Article

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

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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

0. How to Use this Template

1. Introduction

2. Results

This section may be divided by subheadings. It should provide a concise and precise description of the experimental results, their interpretation as well as the experimental conclusions that can be drawn.

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2.1. Subsection

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Bulleted lists look like this:

- First bullet
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- Third bullet

Numbered lists can be added as follows:

1. First item
2. Second item
3. Third item

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2.2. Figures, Tables and Schemes

All figures and tables should be cited in the main text as Figure 1, Table 1, etc.

Figure 1. This is a figure, Schemes follow the same formatting. If there are multiple panels, they should be listed as: (**a**) Description of what is contained in the first panel. (**b**) Description of what is contained in the second panel. Figures should be placed in the main text near to the first time they are cited. A caption on a single line should be centered.

Text
Text

Table 1. This is a table caption. Tables should be placed in the main text near to the first time they are cited.

Title 1	Title 2	Title 3
entry 1	data	data
entry 2	data	data

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$$a + b = c \tag{1}$$

Please punctuate equations as regular text. Theorem-type environments (including propositions, lemmas, corollaries etc.) can be formatted as follows:

Theorem 1. *Example text of a theorem.*

53   The text continues here. Proofs must be formatted as follows:

54   **Proof of Theorem 1.** Text of the proof. Note that the phrase 'of Theorem 1' is optional if it is clear
55   which theorem is being referred to.   □

56   The text continues here.

57   **3. Discussion**

58   Authors should discuss the results and how they can be interpreted in perspective of previous
59   studies and of the working hypotheses. The findings and their implications should be discussed in the
60   broadest context possible. Future research directions may also be highlighted.

61   **4. Materials and Methods**

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

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

71

72   • **Acceleration time constant (T_a):** It also has the units of seconds (s) but this is the ratio of double
73   the kinetic energy (MWs) and generators nominal power output (P_{nom} in MW).
74   Acceleration time constant is a measure of the robustness before disturbances of the system. It
75   could be interpreted as the required time to remove the kinetic energy from the rotating masses of
76   the generators connected in a grid at the rate of the supplied power load. Hence, the higher the
77   time constant, the higher the kinetic energy available. As the share of synchronous generations
78   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:

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

79   In this paper, the inertia constant H is used for the description of synthetic inertia in wind turbines,
80   whereas the system acceleration constant T_a is used to express the whole system inertia related to the
81   load in terms of real power.

82   *4.1. Synthetic Inertia*

83   Synthetic inertia is one of the new techniques that manufactures and researchers are considering
84   to tackle with the low inertia problem in power systems [23, 24]. Frequency support through synthetic
85   inertia was considered with the following assumptions [6, 25]:

86   1. Power output from synthetic inertia is limited to 10% of wind turbine nominal power.
87   2. Due to mechanical and thermal stresses, the additional power can be delivered only for a
88   maximum time of 10 s.
89   3. It is assumed that all wind turbines operate at its maximum power output. The value of 1.5 MW
90   was selected for such purpose.
91   4. In order to avoid wind turbine stall, the removed kinetic energy from the blades (injected to the
92   grid in electrical form) it is limited to half [26].

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 (3), the rate of energy extracted from the wind turbine can be obtained, considering that the rotational speed changes in time ref.

$$P_{pu}(t) = 2 * H_{wt} * \omega_{pu}(t) * \frac{d\omega_{pu}(t)}{dt} \tag{3}$$

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

Figure 2. Representation of equation (3) 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 (3) 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 [27].

$$H_{wt} \approx 1.87 * P_{nwt}^{0.0597} \tag{4}$$

For a wind turbine with nominal power output of 1.5 MW the value of H corresponds to 4.37 s [28]. 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 2. : 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

4.2. 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.

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 3b. Recalling equation (2); it is necessary that the machine's accelerating power (power imbalance) become zero at the critical time.

$$P_a(t_{cr}) = P_{mech} - P_{elec} + P_{IBFPR} = 0 \tag{5}$$

---

[1] Number of wind turbines with synthetic inertia control
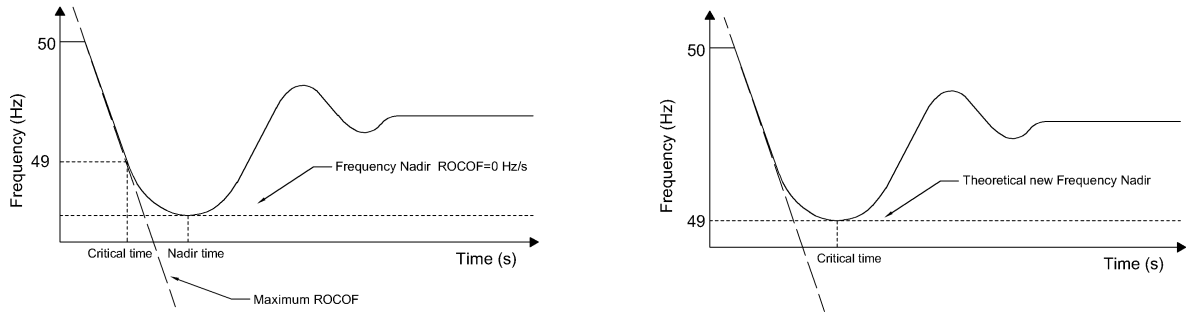
(a) Typical frequency response leading to UFLS

(b) Desired frequency response avoiding UFLS

Figure 3. 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.

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 $\Delta P * t_{cr}/t_{nadir}$ and P_{elec} by ΔP in (5), the following expression is obtained for the P_{IBFPR} at time t_{cr}:

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

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.

$$P_{IBFPR}(t) = \frac{\Delta P * (1 - t_{cr}/t_{nadir}) * t}{t_{cr}} \tag{7}$$

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 [18]. 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.

4.3. 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 [7, 11].

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

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

141

142 • **Large scale grid case:** The European grid scale in which all the synchronous machines are
143 modeled and simplified as one single machine, provided with the characteristic expected from
144 the overall system. Synchronous primary reserve deployment is in the order of ~ 30 s [1, 19].
145 Island frequency response is assumed to be the same that the European response analyzed by
146 ENTSOE ref.

4.4. Simplified IEEE 9 bus Model

148 As a first step to evaluate the impact of inverter based generation and power imbalances in the
149 grid, the whole system is simplified as one single generating unit; neglecting all losses in the system
150 (Transformers, transmission lines and generators) with the assumption that the mechanical output of
151 the prime mover is the same than the electrical power output at generator terminals. Table 3 provides
152 a summary of the elements comprising the base model.

153

Table 3. :Elements of the IEEE 9 bus model.

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

154 Figure 4 is the block representation of the swing equation (2), it only differs in the fact that
155 blocks representing the inverter based generation have been included. The mechanical power
156 is represented by the output of a steam turbine governor model, which is used to represent the
157 synchronous machine [8]. When equilibrium is lost, the accelerating power is multiply by the transfer
158 function $1/(2 * H * S)$, where H is the machine's inertia constant and S is the machine's power rating.
159 From (2) this product equals the derivative of frequency, therefore an integrator block is added to
160 obtain the frequency response [7, 21, 22]. A feedback loop is added and an error signal obtained
161 from the reference frequency so the synchronous machine can react as frequency deviates from nominal.

162

163 The values of kinetic energy and time constants of a synchronous machines of 835 MVA were
164 selected to represent the synchronous response, with the load of 315 MW the system acceleration time
165 constant is 14 s [8], which is approximately today's Europe acceleration constant [1]. This is the base
166 scenario where an 100% synchronous generation is assumed . For the sake of evaluating the impact of
167 the penetration of inverter based generation; the values of lower capacity generators were selected,
168 diminishing in the sense the total system inertia [8].

169

170 Even though load imbalances up to 40% were simulated in each inertia scenario, for estimation of
171 the critical time the power capacity limit of the generators was disregarded. The negative imbalance
172 was simulated by increasing the system load. A block diagram representing the system shown in
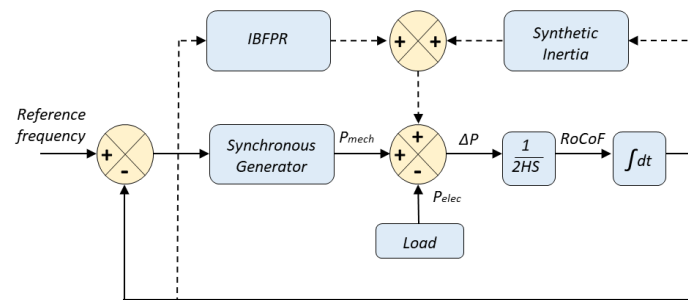
Figure 4. Simplified representation of the IEEE 9 bus model. Blocks linked by the solid line represent the conventional swing equation given by (2). Represented with doted lines, the respective frequency signals to the blocks of IBFPR and synthetic inertia, which add power to the system.

Figure 4 was implemented in SIMULINK with different combinations of power imbalance and system inertia.

4.5. Extended IEEE 9 bus Model

Since it is desired to compare the results obtained in 4.4 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 [20]. 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 5 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
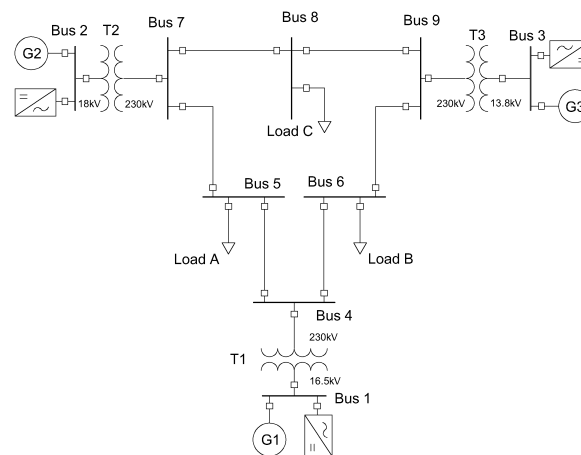
Figure 5. One line diagram of the IEEE 9 bus model. The inverter based frequency response has been added At the same bus of the generating units.

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 4.4, 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 representation. From (8) it can be easily calculated that the system kinetic energy with 14 s is 2205 MWs (100% synchronous generation).

$$T_{sys} = (2 * E_k)/P_{load} \qquad (8)$$

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 4 summarizes the main values for setting system initial conditions; acquired from the power flow tool provided by SIMSCAPE.

Table 4. : Steady state initial conditions of the system

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

4.5.1. 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 (9), the positive sequence component of phase voltage and line current are obtained. [21]

$$S^1_{3\varphi} = 3 * V^1_{LN} * \bar{I_L}^1 \tag{9}$$

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:

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

$$I^1_{Lpeak} = \frac{2 * \bar{S}^1_{3\varphi}}{3 * V^1_{LNpeak}} \tag{11}$$

With the help of the **a** operator ($-0.5 + j\sqrt{3}$ or $1\underline{/120°}$) the values of the positive sequence component of phase voltage can be obtained.

From $V_a + V_b + V_c = 0$ and $V^1_a = \frac{V_a + aV_b + a^2V_c}{3}$:

$$V^1_a = \frac{V_a + aV_b - a^2V_b - a^2}{3}$$
$$= \frac{V_a * (1 - a^2) + aV_b * (1 - a)}{3}$$

Since $V^1_{an} = \frac{V^1_a}{\sqrt{3}\underline{/30°}}$, $\sqrt{3}\underline{/30°} = 1 - a^2$ and $\sqrt{3}\underline{/-30°} = 1 - a$ then after some algebraic manipulation the expression for V^1_{an} becomes:

$$V_{an}^1 = \frac{V_a - a^2 V_b}{3} \tag{12}$$

198 With the obtained expressions for the positive sequence of phase voltage (12) and complex power
199 (10), the needed current (11) to supply the IBFPR related to the measured voltages can be implemented
200 in SIMULINK as depicted in FIGUREXXX. The ramping function will last until the critical time is
201 reached, afterwards, the IBFPR output will remain constant.

4.6. Large Scale Case: Europe Power System

203 Under normal operation ENTSOE has reported values of RoCoF in the range of 5-10 mHz/s for
204 power outages of 1 GW in the current interconnected power system. If an imbalance event of more than
205 3 GW occurs with depleted primary reserve, extraordinary values of frequency and RoCoF might be
206 reached. After serious disturbances the Continental European Power System has experienced RoCoF
207 between 100 mHz/s and 1 Hz/s. Imbalances of 20% or more along with RoCoF greater than 1 Hz/s
208 have been determined by experience to be critical [1]. ENTSOE has determined that under the case of
209 the reference scenario (The loss of 3 GW generation with 150 GW load and 2%/Hz self-regulation) in
210 the interconnected operation, the influence of inverter based generation, and therefore the reduction of
211 system inertia would not jeopardize system stability. Due to the expected increase of non-synchronous
212 generation in the future, international power trade and renewables variability; ENTSOE estates in
213 its future split reference scenario that the power system must be capable of withstanding imbalances
214 greater than 40% with RoCoF of 2 Hz/s or higher. Under these circumstances the resulting islands
215 must avoid load shedding. Hence, only the split scenario is considered for further analysis.
216 When considering the system blackout of November 4th 2006, in which four electric islands
217 resulted from the European system split; system blackout due to under frequency was experienced in
218 the so known western area. This island, at the moment of split, had approximately a load of 190 GW
219 (27% more than the low load scenarioENTSOE) [29]. For its comparable 'size' and the uncertainty of
220 knowing beforehand the resulting islands after a major contingency, the selected load for simulation
221 was the same as the ENTSOE reference scenario as well as the primary reserve deployment time. To
222 simulate the behavior of the resulting island in the European split scenario; a simplified approach was
223 selected. Similarly as it was done with the simplified block model for the IEEE 9 bus model, in the
224 equivalent European representation all the synchronous generation will be represented by a single
225 machine, which will provide governor response when a perturbation takes place. Additional to the
226 synchronous response, a load response of 2% was added to the model, which means that for every
227 Hertz reduced or augmented, the load will reduce or increase by a 2% [1].

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

4.6.1. 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:

$$n = \frac{P_{syncload}}{P_{nom} * dl} \tag{13}$$

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

$$
\begin{aligned}
T_{sys} &= \frac{\sum_{i=1}^{n} P_i * T_i}{P_{LOAD}} \\
&= \frac{n P_{nom} * T_i}{P_{LOAD}} \\
&= \frac{P_{syncload} * T_{nom}}{P_{LOAD} * dl} \\
&= \frac{Syncshare * T_{nom}}{dl}
\end{aligned} \tag{14}
$$

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 [1, 8], 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 [22]. 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 $T_{sys} = \frac{2 * E_k}{P_{LOAD}}$:

$$
\begin{aligned}
\frac{df}{dt} &= \frac{\Delta P * f_0}{P_{LOAD} * T_{sys}} \\
&= \frac{\Delta P_{pu} * f_0}{P_{LOAD} * T_{sys}}
\end{aligned} \tag{15}
$$

In (15) 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.

5. Conclusions

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

6. Patents

This section is not mandatory, but may be added if there are patents resulting from the work reported in this manuscript.

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.

References

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2. Author2, L. The title of the cited contribution. In *The Book Title*; Editor1, F., Editor2, A., Eds.; Publishing House: City, Country, 2007; pp. 32–58.