Tielens P., Van Hertem D., The relevance of inertia in power systems, Renewable and Sustainable Energy Reviews, Volume 55, March 2016, Pages 999-1009.

Digital Object Identifier: doi:10.1016/j.rser.2015.11.016

The Relevance of Inertia in Power Systems

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Abstract

The inertia of today's power system decreases as more and more converter connected generation units and load are integrated in the power system. This results in a power system which behaves differently from before which causes concerns for many grid operators. Therefore, a detailed study is needed to investigate the relevance of this inertia in the operation, control and stability of the system. Moreover, a new definition of the term system inertia is necessary since is it expected that in the future also the renewable electricity generation units will deliver so-called virtual (synthetic) inertia.

In this paper a review of the research related to inertia in a power system is given. Both the challenges as the solutions from an operator point of view to control a system with low inertia are discussed. Also a new definition of inertia is proposed to incorporate the different forms of inertia which are each described in more detail. From recent studies, it can be concluded that the influence of reduced inertia on frequency stability is generally considered as the main challenge for system operators, but with the additional measures listed in this paper, this impact can be mitigated.

Keywords: Synchronous inertia, converter connected generation, renewable energy, virtual (synthetic) inertia, power system stability

1. Introduction

At the start of 2015, after a decade of significant growth, the installed wind and solar power in the EU-28 countries reached a capacity of respectively 128.8 GW and 87.9 GW which corresponds to 14.1 % and 9.7 % of the total European electricity generation capacity [1]. To meet the 2020 targets of the European Union, the installed capacity of renewable energy sources is expected to increase even further. As a result, many countries encounter penetration levels of wind and solar power in excess of 15 % of their overall electricity consumption and some power systems (e.g. in Spain, Portugal, Ireland, Germany and Denmark) have even already experienced instantaneous penetration levels of more than 50 % of converter connected generation [2].

While already dealing with aging infrastructure and an ever increasing demand for electric power, this projected increase of electric power coming from renewable energy sources will put an even higher stress on the already highly loaded power system. From a power system perspective, this dispersed renewable electricity generation behaves quite differently from traditional, centralized generation facilities. Apart from their intermittent nature, most of these sources do not (yet) contribute to the system inertia due to the electrically decoupling of the generator from the grid. Moreover, the available energy buffer, required to deliver inertia, is often missing in these renewable generation units.

This system inertia is often considered as one of the vital system parameters upon which the synchronized operation of current day power systems is based: the inertia in the rotating masses of synchronous generators

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Preprint submitted to Renewable and Sustainable Energy Reviews *December 5, 2015*

and turbines determines the immediate frequency response to inequalities in the overall power balance. When a frequency change occurs, the rotating masses will inject or absorb kinetic energy into or from the grid to counteract the frequency deviation. The lower this system inertia, the less damping is provided to the system and the more nervous the grid frequency reacts to abrupt changes in generation and load patterns.

As the inertia is decreasing, the impact on current power system stability and control is investigated and new control strategies for converter connected generation to deliver so-called virtual (synthetic) inertia are developed. Using the system frequency as one of the controlled variables and inputs to the controller, a power response similar to that of classical synchronous generators is mimicked. By doing so, we facilitate the use of the otherwise masked kinetic energy stored in the rotating masses of the blades of wind turbines or provide virtual inertia by an inverter-fed storage system, e.g. batteries.

In the literature, most studies within this field focus on small isolated systems as the inertia of these systems is already considerably lower compared to large interconnected systems [3, 4, 5, 6, 7]. Furthermore, the ratio of the magnitude of a possible generation outage to the total spinning capacity is usually relatively high for these isolated systems. Hence, small isolated systems are more prone to operational issues related to the reduced system inertia caused by large infeeds from converter connected generation [8]. Although the decrease of inertia is not yet considered an issue in large interconnected systems, the outcome of these studies can support the development of new operational practices and control methods of other power systems in order to ensure a stable system operation in times of low inertia.

However, these studies examine often only one aspect of power system stability or focus on a certain type of converter connected generation. Therefore a general overview of the relevance of inertia in power systems by looking at the different sources of inertia and their impact on the operation of current power systems is presented in this paper.

The remainder of the paper is organized as follows. Section 2 describes the different sources of inertia in traditional and future power systems. Next, in sections 3 and 4, the quantification and measuring of inertia from synchronous as well as converter connected generation and the load is presented. Section 5 deals with the impact of reduced synchronous inertia on power system stability. In section 6, some general solutions are proposed to tackle these challenges in order to operate a system with reduced inertia in a secure and safe way. Finally, section 7 resumes the main conclusions.

2. Inertia in traditional and future power systems

Before discussing the amount of inertia in a power system, a clear definition of the term inertia and its different forms is needed. In general, inertia is defined as the resistance of a physical object to a change in its state of motion, including changes in its speed and direction [9]. Applying this definition to a traditional electrical power system, the physical objects that are in motion are the rotating machinery (synchronous generators and turbines, induction generators, ...) connected to the power system and the resistance to the change in rotational speed is expressed by the moment of inertia of their rotating mass. An example of such a traditional power system with only synchronously connected generation is given in Figure 1(a). In this power system, the inertia mostly comes from the generators and turbines of conventional power plants. Since they are synchronously connected to the system, their mechanical rotational speed (ω_g) is directly coupled with an electrical parameter, namely the electrical angular frequency (ω_e). Therefore the motion of each single generator can be expressed as [10]:

$$\frac{\mathrm{d}J_\mathrm{SG} \cdot \omega_\mathrm{e}}{\mathrm{d}t} = T_\mathrm{m} - T_\mathrm{e} \tag{1}$$

with T_e and T_m respectively the electrical and mechanical torque. J_SG defines the combined moment of inertia from the generator and the turbine referred to the electrical angular frequency by taking the number of pole pairs into account. In power system engineering, it is however more common to express this swing equation in power instead of torque:

$$\frac{\mathrm{d}\frac{J_\mathrm{SG} \cdot \omega_\mathrm{e}^2}{2}}{\mathrm{d}t} = P_\mathrm{m} - P_\mathrm{e} \tag{2}$$

The left-hand side of equation 2 is the derivative of the kinetic energy (E_{SG}) stored in the turbine and generator. This energy is often expressed proportional to its power rating and is called the inertia constant H_{SG}, i.e. the time period in seconds a generator can provide nominal power only using the kinetic energy stored in the rotating mass:

$$H_{\mathrm{SG}} = \frac{\frac{J_{\mathrm{SG}} \cdot \omega_{\mathrm{e},0}^2}{2}}{S_{\mathrm{SG}}} = \frac{E_{\mathrm{SG}}}{S_{\mathrm{SG}}} \tag{3}$$

With S_{SG} the apparent power of the generator and $\omega_{\mathrm{e},0}$ the nominal angular system frequency. Converting equation 2 to per unit values ($\bar{}$), using equation 3 leads to:

$$2 \cdot H_{\mathrm{SG}} \cdot \bar{\omega}_{\mathrm{e}} \cdot \frac{\mathrm{d}\bar{\omega}_{\mathrm{e}}}{\mathrm{d}t} = \bar{P}_{\mathrm{m}} - \bar{P}_{\mathrm{e}} \tag{4}$$

Since the system frequency is considered as a global system parameter, all the power units can be aggregated into one single unit, represented by a single mass model:

$$2 \cdot H_{\mathrm{sys}} \cdot \bar{\omega}_{\mathrm{e}} \cdot \frac{\mathrm{d}\bar{\omega}_{\mathrm{e}}}{\mathrm{d}t} = \bar{P}_{\mathrm{g}} - \bar{P}_{\mathrm{l}} \tag{5}$$

with

$$H_{\mathrm{sys}} = \frac{\sum H_{\mathrm{SG}} \cdot S_{\mathrm{G}}}{\sum S_{\mathrm{SG}}} = \frac{\sum E_{\mathrm{SG}}}{S_{\mathrm{sys}}} \tag{6}$$

the inertia constant of the whole power system (assuming only synchronous connected generation and neglecting the inertia coming from the load and embedded generation), $\bar{P}_{\mathrm{g}}$ the total generated power and $\bar{P}_{\mathrm{l}}$ the total load power. S_{sys} is defined in this paper as the total generation capacity connected to the system. Assuming $\bar{\omega}_{\mathrm{e}} \approx 1$, leads finally to:

$$2 \cdot H_{\mathrm{sys}} \cdot \frac{\mathrm{d}\bar{\omega}_{\mathrm{e}}}{\mathrm{d}t} = \bar{P}_{\mathrm{g}} - \bar{P}_{\mathrm{l}} \tag{7}$$

Looking at this equation and referring back to the general definition of inertia in the beginning of this section, the total inertia in a traditional power system can thus be interpreted as the resistance in the form of kinetic energy exchange from synchronously connected machines (further denoted as synchronous inertia) to counteract the changes in frequency resulting from power imbalances in generation and demand. The kinetic energy that is exchanged during a power imbalance can be expressed as:

$$\Delta E = \sum \Delta E_{\mathrm{SG}} = \int (P_{\mathrm{g}} - P_{\mathrm{l}})\,\mathrm{d}t \tag{8}$$

The exchanged and stored energy in a power system directly after a power imbalance (before governor control is initiated) are schematically illustrated in Figure 2. In this figure, the area of each block is equal to the kinetic energy as the width and height are respectively proportional to $\sum J_{\mathrm{SG}}$ and to $\frac{\omega_{\mathrm{e}}^2}{2}$. The gray area defines the stored kinetic energy at nominal frequency ($\omega_{\mathrm{e},0}$). Since the power system is designed to operate within a certain frequency band, the stored kinetic energy will always vary between the boundaries set by $\omega_{\mathrm{e,min}}$ and $\omega_{\mathrm{e,max}}$. When e.g. an negative imbalance in a traditional power system (system A) occurs, the deficit is initially compensated by the kinetic energy released by the conventional generation units (Eq. 8) which is also called the inertial response of the system. This amount of kinetic energy is indicated by the hatched area. As a result, the system frequency decreases and will reach $[\omega_{\mathrm{e},1}]_{\mathrm{A}}$ at time t_1 as shown in Figure 2(b). In this figure, the frequency decline as well as the exchanged energy (ΔE) in function of time is given. If no further actions are taken to arrest the frequency drop by increasing the power set points of the generation units, the stored kinetic energy gets depleted and the system will collapse.

In a future power system, many of these conventional units will be displaced or switched off in favor of renewable generation units with lower marginal costs. Focusing on the context of inertia, these renewable electricity generation units behave differently from traditional, centralized generation facilities. First of all, these renewable electricity generation units are in general connected through a power electronic converter, which fully or partly electrically decouples the generator from the grid. The link between the rotational speed of the generator and the system frequency is therefore removed. As a result, these converter connected generation units do not inherently contribute to the total system inertia [11]. Secondly, the (kinetic) energy buffer available in conventional power generation units to counteract frequency changes is often missing. Looking for instance at photovoltaic (PV) power generation, where no rotating parts are involved and only a very small amount of energy can be stored in the capacitors. Furthermore, it is expected that more and more HVDC links will be installed in our future power system since they are an interesting option to transport large amounts of renewable energy from the remote sources to the load centers and to fundamentally upgrade the existing AC network. As these HVDC links electrically decouple two or more interconnected systems, the inertia of one system is not directly accessible to the other.

In Figure 1(b), a future power system is shown in which a part of the synchronously connected generation of the traditional system is displaced by converter connected generation. As the total generation capacity (S_{sys}) remains the same, the system inertia as defined by equation 6 decreases. The effect of this decreasing system inertia is further illustrated in Figure 2 (system B). The stored kinetic energy that is available to the system (gray area) is now reduced. Assuming the same power imbalance as before and thus also the same amount of exchanged energy ($\sum \Delta E_{\mathrm{SG}}$), the decrease in system inertia will result in a lower frequency $[\omega_{\mathrm{e},1}]_{\mathrm{B}}$ at $t = t_1$ and a higher rate of change of frequency (ROCOF) as indicated in Figure 2(b).

The converters that decouple the generator or power source from the grid are normally not managed in a way to react on variations in grid frequency. However by measuring the grid frequency deviations the control of the converter can vary the energy exchange with the grid in a controlled manner. In Figure 3, a basic controller that mimics the kinetic energy exchange of synchronous generation is shown [12, 13, 14]. This energy exchange is called the virtual (or synthetic) inertial response and is characterized by the virtual moment of inertia J_{V}. In a system where both synchronous machines and converters deliver respectively synchronous and virtual inertia to the grid, H_{sys} can now be expressed as [15]:

$$H_{\mathrm{sys}} = \frac{\sum E_{\mathrm{SG}} + \sum \frac{J_{\mathrm{V}} \cdot \omega_{\mathrm{e}}^2}{2}}{S_{\mathrm{sys}}} = \frac{\sum E_{\mathrm{SG}} + \sum E_{\mathrm{V}}}{S_{\mathrm{sys}}} \tag{9}$$

As the converters decouple electrically the generation unit from the grid, any type of power source or energy buffer can in principle be utilized to contribute to this system inertia (flywheels, batteries, capacitors, ...). In wind turbines, the kinetic energy from the blades, gearbox and generator can be applied. In a PV system, additional storage can for instance be added in the form of batteries. Also deloading the generation units to have an upward power reserve available counts as an option. However, this energy exchange is restricted to certain limitations e.g. converter operating limits, minimum rotor speeds, maximum deceleration and acceleration of the blades and is highly dependent on the operating point [16].

The inertia in future systems can thus be interpreted as the resistance in the form of any kind of energy exchange from synchronously connected machines (synchronous inertia) and converter connected generation (virtual inertia) to counteract the changes in frequency resulting from power imbalances in generation and demand.

By using available converter connected generation to deliver a virtual inertial response and therefore partially compensate for the reduction in synchronous inertia, the frequency deviation will be less compared to a system in which converter connected units do not respond to frequency changes. This can also be explained based on the schematic representation in Figure 2 (system C). Here for the same power imbalance as considered before, a part of the required energy is coming from converter connected generation by means of a virtual inertial response ($\sum \Delta E_V$). Therefore, the reduction in stored kinetic energy from the synchronous connected units is partially compensated, which results in a higher frequency $[\omega_{e,1}]_C$ at $t = t_1$ compared to a future system without virtual inertial support. The actual source of energy is of course depending on what is behind each converter participating in the virtual inertial control and can consist out of a combination of storage, kinetic energy from wind, power reserves, kinetic energy from other systems connected through HVDC, ...

Although not yet considered, also the load will deliver inertia to the system as the power output of certain load types will vary with the system frequency, e.g. induction motors and fans. In future systems however, this inertia coming from loads is expected to decrease as well since more and more of these devices are controlled using variable frequency drives.

3. Inertia from synchronous connected generation and power system load

To determine the total inertia perceived by a power system, detailed information about each generation unit and load is required. As a first estimate, only the inertia from large conventional power plants is often taken into account. Inertia coming from residual sources, e.g. load and embedded generation, is neglected or assumed constant in most power system studies since less specific information about these sources is available. Another option is estimating the inertia based on frequency measurements, which is further elaborated in the third part of this section.

3.1. Inertia from synchronous connected generation

The inertia of large conventional generation units, which inertia constant (Eq. 3) is measured in seconds, falls typically in the range of 2-9 s, depending upon the size, speed and type of the machine [17, 18]. In general, for power plants with the same technology, the inertia constant is inversely proportional to the rating, see also Figure 4 [18]. As the number and type of operating power plants connected to the transmission system will vary throughout the day depending on the unit commitment and merit order, which is typically determined by the fuel type, the inertia of the generation side will be fluctuating as well [11, 19]. Most of the available system data on inertia constants seems however to be unreliable as large number of machines appear to have the same integer value for their inertia constants in the TSO databases as stated in [20]. These inertia constants are thus likely just an estimate of the real values. Moreover, detailed information about the inertia provided by synchronous generation units connected to the distribution grid is often missing.

3.2. Load inertia

Whether the load will contribute to the system inertia, depends on the dynamics and type of the load. For instance, directly coupled motor loads will contribute to the inertial response of the system since their rotational speed is linked with the system frequency. Other types of load are frequency independent such as resistive loads. Hence, a detailed representation and estimation of the share of each type is necessary. Furthermore, the stochastic nature of the load together with the voltage and frequency variations across the system need to be taken into account to define the inertia of the load connected to the system. In system studies, the load is often represented by a combination of a constant impedance, a constant current, a constant power and an induction motor model. To set the parameters of these load models, the sensitivity of the reactive and active power to changes in voltage and frequency need to be determined. In [21], the load inertia is estimated by subtracting the inertia of synchronous machines from the total inertia, which is calculated by tracking the frequency after a power imbalance. The method is applied to the combined power system of Ireland and Northern Ireland and it is calculated that the load inertia constant is less then one second most of the time, although large fluctuations occur depending on the system demand.

3.3. Measuring and estimating system inertia

In the literature, different methods are studied to estimate the system inertia using frequency measurements after a major power imbalance. In principal, they all calculate the ROCOF and use data from the power imbalance together with the swing equation to determine the inertia of the system.

Several practical issues arise, like filtering the frequency measurements, sampling the frequency to calculate the ROCOF, identifying the exact starting instance of the event, ... which makes it very difficult to accurately estimate the system inertia [22, 23, 24, 25]. Moreover, the swing equation as stated in the previous section (Eq. 7) gives only a good approximation of the system frequency transient during the first couple of seconds directly after the power imbalance. Thereafter, other control actions, like the governor response, are initiated and additional parameters besides the inertia determine the frequency response.

In [25], a novel approach is developed based on multiple synchrophasor measurements spread over the entire power system to obtain a reliable value of the inertia of the Great Britain power system. It was estimated, taking into account the inertia of conventional power plants, that 8-25 % of the total inertia is coming from embedded generation and load.

4. Inertia from converter connected generation

Although no direct coupling from the converter connected generators to the grid is made, a large amount of kinetic energy is stored in these generation units, which together with other forms of energy storage, can be used to deliver inertia. Different aspects are described in more detail in this section. Firstly, a comparison is made between the stored (kinetic) energy in these units and the energy stored in conventional power plants. Secondly, the way the stored energy is exchanged to control and operate a grid with low synchronous inertia is investigated.

4.1. Amount of stored energy in converter connected generation

Looking at current and future power systems, the largest share of converter connected generation is covered by wind and PV. Wind turbines have an amount of kinetic energy available, stored in their blades, gearbox and generator. PV units on the other hand, except for the energy in their capacitor, have no stored energy available, as no rotating parts are involved.

The inertia of a wind turbine mainly depends on its type, size and whether or not a gearbox is installed. In [26] for instance, the kinetic energy of a typical 2 MW turbine is calculated at 12 MJ. Generally, by expressing the stored kinetic energy of a wind turbine in an inertia constant by combining the stored kinetic energy of the blades and the generator as stated in equation 3 for a synchronous machine, values of $H_{\mathrm{WT}} \approx$ 3-6 s can be found in the literature [26, 27, 28, 29] which is comparable to inertia constants of conventional power plants. The inertia constant for a wind turbine is hereby defined at its nominal speed, so within the speed range of the turbine also the stored kinetic energy (and inertia constant) is varying. This is further illustrated in Figure 5 for a standard variable speed wind turbine. In this figure both the power and the stored kinetic energy are given over the whole operating wind speed range. To maximize the power output at low wind speeds, the rotor speed is decreased which results in a smaller amount of stored kinetic energy. At minimum rotor speed, this leads even to a drop of 60 % of stored energy compared to operation at nominal speed. Furthermore looking at the cumulative probability of the stored kinetic energy for a single turbine, it is shown that in about 50 % of the time less than 50 % of the maximum kinetic energy is available. Although these numbers are just indicative as the speed range of a turbine is depending on its type and manufacturer, it shows that the uncertainty of the amount of kinetic energy that is available to deliver inertia should be taken into account. A more detailed study of the availability of kinetic energy from wind turbines can be found in [30].

Photovoltaic units do not have any rotating parts which can be used as an energy buffer to deliver inertia to the system. Other forms of energy reserves need be created to fundamentally contribute to the system inertia. A fast-acting storage unit, e.g. batteries or supercapacitors, can be used for that purpose [5]. Another option proposed in the literature is to deload the PV unit by alter the output voltage from the value set by the maximum power point tracker (MPPT). This way the unit operates at a sub-optimal operating point in order to have a power reserve available to deliver an inertial response [31, 32]. Although the deloading results in a constant loss of power, in [33] it was concluded that to contribute to the frequency control, deloading of a PV unit is more economically feasible than using a battery unit.

4.2. Virtual inertia from converter connected generation

In literature, many controllers to deliver virtual inertia to the system are developed. They mostly mimic synchronous generators by delivering an active power response proportional to the rate of change of frequency as shown in Figure 3 [34, 26, 35]. Although this controller mimics the response of a synchronous machine, it is important to point out the differences between the response of a converter and a synchronous machine. First of all, due to the decoupling, the virtual moment of inertia J_{V} does not need to represent the real amount of inertia or stored energy connected to the converter. This amount is mainly depending on the generation source and its operating point. Therefore the actual inertial response can be freely chosen e.g. to fulfill certain requirements of minimum system inertia, although it is sometimes necessary to limit J_{V} in order to assure a stable operation. In the case of wind power for instance, a high value of J_{V} will rapidly slow down the blades of the turbine resulting in a reduced aerodynamic lift which can lead to stall. On the other hand, by increasing J_{V}, more energy can be released compared to a synchronous machine since its energy release is solely determined by the system frequency and its inertia constant. By comparing e.g. a wind turbine at maximum speed with a synchronous machine having the same inertia constant, a gain of 5.25 [36] in kinetic energy release during a frequency transient can be realized by decelerating the turbine down to its minimum rotor speed. Replacing conventional generation with converter connected generation results thus not necessarily in a decrease in the total inertia of the system, but additional control actions are needed to employ the kinetic energy, taken into account certain constraints together with the variability of the operating points. Moreover, it should be noted that additional time delays need to be included in the control model depicted in Figure 3 to represent the time response of the converter as well as the time required to filter the frequency and to measure the ROCOF. Even though each of these time constants is small, the inertial response of the converters will be slower than the instantaneous, natural response of synchronous machines.

Since the converter can create any form of power response within the limits of the device, also alternative mechanisms of power exchange during the inertial response phase of the system can be found in the literature. In [37, 38] for instance, a response proportional to the frequency (droop control) is proposed while in [39, 4] a step-response is evaluated. The step-response by wind turbines is further optimized in [40] to minimize the adverse effects of energy regain directly after the support [41]. These controllers are in the literature often grouped under the name of fast (primary) frequency control to distinguish them with the traditional, slower reacting frequency control actions [42]. Applying these latter controls in a power system, a mix of various power responses will be delivered after a power imbalance, which will result in a completely different inertial response compared to a power system with only synchronously connected units.

5. Impact of reduced synchronous inertia on power system stability and control

In order to ensure a stable system operation and control, it is necessary to assess the impact of this reduced synchronous inertia on the dynamics of the power system. In Figure 6, a general overview of different power system phenomena and controls is given together with the time scales involved. Synchronous inertia acts on rather short time scales ranging from milliseconds to tens of seconds as indicated by the grey band. Within this time frame, the impact on frequency stability (which was already touched upon in section 2) and short term stability (focusing on rotor angle stability) is discussed as there is a close link between inertia and the dynamics of interest for these forms of stability. Primary voltage control (VC) and under-load tap changer (ULTC) control are not considered in this paper since inertia doesn't directly influence voltage stability. As we focus in this paper on the impact of the reduced inertia and not look how the inertia of each element in the drive train of a synchronous machine influences system operation, also sub-synchronous resonance is not investigated.

5.1. Rotor-angle stability

Rotor-angle stability is generally defined as the ability of a power system to maintain machines synchronous operation when subjected to a disturbance. If this disturbance is sufficiently small that linearization of system equations is permissible, the term small-signal stability is used. The eigenvalues of the system matrix indicate the different oscillatory modes and characterize the small-signal stability of the system [10]. The effect of decreasing the synchronous inertia of synchronous machines is mainly reflected in the electromechanical modes of the system. This is shown in Figure 7 for a single synchronous machine infinite bus system. As the inertia of the connected generator decreases, the imaginary part of the eigenvalues increases which corresponds to faster oscillations and a reduced damping of this mode. This result is logical as the rotor will deviate faster after an imbalance due to the lower resistance to frequency changes.

Also in the case of increased penetration of converter connected units which are not synchronously linked to the system and therefore do not participate in electromechanical oscillations, the modes of the system are influenced [44, 45, 46]. In the literature, there is however no general consensus about the specific effect of the increased penetration of inertialess units on these electromechanical modes and on small-signal stability in general. In [47], the effect of large scale wind power on small-signal stability is discussed. It is concluded that the influence of converter connected wind generation is mainly depending on the location, operating mode and penetration of wind power together with the loading level of the system and the control of the converter. The research efforts related to the impact of PV on small-signal stability are summarized in [47]. Here, no convergent results are visible as well.

Transient stability is a second form of rotor-angle stability and considers the stability of the system after large disturbances such as loss of generation, line-switching operations, faults and sudden load changes. The time frame of interest for this form of stability is usually 3-5 seconds and may extend to 10-20 seconds for very large systems [43]. Whether or not a synchronous machine loses synchronism depends on many factors such as grid, generator and load parameters, grid layout, the location and magnitude of the disturbance and the system state. Furthermore, the control actions initiated directly after the disturbance like fault clearing, voltage and turbine valve control play also an important role in stabilizing the system [48].

After a fault occurs, the machine terminal voltage is significantly reduced and the capability of the machine to deliver synchronizing power to the system decreases. Due to this imbalance of constant mechanical infeed and reduced electrical output power, the rotor accelerates according to the swing equation. As inertia is one of the factors that determines the acceleration of the machines it also influences the transient stability. In general, lowering the inertia of synchronous generators results in larger rotor swings and makes the system more vulnerable to disturbances in terms of transient stability [17, 49].

In systems with high penetration of converter connected generation, the inertia of a single synchronous machine is not lowered but instead the synchronous machines as such are being replaced by converter connected machines which results in lower system inertia. In this case, different aspects that influence the transient stability of the resulting synchronous generators should be discussed. In [50] the effect of increasing distributed generation (DG), induction motors as well as inertialess converter connected units on transient stability is elaborated. It is shown that a maximum penetration level of converter connected generation in terms of transient stability cannot be solely based on the amount of synchronous inertia in the system, but depends significantly on the reactive power scheme and the network topology. Increasing the reactive power and fault ride through capability from distributed generators can help to reach high levels of converter connected generation without jeopardizing the transient stability. Another option that is proposed to improve the stability is assigning certain conventional power plants as synchronous condensers that can provide synchronous inertia and in addition also deliver the necessary amount of reactive power [50]. Furthermore, it is concluded that as most of the DG is installed in distribution grids close to the load, the power flows in the transmission grid are reduced compared to the case with only conventional generation. This inherently improves the transient stability of the transmission system as large power flows have an adverse effect on the damping of oscillations.

Focusing on converter connected wind power, similar conclusions hold. In [46, 51, 52], it is shown that doubly fed induction generators (DFIG) connected wind turbines can have both beneficial as detrimental effects on transient stability depending on the grid layout and location of the wind turbines. The optimal control during and after the fault to stabilize the grid and increase the stability is investigated in more detail in [53, 51, 29]. It is shown that by using the capability of the converters to deliver voltage and reactive power support after a fault, the transient stability margin of the remaining generators increases.

Less research is being conducted to reveal the impact of the integration of PV units on transient stability. In [54], it is observed that the fault-ride through capability of PV units is highly important to ensure transient stability as the loss of distributed PV units may result in large oscillations during moments of high PV penetration. Other research illustrates both the beneficial as well as the adverse effects on stability of increasing PV penetration depending on system layout, location of PV units, ... [55, 56].

5.2. Frequency stability

Reducing the amount of synchronous inertia mainly influences the frequency stability of a power system. This stability refers to the ability of a system to maintain a steady frequency after a significant imbalance between generation and load [43]. If this balance is not restored, large frequency swings occur which may result in tripping of generating units and/or load. Therefore, different mechanisms are activated after an imbalance in order to first stabilize the frequency and subsequently bring it back to its nominal value as indicated in Figure 8 for a frequency dip.

Immediately after the power balance is disturbed, the synchronous connected units will release or absorb kinetic energy in or from the grid (inertial response) to counteract the frequency deviation and to provide a natural time delay for the governors of the power plants to react as is explained in detail in section 2. Within this first phase, the power impact is distributed over all synchronous machines which each experience a different change in load angle and speed, depending on their inertia and electrical distance from the disturbance. Synchronous machines with low inertia will encounter larger rotor swings compared to machines with high inertia values. These rotor swings will eventually dampen out due to network losses, rotor damper windings and other devices like power system stabilizers (PSS) which results in a common frequency over the system [3]. Meanwhile, each generator equipped with a speed controller or governor, will act as soon as the frequency deviations exceeds a certain deadband by increasing or decreasing the power set-point of the prime mover proportional to the speed deviation of the machine. Depending on the type of governor and turbine several time delays are introduced in this process. This control is also known as frequency containment process (FCP) or primary control. Due to this proportional control action, the frequency is stabilized, but still deviates from its nominal value. The restoration of the frequency is achieved in the next phase, also called the frequency restoration process (FRP) or secondary control, by increasing or decreasing the set-point of the prime mover in order to reduce the frequency offset to zero [3].

In a power system with reduced synchronous inertia, the overall inertial response is decreased since the generators of these converter connected generation are electrically decoupled from the grid by their converter and therefore do not contribute in delivering kinetic energy to the system. This reduction in inertia influences both the ROCOF and the minimum frequency (nadir frequency), two parameters which both play an important role in the activation of system protection devices [57, 4]. In Figure 9, the effect on the nadir frequency and ROCOF after a major imbalance between generation and load is illustrated. A simplified system frequency model is applied [10] to simulate the frequency response after a power imbalance (10 % of the total generation capacity) for different levels of converter connected generation. It is assumed that these converter connected units do not deliver any frequency support and gradually displace the synchronous generation units of which the inertia constant is varied between 2 and 8 s. In this case an equal distribution of hydro and thermal power plants is considered. It can clearly be seen that the reduction of synchronous inertia, corresponding to a higher share of converter connected generation, increases the ROCOF and decreases the nadir frequency.

Looking to possible future zero-emission scenarios in which thermal power plants will be displaced in favor of converter connected generation (wind power, PV, ...) combined with hydropower, the effect on the nadir frequency is even aggravated as illustrated in Figure 10 for $H_{\mathrm{SG}} = 6$ s. This is due to the slow response time of hydro power plants and their initial power output change which is opposite to the direction of change in gate position.

This increased ROCOF can be considered as one of the main barriers to operate a system with low inertia in a safe and secure way as it not only reduces the time period for the governor control to react before the frequency exceeds thresholds at which load/generation shedding is initiated, but it also has an impact on current protection schemes and the operation of synchronous units.

In today's system, most of distributed generation is protected against islanding (loss of main) by ROCOF relays [58, 59]. Islanding occurs when a part of the power system becomes electrically isolated from the rest of the power system, yet continues to be energized by generators connected to the isolated subsystem. Consequently, the frequency will change rapidly as the local generation will not exactly balance the remaining load. Depending on the power imbalance and the inertia of the islanded subsystem, high frequency oscillations take place which trigger the ROCOF relay and the islanded subsystem will eventually be disconnected.

Typical ROCOF relays, installed in a 50 Hz system are set between 0.1 and 1 Hz/s, depending on the inertia of the grid [60]. In a system with a high penetration of converter connected generation, not only loss of main, but also major power imbalances can trigger these relays as the ROCOF can be higher than their setting (see also Figure 9(b)). As the disconnection of these units aggravate the initial power imbalance, a cascade effect of disconnecting generation can occur which can eventually result in widespread power outages [61]. Studies for the island grid of Ireland for instance show already that the thresholds of current ROCOF relays should be increased to accommodate the anticipated wind power up to 2025 [62].

Moreover, it is not yet clear if conventional synchronous generators can withstand these increased ROCOF. In Ireland, the TSO has proposed to modify the grid code relating to the ROCOF capability of generation units to accommodate more converter connected generation in their system. In order to allow more than 75 % of converter connected generation, the generation units should be capable to withstand 1 Hz/s compared to the current ROCOF capability which is set at 0.5 Hz/s [63, 64]. From a consultation done by the commission of energy (CER), it was concluded that besides the ability to remain synchronism after high ROCOF, the main concerns for synchronous units are that it could lead to catastrophic failure of the generator or that repeated high ROCOF events would cause an increase wear and tear which effects the lifetime of the generator and turbine [63].

6. Operation of systems with low synchronous inertia

Operating power systems with low synchronous inertia poses thus additional challenges, mainly in terms of frequency control (high ROCOF) as stated in the previous section. In the literature, different operational strategies are proposed in order to operate such a system in a safe and secure way. These studies mainly address the stability of small isolated systems as they are more prone to (frequency) stability issues compared to large interconnected systems. On the other hand, these islands grids can be considered as the precursors of larger interconnected systems when it comes to operating a power system with low inertia and the proposed operational strategies can be applied to these interconnected systems in the future.

At the beginning of the 21st century, low synchronous inertia was however not directly considered an issue in these isolated systems since most of the TSOs had simply set an operational limit to the maximum penetration level of converter connected generation (generally between 20-50 % of total generation) [65]. This limit was mostly self-imposed to avoid technical as well as operational problems (power quality, balancing, grid support, ...) rather than to stay above a certain amount of system inertia. In autonomous island grids of Greece for instance, which are predominantly based on diesel engines, the Public Power Corporation limits wind farms to contribute not more than approximately 30 % of instantaneous load [66]. Also Irelands Electricity Supply Board (ESB) suggested in 2002 that wind power levels should be limited to 30 % of instantaneous load during daytime, with possibly a higher contribution at nights [67].

By increasing the allowable level of converter connected generation even more, issues related to low synchronous inertia emerged. In [62, 68] for instance, the impact of increased wind power penetration on the Irish power system is investigated by their system operator EirGrid. It is concluded that the frequency stability of the system poses a limit of 60-75 % of converter connected generation without additional mitigation actions as e.g. a thorough review of the installed ROCOF relays and generator capabilities. Setting these limits will result in the curtailment of wind of 7-14 % by 2020 [69].

Several options are presented in the literature to deal with these operational issues due to a reduced system inertia as shown in Figure 11. In the DS3-program, a study which develops new solutions to the challenges associated with increasing levels of renewable generation in Ireland, two main approaches are discussed. A first approach mainly focuses on adapting the current power system equipment, grid codes and protection to cope with higher ROCOF and larger frequency swings. The second approach tries to accommodate more converter connected generation by providing different forms of inertia (such as virtual inertia) or incentives more flexible plants or plants with a higher synchronous inertia. This virtual inertia is also identified as a future grid support service in the REserviceS project which sets some technical and economic guidelines and recommendations for the design of a European market for ancillary services [42]. Some studies even propose to implement an inertia constraint within the unit commitment problem to ensure that a minimum amount of system inertia is always available [19, 70].

7. Conclusion

In this paper, the relevance of inertia in power systems was elaborated by defining and quantifying the different forms of inertia as well as describing the effect of the reduced amount of synchronous inertia on power system stability. Moreover, the system inertia of future power systems was discussed. It was illustrated that this inertia will mainly consist out of a mix of inertia from conventional power plants and virtual inertia delivered by converter connected generation which employ a (kinetic) energy buffer to contribute to this system inertia.

Looking at the impact of reduced inertia on system stability, recent studies consider the reduced frequency stability as the main challenge in the operation of the future power system as the ability of the system to resist to large power imbalances decreases. This will result in high ROCOF values which can lead to instability of the system.

From this paper it is thus clear that new approaches are necessary to cope with the reduced synchronous inertia in order to accommodate more converter connected renewable generation in the current system. Different possible measures were proposed but it still remains unclear which measures are the most optimal and cost effective to implement in future systems.

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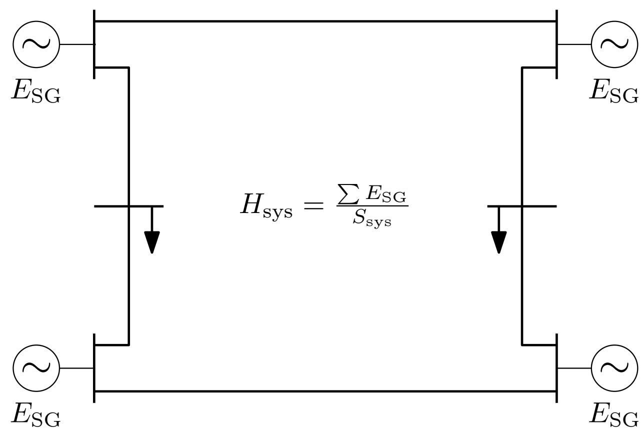
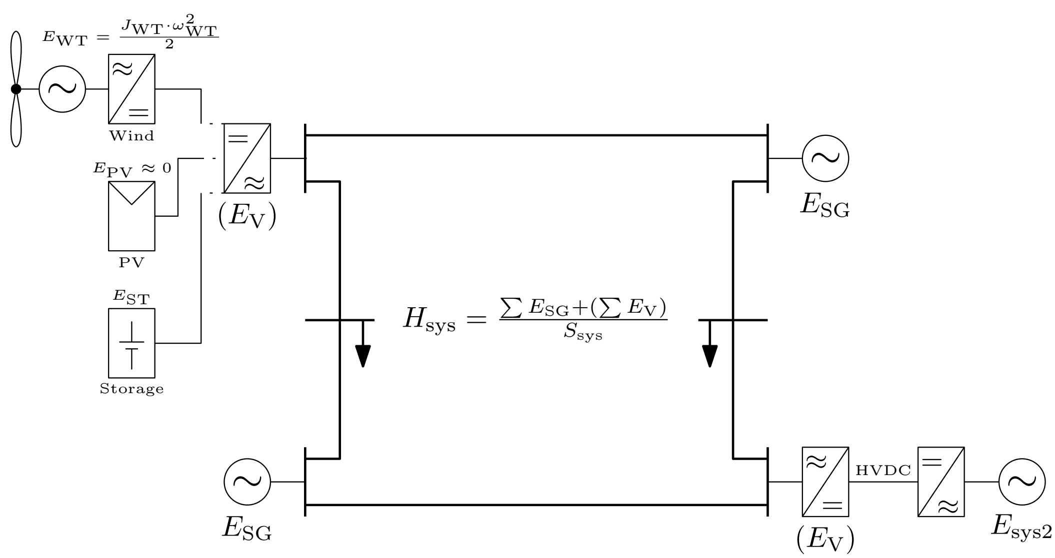
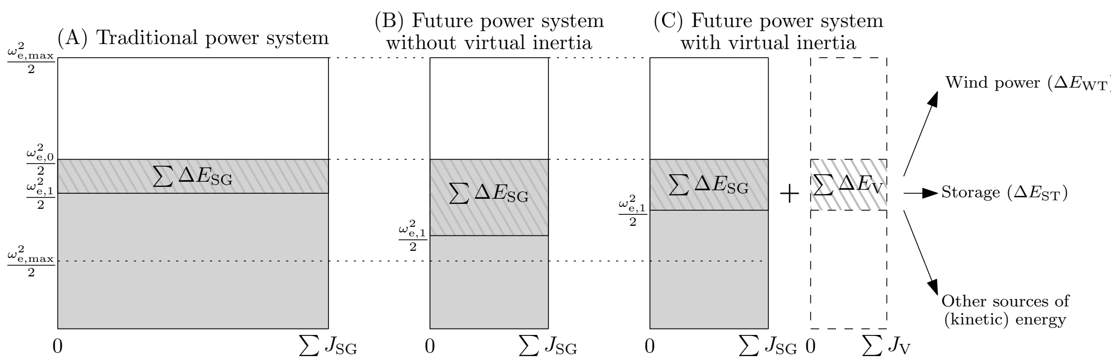


(a) Traditional power system

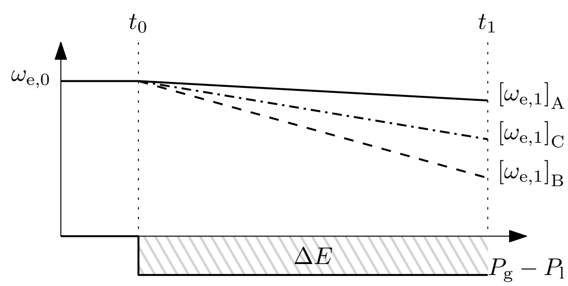


(b) Future power system

Figure 1: Inertia and (kinetic) energy storage in power systems



(a) Schematic representation of (kinetic) energy exchange



(b) Influence on power system frequency

Figure 2: (Kinetic) energy exchange in traditional and future power systems after a power imbalance

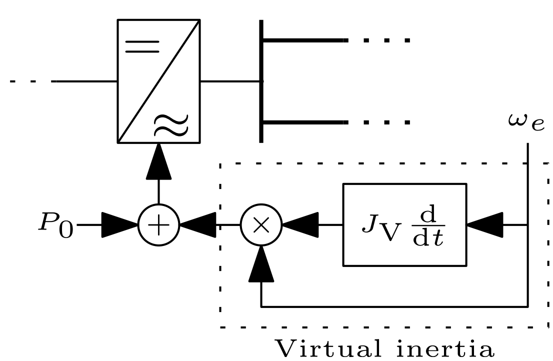


Figure 3: Virtual inertia controller

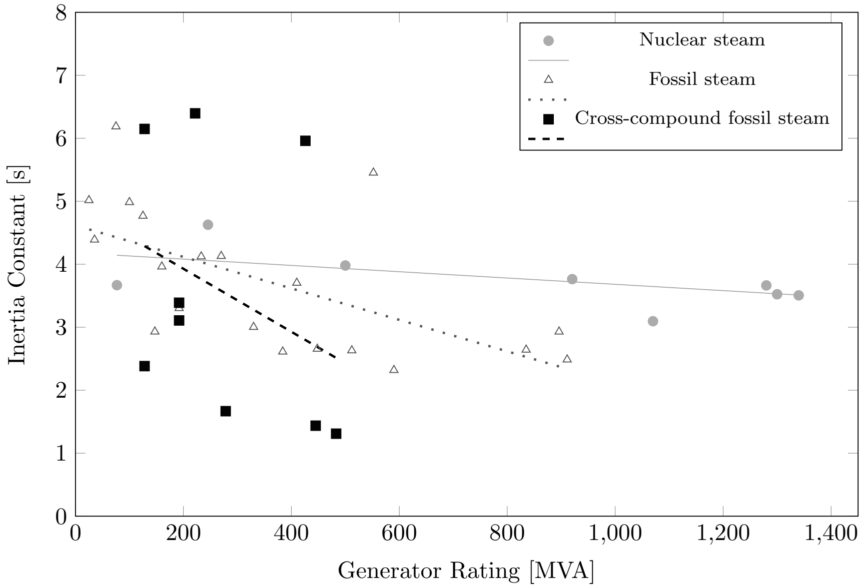
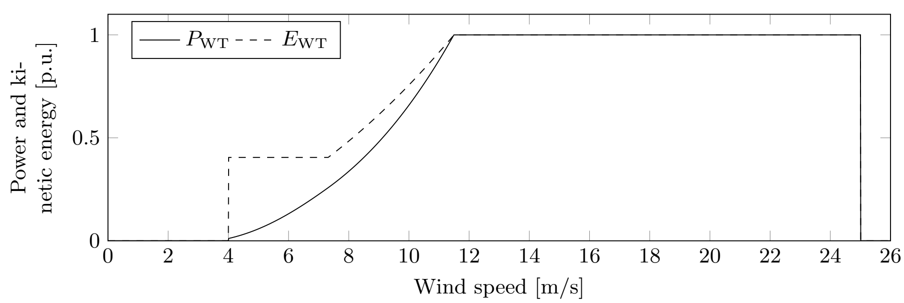
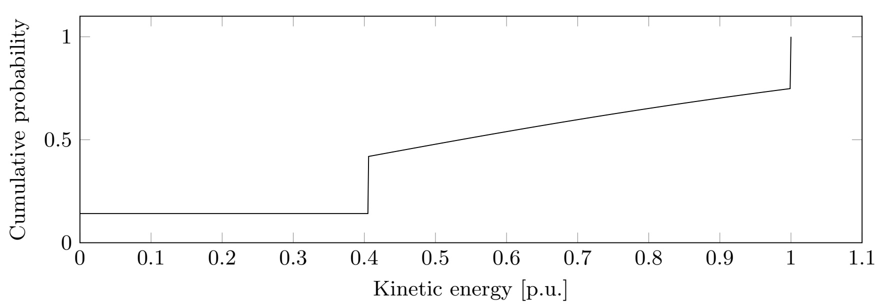


Figure 4: Inertia constants for conventional units (derived from data in [18])



(a)



(b)

Figure 5: Kinetic energy stored in a variable speed wind turbine

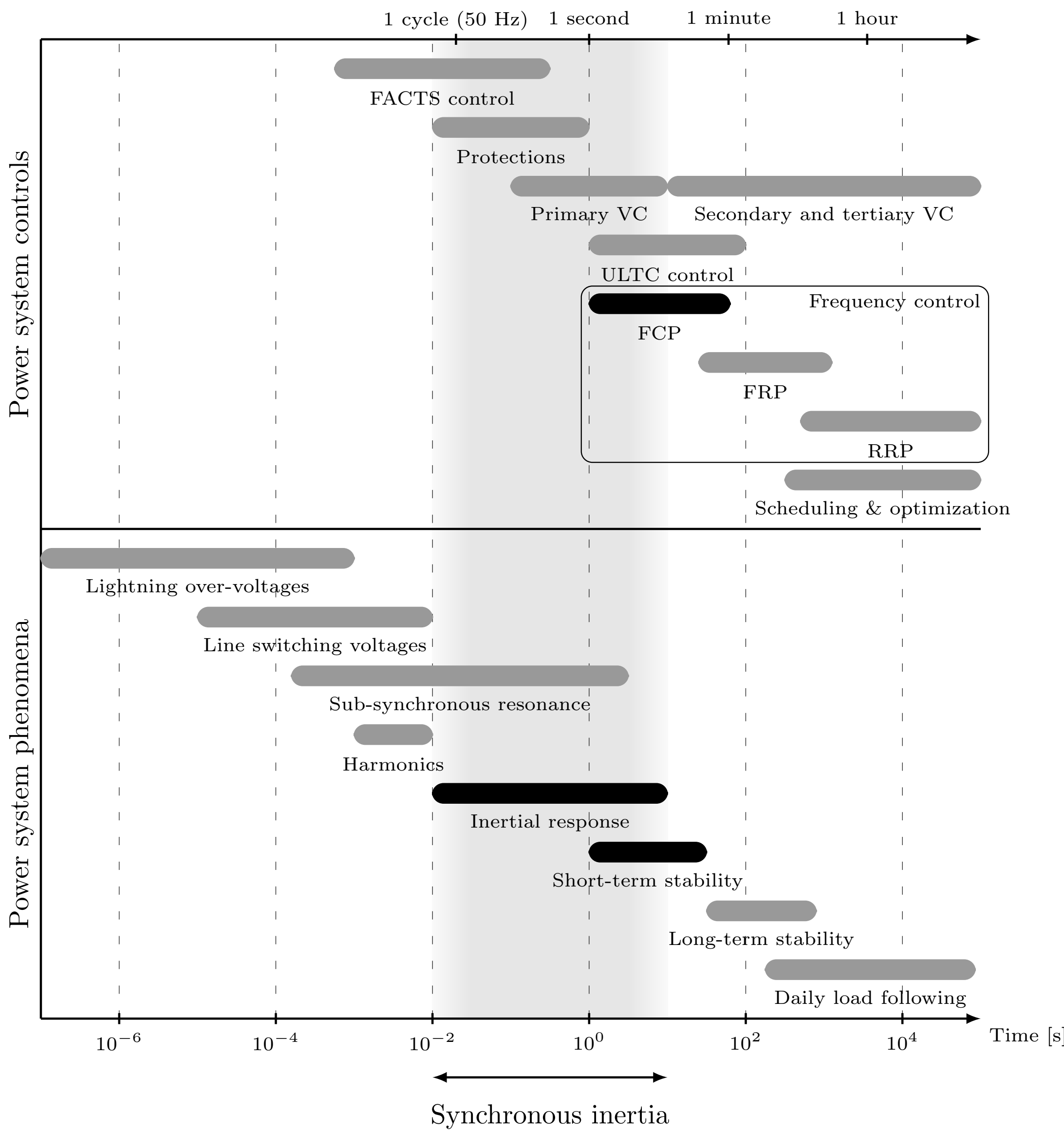


Figure 6: Overview of time scales covered by power system phenomena and controls & synchronous inertia [43]

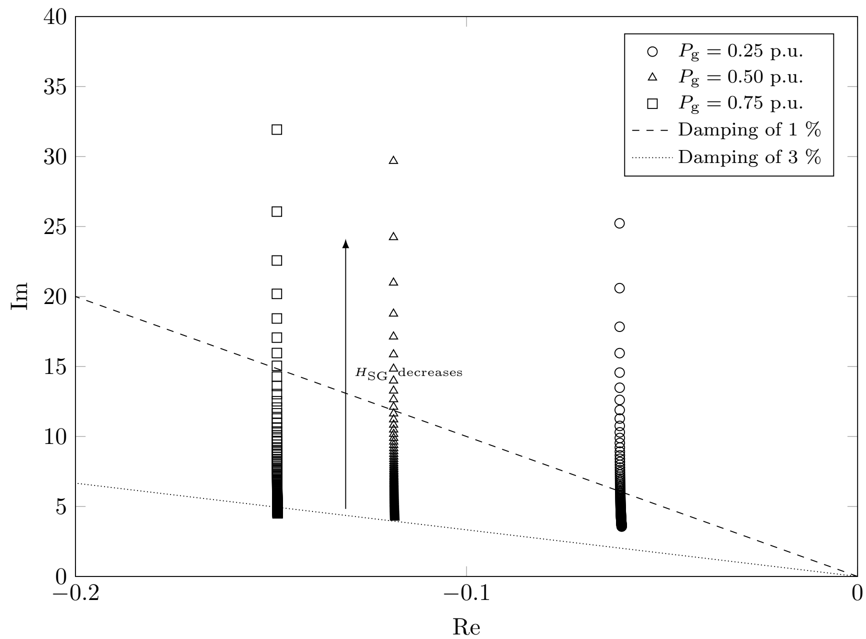


Figure 7: Electro-mechanical modes for a single machine infinite bus system in function of inertia and operating point

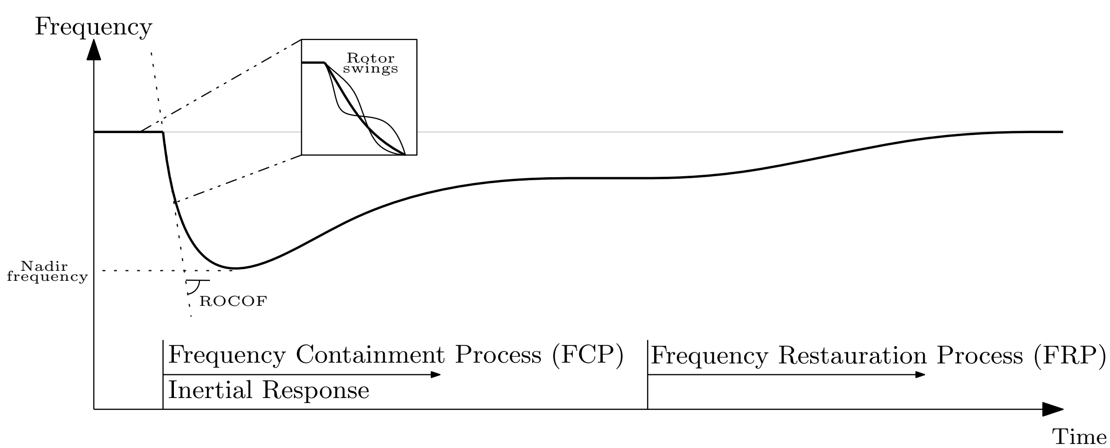
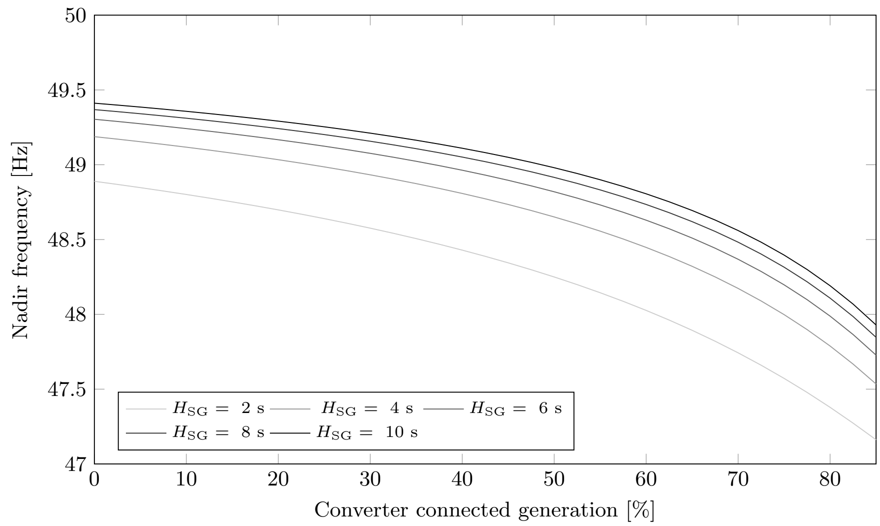
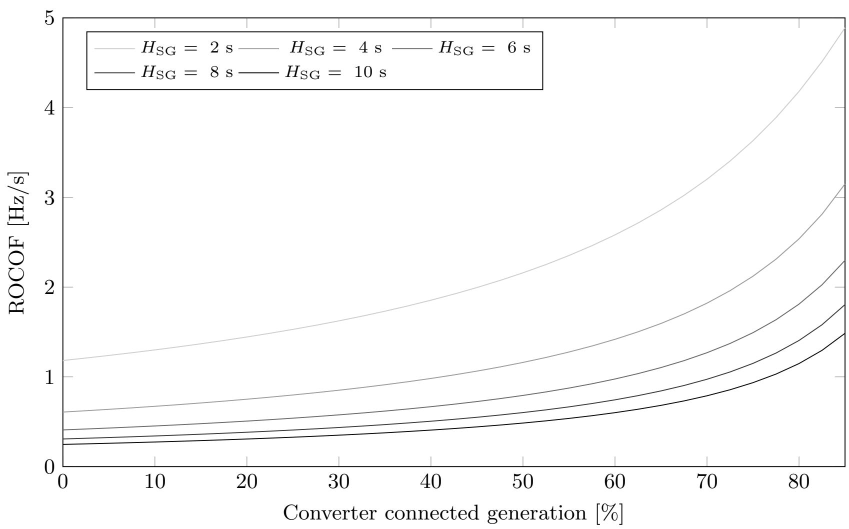


Figure 8: Classification of frequency control mechanisms



(a) Nadir frequency in function of different levels of converter connected generation



(b) ROCOF measured over 500 ms in function of different levels of converter connected generation

Figure 9: Nadir and ROCOF in function of converter connected generation for a power imbalance of 0.1 p.u., assuming an equal share of thermal and hydro power plants. The inertia constants of the synchronous connected units are varied between 2 and 10 s.

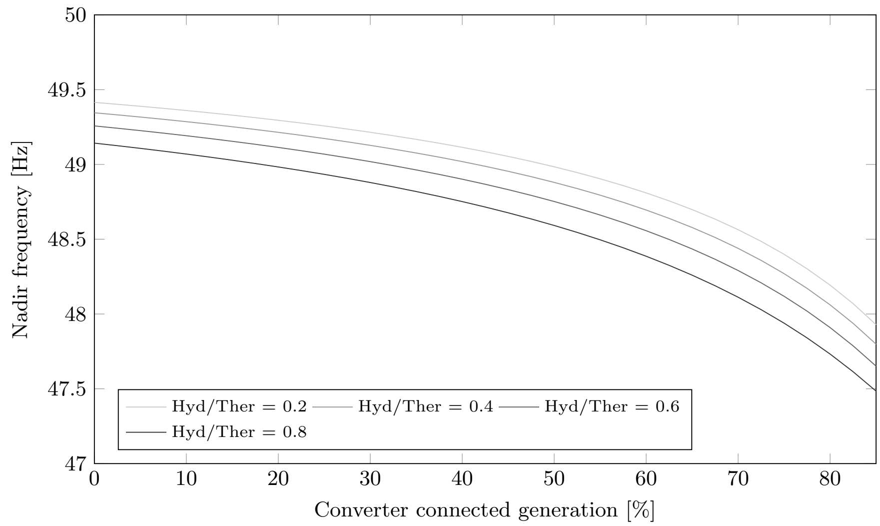


Figure 10: Nadir frequency for a power imbalance of 0.1 p.u., in function of different levels of converter connected generation & increasing share of hydro power. The inertia constants of the synchronous connected units are equal to 6 s.

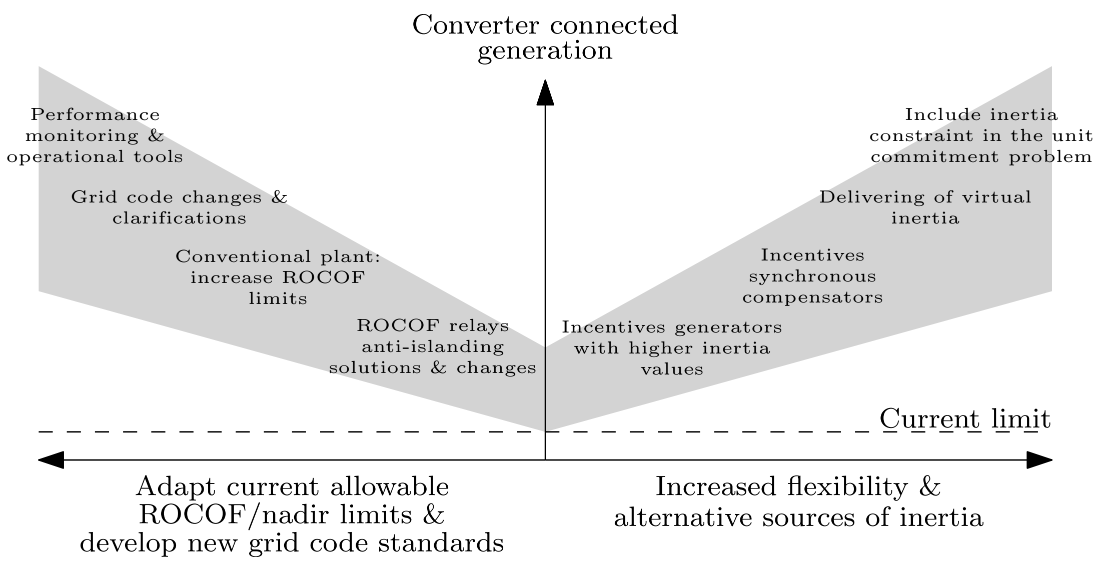


Figure 11: Different proposed options to operate a system with low synchronous inertia in a safe and secure way