatic Generation Control - AGC) operating in closed loop, having performances in accordance with the frequency control policy. The generating units participating in this control level and qualified based on specific test procedures.

The frequency restoration reserve is activated in order to restore the primary reserve so that, at any instant, a larger fast acting power reserve is available to correct rapid frequency variation within the system. Additionally, FRR is designed to cancel the frequency deviation and bring it to the reference value. This will indirectly restore the net interchange power to the scheduled value.

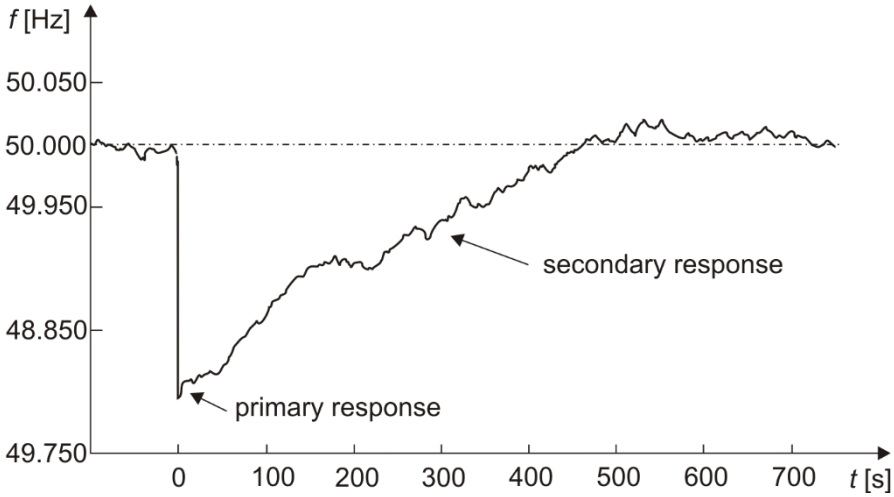


Figure A.10. Example of automatic frequency correction.

The secondary control level is also referred to as Automatic Generation Control (AGC), and most recently Automatic Resources Control (ARC), and consists in increasing or decreasing the generated power by the control units, according to the signal sent by the central regulator. For this reason the secondary reserve is established for both the upward and downward regulation, so that, in real time, the secondary regulation system is able to correct the ups or downs of the load curve. Since the participation to the secondary control involves a visible effort from producers, the procurement of this reserve by the system operator represents the object of a commercial activity.

AGC, called also Load-Frequency Controller (LFC) is a software application, component of the TSO's Energy Management System (EMS), which calculates the required power necessary to restore the frequency to the reference value. The LF Controller processes FRCE measurements every 4-10s and provides - in the same time cycle – automated instructions to aFRR providers that are connected by telecommunication connections [20].

One AGC controller operates within each power system from the interconnection aiming to balance the generation-load inside the system and to restore the power exchange with the neighbour systems to the scheduled value. This is illustrated in Figure A.11, where each synchronous system is provided with identical type of AGC controller. Since the frequency is maintained at the reference value by balancing the generation and load, under small frequency deviations (within the predefined deadband) the AGC reacts only to deviations in the power exchanges.

Even if not applied so far, the AGC controllers in neighbour countries can be coupled to share the frequency restoration reserves. Signals from one AGC to another can be sent to activate FRRs in the neighbour country. By this means, a power margin should be added to the scheduled exchanged power considered in the input to the AGC. This will allow developing inter-TSO markets for frequency control.

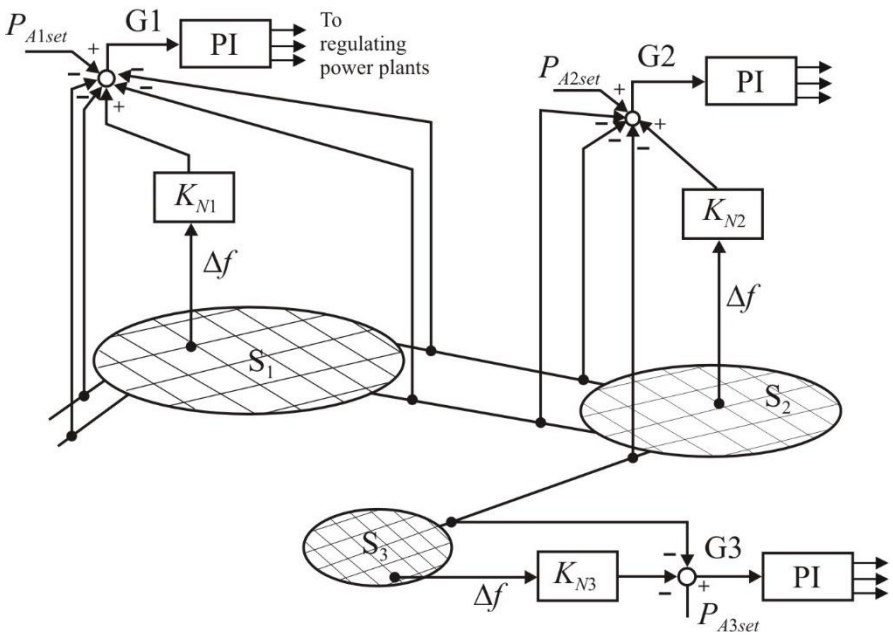


Figure A.11. Representation of the secondary frequency control.

The AGC calculates the Area Control Error (ACE) resulted within the control area using the following formula

$$ACE = \Sigma P_{exch} - P_{sch} + K(f_{meas} - f_n) \tag{A.4}$$

where ΣP_{exch} is the sum of the instantaneous power flows (exchanged) on the interconnection lines, in MW;
P_{sch} – the scheduled net interchange power, in MW;
K – the K-Factor of the control area, in MW/Hz;
f_{meas} – the measured frequency, in Hz;
f_n – the reference/nominal frequency, in Hz.

Under balanced conditions, $\Sigma P_{exch} = P_{sch}$ and $f_{meas} = f_n$, and thus the area control error is equal to zero.

The active power required for system balancing, ΔP_B, is determined using a proportional-integral (PI) regulator, in accordance with the following equation:

$$\Delta P_B = -\beta \cdot ACE - \frac{1}{T_r}\int ACE \, \mathrm{dt} \tag{A.5}$$

where β is the proportional factor (gain) of the secondary controller in the control area, and T_r is the integration time constant. The integral term ensures both the system frequency and power deviations to return to their set points within the required time (without additional control needed). The proportional factor must be carefully chosen in order to ensure the stability of the interconnected system, especially when hydroelectric plants are employed within the secondary control system. Redesigning the secondary controller function will be a challenging factor when the generation sector relies only on renewable energy sources.

Table A.8 shows various technical characteristics related to the automatic FRR in ENTSO-E and continental Europe countries.

Table A.8. Characteristics of the secondary frequency control in various countries.

	Activation	Full availability	Utilization	Controller cycle	Controller type
ENTSO-E	≤ 30 s	≤ 15 min	As long as required	1-5 s	I or PI

Germany	Immediately or ≤ 5 min	≤ 15 min	As long as required	1-2 s	PI
France	≤ 30 s	≤ 430 s or ≤ 97 s	As long as required	5 s	I
Spain		≤ 300-500 s	≥ 15 min	4 s	P or PI, depending on the regulation zone
Netherlands	30 s – 1 min	≤ 15 min	≥ 15 min and by consensus	4s	PI, with additional heuristics
Belgium	≤ 10 s	≤ 10 min	As long as required	5s	PI
Romania	≤ 30 s	≤ 15 min	As long as required	4 s	PI

It is advisable that the primary and secondary reserves should be uniformly distributed among a greater number of generators within the system in order to increase the response time by activating smaller reserve amounts in more generators instead of activating larger power reserves available in a smaller number of generators.

If a powers imbalance lasts for a longer period that require the use of a greater part of the secondary reserve, the third control level will be called upon.

In order to have a more clear overview of the secondary control scheme in a power system, the simplified secondary control scheme in the Romanian power system is presented (Figure A.12).

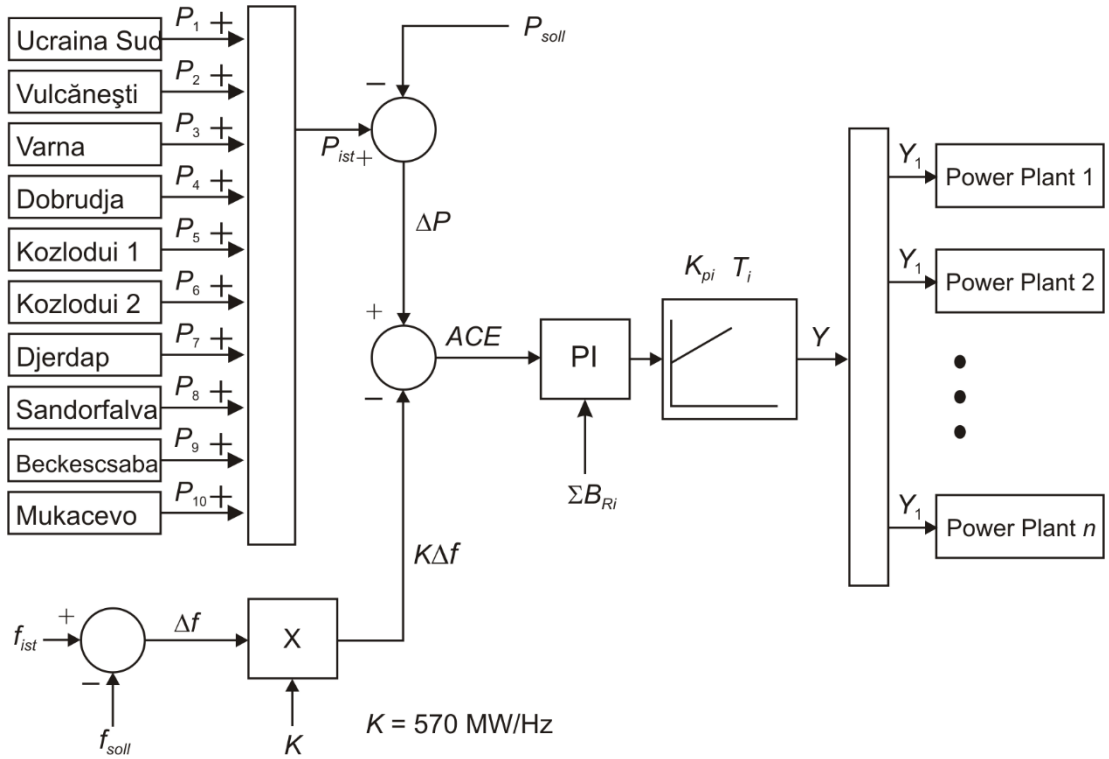


Figure A.12. Secondary frequency control scheme in Romania.

In order to ensure stability of the regulation scheme, irrespective of the regulation band and the generation units participating to regulation, the total mismatch is normalized with the total regulation band of all power plants.

$$X = \frac{\Delta P}{\sum_k B_{R,k}} = \frac{\Delta P}{SRB} \tag{A.6}$$

where: ΔR is the total power mismatch;
$B_{R,k}$ - regulation band of the power plant k;
SRB - total secondary regulation band.

The total secondary reserve band, SRB, is the sum of all individual regulation bands of all participating power plants, that is $SRB = \sum_k B_{R,k}$.

The area control error, ACE, is introduced in a PI controller to achieve the necessary total control order, given by

$$Y = K_P X + \frac{K_P}{K_I} \int_0^t X dt \qquad \text{(A.7)}$$

where: K_P is the proportional constant;
K_I - the integral constant;
Y - the control order;
t - the time.

The output of the PI controller, Y, is limited within a specific range [-Ymax/SRB ; Ymax/SRB]. The value -Ymax/SRB corresponds to operation of the power plants to the lower limit, while the value Ymax/SRB corresponds to operation of the power plants to the upper limit.

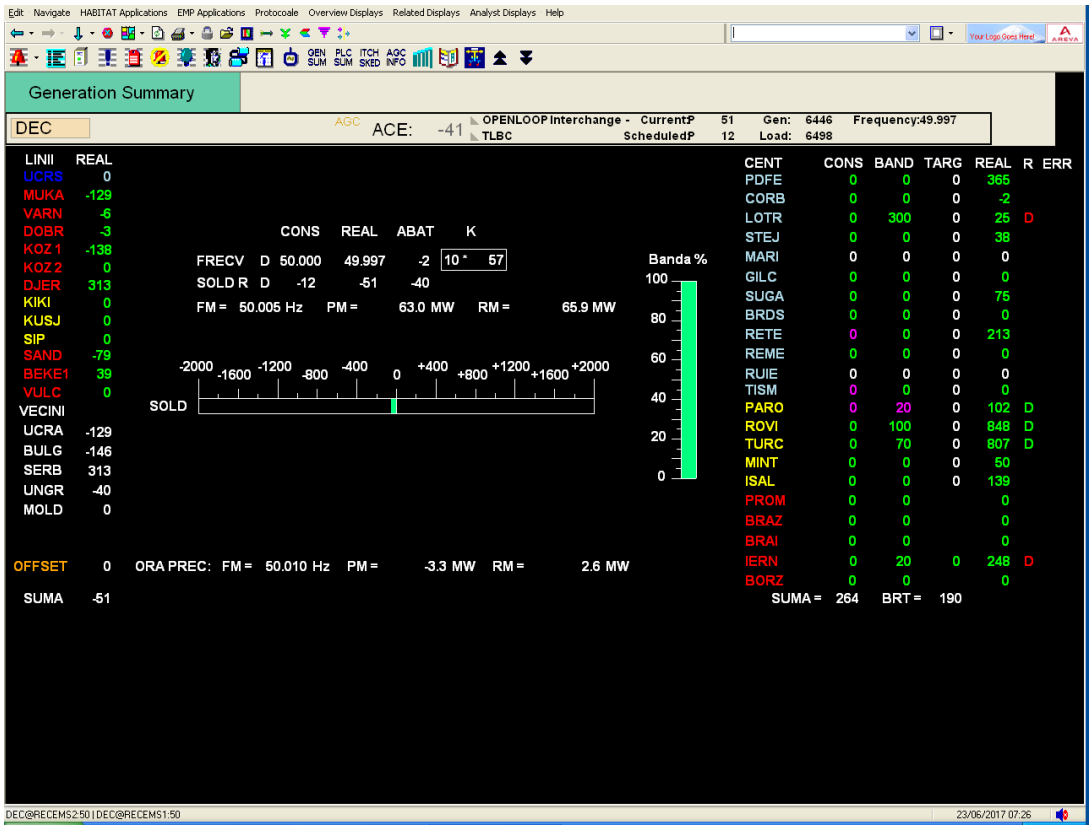


Figure A.13. Snapshot of AGC operation is Romania.

Figure A.13 shows a snapshot of the application that displays in real time the parameters and the operating variables of the automatic generation control. The application shows the following real-time information:

- Power flow on the interconnection lines (lest side).
- Power exchange deviation (SOLD, in the centre).
- The actual band used in secondary control (BAND column, on the right side). One can observe that is a special case when the total secondary reserve was fully used

- Total power generation of all power plants integrated into the AGC scheme.
- The area control error (=-41, for this instant).
- Power system frequency.
- Total generation and load.

A.3.4 Tertiary frequency control

The *tertiary control reserve*, called manual Frequency Restoration Reserve (mFRR), is activated manually when requested by the system operator, and is used for the relief of the secondary reserve, following sudden loss of generation or load, or to correct forecast errors. As the power unbalances can be negative or positive, the tertiary reserve is determined and activated for both the upward and downward regulation. Extended use of the secondary reserve, can involve also full use of the primary reserves, which means that the power system cannot handle alone subsequent power unbalances.

Tertiary reserve can be provided by both the spinning and non-spinning generators. ENTSO-E has formulated a general definition for the tertiary reserve but it is seen somehow different in the member countries because of the peculiarities of their own electrical networks and the power plants connected to it. However, it is usual to refer this reserve as fast tertiary reserve or slow tertiary reserve.

Fast tertiary reserve is characterized by relative small response times so that it can correct the frequency deviations caused by due to power unbalance and restore the power flow on the interconnection lines due to any contingency, by replacing the secondary reserve.

When mismatches between the notified powers curve and the forecasted load curve exist, the system operator will get ready to call upon cheaper power reserves. Generally, these reserves are slow, with small ramp-up rates and high start-up times, being provided by thermal power plants. This is the reason why their providers must be notified to proceed for ramping-up a certain time before the dispatching instant so that they can be ready to load the notified power. In some countries, the slow reserves are also referred to as replacement reserves and are not considered ancillary services.

In terms of the power market mechanisms implemented in the ENTSO-E member countries, the decision of the system operator to use a faster generator or a slower one can be based on optimization procedures. However, the deployment period and amount of the slow tertiary reserve is a decision of the system operator based on years of experience.

Figure A.14 shows the deployment of power reserves in terms of their response time according to the ENTSO-E policy.

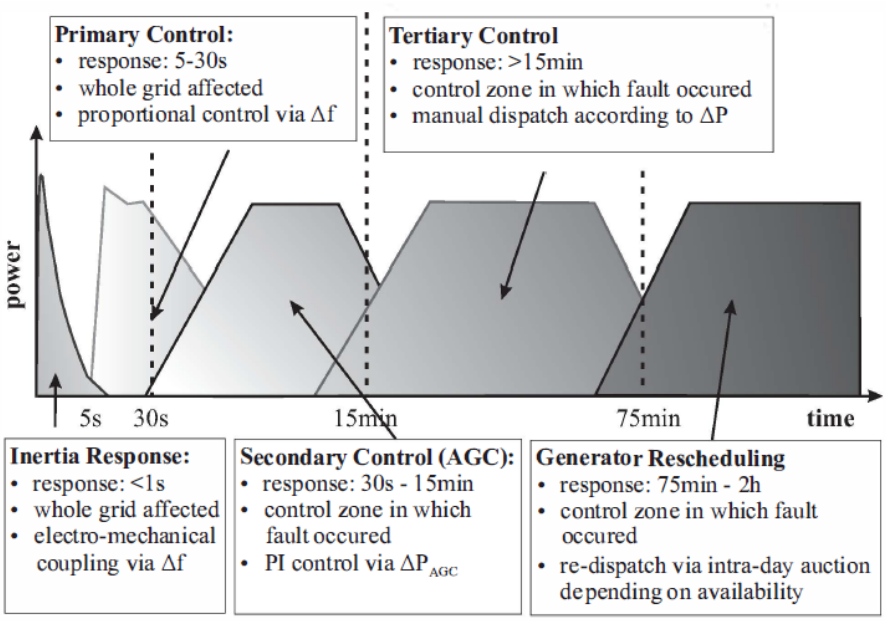


Figure A.14. Power reserves deployment.

A.4 Market related aspects of the frequency control procedures

Beyond the idea that the electrical energy can be sold as a commodity, the system operator must assure to the power system an appropriate security level by continuously maintaining a power reserve available within the system to correct the effects on the frequency of any perturbation. For this reason, the implemented market mechanism should sent incentive signals for the high performance generators persuading them to maintain all the time a power reserve to contribute to maintaining the system in a normal operating state.

The types of reserves defined earlier, attached to the control levels, give an overview on the dispatching activity of the system operator. However, the reserve available to the system operator will result as a consequence of the free competition on specific markets. Although this reserve is treaded on a platform under an optimization problem formulated by the system operator, its existence and the associated price depends to a great extent on the market strategy of the producers.

The available reserve amount is also referred to as *spinning reserve* and denotes the "unused capacity of a generator synchronized to the electrical grid that can be activated when called upon by the system operator, to produce more active power in order to correct frequency variation from the nominal value". If we are referring to a certain instant of time, a generator can produce a certain power amount, scheduled by commercial arrangements, which can be increased up to the maximum available value. In other words, the spinning reserve is the sum of unused secondary and tertiary reserves, being also referred to as *synchronized reserve*.

Based on the above-given definitions, Figure A.15 illustrates the loading domain of energy and power reserves on a scale between the standing limit of the generator and the maximum technical limit (installed power).

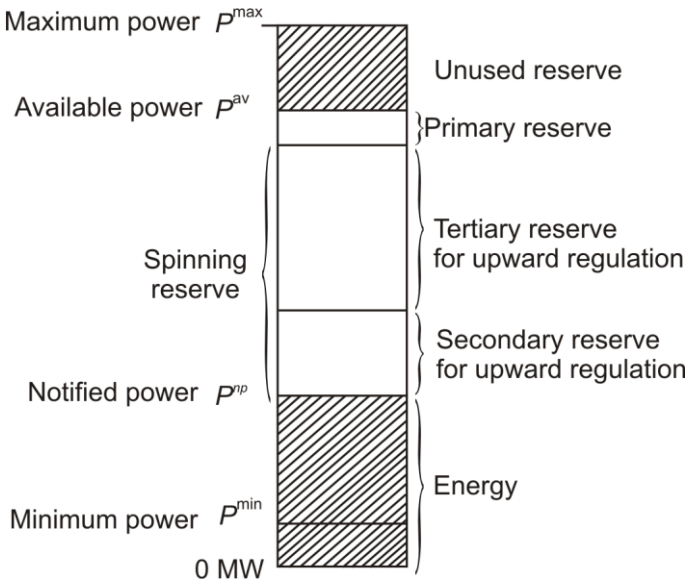


Figure A.15. Definition of the generators power reserves.

Because of some limitations that do not depend on the generator characteristics, such as water availability for hydro power plants, fuel availability for thermal power plants, pressure problems related to the steam turbine, etc., it happen that a generator cannot set the working point at the maximum value. For this reason, the available maximum power value is used instead of maximum technical power.

The frequency restoration reserve (FRR) is usually a symmetrical band around the notified power (Figure A.16). In this case, the maximum reserve band that can be used for secondary control is limited either by the minimum possible power, P^{min}, or by the maximum available power, P^{av}. The

upper power limit is usually the maximum installed power, P^{max}, for various reasons, e.g. reduced pressure to the gas pipe for steam turbines, reduced water flow on the river in the case of hydro power plants, reduced wind speed in the case of wind power plants or low solar irradiance in the case of PV panels.

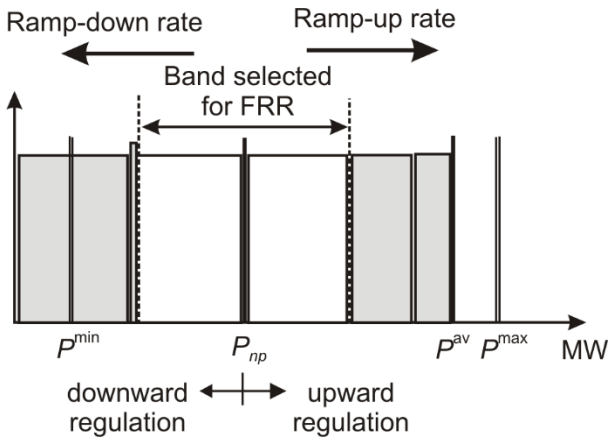


Figure A.16. Determination of the tertiary reserve.

If there is available manual frequency restoration reserve (mFRR) for the tertiary frequency control, this can be employed in either direction, depending on the ramp-up rate or the ramp-down rate.

Depending on the power system needs, the balancing market operator selects power reserves offered by the various participants in the price order.

For security reasons, any of the power reserved should be deterministic, meaning that no change should be done in the available power reserve offered by a generation units.

Annex B Issues caused by intermittency of renewable energy sources

As the frequency control studies are performed on the Romanian power grid, in this deliverable we briefly analyse the characteristics of power generation from wind and photovoltaic power plants installed in Romania.

B.1 Wind generation

The total power capacity installed in wind power plants in Romania is 2963.2 MW [24]. In year 2016, the energy produced was 6.73 TWh, representing 12.3% of the total load [23]. Note that Romania is a net exporter, usually recording energy export during high wind generation.

In order to provide a more realistic image on the power generation from wind in Romania, the set of data recorded from January to June 2017 was considered. The sampling time of data is approx. 10 minutes [21], thus resulting 27400 values. Figure B.1.Figure B.1. Frequency occurrence of wind generation in Romania between January-June 2017 [21]. illustrates the frequency of occurrence of all data from the analysed set, where the data have been grouped into ranges of 50 MW.

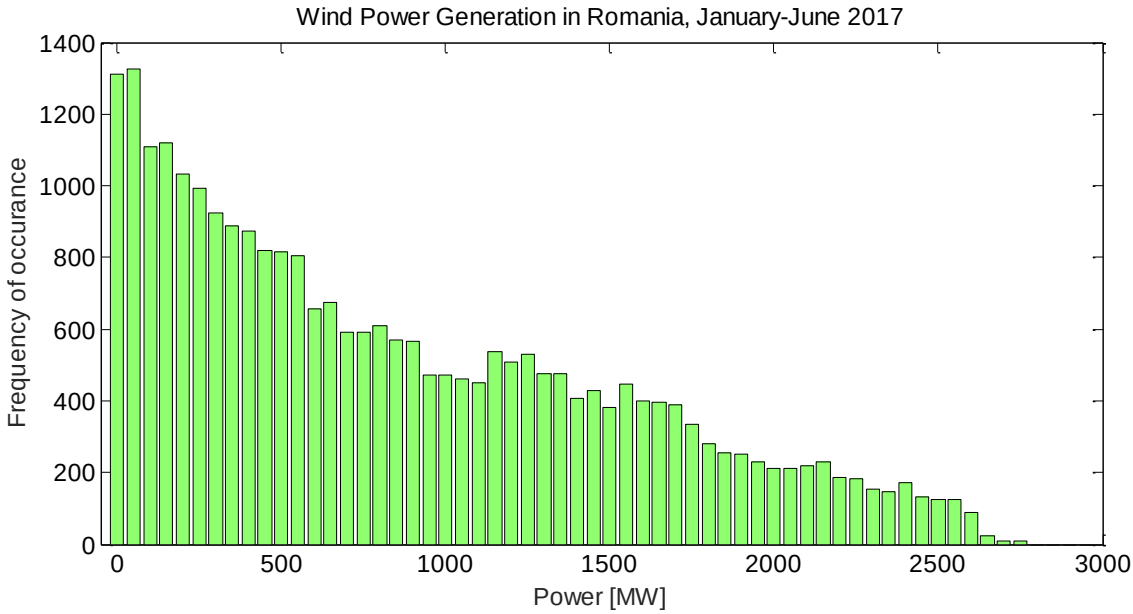


Figure B.1. Frequency occurrence of wind generation in Romania between January-June 2017 [21].

Figure B.2 shows the normal distribution of the whole set of data. The mean value is 867.4 MW, the median is placed at 701 MW, the standard deviation is 684.7 MW, and the maximum value is 2792 MW. The resulted capacity factor is 31.3%; note that this value is smaller for the whole year. From the figures it results also that the smallest probability of occurrence is recorded for values greater than 1700 MW.

In order to emphasize the extreme situations, with the biggest unexpected influence on the power system operation, let us consider the generation-load profiles on July 3rd 2017. As seen in Figure B.3 two sawtooths have been recorded for the wind generation (green curve):

- **Event 1**: Between 1:30 AM and 2:30 AM, which means 60 minutes; the generation variations about 1200 MW, representing about 23% of the total load.
- **Event 2**: Between 5:30 AM and 6:20 AM, which means 50 minutes; the generation variations about 1300 MW, representing about 22% of the total load. An unexpected fast decrease of 800 MW was recorded within an interval of 10 minutes, between 6:13 AM and 6:23 AM.

- **Event 3**: Short-circuit on the busbar of the Iron Gates I (Portile de Fier I), followed by shutting-down the power plant and loss of about 700 MW.

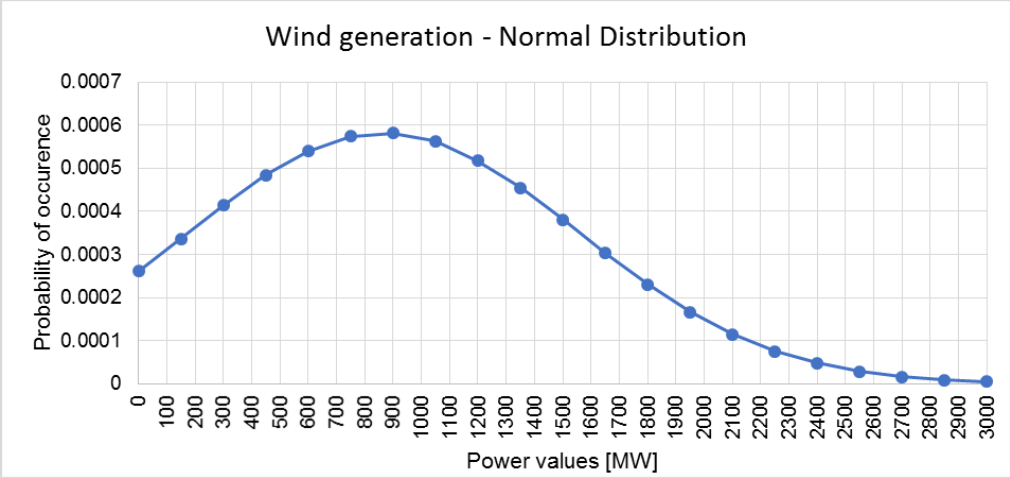


Figure B.2. Normal distribution of wind power generation in Romania, between January-June 2017 [21].

Following the two power variations, similar power variations were observed on the interconnection lines. While the wind generation was increasing, hydro units were unloaded in order to balance the generation, probably by both secondary and tertiary reserves. At the same time, equivalent size variations were observed on the interconnection lines. Furthermore, in the case of the second sawtooth, a probably planned reduction of the hydro generation is observed at the same time with the unexpected reduction of the wind generation. This resulted in larger variation of the power exchange, of 1000 MW in just 9 minutes. This proves that the Romanian power system was not ready to compensate alone the large fluctuations in wing generation, and unplanned contribution from the neighbours was needed.

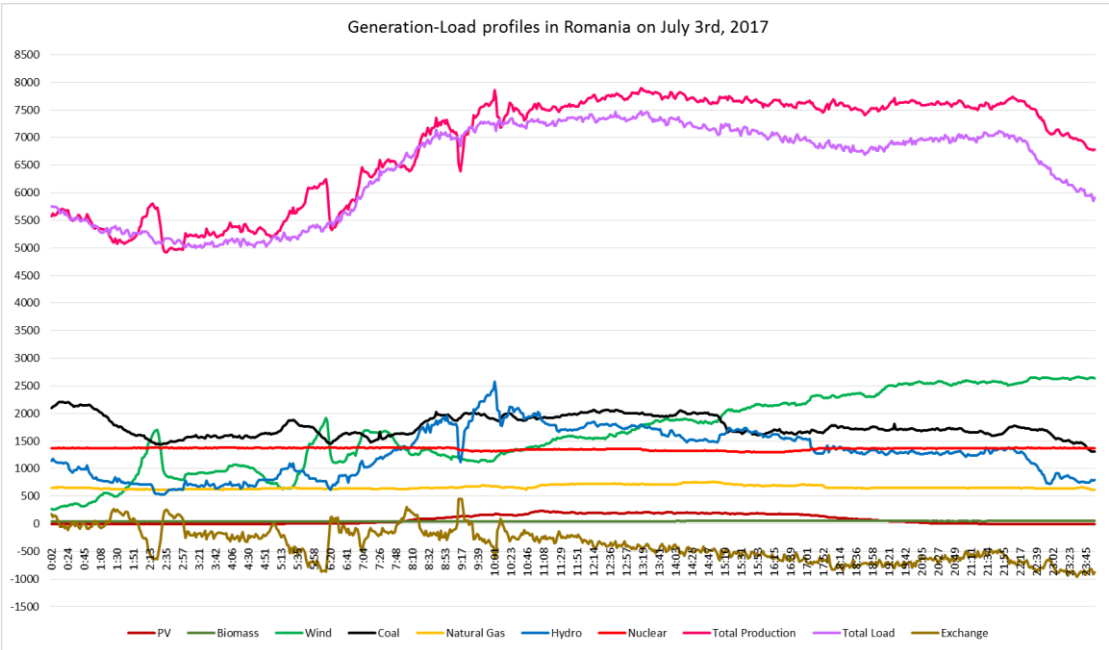


Figure B.3. Generation-load profiles in Romania on July 3rd, 2017 [21].

From Figure B.3 we can see that, as the generation from wind power plants is increasing, the production in hydroelectric units is decreasing, which means that one renewable energy sources is replacing the other. This shows that energy storage units are mandatory.

On the other hand, this shows again that, either the actual technology or the power market rules are not appropriate to allow integration of wind generation sources at large scale. For this reason, battery energy storage systems are required, eventually uniformly distributed in smaller units would be recommended in order to avoid dangerous variations in the power flows, as well as voltage variations.

B.2 Photovoltaic generation

The total power capacity installed in PV power plants in Romania is 1378 MW [21]. In year 2016, the energy produced was 1.25 TWh (unofficial), representing 2.3% of the total load [21]. Note that Romania is a net exporter, usually recording energy export during high wind generation.

A similar analysis was performed for the power generation from PV power plants in Romania, on the set of data in the same period, which is January-June 2017. Figure B.4 shows that frequency of occurrence of power values in ranges of 50 MW.

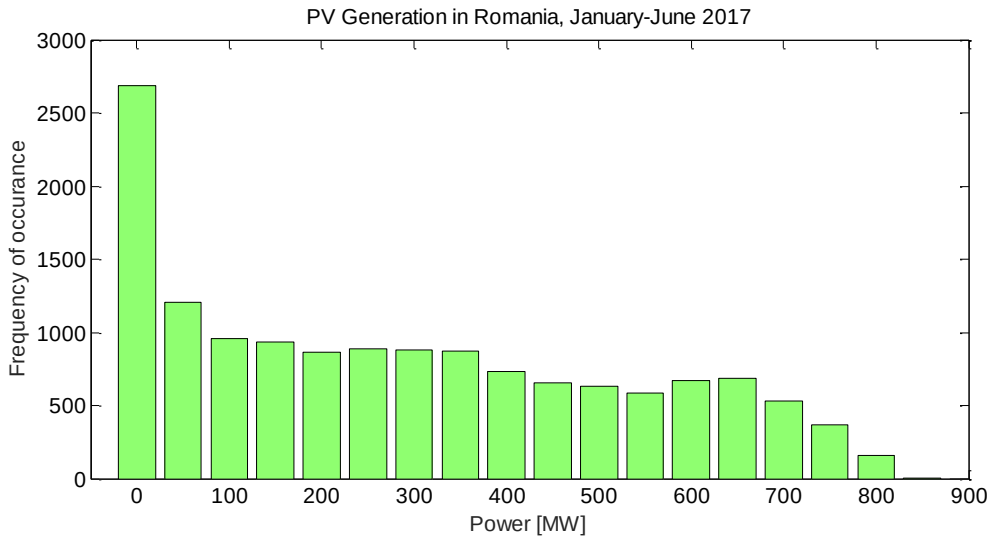


Figure B.4. Frequency of occurrence of power generation from PV in Romania, between January-June 2017 [21].

As compared to the wind generation, the total power generation from PV is more predictable and stable than form wind based units. The PV generation follows a daily shape, of different amplitudes, depending on the meteorological conditions. Small variations may be observed during rain or transient clouds conditions.

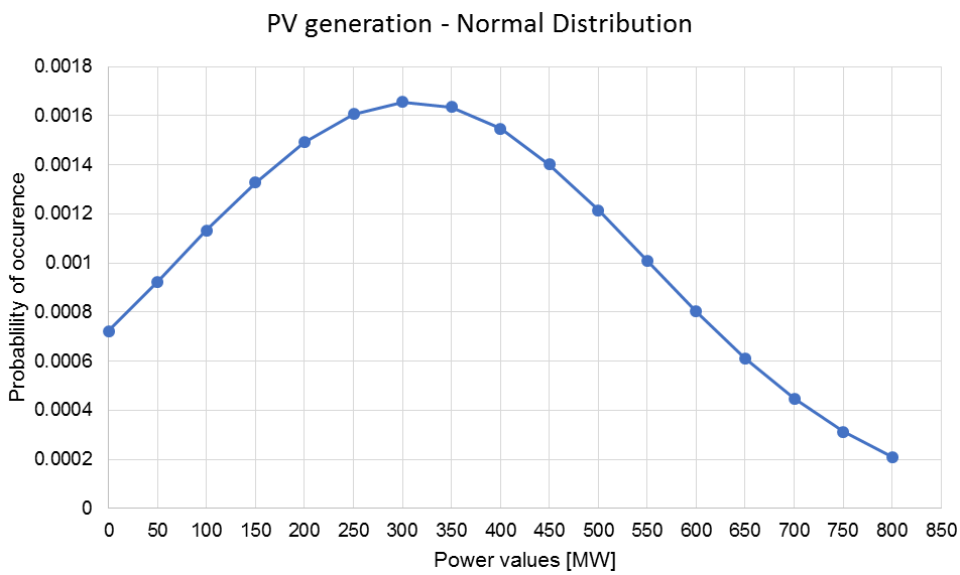


Figure B.5. Normal distribution of PV power generation in Romania, between Jan.-June 2017 [21].

Figure B.5 shows the normal distribution of the whole set of data, from which the zero values were removes. Only daylight periods were considered. The mean value is 310.27 MW, the median is placed at 278 MW, the standard deviation is 240.7 MW, and the maximum value is 858 MW. Considering night periods, the capacity factor is about 12%, while during daylight periods the capacity factor is about 23%. From the figures it results also that the smallest probability of occurrence is recorded for values greater than 620 MW.

A typical generation profile, recorded on July 3rd 2017, is shown in Figure B.6 This is the same day in which sawtooths variations were observed for wind generation. This day was characterized by rainy conditions. However, despite the lower amplitude specific for this day, the generation profile is almost steady and predictable. In sunny days, the PV generation is an easily predictable profile, reaching up to 860 MW.

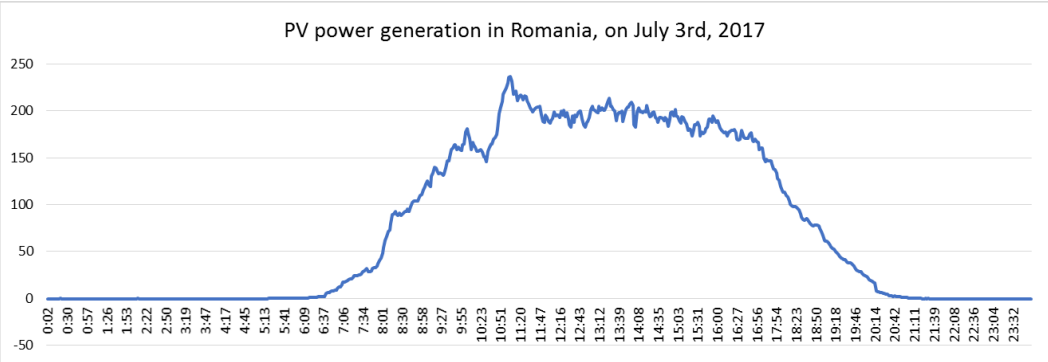


Figure B.6. Typical PV generation in Romania, on July 3rd, 2017 [21].

Comparison of the wind and PV generation in Romania reveals that, from the power system operation point of view, developing the PV power plants seems to be the best solution. The advancements in the PV efficiency can determine investments in PV power plants to achieve a smaller return of investment. Additionally, short term and long term storage systems may help achieving appropriate control on the power generation from RES.

B.3 Analysis of frequency for July 3rd, 2017

Figure B.6 shows the frequency variation in Romania, for a 24-hour time period, on July 3rd, 2017. The frequency was metered using a phasor measurement unit (PMU), installed at University “Politehnica” of Bucharest, in the low voltage network. Analysis of the Figure B.6 reveals usual frequency excursions greater than 50 mHz. The three events that occurred in the Romanian power system are indicated in the figures. However, a much bigger frequency variation is observed around 1:00 AM, of unidentified origin, eventually that occurred in the interconnected power system of ENTSO-E, on the continental Europe.

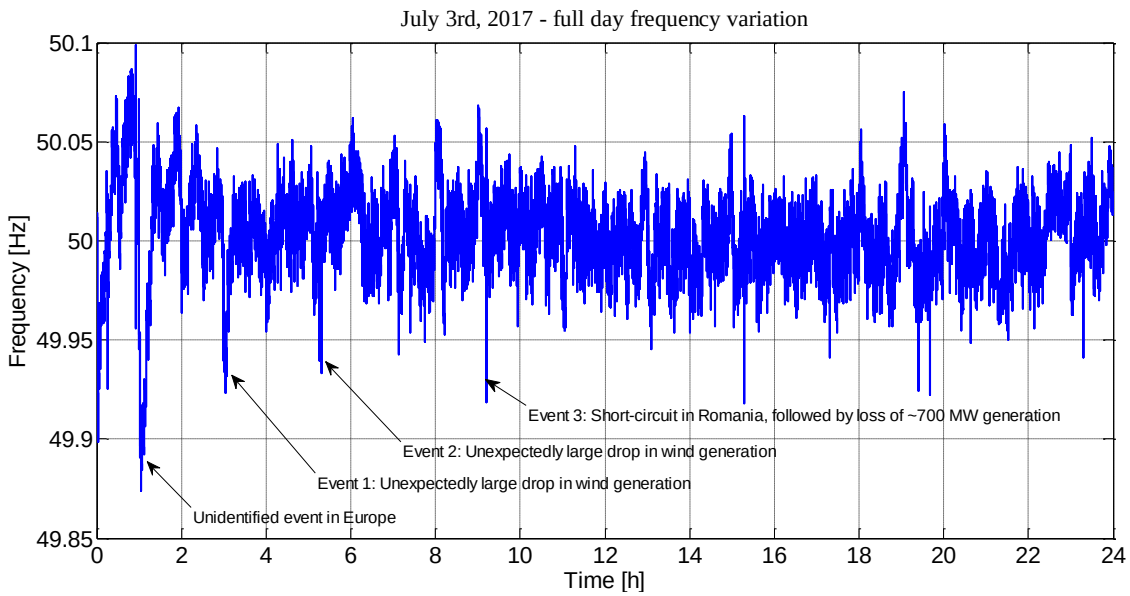


Figure B.7. Frequency variation during July 3rd, 2017.

In order to analyse the severity of the events, the rate of change of frequency (RoCoF) was also calculated to the same day (July 3rd, 2017). The RoCoF indicates the severity of an event in terms of frequency stability. Analysis of Figure B.7 reveals that the most severe events are the Event 3 that occurred in the Romanian power system and the unidentified event in Europe, both probably being the result of a short-circuit followed by the loss of power generation and/or reduced transmission capacity. In the case of the two short-circuit, the RoCoF was up to 2.8 Hz/s on the positive direction, and up to -3.9 Hz/s in the negative direction. The continental Europe interconnected system managed to stop the rapid frequency variation, and maintain the global frequency. However, even if more than usual frequency variations were recorded in the case of Events 1 and 2, meaning large variations in wind generation, they are characterized by usual RoCoF variations.

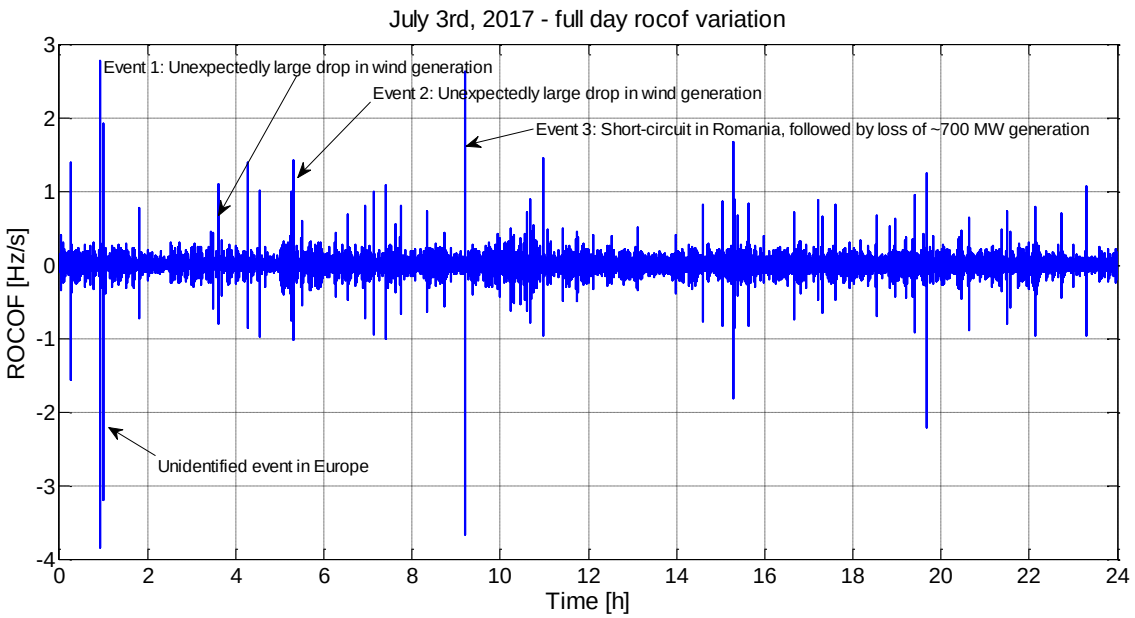


Figure B.8. Rate of change of frequency during July 3rd, 2017.

Figure B.9 shows the distribution of the frequency values during 24 hours, specific to the day of July 3rd, 2017. This reveals that most of the cases the frequency was in the range between 49.95 Hz and 50.05 Hz. However, the graph indicates that the frequency is well maintained around the reference value of 50 Hz.

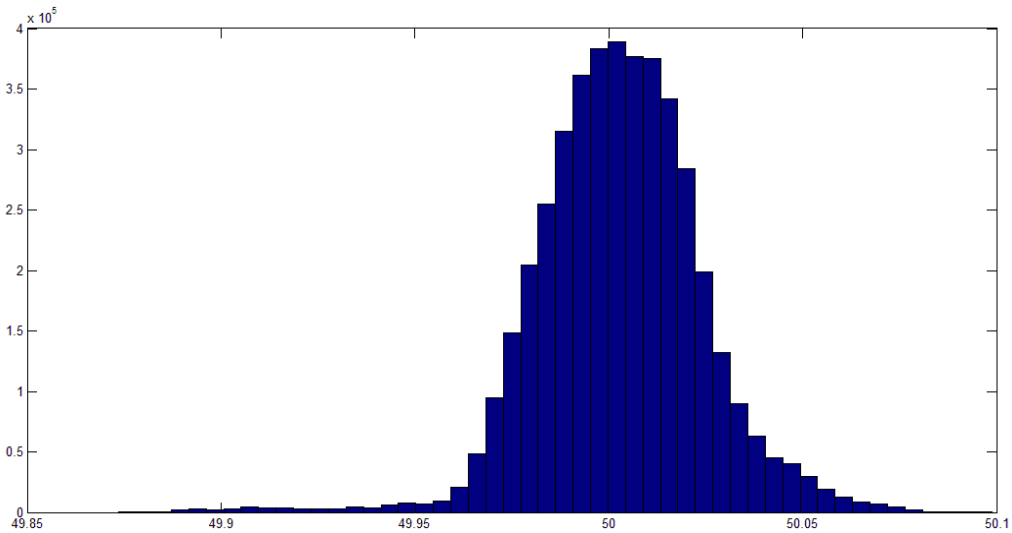


Figure B.9. Occurrence of frequency values, for July 3rd, 2017.

A zoom out of the Figure B.9 is shown in Figure B.10. It reveals that during the day of July 3rd, 2017, the frequency shows more frequency values less than 50 Hz as compared to the frequency values greater than 50 Hz. Furthermore, frequency variations in the decreasing way, greater than 100 mHz, are observed. These frequency decreases are mainly associated to Event 3, which represents a short-circuit followed by the loss of power generation.

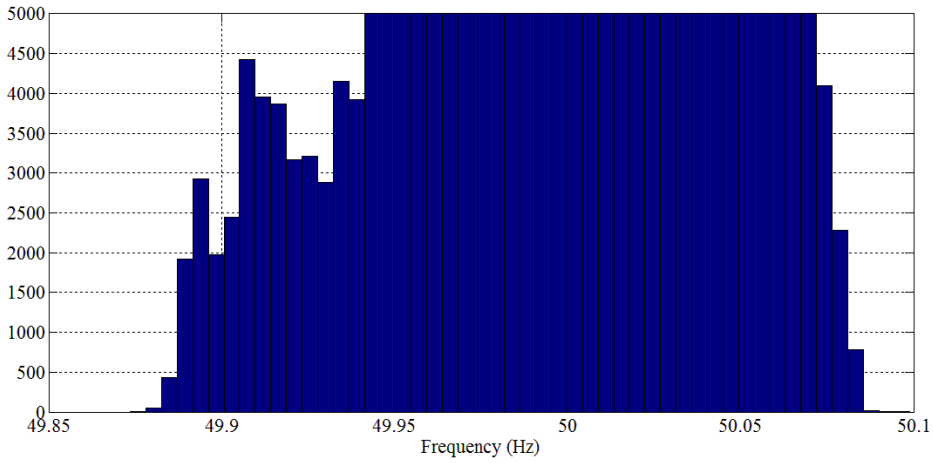


Figure B.10. A zoom-out on the occurrence of frequency values, for July 3rd, 2017.

A closer attention on the short-circuit event that occurred in the Romanian power system, for a 10 minutes window, between 9:10 AM and 9:20 AM, reveals that, the frequency do not exceed 200 mHz. This is valid also in the case of the unidentified event that occurred in Europe.

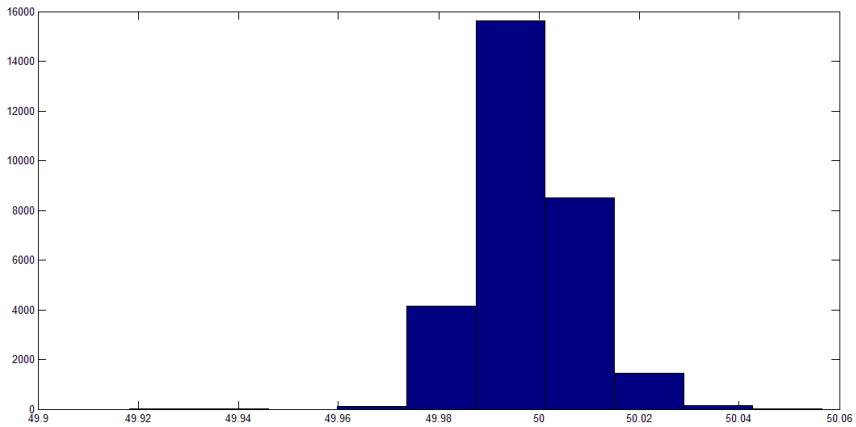


Figure B.11. Occurrence of frequency values, for July 3rd, 2017, 9:10 AM – 9:20 AM.

B.4 Conclusions

The power system security is very important from technical point of view. Frequency instability leading to power system blackouts can have also a large impact from economic and social point of view. For this reason, careful attention must be paid to all events in power systems that can cause large frequency fluctuations or power unbalances.

As shows in this chapter, critical events can be experienced, such as large increased in the power generation from wind followed by immediate drop, as a consequence of very large wind speed variations. At a larger scale, with installed wind power at values that could support the load demand for longer time, a sudden change in the wind speed can have amplified impact than the situation presented in this chapter. For this reason,

- Either appropriately large hydro units to balance the powers or battery energy storage systems to store the inadvertent wind power generation peaks should be used.
- In order to take on-time measure in the power system and avoid any operation problems, correct forecasts must be done. This requires close cooperation between meteorology institutions, wind power plants owners, and the TSO.
- The power markets should be adapted, while the TSO and DSO should closely monitor the power generation to avoid large unbalances in the portfolio of the market participants.

A comparison between wind and photovoltaic generation profiles reveals that the power generation from PV plants is more predictable. At national level, the PV power has a predictable profile, while the amplitude can be easily corrected by intra-day adjustments. This observation is important in the long term strategies for RES support.

Annex C Modelling the power system frequency control

C.1 Dynamic models

C.1.1 AGC and droop control in a two-area system

Figure C.1 shows a simple model for frequency control of a two-area power system; areas I and k are interconnected through a lie-line. Both primary and secondary frequency controls are considered.

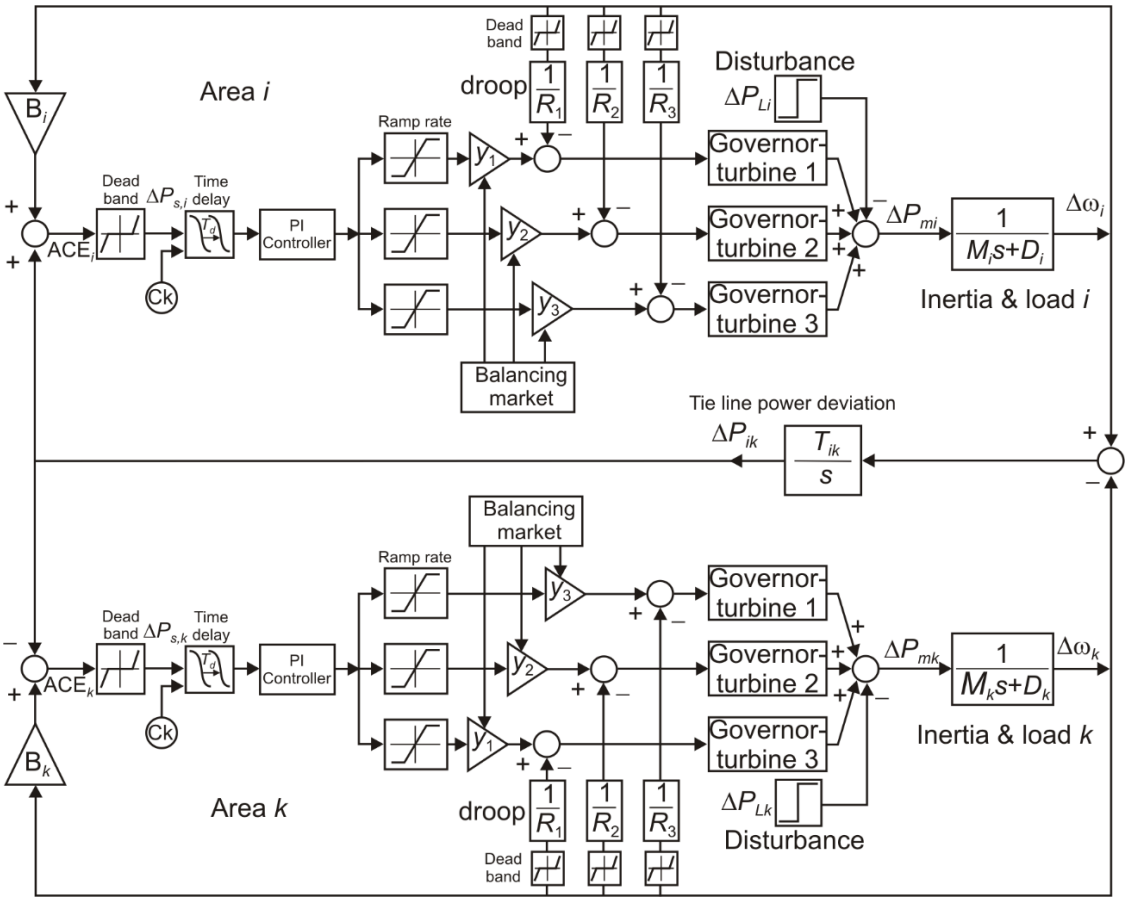


Figure C.1. Frequency control scheme in a power system.

The control scheme consists of the following components:

- Governor-turbine models;
- Power system inertia and load factor;
- Droop control signals (primary control);
- Area control error calculation, within the automatic generation control;
- The tie-line interconnection;
- The power unbalance disturbance, by load change;
- The frequency-bias factor, B = 1/R + D.

C.1.2 Governor-Turbine models

Three types of governor-turbine models are used. Figure C.2 shows the governor-turbine generic model for a hydraulic unit.

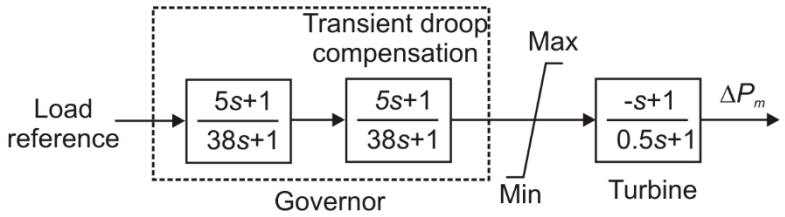


Figure C.2. Block diagram of hydraulic unit.

Figure C.3 shows the governor-turbine generic model for a reheat unit, and Figure C.4 shows the governor-turbine generic model for a non-reheat unit.

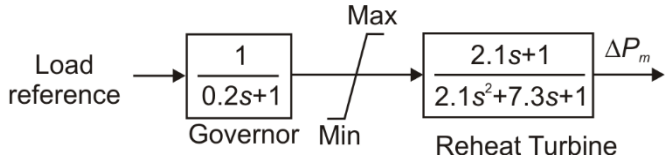


Figure C.3. Block diagram of reheat unit.

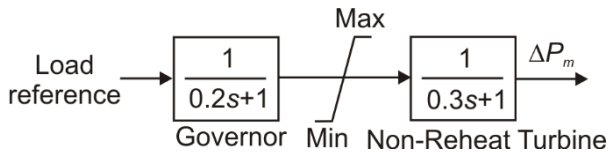


Figure C.4. Block diagram of non-reheat unit.

C.1.3 Primary control

The primary control is provided by the droop control signal, as illustrated in Figure C.1. The droop equation is $R = \Delta\omega / \Delta P$. Using the droop equation, we achieve the contribution of a generation units from any interconnected area, that is

$$\Delta P_{i1} = \frac{-\Delta\omega_i}{R_{i1}} \tag{C.1}$$

C.1.4 Secondary Control

An AGC with a PI controller is provided for each area aiming to bring the steady state deviation to zero. The AGC signal is fed into the governor summing point along with the droop signal as shown. The integral gains K_I for each AGC are adjusted for an optimal response.

An Area Control Error (ACE) is calculated for each area, using the AGC's function. The output signal is fed into a summation block together with the primary control signal. The ACE is area are:

$$ACE_i = \Delta P_{ik} + B_i \Delta\omega_i \tag{C.2}$$

$$ACE_k = \Delta P_{ki} + B_k \Delta\omega_k \tag{C.3}$$

where B is the bias factor, and is the variation of the angular speed $\Delta\omega$.

The tie-line bias control forces the area with the disturbance to meet its own power mismatch (disturbance change) with the other area contributing to the transient condition of the system as a function of the frequency deviation and its bias factor.

C.1.5 The interconnection link

The power flow through the tie-line between the two interconnected systems is given by

$$P_{ik} = \frac{E_i E_k}{X_L} \sin(\delta_i - \delta_k) \tag{C.4}$$

where E_i and E_k are the voltages at the two ends of the tie-line behind the system equivalent reactances, X_L is the tie-line reactance, and δ_i and δ_k are the voltage angles. Note if ΔP_{ik} is assumed positive in one direction for one area, it will be in the opposite sign for the other area.

Linearizing about an initial operating point represented by $\delta_i = \delta_{i0}$ and $\delta_k = \delta_{k0}$, we achieve the active power variation on the interconnection line

$$\Delta P_{ik} = T_{ik} \Delta\delta_{ik} \tag{C.5}$$

where $\Delta\delta_{ik} = \delta_i - \delta_k$, and T_{ik} is the synchronizing torque coefficient between the two power systems, that is

$$T_{ik} = \frac{E_i E_k}{X_L} \cos(\delta_{i0} - \delta_{k0}) \tag{C.6}$$

Note that, in initial conditions, the phase angle difference, $\delta_{i0} - \delta_{k0}$, should not exceed 30°.

C.1.6 Battery model

The simulation assumes participation of a battery energy storage system (BESS), that responds to both frequency variations, Δf, and RoCoF, df/dt. Figure C.5 shows the block diagram of the control model of the BESS. The two coefficients K1 and K2, are gain factors to the input signals. The reaction time of the battery is given by the time T_{BESS}, usually considered 0.1 seconds.

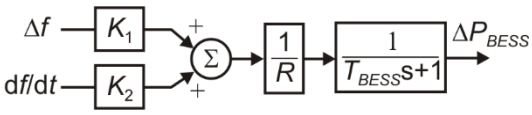


Figure C.5. Simplified primary control scheme of a battery

The output of this block diagram is fed into the summator, together with the mechanical power outputs of the other generation units.

C.1.7. System inertia and load damping

The two areas are each modeled by their inertia and load damping. In Figure C.1, *M* represents the rotor inertia constant, in seconds, and *D* represents the load damping factor.

C.2 Scenarios and simulations

C.2.1 Basic scenarios

This section is intended to identify the frequency related behavior of a two-area interconnected power system for normal and reduced inertia values, then to observe the influence of fast acting energy storage, e.g. battery energy storage, on the frequency stability. Both primary and secondary frequency control are considered in simulations.

Assuming that, in the future, the generation relies only on renewable energy sources, the scenario of 100% will include hydroelectric units only for frequency control. Therefore, hydroelectric units are considered in all frequency control scenarios. The share of RES in the total generation is reflected in the inertia value.

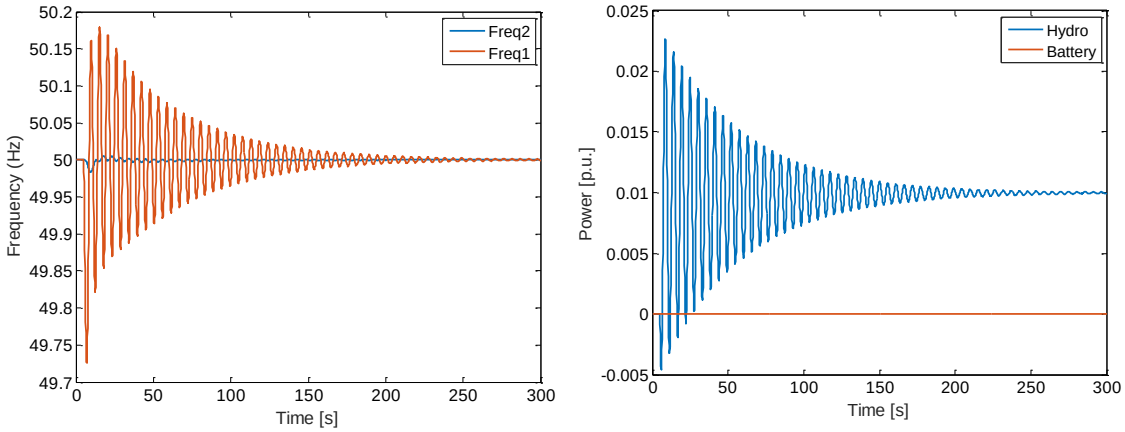
The usual inertia is H = 6.5 s.

In all scenarios, a load variation ΔP_L = 0.01 p.u. that occur at the time instant t = 5 s from the beginning of the simulation is assumed.

Scenario 1)

Hypotheses: *Inertia constant H = 3 s; only hydroelectric units are considered for frequency control.*

Figure C.6 shows poorly damped frequency oscillations under low inertia. A lower inertia may cause frequency instability. This is because both primary (specific for the hydro governor) and secondary controls provide slow responses. The secondary controller is designed for slow reaction in order not to cancel out the contribution from primary control level. It is therefore clear that faster primary response is required in order to achieve frequency instability.

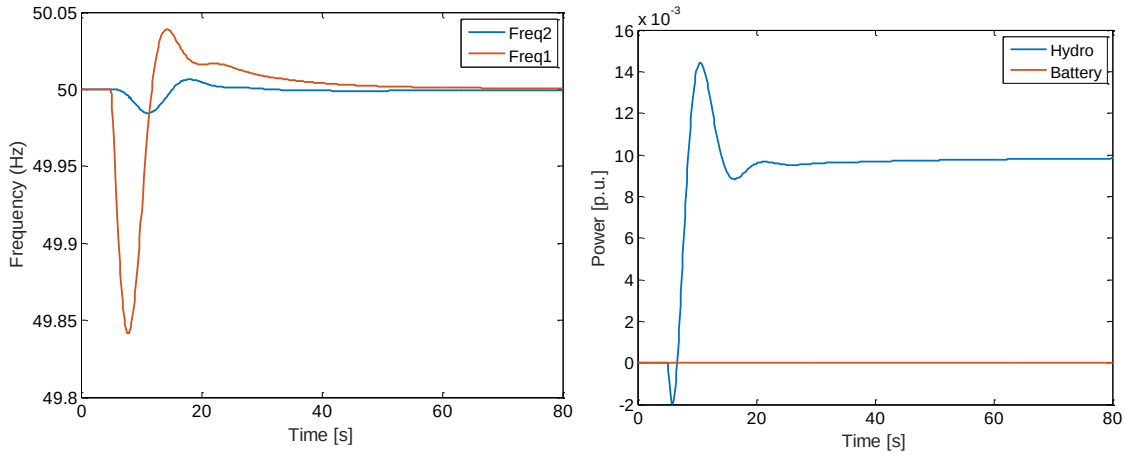


a) Frequency variation. b) Power contribution

Figure C.6. System behaviour under low inertia and hydroelectric based frequency control.

Scenario 2)

Hypotheses: Inertia constant H = 6.5 s; only hydroelectric units are considered for frequency control.



a) Frequency variation. b) Power contribution

Figure C.7. System behaviour under normal inertia and hydroelectric based frequency control.

Figure C.7 proves that, under normal operating conditions, of appropriate inertia, the power system will have no problem in stabilizing the frequency after a sudden load variation.

Scenario 2)

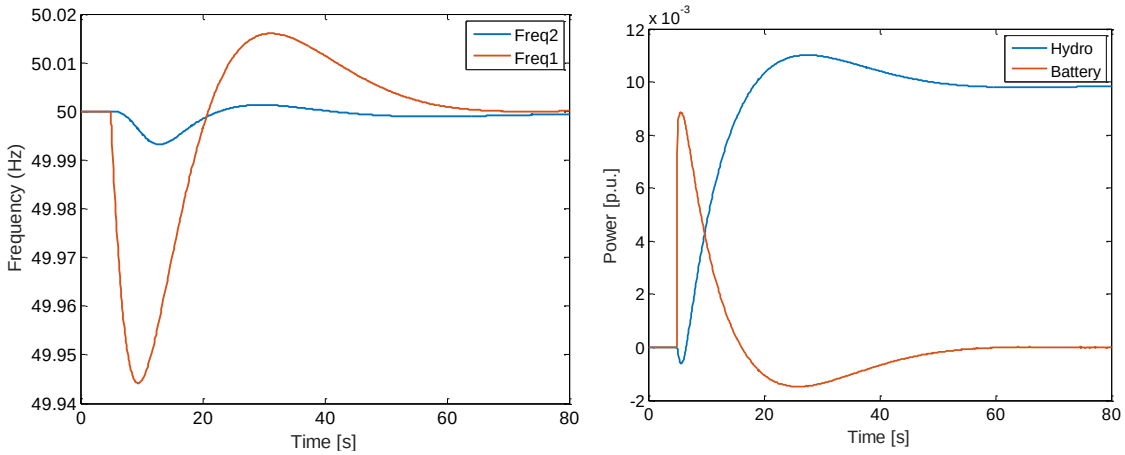
Hypotheses: *Inertia constant H = 3 s; beside hydroelectric units, battery energy storage system (BESS) is considered for frequency control. The battery has no power capability limitation. The battery will react to a binomial signal of the following type: 0.2Δf+0.8df/dt.*

As compared to Scenario 1), the contribution of a storage system that respond quickly mainly to RoCoF signal will provide the necessary stability performances of the power system. Figure C.8b illustrates the power contribution of both hydro and battery units. The battery provides a very fast response for frequency stabilization. As the hydro unit is the only included in the secondary

frequency control to cancel the area control error, it shows sustained power loading, which is then stabilized to a value equal to the power unbalance.

Although the grid code specifies that the automatic frequency replacement reserve (secondary control) must be deployed within maximum 15 seconds, the simulations shows that, with the specified characteristics, the hydro units are capable of providing this reserve within about 60-80 seconds.

It has been observed so far that the primary frequency control is designed to provide frequency stability, while the secondary frequency control is designed to provide power balancing within acceptable timeframe.



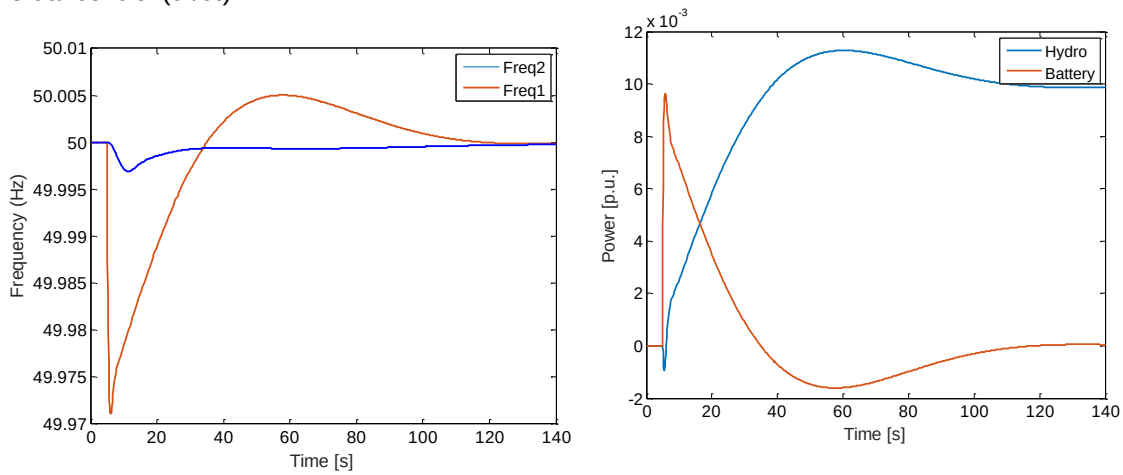
a) Frequency variation. b) Power contribution

Figure C.8. System behavior under low inertia and hydroelectric and battery based frequency control.

Scenario 3)

Hypotheses: *Inertia constant H = 3 s; beside hydroelectric units, BESS is considered for frequency control. The battery will react to a binomial signal of the following type: 0.8Δf+0.2df/dt.*

This scenario was introduced in order to compare the frequency response of the battery as reaction of the input signal, that is the response in the droop control (Δ*f*) and the response in the inertial control (d*f*/d*t*).



a) Frequency variation. b) Power contribution

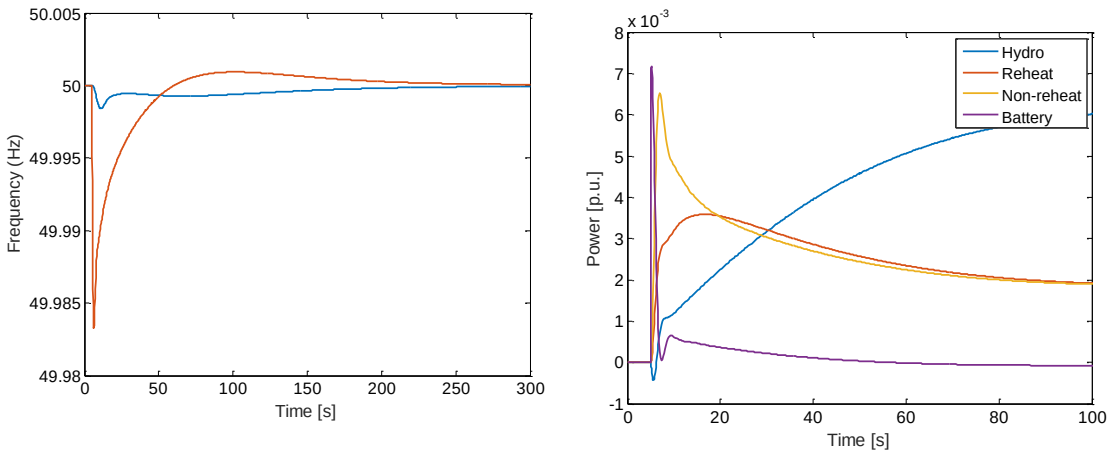
Figure C.9. System behaviour under low inertia and hydroelectric and battery based frequency control.

Comparing the scenarios 3 and 4 it can be seen that Figure C.8 (inertial response) exhibits a better inertial response, while Figure C.9 (droop response) shows that the battery has a faster response and frequency dip is smaller.

Scenario 4)

Hypotheses: *Inertia constant H = 6.5 s; hydroelectric, reheat and non-reheat units are considered in both primary and secondary control; BESS is also considered for frequency control. The battery will react to a binomial signal of the following type: 0.2Δf+0.8df/dt.*

The simulations (Figure C.10) have shown that the thermoelectric power plants (reheat and non-reheat) are capable of providing faster response for frequency stabilization than the hydroelectric units. This corresponds the actual situation, when a large share of generation come from thermal power plants. For instance, in Romania, the instantaneous generation from coal is about 30%, and the generation from natural gas is about 15%.



a) Frequency variation. b) Power contribution

Figure C.10. System behaviour under normal inertia value and all types of generation units considered for frequency control.

As illustrates in Figure C.10a, the frequency deep is smaller than in all the other cases, showing that more distributed is the frequency containment reserve, the better is the frequency stabilization. In terms of power, in this scenario, the response of the hydro unit is shifted in the secondary control timeframe because the task for primary frequency control is taken by the thermal power plant and the storage system.

C.2.2 Analysis of the importance of battery capacity

This sections aims at identifying the contribution to frequency control of the battery energy storage systems (BESS) when considering different power capabilities. Only hydroelectric units are considered as classical units, while the inertia is H = 3 s.

Analysis 1 – Influence of the weighting factor in the binomial input signal to BESS

Hypothesis: *Unlimited power and energy available in battery*

Figure C.11 shows the frequency response when using different weighting factors for the input signals. The simulation results show that a larger weighting factor assigned to the droop control is a better choice to reduce the frequency drop, while a larger weighting factor assigned to the RoCoF will provide a more realistic behaviour in terms of frequency oscillations damping.

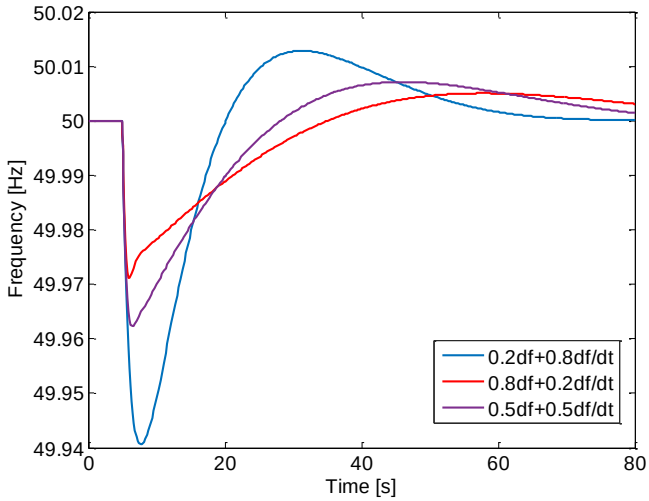


Figure C.11. Frequency response for unlimited battery.

Analysis 2 – The importance of BESS power capacity

Hypothesis: *Unlimited power and energy available in battery*

As illustrated in Figure C.12, when limited power capacity is considered for the BESS, the influence of the weighting factor has no influence on the frequency drop. This shows that:

- The time reaction is important for frequency stability;
- The frequency drop is strongly related to the power capacity that can be deployed by the BESS;
- The energy capacity of the BESS is less important for frequency stability

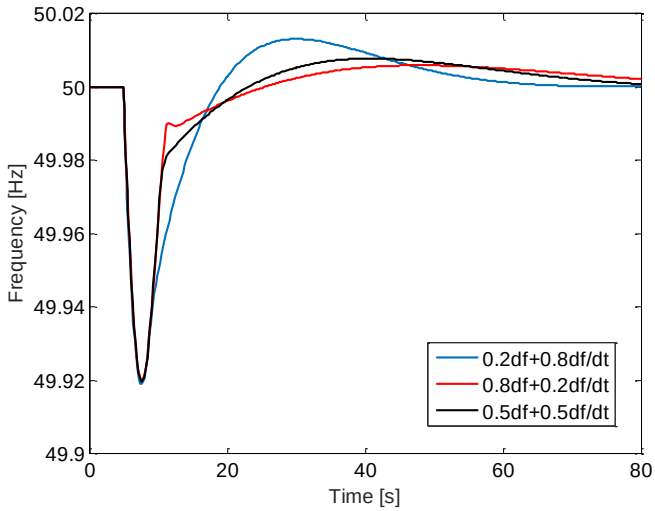


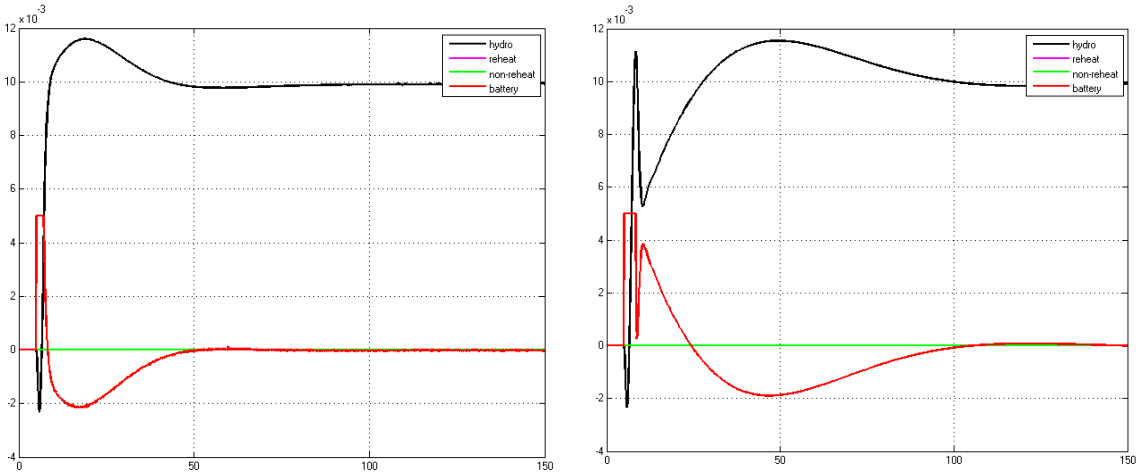
Figure C.12. Frequency response for limited battery

From the above statements, we may conclude the following:

- The **flywheels and super-capacitors** are more appropriate for providing **inertial frequency control** because they are characterized by **high power** and **low energy**, as well as the fastest time reaction for frequency control; we should mention that the two type of storage systems can be charged very fast so that they can be capable of providing inertial response for the next important event that occurs in the power system.
- The **Li-ion batteries** are more appropriate for **primary frequency control** because they are characterized by **low power** and **high energy**; if batteries are used for inertial control, their energy capability will not be efficiently used from economic point of view. On the other hand, for the actual technology of the Li-ion batteries, the fast

change in the operation mode (switching from charging to discharging and vice versa) may significantly reduce their lifetime.

In terms of the power deployed, with the storage unit limited to max = 0.005 p.u. and min = -0.005 p.u., we obtain the results presented in Figure C.13.



a) 0.2Δf+0.8df/dt 0.8Δf+0.2df/dt

Figure C.13. Power contribution for two scenarios of limited power capacity of the BESS

The power supplied by the BESS is quickly deployed, then replaced by the hydro unit. The energy provided by the BESS is also very small. Additionally, we can see that inertial control (Fig. C.13a) provides a more stabilized effect in terms of power control.

C.2.3 Analysis on the influence of droop value

Assumption 1: *H = 6.5 s; no battery used; only hydro unit is used for both primary and secondary control.*

The simulation results (Figure C.14) shows that a larger droop value helps damping the frequency oscillations within acceptable time frame, whereas smaller droop value may lead to frequency instability.

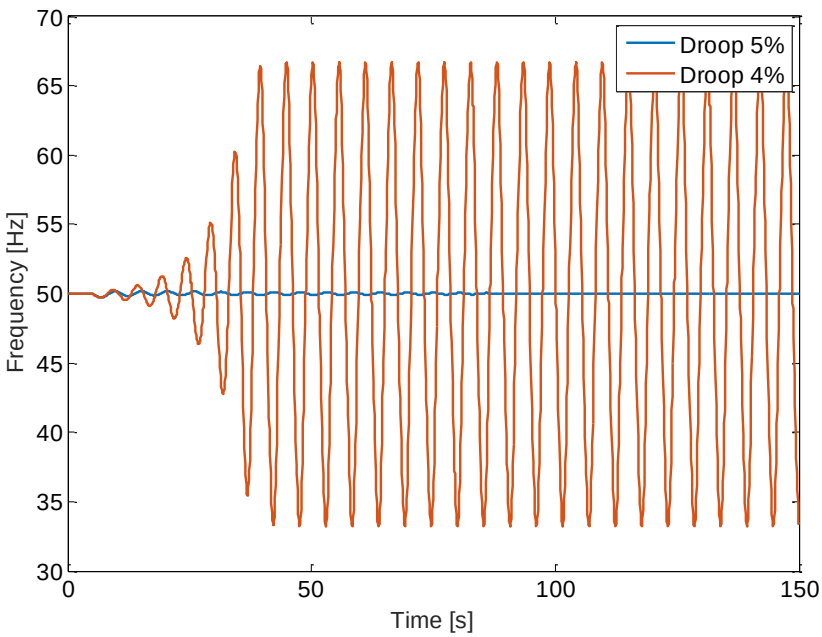


Figure C.14. Comparison of frequency stability for different droop values.

Assumption 2: *H = 6.5 s; a battery is integrated; only hydro unit is used for both primary and secondary control.*

The simulations results from Figure C.15 shows that the energy storage systems can assure frequency stability irrespective of the droop setting.

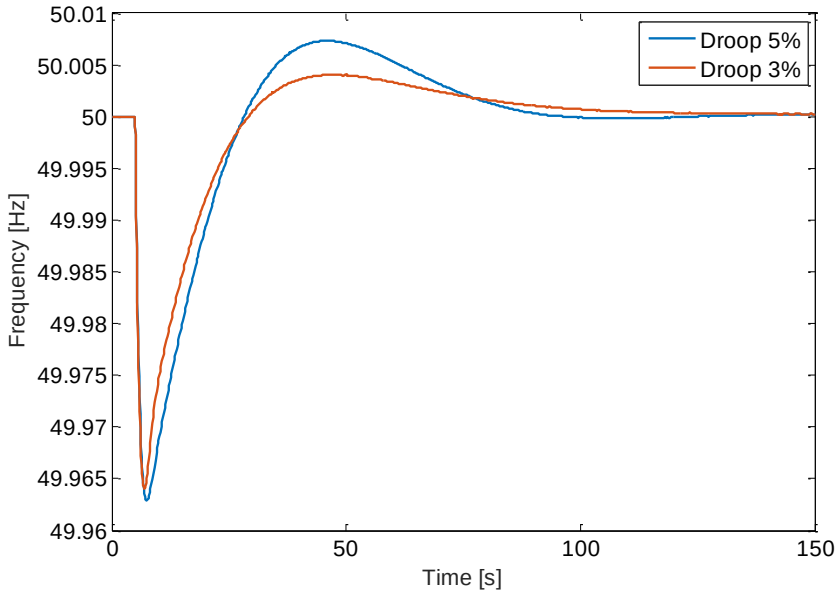


Figure C.15. Comparison of frequency stability for different droop values; the case of using batteries.

C.3 Conclusions

A generic diagram has been used in here to simulate combined primary and secondary frequency controls. The simulations have revealed the following:

- In power systems with reduced mechanical inertia, the hydro units are not capable of stabilizing the frequency.
- In order to allow frequency stabilization, fast reaction power sources, such as battery energy storage systems, must be used in such a way to simulate a virtual inertia.
- In low mechanical inertia systems, the droop value of the hydro units should be increased.
- Frequency stabilization depends on the immediate action of the fast sources. The amount of power produced by the sources influences the amplitude of the frequency drop.
- The primary frequency control level can be improved by compounding two input signals, namely the RoCoF and Δf.