Wind Power within European Grid Codes: Evolution, Status and Outlook

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Article Type:

Overview

Abstract

Grid codes are technical specifications that define the requirements for any facility connected to electricity grids. Wind power plants are increasingly facing system stability support requirements similar to conventional power stations, which is to some extent unavoidable, as the share of wind power in the generation mix is growing. The adaptation process of grid codes for wind power plants is not yet complete, and grid codes are expected to evolve further in the future.

ENTSO-E is the umbrella organisation for European TSOs, seen by many as a leader in terms of requirements sophistication. A current development by ENTSO-E aims to develop a uniform grid code framework for Europe. The new European codes leave many key aspects unspecified, referring instead to regulation by the relevant TSO, but they do provide a positive and encouraging step in the right direction.

The present document is largely based on the definitions and provisions set out by ENTSO-E. The main European grid code requirements are outlined here, including also HVDC connections and DC-connected power park modules. The focus is on requirements that are considered particularly relevant for large wind power plants. Afterwards, an outlook and discussion on possible future requirements is provided. This review has been written by members of IEA Wind Task 25, but it does not represent an official viewpoint of the IEA.

Keywords-wind power plants; requirements for grid connection; grid codes; ENTSO-E

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This is the accepted version of an article published in WIREs Energy and Environment
DOI: 10.1002/wene.28

Introduction

Grid codes are technical specifications that define requirements for any facility connected to electricity grids to ensure the integrity and safe, secure and economic operation of the electricity system. Such facilities include both power plants and loads, although only power plants are addressed in this publication. It is usually the responsibility of the power plant owner to demonstrate that the grid code requirements for the relevant connection point are satisfied. If the grid code requirements are breached, excepting where derogations are in place, severe penalties may be incurred. Ultimately, it is the appropriate grid manager, namely the Transmission System Operator (TSO) or Distribution System Operator (DSO), who determines the requirements for a given project, taking into account special circumstances that may be important. However, more or less standardised grid codes are available in most countries with strongly developed electrical networks, aiming to make the planning and implementation of new projects simpler, streamlined and predictable.

However, grid codes as legal regulation documents are often written in a way that may not be intuitive to understand for engineers. The way of organising and presenting information can differ significantly from other technical documents. Another issue are unclear formulated requirements, which pose a significant challenge for all stakeholders. These ambiguities create unnecessary costs, at least in the form of additional working hours for dealing with them, and can lead to diverse interpretations by different stakeholders, which undermines the underlaying concept of standardisation. These issues leads to the production of summary documents [1], which try to translate grid code documents into a more common format for technical documents. This process, however, is time consuming and may introduce errors.

The overview given here expands upon a previous review article examining wind grid codes[2]. The main European grid code requirements[3] are outlined here, including also HVDC (high voltage direct current) connections and DC-connected power park modules[4], and possible future requirements are discussed. The focus of this article is on requirements that are considered particularly relevant for large wind power plants connected directly to the high voltage network (referred to as 'Type D' in [3]). Small generation units (single turbines or small aggregations of a few turbines) may have different requirements (usually less strict),

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DOI: 10.1002/wene.28

but they are not considered in this article. However, the intention here is not to cover all requirements that may be imposed on a wind power plant.

A collation of grid code requirements in several European countries can be found in[1], and a review of selected grid codes with a world-wide scope can be found in[5].

Evolution of Wind Power Grid Codes

Historic Development

When wind power first appeared in the 1980s it enjoyed a favourable treatment when it came to network requirements (disconnetion instead of grid support), as it was not deployed at sufficient scale to be system relevant. Focus was layed on local phenomena like voltage quality in distribution networks. However, during the 1990s, wind power developments gained momentum, while old regulations remained in place, overlooking the system relevant aspects of wind power. This mismatch led to large capacities of wind power being connected to the grid based on requirements that were not suitable for large-scale deployment. Finally, this resulted in a significant threat to stable grid operation, experienced noticeably during the major grid disturbance in continental Europe in November 2006[6], when the electric power system was split into three separate regions (Figure 1).

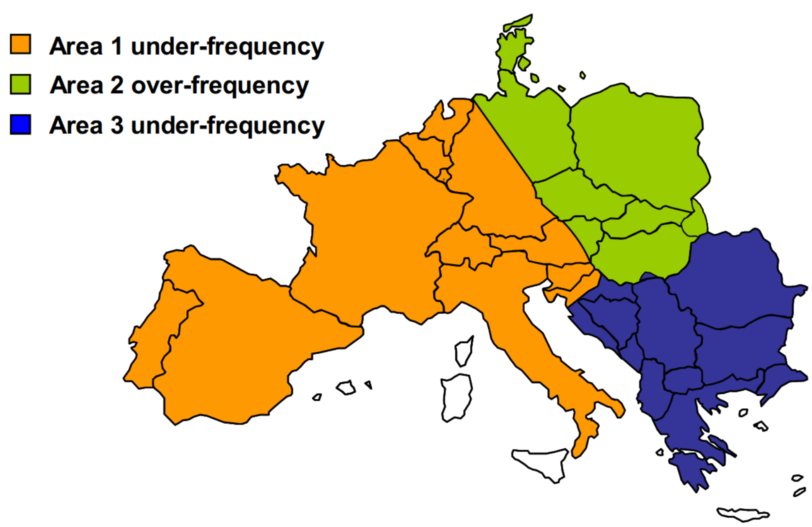

Figure 1: Disturbance on November 4th 2006[6]

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The event was not caused by wind power, but the consequences of the event became more severe due to the contribution from wind power plants. Some wind power plants disconnected during underfrequency condition, worsening the problem. In the over-frequency region, some wind power plants provided full power despite the vast power surplus. However, it was not that the wind power plants were to blame, as they were following the relevant regulations; it was the regulations themselves that were insufficient, especially regarding operation during over-frequency and under-frequency conditions. This event demonstrated the need to improve a range of requirements, e.g. in Spain, whereby relaying protective devices must now be coordinated with the load shedding system[7].

Another example for a lack of foresight, leading to grid code requirements, which were insufficient to cope with large-scale deployment of dispersed converter-interfaced power sources, appeared in the following years in Germany, known as the 50.2 Hz issue[8]. The issue was about required disconnection of generation in overfrequency condition, which can immediately lead to underfrequency problems when applied in large scale. This problem mainly affected solar power plants (and not wind power plants), as it was only relevant for devices connected to the low voltage grid. However, the mechanism behind the problem was the same as those outlined for wind power: large capacities being connected to the grid based on requirements that were not suitable for large-scale deployment. Fortunately, this issue never noticeably affected the electric power system, but it led to significant extra retrofitting costs, which were payed by the electricity consumers.

Nowadays, wind power (and solar power) is fully system relevant, just as conventional power stations. The rising share of wind power has been the reason for the extension and adaptation of grid codes to include wind power generation, resulting in the grid codes that are seen today. For wind turbine manufacturers and wind power plant developers this has generally resulted in requirements that are stricter than those which applied only one decade ago. Possibly, the most well-known requirement that has evolved concerns wind power plant electrical performance during and after short circuits and/or disturbances that lead to large voltage deviations, i.e. fault ride through requirement.

Discussions on similar topics are also underway in the USA, where the North American Electric Reliability Corporation (NERC) and the Federal Energy Regulatory Commission

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(FERC) have been active[9] in identifying essential reliability services (ancillary services) that are critical for maintaining the reliability of the power system as the generation fleet changes.

However, it is not only the total share of wind power that is calling for stricter requirements; it is also advances in technology that enable stricter requirements to be applied. An example of a technology-triggered change of requirements relates to a wider operational range for reactive power control, which became available when a power electronic interface between the wind turbine generator and the grid was introduced. The converter interface was applied for totally different reasons, but the improved reactive power control capability was a welcome side-effect. Reactive power and voltage can be controlled faster, more accurately and at lower cost with modern variable speed wind turbines (Type 4 - full-scale back-to-back converter or Type 3 - doubly fed electrical machines)[10] compared to older (fixed speed) induction generators directly connected to the network without a power electronic converter interface. These extended capabilities can significantly support grid voltage stability when suitably deployed. Incorporating such stability support in grid code requirements would most likely not have happened in the same manner without technological progress triggering its development.

Standardisation

The last decade has seen the installation of many small and dispersed generation units, while the number of electric power producers has increased by several orders of magnitude. The geographical distribution of wind power plants in Germany in 2012 is shown in Figure 2. The map is a few years old, but the dispersion pattern has not changed much since. This dispersion is even more extreme for roof-top photovoltaics.

This development led to a need for standardisation of capabilities and performance. A case-by-case decision for such a large number of small projects would be systematically 're-inventing the wheel', leading to massive economical inefficiency. Standardised grid code requirements have therefore become especially relevant.

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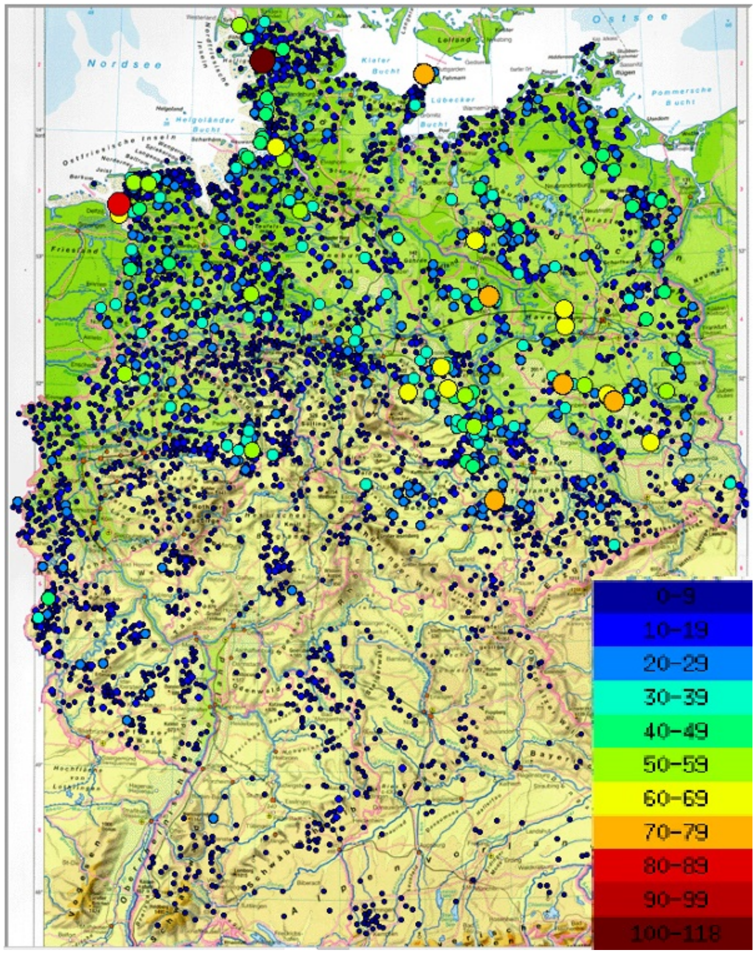

Figure 2: Wind power plants in Germany 2012[11]
(colour scale indicating power rating [MW])

European Harmonisation

Even though grid codes have seen a lot of improvements in recent years, they can differ significantly between European countries. The evolution process, which led to the grid codes that are in place today, has mostly happened on a national level. For island systems, such as Great Britain and Ireland, this is natural, but for the interconnected continental European power system, this fragmented approach has been unfortunate. Especially considering the recent trends towards an integrated pan-European energy system with large power exchanges between countries, a national regulation approach has become a problem, which can even affect system stability. The differences in requirements between countries are also problematic for international market actors, such as wind turbine manufacturers.

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Recent Developments

The European Commission requested ENTSO-E (European Network of Transmission System Operators for Electricity), the umbrella organisation for European TSOs, to bring uniformity in national grid codes and market codes for Europe. This led to the development of European grid codes and market codes, which intrinsically include wind power generation. The market codes are outside of the scope of this article, so only the grid codes are addressed here.

Two documents drafted by ENTSO-E, that are relevant in the context of this article, have been published: The ENTSO-E Network Code Requirements for Generators[3], hereafter referred to as ENTSO-E NC RfG was published in 2012. The ENTSO-E Network Code High Voltage Direct Current[4], hereafter referred to as ENTSO-E NC HVDC was published in 2014.

ENTSO-E NC RfG and ENTSO-E NC HVDC came into force as European Commission Regulation in 2016, serving as a framework for individual TSO grid codes, of which many currently are in an adaption process, to align with the European regulation.

The two ENTSO-E documents ENTSO-E NC RfG and ENTSO-E NC HVDC are coherent, giving very similar requirements for electrical power sources with an AC or DC connection. The main difference between them is that DC-connected generation must withstand fast rates of change of frequency (2 Hz within 1 s)[4], which may be expected in DC-connected low-inertia offshore AC cluster grids. Quantitative specification of the RoCoF withstanding capability is left to TSO level for AC-connected generation. However, the similarity of requirements is sometimes criticised for imposing requirements offshore, which only would be needed onshore.

Operational Range

Grid codes specify a normal operation range for both voltage and frequency, in which stable operation is required. *Power Generating Modules* are required to remain connected and operational during specifically defined variations in frequency and voltage at the *Connection Point*. The grid code specifies this range, with minimum times specified before the generator is allowed to disconnect, depending on the frequency and voltage deviation from the nominal value. ENTSO-E NC RfG gives minimum times for each synchronous area, but permit, in

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some cases, that the relevant TSO can locally demand longer durations.

Operational Frequency Range

The minimal frequency operational ranges for the five synchronous areas - Ireland, Great Britain, Baltic (Estonia, Latvia and Lithuania), Nordic (East Denmark, Finland, Norway and Sweden) and Continental - in Europe are given in Figure 3.

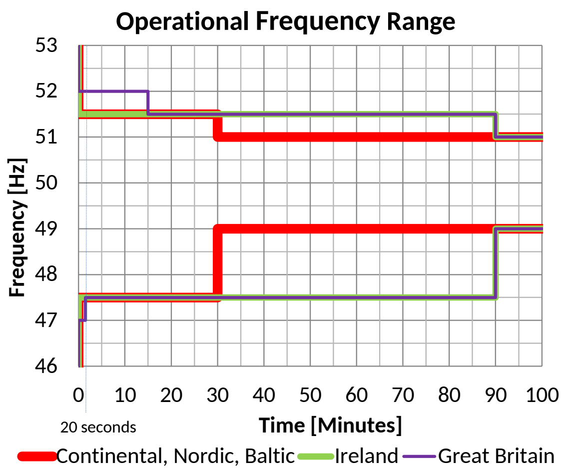

Figure 3: Operational frequency range

Operational Voltage Range

The minimal voltage operational ranges for the five synchronous areas are given in Figure 4a for system voltage levels below 300 kV and in Figure 4b for system voltage levels of 300 kV and above. The voltage range specifically for offshore power park modules are given as separate tables in[3], but they are mostly identical to the onshore values. The main difference is that the upper voltage level in Ireland is always 1.1 pu offshore, while onshore it is 1.118 pu for $U \leq 300\,\mathrm{kV}$ and 1.05 pu for $U \geq 300\,\mathrm{kV}$.

Which of the two figures is valid for a voltage level of exactly 300 kV is not clearly specified in[3], so the form of presentation here is merely an interpretation of the authors.

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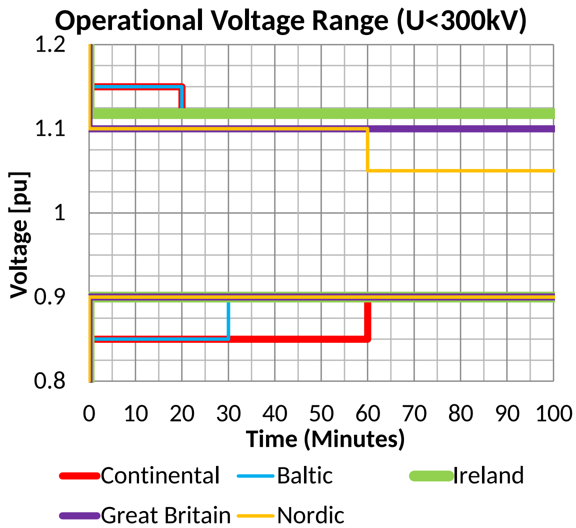
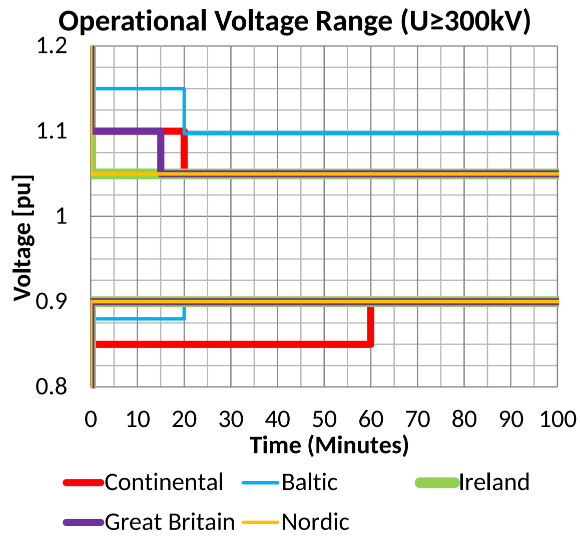


(a) Operational voltage range (U < 300 kV)



(b) Operational voltage range (U ≥ 300 kV)

Figure 4: Summary of operational voltage ranges

Reactive Power Provision

Reactive power capability is essential in order to control the voltage locally across an electricity grid. A voltage drop over the lines towards a node can be compensated for by an increase in reactive power export (or reduction of import) from the node through these lines, while a rise in voltage can be compensated for by a reduction in reactive power export (or increase of import). Grid codes may, therefore, require reactive power control capability for large generators such that they contribute to local short-term voltage stability (as defined in[12]).

U-Q characteristic

Requirements for reactive power capability at maximum active power capacity at different voltage levels are specified through a $U-Q$ profile, as shown in Figure 5a. ENTSO-E defines the outer envelope (black, dashed), but leaves the specific definition of the inner envelope (blue) to the relevant TSO, such that this inner envelope may be located anywhere within the outer envelope. A *Power Park Module* must therefore be capable of providing reactive power for a range *inside* the inner envelope of the $U-Q$ profile. The inner blue $U-Q$ profile can take on different shapes that vary from area to area, but it is always restricted by the fixed

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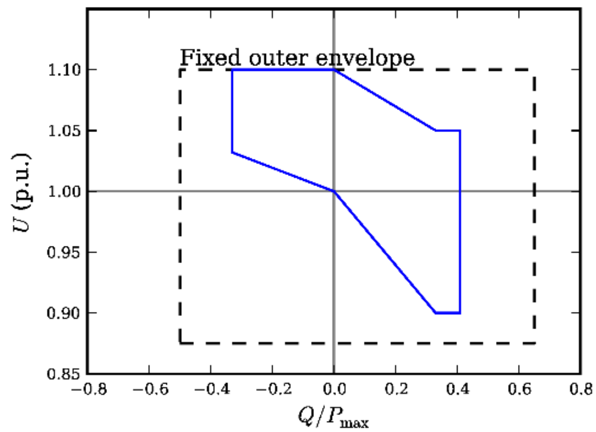
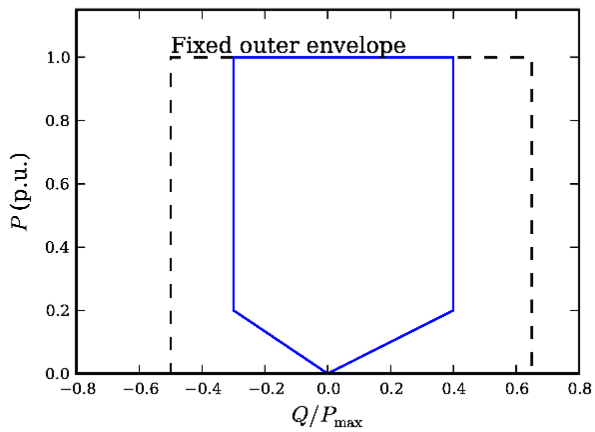


(a) Reactive power capability depending on voltage[13]



(b) Reactive power capability depending on active power[13]

Figure 5: Reactive power capability

outer envelope given in[3] and[4]. The blue profile shown here is an example from the TenneT grid code for German *Offshore Power Park Modules*[13] (Offshore wind power plants).

The blue characteristic in Figure 5a has a 'diagonal' shape, which can be intuitively understood to be useful, i.e. at very high voltages reactive consumption capability is mostly demanded, while at very low voltages reactive production capability is mostly demanded.

The rectangular shape of the fixed outer envelope given in ENTSO-E NC RfG can be challenging to satisfy, as, for example, it potentially requires 0.65 pu reactive power production at 1.1 pu voltage at the point of common coupling, which can lead to even higher voltages within the wind power plant. Such a requirement could impose significant extra costs for a wind power plant, while the value of such capability (reactive power production during an over-voltage) is not obvious. Similar considerations can be made for reactive power consumption during under-voltages.

P-Q characteristic

The requirements for reactive power capability below maximum active power capacity are similarly specified by a $P-Q$ profile, as shown in Figure 5b. The blue profile is again an example showing the requirement from the TenneT grid code for German *Offshore Power*

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Park Modules[13].

The outer envelope given by ENTSO-E enables the TSOs to require large reactive power injection or absorption at zero active power. This may cause significant extra costs for wind power plants which operate at zero active power for a significant share of the time (when there is no or very little wind). Supplying reactive power during a becalmed condition would imply that the wind power plant becomes a consumer, since reactive power provision implies power losses. For photovoltaics, such a requirement would be even more severe, due to the larger share of zero-active power operation (every night).

Active Power Frequency Response

The frequency in a power system depends on the balance between power production and consumption on a system-wide scale. A shortage of power production will cause the frequency to fall, while an excess of power production will cause the frequency to rise.

Active power frequency response (frequency containment) is defined as an automatic adjustment of active power output in response to a change in system frequency from the nominal frequency. The purpose of such capability is to support a stable system frequency, increasing power output when the frequency is low and/or decreasing power output when the frequency is high.

Limited Frequency Sensitivity Mode – Overfrequency (LFSM-O)

LFSM–O represents a Power Generating Module operating mode which will result in an active power output reduction in response to a change in system frequency above a certain value[3]. Such capability is required in ENTSO-E NC RfG, which implies the capability to operate at reduced active power during an over-frequency event, as shown in Figure 6a.

Requesting a (temporary) reduction in power output theoretically gives economic losses to the wind power plant owner since the primary energy source (wind) cannot be (conveniently) stored. However, events when LFSM-O is likely to be activated are assumed to appear rarely, and are usually not of long duration. The total energy not harvested (and also the economic losses) due to LFSM-O are therefore considered to be insignificant. On the other hand, the

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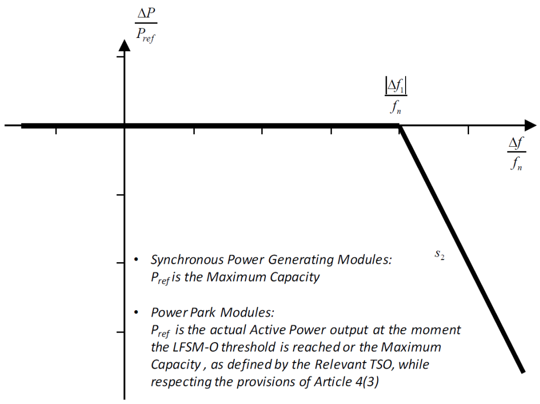
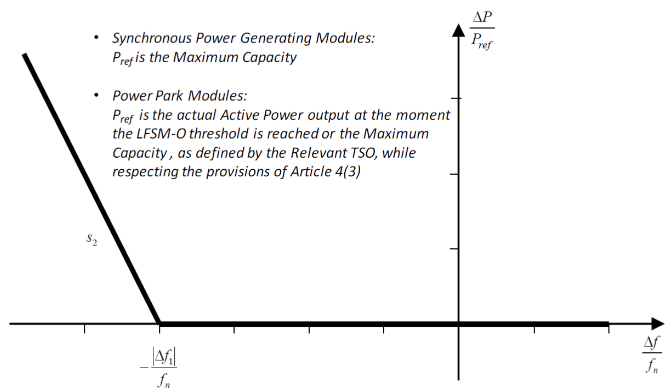


(a) Active Power Frequency Response in LFSM-O[3]



(b) Active Power Frequency Response in LFSM-U[3]

Figure 6: Active Power Frequency Response capability[3]

value given to system stability can be immense, including a reduction in 'negative' reserve requirements from conventional generation.

Limited Frequency Sensitivity Mode – Underfrequency (LFSM-U)

LFSM–U represents a Power Generating Module operating mode which will result in an active power output increase in response to a fall in system frequency beyond a certain value[3]. LFSM–U capability is required in ENTSO-E NC RfG for large *power generating modules*, which implies the possibility of operating at increased active power during under-frequency events, as shown in Figure 6b.

Provision by wind power plants

At present, wind power plants are typically not required to participate in LFSM-U, even though the capability is available. LFSM-U is usually performed by conventional power plants, but not by wind power plants.

At low-medium wind speeds (which is below rated wind speed: $v < 12\,\mathrm{m/s}$), wind turbines are usually operated to harvest as much energy as possible, adopting maximum power point tracking. At higher wind speeds (which is above rated wind speed: $v > 12\,\mathrm{m/s}$), they are usually operated at fixed (maximum) power output. In both cases, a (sustained) increase in

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the active power setpoint is not possible, indicating that there is no margin for under-frequency support (LFSM–U).

However, this is no different from a conventional plant operating at full output. It should be understood that it is possible to provide LFSM-U on a wind power plant, just not with the normal operational scheme. In fact, wind power plants can provide a faster response than most conventional power plants, since the thermal (i.e. steam-based generation) stress issues are much less severe. However, changing the operational scheme, to enable for upward regulation has considerable economic impacts as discussed below.

Economic aspects

A steady-state increase in wind power plant output, when the frequency is low, requires the turbines to have been curtailed in advance. Such an approach would reduce the energy extracted from the wind and therefore increase the Levelised Cost of Energy (LCoE) for that wind power plant. CO_2 emissions would also tend to increase, given that the energy not harvested would be produced by other power stations. Hence, the LFSM-U operational scheme is not normally adapted for wind power plants.

If such capability were to be utilised when power market prices were high, it would lead to significant economic losses, as some of the available energy in the wind was not being harvested (except in those rare occasions when LFSM-U is fully activated). However, if wind turbines only provide under-frequency support when there are no cheaper alternatives available, and/or network loading restrictions or stability considerations require curtailment of wind power, then the economic losses from reduced production are typically very low. Furthermore, when frequency reserves are procured through markets, wind turbine operators have the ability to recoup these economic losses through the frequency control market – otherwise they would not have made the offer in the first place. It can also be advantageous to employ wind turbines for under-frequency support when this enables thermal power plants to be shut down that would otherwise have only been required to provide frequency support: cost reduction, fuel savings and reduced CO_2 emissions are the resulting benefits[14] .

The importance of frequency support from wind power plants is expected to grow due to the steadily increasing share of wind power in the total generation portfolio. There are

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likely to be more frequent situations when frequency support from wind power plants will be appropriate, especially since variable power sources, such as wind power, increase the need for longer-term frequency support (load following and ramping). Including LFSM-U participation will become a necessity when aiming for a 100 % sustainable power supply.

The role of forecasts

From an operational point of view, forecasting wind power production is a crucial aspect in the provision of frequency support[15]. However, while the inclusion of such forecasts directly into the control systems of the wind power plants is technically possible, they are not usually incorporated in practice.

From an upward reserve perspective, wind power forecasts are important mostly in a specific region of system operation. So, when there is sufficient thermal generation online, it is more cost efficient to also utilise these thermal power plants for upward reserves.

Similarly, when there is a high confidence in a sufficient surplus of variable power generation (being curtailed), forecast errors cease to matter as there will be enough curtailed wind power to provide the allocated upward reserves in any event. Hence, forecast uncertainty is important when 1) wind power takes a full or partial responsibility for supplying upward reserves and 2) there is a reasonable chance for no or only small curtailments, so the curtailed wind power will not be enough to provide the allocated upward reserves. Cost savings could result if regulations recognised the operation-dependent relevance of forecast uncertainty.

An important aspect when providing under-frequency support is an estimation of the available power, to assess the amount of available reserves[16] and the power output when curtailment (or down-regulated operation) is released. Several countries have included guidelines on how to estimate the available power. They range from rather simple approaches, such as in the UK, where the total available power is equal to the sum of the individual wind turbine available power SCADA signals[17] to rather detailed methods, as set out by EirGrid and SONI[18]. Similar guidelines are in place in Denmark[19], and Germany[20]. In general, these methods are still subject to improvement, with new approaches being developed (e.g.[16]).

One of the main barriers against the actual delivery of frequency support services from wind power is the manner by which those services are acquired. The methodologies for

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pre-qualification can be highly disadvantageous for wind power plants. For example, with current practice based on schedules, wind power would have to operate in a down-regulated mode, such that it could cover for the uncertainty induced by forecasting systems. Additionally, both the proof of concept and time horizon for service activation and delivery would require change, taking into account the stochastic nature of wind speed, so that wind power could fully contribute. Furthermore, methods for estimating the available (uncurtailed) power need to improve in order to create a sufficient level of confidence that the offered reserve can actually be delivered.

The Irish example

The Irish grid (Republic of Ireland and Northern Ireland) represents a small synchronous zone, which implies that frequency control is generally more challenging compared to larger grids. Only here, within Europe, are both LFSM-O and LFSM-U already adopted within the respective grid codes[21], although to date LFSM-U capability has not been actively deployed for wind turbines. The Irish frequency response characteristic is shown in Figure 7, where points A-E are configurable. The upper left dashed blue line represents LFSM-U, while the lower right dashed blue line represents LFSM-O.

The larger synchronous zones will likely experience similar challenges as Ireland with a delay, making it attractive to have a close look at the Irish experiences. It is therefore entirely plausible that other countries might follow the Irish grid code example in the future.

Fault Ride-Through Requirements

Fault Ride-Through (FRT) capability refers to the ability of a *Power Generating Module* to remain connected to the power system during short periods of under-voltage or over-voltage. FRT requirements were developed to prevent large area voltage collapses in the grid, and since its introduction, grid stability has been largely improved. Figure 8 shows the strong correlation between the number of wind power plants without FRT capability and the volume of infeed losses from disconnecting wind power plants in Spain (based on public data from REE and AEE).

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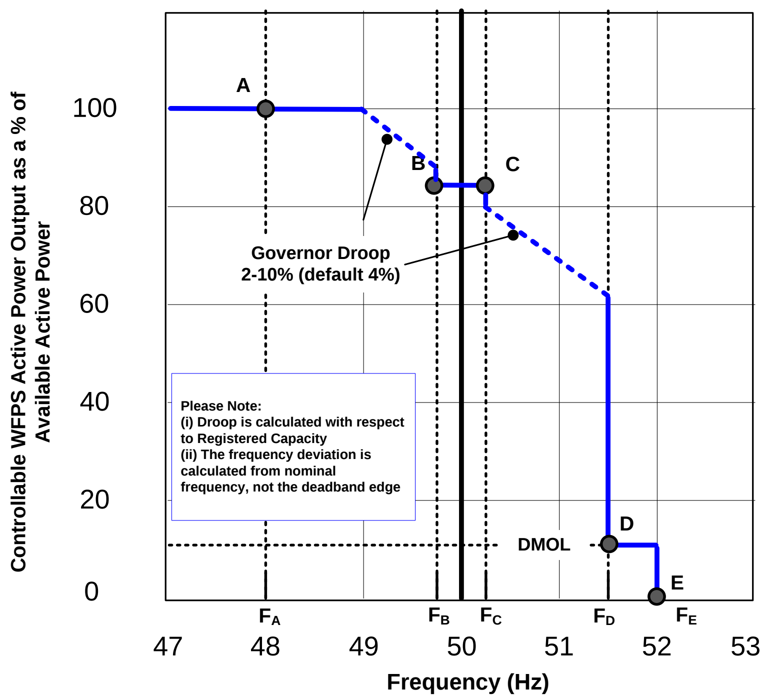

Figure 7: Example of Active Power Frequency Response curve[21] (WFPS = Wind Farm Power Station)

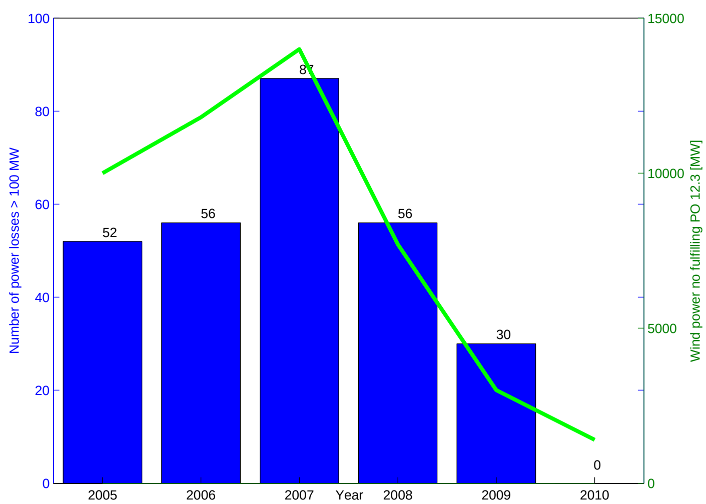

Figure 8: Effect of FRT capability in Spain

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An interesting discussion regarding European harmonisation of FRT requirements can be found in[22].

Under-Voltage Fault Ride-Through Capability

A *voltage dip* represents a sudden reduction of the voltage at a particular point in the electricity system, below a specified threshold, followed by its later recovery. The primary cause of voltage dips are short circuits occurring "nearby" in the power system (nearby not directly depending on geographic distance but rather on grid impedance). Switching by large loads, starting of large motors and, in some cases, variable loads (e.g. arc furnaces) can also be the root cause. Statistical data on real voltage dips in wind power plants can be found, for example, in[23].

The under-voltage ride-through capability is specified in ENTSO-E NC RfG via a generic FRT curve and accompanying tables with ranges of the specific parameter values. The two boundary FRT curves, which are defined by the limiting values of the parameter ranges, are shown in Figure 9.

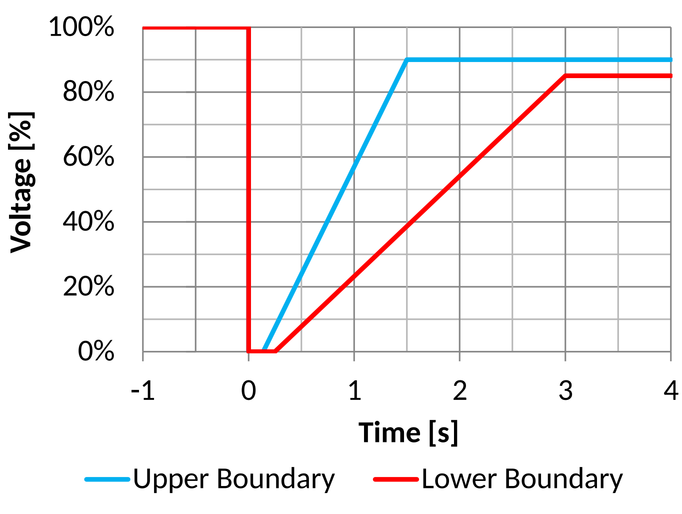

Figure 9: Envelope of under-voltage fault ride-through capability requirements

The two lines in Figure 9 indicate the allowable range in the requirements specified by the relevant TSOs, although the shape of the required curve may vary from region to region. The exact characteristics can take into consideration regional or national particularities. For

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example, the voltage dip duration derives from the maximum activation time of distance protection according to general protection criteria, while the voltage dip recovery time depends on the under-voltage protection of conventional generation units. In some systems, such as Ireland, a minimum grid code FRT requirement is specified, while an ancillary service (fast post-fault active power recovery) incentivises enhanced recovery after the event[24,25].

The minimum voltage which must be reached to define the event as 'complete' is specified as 0.85 pu (for power park modules, not for synchronous power-generating modules), even though the minimum operational voltage is 0.90 pu in some synchronous areas. Consequently, the band between 0.85 pu and 0.90 pu is left undefined, such that it is not entirely clear how a power park module should behave when the fault event is over but the minimum operational voltage has not yet been reached. WindEurope, for example, has developed a proposal for addressing this gap[26]. Figure 9 has been drawn with the minimum operational voltage in a range between 0.85 pu and 0.90 pu.

Over-Voltage Fault Ride-Through Capability

Over-voltages are usually caused by switching off large loads. The subject of over-voltage faults is not addressed in ENTSO-E NC RfG, which might be due to the fact that overvoltage ride through capability is less important for system stability than undervoltage ride through capability.

As above, WindEurope, as an example, has developed a proposal for over-voltage requirements[13]. An example of how such a specification could be designed is given in Figure 10, which is taken from the specification for the Hydro Quebec (non-European) system[27].

Asymmetric Faults

Considering asymmetric faults is highly relevant for grid stability and operation. E.g. a single phase to ground fault can lead to high over-voltages on other phases, which might not be observed when only considering symmetric positive-sequence-voltage. Also a clear definition of symmetry and asymmetry is essential, as it is unlikely that real measurements

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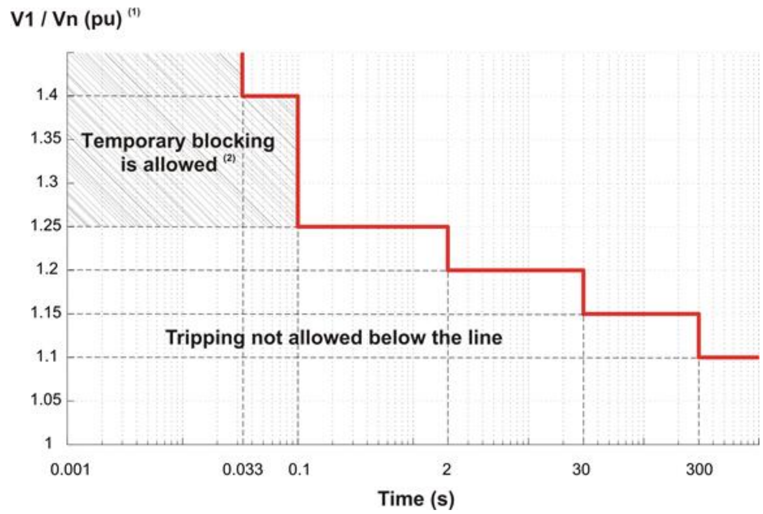

Figure 10: Over-voltage fault ride-through capability specification for Hydro Quebec system

on a three-phase system show perfect symmetry. It also needs to be considered, that the majority of faults are asymmetric.

On this topic, significant differences exist throughout Europe, making it difficult to find uniform European definitions and regulations. Asymmetric faults are mentioned in ENTSO-E NC RfG[3], but specification details are not covered in the European grid code framework in its present form. It would, therefore, be highly beneficial if a future revision of ENTSO-E NC RfG could include detailed specifications for asymmetric faults.

Behaviour during a Fault

The favoured way for expressing desirable wind turbine behaviour during a fault event is to specify requirements for active and reactive current, since power is hard to assess and control during periods of fast changing voltages. It is, however, still more common to specify in terms of power instead of current.

ENTSO-E NC RfG specifies the severity of voltage dips for which a *Power Park Module* must 'remain connected to the network and continue to operate stably', but does not specify how the *Power Park Module* should behave during the event. By giving no specification beyond 'connected' and 'stable'[3], it theoretically opens the case for operation at zero current, which is stable but equivalent to disconnection and not desirable. A similar example from

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the USA is the relay standard NERC PRC-024-1, which only requires plants to have their primary protective relays set such that they do not cause the plant to trip within the 'no trip zone'. It is not a performance standard, which requires the plants to actually ride through the disturbance.

It is, therefore, clear that TSOs must have and do have behavioural requirements for their network area. These TSO-specific requirements vary significantly across the different grid codes, creating a strongly heterogeneous picture across Europe.

However, reactive current injection (for voltage support and increasing fault current level) is a rather common requirement, but the details are subject to large variations, such as prioritising active current, reactive current, or power factor. Another relevant issue, which still lacks harmonisation, is the desired behaviour if the voltage dip is more severe than specified for ride-through. In such a case, is the wind power plant allowed to disconnect, encouraged to disconnect, or obliged to disconnect?

Generally, these requirements can be challenging to fulfil for wind power plants, especially when turbines without a full power converter are employed. Consequently, the implementation details become highly relevant for wind power. However, these detail differ significantly between TSO areas, making it even more challenging for wind turbine manufacturers, and complicating the European grid code harmonisation process. At present, the specification of the behaviour during the fault is not directly covered in ENTSO-E NC RfG[3].

Post-Fault Ramp Rates

ENTSO-E NC RfG states that post-fault ramping rates are TSO-specific, while not stating minimum requirements. The ramp rates are therefore treated as a local issue, which may not be an effective approach, as overall system stability can be affected, e.g. voltage dip induced frequency dips[28]. There are large variations between the approaches taken by the different European TSOs, ranging from recovering active power as quickly as possible, subject to local voltage recovery, as in Ireland[24], versus ramping up active power production in a slow and controlled manner[29]. In addition, particularly for scenarios with a large share of wind power (or other non-synchronous generation), rotor angle stability may become an issue, which have been studied for generic test systems and various types of offshore DC-connected Power Park

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Modules[30].

Sequential Faults

It is relevant to specify the duration of the minimum fault-free time after a fault, which needs to pass, before a new fault must be handled. If two faults appear within only a few seconds, ride-though of the second might be challenging, if the operational state has not yet recovered from the first fault.

Another important aspect is the number of faults that have to be handled during e.g. an hour, a day, a year or the life-time of the wind power plant. Even though two sequential faults with one minute in-between might be acceptable for a wind turbine, demanding the capability to operate through one fault per minute for the entire life-time might not be acceptable.

The recent (2016) blackout in South Australia has also raised the issue of a wind power plant's ability to survive multiple faults in a short period, with different manufacturers adopting different practices[31]. The subject or sequential faults and its various aspects has not been explicitly specified in ENTSO-E NC RfG in its present form.

Offshore Wind Definitions

Originally wind generation was located onshore and connected directly to the existing ac network. Nowadays, however, wind power plants are deployed also offshore in large scale, with a range of different configurations and connection arrangements being utilised.

Existing Definitions

ENTSO-E NC RfG and ENTSO-E NC HVDC adopt the following definitions:

Connection Point (CP) – the AC point in a network connecting equipment owned by two or more parties (. . .) at which technical specifications affecting the performance of the equipment (. . .) can be prescribed, at which the *Power Generating Module* is connected (. . .)

Offshore Connection Point (OCP) – a *Connection Point* located offshore.

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Power Park Module (PPM) – a unit or ensemble of units generating electricity, which is connected to the network non-synchronously or through power electronics, and has a single *Connection Point* (. . .)

DC-connected Power Park Module (DCcPPM) – a *Power Park Module* that is connected via one or more *Interface Point(s)* to one or more HVDC system(s).

Offshore Power Park Module (OPPM) – a *Power Park Module* located offshore with an *Offshore Connection Point*.

Using the above terminology, a wind power plant with multiple turbines, is considered as a *Power Park Module*.

Issues with the Location of the Connection Point

There are basically two competing philosophies when considering the offshore grid connection infrastructure:

- Grid connection infrastructure is part of the power plant
- Grid connection infrastructure is part of the power grid

Considering the grid connection infrastructure as part of the power plant is promoted with the argument that it enables an optimised arrangement for the wind power plant and grid connection, i.e. a lower wind power cost in the short run considering individual projects. It is supported by certain manufacturers and some developers involved in UK Round Three plans. The second approach argues that offshore HVDC systems should be governed by the TSOs, to pave the way towards future offshore HVDC grids. Many of the advantages of a future North Sea Super Grid have been identified and quantified, for example in[32], leading to lower wind power costs in the long run. This approach is supported by ENTSO-E, and is clearly proposed in[4].

In the UK, the situation becomes even more complicated, as the connection point is, to some extent, located both onshore at the so-called Transmission Interface Point (TIP)

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and offshore at the so-called Grid Entry Point (GEP). Furthermore, there is an Offshore Transmission Owner (OFTO) between the TSO and the offshore wind power plant owner.

This disagreement between the two competing philosophies has led to definitions of offshore power park modules and DC-connected power park modules that can be perceived to be confusing. An offshore wind power plant may, or may not, be regarded as an *Offshore Power Park Module*, since the *Connection Point* may, or may not, be located offshore. Many offshore wind power plants built to date employ an onshore *Connection Point*. A wind power plant with a HVDC connection may, or may not, be regarded as a *DC-connected Power Park Module*, since the *Connection Point* may, or may not, be located on the wind power plant side of the HVDC link. There are also plans for offshore wind power plants which include the HVDC link as part of the power plant, leading to a power plant that is not DC-connected.

Whether a power park module is said to be "offshore" or "DC-connected" is therefore not defined by the physical installation, but rather it depends on the details of the contracts between the TSO and WPP owner. Various arrangements are shown in Figure 11.

Missing Definitions

Offshore DC-connected Power Park Modules

Germany already has HVDC based *Offshore Connection Points* for wind power plants. So, for example, Bard Offshore 1[33] is the first *Power Park Module* which is both an *Offshore Power Park Module* and a *DC-connected Power Park Module*. The term *'Offshore DC-connected Power Park Module'* could be applied here, but it does not form part of the existing definitions. There are several other similar wind power plants in operation or under construction in German waters, which should also be considered as *'Offshore DC-connected Power Park Modules'*. The absence of the term makes it difficult to provide a clear categorisation of all grid-connected facilities.

DC Interface Points

Current grid codes consider only AC grids and AC interface points. However, the number of DC installations is steadily increasing, ranging from DC distribution concepts to offshore

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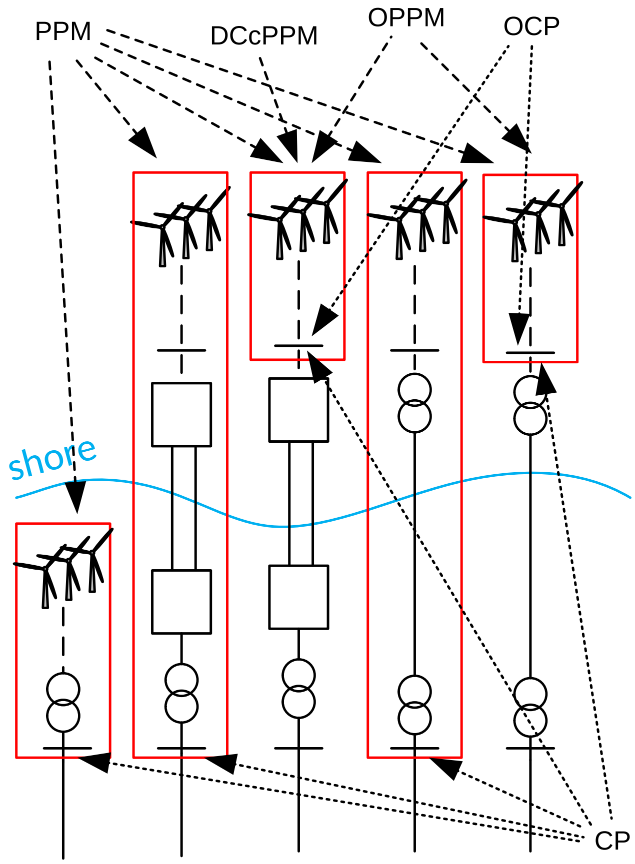

Figure 11: Overview of offshore wind definitions

HVDC grids. At present, all HVDC connected wind power plant projects plan to connect to the AC side of an offshore HVDC converter station, which has been specifically built for connecting wind power plants. However, limiting grid codes to cover connection to an *AC interface point* will in the long run be insufficient. In the future, newly built wind power plants could include a HVDC converter station, which connects to a *DC connection point*, following *DC grid codes*[34].

Possible Future Requirements

Fast Frequency Support

Frequency stability (especially during the first few seconds after an event, such as a power plant loss) in AC power systems is largely based on the inertia of the rotating electrical

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machines (generators and motors). An important system parameter is, therefore, the total inertia: the sum of the inertia of all directly grid connected machines. The total stored rotational energy, which can be needed in these first few seconds, is proportional to the total inertia.

The total online system inertia decreases when directly grid connected machines are displaced by "sinks" and "sources" with power converter interfaces. The likelihood and intensity of this occurring increases as the share of wind and solar power grows, and further HVDC connections are made to neighbouring systems, unless additional measures are taken[35,36]. There can exist dynamic limits regarding the extent to which non-synchronous sources (including photovoltaic generation and HVDC interconnections) can be used in synchronous systems, as they do not naturally provide (synchronous) inertia[37]. Fully converter-based AC systems (all grid connected assets have power converter interface, no classical rotating electrical machines), where the grid frequency is not linked to the rotational speed of machines, remain a challenge today. An example for a fully converter-based AC system is the Bard Offshore 1 wind power plant. This offshore wind power plant has seen significant technical difficulties, leading to long down-times[33 38 39 40 41]. The details on the experienced problems have not been published, making a detailed discussion impossible in the context of this article. However, these small converter-based AC island grids may offer a glimpse into the direction that large AC bulk power grids are slowly developing[42,43].

A power system with low inertia tends to see faster and deeper frequency fluctuations, and it may, therefore, have a need for fast frequency support mechanisms. As part of a possible future requirement for grid codes, a range of technical implementations have been proposed, all having in common that they result in a temporary increase in output power soon (immediately) after the system frequency is seen to significantly fall. Such an increase in power output can be problematic for dynamic frequency support, since non-overrated power electronic converters lack a short-term overload capability.

Inertia Emulation

The *inertia emulation* concept proposes that a power converter is controlled in such a way that it behaves as if it had inertia, in this case called virtual inertia. This requires a change

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in active power output, not based on the frequency deviation, but on the derivative of the frequency, also called the Rate of Change of Frequency (RoCoF). In order to realise a response that is similar to real synchronous inertia, the response characteristic needs to be implemented without a deadband.

Even though the concept is straightforward in theory, practical realisation faces some issues. The most prominent one is the fact that it is difficult to measure the RoCoF dynamically. The faster the measurement, the larger the superimposed noise will be, which will trigger strong undesirable responses from the virtual inertia. The measurement can be (low pass) filtered, but this significantly slows down the measurement, and therefore also delays the control response, which then negates the desire for an instantaneous response.

At the moment, the virtual inertia concept is mostly confined to academic interest, and it has not found its way into the wind industry. However, it has been discussed as a possible future requirement for grid codes, for example, in Spain[44].

Virtual Synchronous Machines

The problems associated with realising virtual inertia can be addressed using the virtual synchronous machine concept, whereby the mechanical component of the machine is modelled within the inverter controller[45]. Subsequently, an inertial response is automatically provided, while relying only on instantaneous voltage and current measurements (no derivative of the frequency necessary). The concept encompasses much more than emulating only inertia, but remains under development, and lies far away from standardisation and adoption into grid codes.

Fast Proportional Frequency Response

The challenges associated with virtual inertia and virtual synchronous machines have led to the development of fast proportional frequency support schemes, which aim to partially decrease the need for inertia. They can be of value in low-inertia systems and may reduce interest in maintaining high inertia levels with *inertia emulation* techniques. However, they cannot address inertia-less (100 % power electronics) systems. These so called fast proportional frequency support schemes (offered by wind turbine manufacturers) are typically based on

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the frequency deviation beyond an activation threshold. Consequently, not being based on the derivative of the frequency, they therefore do not actually emulate inertia. However, they are sometimes falsely advertised as 'inertia emulation', which leads to some confusion regarding use of the term.

Fast frequency support schemes could be defined in grid codes. However, the required capability can be extremely difficult to define if technology agnostic grid codes are seen as the goal, with alternative technologies, such as batteries and flywheels, also an option. Approaching the issue slightly differently, some systems, such as Ireland, are choosing to make fast frequency response an (optional) ancillary service rather than a grid code requirement, implying a 'carrot' rather than a 'stick' approach.

High Wind Extended Production Control

Wind turbines should be shut down during a severe storm to prevent damage. However, with the increasing size of wind turbines and wind power plants, the total installed wind power capacity within a small area, particularly for offshore wind farms, can become quite large. This is becoming a challenge, since a large number of nearby wind turbines (at full power capacity) could be affected by the storm within a short time frame, leading to a large-scale shut down.

The *High Wind Extended Production* concept implements a controlled ramp-down instead of an instantaneous shut-down of wind power plants during storm conditions. Such an approach can be highly beneficial for power grid balancing controllers, as there will be additional time for the secondary controllers (frequency restoration) to be activated, reducing the impact on primary control (frequency containment). *High Wind Extended Production* is an elegant feature, making the power output of wind power plants more controllable, predictable, and 'grid friendly'.

Some modern wind turbine models already offer *High Wind Extended Production* control. The first implementation was Enercon's Storm Control[46], and others followed, such as Siemens' High Wind Ride Through[47]. A requirement for *High Wind Extended Production* control in grid codes would be beneficial for grid stability and may appear in the future. So far, only the Danish grid code[48] includes an active power control requirement for wind power plants up

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to 25 MW (shown in Figure 12), requiring the possibility to continuously downward regulate their active power production to an arbitrary value in the interval from 100 % to at least 40 % of rated power.

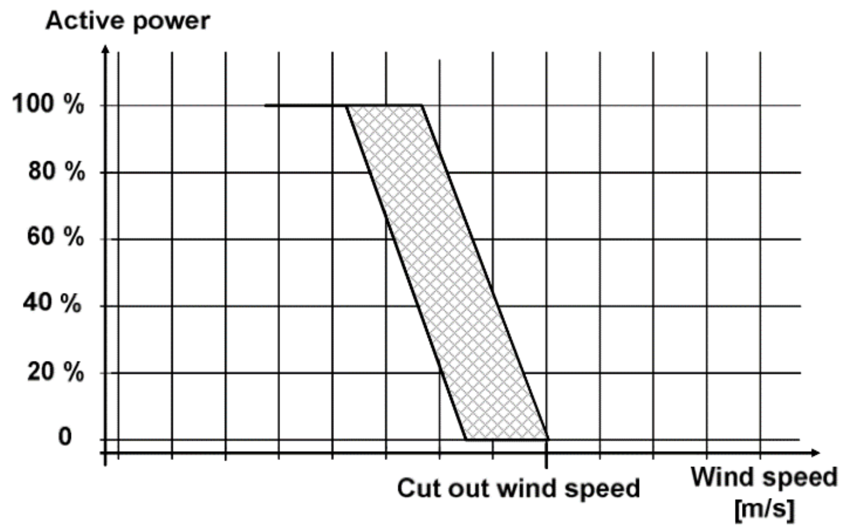

Figure 12: Downward regulation of active power at high wind speeds in Denmark[48]

High Wind Extended Production control can be defined either statically (limiting the power-wind speed gradient) or dynamically (limiting the power-time gradient). The static definition does not directly limit the dynamic power ramp rates, but it does indirectly reduce them in an efficient way[49].

Harmonics

An issue which, until now, has received little attention is harmonics created by a wind power plant (or any other *power park module*). All power electronic converters involve switching operations, which introduce harmonics, and the increasing share of electrical devices with a converter interface indicates the growing importance of carefully addressing issues related to harmonics, such as overheating of components.

The first *offshore power park module*, 'Bard Offshore 1' in Germany, connects to the offshore HVDC converter station 'BorWin Alpha', which forms part of the HVDC link 'BorWin 1'[33]. The wind power plant together with the AC side of the HVDC converter

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station creates an isolated offshore AC island grid. This pioneer project has faced significant technical difficulties (e.g. components catching fire), which have been at least partly caused by harmonic issues[33,38–41].

It has, therefore, become increasingly important to specify clear rules concerning harmonics, to be able to define the cause of a technical disturbance (wind power plant or HVDC converter) and to avoid a repetition of similar problems. Harmonic modelling of wind turbines is currently being addressed (among other groups) by the IEC[50]. However, the process will be difficult, as many HVDC connected wind power plants with isolated AC island grids are currently in the pipeline, of which many will be operational before an adaptation of the grid codes can be put in place. A likely consequence will be retrospective requirements with their associated costs.

Discussion

When creating the 'ideal grid code', several important trade-offs are key, making it difficult to clearly define the ideal design. The 'ideal grid code' would offer the (long-term) technical and economic optimum for the entire electrical power system, including the grid, the power plants and the loads.

TSO vs. Wind Industry Perspectives

Strict grid code requirements may require additional equipment to be installed at the wind power plant or within each turbine, which potentially implies extra cost for a given wind power plant project, but at the same time reduce grid operating costs through the additional performances of the wind power plants which are gained through the requirements.

Unneccessarily strict requirements, where the benefit of the demanded capabilities is less than the implied costs, can increase the cost for society as a whole. An example where consideration is needed is reactive power provision, treated in subsection *U-Q characteristic*. Provision of reactive power during an over-voltage, and consumption of reactive power during an under-voltage both introduce significant costs, while the operational benefit of these capabilities can be questioned.

On the other hand, too soft requirements can increase grid operation costs more than

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the achieved cost saving for the wind power plant. An example is the underfrequency disconnection of wind power plants, as described in subsection *Historic Development*.

Posing unneccessary costly requirements on wind power plants is just as undesirable as paying high system operation cost due to important performances missing in wind power plants. Requirements should always consider the associated (upfront) costs and (long-term) benefits. If the strictness of the requirements is well justified, placing those extra costs on the wind power plant planner may lead to the lowest socio-economic cost for renewable energy.

The ideal grid code should aim for the lowest total cost for society. A challenge for achieving such a goal is the fact that the involved stakeholders tend to seek the lowest total cost, or maximum profitability, for themselves. In theory, it would be desirable for the TSOs if every wind power plant would also supply UPS and STATCOM capabilities at all times, while for the wind industry it would be better to have no requirements at all. Both of these extreme cases are surely not the socio-economic optimum, but where the optimum really lies is difficult to judge, particularly considering the operational life time of electric infrastructure projects. However, both parties share the common interests of a stable and reliable power system, further growth of the share of sustainable energy and continuing public support for the 'Energiewende', and there is an ongoing dialogue between the stakeholders.

Harmonisation vs. Custom-Made Regional Codes

Electric power system parameters, such as short circuit current level, and operational & control regimes can differ significantly from country to country and from region to region. Hence, there can be benefits (even necessities) associated with custom-made grid codes, which take these local peculiarities into account. Tailor-made regional grid codes have the advantage that the most restrictive grid code requirements from the most critical regions do not need to be fulfilled in other regions where such strict rules are not necessary.

However, maintaining a variety of different local grid codes also introduces extra costs. The international wind power industry needs to recognise all the different codes, which can be time consuming. Developing specific products for fulfilling region-specific requirements counteracts the benefits of mass production, while developing 'universal' products may include costly features that may not be needed everywhere. Offshore wind power plants also bring

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more complexity, and the question arises as to how different/similar offshore vs. onshore requirements should be?

The academic world, which often uses generic approaches (e.g. models, controllers,...) when developing new technical concepts, has a significant challenge regarding grid code compliance issues. A new technical concept must of course be designed in a way that grid code compliance can be achieved, but as the geographic location is mostly not relevant during the concept phase, a generic approach towards grid code compliance would be needed. Real grid codes, which are specific to a single TSO region form a poor basis for assessment of new technological concepts. The academic research would therefore significantly benefit from harmonisation.

Again, the ideal grid code should seek the lowest total cost for society. The benefits for custom-made regional codes should be weighed against the challenges induced by regional differences in grid codes. This is not an easy task, since identifying the (long-term) costs for all stakeholders coping with a large array of different grid codes is almost impossible to quantify. Recent political developments in Europe (e.g. Brexit) have shown that the ambition level of European harmonisation in general also changes over time, which might be also influencing grid code harmonisation efforts.

However, many of the differences between the different TSO grid codes cannot be justified by the regional peculiarities of the electric power grid, but rather they originate from independent (historical) national grid code development processes. For example, the time dependent frequency and voltage operational ranges across different synchronous zones (section *Operational Range*) may present a good example, whereby some of the regional differences do not offer (sufficient) regional benefits. Regional differences can (in many cases) be accounted for through uniform grid code requirements containing regional parameter values. Such a structured approach, which removes most of the disadvantages while maintaining most of the benefits, has been considered in ENTSO-E, and ENTSO-E NC RfG[3] shows a very good first step in the right direction.

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Local vs. Global

Grid voltage is a rather local phenomenon, while the grid frequency is a global measure (besides power system oscillations leading to regional short-term frequency deviations). Every grid connected asset influences the voltage and frequency, and therefore the local and global states of the power system. Grid codes, therefore, need to take both aspects into account, and in the case of a conflict, a well-considered trade-off needs to be found. One prominent example is reactive current provision during faults (subsection *Behaviour during a Fault*), which may be in conflict with active current provision, due to converter limitations. Different stakeholders (TSO, DSO), with different areas of responsibility, may have conflicting desires regarding the prioritisation of local and global phenomena.

Grid Code Requirement vs. Ancillary Service Markets

Any service provision usually has associated costs, which can be split into two categories: the (capital) cost for possessing the capability and the (operational) cost for actually performing the service. Some capabilities are costly to possess but almost free to utilise (e.g. reactive current provision during faults (subsection *Behaviour during a Fault*). In contrast, other capabilities are straightforward to implement but can be costly to utilise (e.g. maintaining an active power margin for upward frequency control (subsection *Limited Frequency Sensitivity Mode – Underfrequency (LFSM-U)*). Consequently, operational practice and frequency of activation of service should be considered when evaluating the need for grid code changes.

Capabilities

When it comes to capabilities, where significant capital costs occur just for incorporating such capability (usually investment in extra equipment), a market solution may not be straightforward to achieve[14,15], particularly if some services must be supplied locally. Furthermore, creating incentives for investment in (new) capabilities via a service market is challenging, since it can be difficult to forecast and 'bank' the expected revenues created by offering such services. Risk-adverse thinking will likely lead to an underinvestment in

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capabilities, and hence motivation for following a grid code 'enforcement' route.

Services

When it comes to the utilisation of existing capabilities for performing a service, a market solution can be the appropriate tool to find the least-costly resources to supply the needed performance. This is especially relevant for capabilities that focus on normal operation phenomena, such as steady state reactive power provision. If a market-based solution is chosen, it should provide a level playing field for all market players at the location where the reactive power is needed, whereby implicit or explicit bias towards certain technologies are avoided. However, it needs to be considered that developing, implementing, running and supervising a market also creates significant costs, especially for local phenomena like reactive power provision. When specifying smaller details with rather low costs, or specific services which are only needed on rare occasions, it should be questioned whether the market costs can be compensated for by the savings achieved by the market solution.

It makes sense, therefore, to demand that all services which do not create a significant extra operational cost, but which do improve grid operation, as being mandatory in grid codes (e.g. reactive current provision during faults (subsection *Behaviour during a Fault*). This is especially relevant for those services that are required to cope with low-probability high-impact disturbances. However, considering services that do cause relevant additional operational costs for the wind power plant, it needs to be robustly considered if they should be incorporated in grid codes (e.g. maintaining an active power margin for upward primary frequency control (subsection *Limited Frequency Sensitivity Mode – Underfrequency (LFSM-U)*)[15].

Again, the most relevant aspect for this discussion is to achieve the lowest total cost for society. Providing ancillary services also from renewable power plants can contribute to an overall decrease in system costs. These achievable savings have been estimated to be in the order of a few percentages[51]. However, focussing on this main goal can be challenging, with involved stakeholders actively working to achieve the lowest cost (or highest ancillary service market revenue) for themselves, at a higher total cost for society.

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Progress vs. Planning Reliability

All three components of the electric power system, the grid, the power plants and the loads are in permanent evolution. The 'Energiewende' and the liberalisation of the electric power markets have caused and continue to cause significant changes in recent years. It can be intuitively understood that an evolving grid also needs evolving grid codes. In the theoretical most progressive case, grid codes would be constantly subject to change, to always adapt to the recent developments of the electric power system. Such changes would affect all grid assets. However, making and changing grid codes is a rather time-consuming process, especially at a multi-national level, which has, until now, prevented quickly changing grid code requirements, and is likely to continue so in the future.

These slow processes of changing grid codes also have their positive side. Even though constant grid code evolution might be ideal, considering the ability to adapt, it would introduce severe challenges for all stakeholders, who need to interact with grid codes. A non-static environment makes the development process of future grid assets more challenging and somewhat unpredictable. Predictability and planning reliability are highly important and, for example, a wind turbine manufacturer may have severe problems to develop a product when the relevant codes, that need to be complied with, change during the development process. Similarly, investment decisions for developers becomes more challenging when upfront costs and future revenue streams are less certain. In both cases, additional cost is introduced, which in the end society has to pay.

Even more problems occur when the changes also affect existing assets. High retro-fitting costs can occur, due to regulation changes that also include existing assets, and modifications are required after commissioning. Such interventions are usually a clear indication of short-sighted thinking in the past, leading to oversights in past regulations, as experienced, for example, with solar-power in Germany (subsection *Historic Development*).

The best means to avoid the above mentioned problems is to require capabilities before they are needed, so called 'future proofing'. Some capabilities and services might not be as important today, but might gain relevance in the future, particularly given the likely plant life of individual installations. Demanding performances, whose relevance in the future can

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be foreseen, avoids the need to change regulations later (at a higher cost). However, it comes at the price of today demanding services and capabilities that are not needed at the moment. Due to future uncertainty, security concerns may lead to mandatory capability requirements today, just because the demanded capabilities might become important one day. In the worst case, this can lead to requirements that never serve any purpose, or universal obligations when local requirements would have sufficed. To avoid this from happening, detailed studies should be performed before defining requirements.

Again, the most relevant aspect for discussion is how to achieve the lowest total cost for society. This is a challenging trade-off to make, since the ideal solution depends on an uncertain future.

Long-Term Progress vs. Backward Compatibility

The power systems of today are built and operated around the strengths and limitations of steam- and hydropower-turbines, synchronous machine designs and their control systems. Dynamic behaviour has traditionally not been addressed in detail within grid codes, as much was implied by the physical properties and response times of the power plants. Only some aspects have been subject to specifications, such as fault-ride-through characteristics and primary frequency control response times.

However, power electronic converters do not, in general, provide a uniform and 'grid-friendly' dynamic response. Their dynamic behaviour is mostly determined by sophisticated control systems, which can vary significantly between manufacturers, which may consist of many operational modes, and which are generally unknown (or only partially known) to the TSO. The larger the share from power electronic converters relative to other grid assets, such as synchronous generators, the more important becomes the regulation of the dynamic behaviour: the *inertia emulation* concept and *virtual synchronous machine* concept have, for example, been discussed in this article (section *Fast Frequency Support*).

The question can be raised whether emulation of synchronous machines is actually a desirable way to go in the long run? It might be a good and convenient work-around for the short and medium term future, when significant shares of non-synchronous generation will be connected to a system with operational principles designed for synchronous machines. But,

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DOI: 10.1002/wene.28

maybe, in the longer run, it is not appropriate to operate power converter dominated systems with an ancient operation regime developed for synchronous machine dominated systems. In former times, “mechanical” control systems were gradually replaced by “electronic” control systems, in many domains, and the “features” of those mechanical systems, such as time lags, were often incorporated in the new electronic systems, which clearly offered the advantage of “familiarity”, but also severely underplayed the advantages and capabilities of the “new” electronic technology.

Electric power systems are one of the largest and most complex systems that mankind has created, so introducing radical change is a real challenge, while still maintaining system security, stability and reliability of supply. Considering the enormous value of the existing assets, backward compatibility is very important, but visionary thinking should still be an option, as a guide for the future direction.

Technology Neutrality vs. Technology Consideration

Technology-neutral grid codes have the advantage of simplicity, theoretically providing a level playing field for all technologies to compete. Reality, however, shows that particular specifications may very much not be technology-neutral, as some technologies might have capabilities that are demanded, while other technologies might have different capabilities, which are not 'valued' or excluded by the regulations. Electric power sources without moving mechanical components (e.g. photovoltaics) have much shorter time constants than other power sources, introducing both advantages and disadvantages. Regulation can be theoretically technology-neutral, but still, at the same time be very technology-discriminating. It is easy to design requirements which are almost impossible to fulfil for an electrical machine, but be readily achievable for a power converter (e.g. demanding per-phase response for asymmetrical faults). On the other hand, there may be requirements which are almost impossible to fulfil for a power converter, but achievable for an electrical machine (e.g. demanding high short circuit current provision).

Generally, existing grid codes have been written with steam turbines and synchronous machines in mind, and they can, in reality, be discriminating towards other power sources, even though they are envisaged as being technology-neutral. However, there is a very large

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DOI: 10.1002/wene.28

variety of available technologies, and considering them one by one in grid codes would create tremendous efforts and disrupt a goal of simplicity. It is, therefore, important to achieve the right trade-off. Such an approach is reflected in ENTSO-E NC RfG by the separation between *synchronous power generating modules* and *power park modules*.

Conclusions

There is a clear tendency towards stricter requirements for wind power plants, which is to some extent unavoidable, and even desirable, as the share of wind power in the generation mix is growing. Wind power plant developers and wind turbine manufacturers are, therefore, increasingly facing similar requirements to conventional power stations, based on synchronous generators. The development is not just a 'wind' issue, even though that might be the focus here, as photovoltaics and other sources will also need to supply system support services.

High Wind Extended Production is an elegant feature, making the power output of wind power plants more controllable and predictable, reducing power ramping rates, and therefore also the difficulties of power balancing, during critical weather situations. An *active power frequency response* can assist short-term power balancing. *Inertia emulation* is a 'hot topic' for making wind power plants more similar to synchronous generator based conventional power stations. An interesting concept in this context is the *virtual synchronous machine*, which could be a viable practical implementation for stricter future grid code requirements, which could contain specifications for dynamic behaviour. *Harmonics* related issues are especially relevant regarding HVDC-connected remote offshore wind power plants, but they are also gaining importance onshore.

The adaptation process of grid codes for wind power plants is not yet complete, and grid codes are expected to evolve further in the future. There is still room for improvement, especially concerning international harmonisation of requirements. The new European codes leave many key aspects unspecified, referring instead to regulation by the relevant TSO, but they do provide a positive and encouraging step in the right direction.

This is the accepted version of an article published in WIREs Energy and Environment
DOI: 10.1002/wene.28

Acknowledgements

We would like to thank Harald Svendsen, Atsede Endegnanew, Daniel Fraile, Nickie Menemenlis, Jody Dillon, Poul Ejnar Sorensen, Arjen van der Meer, Lluis Trilla, Lorenzo Zeni, John Olav Tande and Hannele Holttinen for input, comments and other support.

The activities resulting in this article were partly funded by:

- The project IRPWind funded by the European Union through the seventh framework programme
- The Centre for Environment-friendly Energy Research NOWITECH funded by the Research Council of Norway
- The project IEA WIND Task 25 – Phase 4 funded by the Danish Energy Authority under the EUPD programme.
- The project project ENE2016-78214-C2-1-R funded by the "Ministerio de Economía y Competitividad" and European Union (FEDER)

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