Article

Determination of the required Power Response of Inverters to provide fast Frequency Support in Power Systems with low Synchronous Inertia

Alejandro Rubio [1,†,‡], Holger Behrends [1,‡] and Stefan Geißendörfer [2,*]

[1] Affiliation 1; e-mail@e-mail.com
[2] Affiliation 2; e-mail@e-mail.com
* Correspondence: e-mail@e-mail.com; Tel.: (optional; include country code; if there are multiple corresponding authors, add author initials) +xx-xxxx-xxx-xxxx (F.L.)
† Current address: Affiliation 3
‡ These authors contributed equally to this work.

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Abstract: Decommissioning of conventional power plants and the installation of inverter-based renewable energy technologies decreases overall power system inertia. This reduction in system inertia has an impact in the power system frequency response when an imbalance between generation and load occurs, increasing the rate of change of frequency (RoCoF) of the system. In a future scenario where renewables are predominant in power systems and due to the natural variability of the resource, imbalances of 40% or more are prompt to happen. When a system is islanded or operates as such and combined with low inertia, it may lead to frequency collapse. This expected high values of RoCoF shorten the response time needed before load shedding or generation curtailment take place and a subsequent possible black out occurs. Through the simulation of two scenarios with different primary reserve response, the requirements for the fleet of connected inverters was determined in terms of activation time and total power to be provided in order to avoid load shedding. This activation time was determined to be the time at which frequency would reach the load shedding value, known as critical time. With such value and knowing the time required for the synchronous reserve to deploy the imbalance power, a simple expression based on nullifying RoCoF at the critical time was obtained for the required inverter based fast power reserve. It was obtained that full activation time for inverter fast power reserve with penetration above 80% of inverter based generation would need to be between 50-500 ms for imbalances up to 40%; meaning that current frequency measurement techniques and renewable deployment times would not ensure system stability under the foreseen future possible power system conditions. A power ramp in the order of 300% the load per second is necessary for fast power reserve to maintain frequency within the allowed limits.

Keywords: frequency support, flexibilization, renewables, inverters

1. Introduction

As part of the international efforts set to counteract global warming, the deployment of renewable energies in the electric sector has been considered an energetic priority as a measure to reduce CO_2 emissions. This objective is also reflected in the regulatory energy policies and plans of some countries. For instance, in Germany the transformation of the electricity sector through renewables, known as ”Energiewende”, contemplates to achieve a share in electricity consumption from renewables of 80% by 2050 [3]. As part of it, the renewable energy act, ”Erneuerbare Energien Gesetz”, regulates the expansion of renewables and convectional generation decommissioning.

Decommissioning of convectional generating power plants and its replacement with inverter-based renewables power plants has as an effect, the reduction of system inertia and consequently increasing values of RoCoF. The relevance of system inertia is to avoid rapid changes in frequency as load-generation imbalance takes place; in this way, enough time is given to the activation of the primary power reserve to recover the balanced stable conditions[ref]. Currently in Germany, plant commitment of renewable energy plants have a priority in the power market for dispatch due to its zero marginal cost for generation. This has an effect in market auctions and also technical implications [12]. Balancing of the residual load is provided by conventional units, so curtailment of renewable energy resources is the last prefered option for power balancing [16].

As an immediate result of an imbalance between generation and load the system frequency starts deviating from its rated value. The range of 49.8 Hz and 50.2, in Continental Europe, should be maintained by reserves after a power imbalance. This frequency range corresponds to the ordinary operation range. The primary reserve for the interconnected system is able to withstand a power imbalance of 3 GW when the system has a total load of 150 GW [1]. At an European level, the dimensioning reference case scenario of power loss of 3 GW has been found adequate even with high penetration of renewables [1, 16]. Nevertheless, there will be still many hours with positive residual load and due to the decommissioning of conventional power plants [16, 17]; their diminished capacity to provide balancing power services at such low inertia levels will have to be compensated by balancing services coming from renewables/storage. Additionally to the uncertainty of conventional generation availability in the German power system, is also not clear whether instantaneous reserve services from abroad would be available and if transmission capacities will be enough for such [16].

Some ancillary services have been included in the inverter's capabilities; inverter based generation from PV has been employed to contribute in voltage regulation by means of providing reactive power to the grid. Similarly, other approaches have been implemented for over frequency cases, by curtailment implementation and ramping limitation of inverters when system frequency approaches an upper limit allowed by local codes [4, 5]. In the same sense, new techniques have been developed in order to enable inverter based generation, such as PV and wind, to also participate in frequency support for under-frequency cases. The most common techniques try to emulate the droop power-frequency characteristic of the synchronous machine by leaving some power headroom during normal operation, so when a system frequency sag occurs, the inverter is able to push part or the total available headroom power in order to counteract the frequency drop [6]. Hence renewable sources are not any longer operating at its maximum power point, therefore these methods also have some economic constraints. Another approach to limit the frequency drop during the seconds after an event leading to a frequency decay, is to mimic the inertial response of synchronous machines. Since PV systems do not count with rotating masses, this approach is only achievable with wind turbines and called synthetic or hidden inertia [ref]. Due to the decoupling of wind turbines from the grid dynamics, modified control strategies in the power electronics allows the controller to extract part of the stored kinetic energy in the rotating masses of the wind turbine [6].

Although the integration of more inverter based generations brings higher values of RoCoF, they also present the solution with the implementation of fast power reserves for frequency supports. Whereas synchronous power reserve deployment is in the order of few seconds (5-30s), power electronics implementation offer full power deployment in the order of miliseconds [ref]. Table [ref] list some important and typical time scales of the most common power electronic technologies implemented in modern power systems.

Insert table with values of time from GE.

In this investigation the conditions, which should be fulfilled by inverters in highly penetrated grids by non-synchronous generation, to provide an inverter based fast power reserve (IBFPR) are investigated. Then the required triggering time and power response to avoid under-frequency load shedding (UFLS) are estimated. Over-frequency phenomenon is treated with the same approach as the under-frequency case. The effectiveness of synthetic inertia is evaluated under some assumed future scenario conditions. Three cases are utilized in order to assess the influence of the grid size, synchronous response and common simplifications made in power system analysis. The IEEE 9 bus benchmark grid model and an electric power system in the European scale are considered for such purpose; a methodology to determine the requirements of the fleet of inverters to offer frequency support is developed.

Mention some of the results from the investigation.....

2. Methodology

2.1. Background

When the global security of the system is endangered and under/above frequency is experienced then load shedding is activated; the system is said to be in the emergency state [ref]. If the frequency exceeds the range of 47.5 Hz or 51.5 Hz, a system blackout can hardly be avoided [1]. Consequently the system will reach the so-called blackout state and will have to be restored. Before black out, the system tries to recover balance by load shedding and generation curtailment. Load shedding starts at 49 Hz rejecting partial loads as frequecy decreases. On the other hand, curtailment thresholds between 50.2 and 50.5 have been studied by ENTSOE for over-frequency scenarios [1]. In this research, a deviation of 1 Hz is used as threshold before load shedding and curtailment starts. Hence, to keep frequency within such threshold; the investigated critical time and power response, correspond to the maximum allowed activation time for fast power reserve in order to inject power from renewables or storage in case of under-frequency; or to extract power from the grid to be stored or converter in another energy form in the case of over-frequency.

Although the focus of this investigation was centered in the positive power injection to avoid under frequency load shedding; as it will be demonstrated in the result section, the required fast power reserve and critical times can be also understood as negative reserve for over-frequency cases too.

The transitory frequency response of the system and therefore its stable and reliable operation after a perturbation, depends on the inherent characteristics of the power system and the counteraction measurements engaged automatically by the power system. As the share of inverter based generation increases, the more sensible to instability the power system becomes. In this sense the added inverter based fast power reserve must be capable of maintaining transitory frequency value within the allowed limits. Two terms commonly found in the literature of power system stability will be used along this section:

- **Inertia constant (H)**: It has units of seconds (s) and it is the ratio of the kinetic energy stored in the rotating masses of the generators (E_k in MWs) and its nominal capacity (S_{nom} in MVA).

- **Acceleration time constant ($\mathbf{T_a}$)**: It also has the units of seconds (s) but this is the ratio of double the kinetic energy (MWs) and generators nominal power output (P_{nom} in MW).
  Acceleration time constant is a measure of the robustness before disturbances of the system. It could be interpreted as the required time to remove the kinetic energy from the rotating masses of the generators connected in a grid at the rate of the supplied power load. Hence, the higher the time constant, the higher the kinetic energy available. As the share of synchronous generations decreases, this constant decreases proportionally.

With f as frequency, f_0 as nominal frequency and ΔP as power imbalance the swing equation can be expressed as follows [ref]:

$$\frac{df}{dt} = \frac{\Delta P * f_0}{2 * H * S_{nom}} = \frac{\Delta P * f_0}{T_a * P_{nom}} = \frac{\Delta P * f_0}{2 * E_k} \tag{1}$$

In this paper, the inertia constant H is used for the description of synthetic inertia in wind turbines and single synchronous machine representation, whereas the system acceleration constant T_a is used to express the whole system inertia related to the load in terms of real power.

2.2. Frequency Support from Inverter based Generation

In this section the methodology and considerations for the implementation of inverter based generation for frequency support are explained. In this research the application of inverter based generation for frequency support is limited to the implementation of synthetic inertia and fast power reserve.

2.2.1. Synthetic Inertia

Synthetic inertia is one of the new techniques that manufactures and researchers are considering to tackle with the low inertia problem in power systems [7][6]. Frequency support through synthetic inertia was considered with the following assumptions [3][12]:

1. Power output from synthetic inertia is limited to 10% of wind turbine nominal power.
2. Due to mechanical and thermal stresses, the additional power can be delivered only for a maximum time of 10 s.
3. It is assumed that all wind turbines operate at its nominal power output. The value of 1.5 MW was selected for such purpose.
4. The maximum allowable amount of kinetic energy to be extracted from the turbines was limit to half of the kinetic energy while the turmine operates at nominal speed [4].

An adequate control system is needed so the stored energy in the rotating blades can be extracted from the wind turbine. From the expression of power as the derivative of energy stored in the blades (2), the rate of energy extracted from the wind turbine can be obtained, considering that the rotational speed changes in time [ref].

$$P_{pu}(t) = 2 * H_{wt} * \omega_{pu}(t) * \frac{d\omega_{pu}(t)}{dt} \tag{2}$$

Where H_{wt} is the turbine inertia constant and ω_{pu} the rotational speed in per unit.

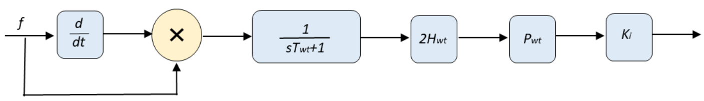


Figure 1. Representation of equation (2) in the model. In the figure it can be seen the insertion of a filter at the output of the multiplication block. A constant block K_i adjusts the initial response in the model. Since equation (2) is given in pu, the output is multiplied by a constant P_{wt} representing the rated power of the turbine.

Typical values for inertia constant of wind turbines are not openly available from the manufacturers to the public. Hence an approximate value was calculated with the utilization of an equation which relates nominal power and inertia constant for wind turbines [8].

$$H_{wt} \approx 1.87 * P_{nwt}^{0.0597} \tag{3}$$

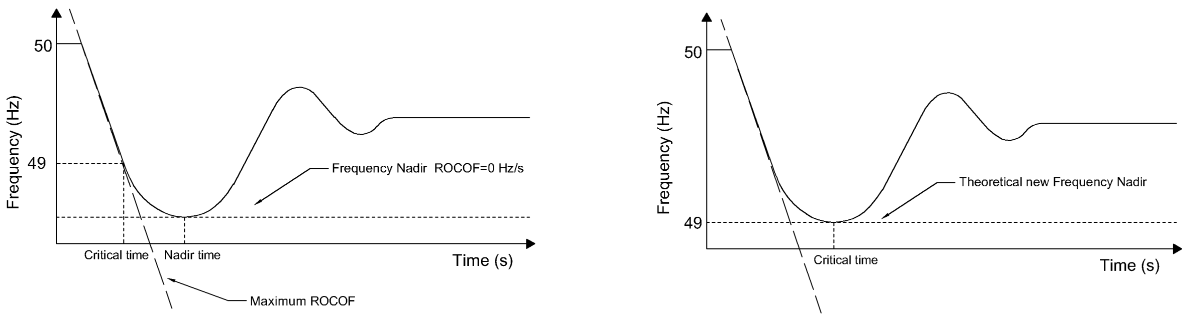
For a wind turbine with nominal power output of 1.5 MW the value of H corresponds to 4.37 s [17]. It is assumed that all the wind turbines deliver their nominal power output. A rated rotational speed of 18 rev/min was considered [28]. To avoid the wind turbine to stall, a reduction of 5 rev/min it is allowed by the implementation of the control system. This change of rotational speed equals a change of 3 MWs reduction on kinetic energy out of a total of 6 MWs.

Table 1. : Constants for implementation of synthetic inertia

T_{wt}	H_{wt} (s)	P_{wt} (MW)	K_i
1	4.37	1.5*n_{wt}[1]	10

2.2.2. Inverter based fast Power Reserve

When a power system is subjected to a negative power imbalance and it is assumed that no load is rejected at UFLS frequency, this continues dropping below 49 Hz. The time at which the system frequency equals the UFLS value is then called critical time. This is the maximum available time for the inverter based reserve to deploy the required power to the system.



(a) Typical frequency response leading to UFLS **(b)** Desired frequency response avoiding UFLS

Figure 2. In (**a**) the frequency response goes below the 49 Hz leading to UFLS at the critical time, whereas in (**b**) the IBFPR is applied avoiding ULFS. In this case the power imbalance is compensated at the critical time by the inverters.

In the critical condition that would lead to load shedding, it is expected from the IBFPR to at least to counteract the RoCoF at the critical time, as illustrated in Figure 2b. Recalling equation (1); it is necessary that the machine's accelerating power (power imbalance) become zero at the critical time.

$$P_a(t_{cr}) = P_{mech} - P_{elec} + P_{IBFPR} = 0 \tag{4}$$

Where P_a is accelerating power, P_{mech} is mechanical power, P_{elec} is electrical power load, t_{cr} is the critical time and P_{IBFPR} is inverter based fast power reserve. From the assumption of a linear mechanical power deployment is given from the synchronous machines governors, the rate of change in mechanical power, after a power imbalance ΔP, is given by $\Delta P/t_{nadir}$, where t_{nadir} represents the time at which the frequency nadir occurs. Given the power balance at the critical time, t_{cr}; the IBFPR response must be equal to $P_{elec} - P_{mech}$, being P_{elec} equal to ΔP.

Substituting P_{mech} by $\Delta P * t_{cr}/_{tnadir}$ and P_{elec} by ΔP in (4), the following expression is obtained for the P_{IBFPR} at time t_{cr}:

$$P_{IBFPR}(t_{cr}) = \Delta P * (1 - t_{cr}/t_{nadir}) \tag{5}$$

It is assumed that P_{IBFPR} remains with a constant power output after t_{cr} long enough to stabilize the system frequency. The result of the previous equation represents the slope of the power output since the inception of the incident until the critical time, which with the implementation of IBFPR, it will be not any longer critical but rather it will be the new desired frequency nadir time.

$$P_{IBFPR}(t) = \frac{\Delta P * (1 - t_{cr}/t_{nadir}) * t}{t_{cr}} \tag{6}$$

According to the obtained expression; it can be realized that the desired power response from the inverters depends exclusively on parameters which cannot be directly measured from the grid connection point. In a real situation the values of ΔP, t_{nadir} and t_{cr} cannot be known in advance, representing this factors a challenge in the implementation of this ideal power response. Those values are dependent on the grid characteristics, the primary conventional reserve deployment time and the overall system inertia [14]. Thus two main cases are considered for the remaining analysis with the intent of covering a wider range of systems with different characteristics and dimensions.

2.3. Simulation Cases

As presented in the previous section, the values of critical time and frequency nadir time depend on the system imbalance and primary reserve deployment time. In spite of assessing the influence of the grid size and the primary reserve characteristics, two main cases are considered. In both cases is assumed that the initial steady frequency is the nominal 50 Hz.

- **Small scale grid case:** For the evaluation of this case typical governor data is considered in a well-known and studied benchmark grid topology as the WSCC model, also known as the IEEE 9 bus model. Synchronous reserve deployment is in the order of a few seconds due to governor response [11][15].

  Scenario A - Simplified Model: The power system is represented by an equivalent single machine model in which losses are neglected. It is investigated the critical time for inverters' activation and the required IBFPR is also determined. Furthermore, the impact of synthetic inertia and the frequency measurement delay in frequency response is analyzed.

  Scenario B - Extended Model: All the power system components (transmission lines, transformers, exciters and governors of the three generators) and its dynamic characteristics are considered in the IEEE 9 bus model.

- **Large scale grid case:** The European grid scale in which all the synchronous machines are modeled and simplified as one single machine, provided with the characteristic expected from the overall system. Synchronous primary reserve deployment is in the order of $\sim$ 30 s [5][10]. Island frequency response is assumed to be the same that the European response analyzed by ENTSOE [5].

2.4. Simplified IEEE 9 bus Model

As a first step to evaluate the impact of inverter based generation and power imbalances in the grid, the whole system is simplified as one single generating unit; neglecting all losses in the system (Transformers, transmission lines and generators) with the assumption that the mechanical output of the prime mover is the same than the electrical power output at generator terminals. Table 2 provides a summary of the elements comprising the base model.

Figure 3 is the block representation of the swing equation (1), it only differs in the fact that blocks representing the inverter based generation have been included. The mechanical power is represented by the output of a steam turbine governor model, which is used to represent the synchronous machine [1]. When equilibrium is lost, the accelerating power is multiply by the transfer function $1/(2 * H * S)$, where H is the machine's inertia constant and S is the machine's power rating. From (1) this product equals the derivative of frequency, therefore an integrator block is added to

Table 2. :Elements of the IEEE 9 bus model.

	Quantity
Buses	9
Transformers	3
Transmission Lines	6
Generators	3
Load	315 MW

obtain the frequency response [11][9][13]. A feedback loop is added and an error signal obtained from the reference frequency so the synchronous machine can react as frequency deviates from nominal.

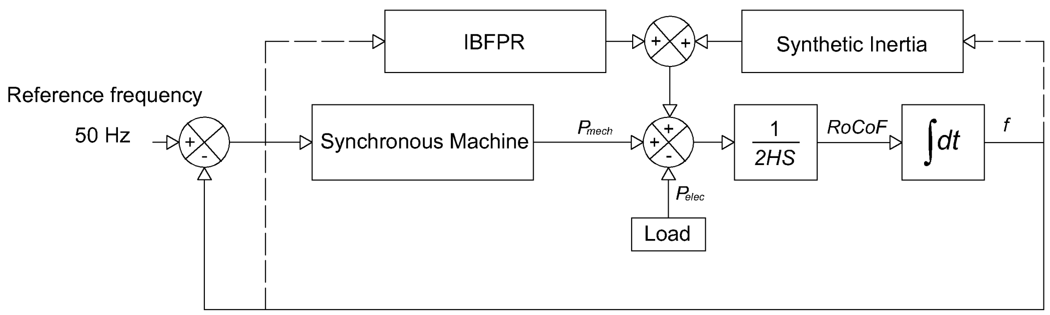


Figure 3. Simplified representation of the IEEE 9 bus model. Blocks linked by the solid line represent the conventional swing equation given by (1). Represented with doted lines, the respective frequency signals to the blocks of IBFPR and synthetic inertia, which add power to the system.

The values of kinetic energy and time constants of a synchronous machines of 835 MVA were selected to represent the synchronous response, with the load of 315 MW the system acceleration time constant is 14 s, which is approximately today's Europe acceleration constant [5]. This is the base scenario where an 100% synchronous generation is assumed . For the sake of evaluating the impact of the penetration of inverter based generation; the values of lower capacity generators were selected, diminishing in the sense the total system inertia [1].

Even though load imbalances up to 40% were simulated in each inertia scenario, for estimation of the critical time the power capacity limit of the generators was disregarded. The negative imbalance was simulated by increasing the system load. A block diagram representing the system shown in Figure 3 was implemented in SIMULINK with different combinations of power imbalance and system inertia.

2.5. Extended IEEE 9 bus Model

Since it is desired to compare the results obtained in 2.4 against some model that takes into account the whole system components, losses and dynamics; An extended representation of the IEEE 9 bus model was implemented in SIMULINK [2]. In this representation, simulations for different values of system inertia and load imbalance were performed, similarly as it was done with the simplified representation of the model. Figure 4 shows the extended IEEE 9 bus grid architecture with IBG added. In order to evaluate the validity of the equation describing the IBFPR needed to avoid ULFS, the IEEE model was modified with the insertion of ideal controlled power sources blocks, which were set up to inject power into the grid accordingly to the simulated scenario. Therefore, no means of frequency measurement were included and only IBFPR was assessed. Similarly as it was done in section 2.4, the total acceleration time constant of the system equals 14 s. Hence the same kinetic energy should be distributed among the three generators' rotating masses in the extended model as in the simplified

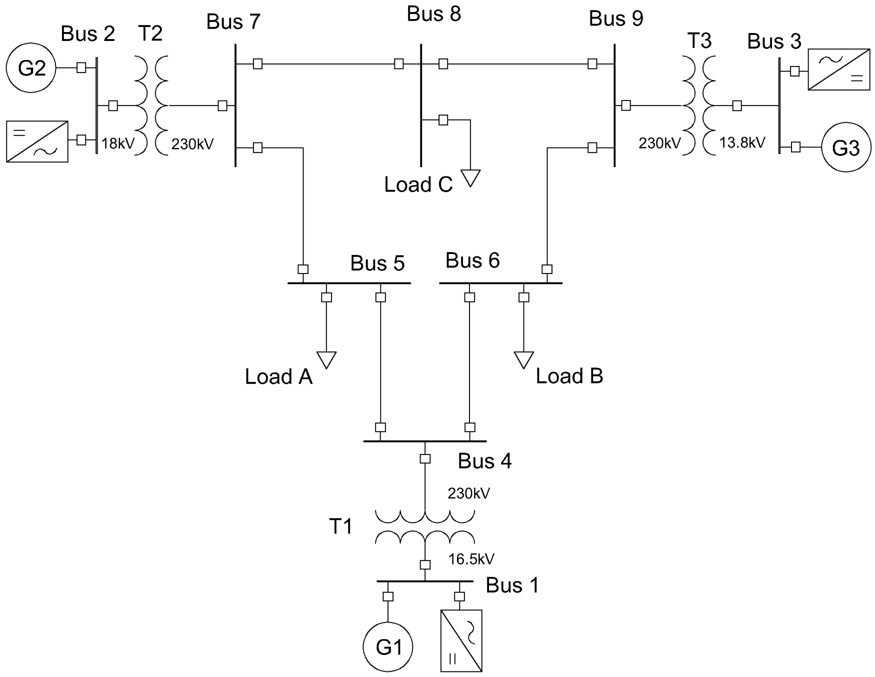


Figure 4. One line diagram of the IEEE 9 bus model. The inverter based frequency response has been added At the same bus of the generating units.

representation. From (7) it can be easily calculated that the system kinetic energy with 14 s is 2205 MWs (100% synchronous generation).

$$T_{sys} = (2 * E_k)/P_{load} \tag{7}$$

Due to the fact that inverter based generation reduces the system kinetic energy; for different levels of inverter based generation, the generators nominal capacity values were kept constant and the inertia constant of each machine multiplied by the synchronous share factor fss. The total kinetic energy of the system is the summation of all units. In such manner the synchronous generators in the initial state of equilibrium represent both power sources, inverter based plus synchronous.
In order to start the simulations in steady state, a load flow calculation of the grid was carried out with the objective of calculating the initial conditions for the exciter and prime mover models. Table 3 summarizes the main values for setting system initial conditions; acquired from the power flow tool provided by SIMSCAPE.

Table 3. : Steady state initial conditions of the system

Bus number	Bus Type	Voltage (pu)	Active Power (MW)	Reactive Power (MVAr)
1	Slack	$1.04 \angle 0^\circ$	72.2	25.64
2	PV	$1.025 \angle 9.83^\circ$	163	8
3	PV	$1.025 \angle 4.63^\circ$	85	-9.41
5	PQ	$0.9949 \angle -4.42^\circ$	125	50
6	PQ	$1.01211 \angle -4.16^\circ$	90	30
8	PQ	$1.0172 \angle 0.17^\circ$	100	35

2.5.1. IBFPR Representation

The IBFPR was modeled as controlled current sources. These controlled sources inject active power according to the load imbalance and system inertia simulated. The continuous measurement of voltage is required in order to determine the amount of current needed to supply the requested power.

The IBFPR will have symmetrical and balanced characteristics. Due to this reason, the magnitude and angle of the current phasor will be obtained from the positive sequence of the measured voltage. From the definition of complex power and voltage symmetrical components in three phase systems (8), the positive sequence component of phase voltage and line current are obtained [9].

$$S_{3\varphi}^{1} = 3 * V_{LN}^{1} * \bar{I_L}^{1} \tag{8}$$

This equation is valid for RMS values of voltage and current; nevertheless the measured voltage values and the sought current values are given in peak values, the equation for power and current become:

$$S_{3\varphi}^{1} = \frac{3 * V_{LNpeak}^{1} * \bar{I}_{Lpeak}^{1}}{2} \tag{9}$$

$$I_{Lpeak}^{1} = \frac{2 * \bar{S}_{3\varphi}^{1}}{3 * V_{LNpeak}^{1}} \tag{10}$$

With the help of the **a** operator ($-0.5 + j\sqrt{3}$ or $1\angle 120^{\circ}$) the values of the positive sequence component of phase voltage can be obtained.
From $V_a + V_b + V_c = 0$ and $V_a^1 = \frac{V_a + aV_b + a^2V_c}{3}$:

$$\begin{aligned} V_a^1 &= \frac{V_a + aV_b - a^2V_b - a^2}{3} \\ &= \frac{V_a * (1 - a^2) + aV_b * (1 - a)}{3} \end{aligned}$$

Since $V_{an}^1 = \frac{V_a^1}{\sqrt{3}\angle 30^{\circ}}$, $\sqrt{3}\angle 30^{\circ} = 1 - a^2$ and $\sqrt{3}\angle -30^{\circ} = 1 - a$ then after some algebraic manipulation the expression for V_{an}^1 becomes:

$$V_{an}^{1} = \frac{V_a - a^2V_b}{3} \tag{11}$$

With the obtained expressions for the positive sequence of phase voltage (11) and complex power (9), the needed current (10) to supply the IBFPR related to the measured voltages can be implemented in SIMULINK as depicted in FIGUREXXX. The ramping function will last until the critical time is reached, afterwards, the IBFPR output will remain constant.

2.6. Large Scale Case: Europe Power System

Under normal operation ENTSOE has reported values of RoCoF in the range of 5-10 mHz/s for power outages of 1 GW in the current interconnected power system. If an imbalance event of more than 3 GW occurs with depleted primary reserve, extraordinary values of frequency and RoCoF might be reached. After serious disturbances the Continental European Power System has experienced RoCoF between 100 mHz/s and 1 Hz/s. Imbalances of 20% or more along with RoCoF greater than 1 Hz/s have been determined by experience to be critical [5]. ENTSOE has determined that under the case of the reference scenario (The loss of 3 GW generation with 150 GW load and 2%/Hz self-regulation) in the interconnected operation, the influence of inverter based generation, and therefore the reduction of system inertia would not jeopardize system stability. Due to the expected increase of non-synchronous generation in the future, international power trade and renewables variability; ENTSOE estates in its future split reference scenario that the power system must be capable of withstanding imbalances greater than 40% with RoCoF of 2 Hz/s or higher. Under these circumstances the resulting islands must avoid load shedding. Hence, only the split scenario is considered for further analysis.

When considering the system blackout of November 4th 2006, in which four electric islands resulted from the European system split; system blackout due to under frequency was experienced in the so known western area. This island, at the moment of split, had approximately a load of 190 GW (27% more than the low load scenario of ENTSOE) [16]. For its comparable 'size' and the uncertainty of knowing beforehand the resulting islands after a major contingency, the selected load for simulation was the same as the ENTSOE reference scenario as well as the primary reserve deployment time. To simulate the behavior of the resulting island in the European split scenario; a simplified approach was selected. Similarly as it was done with the simplified block model for the IEEE 9 bus model, in the equivalent European representation all the synchronous generation will be represented by a single machine, which will provide governor response when a perturbation takes place. Additional to the synchronous response, a load response of 2% was added to the model, which means that for every Hertz reduced or augmented, the load will reduce or increase by a 2% [5].

In order to fit the behavior of the system to the modeled by ENTSOE, an additional block was added the IEEE simplified model in the steam turbine governor; this was done with the intention of adjusting the time response of the primary reserve as much as possible to the desired one. With this approach, the primary power reserve can be easily tuned with the assistance of the Control System Tuner App available in MATLAB. The period of time of utmost interest for analysis is from the inception of the power imbalance and the nadir time. Therefore, the system must perform as similar as possible in this region compared to the ENTSOE reference, whereas after the nadir time, the disparity between responses can be neglected. In the European scale the reserves must be completely deployed within 30 s after the occurrence of the disturbance.

2.6.1. System Parameters

A power system of n number of synchronous machines is assumed; having each of them a capacity S in MVA, a nominal power P_{nom} in MW. Assuming that each machine operates at a de-load factor dl of P_{nom}; with an acceleration constant equal to T_{nom} then the number of machines n, for the load $P_{syncload}$, served by synchronous machines is:

$$n = \frac{P_{syncload}}{P_{nom} * dl} \tag{12}$$

Then the time acceleration constant of the system T_{sys} can be obtained as follows:

$$\begin{aligned} T_{sys} &= \frac{\sum_{i=1}^{n} P_i * T_i}{P_{LOAD}} \\ &= \frac{nP_{nom} * T_i}{P_{LOAD}} \\ &= \frac{P_{syncload} * T_{nom}}{P_{LOAD} * dl} \\ &= \frac{Syncshare * T_{nom}}{dl} \end{aligned} \tag{13}$$

In this sense the system time acceleration constant can be calculated with a synchronous share of 100%, resulting in $T_{sys} = 12.5$ s with values of $T_{nom} = 10$ s [5][1], and a de-load factor $dl = 0.8$. The values of the additional block in the model are set in order to have a step response with 2% overshoot and a time constant of 8 seconds [13]. Considering only the swing equation, as done in the model, it can be demonstrated that the RoCoF and therefore the frequency response of the system is only dependent on the percentage of load imbalance and the system acceleration time constant. From the definition of RoCoF as $\frac{df}{dt} = \frac{\Delta P * f_0}{2 * E_k}$ and $T_{sys} = \frac{2 * E_k}{P_{LOAD}}$:

$$\frac{df}{dt} = \frac{\Delta P * f_0}{P_{LOAD} * T_{sys}} = \frac{\Delta P_{pu} * f_0}{P_{LOAD} * T_{sys}} \tag{14}$$

In (14) the value of ΔP_{pu} is the normalized value of power imbalance having as base power the value of load P_{LOAD}. As shown in the equation, when only the swing equation is considered, the frequency response is only dependent on system acceleration constant and the relative value of imbalance. This relative value of imbalance varies during time, depending on load response to change on frequency and the response of primary reserve of the system.

3. Results

3.1. Analysis of Critical Time

When the simplified and the extended models of the IEEE benchmark are compared for the estimation of the critical time, it is noticed a higher deviation in the low range of RoCoF. This due to the fact that in this range of RoCoF the critical time is long enough to allow the governor response activation of the respective synchronous machines representation. Therefore it can be stated that the simplifications made in the model have a greater influence on the results for low values of penetration of IBG and low power imbalances; in this sense, the simplifications become less significant as the RoCoF increases in such a manner that the activated synchronous primary reserve is not relevant in frequency support.In the range of higher values of RoCoF than 2 Hz/s, the critical time trend for the European grid-scale and the simplified IEEE model get closer each other as RoCoF increases.

Therefore under high RoCoF conditions in any of the models, the primary reserve does not significantly counteract the frequency drop [16]. Figure 5 1 demonstrates that primary reserve can be neglected for determining the critical time when the combination of IBG and load imbalances would lead to high values of RoCoF; as RoCoF increases, the approximation of critical time as 1Hz/RoCoF narrows the difference with the results obtained from simulations [14].Nevertheless, such simplification applies to the simplified IEEE model and the European island. Hence, the influence of all the dynamics and machine components, such as generator exciter and damping windings, seems to improve the critical time. Damping torque in equation [7, 8] was not considered for the IEEE simplified model; the inclusion of such may lead to more precise times when compared with the extended model.

Table 4. : Critical time for European-scale case given in seconds.

IBG share (%)	Load Imbalance (%)							
	3	4	5	6	7	8	9	10
20	-	-	6.081	4.517	3.629	3.050	2.638	2.316
40	-	6.226	4.169	3.215	2.628	2.222	1.934	1.705
60	7.142	3.639	2.623	2.062	1.698	1.451	1.263	1.122
80	2.753	1.744	1.277	1.018	0.843	0.722	0.628	0.559
92	1.109	0.700	0.514	0.406	0.338	0.288	0.252	0.224
95	0.697	0.436	0.322	0.254	0.211	0.179	0.157	0.140

Due to the fact that the characteristics of the European interconnected scenario provided by ENTSOE were assumed to be the same than the resulting islands after a severe event; the results for the large scale model can be understood as the behavior of the whole European system with bigger perturbations. The dimensioning scenario assumes a power imbalance of 3 GW, which corresponds to a 2% of the 150 GW load [1]. If in future a bigger dimensioning case is utilized, then synchronous response would not be enough to balance the system before load shedding occurs. Table 5 1 exhibits the required time when the dimensioning scenario is increased up to 10% for different IBG penetration.

3.2. Analysis of Synthetic Inertia and Fast Power Reserve

3.2.1. Effect Synthetic Inertia on Frequency

In this section are presented the results of the simulations carried out in the simplified IEEE model and the European model with the implementation of synthetic inertia control to the wind share of the IBG. The frequency nadir for such systems without any additional power support apart from synchronous response are illustrated in figures XXX and XXX.

Insert the figures here of no SI support

this as caption For the acceleration constant corresponding to the 80% of the IBG, the frequency nadir reaches values lower than 49 Hz with power imbalances starting at $\sim$ 7%. this as caption At 80% of IBG, frequecy nadir reaches 48.73 Hz with only $\sim$ 3% of imbalance.

Insert figures with synthetic inertia here.
In any of the cases UFLS is not avoided for all combination of variables (imbalance and acceleration constant). It can also be observed that frequency nadir under 49 Hz are reached for imbalances bigger than 14% combined with shares of IBG above 80%. simplified.

In the same manner than fig, in fig XXX the synthetic inertia is not enough for withstanding severe imbalances under high penetration of inverter based generators. At 80% of IBG, the frequecy nadir reaches 48.89 Hz with an imbalance of 3%.

An enhanced performance is achieved in the simplified IEEE model as depicted in FIGIRE XXX. The reason behind this, is the faster response of the synchronous share present in the system, which jointly performs with the synthetic inertia to improve over all frequency response performance. In Figure XXX can be observed how power is deployed in a few seconds in the simplified IEEE model whereas in the European model the response is always limited to fully deployment in the order of $\sim$ 30s.

Insert figure of the power response and freq response over time

Figure 4 9 and Figure 4 10 indicate the frequency response obtained of the system with an non-synchronous generation of 80% for different load imbalances. In Figure 4 9 can be observed how the frequency drops below 49 Hz with a 10% of imbalance, when no IBFPR or synthetic inertia is used as frequency support estrategy. In the same figure, the frequency responses for different levels of synthetic inertia is presented.

It is noticed the improvement in FIG XXX in the response with the implementation of synthetic inertia with each contribution of wind energy to the non-synchronous generation. UFLS is avoided for every share of synthetic inertia, assuming that primary reserve takes place after SI. As the imbalance increases, the effectiveness of the synthetic inertia decreases, depending on the contribution of wind power to the inverter based generation. Figure 4 10 shows how a contribution of wind power of 40% from the inverter based generation is capable of avoiding UFLS. Nevertheless the share of 80% begins with a low rate of frequency decrement, the frequency sudenly drops below 49 Hz. This is due to the high amount of synthetic inertial power when compared to the load imbalance. This situation leads to UFLS after the 10 s because frequency has been sustained during that time by the synthetic inertial power. Since 10 seconds is the assumed time limit for exceeding nominal turbine power rate; the synthetic inertial power, which has a big contribution to counteract the power imbalance, is switched off as depicted in Figure 4 11. On the other hand, when a higher imbalance occurs and the synthetic inertial response is saturated, due to the limitation of 10% of rated power, the mechanical power increases at 10 seconds, having a less severe impact the switching off of the inertial response.

3.2.2. Effect of Power Ramp Response on Frequency

The contribution from the ramping power in diminishing system RoCoF during the inception of the perturbation until the critical time was disregarded when 5 was calculated. Assuming an instant switching of the IBFPR at critical time, the frequency nadir would be 49 Hz. Nevertheless, a ramp power response was assumed instead. Therefore the calculated power ramp, when applied to the unbalanced system, commonly exhibits a frequency nadir higher than 49 Hz, due to the contribution of the ramping period. In this sense, it can be inferred that the longer the ramping period, the higher frequency nadir will be obtained. Here again the relevance of the prompt activation in time of the IBFPR. On the other hand, with the faster IBFPR activation, the ramp slope and the steady power output (Inverter based power reserve) can be diminished compromising frequency nadir.
When a comparison is established beween all the calculated power ramp slopes in per unit (pu), it is noted that with high penetration of non-synchronous power in the power system, the required power to ensure no UFLS have a consistent trend between the three models and a close proximity in the values for RoCoF in the range of 2 to 5 Hz/s is observed between both IEEE models. Such trends can be seen in Figure 5 2. A bigger amount of power ramp slope is needed in all the range of RoCoF for the European case. After inspecting 6, it is noticed that the IBFPR is affected by the factor $1 - t_{cr}t_{nadir}$, then as nadir time increases, IBFPR increases as well. The nadir time for the European case, due to the action of the self-regulation and primary reserve deployment of 30 seconds, is in the range of 3-12 seconds (6 seconds for 80% IBG penetration) whereas the nadir time for the simplified IEEE model is between 1-3 seconds.

Insert power ramp comparisson here

3.2.3. Fast Power Reserve

The required power ramp to avoid load shedding has been found for both IEEE 9 bus models with a fast governor response and for the European-scale model with conventional primary reserve response. Hence, the IBFPR at critical time which remain constant after the critical time, would be accounted as the fast power reserve.

Table 5. : Fast power reserve in per unit for European case. Power reserve expressed in pu with power load as the base

IBG share (%)	**Load Imbalance (%)**							
	3	4	5	6	7	8	9	10
20	-	-	0.025	0.038	0.049	0.060	0.070	0.081
40	-	0.016	0.030	0.041	0.052	0.063	0.073	0.083
60	0.005	0.024	0.035	0.045	0.056	0.066	0.077	0.087
80	0.016	0.028	0.039	0.049	0.062	0.070	0.080	0.09
92	0.021	0.033	0.043	0.054	0.064	0.074	0.084	0.094
95	0.024	0.035	0.045	0.055	0.065	0.075	0.085	0.096

When IBFPR is implemented in all three cases, frequency drop below 49Hz is avoided for all the most of the RoCoF simulated, provided that enough IBFPR is available for the given imbalance. Figures XXX to XXX show how frequency is kept above 49 in all the cases.

Insert figures of IBFPR nadir here

3.3. Synchronizing effect, lack of damping torque and implications

The diminishing of synchronous machines leads to a very weak network where synchronizing and damping torque, which are inherent characteristics of synchronous machines, are not enough to stabilize the system[7]. Although the implementation of IBFPR contributes keeping synchronous machine on step, oscillations in the speed/frequency response of the rotor are observed. This oscillations are created by the lack of damping torque which is provided mainly by the synchronous machines through damping windings, rotor field exciter and power system stabilizer[ref].

Insert figures here

For the simplified IEEE model and the European island, only transfer functions describing an equivalent system governor were modeled. Hence in such approaches, the effect and dynamics of synchronous generator's exciters and inter-machine interaction were not taken into account. The before mention factors influence greatly small signal stability [7, 8] Even though the scoop of this thesis is to analyze the power-time characteristics needed to avoid frequency collapse; oscillations associated to big perturbation were observed but they could not been addressed by the simple injection of power to the system. Also in the IEEE model, when a penetration of 95% of inverter based generation and 2% of load imbalance are considered, UFLS is not reached but the system becomes unstable as shown in Figure 5 6 and Figure 5 5. From penetrations levels above 85% complete frequency stability is not ensure with the injection of fast power reserve, only UFLS on the first 10 seconds approximately. Then the system becomes unstable with increasing amplitude oscillations. It is important to note that ENTSOE in its EUROPEAN interconnected scenario, determined that there is no UFLS when an unbalance of 2% with high contribution of non-synchronous generation occurs. Nevertheless, no inter-machine interaction was considered and therefore a similar effect as the one in Figure 5 6 could be experienced.

4. Discussion

Conventional synchronous machines were found not to be able to ensure transient frequency stability in such conditions. The slow governor operation in the order of seconds is by far too slow to constitute the unique solution for frequency support during the transient period. Inverter based fast power reserve would be needed to be activated in an extreme short time.

To avoid load shedding in penetration scenarios above 80% of non-synchronous generation, inverter based fast power reserve must be deployed over a time in the order of 50-500 ms for load imbalances up to 40%. Nevertheless, today's full power activation time of renewable sources without storage is in the range of 200 to 600 ms. Hence with today's frequency measuring time and power deployment from renewable sources; load shedding and possible total black outs would not be avoided. In scenarios with plenty of renewables and high expected imbalances, storage would be a key factor in order to avoid de-loading and curtailment of renewables, the fast activation times (<50 ms) and promising price reduction make storage a good strategy to provide power balancing in both over and under frequency cases. Synthetic inertia could tackle with under-frequency phenomenon. With penetrations of 80% or higher of IBG, and contribution of at least 20% of the IBG from Wind turbines with synthetic inertia controls, UFLS is avoided up to imbalances of 10% with a fast synchronous response (1-3 s in the IEEE modeled cases). For primary reserve deployment of 30 s (European model), synthetic inertia was not enough for avoiding UFLS.

An effective frequency measurement in shorter time would contribute to reduce the amount of inverter based power reserve and therefore, to diminish the de-loading factor or the storage capacity needed to provide it, up to a 10%. In order to avoid UFLS, ramping capabilities up to 3 times the base power load per second (3 pu/s) would be required from the inverter based sources; for combinations of inverter based generation above 80% and load imbalance in the order of 30% in both, micro grid and

European scale islands. To achieve such response from distributed source, a continuous knowledge of the connected inertia to the system is required by the inverters since the IBFPR is based on the imbalance on the system and the critical time, which depends on system inertia. Additionally, system inertia is the linking bridge between RoCoF and power imbalance determination.

If the reference scenario for primary reserve is increased (imbalance higher than 2%) in the European context, synchronous response is not fast enough for imbalances higher than 2%. Full activation time in the range of 0.14 and 2.75 seconds would need required for the fast power reserve for penetrations of non-synchronous generation above 80 % (2.5 s) and imbalances between 3 and 10%. Additionally, fast power reserve would be almost equivalent to the imbalance. Faster synchronous response reduces needed fast power reserve. Although UFLS is avoided in the extended model in scenarios with penetrations of non-synchronous generation above 85% with injection of inverter based fast power reserve; total system stability is not ensured after a few seconds (5 s), due to the presence of undamped oscillations provoked by the poor damping torque present in the system as consequence of synchronous share reduction. Even though the approach considered throughout this work was the fast power reserve deployment to avoid under-frequency load shedding. If the same frequency deviation from nominal is considered as the critical for the over-frequency case (51 Hz); the same values would be obtained for critical time and power response. The difference lies in the power direction, in this case power should be removed from the grid or the excess converter to another form of energy, like electrochemical storage. In the case of batteries, the critical time would represent the needed time to allow charging the surplus of power available from renewables.

In general, similar behavior is exhibit from the different models and approaches, even though they differ considerably in size and complexity. Hence, simplified block representation of the power system seems to be a fair way to sketch overall system trends and responses. The difference in critical time estimation between a full grid simulation and a simplified model was calculated to differ between 20-35%, such difference could be crucial in fast power reserve studies and therefore should be considered when precise applications are implemented. A comprehensive method for estimation of the inverter based fast power reserve and critical time were developed and proved through the implementation in the two cases.

5. Conclusions

This section is not mandatory, but can be added to the manuscript if the discussion is unusually long or complex.

Author Contributions: For research articles with several authors, a short paragraph specifying their individual contributions must be provided. The following statements should be used "conceptualization, X.X. and Y.Y.; methodology, X.X.; software, X.X.; validation, X.X., Y.Y. and Z.Z.; formal analysis, X.X.; investigation, X.X.; resources, X.X.; data curation, X.X.; writing–original draft preparation, X.X.; writing–review and editing, X.X.; visualization, X.X.; supervision, X.X.; project administration, X.X.; funding acquisition, Y.Y.", please turn to the CRediT taxonomy for the term explanation. Authorship must be limited to those who have contributed substantially to the work reported.

Funding: Please add: "This research received no external funding" or "This research was funded by NAME OF FUNDER grant number XXX." and and "The APC was funded by XXX". Check carefully that the details given are accurate and use the standard spelling of funding agency names at https://search.crossref.org/funding, any errors may affect your future funding.

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the design of the study; in the collection, analyses, or interpretation of data; in the writing of the manuscript, or in the decision to publish the results".

Abbreviations

The following abbreviations are used in this manuscript:

MDPI	Multidisciplinary Digital Publishing Institute
DOAJ	Directory of open access journals
TLA	Three letter acronym
LD	linear dichroism

Appendix A

Appendix A.1

The appendix is an optional section that can contain details and data supplemental to the main text. For example, explanations of experimental details that would disrupt the flow of the main text, but nonetheless remain crucial to understanding and reproducing the research shown; figures of replicates for experiments of which representative data is shown in the main text can be added here if brief, or as Supplementary data. Mathematical proofs of results not central to the paper can be added as an appendix.

Appendix B

All appendix sections must be cited in the main text. In the appendixes, Figures, Tables, etc. should be labeled starting with 'A', e.g., Figure A1, Figure A2, etc.

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Sample Availability: Samples of the compounds ...... are available from the authors.