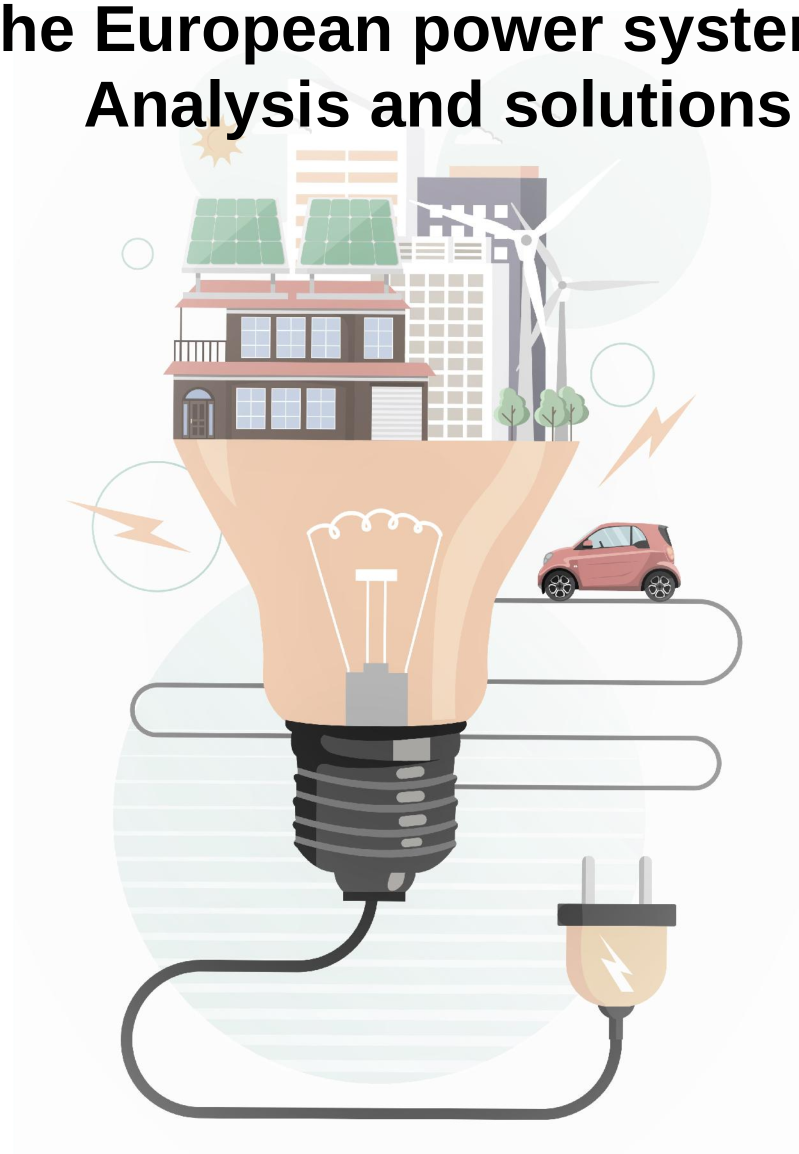
ASSET STUDY on

Penetration of renewables and reduction of synchronous inertia in the European power system – Analysis and solutions



AUTHORS

Pieter Tielens (Tractebel Impact)

Pierre Henneaux (Tractebel Impact)

Stijn Cole (Tractebel Impact)

EUROPEAN COMMISSION

Directorate-General for Energy
Directorate for Internal Energy Market
Unit C.2.: New Energy Technologies
Contact: Feilim O'Connor
E-mail: ENER-C2-SECRETARIAT@ec.europa.eu
European Commission
B-1049 Brussels

Legal Notice

Luxembourg: Publications Office of the European Union, 2020

PDF ISBN 978-92-76-24738-8 doi: 10.2833/35606 MJ-04-20-645-EN-N

About the ASSET project

The ASSET Project (Advanced System Studies for Energy Transition) aims at providing studies in support to EU policy making, research and innovation in the field of energy. Studies are in general focussed on the large-scale integration of renewable energy sources in the EU electricity system and consider, in particular, aspects related to consumer choices, demand-response, energy efficiency, smart meters and grids, storage, RES technologies, etc. Furthermore, connections between the electricity grid and other networks (gas, heating and cooling) as well as synergies between these networks are assessed.

The ASSET studies not only summarize the state-of-the-art in these domains, but also comprise detailed qualitative and quantitative analyses on the basis of recognized techniques in view of offering insights from a technology, policy (regulation, market design) and business point of view.

Disclaimer:

The study is carried out for the European Commission and expresses the opinion of the organisation having undertaken them. To this end, it does not reflect the views of the European Commission, TSOs, project promoters and other stakeholders involved. The European Commission does not guarantee the accuracy of the information given in the study, nor does it accept responsibility for any use made thereof.

Authors

This study has been developed as part of the ASSET project by Tractebel Impact.

Authoring Team: Pieter Tielens, Pierre Henneaux and Stijn Cole (Tractebel Impact)

Executive summary

The various efforts of promoting the use of renewables has resulted in a steady growth of electricity coming from renewable energy sources which is expected to continue even further into the future.

From a physics point of view, many of these renewable energy sources behave quiet differently from the synchronous generators installed in conventional power plants. Synchronous generators have mechanical inertia and are therefore capable of storing kinetic energy in their rotating mass. Moreover, since the terminals of these generators are directly linked with the network, this energy is inherently exchanged with the system during disturbances which makes the network less prone to frequency fluctuations in case of an imbalance between generation and load.

Renewable generation units (mainly photovoltaic solar and wind power) on the other hand, are equipped with a power electronic converter which decouples the generator from the grid and as such provide no inertia to the system. As it is projected that many of the conventional power plants will be gradually displaced by these renewable energy sources, the total inertia perceived by the system will thus decrease.

As discussed in this study, it expected that inertia related issues will mainly arise in terms of frequency control as low system inertia results in high rate of change of frequency (ROCOF) values and substantial frequency deviations which can lead to instability of the system including load shedding or even a blackout. There are however many possible solutions available to cope with these issues, which are all described in more detail in the report, ranging from a simple redispatch to a modified control approach for converters.

Within Europe, many efforts have already been made by ENTSO-E to deal with the inertia issues in a coordinated and harmonized way though their operational guidelines, network codes and system studies. However, as most of the guidelines and network codes related to system inertia are non-exhaustive, there is still a wide variety in the way each TSO implement them. TSOs in large interconnected synchronous areas, such as the Continental European system, currently only adapt the allowed ROCOF relay settings or include a ROCOF withstand capability (for new units) in their grid code. Island systems on the other hand, such as Ireland and GB, are already a step ahead as they expect to encounter high levels of converter penetration. Currently they mostly try to limit the ROCOF by limiting the largest credible loss or keeping the inertia above a certain minimum value. However, to reach even higher penetration levels, new system services will need to be procured.

A prognosis of the future system inertia in 2030 within the synchronous area of Continental Europe is made based on the generation capacities of the EUCO30 scenario. Although it expected that there will be a substantial increase in converter connected penetration by 2030, the analysis shows that there remains enough inertia in the system to cope with imbalance which are much higher than the current reference incident.

Nevertheless, in accordance with the operation guidelines of ENTSO-E, it is recommended that a tool to monitor and forecast the inertia at operational level is gradually put into place within the Continental European System. Furthermore, to be future proof, it is also necessary to already draft procedures to cope with a possible lack of inertia. In this respect, it is important to take into account the operational experience gained by TSOs in smaller systems such as the one of Ireland.

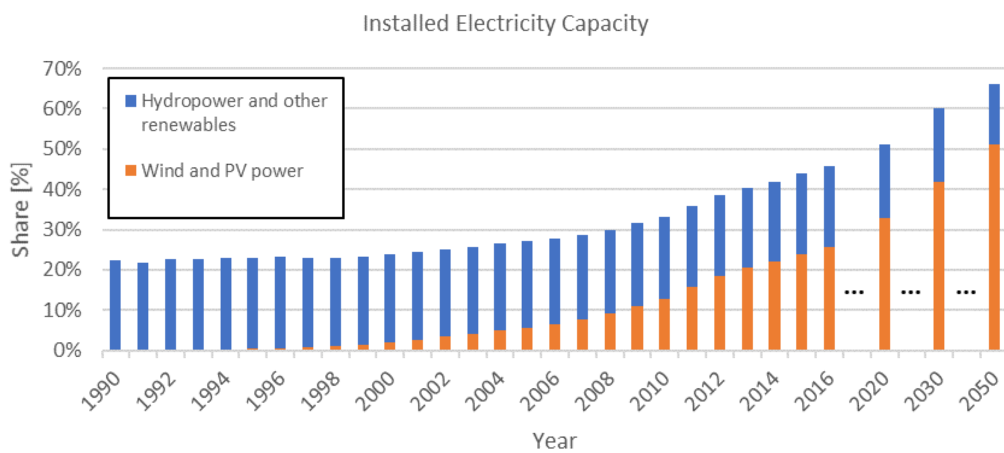
Table of Contents

Introduction

Context

The finite supply of fossil fuels and the growing awareness of the environmental impacts of global warming have reinforced the quest to a more secure, sustainable and cost-effective energy supply. The future energy transition to achieve this goal is considered one of the main challenges that nations worldwide will face in the decades to come, as it is vital for future prosperity and for the well-being of the people, industry and economy.

The European Union (EU) can be considered as the precursor in this quest, since it has already set ambitious energy and climate objectives through its 20-20-20 targets which were enacted in legislation in 2009. These targets aim at reducing the greenhouse gas emissions by 20% compared to the 1990 level, 20% increase in energy efficiency and 20% share of renewable energy in the overall energy consumption of the European Union by the year 2020 [1].



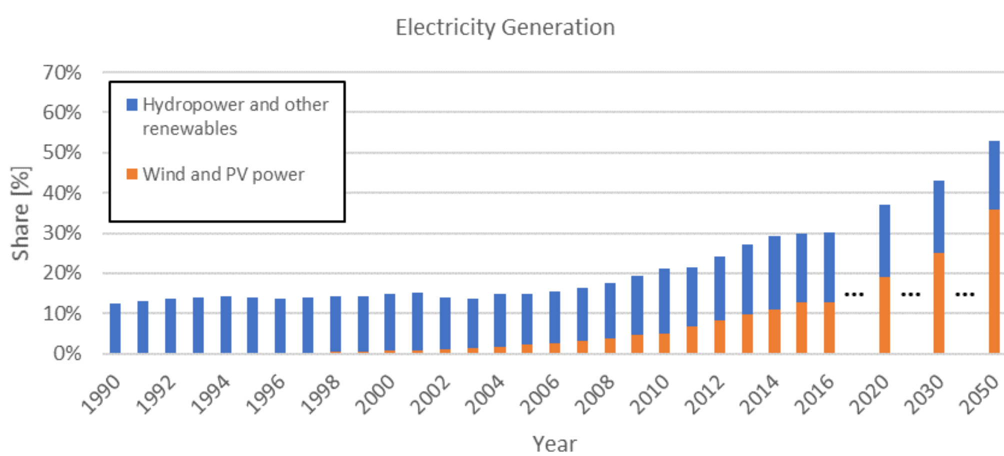


Figure 1: Share of renewable electricity in the total installed capacity and production within the EU-28 member states [2, 3]

With respect to electricity, the various efforts of promoting the use of renewables has resulted in a steady growth of electricity coming from renewable energy sources which is expected to continue even further into the future, see *Figure 1*. By the end of 2016 for instance, a total renewable energy capacity equal to 453 GW was installed within the EU-28 covering 30% of the total electricity production.

Until the beginning of this century, the main share of renewable electricity capacity was covered by hydropower. Solar photovoltaic (PV) and wind power have however gradually been catching up and by 2016 they represent 25% of the total electricity capacity. By 2050, it is estimated that this will increase to 51%. However, as the capacity factors of solar PV and wind power units are relatively low compared to conventional generation, it only corresponds to a share of 36% of the total electricity production in 2050.

Along with this transition towards more renewable electricity units, a shift is generally taken place in the way generation units are interfaced with the grid. Traditional large-scale power systems are currently still mainly powered by a relatively small number of (synchronous) generators, installed in conventional power plants. The unique characteristics of these machines have determined how power systems have been planned and operated since the development of the first alternating current (AC) transmission network at the dawn of the electricity era, more than a century ago.

From a physics point of view, the synchronous generators and coupled drive train have mechanical inertia and therefore, can store kinetic energy in their rotating mass. Since the terminals of the generator are directly linked with the network, this energy is inherently exchanged with the system during disturbances which makes it less prone to frequency fluctuations in case of an imbalance between load and generation [4].

On the contrary, converters within PV and wind power units typically transform direct current (DC) electricity to AC power by controlling semiconductor devices. Due to this intermediate DC link which decouples the generator from the grid, no energy is normally exchanged with the grid to limit power imbalances. Instead of physical characteristics, the control strategy of the converter predominately determines the electrical dynamic interaction with the system.

As a result, due to the displacement of conventional power plants by converter connected units, the total inertia (and kinetic energy) perceived by the system will decrease which will have an impact on the operation and stability of our power system.

Scope and structure of the study

In this study, the impact of reduced inertia on power system stability and operation is assessed and the main solutions are presented. Although the different aspects of this report can be generally applied, the main focus of this work is on the European power system.

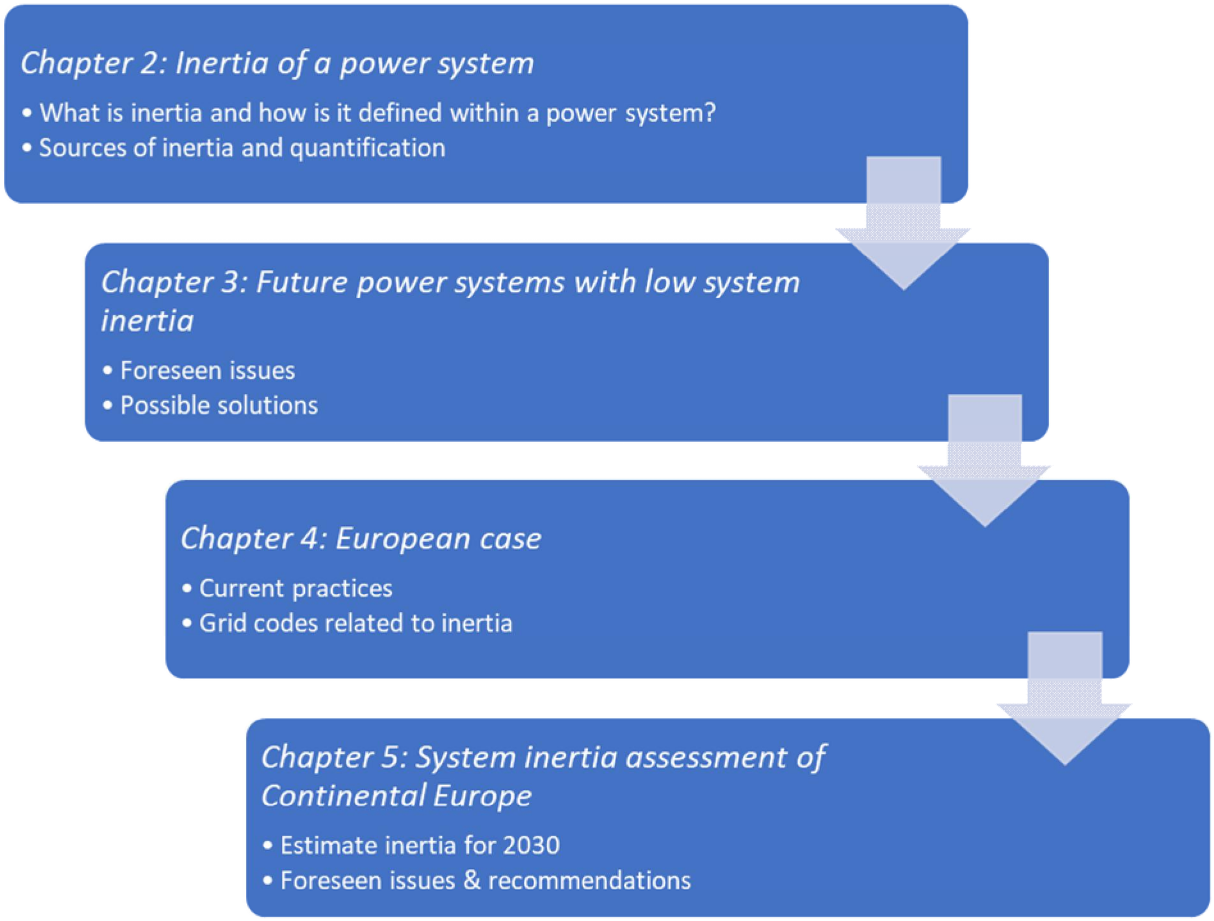


Figure 2: Structure and short summary of the main chapters within the study

The outline of this study with the main contributions are presented in Figure 2. Chapter 0 discusses the fundamentals of inertia in power systems. Also, a short description and quantification of the main sources of inertia are given. A general overview of the foreseen issues with low inertia and the possible solutions are elaborated in Chapter 0. Chapter 0 and 0 focus on the European power system. First, the current practices and grid codes related to inertia within Europe are analysed. Next, an assessment of the system inertia within Continental Europe for the year 2030 is made. The foreseen issues and recommendations for the near future are given. Finally, Chapter 0 presents the main outcomes of the study.

Inertia of a power system

Introduction

In this chapter, the fundamentals of power system inertia are described. First some definitions are presented and the link between the inertia of a synchronous machine and system inertia is explained. Next, the contribution to this inertia from different generation (and load) units is elaborated. Finally, the way the total system inertia is estimated, is briefly explained [1].

Inertia of synchronous machines and system inertia

The concept of inertia is one of the well-known and fundamental principles of classical mechanics used to describe the motion of objects and how they are affected by applied forces. In general, it is defined in its elementary form as the resistance of any physical object to a change in its state of motion, including changes in (rotational) speed and direction [5].

Within an alternating current (AC) electrical power system, the rotational speed of grid connected machines are closely coupled with the frequency at their terminals. As such, the total mechanical inertia that is stored in these machines (total drive train: rotating part of the generators, turbines, …) offers not only some sort of resistance to the change in their rotational speed, but also inherently counteracts any change in the frequency of their internal voltage. The inertia of these machines is therefore considered as a vital parameter upon which the synchronized operation of current day power systems is based.

Although every motor or generator unit directly connected to the grid provides to some extent inertia to the system, the major share of the inertia in current power systems comes from synchronous machines (and their connected turbines) installed in conventional power plants. Since these synchronous machines still form the main source of electrical power generation, they can be considered as the cornerstone of current power system operation.

Taking a single synchronous machine, the mechanical dynamics are governed by its so-called swing equation. By using the rated machine power and rate system frequency (50 Hz in Europe) as base values and assuming only small deviations from the rated frequency, this swing equation is expressed in per unit as [6]:

$$2H\frac{df}{dt} = P_m - P_e \tag{1}$$

P_m and P_e denote the mechanical and electrical power. f represents the frequency at the terminals of the machine. The parameter H is used to quantify the inertia. It is called the inertia constant and it is expressed in seconds as it indicates the time in seconds a generator can provide its rated power solely using the kinetic energy (E_{kin}) stored in the rotating mass of its drive train:

[1] This chapter is based on the PhD dissertation of one of the authors, see [12].

$$H = \frac{\frac{J{\omega_0}^2}{2}}{S} = \frac{\frac{J(2\pi f_0)^2}{2}}{S} = \frac{E_{kin}}{S} \quad (2)$$

with S the rated power of the machine, J the moment of inertia and ω_0 the rated rotational speed (rad/s)[2]. The inertia of a single unit is often also defined by the mechanical time constant (2H), which is equal to the time in seconds it takes to accelerate a generator from standstill to rated speed when a constant torque equal to $\frac{S}{\omega_0}$ is applied [7].

Looking at equation (1), it can be concluded that the inertia of a synchronous machine, denoted by its inertia constant H, expresses the resistance to a change in frequency resulting from an imbalance in mechanical and electrical power.

This concept of rotational inertia provided by a single synchronous generator or power plant can be translated to the total inertia perceived by an interconnected AC power system.

In such an AC power system, every synchronous machine operates at the same frequency in steady state. On the contrary, if a large power imbalance (e.g. outage of a large unit) takes place, each generator will follow a different oscillatory motion around the centre of inertia (COI), depending on its imbalance of mechanical and electrical power (see equation (1)). However, the synchronizing forces between the machines will tend to pull them together and because of the damping provided by rotor damper windings, grid losses or external control devices such as a power system stabilizers (PSS), all machines eventually acquire the same speed.

Due to this inherent synchronization mechanism within the transmission network, all individual machines can actually be aggregated into a single unit, which mechanical behaviour is governed by a single swing equation to represent the coherent response of all generators (expressed in per unit):

$$2H_{sys}\frac{df_{COI}}{dt} - P_G - P_L \quad (3)$$

With H_{sys} the equivalent inertia of the whole power system, also called system inertia. It is defined as the weighted sum of the inertia constants of each connected machine:

$$H_{sys} = \frac{\sum_{i=1}^{n} H_i S_i}{S_{sys}} = \frac{E_{kin,sys}}{S_{sys}} \quad (4)$$

S_{sys} is the system base, which is often taken equal to the total (synchronous) generation capacity connected to the system. $f_{COI} = 2\pi\omega_{COI}$ represents the frequency at the centre of inertia and is calculated by:

$$f_{COI} = \frac{\sum_{i=1}^{n} H_i S_i f_i}{\sum_{i=1}^{n} H_i S_i} \quad (5)$$

[2] Note that in this analysis, the system electrical speed (i.e. frequency) is assumed to be equal to the rotational mechanical speed of the machine. This is only valid in case the machine has a single pole pair (p). Otherwise: $\omega_0 = 2\pi f_0/p$

With n the total number of synchronous machines connected to the system. As given in equation (3), the equivalent unit is driven by the combined mechanical outputs of the individual turbines of the generators ($P_G = \sum_{i=1}^{n} P_{m,i}$) and the output power is set equal to the total load in the system (P_L). Both values are expressed in per unit on the system base S_{sys}.

Looking at the swing equation (3), the system inertia can be interpreted as the resistance in the form of kinetic energy exchange from all directly connected synchronous machines to oppose changes in the frequency at the centre of inertia resulting from power imbalances in generation and demand. The system inertia is not a constant system parameter as the number and type of grid connected machines, both at load and generation side, varies in time.

Although equation (3) is very useful to perform a first assessment on the general frequency dynamics of a system the first instances after an event, it is important to keep the following things in mind. First, it is important to note that it only represents the frequency behaviour at the centre of inertia. The frequency at each node in the network will mostly not be equal to this f_{COI} during a system disturbance but experiences an oscillatory motion around f_{COI}. Secondly, frequency damping (proportional to the frequency deviation) is not included in the equation. Thirdly, both P_G and P_L are a function of time, so in order to accurately model the frequency at COI, a detailed representation of the total power at the load and generation side is required.

Sources of inertia: quantification and classification

In the former section, the concept of system inertia has been explained by mainly looking at synchronous machines. However, the amount of kinetic energy that is stored within each synchronous machine and their connected drive train can be quite different. Moreover, to perform a detailed assessment, it is also important to have a closer look how other types of generation or load will inherently react to a change in frequency, i.e. to look at what kind of inertial response they provide. An extensive overview is therefore given in the next sections.

Conventional power plants

Large conventional units like e.g. coal fired, gas, oil, nuclear and hydropower plants using synchronous machines to convert the mechanical power from their turbine to electrical power are the main sources of inertia in today's power system. Their inertia constant H falls typically in the wide range of 2-9 s [8, 9].

This constant covers the total kinetic energy stored in the drive train of the power plant, comprising the rotors of the synchronous generator and the prime mover. For steam turbo generators roughly 30 to 60% of the total inertia comes from this prime mover, whereas only 4 to 15% of the total kinetic energy of a hydro power unit is usually stored in the water wheel (including the water itself) [10].

In Figure 3, the inertia constants for several steam and hydropower plants with different power ratings are given. One may notice that there is no clear consistency in the inertia constants for a specific type of technology or size. The amount of inertia of a power plant is thus very much case specific and strongly depends on the design of both the generator and turbine. However, in [11] it is stated that with respect to thermal power plants, units equipped with a four-pole synchronous generator (1500 rpm in a 50 Hz power system) generally have larger inertia constants than units using a two-pole generator running at a higher speed (3000 rpm in a 50 Hz power system). For large thermal units using a four-pole generator, the inertia constant can even exceptionally reach values up to 10 s.

With respect to gas turbines, there is often also a clear distinction in the inertia constants of aeroderivative gas turbines and heavy-duty ones. Flexible aeroderivative turbines generally weight considerably less than the heavy-duty ones which results in an inertia constant at the low end of the range of 2-9 s. The inertia constant of heavy duty gas turbines is more in the order of 4-6 s.

Finally, it should be noted that current-day turbines and generators are generally lighter than the one developed in the '70s and '80s, resulting in a lower H.

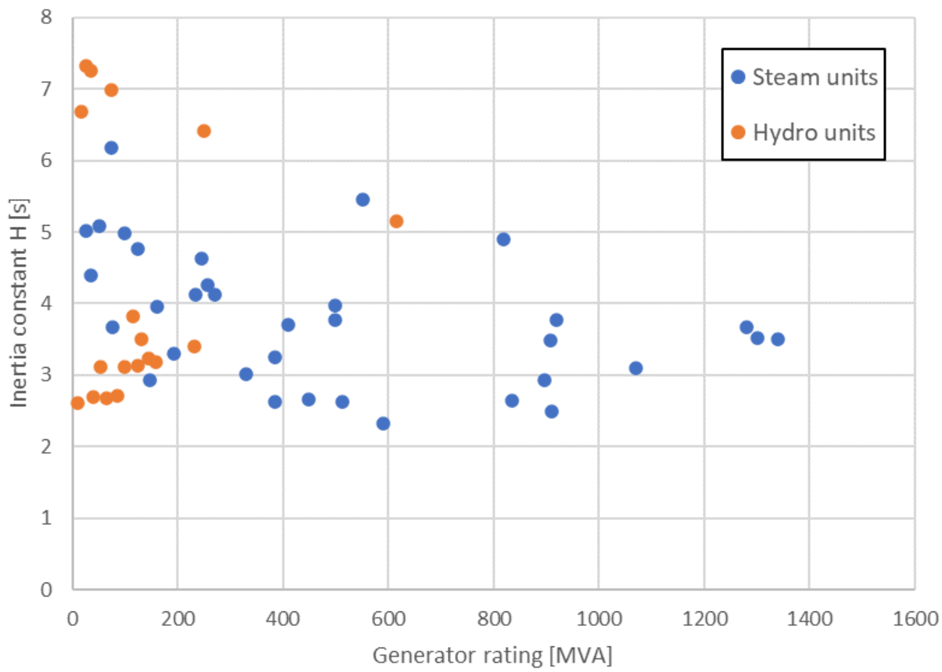


Figure 3: Typical inertia constants for conventional units. Data taken from [8]

Synchronous condensers

Synchronous condensers (or also called synchronous compensators) are voltage controlling devices that comprise a freely spinning synchronous machine connected to the high voltage network via a step-up transformer. By regulating the excitation current of the machine, dynamic voltage and reactive power support is provided. As they are synchronously connected to the system, they will contribute to the total inertia. However, as they do not produce any active power, no prime mover is driving the synchronous machine. Consequently, the stored kinetic energy is rather low with an inertia constant around 1 s [6].

Wind and solar photovoltaic (PV) power

Contrary to conventional power plants, renewable energy units do mostly not apply a directly connected synchronous machine as interface with the system. Therefore, their inertia contribution is very low, or they provide a completely different inertial response to the system.

For wind power units for instance, different ways of converting the mechanical power from the blades to electrical power is used depending on the applied topology. The most basic (and oldest) wind turbine topology applies a direct induction generator coupling, also called fixed speed wind turbine (see Type 1 & 2 in Figure 4)[3].

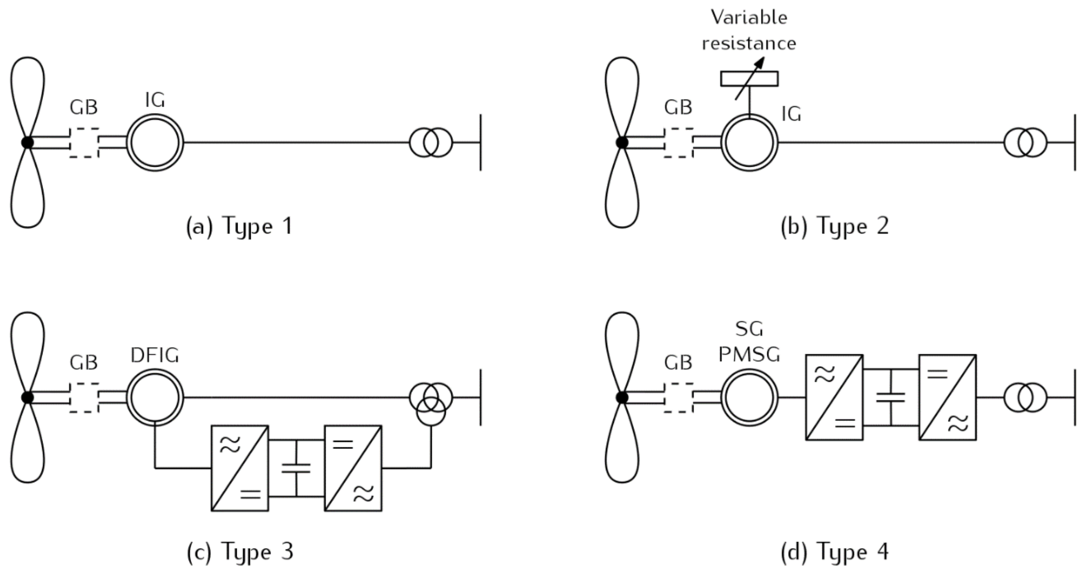


Figure 4: Common wind turbine topologies (GB: gearbox, IG: induction generator, SG: synchronous generator, DFIG: doubly fed induction generator, PMSG: permanent magnet synchronous generator). Adapted from [12]

Due to the direct coupling of the induction generator an inertial response is provided to the system. By quantifying the stored energy within the blades and generator of such wind turbine, similar inertia constants as the one of conventional power plants are reached (H=±5s). In [13] for instance, it is stated that the kinetic energy of a 2 MW turbine rotating at a rated speed of 1.8 rad/s is almost 7.3 MWs. Adding the inertia from the generator (H = 1 s), the total inertia constant becomes 4.65 s.

However, the way this inertia is delivered, slightly differs from a synchronous machine. Due to the slip of the machine, the inertial response from the induction generator is slightly slower and lower, see also the results presented in [14, 15].

This topology offers a simple and robust power conversion, but it has also many disadvantages, such as the need for reactive power compensation and the limited ability of varying its rotational speed with the wind speed resulting in a low efficiency over the whole wind speed range [16]. Therefore, although there is still a large amount of these fixed speed wind turbines in operation (mainly in the pioneer countries e.g. Germany, Spain and Denmark), they are gradually squeezed out of the market as new installations or the repowering of old turbines consist predominantly of variable speed wind turbines equipped with a DFIG or full-scale converter interface (see respectively see Type 3 & 4 in Figure 4) [17]. Already in 2010, it was estimated that these two types combined covered a market share of almost 80% in Europe [18]. Worldwide estimates indicate also an increasing trend of variable speed wind turbines due to their flexible control and grid support capabilities [19].

Type 3 provides a partial direct grid coupling via the stator windings of the DFIG, but the inertial response from these units seems to be almost negligible, mainly due to the fast-acting converter controller which is usually designed to regulate the electrical

[3] Type 1 includes a standard induction generator while a type 2 wind turbine employs a wound rotor induction generator with adjustable external resistors to increase its allowed speed range.

torque. Hence, during a frequency transient, it will control the rotor current in order to keep the electrical torque equal to its pre-disturbance value. In [20], the influence of the bandwidth of this controller on the inertial response is further investigated. Only if a low controller bandwidth is assumed, a small inertial response can be noticed. A low controller bandwidth would however adversely affect the control capability during normal operation where a fast-current controller is desired. In [21], it is demonstrated that in case the stator power is controlled instead of the electrical torque, an inertial response is provided by the turbine through the changing rotor power. This control strategy is considered quite uncommon though and is only reported in a few research articles [22].

Finally, a back-to-back configuration comprising an alternating current/direct current (AC/DC) and DC/AC converter (full scale converter) can be applied for wind turbines, which allows an extended variable speed operation in order to obtain maximum efficiency (Type 4 wind turbine, see *Figure 4*). The concept can accommodate different generator types, but mostly a synchronous generator is used, either with permanent magnets or electrical excitation (PMSG) [23]. In case a direct driven multipole generator with a large diameter is applied, the generator and the blades can operate at the same speed so that the gearbox can be omitted. The generator is completely decoupled in this case due to the separate controls of the generator and grid side converter linked by a DC capacitor. Due to this decoupling, no inertia to the power system is provided.

In a PV system (see *Figure 5*), a similar topology as a type 4 wind turbine is applied except that the generator, turbine and blades are replaced by (a string of) PV panels. As these panels produce DC power, no AC to DC conversion stage is required, but often an intermediate DC/DC conversion stage is included to regulate the DC voltage in order to extract the maximum available power [11]. Due to decoupling with the system and the lack of any rotational parts in the PV system, no inertia is provided to the power system.

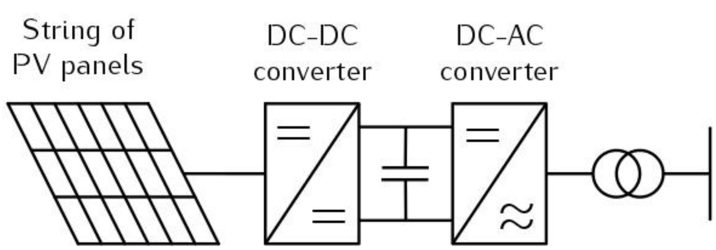


Figure 5: Typical solar (PV) topology

Other types of (distributed) generation

The grid interfaces applied for all other types of (distributed) generation, which mostly make up a much smaller part of the total generation mix, are in general similar to one of the topologies discussed in the former sections.

In a concentrated solar power (CSP) plant, the concentrated light is converted to heat, which is applied to produce steam. This steam drives a steam turbine connected to a synchronous generator. As such, the grid interface and drive train of these CSP plants is quite comparable to a conventional steam power plant, with inertia constants equal to the one presented in Figure 3.

A directly connected synchronous machine such as within large conventional power plants is also often applied in (small) hydropower units, internal combustion engines and some low-speed microturbines, in which the motor or turbine is optimally designed to operate at constant speed. Looking at the inertia of these small hydro and thermal units equipped with a synchronous machine, it is indicated in [11] that the inertia constants are much lower (about 50%) compared to large conventional units of the same type.

Furthermore, in case of internal combustion engines for instance, a power electronic interface (similar to a type 4 wind turbine) is sometimes included to offer an increased fuel efficiency as the engine speed can be optimized depending on the load [24]. Also, for high-speed single shaft microturbines, becoming widely popular as energy producers in combined heat and power (CHP) systems, a converter is used to transfer the power from the generator operating at high speed ranging from 50000-120000 rpm [25]. The converter decouples the generator from the power system and consequently, no inertia is provided.

Storage

For storage units, it will be depending on the applied technology how much inertia is delivered. Hydro (pumped) storage and compressed air energy storage (CAES) provide inertia as they use a synchronous generator (and connected turbine) to interface with the grid. Chemical storage devices such as batteries do not apply any generator and always use a power electronic converter as grid interface. No inertia is therefore delivered.

Load side

Whether the load will contribute to the system inertia, depends on the dynamics and type of the load. Directly connected motor loads in the form of fans, drives, pumps, … deliver inertia just like synchronous and induction generators do. Motor loads are present in both residential, commercial and industrial areas and cover a fundamental share of the total system load, generally consuming 60-70% of the total energy supplied by a power system [6]. The heavy rotating machinery of large industrial consumers mainly contributes to the system inertia. The small and medium sized motors on the other hand, installed in residential and commercial areas (e.g. used in air conditioning and refrigeration units), are characterized by a low inertia constant between 0.1-0.3 s [26].

Motor loads equipped with a variable speed drive (VSD) on the other hand do not provide inertia due to the electrical decoupling of the motor. Although some industry studies show that only 15-20% of the motors use such a VSD today, it is expected that this share will further increase [27]. All other load types do not react on frequency variations such as resistive or power electronic coupled loads (lighting, heating, IT infrastructure, …) and consequently offer no inertia.

Summary

As explained in the previous sections, the way generation units provide inertia mainly depends on their interfacing technology (see Figure 6). Therefore, a summary of the different energy sources, their interfacing technology and inertia contribution is given in Table 1.

One must keep in mind that H for a single unit is in most cases expressed with respect to the nominal power rating of that unit. This means that when comparing the inertia of different units, it is important to take into account its size. For instance, a generation unit with H=1 s and S=300 MVA will contribute 3 times more to the system inertia than a unit with H=5 s and S=20 MVA. When the system inertia (assuming only contribution from these two units) is calculated and expressed on a base of 320 MVA, H_{sys} becomes:

$$H_{sys} = \frac{\sum_{i=1}^{2} H_i S_i}{S_{sys}} = \frac{1\,s\ \times 300\,MVA + 5\,s\ \times 20\,MVA}{320\,MVA} = 1.25\,s \qquad (6)$$

H is thus intrinsically expressed in per unit which can sometimes lead to confusing results, especially if no clear base (power) value is given. Therefore, system inertia is often also given in terms of the stored kinetic energy synchronously linked with the power system (see $E_{kin,sys}$ in (4)), which results for the previous example in:

$$E_{kin,sys} = E_{kin,1} + E_{kin,2} = 300\,MVAs + 100\,MVAs = 400\,MVAs \qquad (7)$$

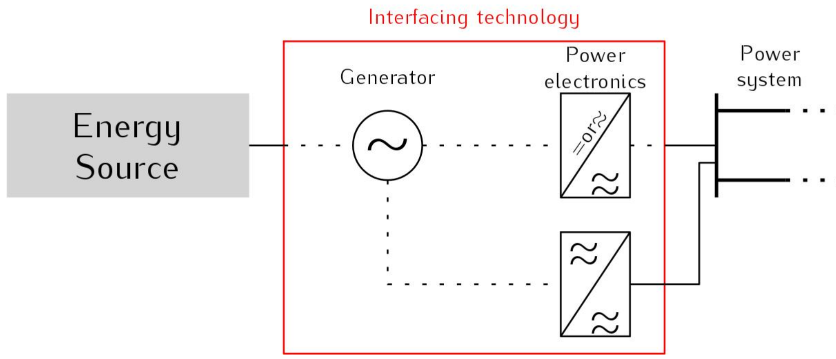


Figure 6: Interfacing technology (schematic overview)

Energy source type	Generator	Power electronics	Inertia?
Conventional power plants (hydro, nuclear, gas, oil, coal, ...)	SG	/	Yes, H=2-9 s
Concentrated solar power	SG	/	Yes, H=2-9 s
Wind power	IG (Type 1 & 2)	/	Yes, but smaller and delayed (stored energy: H=±5 s)
	DFIG (Type 3)	AC/AC to rotor windings	No
	SG, PMSG (Type 4)	AC/AC (with intermediate DC bus)	No
PV power	/	DC/AC (with intermediate DC bus)	No
Internal combustion engines (small scale, distributed: e.g. for combined heat and power (CHP) applications)	SG, IG	Optional: AC/AC (with intermediate DC bus)	Yes, if no AC/AC converter is used (H=1-4.5s)
Microturbines	SG, IG	Optional: AC/AC (with intermediate DC bus)	Yes, if no AC/AC converter is used (H=1-4.5s)
Small hydropower	SG	/	Yes, H=1-4.5s
Fuel cell/battery storage	/	DC/AC (with intermediate DC bus)	No
None (Synchronous condenser)	SG	/	Yes, H=1 s

Table 1: Interfacing technology (see Figure 6) and inertia contribution for different generation sources

Estimating system inertia

In the former section, each type of units has been assessed individually. However, when looking at a power system it is important to determine the combined system inertia of all spinning units at each moment in time. At first side, and especially for very small power system, this calculation looks quite easy and straightforward (see e.g. the calculation of (6) and (7)). However, some side notes have to be made:

- To determine the system inertia, the inertia contribution of each generation unit within the synchronous area must be included. Data exchange among different transmission system operators (TSOs) is therefore required to assess the system inertia in large synchronous areas (e.g. Continental Europe).
- Each TSO has a good overview which (large) conventional power plants are in operation at each moment in time. However, this may not be the case for smaller units connected to the distribution grid (e.g. smaller CHP units).
- To calculate the aggregated inertia from the system load, a detailed representation and estimation of the load composition is required (how many SGs, IGs, … are connected?). However, due to the large number of devices involved together with the spatial distribution, the time-varying and stochastic nature of the load, it is very complicated to assess the exact share of each type.

In practice, it is thus very challenging to get a good estimate of the inertia in a large interconnected power system, certainly if there are many small generation and load units equipped with a motor connected to the distribution side. Nevertheless, within the context of an expected decrease of inertia, some TSOs are developing methods to determine the inertia in their system in real-time.

In 2015 for instance, a tool was developed by the Nordic Analysis Group (NAG) to estimate the inertia of the Nordic power system, comprising the synchronously interconnected power systems of Norway, Finland, Sweden and Eastern Denmark [28]. To monitor the inertia in real time, each TSO performs an estimate of its own control area, thereafter all inertia values are combined to perform an estimation on Nordic system level.

In the Swedish power system, the inertia is estimated based on the circuit breaker position and corresponding inertia constant of each generator. 421 generators are included in the study which all combined have a total stored kinetic energy of 166.5 GWs. However, for 125 generators, no SCADA measurements are available to distinguish whether or not they are connected to the system. Furthermore, from 173 small generators, inertia data is missing. Therefore, the estimate from SCADA measurements is complemented with estimates of missing machines based on their production type and total system load. A similar method is applied by the Finnish TSO.

The kinetic energy for the Norwegian system on the other hand is currently estimated based on the total production corresponding to different consumptions levels. A more accurate approach as used by the Swedish and Finish TSOs is postponed to the implementation of a new SCADA system. The final tool will approximately include 2000 generating units.

Finally, in the Danish system, SCADA measurements for each generating unit over 1.5 MW are included. If the circuit breaker position of a generator unit is not known, power measurements are used to determine whether or not they are synchronized.

The kinetic energy of the system within the time period of 2009 to 2015 is analysed using historic data, see *Figure 7*. A clear seasonal and weekly variation of system inertia is illustrated in the figure (more load = more generation = more inertia). The lowest kinetic energy was 115 GWs during the summer of 2009 which is due to the low availability of nuclear power during that year.

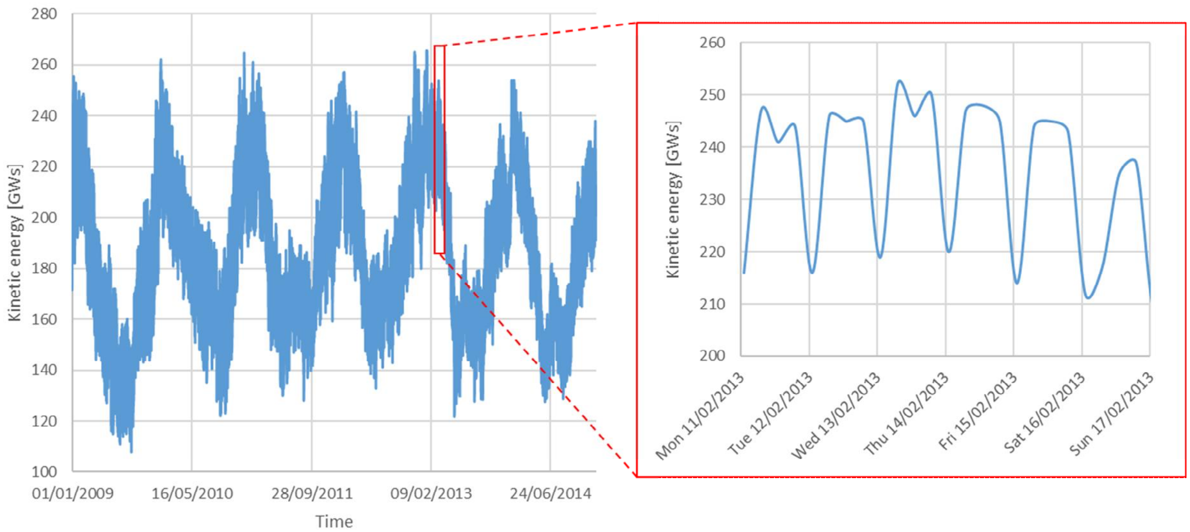


Figure 7: Estimation of historic kinetic energy in Sweden, Finland and Norway. Data from [28]

For the sake of completeness, although system inertia cannot be measured directly, it is possible to determine it by analysing past (large) frequency excursions. By taking the data about the measured frequency profile (the rate of change of frequency: ROCOF) and power imbalance as main inputs and using equation (3) the system inertia is calculated[4]. However, as shown in [29, 30], this approach only gives a rough indication of the amount of inertia since many factors related to filtering, measurement errors, … significantly influence the accuracy of the applied method. Moreover, this method is not considered to be relevant for real time system operation due to its retroactive approach of analysing past frequency transients.

Finally, in *Figure 8*, the estimated stored kinetic energy (minimum and maximum) is given for several power systems around the world together with their minimum and maximum load (data taken from [31]). The kinetic energy content varies over a wide range as the size of the systems are also very different. In order to compare the energy independent of the system size, we divide the maximum kinetic energy by the maximum load. The results are presented in *Figure 9*. It is clear that especially the power system of Australia (Queensland, Victoria, New South Wales and South Australia) has a relative low amount of kinetic energy available.

[4] For more info on the possible calculation approaches, see [29, 30, 76].

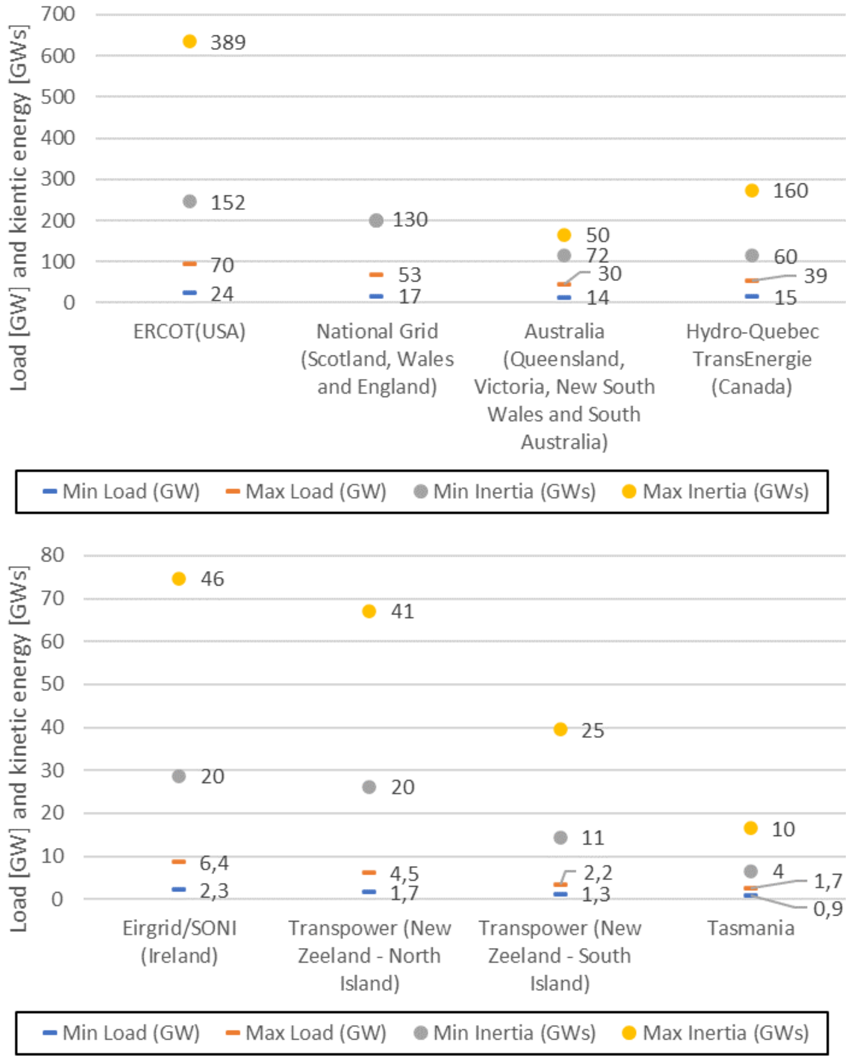


Figure 8: Minimum and maximum inertia of different power systems (data is taken out of a survey conducted by the Nordic transmission system operators), see also [31]

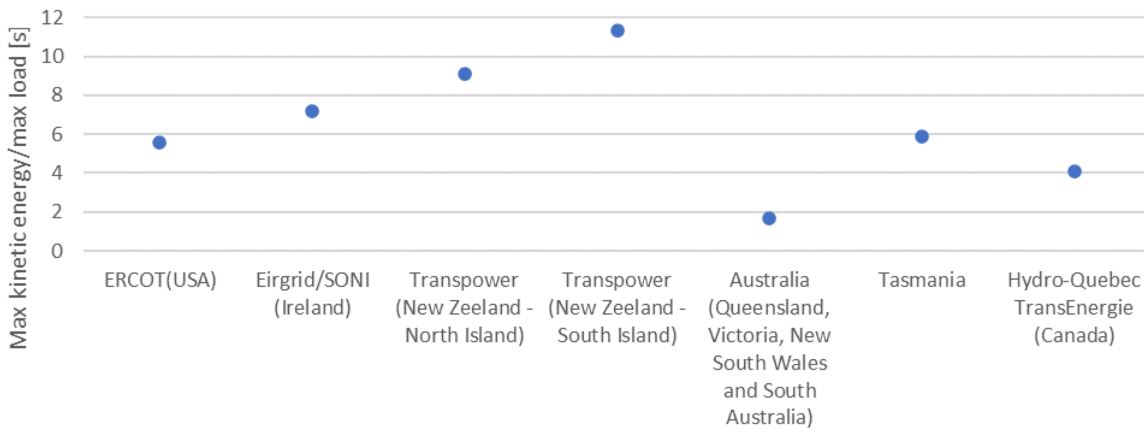


Figure 9: Max kinetic energy divided by the maximum load for different power systems

Conclusion

System inertia can be defined as the amount of stored kinetic energy from direct (synchronously) connected machines that offer resistance to any change in the frequency at the centre of inertia. Although the load and distributed units also contribute to some extend to the total system inertia in an interconnected AC power system, the lion's share of system inertia is provided by the synchronous machines installed in conventional power plants. PV and wind power, except from fixed speed wind turbines, provide no inertia at all due to their power electronic converter which decouples the generator from the system. Therefore, as a first estimate, only the inertia of conventional power plants is taken into account in most power system studies.

Future power systems with low system inertia: issues and possible solutions

Introduction

As introduced in Chapter 1, due to the increased share of renewables, many of the traditional sources of inertia will be displaced by converter connected units providing no inherent inertial response. Consequently, the total system inertia will decrease. In this chapter, the foreseen issues with operating a power system with lower inertia are listed. Furthermore, also some possible measures to manage this inertia reduction are presented.

Foreseen issues with lower system inertia

Power system stability problems: Frequency stability/control

Power system stability refers to the ability of a system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact (definition by IEEE/Cigré [32]). The disturbance can consist out of a (large) outage, switching actions, faults, …

Power system stability is further classified depending on the system variable of interest. The standard and main forms of system stability are rotor angle, voltage and frequency stability. As inertia is an important parameter of every synchronous generator within the system, it will have an influence on each form of stability. However, from other research works [12, 33], it can be concluded that there is no direct positive or negative link between a decrease of synchronous system inertia and rotor angle (or voltage) stability[5]. For rotor angle stability, mainly the control (and location) of the converters that displace the synchronous machines do have a large influence on this form of stability. For voltage stability, there is no direct link with inertia.

However, inertia plays an important role in the frequency stability of the system. Frequency stability is defined as the ability of a power system to maintain steady frequency following a severe disturbance between generation and load (definition by IEEE/Cigré [32]). Frequency instability may lead to sustained frequency swings leading to tripping of generation units or loads if the frequency exceeds a certain band or in case the rate of change of frequency (ROCOF) becomes too high (see section 0).

In *Figure 10*, a typical frequency profile after a large generation outage is given. To explain how the frequency is generally controlled in that case (to remain within a specific range) and the role of inertia, we retake the aggregated machine equation out of chapter 0:

$$2H_{sys}\frac{df_{COI}}{dt} = P_G - P_L \tag{8}$$

In steady state, the total generation and demand is balanced ($P_G = P_L$) such that the frequency is constant ($\frac{df_{COI}}{dt} = 0$) equal to its rated values (f_0, 50 Hz in Europe). As soon as a power imbalance takes place, the frequency starts to deviate. Such imbalance can occur during normal (continuous) operation (random switching of load units, intermittent power generation from renewable energy sources, even market driven events, …) or during contingencies (power plant outage or load step).

[5] Keep in mind that there is a close coupling between the inertia of a single synchronous machine and its transient stability margins. However, if we look to the total system inertia, no direct positive or negative link with the transient stability is present.

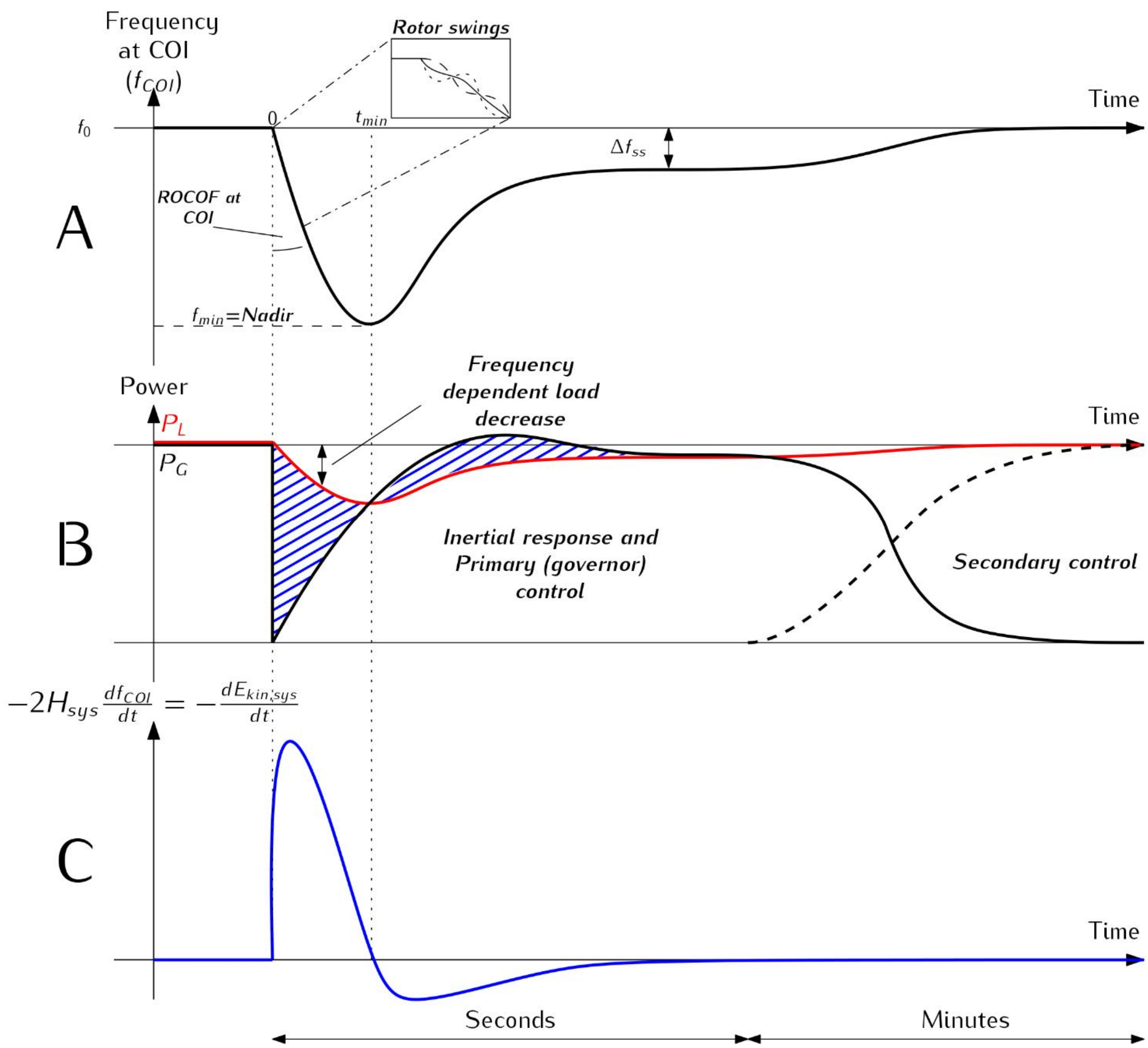


Figure 10: Typical frequency response after a generator outage, i.e. drop in PG (A: frequency, B: load and generation power, C: inertial response). Adapted from [12]

At the instant of the power imbalance, the frequency starts to deviate (decreasing in case of $P_G < P_L$ and increasing in case of $P_G > P_L$) as the power deficit (or surplus) is not instantaneously compensated by a corresponding increase or decrease in mechanical turbine power of the power plants offering frequency support. The imbalance is in this phase fully compensated by the release of kinetic energy (or inertia) of the connected machines ($2H_{sys}\frac{df_{COI}}{dt} = \frac{dE_{kin,sys}}{dt}$), see also the hatched area within Figure 10.B or the blue curve in Figure 10.C. Therefore, this phase in the frequency control is also named the inertial response.

As shown in Figure 10.A, since the power impact is distributed over all synchronous machines each experiencing a different change in rotor angle and speed (i.e. rotor swings). Once these oscillations are damped out, a common frequency decline among the whole system is reached.

In the meantime, all units equipped with a governor or speed controller jointly act as soon as the frequency exceeds a certain dead band (±20 mHz in Continental Europe), also called primary control[6]. They react by altering their power output of the prime mover proportional to the speed deviation of the machine. Depending on the type of power plant (i.e. type of governor and turbine), several time delays are involved in this control process. Due to the common control action, the frequency deviation is limited and the balance between load and generation is restored. Since the controller only acts proportional to the frequency, it still deviates from its rated value with an offset equal to Δf_{ss}. It is also important to note that not only the generated power (P_G) will alter, but also the load power (P_L) will react on the frequency deviation (i.e. load damping). Mainly for motor loads, such as fans and pumps, the electrical power demand changes with frequency, therefore P_L is often expressed in frequency studies as:

$$P_L = P_{L,0} + D_{sys}(f - f_0) \tag{9}$$

With D_{sys} the load damping constant (typical values are 1-2%) [6]. The restoration of the frequency is performed in the next stage, also named secondary control, by further changing the power setpoints of prime movers within selected units. This additional control action is much slower than the governor action (primary control), with a time constant in the range of 10-15 min. Depending on the system, a manual adjustment of the setpoints is made (e.g. the Nordic system [34]) or the control is automated, typically the case in large systems such as the synchronous grid of Continental Europe [35]. For the sake of completeness, generally also a tertiary control action is implemented, which restores the secondary control reserves used or provides the most economically allocation of these reserves within the set of generating units in service.

Some other important parameters to assess the frequency control/stability are given in *Figure 10*, such as the minimum frequency (f_{min}) also called Nadir frequency or the rate of change of frequency (ROCOF) at the COI. The former analysis has been done for a frequency drop, for an over frequency event on the other hand (e.g. sudden load loss), the curves within *Figure 10* will be mirrored along the horizontal axis.

Influence of inertia on frequency control/stability

Inertia has a major influence on the inertial response and primary control action of a power system. During the inertial response, the primary control action of the power plants is still not (fully) activated and the frequency dynamics are fully governed by the swing equation of the system, see equation (8). Therefore, the frequency in function of time in per unit can be approximated during the first instances after the imbalance by (in per unit):

$$f_{COI}(t) = 1 + \frac{P_G - P_L}{2H_{sys}} t = 1 + \frac{\Delta P}{2H_{sys}} t \tag{10}$$

with ΔP the initial power imbalance (i.e. minus for a generation deficit). This leads to a very simple formula for the ROCOF:

$$ROCOF = \left. \frac{df_{COI}}{dt} \right|_{t=0} = \frac{\Delta P}{2H_{sys}} \tag{11}$$

[6] The different control actions are nowadays denoted in Europe (i.e. within ENTSO-E) by frequency control, frequency containment and frequency restoration process. However, as the traditional terminology is still widely used by many TSOs, the terminology of primary, secondary and tertiary control action is adopted in this work.

In Figure 11.a, the frequency as a function of time is given for a power imbalance of 0.1 p.u.. It highlights that for a given imbalance, the frequency drop is much larger and faster if inertia is decreased. For a lower H_{sys}, the governor control therefore needs to react sooner to cease the frequency decline before it reaches critical values (see next section). Furthermore, as the ROCOF and H_{sys} are inversely proportional, low system inertia can result in very high ROCOF values, see *Figure 12Figure 11*.b.

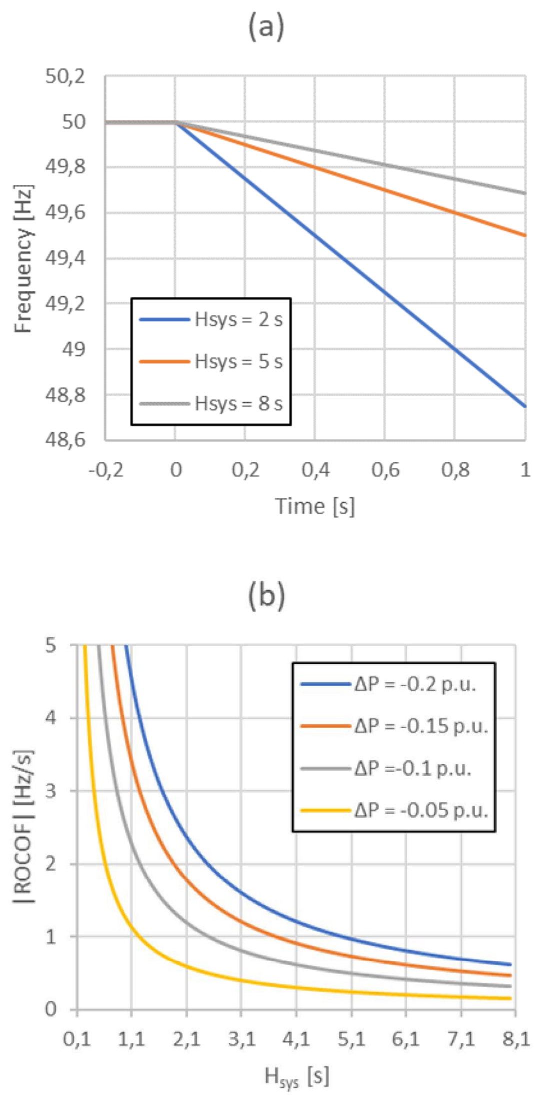


Figure 11: Inertial response: (a) Frequency at COI after a ΔP = -0.1 p.u. (b) initial ROCOF

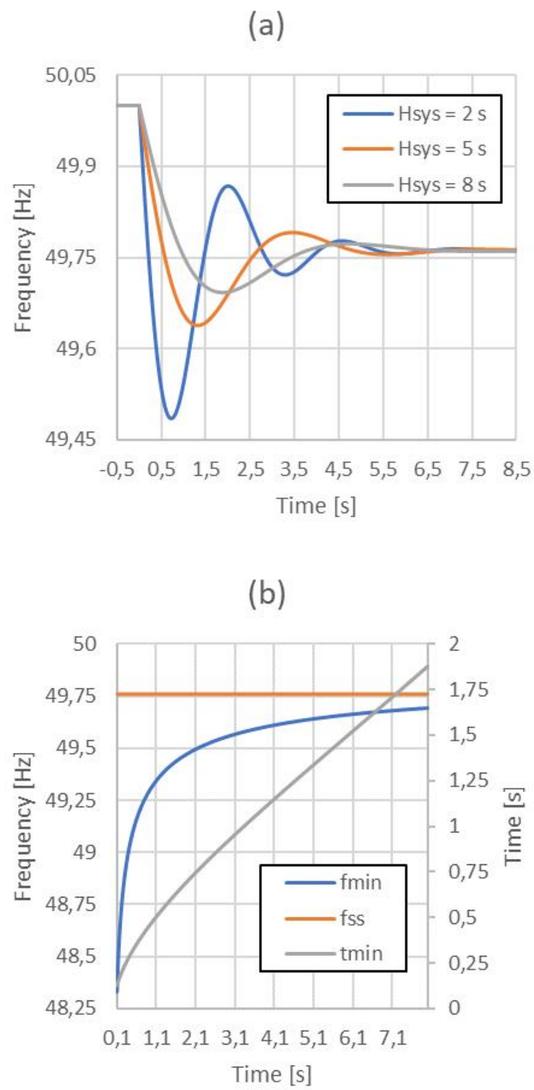


Figure 12: Primary control action for ΔP = -0.1 p.u., Rsys=0.05 and Dsys=1: (a) Typical frequency response and (b) Minimum frequency (nadir), steady state frequency and time to reach nadir

Once the governor control is activated, the frequency decline is arrested, and the frequency will eventually become stabilized. However, as system inertia decreases the minimum frequency will drop lower (for the same type of governor control) as shown in Figure 12.a. Furthermore, decreasing inertia also reduces the time to reach this f_{min}, denoted by t_{min} (see Figure 12.b). On the contrary, the steady state frequency, f_{ss}, remains unaltered if the inertia varies. It is only a function of the system droop and load damping [6]:

$$f_{ss} = 1 + \frac{\Delta P}{\frac{1}{R_{sys}} + D_{sys}} \tag{12}$$

With R_{sys} defined as:

$$\frac{1}{R_{sys}} = \sum_{i=1}^{n} \frac{S_i}{R_i S_{sys}} \tag{13}$$

R_i is the droop of each individual machine and represents the % change in grid frequency that causes 100% change in valve position or power output of the corresponding generation unit.

It should also be noted that the frequency profiles within Figure 12 are determined for a specific generation mix. Since the time constants of the primary control action also largely depends on the time delays within the prime mover of the unit (hydro turbine, steam turbine, gas turbine, …) and the governor, each generation mix will have a different frequency profile.

In Figure 13, three typical frequency response profiles are given to compare a steam, hydro or gas turbine base power system (in Figure 12, a steam turbine based system is applied)[7]. It demonstrates that, although the inertia and permanent droop are equal in the three cases, the different plant characteristics significantly influence the transient frequency response. Due to the non-minimum phase behaviour and slow response of the hydro turbine, the frequency drop is much larger compared to the case where the steam or gas turbine provide primary control. It is therefore important to include all the parameters to assess the frequency control. For instance, it may be possible that a steam turbine based system with low inertia can have an higher nadir than a hydro based system with high inertia for the same power imbalance.

In can thus be concluded that reduced system inertia will in general deteriorate the frequency stability and control in a system as it results for the same power imbalance and generation mix into an increase in ROCOF and lower minimum frequency (or high maximum frequency). However, each system will have a distinct frequency response depending on its generation mix, load composition, … such that a system specific assessment is always required to analyse the frequency stability with reduced inertia.

[7] Typical parameters for the steam, hydro and gas turbines modelling are taken from [6]. However, for a detailed assessment, a more extensive modelling with specific turbine data is required.

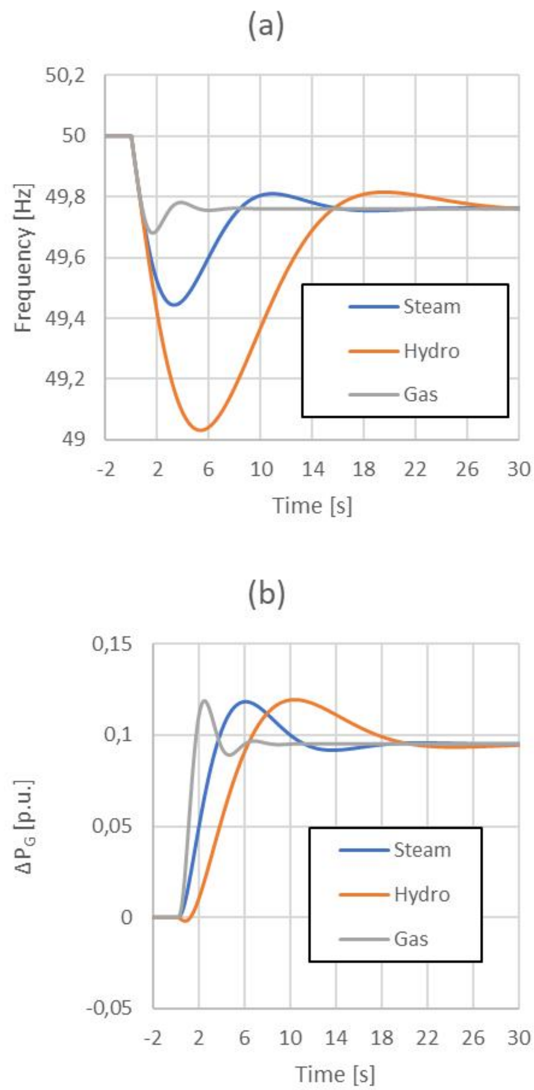


Figure 13: (a) Typical Frequency and (b) turbine response for three different types of power plants (ΔP = -0.1 p.u., Rsys = 0.05, Dsys = 1 and Hsys = 8 s)

Frequency and ROCOF limits

After discussing the frequency control in power systems and the influence of inertia, it is important to have a closer look at the allowed frequency range and ROCOF values. As such we can analyse how low the inertia of a power system may go before (frequency) instability may occur, i.e. before load or generation units will be disconnected (i.e. activation of load shedding or generator protection).

First of all, it is important to know that a large frequency deviation (from its nominal value: 50 Hz in Europe) may have a detrimental effect on the operation of (conventional) power plants. For instance, operating at a reduced frequency results in a decreased ventilation of the synchronous generator and leads to additional vibrational stresses on the turbine blades. As the effects are cumulative with time, the frequency must be quickly restored [36]. Additionally, since the speed of all grid connected motors is directly linked to the frequency, also the performance of the auxiliary equipment (fuel, feed-water and combustion air supply systems) is impacted. The critical frequency at which the performance of the equipment will affect the plant capability highly depends from plant to plant, but additional safeguards should be considered in order to protect the plant and trip the unit in case of an excessive frequency excursion.

Each TSO defines also a required frequency operating range in its grid codes which sets a certain tolerance around the nominal frequency within which generators should remain connected to the transmission grid. For large interconnected systems, this tolerance is mostly around ±2%, while in smaller or island systems, slightly larger bands are required as frequency control is more challenging. Outside these frequency bands, generators must remain connected for a certain amount of time or may disconnect immediately [102]. In Figure 14, an overview of the frequency bands defined by a number of TSOs within ENTSO-E[8] is given.

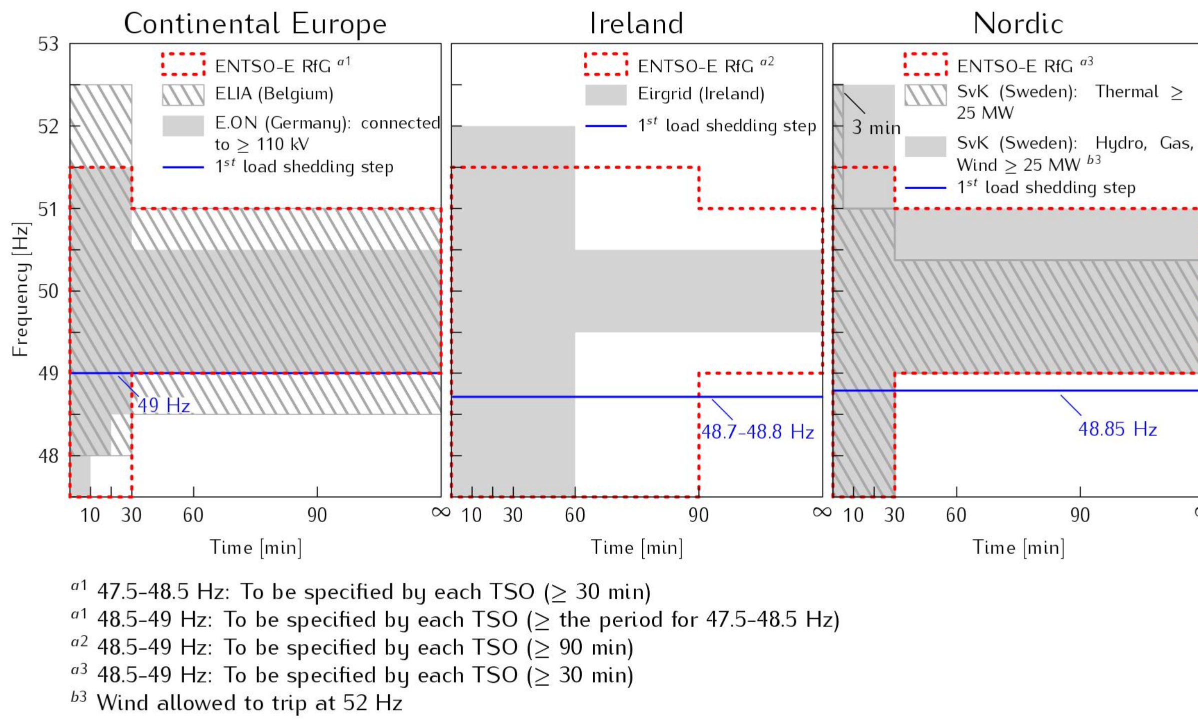


Figure 14: Frequency capability curve for different synchronous areas within ENTSO-E9. Adapted from [12]

With respect to load shedding, the specific frequency at which the first load shedding step is activated, and the amount of load disconnected at each step depends on the implemented load shedding scheme, often designed nationally (see [37] for an extensive overview). As given in *Figure 14*, the first load shedding step is activated at ±49 Hz in most of the synchronous areas within ENTSO-E. When the power system of continental Europe exceeds the wide range of 47.5 Hz – 51.5 Hz, a system blackout can hardly be avoided [38].

[8] ENTSO-E: European Network of Transmission System Operators for Electricity

[9] Requirements for Generators (RfG) refers to the established European network code on the requirements for the grid connection of new generator facilities. This network code is in force under European law since 2016 and will be adopted by each country during the coming years.

Besides the allowed frequency range, it is important to analyse the admissible ROCOF immediately after the imbalance. This ROCOF is often used in combination with the frequency deviation to trigger load shedding relays as it provides a more selective and/or faster operation. Due the rotor swings following an event, the ROCOF oscillates. Therefore, an average of the measured instantaneous ROCOF values is generally used.

Moreover, the ROCOF should be limited to prevent false tripping of ROCOF relays within low and medium voltage networks, often applied to protect distributed generation against islanding (also called loss-of-mains protection) [39]. 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. When islanding occurs, local generation does not exactly balance the remaining load. Consequently, frequency changes rapidly, depending on the power imbalance and the inertia of the islanded subsystem. This triggers the ROCOF relay and the islanded subsystem is 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 power system [40]. The amount of generation protected against islanding by this type of relay is system dependent.

Additionally, it is also not yet clear what the impact of a high ROCOF event is on conventional generating units. The main concerns of conventional power units about high ROCOF values are the instability and reduced life time due to additional wear and tear. Since ROCOF withstand capability has not been a design requirement historically, more research is required to further assess this impact.

For power systems within large synchronous areas, requirements of the allowed ROCOF range, ensuring a continuous and uninterrupted operation of the power plants, are often missing in the grid codes since large sustained frequency gradients are quite rare. In the power system of continental Europe for instance, ROCOF values of only 5-10 mHz/s are observed after a power plant outage of 1 GW [38].

Discussion: System inertia, how low can it go?

So, we have investigated to what extent inertia will impact the frequency control and we presented some frequency and ROCOF limits for a number of power systems. Consequently, the next question that arises is: How low can the system inertia go before these limits are reached?

To answer this question, we will have a look at Figure 15 and Figure 16. Even though some very basic system models have been used to create these figures, they are quite useful to quickly assess the inertia need in a system (it can be applied to every system due to the per unit modelling). In Figure 15, the minimum required inertia to keep the ROCOF above a certain value for several power imbalances is presented. A conservative approach is taken to set the ROCOF limit, which is equal to 1 Hz/s. The minimum required inertia is directly proportional to the size of the imbalance, but inversely proportional to the ROCOF (limit). Taking for instance the data of the Nordic system (see *Figure 7*), and assuming that the stored kinetic energy is equal to 200 GWs (equal to H_{sys}=5s on a base of 40GW), the system can cope with imbalances up to 8 GW before a ROCOF of 1Hz/s is reached[10]. However, for the reference incident of 1.4 GW[11] (0.035 p.u. on a base of 40 GW) only an inertia constant of 0.875 s is required.

[10] Such an imbalance is considered to be highly unlikely for that system, since it is much higher than the power input or output in a single node in the system.

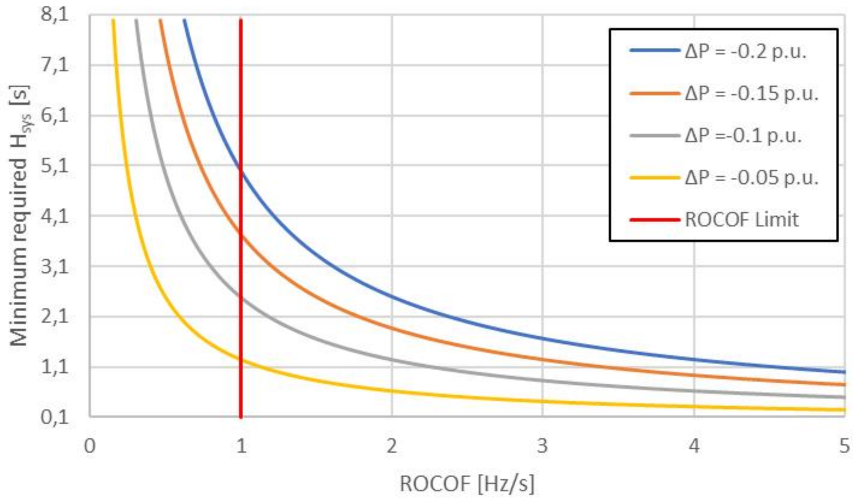


Figure 15: Minimum required system inertia for different ROCOF values

However, the required inertia to stay above a certain frequency threshold at which load shedding is activated (of e.g. 49 Hz in Continental Europe) is a bit more challenging to determine. This is mainly because many other parameters play an important role during the primary response phase of the system (such as generation mix, load damping, …) see explanation within section 0 and section 0). In order to assess the required amount of inertia, we make abstraction of the generation mix and represent the time delay of the total systems droop response by a single time constant (first order lag), which leads to:

$$P_G = P_{G,0} - \frac{1}{1 + \tau_{sys} s} \frac{(f - f_0)}{R_{sys}} \tag{14}$$

with s the Laplace operator and τ_{sys} the systems aggregated governor time constant. In *Figure 16*, the minimum required system inertia is given for various droop (R_{sys}) and aggregated governor time constants (τ_{sys}). Increasing R_{sys} and τ_{sys} results in a higher required inertia for the same power imbalance. The vertical dotted lines in *Figure 16*.A represent the system droop at which the f_{ss} becomes equal to 49 Hz, i.e. even if you increase the inertia, the minimum frequency will always be below 49 Hz. It is also important to note that the minimum required inertia and aggregated governor time constant are almost directly proportional to each other (i.e. decreasing inertia can be compensated by reducing the aggregated governor time delay).

[11] Equal to the capacity of the planned HVDC links between Norway-Germany (Northlink) and Norway-England (North Sea Link)

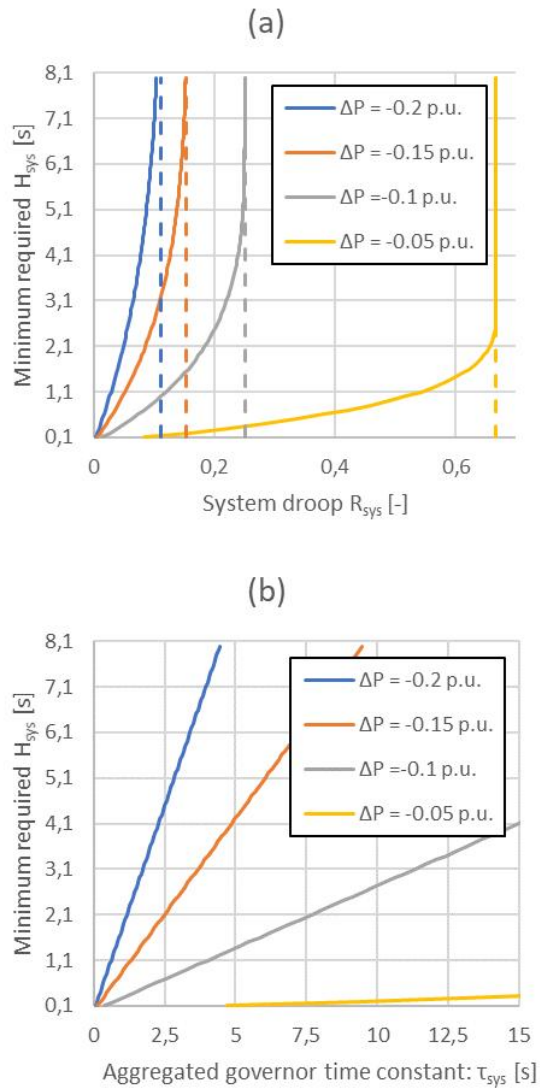


Figure 16: Minimum required system inertia to keep the frequency above 49 Hz for (a) different droop factors (τsys=0.8s & Dsys=1) and (b) different system time constants (Rsys=0.05 & Dsys=1)

Finally, it is important to note that although a minimum amount of system inertia can be defined, it still is very difficult to directly link it with a certain penetration of renewable energy sources interfaced with converters (i.e. mainly wind and PV power). This can be demonstrated by a small example. Take for instance a power system with a total generation capacity of 10 GW (see *Table 2* for a more detailed description). Since the ROCOF must be limited to 1 Hz/s for the considered reference incident, a minimum system inertia of H_{sys}=1.25 s is required (10 GW as base power).

Conventional power plants	§ 10x500 MW with H=6s § 10x500 MW with H=2s
Minimum load	6 GW
Maximum load	9 GW
Required reserves	1 GW
Required ROCOF	<1Hz/s
Reference incident	Loss of 1 GW
Base power (in figures)	10 GW

Table 2: Test system description

Assume now that the synchronous generation capacity is gradually replaced by converters such that the converter connected penetration (i.e. converter connected power output/total load power) rises from 0 to 100%. Even considering such a small system, the inertia can vary over a wide range for a certain level of converter connected penetration and considered load power as shown in *Figure 17*. In this figure, the maximum and minimum inertia is given for different levels of converter connected generation. Both peak load and minimum load is considered.

At 0% for instance, the minimum load (6GW) and available reserves (1GW) can be covered by 10 units of H=6s and 4 of H=2s, resulting in a system inertia equal to 3.4s (10 GW as base) (see *Figure 17*.a). On the other hand, if the power was covered by 4 units of H=6s and 6 of H=2s, H_{sys} is only 2.2 s. Even lower inertia constants are achieved in case the 1 GW would be covered by converter connected units (e.g. batteries), see *Figure 17*.b[12].

Since the inertia constant can vary over a wide range for a certain level of converter connected penetration (e.g. for 50% converter connected penetration, H_{sys} varies from 0.8 to 3.1 s), also the level at which the minimum inertia is reached can be very different. If we give priority to the power plants with a high inertia constant, levels up to 85-90% can be reached for case (a). On the other hand, with only units with a low inertia constant in operation, only ±32.5% can be reached during low load in case (a).

[12] A very simple unit commitment has been used for the simulations which doesn't take into account minimum loading, economic dispatch,... Only the extreme situations are presented in the figures.

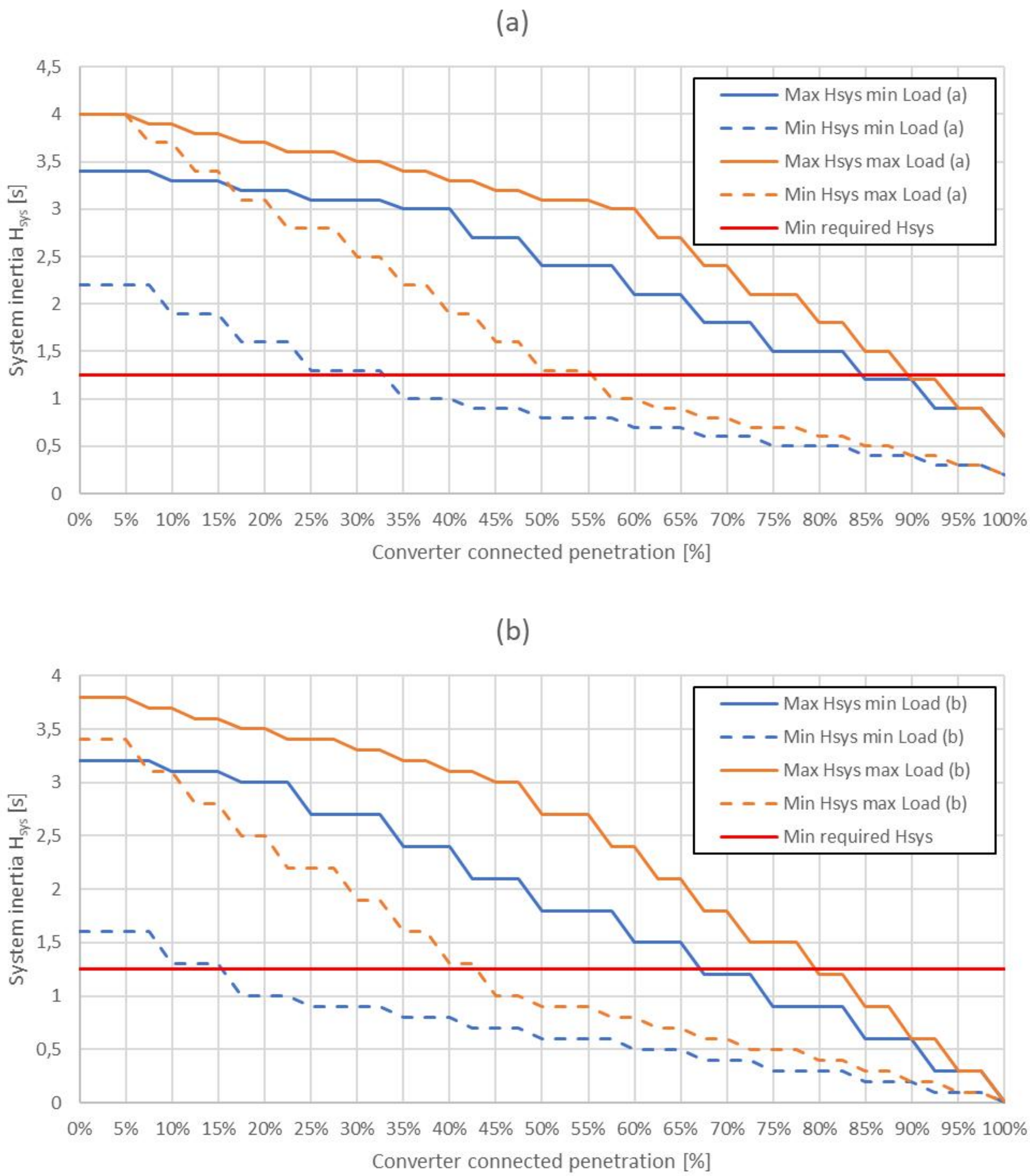


Figure 17: Variation of system inertia within the test system for minimum and maximum load: (a) synchronous machines provide reserve (b) converters provide reserve

Possible solutions

Overview

Different solutions exist to cope with the issues presented in the former section. These solutions can roughly be classified in two groups which are called: “Manage” and “Adapt” (see also Figure 18).
In the first group, “Manage”, all options are listed in which we try to manage a system with reduced inertia, i.e. we accept to have higher ROCOF and lower nadir frequencies. In other words, the system is adapted instead of tackling the root cause.
In a second group, “Adapt”, different measures are proposed to adapt the current system control to keep the ROCOF and minimum frequency above the predefined values.
In the next sections, every solution within Figure 18 is elaborated (for more details, see the corresponding references). The application of the solution within the European power systems is further described in chapter 0.

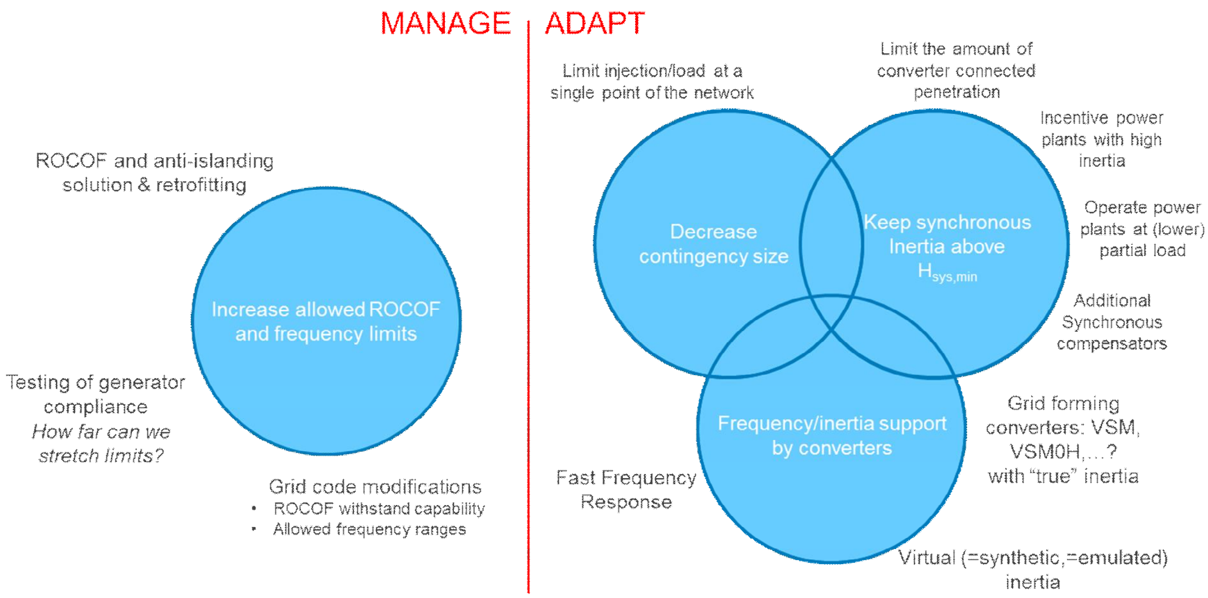


Figure 18: Overview of different solutions to cope with the foreseen issues related to reduced system inertia

Manage

ROCOF and anti-islanding solutions & retrofitting

In case distributed generation is protected against islanding by means of ROCOF relays and we have a low system inertia, a false tripping of these relays may occur during a system wide power imbalance, since the ROCOF may be higher than the relay setting. This will aggravate the initial event (i.e. power imbalance) and jeopardize the frequency stability since large amounts of generation could be disconnected simultaneously. The amount of (distributed) generation that applies these kinds of relays is very system dependent. For Ireland for instance, almost half of the wind turbines connected to the distribution network uses this type of relay [41].

A simple solution would be to retune these relays by increasing their ROCOF settings. On the other hand, also a retrofitting would help, by for instance replacing them by other types of relays, such as vector shift relays [42].

Grid code modifications

The allowed frequency range to ensure a satisfactory system operation is set within the grid code. This grid code could be modified in order to enlarge the frequency band within which conventional power plants must remain connected such that the frequency can drop lower after an imbalance. In a first step, such a wider band can be defined in the grid code only for new power plants. To increase the required operating range for the existing equipment, a more detailed analysis would probably be required: What is the influence on the performance of each plant? What is the effect on large machines at the load side? How would the load shedding scheme look like?, … are all questions that still remain unanswered.

The same applies to a modification of the ROCOF settings within the grid code (note that not many TSOs have defined such limits yet in their grid code): the limits could possibly be stretched, but more research is needed to assess the influence on the grid equipment, especially the effect on large (synchronous) machines.
Except form the protection (ROCOF relays), no special problems are expected for converter connected units if the frequency (or ROCOF) would exceed the current limits. In for instance [43], wind turbine manufactures indicate can (easily) cope with ROCOF values up to 4 Hz/s.

Adapt

Limit injection/load at a single point of the network

Looking at equation (11), it is clear that the ROCOF after a power imbalance is directly proportional to the size of that imbalance, see also Figure 19 (the same applies to some extent to the nadir frequency, although no linear relationship can be derived). If we limit the amount of power injection/absorption in one point of the system, we consequently also limit the possible power imbalance due to a loss of one system element.
In most systems, such a limit is already (directly or indirectly) set as the current frequency control is designed to cope with a specific reference incident (e.g. In continental Europe, the present reference incident corresponds to the loss of the two largest nuclear units, equal to a total power capacity of 3000 MW [44]).

Limit the injection/load or increasing the current limits will however have an impact on the dispatch and future grid development. The limit will for instance constrain the maximum amount of power that can be transferred by any asynchronous interconnection with another synchronous area (e.g. future and current HVDC links) or will limit the power output of (large) conventional power plants.

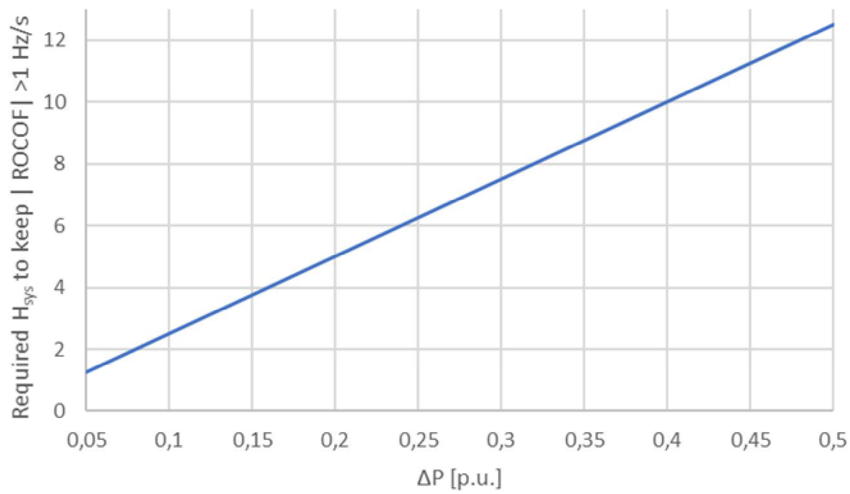


Figure 19: Required system inertia for a certain power imbalance to stay above 1 Hz/s

Operate power plants at (lower) partial load, incentive power plants with higher inertia and/or limit the amount of converter connected penetration (i.e. redispatch)

From a system inertia perspective, it is in most cases more beneficial to have many units in operation at partial load than a few power plants at maximum load (e.g. assuming the same inertia constant for every plant, it is better to produce 10 GW using 20 units of 1 GW at 50% instead of 10 units at 1GW). In most cases, such operation will however conflict with the optimal economic dispatch.

Another way of getting more inertia in the system is by incentivizing power plants with high inertia (e.g. consider it as an ancillary service and remunerate the units for inertia). As such, the marginal cost of expensive (high fuel cost) high-inertia units may be reduced such that they re-enter the merit order.

One can also set a strict limit to the amount of converter connected penetration in order to stay above the minimum required inertia, which will lead to the curtailment of renewable energy sources. However, as discussed in section 0, there is no fixed relationship between inertia and converter connected penetration, so probably different limits have to be defined depending on the load power and availability/dispatch of conventional power plants.

All these measures will help to increase the inertia, but they also conflict with the current market principles and renewable energy goals (e.g. by curtailing wind and PV). However, in case the inertia is expected to drop below its required minimum only for a few hours a year, it may be considered an appropriate and cost-effective solution to do a simple redispatch (e.g. a combination of limiting the injection of converter connected generation, prioritizing units with higher inertia, …).

Additional synchronous compensators

As introduced in section 0, synchronous compensators are mainly applied to provide voltage control to the power system, but they also intrinsically increase the system inertia and provide additional short-circuit power to the connection point. In that respect, they can be considered as a simple solution to address the increase of converter connected units as these units both lack inertia as well as short-circuit power.

A typical synchronous condenser has a low inertia constant, but the inertia can (easily) be increased by attaching a flywheel to the shaft. Besides installing new synchronous compensators, it is also feasible to convert existing (retired) power plants to synchronous compensators, see also [45].

Frequency support by converters: Virtual (=synthetic, =emulated) inertia and fast frequency response

Due to their converter interface, many renewable energy units (e.g. most of PV units and wind turbines) will not inherently react to any change in the system frequency. However, the control of the units can easily be modified to restore the coupling with the grid frequency and provide an additional power output in function of the measured frequency at their terminals (see schematic illustration in *Figure 20*). Furthermore, also high voltage direct current (HVDC) links can be managed to react on the frequency (see schematic illustration in *Figure 21*).

Many different terms are used in the literature to indicate such control principle depending on the time scale they act on or what type of synchronous generator response they mimic, e.g. virtual inertia, fast frequency response, improved frequency response, temporary primary frequency control, … [46, 47, 48] Nevertheless, the general operating principle is in all cases more or less the same.

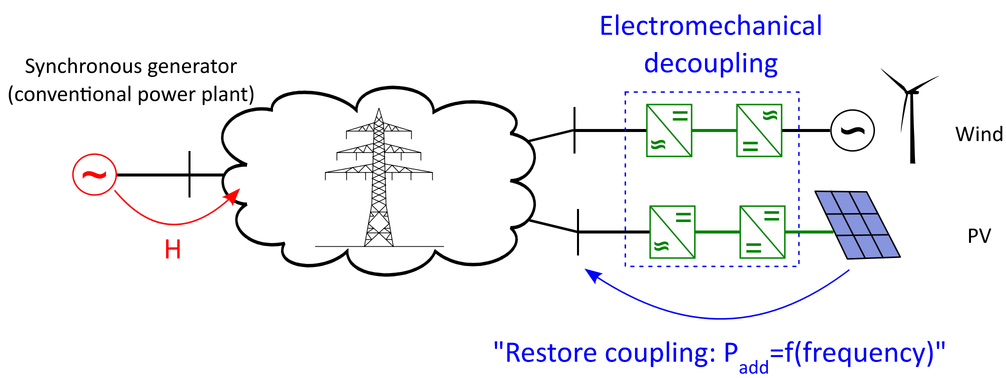


Figure 20: Frequency support by wind and PV: schematic illustration

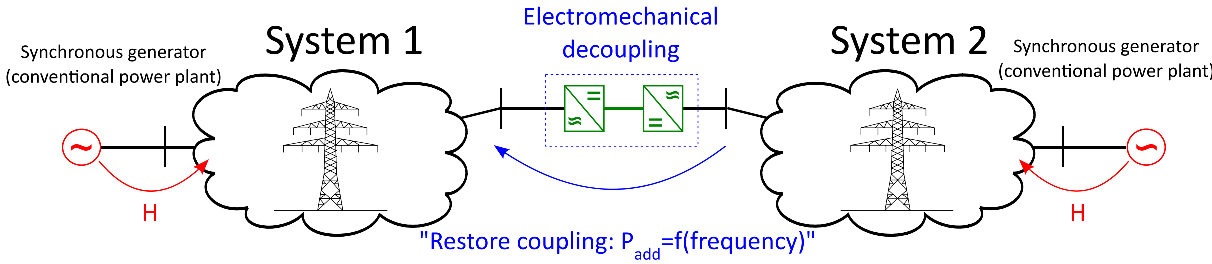


Figure 21: Frequency support by HVDC: schematic illustration

Most of the studied frequency support controllers try to mimic the frequency response of conventional power plants, i.e. their inertial response and primary control action (see section 0). In Figure 22, some control options are displayed. As shown in the figure (in the red box), an additional active power setpoint in function of the measured frequency is added within the power controller of the converter.

Firstly, if the derivative of the frequency is applied such as in case A in the figure, the inertial response of a synchronous machine is mimicked, called virtual inertia (also named synthetic or emulated inertia). By changing the constant H_V, the amount of provided virtual inertia is regulated. Secondly, if the active power support is proportional to the frequency deviation ($f-f_0$), a power response like the one of case D is achieved, which resembles the primary control action of conventional power plants.

All other control actions (see case B, C and E) are derived from these two main approaches[13]. For case B, a more stepwise inertial support is created depending on the

[13] Due to the control flexibility, many other control functions are possible taking into account power and energy constraints.

sign of the measured ROCOF (boost for ROCOF<0, sudden decrease for ROCOF>0). Case C is almost equal to B, but it only supports during ROCOF<0. In case E, also a stepwise response is delivered, but it is activated as soon as the frequency drops below a certain value and deactivated as soon as the frequency is recovered. As C is very similar to A it may be classified as virtual inertia, and even B which acts during the inertial response phase of the system is sometimes called virtual inertia. The term "Fast frequency response" on the other hand is more general and is applied for any form of frequency support that acts on a faster time scale than conventional power plants (i.e. faster than the governor and turbine response) [31].

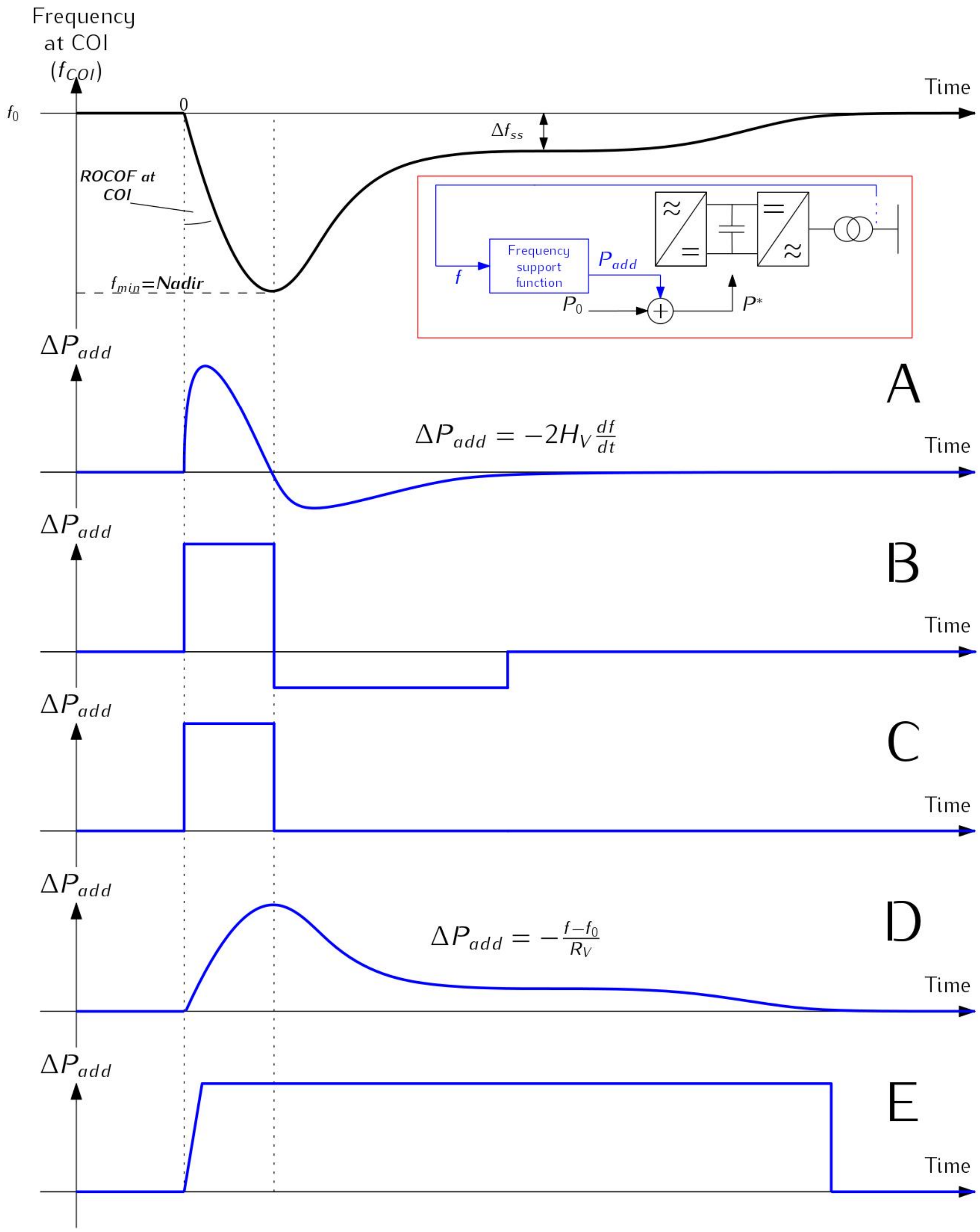


Figure 22: Possible frequency support functions

Conventional power plants use the energy stored in their rotating mass (inertial response) and energy stored in their primary energy source (primary control) to offer frequency response. To provide an equivalent response by converter connected generation, an energy buffer and power margin need to be available or created.

This can be accomplished in three different ways. In a first approach, the PV or wind units are operated in a non-optimal operating point (i.e. deloading the unit) such that a power (and energy) reserve is created. However, this deloading of renewable energy units is mostly considered undesirable as it results in a lower energy yield during normal operation and hence a very high cost.

A second approach comprises the use of the intrinsically available energy buffers within these converter connected units. In *Figure 23*, an overview is given of the stored mechanical and/or electrical energy for several generation technologies over a broad range of power ratings. The solid lines connect the points with the same inertia constant, used to normalize the stored energy for different ratings. The areas bounded by the lines of 2 and 9 s, corresponds to the inertia of conventional power plants. Looking at wind turbines (DFIG and full converter), although some energy is stored in the DC link capacitor of the converter, most of the available energy comes from the rotating blades. As shown in the figure, the total inertia constant becomes 4.65 s which is comparable with the one of conventional power plants. The energy buffer of other converter units, such as PV and HVDC, is mainly coming from the energy stored in the DC link capacitors [49]. The energy within other parts of the power electronic system (filters, line reactors, ...) is negligible.

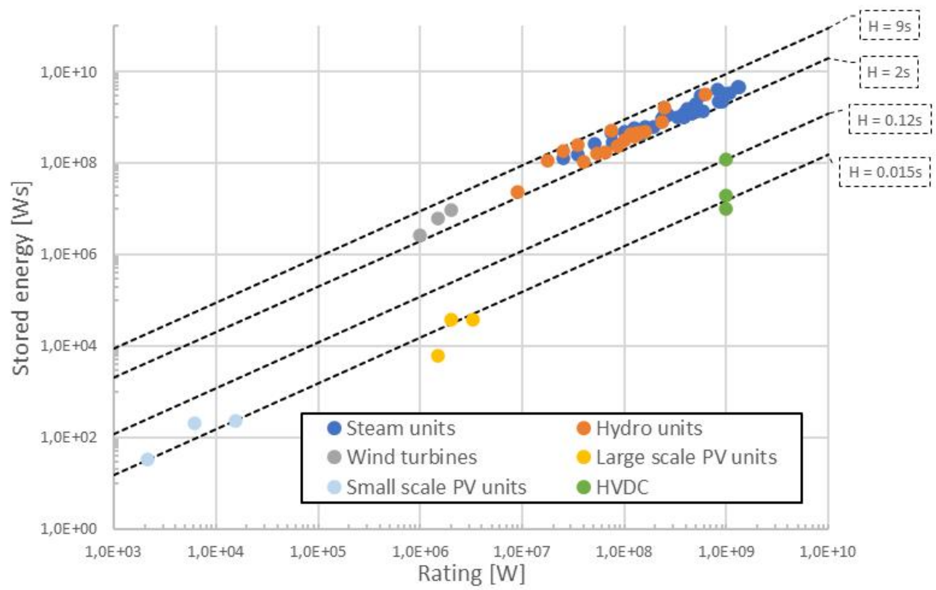


Figure 23: Energy buffers within function of capacity for different generation technologies (without additional storage). Adapted from [12])

As the kinetic energy content of most wind turbines (spinning blades, generator and gearbox) is quite substantial, many control strategies have been presented in the literature (both from academia and industry) which only apply the kinetic energy to provide frequency response. By reducing the speed of the turbine, part of the kinetic energy is released in the system after a frequency drop such that a power boost is provided. Afterwards, the rotational speed is brought back to its optimal value (which is depending on the wind speed) by decreasing the power output. Consequently, an additional power output similar to case A and B of *Figure 22* is provided. Again, due to the control flexibility, many variations of this basic control approach are feasible.

Thirdly, also energy storage systems (ESS) can be applied to provide the required energy exchange (and buffer) to deliver frequency support. Regarding these energy storage systems, their rating and capacity mainly determine how much inertial support they can provide [50]. A broad range of storage technologies can be used such as short-term storage devices (e.g. ultracapacitors) or other fast-acting technologies (e.g. li-ion batteries).

For HVDC connections linking two asynchronous areas, the same control approach can be applied. In this case, the additional power that is provided is transferred from one system to another. As such, the available synchronous inertia or primary energy reserve from one system is applied to support the other. This control approach will of course not work for HVDC interconnections embedded in the same synchronous zone.

Finally, it should be noted that although the converters mimic the inherent (i.e. instantaneous) inertial response of conventional units, they can never exactly match it because there are always inaccuracies and time delays involved in the control process (due to measuring, filtering, ...). Furthermore, almost all converter connected generation units, used to convert the energy from wind turbines or PV panels to the grid, are specifically designed to provide power to an already energized grid. They do not set the grid voltage and frequency themselves but are synchronized with the AC system using a precise synchronisation mechanism (e.g. a phase locked loop (PLL)). Consequently, they can support the system inertia as long as there are other synchronous machines connected to the system, but in case we move to a completely converter based system, novel converter control approaches are required, such as a grid-forming converter control.

Grid-forming converters

In essence, current standard converter control can be considered grid-following as they estimate the instantaneous angle of the voltage at their terminals and subsequently inject a current into the grid that tracks the sinusoidal voltage angle, see also the illustration in *Figure 24*. Therefore, as explained previously, it is required that a “stiff” AC voltage (with a certain amplitude and frequency) is maintained such that it can simply follow this local voltage and inject a controlled current. As such, a zero-inertia system (i.e. without synchronous generators) is not feasible with only using (standard) grid-following converters.

Grid-forming converters do have a completely different control approach, which enables the transition to a converter based power system. These converters set the amplitude and grid voltage themselves and consequently do operate as an (ideal) voltage source . No additional frequency estimation is required (e.g. PLL as within a grid following converter), but due to its control they inherently become self-synchronized[14].

A variety of grid-forming control strategies are possible. In [51] for instance, the physical phenomena of a synchronous machine (including its inertial response) are emulated (i.e. programmed) to create a so-called virtual synchronous machine (VSM). By simplifying the control equation of a VSM and only applying a linear relationship between real and reactive power compared to frequency and voltage, we get a so-called droop-controlled grid-forming converter (also named VSM0H, since it resembles a VSM with zero virtual inertia). Finally, also an approach based on the dynamics of nonlinear oscillators is feasible, which control is based on the synchronization in networks of

[14] For some more technical background information on the control architecture of grid-forming converters, see [77, 4, 52, 12].

coupled oscillators. These new "virtual" oscillator controllers yield rapid response times and it has been demonstrated to enable a zero-inertia, inverter-based systems [52, 4].

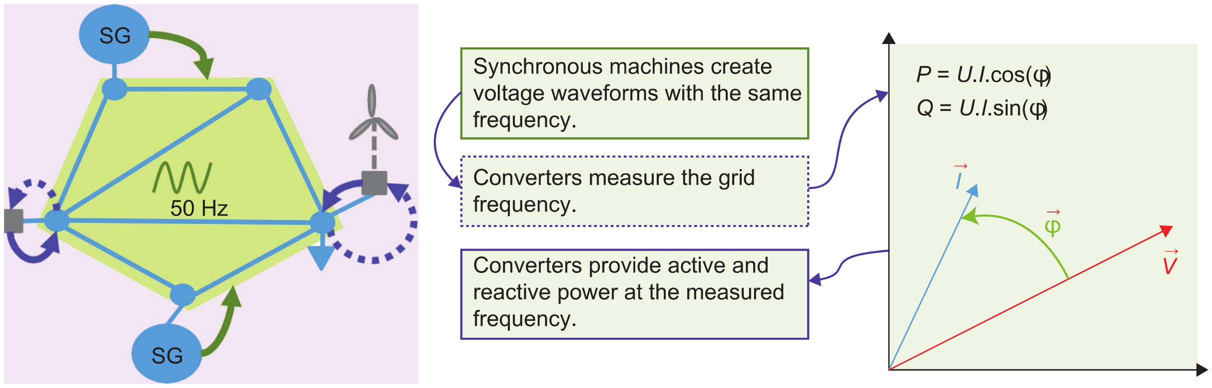


Figure 24: Schematic illustration of the actual grid operation with grid-following converters [52]

To the best of the author's knowledge, grid-forming control has not yet widely been implemented within power converters connected to the transmission or distribution system and is up till now mainly employed for units operating in stand-alone operation (within uninterruptible power suppliers (UPS) or HVDC converters linked to offshore wind farms) or to provide communication-less load sharing amongst parallel converters within micro-grids.

Implementation of proposed solutions

Some of proposed solutions described in the former section comprise a (slight) modification of current operating principles, ancillary services or market products, while others imply a complete paradigm shift in the way we operate the system. In *Figure 25*, a first general ranking of the different solutions is proposed, based on the expected changes compared to current system operation.

A more specific analysis for each system is of course required to assess the difficulties that need to be overcome and the accompanied cost for the implementation in each system.

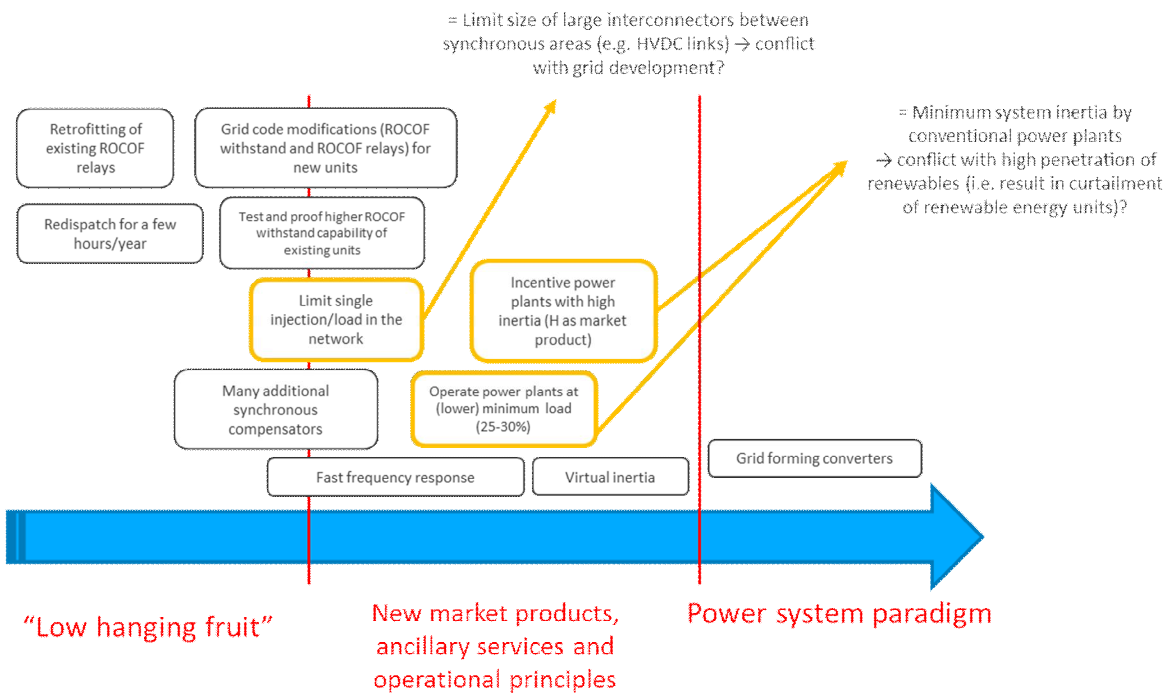


Figure 25: Implementation of proposed solution to operate as system with low inertia: overview

Conclusions

In this chapter, the main issues and solutions of operating a system with low inertia are presented. Although the system inertia plays an important role in different forms of power system stability, it is found that issues mainly arise in terms of frequency control as the ability of the system to resist to large power imbalance decreases. It results in high ROCOF values and substantial frequency deviations which can lead to instability of the system.

Therefore, different solutions have been proposed which were further classified into two groups. In a first group, options to adapt the system such that it can cope with higher ROCOF and higher frequency deviations were given. In a second group, several solutions to prevent frequency stability issues by increasing the inertia (by means of additional inertia from synchronous machines or virtual inertia from converters) or by decreasing the possible contingency size have been presented. Further assessment however is required to define the optimal and most cost-effective solution for each power system.

European case: current practices and grid codes regarding system inertia

Introduction

In the previous chapters, the issues and solutions of operating a system with low inertia have mainly been discussed from a theoretical point of view. The way these solutions are implemented in our European system is presented in the next sections. Firstly, it is discussed which actions are taken by ENTSO-E (the European Network of Transmission System Operators) to cope with the expected reduction of inertia. To this end, the (European) network codes, some additional studies, operational guidelines, … are analysed.

Secondly, we have a closer look at two synchronous areas which (will) have a very high penetration of converter connected generation, namely Ireland and Great Britain (GB).

ENTSO-E Considerations

Overview

ENTSO-E represents TSOs from 36 countries across Europe. ENTSO-E was established in 2008 and given legal mandates by the EU's Third Legislative Package for the Internal Energy Market in 2009, which aims at further liberalising the gas and electricity markets in the EU. ENTSO-E members share the objective of setting up the internal energy market and ensuring its optimal functioning, and of supporting the ambitious European energy and climate agenda [53].

System inertia, their influence on system stability and the implementation of possible options are dealt with by the different committees within ENTSO-E (see *Figure 26* and list below):

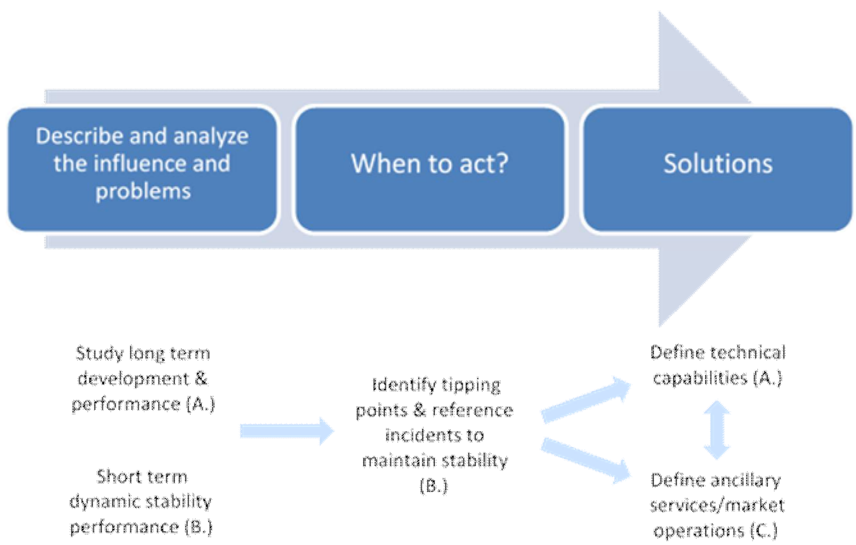


Figure 26: Linking the work done by the different committees in the context of system inertia (see also list below)

A. Committee on System development & design

§ Studies on long term system development: Ten Year Network Development Plan (TYNDP)

§ Legislative obligations defined in the Grid connection Codes (CNC) & their corresponding implementation guideline documents

- Network Code on Requirements for Generators (RfG)
- Network Code on Demand Connection (DCC)
- Network Code on High Voltage Direct Current Connections (HVDC)

B. Committee on System operation

§ Legislative obligations defined in the system operation guideline/codes (SO GL)

§ Specific studies performed by the regional working groups

§ Committee on Markets

§ (No specific market design/product yet, but internal considerations on inertia as a future ancillary service [54])

Each bullet point and the relevant aspects regarding system inertia of the different studies and grid codes are described in more detail in the following section. More information can be found in [54], or in the other references included in the different subsections.

System development and design

TYNDP

Long term studies on the expected evolution of system inertia for the next years and decades are performed in the context of the ten-year network development plan (TYNDP). This TYNDP is a pan-European network development plan, providing a long-term vision on the European power system. It is published by ENTSO-E every two years and serves the basis for the European grid planning. In this context, it will also specify the transmission projects that are eligible to be labelled as "projects of common interest" (PCI).
As part of the TYNDP 2018, it is investigated how the European power system would look like by 2040, see [55]. In this study, duration curves for the estimated system inertia within the different synchronous zones are given together with some possible mitigation issues (corresponding to the one presented in section 0).

However, as stated in the report: "The TYNDP does not try to find infeasible or unacceptable situations, it rather provides a factual explanation of their related challenges and a basis from where the necessary measures, that make sure the system is secured, can be derived". TYNDP has thus the objective to list the facts, challenges and solutions, but provides no reference incidents and associated tipping points at which these solutions should be implemented.

Grid connection codes

The different grid connections codes specify harmonised requirements for the grid connection of generators, HVDC systems (& DC-connected power park modules) and demand/distribution facilities (only applied to new units). The main objective is to ensure that system users are equipped with the capabilities to provide adequate

performance under normal and disturbed operating conditions and as such can contribute to maintain and restore system stability [54].
These requirements are set out in a European regulation and consequently need to be implemented by each TSO in the European union. Many of the requirements are however non-exhaustive such that each TSO need to further specify the applied parameters or approach at national level[15]. The national specifications need to be submitted to ENTSO-E within 2 years after the regulations enter into force (EIF):

- Network Code on Requirements for Generators (RfG): EIF on 17/05/2016 [56]
- Network Code on Demand Connection (DCC): EIF on 28/09/2016 [57]
- Network Code on High Voltage Direct Current Connections (HVDC): EIF on 6/09/2016 [58]

The relevant capabilities with respect to system inertia are listed in *Table 3* below.

Network code	Article	Description
RfG	13.1(b)	With regard to the rate of change of frequency withstand capability, a power-generating module shall be capable of staying connected to the network and operate at rates of change of frequency up to a value specified by the relevant TSO, unless disconnection was triggered by rate-of-change-of-frequency-type loss of mains protection. The relevant system operator, in coordination with the relevant TSO, shall specify this rate-of-change-of-frequency-type loss of mains protection.
RfG	21.2(a-b)	Type C and D power park modules shall fulfil the following additional requirements in relation to frequency stability: a) the relevant TSO shall have the right to specify that power park modules be capable of providing synthetic inertia during very fast frequency deviations b) the operating principle of control systems installed to provide synthetic inertia and the associated performance parameters shall be specified by the relevant TSO.
DCC	30	1. The relevant TSO in coordination with the relevant system operator may agree with a demand facility owner or a closed distribution system operator (including, but not restricted to, through a third party) on a contract for the delivery of demand response very fast active power control. 2.If the agreement referred to in 1. takes place, the contract referred to in 1. shall specify: a) a change of active power related to a measure such as the rate-of-change-of-frequency for that portion of its demand; b) the operating principle of this control system and the associated performance parameters; c) the response time for very fast active power control, which shall not be longer than 2 seconds.
DCC	28.2(k)	Demand units with demand response active power control, demand response reactive power control, or demand response transmission constraint management shall have a withstand capability to not disconnect from the system due to the rate-of-change-of-frequency up to a value specified by the relevant TSO. With regard to this withstand capability, the value of rate-of-change-of-frequency shall be calculated over a 500 ms time frame.
HVDC	12	An HVDC system shall be capable of staying connected to the network and operable if the network frequency changes at a rate between – 2,5 and

[15] Note that there are also non-mandatory requirements introduced in the network codes which can be made mandatory at national level, if required by each TSO.

		+ 2,5 Hz/s (measured at any point in time as an average of the rate of change of frequency for the previous 1 s).
HVDC	39.3	With regards to rate-of-change-of-frequency withstand capability, a DC-connected power park module[16] shall be capable of staying connected to the remote-end HVDC converter station network and operable if the system frequency changes at a rate up to +/– 2 Hz/s (measured at any point in time as an average of the rate of change of frequency for the previous 1 second) at the HVDC interface point of the DC-connected power park module at the remote end HVDC converter station for the 50 Hz nominal system.
HVDC	14	If specified by a relevant TSO, an HVDC system shall be capable of providing synthetic inertia in response to frequency changes, activated in low and/or high frequency regimes by rapidly adjusting the active power injected to or withdrawn from the AC network in order to limit the rate of change of frequency. The requirement shall at least take account of the results of the studies undertaken by TSOs to identify if there is a need to set out minimum inertia. The principle of this control system and the associated performance parameters shall be agreed between the relevant TSO and the HVDC system owner.

Table 3: Overview of relevant technical capabilities within the network codes of ENTSO-E regarding the operation of a power system with reduced inertia [56, 57, 58]

The requirements related to synthetic inertia, ROCOF withstand capability, ROCOF relay settings as well as very fast active power control (i.e. fast frequency response as defined in section 0) are mostly non-exhaustive (i.e. specific parameters need to set on a national basis within ranges specified in the network codes).

To support this national implementation in line with the legal requirements, ENTSO-E has drafted different (18 in total) non-binding implementation guidance documents (IGDs). The guidance documents are mainly addressed to the TSOs and other system operators and further elaborate the elements of the codes requiring national decisions. They explain the technical issues, conditions and interdependencies which need to be taken into consideration [59]. Three IGDs of interest are shortly discussed below.

<u>IGD on ROCOF withstand capability [60]</u>

In this document, a general introduction is given to the relationship between inertia, ROCOF and the expected power imbalance. It highlights that it is important to define a withstand capability by not only assessing the current system, but also taking into account the future changes in the network, generation and demand. As such the required capability should be future-proof taking into account the asset life of the units. Furthermore, a close collaboration between the different TSOs within a synchronous area is needed to ensure that a minimum ROCOF requirement is applied to all grid users.

Based on the studies performed in the working group "System Protection & Dynamics" (e.g. [61]), the following ROCOF values are proposed for the power generating modules within Continental Europe:

- ±2 Hz/s for moving average of 500 ms window
- ±1.5Hz/s for moving average of 1 s window
- ±1.25Hz/s for moving average of 2 s window

It is indicated that to ensure the units can withstand these ROCOF values, each TSO may define a compliance test (by for instance imposing a set of frequency against time test profiles as given in *Figure 27*).

[16] A DC-connected Power Park Module means a Power Park Module that is connected via one or more Interface Point(s) to one or more HVDC System(s).

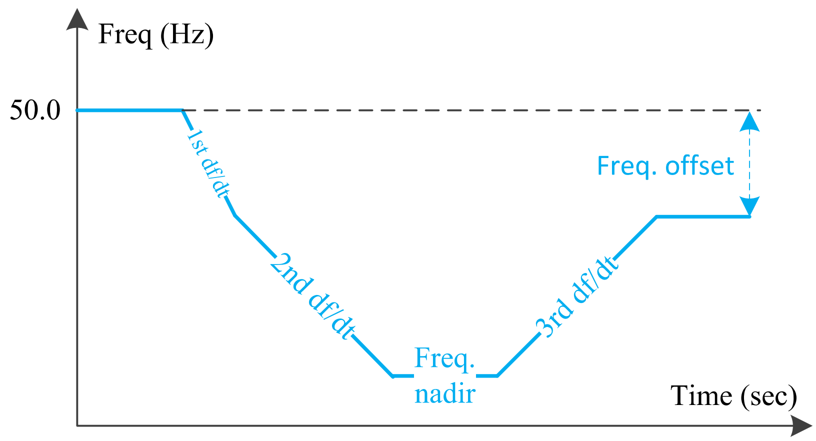


Figure 27: Proposed under-frequency test profile in IGD on ROCOF withstand capability

<u>IGD on Need for synthetic inertia [62]</u>

Besides a general introduction on synthetic inertia, some specifications regarding the application of synthetic inertia that need to be defined by each TSO are presented, i.e.:

- Frequency or ROCOF measurement criteria: time window, accuracy and total delay time
- Function characteristics (e.g. power output proportional to ROCOF or Δf & the applied dead band)
- TSO input signal for activation and access to alter the settings (e.g. droop factor)

Furthermore, it highlights that, although already many studies and patents discussing the topic exist, synthetic inertia needs further research and development which further assesses the potential measurement limitations (fast transient movements), operational limits, the possibility to increase the size of DC-link capacitors, the capability of using demand respond for synthetic inertia, … etc.

It is also mentioned that synthetic inertia is currently only applied in the Hydro-Québec power system (Canada) where wind farms with a nominal rating greater than 10 MW have to emulate an inertia of minimum H=3.5 s during 10s in case the frequency deviation is greater than 500 mHz. It should be noted that it is called synthetic inertia even though a stepwise response is provided (similar to B&C in *Figure 22*, see also the discussion on the naming of frequency control approaches by converters in section 0). This capability was however not introduced because the system had a low system inertia. Instead it has been applied to compensate for the shortcomings of the applied hydro governors when a sudden frequency dip takes place (due to inertia of the water, the change in turbine power is initially opposite to a change in the position of the gate at the foot of the penstock, see also *Figure 13*) [63].

<u>IGD on High penetration of power electronics interfaced power systems (HPOPEIPS) [64]</u>

A more general overview of the operation stability challenges (frequency stability, system strength, voltage stability) related to the high penetration of converter connected generation is presented in this document. Also a detailed description of the operation of grid-forming converters is included.

Since many of the deadlines regarding the proposal for national implementation have already passed (EIF+2 years), most of the TSOs proposals are publicly accessible. A comparison between some TSOs is made in *Table 4* for the RfG network code.

	Maximum ROCOF for which the Power Generating Module shall stay connected (Article 13.1(b))	Specify ROCOF of the loss of main protection (Article 13.1(b))	Synthetic inertia capability for PPM (type C & D) (Article 21.2(a-b))
Austria	2 Hz/s	Project specific	PPMs must be able to provide synthetic inertia
Belgium	2 Hz/s	1Hz/s (For loss of mains, DSO is still investigating alternatives)	
Switzerland		Project specific	
Czech Republic	2 Hz/s		
Germany	2 Hz/s, 1.5 Hz/s (1 s window), 1.25 Hz/s (2 s window)	Project specific	
Denmark	2 Hz/s		Planning of workshop and meetings with different manufactures
Estonia	2.5 Hz/s		
Spain	2 Hz/s		Some requirements are defined
Finland	2 Hz/s		
United Kingdom	1 Hz/s	1Hz/s	
Croatia	2 Hz/s	Project specific	
Hungary	PPM Type A :2.5 Hz/s PPM Type BCD: 2.0 Hz/s	Project specific	
Ireland	1 Hz/s	Transmission system connected: 1 Hz/s[17]	Not Mandatory – can be agreed on a case by case basis with System Services Contracts
Italy	2,5 Hz/s (5 cycles window = 100ms)		Wind farm type D predisposed to some requirements
Luxembourg	2 Hz/s		
Latvia	2.5 Hz/s	2.5 Hz/s	
Netherlands	2 Hz/s	2 Hz/s	
Norway	1.5 Hz/s		Case specific, but subject to national guidelines.
Poland	2.0 Hz/s	Project specific	Project specific
Portugal	2 Hz/s		
Romania	1 Hz/s for synchronous generators		

[17] Distribution Connected: DFIG / Full Converter Generator 2 Hz/s (0.3 s window)/Synchronous Generator / Directly Connected Induction Generator H > 3 MWs/MVA 0.6 Hz/s (0.6 s window)/Synchronous Generator / Directly Connected Induction Generator H ≤ 3 MWs/MVA 1.0 Hz/s(0.6 s window)

Slovenia	Interconnected operation: at least ± 2 Hz/s		
Slovakia	2 Hz/s	Project specific	

Table 4: Current proposals for national implementation of Articles 13.1(b) and 21.2(a-b) of RfG network code (countries which do not specify any requirements (yet) are not included in the list) [65]

From this table it can be concluded that there are only a few TSOs that consider including the synthetic inertia capability of power plant modules in their national grid codes. Regarding the ROCOF withstand capability and ROCOF setting for loss of mains protection, these vary in the range of 1-2.5 Hz/s. While the synchronous areas of Great Britain and Ireland take 1 Hz/s as standard value, most of the TSOs within Continental Europe are applying ROCOF values in line with the one proposed in the IGD, namely 2 Hz/s.

System operation

System operational guideline

Legal obligations with respect to stability and inertia are defined in different articles of the European regulation 2017/1485 (EIF 14/09/2017), which establishes a guideline on electricity transmission system operation. The most relevant elements in the guideline with respect to system inertia are listed in below [54, 66].

Article	Description
38	Dynamic stability monitoring and assessment: Each TSO shall perform a dynamic stability assessment at least once a year to identify the stability limits and possible stability problems in its transmission system. All TSOs of each synchronous area shall coordinate the dynamic stability assessments, which shall cover all or parts of the synchronous area. *(this includes also frequency stability and the power stability problems related to low system inertia)*
39.3	In relation to the requirements on minimum inertia which are relevant for frequency stability at the synchronous area level: a) all TSOs of that synchronous area shall conduct, not later than 2 years after entry into force of this Regulation, a common study per synchronous area to identify whether the minimum required inertia needs to be established, taking into account the costs and benefits as well as potential alternatives. All TSOs shall notify their studies to their regulatory authorities. All TSOs shall conduct a periodic review and shall update those studies every 2 years; b) where the studies referred to in point (a) demonstrate the need to define minimum required inertia, all TSOs from the concerned synchronous area shall jointly develop a methodology for the definition of minimum inertia required to maintain operational security and to prevent violation of stability limits. That methodology shall respect the principles of efficiency and proportionality, be developed within 6 months after the completion of the studies referred to in point (a) and shall be updated within 6 months after the studies are updated and become available; and c) each TSO shall deploy in real-time operation the minimum inertia in its own control area, according to the methodology defined and the results obtained in accordance with paragraph (b.
41.4	To coordinate the dynamic stability assessments pursuant to Article 38(2) and (4), and to carry them out, each TSO shall exchange with the other TSOs of the same synchronous area or of its relevant part the following data: a) data concerning SGUs which are power generating modules relating to, but not limited to:

	i. electrical parameters of the alternator suitable for the dynamic stability assessment, including total inertia;
153.2(c)	For the CE and Nordic synchronous areas, all TSOs of the synchronous area shall have the right to define a probabilistic dimensioning approach for FCR (frequency containment reserve) taking into account the pattern of load, generation and inertia, including synthetic inertia as well as the available means to deploy minimum inertia in real-time.

Table 5: Overview of most relevant elements in the system operational guideline with respect to system inertia [66]

The stability assessment as given in article 38 is already performed annually by each individual TSO. To be compliant with article 39.3, the TSOs of a synchronous area must closely cooperated (exchanging data since inertia is shared across the control areas) and follow the next steps:

1. Define whether or not it is required to set a minimum system inertia ($H_{sys,min}$, instead of applying other solutions: e.g. inertia support by converter connected units)
2. If yes, develop a methodology for the definition of $H_{sys,min}$
3. Keep the system inertia above the $H_{sys,min}$ in real-time operation (applying the measures listed in section 0 and 0 for instance)

As this guideline entered into force at 14/09/2017, the first results of the studies related to $H_{sys,min}$ are expected to be available by the summer of 2019.

Additional studies performed by regional working groups

Some additional analyses have been made within the different regional groups. The subgroup System protection and dynamics (Continental Europe) for instance has published in March 2016 a report on the "Frequency stability evaluation criteria for the synchronous zone of Continental Europe" [38]. The study focuses on large system splits (power imbalance up to 40%) and lays the ground for an easy determination of the minimum system inertia based on the overall control capabilities. Not only underfrequency events are analysed, but also the required technical characteristics of the Limited Frequency System Mode response for Overfrequency (LFSM-O) is further assessed.

A more elaborated study is performed by the regional group Nordic (Nordic analysis group) of which the results are published in two parts: "Future system inertia 1 & 2" [28, 67]. The study investigates inertia-related issues within the Nordic system (i.e. Sweden, Eastern Denmark, Norway and Finland) and develops proper forecasting tools and mitigation measures to anticipate and avoid the accompanied detrimental effects.

By estimating the amount of kinetic energy for the coming years/decades, it has been estimated that for the years 2020 & 2025 for instance, the inertia only falls below respectively 120 GWs & 134 GWs[18] in one percent of the time. For the year 2020, as the number of low-inertia hours (i.e. below 120 GWs) is very limited, no market mitigation measures are considered.

The most optimal solution in terms of cost (and one that can also be available by 2020) consist out of combination of providing frequency support by HVDC (emergency power control) and load disconnection (including the disconnection of pumps for hydro storage). This emergency power control (EPC) corresponds to a power boost after a frequency decrease (thresholds in the range of 49.7 - 49.3 Hz) that is provided with very high ramp rates (>100 MW/s). I can be considered similar to case D presented in Figure 22. The reduction of the dimensioning incident (see also section 0) is considered as "plan B".

[18] The 99 percentile in 2025 is higher than the one of 2020 due to the higher availability of a the nuclear power plant Olkiluoto 3.

Moreover, the working group has sent out a survey to several system operators responsible for small to midsized synchronous zones in order to bundle the experience and knowledge on the operation with low inertia. In *Table 6*, the answers to two of the questions out of this survey are given. It is interesting to note that many TSOs consider a fast acting power response from HVDC as a tool to cope with low-inertia situations (synthetic inertia is of less interest).

	What do you have in place to support the low-inertia situations?			Which units provide synthetic inertia or fast-acting reserves?
	Synthetic inertia	Fast-acting reserves	Something else	
Nordic TSOs		x		HVDC
ERCOT (USA)		x		Load reduction
National Grid (Scotland, Wales and England)				
Eirgrid/SONI (Ireland)		x		HVDC
Transpower (New Zeeland)		x	x	HVDC
Farou Islands	x		x	Power electronic converters, Batteries
Australia (Queensland, Victoria, New South Wales and South Australia)				
ESKOM (South-Africa)				
Hydro-Quebec TransEnergie (Canada)	x	x	x	HVDC, Power electronic converters

Table 6: Tools for supporting a system with low-inertia situations (taken from survey in [67])

Measures implemented in Ireland and Great Britain (GB)

Besides the more general considerations of ENTSO-E, it is also interesting to have a closer look at how Ireland and GB are dealing with inertia related operational issues since they can be considered the European forerunners with respect to power system operation with high penetration of converter connected generation. Look for instance at *Figure 28*, it is clear that the penetration levels for the year 2020 are much higher for Ireland and the GB compared to other synchronous areas. Note that the penetration is expressed with respect to the total demand, so instantaneous penetration levels will be even (much) higher. For Ireland for instance, the instantaneous penetration is expected to raise up to 75% by 2020 (covered mainly by wind power).

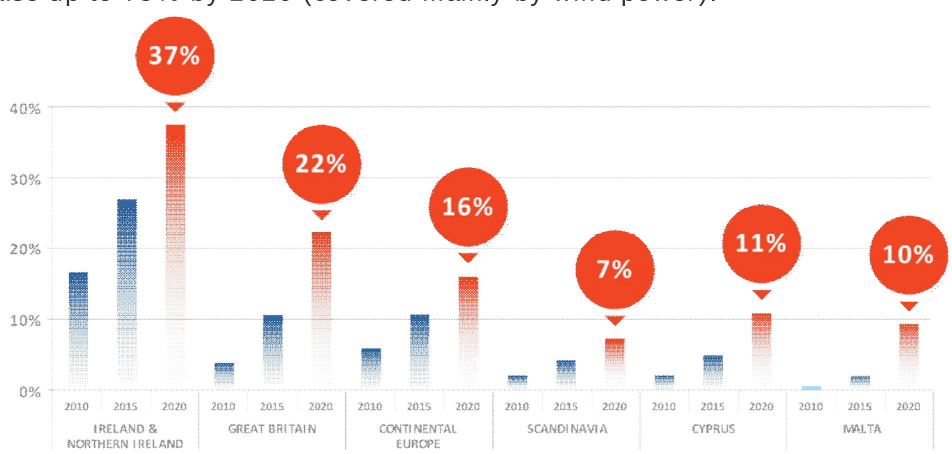


Figure 28: Penetration of non-synchronous renewables with respect to the total demand in each synchronous system for 2010-2020. Adapted from [68]

In order to operate the Irish system in a secure matter while achieving the binding European 2020 targets on renewable electricity (40% by 2020), the EirGrid Group[19] has launched the DS3 program in 2011 (Delivering a Secure, Sustainable electricity system) [68]. It is a multi-year programme which includes a number of grid code modifications, new system services and operational practices to securely operate a system with very high penetration of converter connected generation, see also *Figure 29*.

Figure 29: Three main pillars of the DS3 program. Adapted from [68]

A combination of measures is implemented to address the issues with lower system inertia and the accompanied higher ROCOF such that the converter connected penetration can be gradually increased up to a level of 75% by 2020 (see also the overview in *Table 7*).

First of all, since many of the wind turbines connected to the distribution system apply a ROCOF relay, the settings of all relays are increased from 0.5 Hz/s to 1 Hz/s.

Secondly, the inertia is monitored, and it is kept above a certain minimum by for instance reducing the minimum generation levels of a number of units and by introducing a new system service SIR. SIR stands for synchronous inertial response and compensates synchronous generators on the basis of the available stored kinetic energy to help manage system events within each half hour period. Consequently, the Irish power system is actually the first system in which units get payed for their inertia.

Thirdly, another system service called Fast Frequency Response (FFR) is being procured, starting from September 2018. FFR corresponds to an active power boost with a response time of 2-10 seconds. It is required to ensure system stability after an event at times when the penetration is higher than 60%. As such it will mainly help to increase the nadir, but it is planned to boost the revenues for units that can respond faster (up to a minimum of 0.15 s). Consequently, it will also improve the ROCOF.

	2017	2018	2019	2020
Converter connected penetration (instantaneous)	60→65%	65→70%	70→75%	75%
ROCOF (relay setting and withstand capability)	0.5 Hz/s	0.5→1 Hz/s	1 Hz/s	1 Hz/s

[19] EirGrid Group includes EirGrid (system operator of Ireland), SONI (system operator of Northern Ireland) and SEMO (Single electricity market operator of Ireland)

Minimum inertia (kinetic energy)	23 GWs	20 GWs	17.5 GWs	17.5 GWs
System services	11 services → 14 services (SIR and FRR will mainly help to improve ROCOF)			

Table 7: Overview of measures to increase the converter connected penetration from 60 to 75% [69]

In [70], an estimate of the cost of procuring all these system services is given for 2019/2020. As shown in Figure 30, the costs are quiet high compared to the cost of the more standard system services such as primary and secondary operating reserves (POR & SOR). The total annual cost is estimated between 169-220 M€ depending on the modelling scenario.

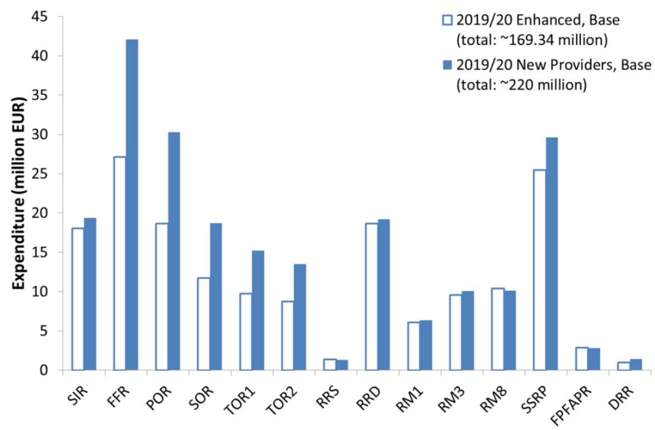


Figure 30: Estimated 2019/20 expenditure per system service [70]

The most cost-effective solution for GB to cope with low inertia situation consist currently of limiting the largest credible loss (i.e. limiting the largest infeed or load). In parallel, a large-scale retrofitting of the loss of mains protection have been taken place. New relays are set to 1 Hz/s while the setting of existing relays is increased from 0.125 Hz/s to 0.5 Hz/s.

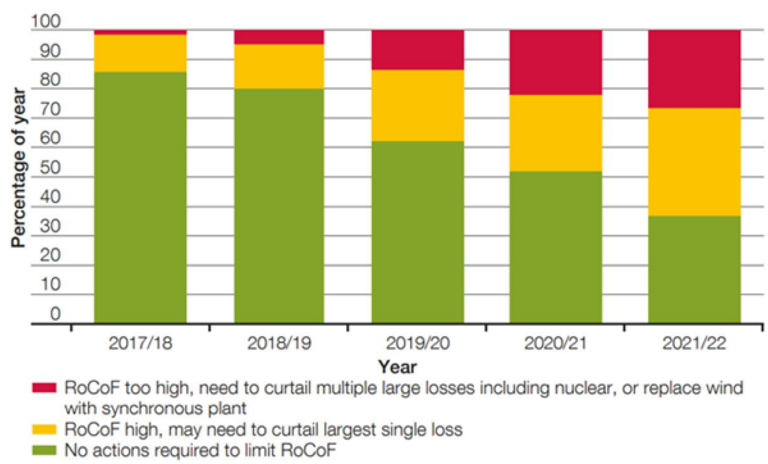


Figure 31: Prognosis of the measures to reduce ROCOF (red bars requires additional tools compared to the standard one currently in use) [71]

For the coming years, it is however expected that additional measures are required, which are further discussed in the report "System needs and product strategy [71]", see also *Figure 31* (red bards).
It is for instance proposed to take the value of inertia into account in a new frequency response product (see e.g. SIR Ireland) or install additional synchronous compensators (including generators with a synchronous compensator mode) and similar devices which can provide operational benefits such as inertia and voltage control without generating active power.

Conclusion

In this chapter, the different approaches of the European TSOs to tackle the operational issues related to a reduced system inertia are analysed.

Many efforts have been done by ENTSO-E to deal with the inertia issues in a coordinated and harmonized way though their operational guidelines, network codes and system studies. However, as most of the guidelines and network codes related to system inertia are non-exhaustive (or even non-mandatory), there is still a wide variety in the way each TSOs implement them.

TSOs in large interconnected synchronous areas, such as the Continental European system, follow a more pragmatic approach and only adapt the allowed ROCOF relay settings or include a ROCOF withstand capability (for new units) in their grid code.

Island systems on the other hand, such as Ireland and GB, are already a step ahead as they expect to encounter high levels of converter penetration. Currently they mostly try to limit the ROCOF by limiting the largest credible loss or keeping the inertia above a certain minimum value. However, to reach even higher penetration levels, new system services will need to be procured. Ireland can be considered the forerunner in this respect, as it has established an elaborated framework called DS3 to ensure system stability for penetration levels up to 75%.

System inertia assessment of Continental Europe (2030)

Introduction

In this chapter we focus back on the European power system and more specifically on the synchronous area of Continental Europe. In the coming sections, it is analysed whether we would encounter any low inertia issues in the coming decades. To this end we try to estimate the amount of inertia for the year 2030 by taking the EUCO30 scenario as input.

Methodology and approach

Overview of the methodology

Different steps are followed in order to estimate the total system inertia within continental Europe for the year 2030, see also *Figure 32*. First, the input data is collected including the assumed available generation capacity per country (EUCO30 policy scenario & TYNDP2018 dataset, see section 0), the cost for each type of generation, the hourly load and a forecast of the wind and solar production. Moreover, also a typical unit size and inertia constant for each generation sources are required as input for the assessment.
Next, an hourly dispatch is obtained using the SCANNER software tool. Since the dispatch only gives an aggregated generation output for each country, the number of

spinning units need to be calculated using the typical unit size. Once the number and type of spinning units are known, the total system inertia is calculated based on the typical inertia constant for each type of unit.
Finally, the hourly inertia data is further analysed including for instance an estimate of the expected ROCOF after a major power imbalance in the system. The different steps are discussed in the following paragraphs, the input data (& the assumptions) are given in section 0.

Figure 32: Different steps within the inertia assessment

Hourly dispatch of generation per country

The hourly dispatch is obtained using the SCANNER software tool developed by Tractebel, which optimizes the behaviour of the electricity market for a one-year period in hourly time steps. Based on the characteristics of the generating units and hourly profiles describing the load and the availability of renewable energy sources, SCANNER performs the economic dispatch of the generators by minimizing the operating cost in three steps:

- The first step is the annual allocation of hydrological resources.
- The second step is the daily management of storage, performed in day-ahead.
- The third step is the intraday economic dispatch.

The annual allocation of hydrological resources optimizes the amounts of hydroelectricity that will be used during each week of the year by minimizing the total operating cost during the overall year. Different time granularities can be used, but each week is usually represented as a single point in time. The daily day-ahead management of storage optimizes the dispatch of storage units by minimizing the total operating cost for one week. In this optimization problem, the time granularity is one hour, and RES generations and load demands are supposed to be perfectly known. Constraints on hydrological resources coming from the annual allocation are enforced. The intraday economic dispatch optimizes the generation of each generating unit by minimizing the total operating cost for each hour.
The constraints imposed by the transmission grid are considered using a multi-area model consistent with the current organization of the European power market: nearly each country is considered as a single market area (some countries like Italy, Norway and Sweden are divided into several market areas), and power flows between market areas are limited by the corresponding Net Transfer Capacities (NTCs) given by the ENTSO-E TYNDP2018 for 2030. This is in line with the approach followed by ENTSO-E in the TYNDP2018 to estimate the costs and the benefits of interconnections between countries.

Spinning units per country

Starting from an aggregated hourly dispatch and a typical unit size for each generation technology, the number and capacity of the spinning units is determined. A simple approach is followed in which the number of units is determined by dividing the produced power by the typical unit size and rounding up the result the result to the next integer (e.g. 510 MW distributing amongst units of 100 MW each result in 6 spinning units producing 85 MW). As such we inherently create some reserve in our system.

Inertia calculation

Finally, starting from the number of spinning units (N_i), their typical size (S_i) and inertia constant (H_i) for each type of generation technology, the total system inertia (or kinetic energy) can easily be calculated by (see also formulas in Chapter 0):

$$H_{sys} = \frac{\sum_{i=1}^{n} H_i S_i N_i}{S_{sys}} = \frac{E_{kin,sys}}{S_{sys}} \tag{15}$$

With n the number of considered generation technologies. S_{sys} can be freely chosen but must be specified.

Input Data & assumptions

The EUCO30 scenario

The EUCO30 policy scenario was created as part of the European Commission's impact assessment work in 2016. It uses the PRIMES model with the EU reference scenario 2016 as a starting point[20]. The scenario models the achievement of the 2030 climate and energy targets as agreed by the European Council in 2014 but including an energy efficiency target of 30% [72].

The EUCO30 scenario is a decarbonisation scenario, i.e. it is compatible with a 2°C trajectory and the Europe's intended nationally determined contribution (INDC) to the united nations framework convention on climate change (following the COP-21 meeting in Paris in 2015). They achieve about 80% GHG emissions reduction in 2050 compared to 1990 levels, in line with the European Commission "Energy Roadmap 2050" [73].

The main elements of the EUCO30 scenario are given in *Figure 33*.

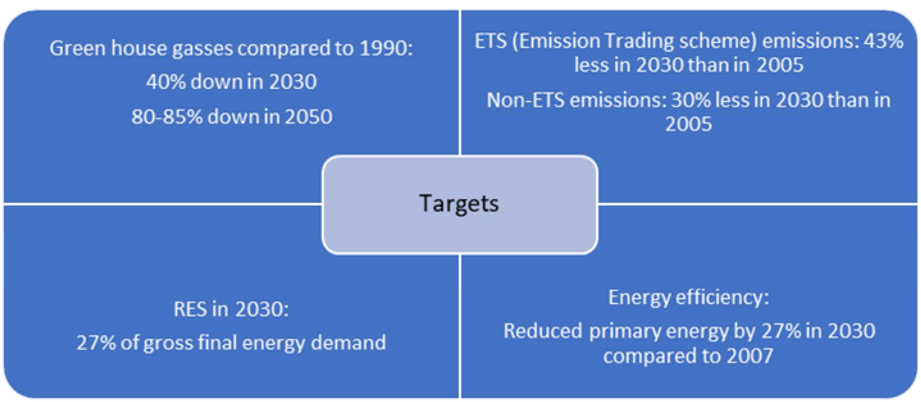


Figure 33: Climate and energy targets for the EUCO30 scenarios. Adapted from [74]

For this study, we are mainly interested in the estimated installed electricity capacity of each generation source within Continental Europe for the year 2030, which is used as input to the SCANNER software. The applied dataset of generation capacities for the EUCO30 scenario can be found in [75] or in *Table 9* of the Appendix.

[20] The EU Reference Scenario is one of the European Commission's key analysis tools in the areas of energy, transport and climate action. It allows policy-makers to analyse the long-term economic, energy, climate and transport outlook based on the current policy framework. More information on the energy modelling can be found through the website of the EC, see also [72].

In *Figure 34*, the share of inertialess capacity (wind and PV power) for each considered country is given. Germany and West-Denmark have the highest share (almost 70%), the average over all countries is equal to 43% (corresponding to the numbers given in *Figure 1*).
Note that a very conservative approach is taken in a first step as Morocco and Turkey are not included in the dataset. Consequently, the inertia from these power systems is not taken into account. Although these countries are both weakly connected to the Continental European system (Turkey is synchronized with Europe since April 2015), they can provide inertial response through their AC interconnections. The Baltic countries on the other hand are included in the study, assuming that the networks are synchronized with the remaining power system through an AC link with Poland.

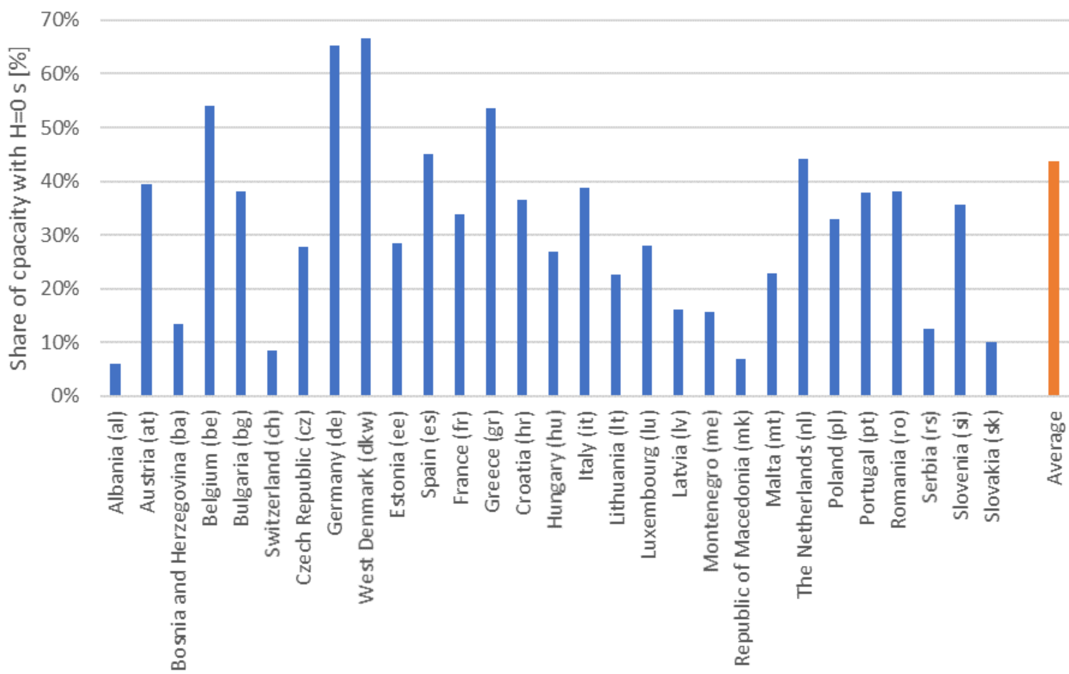


Figure 34: Share of inertialess capacity within the considered countries (average is equal to 43%)

Load and RES data

Time series describing the hourly profile of the load in each country are taken directly from the dataset provided by ENTSO-E in the framework of the TYNDP 2018. However, that data set does not provide time series describing the available renewable energy (i.e. solar PV and wind). These time series are thus derived from the historical data of the year 2017 provided by the Open Power System Data platform[21]. When no time series is available for a country, it is interpolated from neighbouring countries. Furthermore, the capacity of hydro reservoirs for each country is taken from the ENTSO-E transparency platform.

Inertia data and capacity of generation units

The ratings and inertia constant applied in this study are given in Table 8 (these values are obtained from ENTSO-E). Note that the units with zero inertia are not included in the list since these units are not considered in the calculation of the total system inertia (equation (15)).

[21] https://open-power-system-data.org/

Generation technology	Typical rating [MW]	Typical inertia constant H [s]
Biofuels	208	3.3
Hard coal	361	4.1
Gas	168	4.3
Lignite	310	3.9
Nuclear	869	6
Oil (THN)	153	4.3
Hydro-pump	140	4
Hydro-run	59	2.7
Hydro-dam	140	4
Other non-RES	104	3.7
Solar-thermal	150	3

Table 8: Typical (average) rating and inertia constant used in the study

Results & Analysis

(Maximum) Available kinetic energy

Firstly, the (maximum) available energy of 2030 is compared with the year 2020. For 2020, the “Best estimate 2020 (2020BE)” scenario out of the TYNDP2018 of ENTSOE-E is chosen to obtain the installed generation capacities (it labelled as Best Estimate scenario due to a lower level of uncertainty).
For 2030, a total kinetic energy of 2422 GWs is available within the considered countries compared to 2633 GWs in 2020, corresponding to a drop of 9%. Larger systems (with more generation capacity) will in general also have more kinetic energy available compared to other systems, see also *Figure 35*. In 2030, it is estimated that France will have the highest available kinetic energy (518 GWs), which is about 1/5 of the total amount.
The countries with a nuclear phase out (e.g. in Germany and Belgium) will encounter a large drop in 2030 compared to the year 2020 (about 28% for Germany and Belgium).
It should be highlighted that these numbers represent the (theoretical) maximum kinetic energy, i.e. when all power plants in the system are operating. In practise, these values can of course never be obtained. Even during peak load, there will always be units that are shut down due to maintenance, operational costs that are too high, …

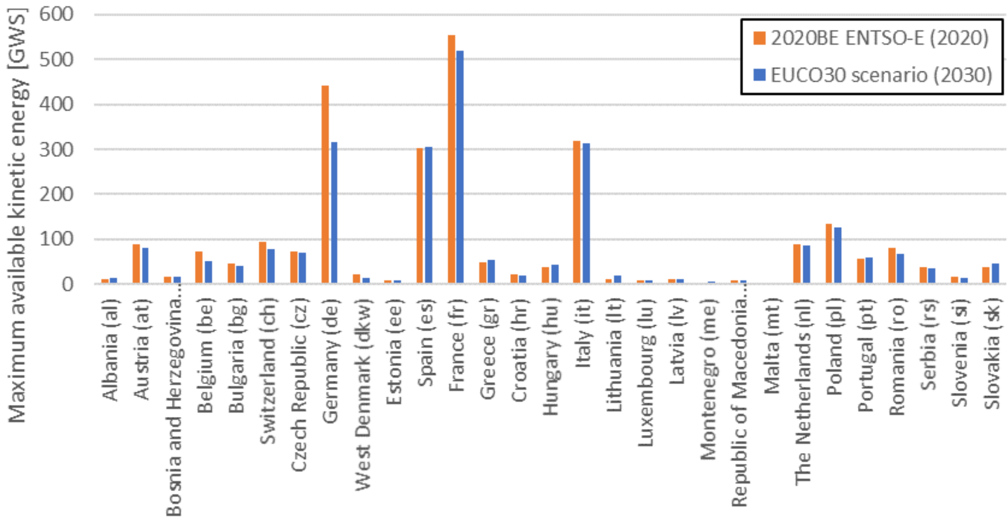


Figure 35: Maximum available kinetic energy for the year 2020 and 2030

Hourly estimates of inertia/kinetic energy

Starting from the SCANNER output, the estimated total kinetic energy for each hour during the year 2030 is calculated, see the results presented in Figure 36. The maximum kinetic energy is obtained during winter (high load) and is equal to 1850 GWs. It corresponds to about 2/3 of the maximum available kinetic energy as discussed in the previous section. During low load (spring and summer), the load and consequently also the kinetic energy drops, with a minimum value of 661 GWs. In *Figure 36*, also the three main contributors to the total inertia are given (France, Germany and Spain). France provides the most, with an hourly kinetic energy content corresponding to ±1/3-1/4 of the total energy.

Figure 36: Estimated hourly kinetic energy in GWs for the scenario EUCO30 (the three main contributors are also included as a stacked plot)

In Figure 37, the kinetic energy for the second week of 2030 is given. This figure again illustrates the clear link between load and kinetic energy. Finally, the duration curve of the estimated kinetic energy is presented in Figure 38.

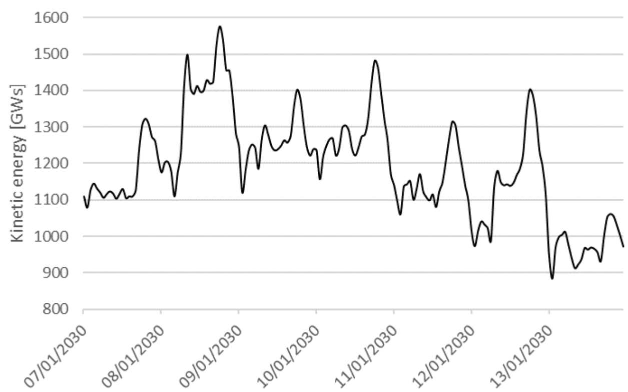


Figure 37: Estimated hourly kinetic energy during the second week of 2030 (zoom of Figure 36)

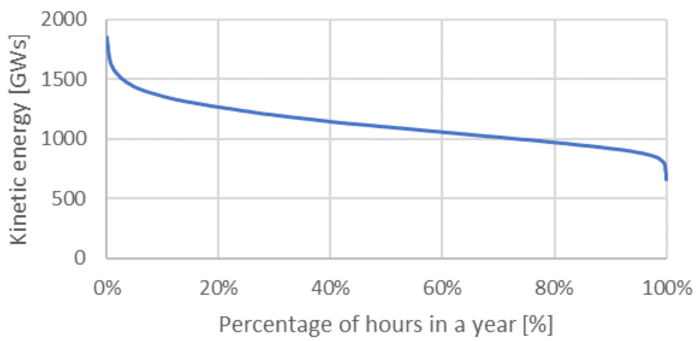


Figure 38: Duration curve of the estimated kinetic energy in 2030

ROCOF considerations

If we consider the current reference incident in Europe, which is taken equal to 3 GW (corresponding to the loss of the two largest nuclear units), we theoretically only require 75 GWs (37.5GWs) to keep the ROCOF above 1 Hz/s (2Hz/s) (see equation (11)). This means that even during periods of low load (and low inertia), there is still more than sufficient kinetic energy available. The minimum imbalance that will result in a ROCOF of 1 or 2 Hz/s is given in *Figure 39*. The minimum kinetic energy content of 661 GWs corresponds to an imbalance of 26GW and 52GW for respectively a ROCOF of 1Hz/s and 2Hz/s.

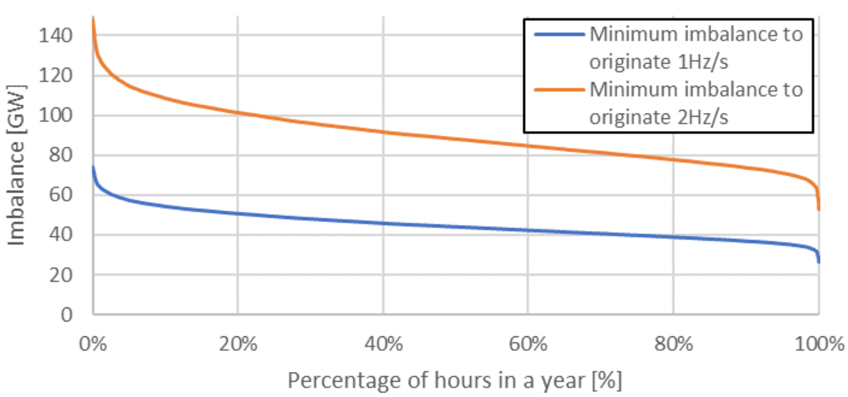


Figure 39: Duration curve of the minimum power imbalance to originate a 1Hz/s or 2Hz/s event

Many assumptions have been made to determine the minimum inertia during the year (load, generation data, inertia constants, …). Therefore, apart from the simulations presented above, lets follow a different reasoning to determine the worst case in terms of ROCOF. As a starting point we take the expected minimum load during 2030 (i.e. ±250 GW during the night). Additionally, we assume that this load is for 90% covered by inertialess generation, for instance mainly wind power (there is 222.34 GW of installed capacity in the EUCO30 scenario). The other 10% (=a rough assumption!) need to be produced by synchronous generation due to other operational constraints: to provide reserves, short circuit capacity, …. If this 25 GW is produced by conventional power plants with a total capacity of 50 GW (to have sufficient reserve), we still have 150 GWs of inertia available if an average inertia constant of 3s is assumed (i.e. the low end of the range of values in *Table 8*). Applying the above assumptions, it can be concluded that even if we go to penetration levels of 90% there is still two times more kinetic energy available than required to keep the ROCOF above 1 Hz/s after an imbalance of 3GW.

Discussion & recommendations

Although it is expected that there will be a significant increase of converter connected generation in the European Continental system by 2030, the total kinetic energy content remains quite substantial. Compare for instance the minimum kinetic energy of 661 GWs with the values given in section 0. In the Nordic system, the estimated inertia during 2009-2015 was on average 200 GWs. For the ERCOT system (US), the maximum value is only 389 GWs.

Due to the high amount of kinetic energy, the minimum imbalance to originate a ROCOF of 1Hz/s of 2Hz/s (minimum of 26 GW and 52 GW) is also much higher than the current reference incident of 3 GW. The Continental European system actually mainly benefits from its size since inertia is roughly proportional to the size of the system while this is not the case for considered reference incident.

Higher imbalances than the current reference incident can possibly be encountered during a system split. However, the ROCOF values for such event are very hard to determine since it is difficult to predict how the system will exactly split, what amount of power was transferred between the zones before they split, …

Since we do not expect any issues related to inertia in 2030, it is also not required, at least not in the short term, to implement measures that imply radical changes in the way our current system is operated (i.e. new market products such as virtual inertia, grid-forming converters, limit the penetration of converter connected generation).

Nevertheless, it is highly recommended to gradually put in place a monitoring and forecasting tool for system inertia. This requires, especially for the Continental Europe, a close collaboration between the different TSOs as inertia and operational data has to be exchanged on synchronous area level.

With such a tool, a more detailed prognosis can be made for the expected decrease of inertia for the coming months, years and even decades. Moreover, once this tool is in place, special procedures and measure can already be defined to cope low inertia situation. Since such situations will be very rare in the near future, the most relevant and cost-efficient solution appears to be a simple redispatch. Redispatch, including curtailment of renewable generation or the activation of more expensive units with a high inertia, is neither always efficient or desirable, but can be very cost-efficient compared to the other solution presented section 0 in case it is only required for a few hours a year.

Conclusion

In this chapter, a prognosis of the future system inertia within the synchronous area of Continental Europe is made based on the generation capacities of the EUCO30 scenario. Although it expected that there will be a substantial increase in converter connected penetration, the analysis shows that there remains sufficient inertia in the system to cope with imbalance which are even much higher than the current reference incident.

Conclusion & Recommendations

General summary and conclusions

The increasing penetration of converter connected generation (mainly wind and PV power) in our power system will lead to a decreasing amount of system inertia. In this study, a clear analysis and understanding of the expected stability problems related to this reducing inertia are presented. Moreover, in order to cope with these issues, multiple solutions are proposed and elaborated to securely operate and control such a system with low inertia.

The findings and simulation results presented in the first part of this work (chapter 0 and 0) are more general but can be applied to set out (future) approaches for the operation and control of large-scale power systems with reduced inertia. In the second part of this study, we mainly focus on the European system by analysing the current efforts and measures that are put in place. Furthermore, an assessment of the available inertia and possible related stability issues within the Continental European system for the year 2030 is made.

By investigating the different sources of inertia, it can be concluded that, although the load and distributed units also contribute to some extent, the lion's share of system inertia is currently still provided by the synchronous machines installed in conventional power plants. PV and wind power, except from fixed speed wind turbines, provide no inertia at all due to their power electronic converter which decouples the generator from the system. As these "inertialess" units will more and more displace the conventional power plants, the total system inertia will drop.

This system inertia plays an important role in many different forms of power system stability, but it is expected that issues will mainly arise in terms of frequency control as the ability of the system to resist to large power imbalance decreases. Low inertia results in high ROCOF values and substantial frequency deviations which can lead to instability of the system. Therefore, options to adapt the system such that it can cope with higher ROCOF and higher frequency deviations were discussed. Moreover, also several solutions to prevent frequency stability issues by increasing the inertia (by means of additional inertia from synchronous machines or virtual inertia from converters) or by decreasing the possible contingency size have been presented. Further assessment however is required to define the optimal and most cost-effective solution for each power system.

Many efforts have already been done by ENTSO-E to deal with the inertia issues within Europe in a coordinated and harmonized way though their operational guidelines, network codes and system studies. However, as most of the guidelines and network codes related to system inertia are non-exhaustive (or even non-mandatory), there is still a wide variety in the way each TSOs implement them. TSOs in large interconnected synchronous areas, such as the Continental European system, currently only adapt the allowed ROCOF relay settings or include a ROCOF withstand capability (for new units) in their grid code. Island systems on the other hand, such as Ireland and GB, are already a step ahead as they expect to encounter high levels of converter penetration. Currently they mostly try to limit the ROCOF by limiting the largest credible loss or keeping the inertia above a certain minimum value. However, to reach even higher penetration levels, new system services will need to be procured.

Finally, a prognosis of the future system inertia within the synchronous area of Continental Europe is made based on the generation capacities of the EUCO30 scenario. Although it expected that there will be a substantial increase in converter connected penetration, the analysis shows that there remains sufficient inertia in the system to cope with imbalance which are much higher than the current reference incident.

Recommendations

The main recommendations with respect to the European system are shortly presented below:

For Continental Europe (Low inertia situations are very unlikely but not impossible in the far future!)

- § Gradually put in place a tool to monitor and forecast the inertia at operational level (cooperation between all TSOs within Continental Europe required)
- § Define procedures to cope with the lack of inertia (for now: just apply redispatch to increase the inertia)
- § Review regularly the long-term needs to check if other measures to cope with the reduce inertia are necessary

For other (smaller) synchronous areas within Europe

- § Detailed studies have been carried out and solutions are being implemented (see Ireland and GB)
- § They can be considered the European forerunner with respect to operating a power system with low inertia: it is therefore important to share the main outcomes, problems and experience with the TSOs from other synchronous areas.

For small islanded systems

- § Local, ad-hoc solutions are required which are very system specific. No coordination between different operators is normally needed.

Appendix 1: Dataset of the EUCO30 scenario for continental Europe (year 2030)

Country name	Biofuels	Hard coal	Gas	Lignite	Nuclear	Oil	Hydro-pump storage	Hydro-run	Hydro-dam	Other non-RES	Other RES	Solar-thermal	Solar-PV	Wind-on-shore	Wind-off-shore	Total capacity
Albania (al)	0	0	700	0	0	0	0	468	2402	0	0	0	80	150	0	3800
Austria (at)	0	777	2566	0	0	423	6508	4672	5765	465	1373	0	6501	5888	0	34938
Bosnia and Herzegovina (ba)	0	0	0	2536	0	0	440	1144	680	0	0	0	100	640	0	5540
Belgium (be)	810	16	9688	0	0	218	1150	117	158	0	0	0	6907	4146	3240	26450
Bulgaria (bg)	99	1011	790	2370	1920	2	933	600	1867	0	0	0	3069	2852	0	15513
Switzerland (ch)	0	0	1364	0	1190	8	4593	4139	8987	0	588	0	0	1301	0	22170
Czech Republic (cz)	0	1596	868	7202	4006	64	1000	365	50	211	617	0	2617	2690	0	21286
Germany (de)	8567	22930	17081	13782	0	1247	9792	4329	791	1671	0	2	81501	59902	9547	231142
West Denmark (dkw)	1886	602	788	0	0	82	0	7	0	0	0	0	555	4353	1818	10091
Estonia (ee)	0	1	333	0	0	1412	0	10	0	50	204	0	0	512	0	2522
Spain (es)	2075	3968	27921	0	7399	2951	8280	3850	10920	195	0	6133	25835	34534	63	134124
France (fr)	3853	3780	7642	0	59493	1701	5500	13600	8000	620	0	0	28354	19115	6035	157693
Greece (gr)	262	0	4738	2865	0	733	1289	275	2720	0	0	0	7675	7157	0	27714
Croatia (hr)	0	655	834	1	0	370	300	500	2000	0	30	0	1453	1211	0	7354
Hungary (hu)	358	0	2769	414	4482	5	0	60	0	89	0	0	1766	1226	0	11169
Italy (it)	6073	4328	43026	0	0	2170	5514	5590	10519	379	0	27	35318	13733	3	126680
Lithuania (lt)	142	0	1348	0	1117	0	950	138	175	0	0	0	74	1053	0	4997
Luxembourg (lu)	37	0	442	0	0	2	1026	34	284	0	0	0	390	323	0	2538
Latvia (lv)	138	21	1090	0	0	15	0	0	1619	0	0	0	0	500	49	3432
Montenegro (me)	0	0	0	450	0	0	0	132	1139	0	39	0	30	250	0	2040
Republic of Macedonia (mk)	0	120	290	915	0	0	0	151	647	0	26	0	32	100	0	2281

Malta (mt)	3	0	615	0	0	287	0	0	0	0	0	0	264	4	0	1173
The Netherlands (nl)	2690	4429	10379	0	485	2066	0	0	0	433	0	0	5933	7674	2561	36650
Poland (pl)	2358	12979	4522	6369	0	2355	1488	1033	0	369	0	0	1146	13551	777	46947
Portugal (pt)	659	0	3744	0	0	1000	4120	735	4346	0	0	50	2077	6849	27	23607
Romania (ro)	219	232	3846	1678	2828	676	0	3291	3310	6	0	0	3214	6730	0	26030
Serbia (rs)	0	0	580	5306	0	0	1260	2025	503	0	118	0	200	1068	0	11060
Slovenia (si)	118	68	207	553	696	0	600	1500	0	0	0	0	1743	337	0	5822
Slovakia (sk)	455	328	1007	126	4020	84	1486	974	806	96	0	0	680	374	0	10436

Table 9: Estimated electricity generation capacities for the year 2030 (EUCO30 scenario)

References

[1] European Commission (EC), "2020 Climate & Energy Package," 2009. [Online]. Available: https://ec.europa.eu/clima/policies/strategies/2020_.

[2] European Commission (EC), "EU energy statistical pocketbook and country data," 2018. [Online]. Available: https://ec.europa.eu/energy/en/data-analysis/energy-statistical-pocketbook.

[3] European Commission (EC), "EU Reference Scenario 2016: Energy, transport and GHG emissions Trends to 2050," Technical Report, 2016.

[4] B. Kroposki, B. ,. Y. Johnson, V. Gevorgian, P. Denholm, B. M. Hodge and B. Hannegan, "Achieving a 100% renewable grid: Operating electric power systems with extremely high levels of variable renewable energy," *IEEE Power and Energy Magazine,* vol. 15, no. 2, pp. 61-73, 2017.

[5] R. Serway, R. Beichner and J. Jewett, Physics for Scientists and Engineers, Holt Rinehart & Winston, 2000.

[6] P. Kundur, Power System Stability and Control, New York: McGraw-Hill, 1994.

[7] J. Machowski, J. Bialek and J. Dumby, Power system dynamics: stability and control, Wiley, 2009.

[8] P. Anderson and A. Fouad, Power system control and stability, Wiley - IEEE press, 2002.

[9] W. Stevenson and J. Grainger, Power System Analysis, New York: McGraw-Hill, 1994.

[10] E. Kimbar, Power system stability, Wiley-IEEE, 1995.

[11] M. Bollen, Hassan and F., Integration of distributed generation in the, Wiley-IEEE Press, 2011.

[12] P. Tielens, "Operation and control of power systems with low synchronous inertia," KU Leuven, Ph.D. Dissertation, 2017.

[13] J. Morren, J. Pierik and S. W. De Haan, "Inertial response of variable wind turbines," *Electric Power Systems Research,* vol. 76, no. 11, pp. 980-987, 2006.

[14] G. Lalor, A. Mullane and M. O'Malley, "Frequency control and wind turbine technologies," *IEEE Transactions on Power Systems,* vol. 20, no. 4, p. 1905–1913, 2005.

[15] I. Moore, "Inertial response from wind turbines," Cardiff University, Ph.D. dissertation, 2012.

[16] J. Soens, "Impact of wind energy in a future power grid," KU Leuven, Ph.D. dissertation, 2005.

[17] P. Fairley, "Europe replaces old wind farms," *IEEE Spectrum,* vol. 46, no. 1, p. 13, 2009.

[18] The European Wind Energy Association, "Powering Europe: wind energy and the electricity grid," EWEA, 2010.

[19] S. Chandrasekaran, "Grid connected doubly fed induction generator based wind turbine LVRT," University of Bologna, Ph.D. Dissertation, 2014.

[20] A. Mullane and M. O'Malley, "The inertial response of induction-machinebased wind turbines," *IEEE Transactions on Power Systems,* vol. 20, no. 3, pp. 1496-1503, 2005.

[21] M. Kayikçi and J. Milanovic, "Dynamic contribution of DFIG-Based wind plants to system frequency disturbances," *IEEE transactions on power systems,* vol. 24, no. 2, p. 859–867, 2009.

[22] V. Akhmatov, "Variable-speed wind turbines with doubly-fed induction generators: Part I: Modelling in dynamic simulation tools," *Wind Engineering,* vol. 26, no. 2, pp. 85-108, 2002.

[23] A. Perdana, "Dynamic models of wind turbines: a contribution towards the establishment of standardized models of wind turbines for power system stability studies," Chalmers university of technology, Ph.D. Dissertation, 2008.

[24] W. Kramer, S. Chakraborty, B. Kroposki and H. Thomas, "Advanced power electronic interfaces for distributed energy systems," NREL, Technical report, 2008.

[25] M. Mahmoud and F. Al-Sunni, Control and Optimization of Distributed Systems, Springer, 2013.

[26] C. Taylor, Power system voltage stability, McGraw-Hill Ryerson, 1994.

[27] IEA, "Energy efficiency roadmap for electric motors and motor systems," IEA (4E Energy Efficient End-use Equipment), Technical report, 2015.

[28] E. Ørum, M. Kuivaniemi, M. Laasonen, A. Bruseth, E. Jansson, A. Danell, K. Elkington and N. Modig, "Future system inertia," ENTSO-E (Nordic analysis group), Technical Report, 2015.

[29] P. Wall and V. Terzija, "Simultaneous estimation of the time of disturbance," *IEEE Transactions on Power Delivery,* vol. 4, no. 29,

p. 2018–2031, 2014.

[30] D. Chassin, Z. Huang, M. Donnelly, C. Hassler, E. Ramirez and C. Ray, “Estimation of wecc system inertia using observed frequency transients,” *IEEE Transactions on Power Systems,* vol. 20, no. 2, p. 1190–1192, 2005.

[31] E. Orum, L. Haarla, M. Kuivaniemi, M. Laasonen, A. Jerko, I. Stenklov, F. Wik, K. Elkington, R. Eriksson, N. Modi and S. P., “Future system inertia 2,” Nordic system operators, Technical Report, 2018.

[32] P. Kundur, J. Paserba, V. Ajjarapu, G. Andersson, A. Bose, C. Canizares, N. Hatziargyriou, D. Hill, A. Stankovic, A. Taylor, T. Van Cutsem and V. Vittal, “Definition and classification of power system stability IEEE/CIGRE joint task force on stability terms and definitions,” *IEEE transaction on Power Systems,* vol. 19, no. 3, pp. 1387-1401, 2004.

[33] M. Reza, “Stability analysis of transmission systems with high penetration of distributed generation,” TU Delft, Ph.D. Dissertation, 2006.

[34] Nordel, “The nordic grid code 2007 (nordic collection of rules),” Nordel, Technical Report, 2007.

[35] ENTSO-E, “Continental Europe operation handbook,” ENTSO-E, Technical Report, 2009.

[36] S. Prabakaran and G. Pradeep, “A study on turbine blade fatigue protection,” in *Eighteenth Power Systems Conference (NPSC)* , Guwahati , 2014.

[37] I. Young, “A collation of international policies for under-frequency load shedding,” Transpower, Technical Report, 2009.

[38] ENTSO-E, “Frequency Stability Evaluation Criteria for the Synchronous Zone of Continental Europe,” ENTSO-E, Technical Report, 2016.

[39] W. Freitas, W. Xu, C. Affonso and Z. Huang, “Comparative analysis between ROCOF and vector surge relays for distributed generation,” *IEEE Transactions on Power Delivery,* vol. 20, no. 2, p. 1315–1324, 2005.

[40] H. Kazemi Kargar and J. Mirzaei, “New method for islanding detection of wind turbines,” in *2nd International Power and Energy Conference*, Sydney, 2008.

[41] L. Ruttledge and D. Flynn, “Short-term frequency response of power systems with high non-synchronous penetration levels,” *Wiley Interdisciplinary Reviews: Energy and Environment,* vol. 4,

no. 5, pp. 452-470, 2015.

[42] Dysko, A. (University of Strathclyde), "Loss of Mains Protection," [Online]. Available: https://www.nationalgrid.com/sites/default/files/documents/16968-Meeting%203%20Presentation%20-%20Loss%20of%20Mains%20Protection.pdf.

[43] Eirgrid, System Operator for Northern Ireland (SONI), "DS3 Joint Grid Code Working Group Position Paper on ROCOF," Eirgrid, SONI, Technical Report, 2012.

[44] ENTSO-E, "Operation reserve ad hoc team report: final version," ENTSO-E, Technical Report, 2012.

[45] J. Fogarty and R. LeClair, "Converting Existing Synchronous Generators into Synchronous Condensers," 10 01 2011. [Online]. Available: https://www.power-eng.com/articles/print/volume-115/issue-10/features/converting-existing-synchronous-generators-into-synchronous-condensers.html.

[46] S. De Rijcke, "Dynamic grid support by wind farms: Potential of rotating kinetic energy," KU Leuven, Ph.D. Dissertation, 2014.

[47] N. Ullah and T. Thiringer, "Temporary primary frequency control support by variable speed wind turbines," *IEEE Transactions on power systems,* vol. 23, no. 2, pp. 601-612, 2008.

[48] J. Conroy and R. Watson, "Frequency response capability of full converter wind turbine generators in comparison to conventional generation," *IEEE Transactions on power systems,* vol. 23, no. 2, pp. 649-656, 2008.

[49] R. Renner and D. Van Hertem, "Potential of using DC voltage restoration reserve for HVDC grids,"," *Electric Power Systems Research,* vol. 134, no. 1, pp. 167-175, 2016.

[50] G. Dedile and B. M. Francois, "Dynamic frequency control support by energy storage to reduce the impact of wind and solar generation on isolated power system's inertia," *IEEE Transactions on sustainable energy,* vol. 3, no. 4, pp. 931-939, 2012.

[51] D. S., S. J.A., O.B. and Fosso, "A virtual synchronous machine implementation for distributed control of power converters in smartgrids," *Electric Power Systems Research,,* vol. 122, no. 1, pp. 180-197, 2015.

[52] T. Ackermann, T. Prevost, V. Vittal, A. Roscoe, J. Matevosyan and N. Miller, "Paving the way: A future without inertia is closer then you think," *IEEE Power and energy magazine,* vol. 15, no. 6, pp. 61-69, 2017.

[53] ENTSO-E, "Who is ENTSO-E?," [Online]. Available: https://www.entsoe.eu/about/inside-entsoe/objectives/.

[54] R. Pfeiffer, "System inertia considerations at ENTSO-E," ENTSO-E, 2017.

[55] ENTSO-E, "Completing the map: European Power System 2040: Technical Appendix," ENTSO-E, Technical Report, 2018.

[56] European Union, "Commission regulation (EU) 2016/631: Establishing a network code on requirements for grid connection of generators," Official Journal of the European Union, 2016.

[57] European Union, "Commission regulation (EU) 2016/1388: Establishing a network code on demand connection," Official journal of the European Union, 2016.

[58] European Union, "Commission regulation (EU) 2016/1447: Establishing a network code on requirements for grid connection of high voltage direct current systems and direct current-connected power park modules," Official journal of the European Union, 2016.

[59] ENTSO-E, "ENTSO-E Connection Codes Implementation Guidance Documents," [Online]. Available: https://consultations.entsoe.eu/system-development/entso-e-connection-codes-implementation-guidance-d/consult_view/.

[60] ENTSO-E, "Rate of Change of Frequency (RoCoF) withstand capability: ENTSO-E guidance document for national implementation for network codes on grid connection," Technical Report, 2018.

[61] RG-CE System Protection & Dynamics Sub Group (ENTSO-E), "Task Force Code - System dynamic issues for the synchronous zone of continental Europe," ENTSO-E, Technical Report, 2017.

[62] ENTSO-E, "Need for synthetic inertia (SI) for frequency regulation: ENTSO-E guidance document for national implementation for network codes on grid connection," Technical Report, 2018.

[63] Hydro-Québec (Transenergie), "Technical requirements for the connection of generation facilities to the Hydro-Québec transmission system: Supplementary requirements for wind generation," Technical Report, 2003 (Revised in 2005).

[64] ENTSO-E, "High Penetration of Power Electronic Interfaced Power Sources (HPoPEIPS): ENTSO-E Guidance document for national implementation for network codes on grid connection," Technical Report, 2017.

[65] ENTSO-E, "Monitoring files (excel file)," Available at: https://docs.entsoe.eu/cnc-al/, Technical Report, 2018.

[66] European Union, “Commission regulation (EU) 2017/1485: Establishing a guideline on electricity transmission system operation,” Official journal of the European Union, 2017.

[67] E. Ørum, L. Haarla, M. Kuivaniemi, M. Laasonen, A. Jerko, I. Stenklov, F. Wik, K. Elkington, R. Eriksson, N. Modig and Schavemaker, “Future System Inertia 2,” ENTSO-E (Nordic analysis group), Technical Report, 2017.

[68] EirGrid,SONI &SEMO, “The DS3 Programme: Delivering a Secure, Sustainable Electricity System,” The EirGrid Group, Brochure, 2011.

[69] Connaughton, I. (EirGrid), “DS3 Advisory Council: DS3 Programme Status Update,” EirGrid & SONI, January 2018.

[70] EirGrid & SONI, “Consultation on DS3 System Services Enduring Tariffs: DS3 System Services Implementation Project,” July 2017.

[71] National Grid, “System Needs and Product Strategy,” Technical Report, 2017.

[72] European Commission (EC), “Energy modelling,” [Online]. Available: https://ec.europa.eu/energy/en/data-analysis/energy-modelling.

[73] European Commission (EC), “Energy Roadmap 2050 - Impact assessment and scenario analysis,” 2011.

[74] Tractebel, Ecofys & E3M, “A foresight perspective of the electricity sector evolution by 2050,” ASSET, Technical Report, 2018.

[75] E3MLab & IIASA, “Technical report on Member State results of the EUCO policy scenarios,” European Commission (EC), December 2016.

[76] P. M. Ashton, C. S. Saunders, G. A. Taylor, A. M. Carter and M. E. Bradley, “Inertia estimation of the GB power system using synchrophasor measurements,” *IEEE Transactions on Power Systems,* vol. 30, no. 2, p. 701–709, 2015.

[77] J. Rocabert, A. Luna, F. Blaabjerg and P. Rodriguez, “Control of power converters in ac microgrids,” *IEEE transactions on power systems,* vol. 27, no. 11, pp. 4734-4749, 2012.

GETTING IN TOUCH WITH THE EU

In person

All over the European Union there are hundreds of Europe Direct information centres. You can find the address of the centre nearest you at: https://europa.eu/european-union/contact_en

On the phone or by email

Europe Direct is a service that answers your questions about the European Union. You can contact this service:

– by freephone: 00 800 6 7 8 9 10 11 (certain operators may charge for these calls),

– at the following standard number: +32 22999696 or

– by email via: https://europa.eu/european-union/contact_en

FINDING INFORMATION ABOUT THE EU

Online

Information about the European Union in all the official languages of the EU is available on the Europa website at: https://europa.eu/european-union/index_en

EU publications

You can download or order free and priced EU publications at: https://publications.europa.eu/en/publications. Multiple copies of free publications may be obtained by contacting Europe Direct or your local information centre (see https://europa.eu/european-union/contact_en).

EU law and related documents

For access to legal information from the EU, including all EU law since 1952 in all the official language versions, go to EUR-Lex at: http://eur-lex.europa.eu

Open data from the EU

The EU Open Data Portal (http://data.europa.eu/euodp/en) provides access to datasets from the EU. Data can be downloaded and reused for free, for both commercial and non-commercial purposes.

Publications Office
of the European Union