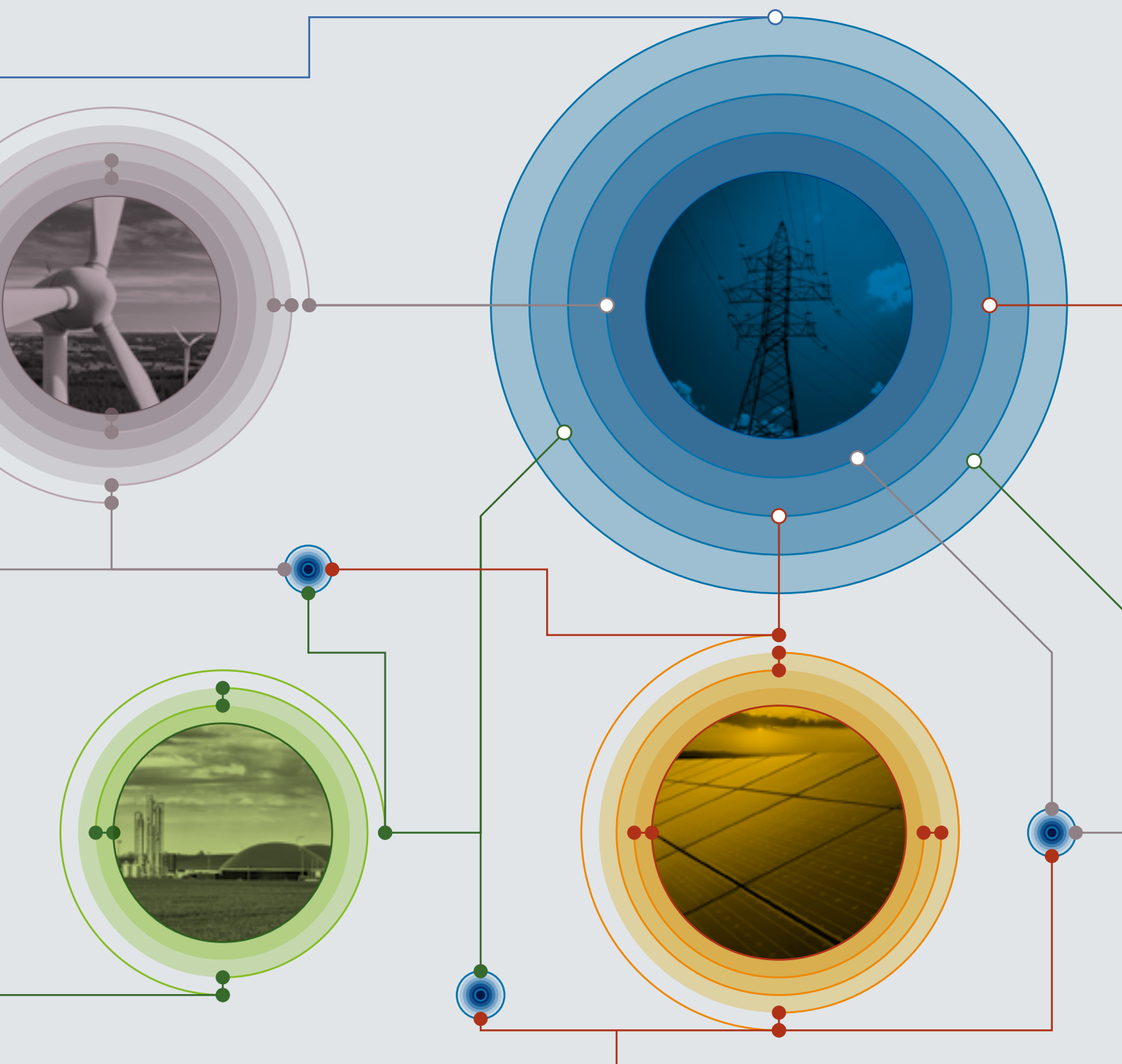


GRID CODES

FOR RENEWABLE POWERED SYSTEMS



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ABBREVIATIONS

AC	Alternating current	kV	Kilovolt
AEMO	Australian Energy Market Operator	kW	Kilowatt
AGC	Automatic generation control	LFSM-O	Limited frequency sensitive mode for overfrequency
AGIR	Authorities governing interconnecting requirements	LFSM-U	Limited frequency sensitive mode for underfrequency
CCT	Critical clearing time	LOM	Loss-of-mains
CEA	Central Electricity Authority	LVRT	Low voltage ride through
CHP	Combined heat and power	MER	Mercado Eléctrico Regional
CIP	Critical Infrastructure Protection	MW	Megawatt
CNC	Connection Network Code	MWh	Megawatt hour
CRIE	Comisión Regional de Interconexión Eléctrica	MW-s	Megawatt second
DC	Direct current	NERC	North American Electric Reliability Corporation
DER	Distributed energy resources	PFR	Primary frequency response
DSO	Distribution system operator	p.u.	Per unit
ENTSO-E	European Network of Transmission System Operators for Electricity	PV	Photovoltaic
ERC	Electricity Regulatory Commission	RfG	Requirement for generators
ERCOT	Electric Reliability Council of Texas	RMER	Reglamento del Mercado Eléctrico Regional
EU	European Union	RoCoF	Rate of change of frequency
EU NC RfG	EU Network Code Requirements for Generators	RTO	Regional transmission operator
EV	Electric vehicle	RTR	Red de Transmisión Regional
FFR	Fast frequency response	SAARC	South Asian Association for Regional Cooperation
FRT	Fault ride through	SADC	Southern African Development Community
FSM	Frequency sensitive mode	SAPP	Southern African Power Pool
GMS	Greater Mekong Subregion	SCADA	Supervisory control and data acquisition
HVDC	High voltage direct current	SIR	Synchronous inertial response
HVRT	High voltage ride through	SMGW	Smart meter gateway
Hz	Hertz	SNSP	System non-synchronous penetration
IBR	Inverter-based resource	THD	Total harmonic distortion
IEC	International Electrotechnical Commission	TSI	Total system inertia
IEEE	Institute of Electrical and Electronics Engineers	TSO	Transmission system operator
IPP	Independent power producer	UFLS	Under frequency load shedding
IRENA	International Renewable Energy Agency	VRE	Variable renewable energy
ISO	Independent system operator	WECC	Western Electricity Coordinating Council
kHz	Kilohertz		

ES EXECUTIVE SUMMARY

This report contains the latest developments and good practices to develop grid connection codes for power systems with high shares of variable renewable energy (VRE) – solar photovoltaic (PV) and wind. The analysis is an update of the 2016 International Renewable Energy Agency (IRENA) report *Scaling up variable renewable power: The role of grid codes* and elaborates on the latest developments and experiences related to technical requirements for connecting VRE generators and enabling technologies such as storage, electric vehicles (EVs) or flexible demand and their incorporation in grid connection codes.

There is an urgent need to adopt clean energy solutions to cope with growing demand and replace existing polluting generators. Utility-scale solar PV and wind farms are already operational in many countries with high shares of instantaneous demand being covered by VRE generation. An increasing number of countries aim to replace fossil fuel-based generation with more VRE generation,¹ which would lead to almost **100% renewable power** in those countries before mid-century. An advantage, especially for solar PV, is that renewable energy can be deployed at lower voltage levels for direct consumption, with high demand correlation. Renewable energy is also inexpensive in the long run, producing affordable electricity. Wind power, though deployed at sites away from load centres, can be transported using transmission lines. Alternatively, it can be stored at site using energy storage solutions that could cover for peak loads or as required by the system operator.

VRE impacts the way power systems are operated

Traditional power systems are composed of largely conventional generators. These are synchronous generators: large, centralised dispatchable assets, contributing to system's inertia and feeding large amounts of power into the transmission grid, from where power is transported to load centres. Electricity systems are changing, however, and the optimal generation mix in a power system now comprises diverse generation assets that can be distributed, located closer to consumers and decentralised in operation. Renewable generation technologies, most of which can only generate when the primary resource is available, are sustainable and cost-effective. Solar PV and wind power generators, which are **VRE sources**, are now mature technologies that are expected to grow exponentially in installed capacity in the future. Favourable ecosystems for the growth of renewables have ensured that this continues. The nature of VREs introduces challenges to system operation. VREs are **variable**,² **uncertain**,³ **location constrained**⁴ and **inverter-based**,⁵ replacing conventional synchronous generation technologies. This changes the dynamic behaviour of the power system to events.

¹ See <https://ukcop26.org/end-of-coal-in-sight-at-cop26/>.

² Variable due to their dependency on the variable primary resource such as the sun and wind and therefore non-dispatchable.

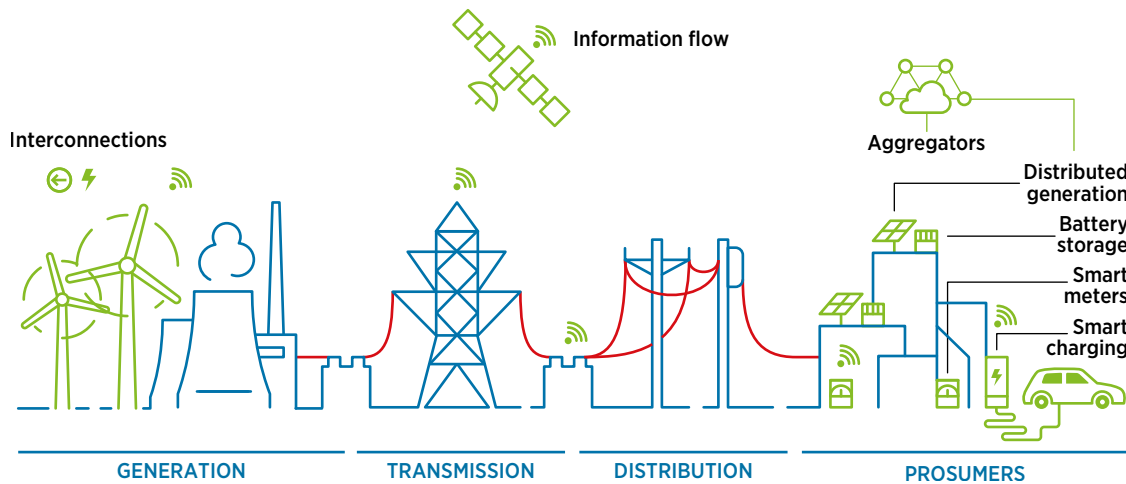
³ Uncertain because their predicted values may be different from what is actually generated due to unforeseen variations in weather.

⁴ Location constrained by the favorable sites for wind and sun availability.

⁵ Their nature of interconnection is through power electronics-based inverters, which also gives them the name “inverter-based resources” (IBRs).

Furthermore, three trends being observed in power systems are **decentralisation, digitalisation** and **electrification of end users**, which are driving the growth of the power system in a new and different direction. All of this comes at a cost to the system. The system operator has to ensure that the system is both **flexible** (able to accommodate the frequent imbalances between demand and supply) and **stable** (able to recover in event of any contingency).

Figure i **Innovations of the power system**

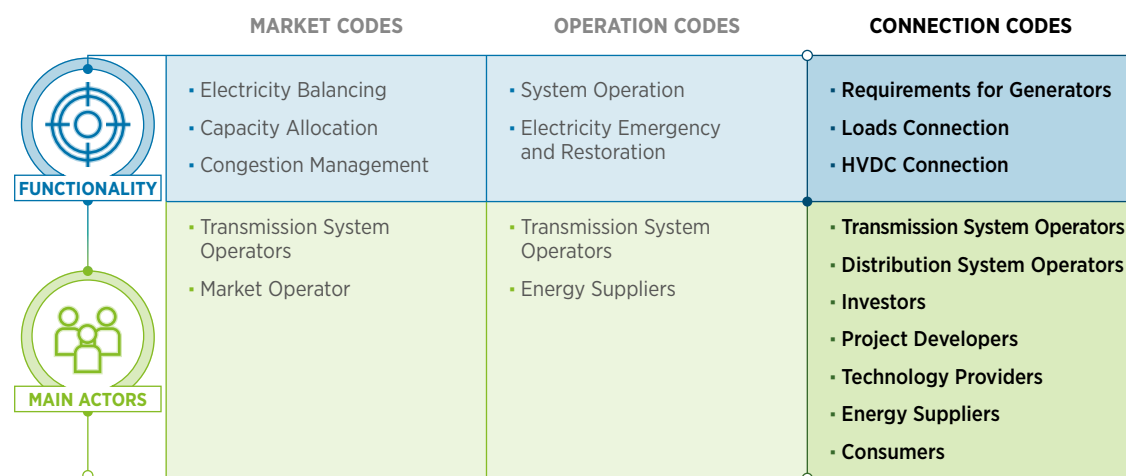


With the power system evolving in operation, structure and organisation, there is a need for better monitoring, controllability and co-ordinated control of the different assets, assigning their roles and contribution to the system at different times of the day. Different assets also mean multiple stakeholders. With independent power producers (IPPs) owning and operating renewable projects, regulators performing regulatory overview, and planners looking at how the system can develop in the future. The real-time monitoring control and operation of the power system lie with the system operator. Co-ordination between different actors and different assets is only possible if credible regulations or principles governing their conduct, such as **grid codes**, are in place.

The role of grid codes in building trust between different actors

Grid codes define the technical regulations and behaviour for all active participants in the power system, including power generators, adjustable loads, storage and other assets. The implementation of these codes gives system operators confidence that assets connected to the system will not endanger the security of the electricity supply. Establishing a grid code is an important step in opening up the power sector to private developers or new plant operators and enabling efficient integration of distributed VRE generators. The purpose of grid codes is manifold and includes ensuring co-ordination among the various actors, increased transparency, grid security, reliability and VRE integration. Grid codes enumerate the technical requirements that are to be followed to keep the **system functioning smoothly and to build trust between power system actors**. They encompass different aspects of the power system, such as markets, operation, planning and connection.

Figure ii **Categories of grid codes in Europe, functionality and main actors**



Note: HVDC = high voltage direct current.

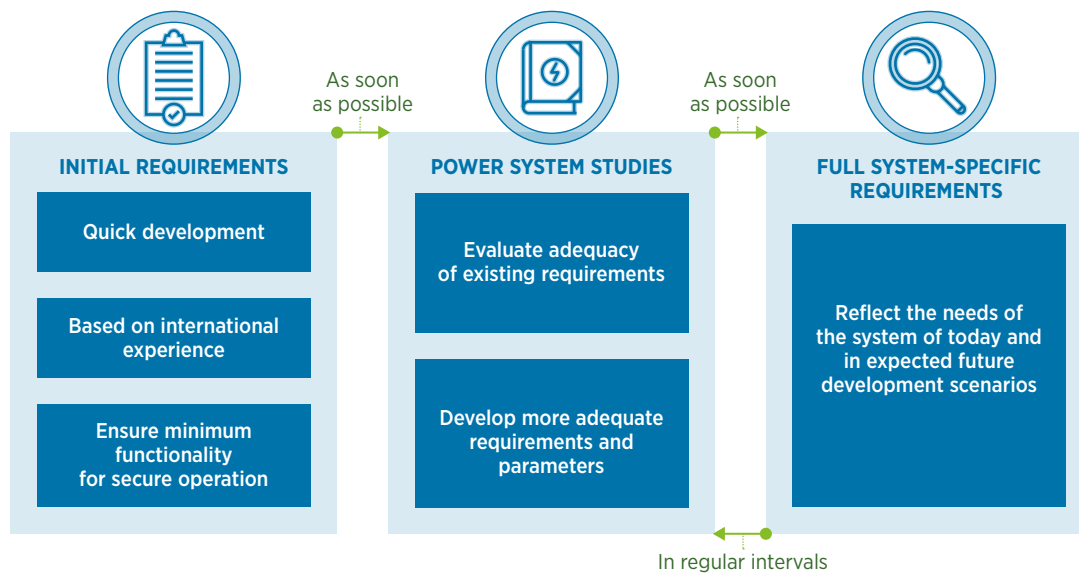
This report focuses on **grid connection codes**. It elaborates on the minimum technical requirements that VRE generation plants and new enablers of VRE need to meet to be granted grid access. It discusses the development trends observed across the most advanced grid codes to adapt to further increasing VRE penetration and to the accompanying transformative trends of **decentralisation, digitalisation and electrification of the end-use sector** (IRENA, 2019a).

An imperfect grid code is, in many cases, better than no grid code at all

Formulating grid codes starts with a consensus-building process including all possible stakeholders. This process uses technical studies to determine the technical limitations in the system. For technological improvements and newer trends and services to be put in place, grid codes must be continuously updated and improved, aiming for **system-friendly behaviour**. Establishing a grid code is an important step in opening up the power sector to private developers or new plant operators and enabling efficient integration of distributed VRE generators. The development of grid codes may be based on international experience. An imperfect grid code is, in many cases, better than no grid code at all, especially when economic conditions allow for renewable energy development to pick up pace. In this situation, the development of grid codes is needed quickly. Even if the initial grid codes are not perfectly suited to the needs of the system, they ensure a certain minimum functionality of new generators. Furthermore, it is usually easier and cheaper to re-parametrise functionality to better reflect the needs of the system later. Special care should be taken not to ask for excessive requirements that would turn into higher costs that could restrain VRE development. On the other hand, requirements that are too loose put the system at risk.

Power system transformation towards decentralisation, digitalisation and electrification calls for evolving grid codes

Figure iii Grid code parameter development and revision process



Grid codes should be technology-neutral and should evolve to meet system needs

Grid codes should specify the requirements in a **technology-neutral manner** as far as possible to help avoid the introduction of technical barriers for individual technologies and to allow users to adopt the most economically efficient technical solution to suit their needs and business cases. In case the requirements of a system change over time and grid codes are updated, **the cost of upgrades should not fall entirely on existing grid users, and a compromise should be reached on the burden of the cost.** If the connection requirements applying to existing assets never change while the rules for new assets become stricter, the result could be a delay in the replacement of old with newer, more advanced technology. On the other hand, if connection requirements evolve constantly for existing assets, huge investment uncertainty is created. A balance needs to be struck between the two extremes. Existing assets should be treated differently from new assets to some extent. However, existing assets that are significantly refurbished can be considered new. Alternatively, in exceptional circumstances, existing assets can also be forced to comply with new rules.

Countries already in possession of grid codes should evolve and adapt to define requirements based on the size and user, interconnectivity, expansion plans, existing capabilities and VRE share. **Low-voltage distribution systems are increasingly required to provide the same technical capabilities as larger generators.**

Grid codes should enable innovations to connect safely to the grid

Grid codes have been revised to include the full potential of **vehicle-to-grid services from EVs**. In this respect, EV charging stations need to fulfil requirements set for inverters, which include electrical safety, power quality, voltage support, demand response modes, anti-islanding requirements and withstanding of grid conditions (fault ride through, or FRT) (Jones *et al.*, 2021). Some of the most advanced network codes discuss EVs based on their role as demand (V1G) or generation (V2G) under the demand connection codes and requirement for generators (RfG), respectively.

Distributed energy resources (DER) connected at lower voltage levels require distribution system operators (DSOs) to develop the operational capacities to deal with significant generation fed into their grid. This is driving the development of new network codes pertaining to distribution grids. In the European Union (EU), an entity of distribution system operators (EU DSO entity) has been established, aiming to “increase efficiencies in the electricity distribution networks and to ensure close co-operation with TSOs [transmission system operators] and ENTSO-E [European Network of Transmission System Operators for Electricity]” (Meeus *et al.*, 2020).

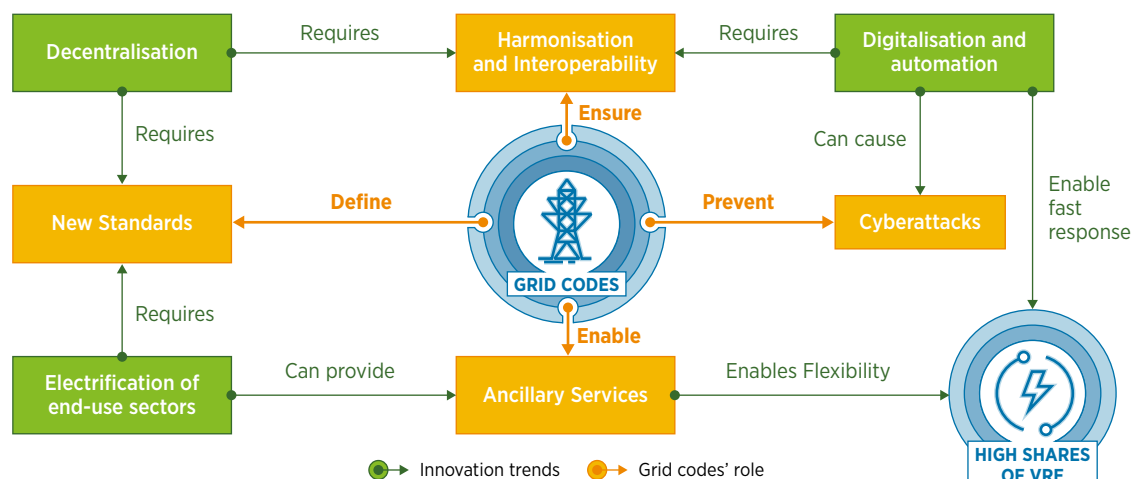
Storage and other consumer-producer connections are mentioned in the most advanced grid codes, such as in Europe and United States, which have specific requirements for new users. For example, Belgium treats storage as a generation asset for some requirements, which cover frequency, robustness and low voltage ride through (LVRT), voltage stability, and reactive power capacity. In Germany, rules for low voltage DER’s connections distinguish between facilities for consumption, generation, storage and EV charging.

It is also possible to use grid codes to ensure implementation of enabling solutions such as generation forecasts and better communication interfaces and protocols to enable better dispatch and procurement of services from VRE generators.

Grid connection codes in a transforming power system

One of the oldest grid codes requirement for conventional generation units is the **frequency and voltage ranges** that should be maintained during normal operation and during contingencies. Over the years they have evolved to define the behaviour of the VRE plants during faults and contingencies. Some of the recent modifications to grid codes involve addressing the loss of inertia, available usually from synchronous generator rotors and rate of change of frequency (RoCoF). The introduction of VRE reduces the inertia and increases RoCoF, which is the rate at which frequency changes post-event and a measure that can activate protection devices in the system. Therefore, newer limits and operational constraints, operational measures, and innovative mechanisms to counter the constraints on inertia and non-synchronous penetration limits should be looked into. **For systems looking to achieve near 100% of renewables in the long run, the use and role of grid-forming inverters and participation of VRE in black start needs to be emphasised through grid codes.**

Figure iv Grid codes and innovation trends



Ancillary services, which are services from the different active assets in the grid to keep the system going, are described in grid codes. In some power systems, VREs participate to provide ancillary services such as fast frequency response (FFR) and provide reactive power and frequency regulation support with adequate control in place. The type of VRE units that should adhere to controls and the power reduction and power restoration ramps for these units to participate in can also be specified by grid codes.

Real-time Internet-based communication is becoming necessary for power system operation, control and monitoring. As a result, **cybersecurity** is also becoming critical. There is increased reliance on dynamic data communication and the use of technologies like artificial intelligence and machine learning to provide better operational capabilities. This leaves the communication channels vulnerable to cyberattacks, which can destabilise power system operation, energy market operations and grid reliability. Grid codes are evolving towards recommending standards and improving cybersecurity in power systems while ensuring harmonisation and interoperability. Ongoing development for the network code on energy cybersecurity framework (Electricity Regulation [Regulation (EU) 2019/943]) is being done in Europe. In the United States, the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards applicable to bulk systems cover the different aspects of network security, such as asset classification, vulnerability assessments, etc.

Ensuring compliance with the code is key

Grid code compliance is a mandatory process for all new generation units wishing to access the grid. It should be instituted wherever reasonable in the planning, development, implementation and operation phases of each asset type and each facility. **Grid code compliance rules need to be formulated with consensus from all stakeholders because achieving compliance is essentially a collaborative effort among equipment manufacturers, project developers and power system operators.**

International standardisation and regional grid codes facilitate sharing of flexibility and increased economy of scale for equipment manufacturers

In a regional context, grid codes serve the purpose of facilitating international power trade and ensuring competitiveness in regional markets. Examples are identified in the United States and the European Union, focusing on operational security and power system stability in the regional market and co-ordination among TSOs. Harmonised requirements facilitate regional sharing of flexibility and hence contribute to a successful energy transition. Further, they enable fair competition within regional markets and therefore more market efficiency and lower consumer prices. **Harmonisation and interoperability** can be difficult to achieve due to differences in the acceptable ranges of parameters within each individual system, but **RfGs and Institute of Electrical and Electronics Engineers (IEEE) standards can guide TSOs on the allowable range of parameters.**

In the case of **small islands**, the development of an aligned grid code for countries within the same region, with exact parametrisation left to the local operators, could provide access to technical advancements. An aligned grid code could also enable small islands to access the benefits of VRE's significant cost advantage. If implemented successfully, it could prove a valuable resource in **developing internationally harmonised island grid codes in areas like the Pacific Islands and the Caribbean in the future.**

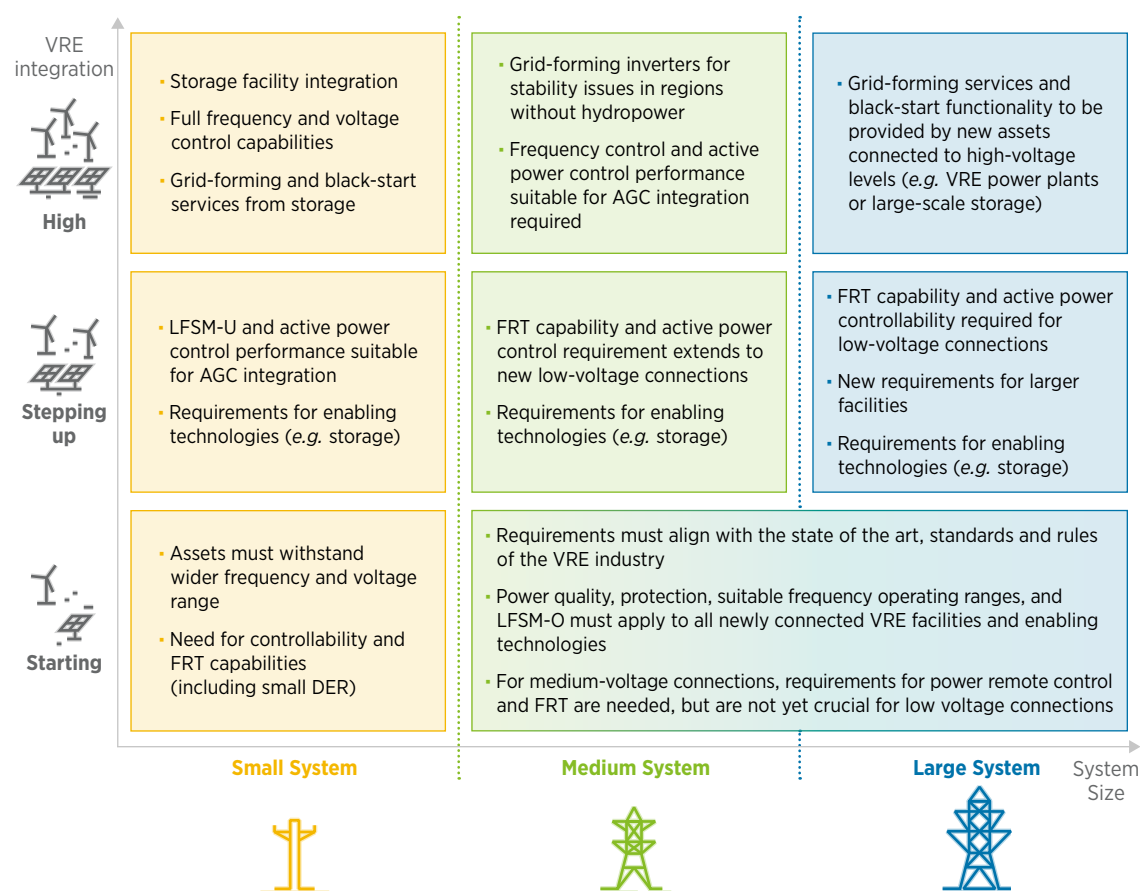
Nationally customised implementation of international or regional grid codes is needed because regulations applicable to larger areas cannot capture the specificities of each power system. Co-ordination between international equipment standards and grid codes continues to be an important point. This report discusses the ongoing efforts in different regions of the world to derive mutual benefit from interconnections and cross-border power trades and provides recommendations for **formulating regional grid codes**. A list of International Electrotechnical Commission (IEC) and IEEE product specification standards relevant to power systems and VRE integration is also provided in this report.

Tailoring grid connection code requirements to country/system context

The connection requirements vary with the level of VRE integration and power system archetypes. The classification of power systems into groups, though challenging, can be accomplished. With the aim to capture the most common typical cases in developing countries, where more guidance on designing grid codes for scaling up VRE is usually needed, this report classifies power systems based on their size as large, medium and small, and considers weak or no interconnection with neighbours.

Figure v depicts the different technical requirements that would be needed in a power system based on a) the expected penetration of VRE generation and b) the size of the system.

Figure v **Grid code formulation guidance according to grid size and VRE integration level**



Note: AGC: Automatic generation control; DER: Distributed energy resources; FRT: Fault ride through; LFSM-O: Limited frequency sensitive mode for overfrequency; LFSM-U: Limited frequency sensitive mode for underfrequency; VRE: Variable renewable energy

Systems with stronger interconnection and the presence of high shares of hydropower, and therefore less fossil generation to replace, find that their VRE adoption process is less challenging and therefore are not addressed in this report.

Countries with a **large or medium size grid** and hardly any existing VRE should not make the mistake of imposing lax connection requirements in the beginning. The requirements should be based on the state of the art of the VRE industry as identified from the latest standards and rules in the countries that have already achieved significant VRE integration. Colombia is a good example. The country is starting the integration of variable renewables by running grid studies, identifying suitable connection points and transmission needs, and looking into different strategies such as incorporation of an intraday market, balancing markets for system services, improving generation forecasts, and optimising reserves and dispatch. In the case of **smaller grids**, there is the need to withstand wider frequency and voltage fluctuations than in larger systems. Controllability and FRT capabilities will be needed even for small DER on the low voltage level.

To **step up VRE** integration, connection requirements previously only applicable to larger facilities, such as FRT and active power controllability, should be applied to new small facilities. Small systems without flexible non-variable renewables need to introduce demanding requirements for all sizes of user facilities. In the case of systems with reduced hydropower capacity, if a VRE development is located away from load centres voltage stability issues will arise. This can be solved by having VRE controls designed for low grid strength (low short circuit ratio) and through transmission reinforcements. In Australia, a certain level of system strength is required by the system operator. This level has to be ensured by transmission service providers, who in turn may require VREs developing in the area to provide it or install additional transmission assets to achieve it.

In the case of large grid systems looking to incorporate **high VRE shares**, much more time and effort are needed to convert to high VRE shares than is the case for smaller systems. Grid-forming services and black-start functionality will need to be provided by VRE power plants, or large-scale storage and corresponding technical requirements should be specified in the grid codes. For type medium systems targeting high VRE shares, the grid codes must require frequency control support through frequency sensitive mode (FSM) and active power control performance suitable for automatic generation control (AGC) integration. They should also explicitly facilitate the integration of enabling technologies. In small grids, storage facilities will be needed to achieve high annual electricity shares of VRE. Grid codes need to require full voltage and frequency control capabilities from the storage plants and should also require the capabilities to provide black-start and grid-forming services from them.

It is also important for countries to foster international collaboration and exchange of experiences in developing and implementing grid connection codes. Such an information exchange can be facilitated in international standardisation processes and **multilateral platforms for targeted dialogue on best practices for VRE integration as facilitated by IRENA**.

It is important for countries to foster international collaboration and exchange of experiences in developing grid connection codes.

01 GRID CODE DEVELOPMENT



KEY TAKEAWAYS OF THIS CHAPTER:

- › Grid codes encompass different aspects of the power system: market, operation, planning and connection. This report focuses on grid connection codes specifying the minimum technical requirements all such power plants need to meet to be granted grid access.
- › A new grid code formulation starts with a consensus-building process that includes all possible stakeholders, depending on the institutional set-up, playing different roles in the process and using studies to determine technical limitations and cost-effective solutions looking to the future.
- › Establishing a grid code is an important step in opening up the power sector to private developers or new plant operators and enabling efficient integration of distributed variable renewable energy (VRE) generators.
- › Grid code purposes are manifold and include co-ordinating actors, increasing transparency, ensuring grid security and reliability, and helping to integrate VRE.
- › The transformation in the electricity sector, which is driving increased digitalisation and decentralisation in the power system and electrification of end-use sectors, is a motivating factor in the need for revision and evolution of technical requirements in grid codes.
- › For technological improvements and newer trends and services to be put in place, grid codes must be continuously updated and improved. Involving different stakeholders is key to efficiently and successfully updating grid codes.
- › Grid codes are a key component in energy policies. Grid codes should take into consideration system security requirements for planned VRE shares. Similarly, the VRE share targets in the energy policy should be set while bearing in mind existing and future grid code requirements.



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Grid codes provide rules and define responsibilities for entities interacting with power system and energy market operation. They are developed and maintained by power system operators and regulators in consultation with other relevant stakeholders, and the authority to require and enforce compliance with them is installed by law. Grid codes enable system operators, generators, suppliers and consumers to interact and function efficiently within a common operational framework, each within their individual scope of responsibility. This ensures operational stability and security of supply, and can also contribute to well-functioning power markets.

This chapter provides an introduction to the grid code landscape. The first section introduces the role of different types of grid codes and briefly discusses the purpose and function of grid connection codes, the focus of this report. Further sections consider the relation of grid connection codes to energy policies, relevant transformations in the electricity sector, and a high-level overview of grid code development and revision planning.

1.1 THE ROLE OF GRID CODES IN ELECTRICITY SYSTEM REGULATION

Grid codes regulate different aspects of the power system, and they can take different names accordingly. For example, the European (European Union [EU] level) grid codes include network connection codes, operating codes and market codes. Because grid codes are the result of the stakeholders' landscape and the power system organisation structure that is in place, each jurisdiction can have a different grid code structure. For example, in vertically integrated systems, planning codes might not be defined, as the long-term actions of a vertically integrated utility are regulated. Similarly, metering code is needed when multiple players need access to the meter data, which may not be applicable in vertically integrated systems.

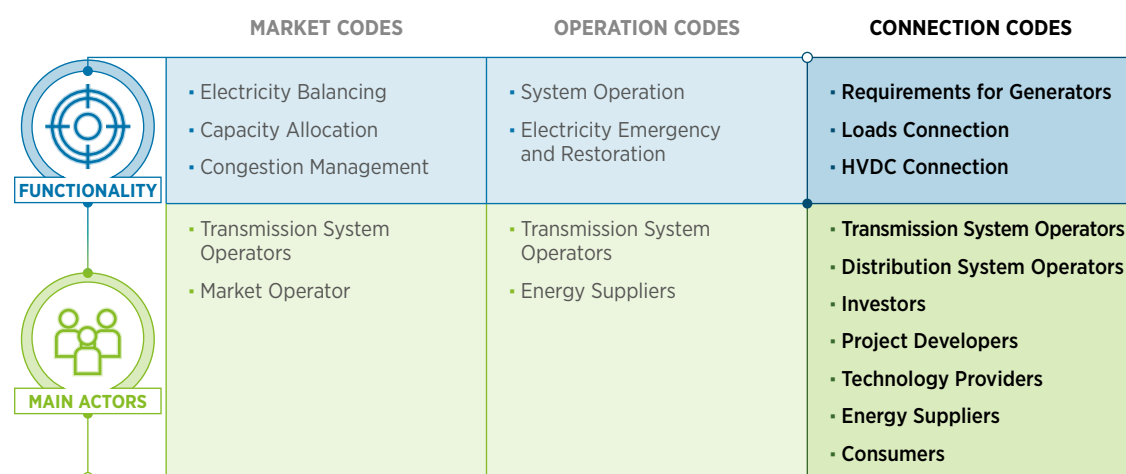
For example, the Mexican grid code includes a planning code besides the connection and operation codes (Comisión Reguladora de Energía, 2016). The Western Australia power system includes a metering code as well (Western Australia Government, 2012). The Electric Reliability Council of Texas (ERCOT) has a Nodal Protocol, which is like an overarching grid and market code, planning guide and operating guide, and other binding documents.

A prominent example for illustrating a system of grid code documents complementing each other are the European Union Network Codes, a collection of eight documents that are classified as market codes, operation codes and connection codes (Figure 1).

- The market codes provide guidelines and rules for regional (*i.e.* supranational) market functioning. These include the basic market mechanisms and/or common conditions for electricity balancing, capacity allocation and congestion management.
- Operation codes provide rules for the operation of the electrical power system and emergency and restoration processes.
- Connection network codes provide technical requirements for generators and high voltage direct current (HVDC) transmission facilities to connect to the grid. The network codes also enable consumers to provide demand side response services. They also describe high-level approaches for managing compliance with these requirements.

Not all stakeholders in the power sector are directly affected by each of the codes. The figure lists the main stakeholders bound by the corresponding rules.

Figure 1 Categories of grid codes in Europe, functionality and main actors



This report focuses on grid connection codes and, in particular, on the provisions relevant to the connection of generators based on variable renewable energy (VRE) and the provisions for the connection of other generators and assets that can enable the integration of VRE in the system. Ancillary service market considerations and harmonisation and standardisation efforts are also discussed briefly.

Wind and solar photovoltaic (PV) are the most dominant VRE technologies. Grid connection codes specify the minimum technical requirements all such power plants need to meet to be granted grid access. Therefore, these requirements must be designed to ensure system safety and stability with increasing shares of the corresponding generator technologies. Inappropriately designed or incomplete requirements will either increase the risk of unplanned consumer supply interruptions (blackouts) and other grid incidents, causing unnecessary expenditures for grid and generator owners (and consequently for consumers) or prevent the system from reaching its VRE penetration targets by impeding the necessary investment. By providing appropriate rules for VRE generators, VRE grid codes support the effectiveness of national and regional energy policies for renewables integration.

Technical impact of VRE generation

Variable renewable generation differs in important ways from conventional generators like thermal or hydroelectric power stations with reservoirs.

The **variable power output**, caused by fluctuating weather conditions, makes it more challenging to achieve the constant balance of supply and demand necessary for electricity systems to work. While conventional power plants have always been designed to cope with the variability of the power demand, the additional variability introduced on the supply side increases the need for system flexibility. The available technical options to address this challenge include enhancing the flexibility of conventional generators, facilitating demand-side flexibility, increasing deployment of storage and cross-sector power exchange (sector coupling), and establishing higher power transfer capacities to other regions, among others (IRENA, 2018a).

VRE technologies are uncertain. Options to reduce the need for system flexibility include implementing advanced techniques for weather forecasting to better cope with weather uncertainty and accepting limited levels of curtailment from VRE generation to avoid having to design a system for a level of peak VRE generation occurring only during a few hours each year.

While the bulk of conventional power generation comes from large power stations, major contributions of variable renewable power come from **smaller generation facilities** connected to the sub-transmission and even distribution grids. Limited technical capabilities of distributed generators are acceptable at low penetrations due to the limited impact of each individual unit. They are also desirable for economic reasons (less expensive equipment facilitates faster technology adoption), but the limitations become a problem when they form a large part of the generation capacity. Additionally, the fact that distributed generators are connected at lower voltage levels also means that the distribution system operators (DSOs) need to develop the operational capacities to deal with significant generation infeed within their systems (concerning system planning/extension, monitoring and observability, and controllability). For example, an entity of DSOs in the European Union (EU DSO entity) has been established, aiming to increase efficiencies in the electricity distribution networks and to ensure close co-operation with transmission system operators (TSOs) and the European Network of Transmission System Operators for Electricity (ENTSO-E). In addition, where relevant for distribution networks, the EU DSO entity will be involved in preparing and rolling out new network codes (Meeus *et al.*, 2020).

All solar PV and all large wind turbine generators are based on **power electronic inverters**. These inverters have different technical characteristics than the synchronous generators used in conventional power plants, which have an inherent electro-mechanical link to the grid. Synchronous-machine-like generator behaviour can no longer be taken for granted, and the behaviour desired and required from inverters – or groups of such devices – must be worked out in detail by system operators, specified in grid codes and implemented by project developers in collaboration with generator and inverter manufacturers, for whom the requirements usually represent significant design factors. Co-operation between the involved parties has already enabled VRE generators to provide services like reactive power for voltage control, active power reduction during congestion or over-frequency events, and voltage support during faults.

Box 1 What is the purpose of grid codes?

Grid connection codes specify the minimum technical requirements all power plants need to meet to be granted grid access. Grid codes serve to co-ordinate independent actors in power systems with different regulatory frameworks. In many power systems there are many different independent actors that need rules to co-operate efficiently towards a common objective. Grid codes are developed to provide these rules and are regularly updated to reflect and facilitate the development of the technological and operational capabilities of the systems within their jurisdiction.

As technical rules, grid codes regulate grid access and network user operation regardless of whether the power system is operated and supervised by a specific operator or by a vertically integrated utility. They increase transparency and enable fair treatment by making the same rules apply to all and inform future generation technology needs. Establishing a grid code is an important step in opening up the power sector to private developers or new plant operators and enabling efficient integration of distributed VRE generators. Regional grid codes are useful to support the development of regional power markets.

Function of grid connection codes

The technical connection requirements for generators and other grid users must be designed to ensure the continued reliability, security and quality of the power supply. For example, generators must be required to provide adequate robustness and capabilities for responding to disturbances, and in some cases the capabilities to provide ancillary services. Other grid users or assets such as battery electricity storage systems, consumer-producer facilities (e.g. consumer sites with rooftop PV) and consumers may have different needs resulting in different required capabilities. For a given task addressed in the grid code, the solution should be as much as possible technology neutral.

The diversity in terms of sizes and technologies of distributed generators (and other electric energy resources) is a challenge for identifying appropriate solutions. The technical requirements need to be adapted to what is both technically necessary and economically viable. Connection codes address this challenge by specifying different sets of requirements depending on the voltage level of the connection and/or the maximum power capacity of the connected facility, and the interface with the connection point (e.g. convert based or not).

For example, requirements for providing reactive current during faults are specified differently depending on the voltage level or the facility size (power capacity) in most grid codes. Faults occurring at the transmission network level have a high impact (in that the resulting voltage dips and spikes reach many grid users), so it makes sense for VRE generators connected to the transmission network to feed in reactive current during a fault to support the voltage and help limit the impact of the fault. On the other hand, requesting the same behaviour from VRE generators connected to the low voltage distribution grid would generally offer little to no benefit, so they are currently not required to provide it. Nevertheless, this situation may change in the future with very high shares of distributed generation. It is also desirable from a system stability point of view that VRE plants connected to the low voltage distribution grid at least remain in operation, and their power output should be restored immediately as the grid voltage recovers after the fault.

Grid code requirements also take account of variations among the technical capabilities of synchronous machines, inverter-based VRE generation and storage systems, and heterogeneous aggregations of flexibility-providing facilities such as hybrid or virtual power plants. Due to the different levels of existing power system integration of these grid user types, their respective requirements are sometimes specified in separate technology-specific grid code documents. However, with the aim of establishing a level playing field for different actors on the market, the most common approach is to unify the requirements and aim towards technology neutrality as much as possible.

Since the needs of a power system evolve as the system develops, grid codes are updated every few years to reflect new knowledge on what is technically and economically feasible, and to ensure that the continuing transformation of the power system is not impaired through unacceptable risks to system safety and reliability. As the shift of power systems towards more renewables is linked to policy goals, this is where grid codes interact with energy policy. In principle though, grid codes and especially connection codes should be forward looking and maintain a longer-term perspective. This is important for the industry as well, which needs to plan investment cycles, design products fit for purpose, etc.

1.2 RELEVANCE OF GRID CODES IN ENERGY POLICIES

The energy policy provides the framework in which a country co-ordinates how its energy needs are addressed. It is guided by a long-term roadmap describing expectations and requirements, including the development of energy consumption and the utilisation of different energy sources. The energy policy may use exemptions from competitive market conditions, strategic taxation and subsidies as instruments to achieve the desired development. The legal instruments implementing the energy policy usually do not specify detailed technical requirements but delegate their specification to other institutions. The institution tasked with developing the grid code requirements varies between countries; it can be the TSO or a power industry association. The legal status of a grid code is also very country specific. Grid codes receive their normative force from the legal acts authorising their use as binding conditions.

Box 2 Legal status of the grid code in India

In India, the grid codes by the Electricity Regulatory Commissions (ERCs) and the Technical Standards for Connectivity to the Grid by the Central Electricity Authority (CEA) are in the nature of regulations, namely sub-ordinate legislation. In fact, the Electricity Act itself mentions these regulations.

The Electricity Act 2003 mandates that every such regulation by the Central ERC or CEA is presented to each House of Parliament, and the latter is free to amend any section (although to date this has never happened at the central level).

The renewable energy policy is an integral part of a country's energy policy. It often includes specific targets for the share of renewables in the power system. To reach these targets, it provides the corresponding investment incentives. Feed-in tariffs and premiums for wind and solar PV have been a common approach to supporting an introduction of VRE in a power system; other common approaches are net metering schemes and auction systems (IRENA, 2020). VRE grid codes provide the technical regulations for the connection of VRE generators to the grid and thereby reduce the technical barriers to reaching the energy policy targets, while maintaining power system stability and security.

Among other factors, the technical requirements necessary in the grid code depend on the level of VRE integration in the power system. The grid code is thus related to a country's energy policy by the need to co-ordinate the technical requirements with the expected VRE share and also participate in a larger regional interconnected system. It is important that grid codes take into consideration system security requirements for planned VRE shares. In the energy policy, VRE share targets should likewise be established while taking into account current and future grid code requirements. Just as a legislator needs to plan when passing energy laws, the grid code working group must plan when drafting the grid code and anticipate future requirements to provide the stable and predictable regulatory environment needed to achieve the desired levels of investment. Inappropriate technical requirements will prevent the system from reaching its VRE penetration targets or compromise the security of supply, and requirements that change too frequently prevent investment by increasing uncertainty for investors.

While making changes to grid code requirements too frequently must be avoided, not having enough change is equally problematic in a changing environment. The rise of VRE together with the rapid deployment of energy storage and increased demand response are rapidly transforming the energy sector in many other ways, with different consequences relevant to grid codes as briefly discussed in the next section.

1.3 ELECTRICITY SECTOR TRANSFORMATION

Figure 2 lists the major paradigm changes transforming the power systems today. These trends have not only necessitated the inception of grid codes, but they continue to influence their technical content. In addition to these transformations, the socio-economic structure of the power system is also going to be transformed, for example with more and more distributed ownership of the power system elements (IRENA, 2020a).

Three interrelated trends illustrate the ongoing transformation of the electricity sector: decentralisation, digitalisation and electrification of the end-use sector (IRENA, 2019a).

Decentralisation

Decentralisation refers to the fact that rising VRE penetration is introducing significant amounts of new generation capacity in the distribution grids. Along with an increasing share of VRE, other distributed energy resources (DER) are also being connected to the distribution grids (such as batteries, chargers for electric vehicles [EVs], etc.). Dealing with grid connections is no longer a task for TSOs only; even the smallest DSOs may have to integrate them into their procedures. Grid codes specifying technical requirements need to reach down into the lowest voltage level.

Since distributed generators are often connected at consumer sites, decentralisation is also blurring the distinction between generator and consumer connections (and respective definitions in grid codes). Grid codes have to specify their requirements in ways that are increasingly independent of whether a facility is labelled as consumer or generator. The rising adoption of storage and activation of demand flexibility also contribute to this necessity.

Figure 2 **Technological transformation trends in the power system**

ONGOING TRANSFORMATIONS IN THE POWER SYSTEM	
Previous state	New state
Regulated fuel influx	Variable Renewable Energy
Synchronous machines	Inverter-based resources
Large-scale power plants	Distributed generation
Flexible generation	Flexible generation, demand and storage
Process automation	Autonomous operation / Digital Smart Grid
Electric light and power	Electric light, power, heating and mobility
Consumers	Prosumers

With increasing generation capacity and flexibility available in distribution systems, both new challenges and new optimisation potential come alongside decentralisation. The challenges include monitoring and managing the system state in distribution systems to avoid violating operational limits, and efficient planning and investment in the light of higher variability and uncertainty about future use. The opportunities are related to using new flexibility to achieve more efficient utilisation of grid assets and defer investment in system reinforcement. An additional option in the future will be the provision of system services. Solving the challenges and using the opportunities are becoming possible through intelligent digital control systems.

Digitalisation and automation

Due to the small sizes and high numbers of distributed generators (and other DER), neither manufacturers nor owners can reasonably employ human staff to efficiently monitor and supervise the individual units. Fortunately, thanks to the ongoing worldwide rollout of digital communication infrastructure, this is not necessary. Modern wind energy converters, solar PV inverters, battery controllers and electricity-consuming appliances are equipped with digital communication interfaces that allow the users to check their state and keep track of their performance. These interfaces are easily connected to data networks beyond the user site, enabling remote supervision and limited remote maintenance (e.g. installation of software updates).

Decoupling hardware and software is an essential component of digitalisation. This not only concerns the communication equipment, but even the power equipment itself. The behaviour of inverter-based resources (IBRs) is programmable to a far higher extent than it is with synchronous machines. For example, the response to disturbances in voltage or frequency depends nearly entirely on the controller software and can therefore be changed relatively easily, as long as it remains within the possibilities of the primary energy source. For synchronous machines, much of it is defined by the inherent parameters of the machine and is therefore hard to modify.

Wherever power hardware is accessible through remote supervision and control interfaces, it is important that the corresponding communication software is sufficiently secure to prevent unauthorised access. Updating the software at any time to close newly identified security holes must be possible; otherwise, both programming errors and malicious interference become additional vulnerabilities to power system security and reliability. The software update functionality is a potential attack vector, so this too must be secured against unauthorised third-party interference, both on the sending and receiving end. Besides preventing malicious action, detecting compromised components must be possible and there need to be procedures to deal with that situation. Cybersecurity is one of the major challenges of digitalisation.

There is ongoing development for network code on energy cybersecurity framework (Electricity Regulation [Regulation (EU) 2019/943]), and a report released by the Smart Grids Task Force has provided a recommendation for minimising the risk of digitalisation.

Privacy protection is another major challenge. Small-scale DER are typically installed at consumer sites; therefore, any monitoring or supervision is likely to provide information about local consumption patterns from which conclusions about user behaviour can be drawn. Since this is not desirable, access to user-level data must be controlled, and aggregation procedures must be designed carefully to prevent such access. When smart metering infrastructure is designed and rolled out, this is one of the factors to be considered. In some countries, such as Germany, the communication facilities from the smart meters can also serve as communication nodes managing secure communications between system operators and the locally installed DER.

Electrification of the end-use sector

Unified access to controllable resources on user sites is desirable for security and privacy reasons. It is also increasingly important because more and more resources are being made accessible to offer flexibility. Home automation systems, flexible heating, ventilation, air conditioning devices, battery storage, heat pumps and micro-CHP (combined heat and power) generators all contribute limited amounts of flexibility that can be useful for operation optimisation. Significant additional flexibility is expected from the integration of EVs. Integrating this flexibility with power system operation and control is an important focus in ongoing research and development.

The described electrification of the end-use sector improves VRE power system integration in two ways: it encourages local VRE installations that can be used for on-site energy optimisation, and it offers flexibility to system operators that enables the accommodation of increased VRE shares in the entire system. The connection grid codes aim to specify the requirements that the user facilities must meet to achieve these purposes.

Due to the complex and partially conflicting goals that the connection rules must accommodate, a systematic development and revision planning process with extensive stakeholder participation is needed for any grid code. The next section outlines the high-level structure of this process as it is implemented in most countries.

1.4 GRID CODE DEVELOPMENT AND REVISION PLANNING

Table 1 describes the initial process of developing a grid code in five steps. The process to maintain a grid code by updating and revising it is described subsequently in steps 6 to 10.

Table 1: Steps for developing, maintaining and revising a grid code

Step	Tasks	Actors
1 Policy mandates that grid codes must be written	• Definition of scope and applicability • Specification of required completion date • Appointment of responsible lead institution	Policy makers
2 Formation of working group and appointment of responsible lead persons	• Definition of group internal processes for consensus building and decision making • Agreement on a first draft table of contents • Assignment of tasks to working group members • Schedule and arrangement of regular meetings	Lead institution (e.g. system operators, such as TSOs or DSOs)

● Grid code development. ● Grid code revision.

Step	Tasks	Actors
3 Grid code drafting phase	- Structured creation of draft sections and review by the entire working group - Competent members to conduct studies (mainly dynamic behaviour/stability studies) where needed to determine technical parameters - Approval of all sections using previously defined decision-making processes	Working group consisting of representatives from TSO(s), DSO(s), facility owners, original equipment manufacturers, project developers, regulator, consumers, researchers
4 Consultation beyond working group	- Managed process involving: - Distributing and publishing draft grid code - Collecting and consolidating feedback - Addressing the comments in the working group	Any other stakeholders to provide comments, working group to revise and finalise document
5 Entry into force	Approval by authorities	Regulator or state administrative bodies
6 Grid code performance review and identification of gaps (can be continuous rather than a dedicated work phase/step)	- Evaluation of implementation experience: - Where are requirements no longer appropriate? - Where do requirements need to change or new rules be added? - Were there weaknesses in the working group setup and responsibility structure that need to be changed? - Continuous review of international grid code development and best practices	Working group, or other policy maker appointed committee
7 Working group reformation	Previous working group can continue if no major changes are needed	Working group
8 Grid code revision process	- Address identified gaps and weaknesses - Adapt to technical development and new system development targets where applicable	Working group
9 Consultation beyond working group	- Distributing and publishing draft grid code - Collecting and consolidating feedback - Addressing the comments in the working group	Any other stakeholders to provide comments, working group to revise and finalise document
10 Entry into force	Approval by authorities	Regulator or state administrative bodies or relevant ministry

● Grid code development. ● Grid code revision.

The stakeholders responsible for each stage of the grid code drafting, approval and revision process may vary, depending on the institutional setup in the individual country and the extent of unbundling in the power sector. In Australia, for example, the regulator writes and maintains the grid code, while the network operator provides the regulator with technical assistance for specifying the requirements. In Uruguay, although it has not been fully implemented, it is the same procedure, according to the current regulation. It has also required the opinion of the Ministry of Industry, Energy and Mining. The role of the ministry, although technical, has mainly been to assure the connection conditions do not compromise energy policy objectives. In India too, effective as of 2003, it is the regulator who is responsible for writing the grid code. Prior to this period, the TSO was asked by the regulator to write the grid code and have it approved by the regulator.

Concerning the grid code drafting process, it has proven beneficial to install a working group with a diverse set of stakeholder representatives from the very beginning, and not to task an individual stakeholder with setting up the first draft version. The reason is that no individual stakeholder has in-depth knowledge of all relevant technical details. Involving all relevant actors early on shortens the feedback loops and leads to a higher-quality draft and shorter time intervals when moving to public consultation and final approval. It will also be more likely that the specified technical requirements are appropriate for reaching the designated VRE share policy goals, because this approach encourages important stakeholder contributions in the drafting process like:

- expert knowledge of the country's power system, including all information about the existing electricity network and both the conventional and renewable generation fleet
- an understanding of the challenges of VRE integration and the experience of grid codes in other countries
- simulations and stability studies to assess the benefit of different grid code requirements for the country's power system, including the future VRE share
- a cost-benefit analysis of the different grid code requirements balancing implementation costs with system reliability benefits and a higher VRE share
- the long-term plan for the power system infrastructure, including renewable energy targets up to 20 years in advance.

While grid codes can be developed and put into force separately for different grid user groups (e.g. separate codes for connections to each of the main voltage levels), overall co-ordination and some reasonable membership overlap between the working groups are advisable to ensure that the systemic perspective is adequate.

When developing a VRE grid code, differences in grid operations based on area, country or region may also need to be considered, such as (Ackermann, Schierhorn and Martensen, 2017):

- the size of the VRE plants that contribute during peak load
- VRE interconnection (whether it is isolated or connected to the main grid)
- the capacity reserves in the grid to support the VRE
- existing and planned VRE capacities
- existing conventional generators in the grid to support the VRE
- the state of art of the VRE (depending on the technologies and grid design adopted).

Grid code revision

As with any regulatory document, the grid code needs to be adapted to changing circumstances from time to time, such as new technical capabilities of equipment or new operational practices, and the evolving penetrations of different generation types. The VRE policy targets may also change. The effectiveness and adequacy of the existing rules should be assessed, so that mistakes and omissions can be corrected.

One particularly challenging aspect that may lead to necessitating changes in the grid code is enforcement and verification of grid code compliance. The processes involved in achieving reasonably efficient and reliable compliance may need significant experience and tuning, which implies that time is needed for proper assessment. For example, the compliance verification processes in Germany, based on certification, have gone through a continuous refinement process for more than ten years.

The length of a suitable grid code revision cycle can depend on the speed of VRE integration. In Denmark, for example, the first grid code for wind power plants was adopted in 1999. Major revisions followed in 2004, 2010 and 2015. In India, the first grid code was approved in 1999, the next major revision was done in 2010, and the next one is due in 2021/22. If the grid code is revised too often, it may be difficult for installers and manufacturers to keep up with changing requirements. If the revision cycle is too slow, requirements may not be updated in time to help a stable development and operation of the power system.

Writing the grid code, verifying whether generators are complying, and enforcing and revising the grid code all require investments in time, qualified staff and expertise. **Countries may strive to pool resources in areas like generator testing and certification to facilitate this. Before compliance management and international co-operation are discussed, however, it is worth taking a deeper look at technical connection requirements.** This is the subject of the following three chapters.



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02 GRID CODE TECHNICAL REQUIREMENTS

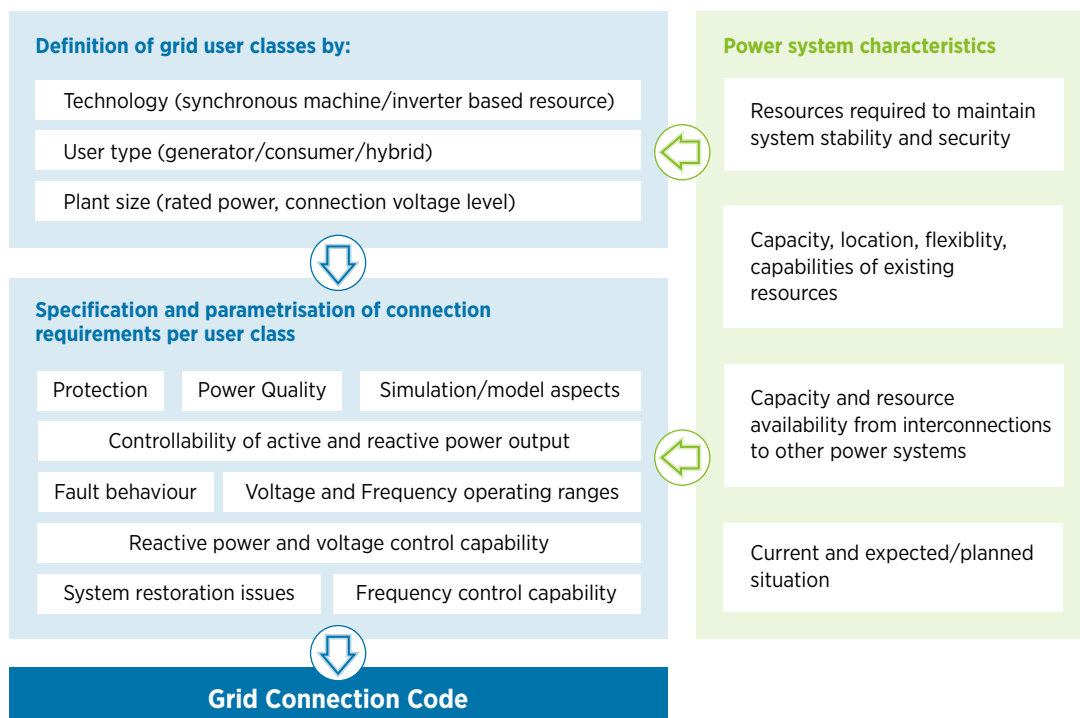


KEY TAKEAWAYS OF THIS CHAPTER:

- › Defining grid codes specific to each system's characteristics (size, interconnectivity, islanded /isolated, expansion plans and capabilities of existing assets) enables the setting of appropriate technical requirements for VRE integration and good system functioning.
- › The development of grid codes may be based on international experience, but it needs to reflect the adequacy of the existing system and the needs of current and future development scenarios. This could be based on dynamic stability studies that assess future situations in which the situation in the grid may have changed significantly.
- › The most common approach in formulating technical requirements is to aim for technology neutrality as much as possible within grid codes to provide a level playing field for different actors on the market.
- › Technical requirements are evolving to allow higher VRE penetration. Evolving technical requirements cover operating ranges of frequency and voltage, active power control from VRE such as downward and upward reserves reactive power support, fault behaviour, communication capabilities, power quality requirements and protection co-ordination.
- › Although grid codes are formulated following detailed studies, their creation should not be delayed. It is easier and cheaper to later re-parametrise functionality to better reflect the needs of the system. An imperfect grid code is, in many cases, better than no grid code at all, especially when economic conditions allow for renewable energy development to pick up pace.
- › Frequency operating ranges are one of the oldest requirements in grid codes and were based on Institute of Electrical and Electronics Engineers (IEEE) and International Electrotechnical Commission (IEC) standards. Recently the ranges have been adapted to reflect the current system status, size of the system, and needs, as well as new technological updates. Grid codes also specify the minimum rate of change of frequency (RoCoF) withstand requirement for protection devices, which is highly dependent on the amount of inertia and thus VRE generation.
- › Although fault ride through (FRT) is a normal grid code requirement for most VRE generators and is influenced by the behaviour of existing synchronous generators, inverter-based technology can further support the system during faults through dynamic current. Their application should be selected according to the system needs and priorities, which must be addressed by grid codes.

The technical connection requirements specified in grid codes can be divided according to the issues addressed. These high-level requirements (or requirement categories) are the essential components of any grid connection code. While the basic requirement specifications are also often similar, there are significant variations in the chosen parameters and in the range of grid user facilities where they apply based on country and site specifications. This is illustrated in Figure 3. Identifying the appropriate parameters for suitable user facility classes, according to the system needs, is a crucial part of grid code design.

Figure 3 Application of high-level requirements according to system needs



This chapter includes a brief overview of the common high-level requirements. More detailed discussions of the basic requirements are available in IRENA (2016) and other literature. This chapter also examines how to determine suitable parameters for three selected requirements: frequency ranges, RoCoF limits, and FRT envelopes.

2.1 REQUIREMENTS OVERVIEW

System needs are the main driver for grid code development. All system users need to contribute according to their technical restrictions. One of the key motivations behind the development of grid codes targeted at VRE generators was to force them to show the same system-stabilising behaviour as synchronous machines, to the greatest extent possible. Historically, this developed from very basic functionality such as the first **low voltage ride-through (LVRT)** envelopes, which appeared around the year 2000 (Deutsche Verbundgesellschaft EV, 2000), towards more comprehensive requirements for frequency and voltage control as installed capacities reached system relevant shares in some countries the early 2000s. Grid code developers were

relatively quick to realise that IBRs did not have to be regarded as a threat to the stability of traditional power systems. They realised that inverter-based generation also allows for the implementation of additional functionalities that synchronous machines cannot provide easily.

This is clearly visible in early grid codes. For example, the 2001 code of German TSO E.ON Netz GmbH (E.ON Netz GmbH, 2001) specified much larger LVRT ranges for wind turbines that would be difficult to fulfil for synchronous generators. The 2004 iteration of the Danish wind grid code (Elkraft System; eltra, 2004) required post-fault active power restoration from inverter-based generators at a ramp rate that cannot be provided by any conventional generators. To some degree, the objective of utilising the technical capabilities of VRE generators to the full extent clashed with principles of open market power systems, in which regulation should be technology neutral. In most cases this was resolved by generally requiring the most system-friendly behaviour from all generators and granting derogations in the form of more relaxed requirements for certain generation technologies wherever technologically unavoidable. The following technical requirements are typically included in grid codes as of 2021.

Voltage and frequency operating ranges are usually applied to all generators in a system alike. The goal is to have predictable behaviour for all generating units within a defined operating range or a number of defined operating ranges. Generators are typically required to be capable of time-unlimited operation up to rated active power in the normal operating ranges of the grid and required to remain online for a limited time within a larger voltage-frequency range. In China, for example, the normal operation voltage ranges from 0.9 per unit to 1.1 per unit. When the voltage is between 1.1 per unit and 1.2 per unit, power sources are required to remain connected and provide active power for at least 10 seconds, and for at least 0.5 seconds when between 1.2 per unit and 1.3 per unit.

Frequency control capability requirements in grid codes vary, especially concerning application to VRE. Requirements for overfrequency active power reduction (limited frequency sensitive mode for overfrequency, or LFSM-O) for all generators were introduced in most transmission and distribution codes in the wake of the 50.2 hertz (Hz) issue⁶ in Europe. Requirements for active power increase at underfrequency (limited frequency sensitive mode for underfrequency, or LFSM-U) are also common, but mostly relevant when generators are not operating at their rated capacity (partial load in conventional units, curtailed operation in VRE), or they have storage units. When generators are operating at their rated capacity, it is still feasible for them to increase their active power output for a limited time to support the frequency, e.g. inertia response or fast frequency response (FFR).

The capability to provide frequency containment reserve and frequency restoration reserve is still mostly required only from conventional generators above a certain size threshold. Requirements for transmission-connected VRE generators to be capable of providing such services have become more common in recent years, with Denmark, Ireland and Great Britain⁷ requiring the capability to provide both upwards and downwards reserve from transmission-connected VRE generators. The grid code requirement for this capability does not imply an obligation to provide the corresponding service.

⁶ In 2005 according to German requirements, PV inverters for distributed generation were supposed to disconnect at a narrow setting of 50.2 Hz. Since there were already more than 3 gigawatts of installed capacity, the simultaneous disconnection would have exceeded the primary reserves, which was a threat to system security. This is an example of a bad grid code requirement. At the time it was written the system operators did not anticipate that PV would ever play a significant role in the system.

⁷ The United Kingdom of Great Britain and Northern Ireland is a sovereign state. This report refers to Great Britain as the official collective name of England, Scotland and Wales and their associated islands. It does not include Northern Ireland.

Requirements for generators to provide reactive power for voltage control contain two different aspects: the capability of a generator to provide reactive power and the capability to implement different control schemes (e.g. constant power factor, volt-var control, watt-var control). Both requirements are imposed to synchronous and inverter-based generators in almost all transmission and sub-transmission grid codes, as well as in a large number of distribution codes worldwide. For example, the Chinese code of connecting wind farm specifies that the power factor should be dynamically controlled between lead 0.9 and lagging 0.95.

The actual provision of this service to the grid can and should be seen independently from the capability. Grid codes traditionally do not distinguish this, because for a synchronous generator running at (or near) rated power, the difference is very small. For VRE plants, running most of the time at partial load, the operating expense can be significant.

Moreover, the reactive power capability has to be seen in relation to the voltage at the reference point (usually point of common coupling [PCC]) and the active power produced at that moment in time. This Q-U-P (reactive power, voltage, active power) capability is related to the capital expense of a (VRE) power plant. How it is being used day to day has an impact on the currents; hence the losses in inverters, cables, transformers and switched Q-sources, as may be the case.

Fault behaviour requirements in grid codes focus on ensuring predictable system behaviour and resilience to grid faults (in particular short circuits). A defined behaviour of all generators in fault cases is required. Differentiation is usually made between synchronous and inverter-based generators (and sometimes asynchronous, and doubly-fed induction generators) due to different capabilities of the generator types (higher, but inherent short circuit current from synchronous units vs. limited current, but more controllability from inverter-based units).

Protection of customer facilities (loads and generators) is generally intended to protect the facility itself. Protection is therefore usually the responsibility of the owner/operator. Grid codes need to specify operational ranges and FRT requirements appropriately so that customers do not overprotect their facilities. Some grid codes do require or recommend certain protection settings, and almost all grid codes require the co-ordination of protection with the responsible grid operator, sometimes in the form of a protection co-ordination study to be executed before connection.

The requirements for anti-islanding⁸ protection of generators, aiming at protecting the grid from unwanted continuous generator operation in case of separation from distribution grid areas, are an exception. Examples on the implementation of anti-islanding protection based on RoCoF and the specifics of such requirements from grid users such as storage and electric vehicles are discussed in Chapter 2, Section 4, and Chapter 3, Sections 5 and 7.

Controllability of active and reactive power output was required for transmission-connected large VRE units relatively early on. In industrialised countries, a system-wide supervisory control and data acquisition (SCADA) system was and is the norm in transmission systems, and VRE units are routinely connected to it, enabling remote setpoint changes and/or connection to automatic generation control (AGC) systems for balancing.⁹ In developing countries, controllability is also universally required but is often realised manually via radio or telephone requests, thereby increasing communication delays. Even if a system-wide SCADA is not available yet, it is sensible for the system operator in such countries to require a SCADA and AGC interface at every transmission-connected generator, so that they can be easily connected

⁸ **Islanding** refers to the condition in which a generator continues to power a section of a grid although it is disconnected from the main grid. This poses risks to system security if it happens unintentionally and is not co-ordinated properly.

⁹ Integration of VRE power plants in AGC systems is a rare exception but is already possible (Katz and Chernyakhovskiy, 2020; Kroposki, 2017).

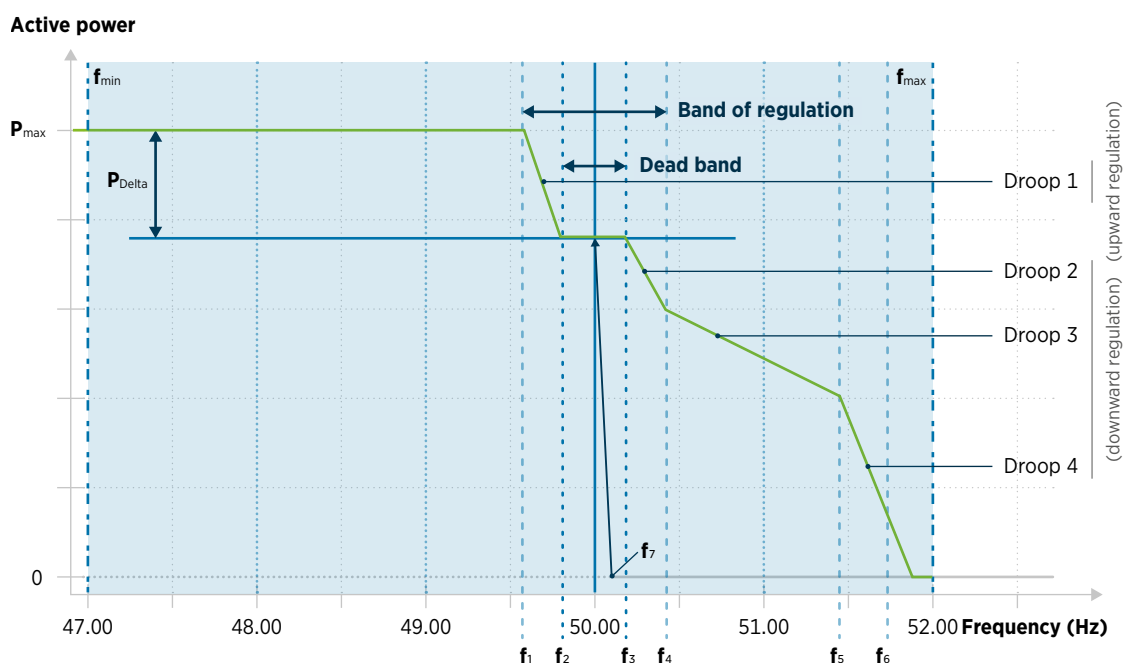
once the system is in place. Communication protocols, signal lists, and response speed and accuracy have to be defined in grid codes, to certain extent. Alternatively, they can be left to the system operator, which will prepare a detailed procedure in a consultative manner that can easily keep evolving with technology. Hard coding such details in the grid code can make it difficult to quickly carry out amendments.

As of 2021, the same is true for most grid codes applicable to sub-transmission and primary distribution (medium voltage) levels. The need for controllability of resources connected to low voltage grids is, however, just emerging in most countries and is addressed in more detail in Chapter 3, Section 1.

Active power controllability requirements also include minimum and maximum ramp rates that may be imposed on generators. Typical are minimum ramp rate requirements for conventional and battery units, and maximum ramp rate requirements for VRE. Ramp rate limits for VRE are often only applicable at setpoint changes, shutdown or start-up, because a requirement to generally limit ramps would cause significant yield losses or implicitly require some storage capacity.

The curtailment of VRE or down-reserves to support the system in the event of load rejection and in turn support the thermal base load units, which provides local governor action and droop control, has been discussed in the Hawaii solar grid integration studies (Hawaii's Natural Energy Institute, 2012). A similar droop control can be applied to wind and solar plants and effectively reduces their curtailment and fuel costs. Technical regulations in the Danish power system specify the need for PV power plants above 11 kilowatts (kW) to be equipped with active power control functions to control the active power supplied by a PV power plant at the point of connection using activation orders with set points with a resolution of at least 0.1 kW. This functionality covers the role of the PV to support grid stability participating in frequency control during over frequencies (EnergieNet, 2016).

Figure 4 Frequency control curve for a PV power plant



Source: EnergieNet (2016)

Power quality requirements limit the current waveform distortions, such as harmonics or flicker. Harmonics distortion is the presence of frequencies that are integer multiples of nominal frequency in voltage and current waveforms. This causes losses and maloperation of protection devices and the possibility of resonance in the systems. Harmonics distortion can be classified as active distortion introduced from the new source or passive distortion due to interaction between the unit's and the grid's harmonic impedance. Among other sources, inverters or power electronic equipment of VREs contribute to harmonics due to their switching dynamics. Strict regulations are imposed to limit this, characterised by the total harmonic distortion (THD) permissible at the PCC on plant owners.

Table 2 **Current harmonics distortion limits of the PV systems**

The Standards	Type	Harmonic Order (h)	Distortion Limit	THD (%)
IEEE 1547 AS 4777.2 (Australia), GB/T (China), and ECM (Malaysia)	Odd	$33 < h$	$<0.3\%$	$<5\%$
		$23 \leq h \leq 33$	$<0.6\%$	
		$17 \leq h \leq 21$	$<1.5\%$	
		$11 \leq h \leq 15$	$<2\%$	
	Even	$3 \leq h \leq 9$	$<4\%$	
		$10 \leq h \leq 32$	$<0.3\%$	
UK (EREC G83 Stds.)	Odd	$2 \leq h \leq 8$	$<1\%$	$<3\%$
		$h = 3, 5, \text{ and } 7$	$<(2.3, 1.14, \text{ and } 0.77)\%$	
		$h = 9, 11, \text{ and } 13$	$<(0.4, 0.33, \text{ and } 0.21)\%$	
	Even	$11 \leq h \leq 15$	$<0.15\%$	
		$h = 2, 4, \text{ and } 6$	$<(1.08, 0.43, \text{ and } 0.3)\%$	
		$8 \leq h \leq 40$	$<0.23\%$	
IEC 61000-3-2	Odd	$h = 3, 5, \text{ and } 7$	$<(3.45, 1.71, \text{ and } 1.15)\%$	$<5\%$
		$h = 9, 11, \text{ and } 13$	$<(0.6, 0.5, \text{ and } 0.3)\%$	
		$15 \leq h \leq 39$	$<0.225\%$	
	Even	$h = 2, 4, \text{ and } 6$	$<(1.6, 0.65, \text{ and } 0.45)\%$	
		$8 \leq h \leq 40$	$<0.345\%$	

Table 2 shows the harmonics limits for current and Table 3 shows the limits for voltage distortion that should be achieved at the PCC for PV systems (Ali Q. Al-Shetwi *et al.*, 2020).

Table 3 **Voltage harmonics distortion limits of the PV systems**

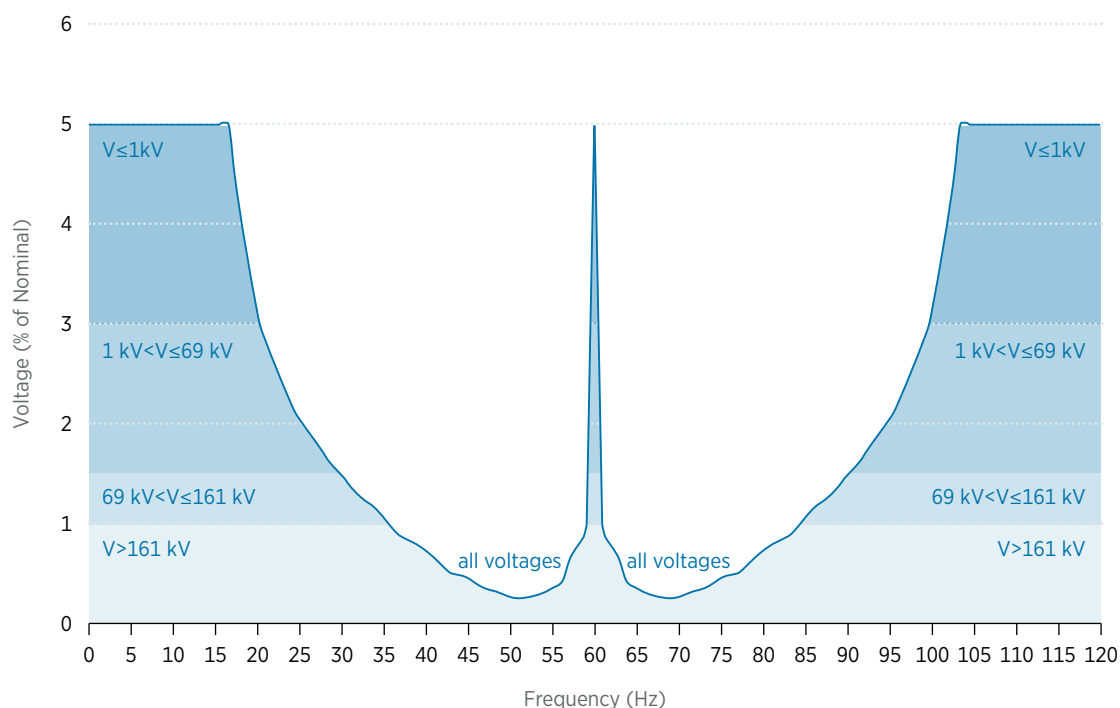
The Standards	Voltage Bus	Max. Individual Harmonics	THD (%)
IEEE 519	$(V \leq 1) \text{ kV}$	5%	8%
	$(1 \leq V \leq 69) \text{ kV}$	3%	5%
	$(69 \leq V \leq 161) \text{ kV}$	1.5%	2.5%
	$(> 161) \text{ kV}$	1%	1.5%
IEC 61000-3-2	$(2.3 \leq V \leq 69) \text{ kV}$	3%	5%
	$(69 \leq V \leq 161) \text{ kV}$	1.5%	2.5%
	$(> 161) \text{ kV}$	1%	1.5%

Another class of harmonics is interharmonics, which is a non-integer multiple of the fundamental frequency. The source for these interharmonic distortions is usually nonlinear loads and power electronic devices connecting two alternating current (AC) systems by a direct current (DC) link, as is the case with VREs. The interharmonic current can cause flicker and trigger harmonic instabilities and sub-synchronous oscillations. In the case of PV systems, the different control strategies applied for inverters and the sampling rate of maximum power point tracking can influence the interharmonic frequencies. Both of the above phenomena are created due to the flow of currents through impedance and can be corrected by modifying the impedance through which it flows. The IEC recommends interharmonics be a criteria for assessment of grid code compliance in wind and PV power plants.

IEEE-519 & IEEE 1547 standards provide guidelines to define the requirements for grid-tied inverters harmonics. The 2014 IEEE Standards 519 revision gives the IEEE recommended practice and requirements for harmonic control in electric power systems. The interharmonics limits has been defined as shown in Figure 5. The limits have been based on flicker measurements and do not include the effects of interharmonics on other equipment. Appropriate limits should be set case by case depending on the impact on users and system specifications with provision for future users.

According to IEC61000-3-6, the interharmonics is required to be below the neighbouring harmonics.

Figure 5 IEEE 519 informative interharmonic voltage limits based on flicker for frequencies up to 120 Hz for 60 Hz systems



Source: Schneider Electric (2014) and Marz (n.d.)

Power system balancing through dispatch of conventional power plants requires an approximate advance knowledge of the load demand to be covered. With significant shares of VRE in the system, this refers to the residual demand. Therefore, **VRE generation forecasting** is essential for system operation. While VRE forecasting is commonly provided by dedicated service providers commissioned by the TSO or the market operator, there are also jurisdictions where VRE power plants are required by the grid code to report power generation forecasts 24 hours or 72 hours ahead. For example, the Chinese grid code and, in the United States, the New Mexico Power Corporation and Texas Power Reliability Commission (ERCOT) have made it mandatory for wind power plants to carry out power forecasting.

Box 3 VRE forecasting requirements in China

According to the Chinese grid codes for wind power plants (GB/T 19963-2011) and PV stations (GB/T 19964 -2012), a generation forecasting system shall be configured in each wind and PV power plant. They shall report the predicted power generation curve of the power plant for all hours of the next day every day at the time specified by the power system dispatching organisation and automatically report the predicted power generation curve of the power plant for the next 4 hours to the power system dispatching organisation every 15 minutes. The required time resolution of the predicted power curves is 15 minutes.

2.2 DETERMINATION OF TECHNICAL PARAMETERS

Setting the parameters (limits, thresholds, times, etc.) of many requirements means investigating the needs of the power system. Requirements must consider the capabilities of available generators and grid conditions in the system in order not to obstruct VRE adoption, and must also be future-proof, which requires some forecasting of the future power system. In this regard, long-term power system expansion plans or forecasts are important inputs to grid code development.

When developing a VRE grid code, there is also a need to consider differences in the power systems based on the area, country or region such as below (Ackermann, Schierhorn and Martensen, 2017):

- the size of the power system – peak load and geographical size
- interconnectivity of the power system – whether it is isolated or interconnected with other systems
- the transmission capacity margins in the grid to support the transmission needs of new VRE generation capacity
- existing and planned VRE capacities
- the capabilities of existing conventional generators in the grid to provide flexibility
- the state of the art of VRE technology.

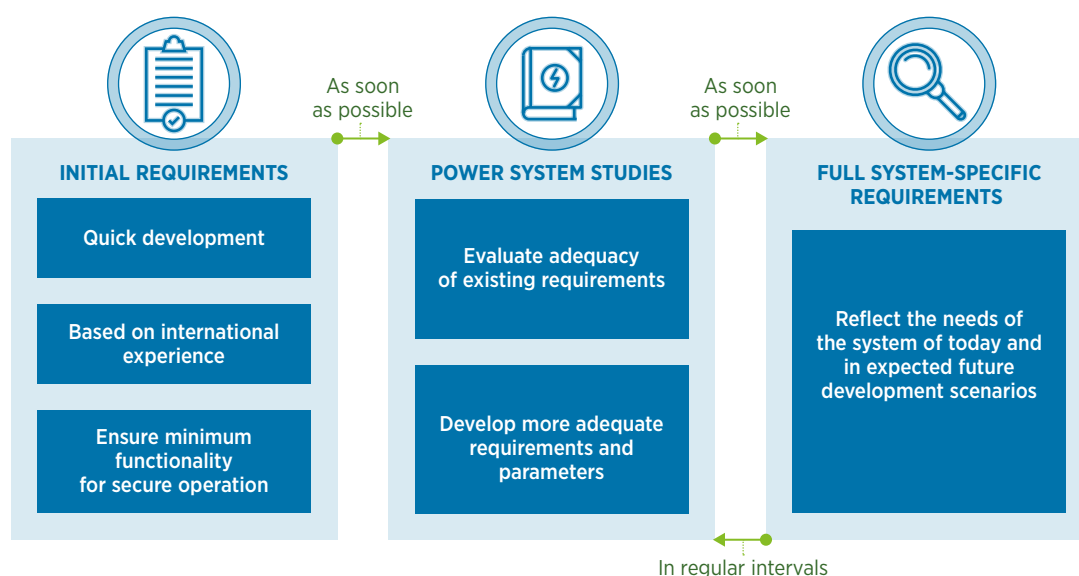
The majority of grid codes worldwide were initially developed based on operational data and operator experience and refined using more detailed studies. This approach is also recommended for countries or grid operators just starting out in VRE development. **An imperfect grid code is in many cases better than no grid code at all, especially when economic conditions allow for renewable energy development to pick up pace.** In this situation, the development of grid codes (or a set of technical requirements to be imposed on generators by way of the power purchase agreement) is needed quickly. Such initial requirements can be developed based on international experience and good practice from countries of similar power system specificities. They may not be perfectly suited to the needs of the system, but they ensure certain minimum functionality of new generators. It is usually easier and cheaper to later re-parametrise functionality to better reflect the needs of the system. Requirements can then be evaluated and refined using more detailed power system studies, which should be repeated on a regular basis (Figure 6). Special care should be taken to not to ask for excessive requirements that would turn into higher costs that could restrain the development of VRE.

The following studies are usually performed:

- load flow studies to investigate the necessary reactive power capabilities of generators
- consulting manufacturers to identify the capabilities of existing products and to evaluate potential costs of extended capabilities
- static and dynamic short circuit studies for evaluating protection and FRT requirements
- ramping studies, ideally including frequency stability studies, to calculate reserve requirements and gradient limitations.

This list should be added to studies to be conducted regularly for system planning and operation purposes. A good overview of technical planning studies for the integration of variable renewable energy is provided in IRENA (2018b).

Figure 6 **Parameter development and revision process**

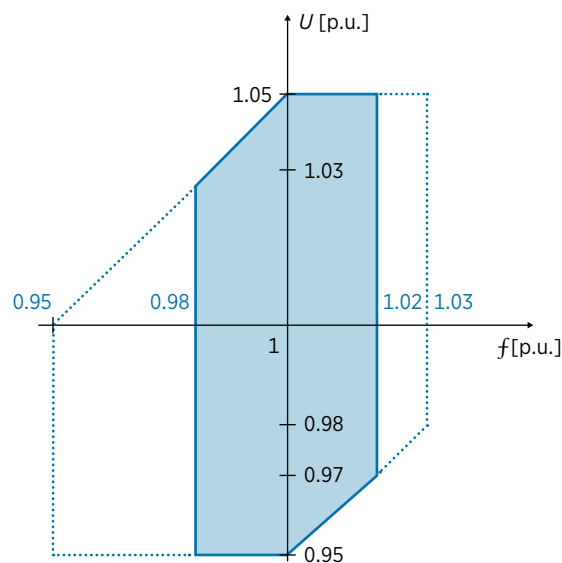


2.3 DETERMINING FREQUENCY RANGES

Operating ranges for generators are specified in the frequency and voltage domain in most grid codes, with the objective of avoiding unpredictable tripping behaviour during contingencies. Generators are typically required to be capable of continuous operation within certain voltage and frequency ranges (example: 0.95 to 1.05 per unit voltage and ± 1 Hz in 50 Hz frequency) and to remain connected at least for a defined time within a larger range (to account for temporary disturbances). Voltage ranges may vary by area or connection voltage level, but frequency ranges should be aligned for all generators connected to the same synchronous area.

Voltage and frequency operating ranges go back to international standards applied by manufacturers of synchronous machines (Figure 7), with generators always designed to operate within a certain voltage and frequency range, limited by capabilities of the prime mover and the generator and exciter windings. In this regard, providing operation across a larger range is much less problematic for inverter-based generators, as the inverter current rating is the main limiting factor, together with the protection of semiconductor hardware against voltages that are too high.

Figure 7 IEEE C50.13 and IEC60034-3 limits on voltage and frequency



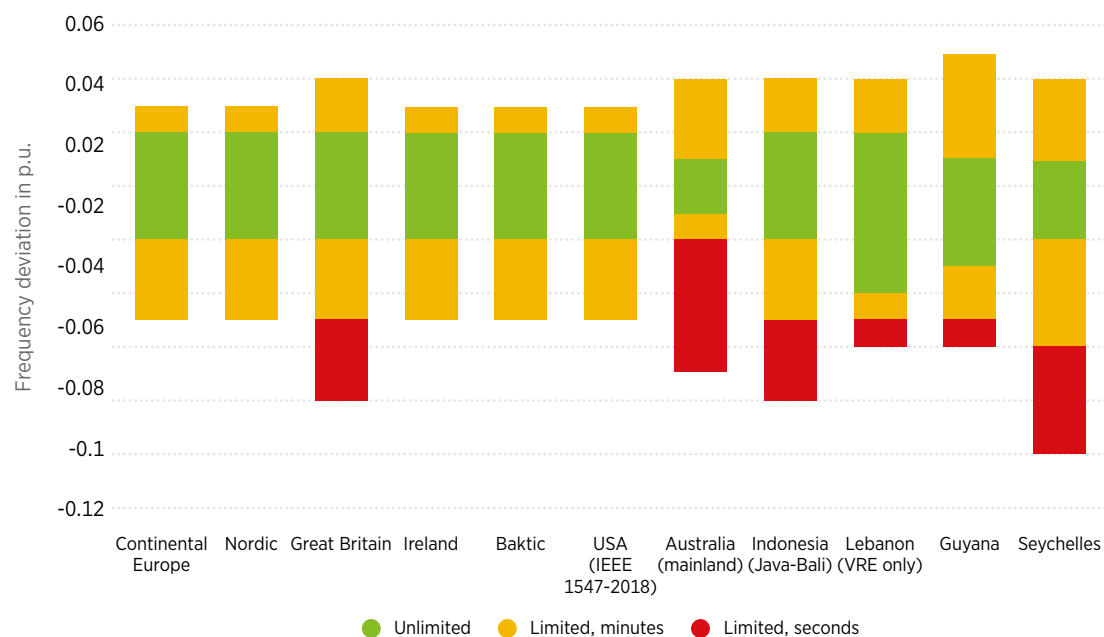
Source: IEEE Electrical Machinery Committee Task Force on Grid Code Impacts on Generator Standards (2018)

Note: U = voltage; f = frequency; p.u. = per unit; limit indicated by dotted envelope.

An imperfect grid code is in many cases better than no grid code at all, especially when economic conditions allow for renewable energy development to pick up pace

Most grid code requirements for time-unlimited (continuous) frequency operating ranges can be traced back directly to the IEEE and IEC standards, as evidenced by the ± 0.02 per unit range required by almost all examples shown in Figure 8, which shows the acceptable frequency deviation for different countries.

Figure 8 Frequency ranges required in grid codes in different synchronous areas of different sizes



Source: European Commission (2018), IEEE Standards Association (2018), Australian Energy Market Commission (2021), Menteri Energi dan Sumber Daya Mineral Republik Indonesia (2007), Guyana Power and Light (2018), Public Utilities Corporation (2018)

Further observations can be made based on this graphic:

- Synchronously independent systems (Great Britain, Guyana, Ireland, Java-Bali, Indonesia, Lebanon, Seychelles) tend to have extended time-limited ranges to account for the higher frequency sensitivity of smaller systems and the subsequent higher chance of frequency excursion events.
- The Lebanese system has been operating with a generation deficit for decades. Therefore, severe under frequencies are frequent and generators need to withstand those for at least a few seconds until the load shedding scheme reacts. The Lebanese system has separate grid codes for wind and solar and withstand ranges for non-VRE might be different.
- The Java-Bali system in Indonesia experiences frequent under frequencies and small-scale load shedding; the range is therefore expanded here as well.
- Australia has a narrow unlimited/continuous operation range, but extended time-limited ranges owing to the fact that the Australian system is prone to system splits, which can cause large short-term frequency deviations.

Regarding these international standards and requirements, the following recommendations can be given for the development of frequency operating range requirements in grid codes:

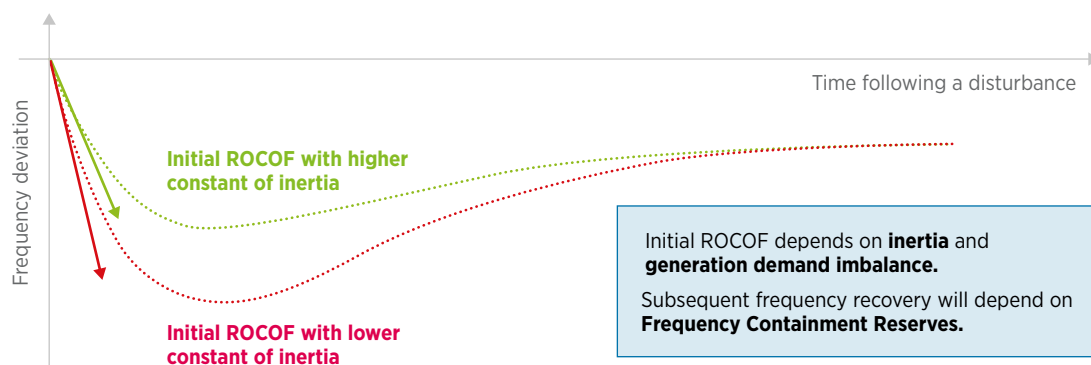
- The standard unlimited operational range is ± 0.02 per unit (± 1 Hz in 50 Hz systems, ± 1.2 Hz in 60 Hz systems). This range is limited by the design capabilities of synchronous generators and system inertia. It should only be larger if the system frequently operates outside this range and existing generators can comply with it.
- Time-limited operation for durations between 20 and 90 minutes is typically $+0.03$ or -0.05 perunit for the same reason.
- The shorter time-limited operating ranges need to be aligned with the underfrequency load shedding scheme applied in the system. Generators should not be allowed to disconnect before load-shedding schemes have reacted. An exception to this is the ERCOT interconnected power system, where in case of prolonged operation of generators under low-frequency – even though not to the level of under frequency load shedding (UFLS) activation, which happens at 59.3 Hz – generators are allowed to disconnect in 9 minutes of operation at 59.4 Hz.
- In big interconnected systems with lots of VRE, the overfrequency incidents are of big concern to the TSOs, because not enough synchronous generators are available to reduce the active power in case of system splits. Requirements for overfrequency active power reduction (LFSSM-O) for all generators were introduced in most transmission and distribution codes in the wake of the 50.2 Hz issue in Europe.

2.4 DETERMINING RoCoF LIMITS

The RoCoF at a system disturbance is of importance for different power system parameters and hence impacts multiple grid code requirements.

The higher the RoCoF, the faster the decline in frequency and the faster the response times from reserves to keep frequency stable. As the RoCoF is inversely proportional to the amount of inertia in the synchronous systems – and with increased shares of VRE replacing synchronous generation, which are inverter based and do not naturally contribute to inertia – it tends to go up. This can be exacerbated during days with low load and high VRE generation.

Figure 9 **The impact of total system inertia (TSI) constant on the frequency response of an interconnected system**



Source: ENTSO-E TYNDP (2018)

Figure 9 shows the RoCoF with different inertia levels in the system. The RoCoF is system dependent and also influenced by the load growth, synchronous generation mix and its flexibility, the number of must-run and base-load units (e.g. nuclear), etc.

In large interconnected systems, this is not (yet) an issue, unless there is a system split and smaller islands are created, but it is very clearly visible in smaller, synchronously independent systems. The systems in Australia, Great Britain, Ireland and Texas (United States) have all had to undertake measures to limit RoCoF for a number of different reasons:

- A high RoCoF is generally undesirable as it reduces the time window for frequency containment reserves to contain the frequency deviation.
- Synchronous generating units are mostly not designed to withstand high RoCoF events, which physically strain the generator, drivetrain and prime mover.
- RoCoF is used as an indicator in some anti-islanding protection schemes, potentially resulting in DER disconnecting at high RoCoF events, based on the assumption that fast and steep frequency changes can only be observed in unintentionally disconnected grid segments.

RoCoF issues can be addressed in different dimensions. The first and most obvious one is a requirement for a certain minimum amount of inertia that always must be present in order to limit the RoCoF to an acceptable value. Such “inertia floors” are imposed in Great Britain, Ireland, the Nordic Synchronous System and ERCOT, but only present a short-term solution as they inevitably limit non-synchronous penetration and thus VRE contribution. In ERCOT they are called critical inertia. Below this inertia level, the frequency response mechanisms are too slow to stop the frequency before it attains UFLS after the biggest loss of generation (Matevosyan, 2018).

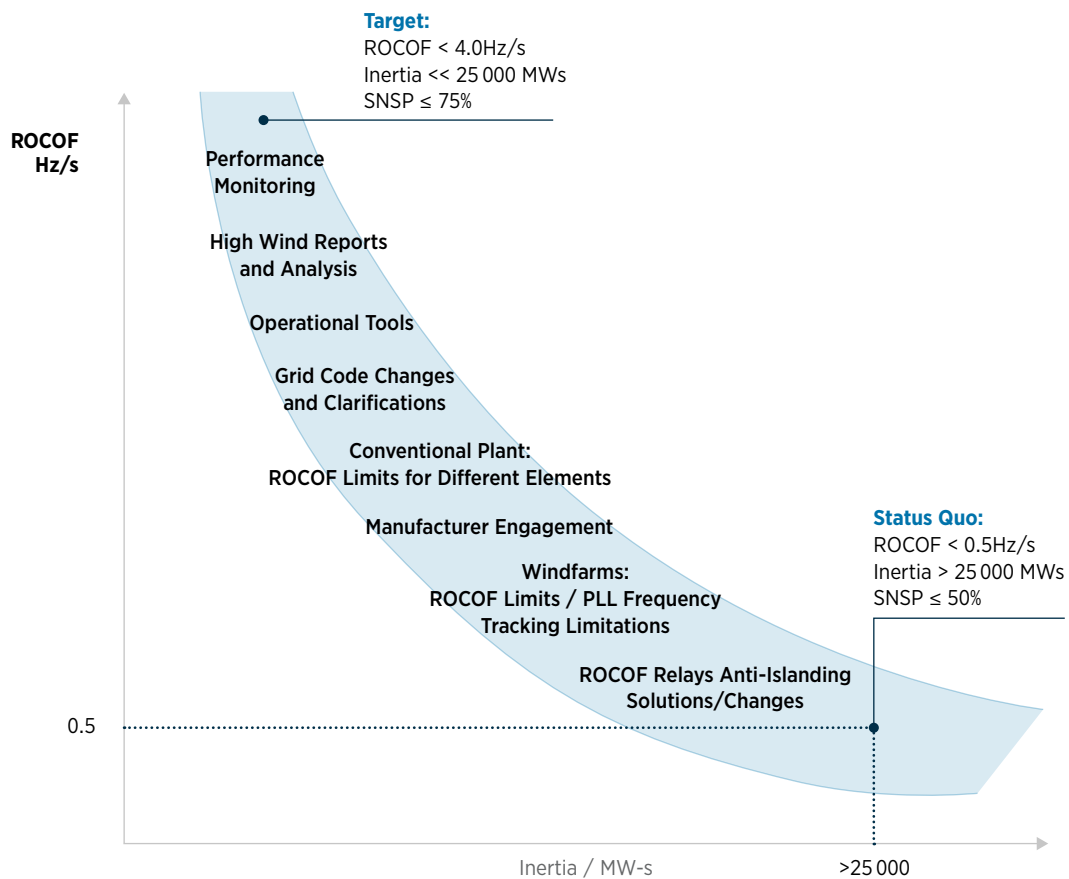
Measures can be, and are, undertaken to reduce either the amount of necessary system inertia or the amount of conventional generation that needs to be online to achieve the necessary inertia. Ireland is a good example in this regard, as Irish TSO EirGrid constantly updates its requirements through the DS3 programme (EirGrid Plc and SONI, 2012; EirGrid, ESB Networks and CRU, 2018) to increase the permissible system non-synchronous penetration (SNSP). The issue has been tackled on multiple levels in parallel:

- Generators are incentivised to reduce their minimum stable active power output (the inertia of a generator is independent of the power output, as long as the generator remains online).
- Generators and DER have been requested to retrofit or confirm withstand capability for RoCoF values above the initially required 0.5 Hz per second.
- Anti-islanding protection requirements in distribution grids have been revised (although Great Britain is a more prominent example here, as RoCoF-based loss-of-mains [LOM] protection is more commonly used in Great Britain than in Ireland).
- FFR (see Chapter 4, Section 3) has been introduced as an additional ancillary service to quickly limit frequency deviations, especially in high RoCoF events. This has incentivised the investments in resources that can respond faster (e.g. battery storage).
- Dynamic stability analysis is conducted with real-time data and short-term forecasts. Based on the results, it has been possible to raise the SNSP limit every one to two years.
- Monitoring of the largest credible contingency in near real-time has allowed the inertia floor to be lowered.

The measures however all address issues appearing in an existing system with existing generators. One reason for the appearance of such issues are past grid code requirements that did not foresee the rapid development of non-synchronous generation. New grid code requirements cannot mitigate these issues to the full extent, as retroactive applicability is inherently a bad idea, but can at least contribute to mitigating by requiring new generators to not cause any additional issues.

To avoid issues with generators going forward, minimum RoCoF withstand requirements have recently been introduced into a number of grid codes. In the case of Ireland, the motivation and development process is clearly outlined in documents published through EirGrid's DS3 programme. Maximum RoCoF was expected to rise from 0.5 Hz per second at a minimum system inertia of 25 000 megawatt seconds (MW-s) and an SNSP limit of 50% in 2011 to 4.0 Hz per second at 75% SNSP targeted for 2021 if no measures were taken, based on a dynamic stability analysis of the all-island system (Ireland and Northern Ireland) conducted by EirGrid (Figure 7) (EirGrid Plc and SONI, 2012; EirGrid, ESB Networks and CRU, 2018).

Figure 10 RoCoF vs. system inertia projection for the Irish system, 2012



Option 1 - Achieve higher allowable SNSP values through higher ROCOF limits and Grid Code standards

Source: EirGrid Plc and SONI (2012)

Note: Hz/s = Hertz per second.

The RoCoF withstand capability required by the grid code was raised from 0.5 Hz per second to 1.0 Hz per second in 2015, both measured over a sliding window of 500 milliseconds. EirGrid also incentivised retrofitting and compliance testing on existing generators. As of the end of 2019, 100% of wind power plants and more than 80% of synchronous generators in the all-island system were compliant with the new requirement. At the same time, additional measures were undertaken to limit RoCoF, such as the introduction of the synchronous inertial response (SIR) and FFR services. The regular operational limit remains at 0.5 Hz per second as of 2021, at a minimum inertia of 23 000 MW and a 65% limit on SNSP. Trials for 70% SNSP are ongoing as of 2021, and the system has been shown to operate stably with that limit as well (EirGrid/SONI, 2021; CRU, 2019).

While in Ireland, compliance of synchronous generators with the new requirement was (and continues to be) the most significant challenge, increasing RoCoF in the the system in Great Britain has most significantly impacted requirements for distributed generators. RoCoF values of up to 0.5 Hz per second are expected in the British system in the coming years (National Grid ESO, 2020). Distributed generators connected to British systems are required to implement LOM protection to avoid unintentional islanding, and while more complex and reliable active protection schemes exist, this was mostly realised through RoCoF relays set to disconnect the units if RoCoF exceeded 0.125 Hz per second (Energy Networks Association, 2015). While this value may at first glance seem unreasonably low compared to the previously mentioned Irish requirements, research done by the University of Strathclyde on behalf of British TSO National Grid showed that increasing the RoCoF threshold on such protections to 1.0 Hz per second reduces their ability to reliably detect an islanding situation (Dyśko, Tzelepis and Booth, 2015, 2017). The engineering recommendations referred to by the British distribution code were however updated to require a RoCoF withstand capability of 1.0 Hz per second for 500 milliseconds in 2018, as the risk was deemed acceptable after further research (Distribution Network Operators (DNOs) in Great Britain, 2020; Energy Networks Association, 2018).

2.5 DETERMINING FRT ENVELOPES

The shape of the FRT envelope, which usually includes requirements for both under- and overvoltage situations as of 2021, depends on the system's response to a grid fault and on the corresponding needs of further system components. This response is directly dependent on the fault type, the protection scheme, and the capability of the connected generators and loads to remain connected and recover to normal operation after a fault. The protection scheme in turn depends on the critical fault clearing time of the system, determined by the rotor angle stability of the connected synchronous machines. In this regard, the fault behaviour required from new generators to a large degree depends on the capabilities of the existing generators and may have to be reviewed and revised from time to time as generator fleets (and load characteristics) change.

As FRT requirements started appearing in grid codes in the early 2000s, the process of developing FRT requirements based on the characteristics of an existing system is well documented (Deutsche Verbundgesellschaft EV, 2000; E.ON Netz GmbH, 2001). Requirements can be developed based on actual fault recordings and the typical system behaviour known to the system operator or based on dynamic stability studies. The latter can be especially useful to assess the suitability of potential FRT envelopes for future situations in which the situation in the grid may have changed significantly. In most countries that have had the requirement in their

codes for longer periods of time, there was usually an iterative process between developing FRT envelopes based on the current system and implementing those in the grid code as quickly as possible, and the assessment of the suitability of applied envelopes for future situations. FRT envelopes are routinely modified as the situation changes.

Inputs to the development of FRT requirements are the following, which will be elaborated in detail in the next sections:

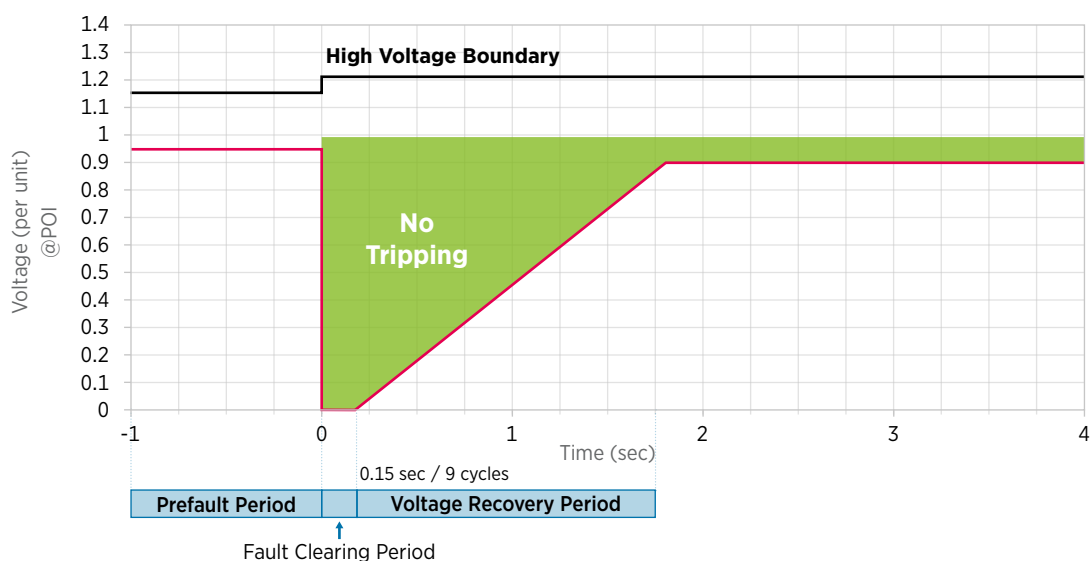
- Study of system critical clearing time (CCT) – the latest time by which a short circuit has to be cleared to not endanger rotor angle stability of synchronous generators in the grid, and used to develop protection time settings.
- Information from manufacturers of both VRE and conventional generators on the current and potential future capabilities of their products regarding FRT.
- Voltage traces of high-resolution measurements obtained during actual grid faults.
- Results of dynamic stability analysis.

FRT requirements, like other grid code requirements, are subject to review by power system stakeholders (including equipment manufacturers) in most countries. The final FRT requirements found in grid codes usually seek to balance the interests of the system operator (focus on stability) and the manufacturers (focus on clarity of requirements and economic impact).

One of the earliest examples of an FRT envelope from ERCOT depicts that the wind power plants are to set their generator voltage relays to remain in-service during all faults and to remain interconnected during three phase faults for voltages as low as zero volts at least for nine cycles. This may be done with the help of additional equipment if necessary.

Dynamic fault behaviour of inverter-based generators must also be tuned to the system's needs, while the behaviour of synchronous generators is largely inherent. There are generally three different dynamic current modes, with different applications:

Figure 11 **Voltage ride-through boundaries for wind-powered generation resources in ERCOT**



Source: EirGrid (2010)

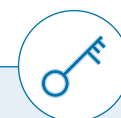
- **Dynamic reactive current requirements**, in which generators are required to provide a reactive current up to their current rating for the duration of the fault while reducing active power as necessary. These are common in large interconnected systems, as spatial containment of the voltage dip has priority over the potential impact of active power reduction.
- A priority on retaining the active current or as much of the active power output as possible is more common in islanded systems, as the frequency impact of active power reduction may be more dangerous at system level than the spread of the voltage dip. However, depending on transient stability conditions in the grid, some island grids may also require a **dynamic reactive current requirement**.
- **Combined requirements** intend to hit the balance between the two, with for example Ireland requiring generators to retain pre-fault active current while providing additional reactive current using the rest of the rated capacity. A similar requirement was adopted in the grid code of Madeira. This approach will require some reduction of reactive current injection capability, such that additional room is given to active current.

Concerning the choice of dynamic current mode for a grid code, the interests of a TSO can differ from those of the DSO. DSOs tend to prefer that any new DER shall not change the existing protection scheme in the grid area. The easiest way to achieve this is to require that the DER shall not inject any fault current at all. This approach assumes that at any time, all short circuit current is provided from higher voltage levels. From a TSO perspective this is not desirable. To keep the voltage dip impact on the transmission system as small as possible, a fault current contribution is desired from all connected power plants, regardless of whether they are connected to the distribution or to the transmission level. TSOs focus on overall system stability and may not be interested in avoiding the potentially needed effort of the DSO to adjust a local protection scheme. Such conflicting interests have to be addressed and resolved when developing the grid code requirements.



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03 EVOLUTION OF TECHNICAL REQUIREMENTS



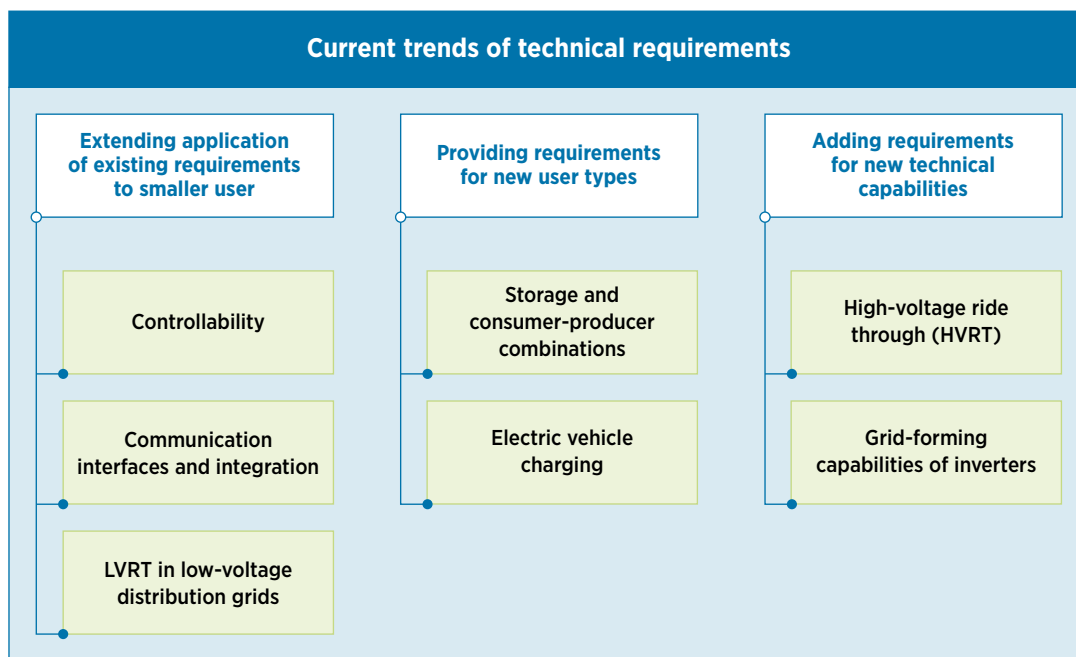
KEY TAKEAWAYS OF THIS CHAPTER:

- › Grid code requirements were previously only applicable to larger users, but they should be extended to smaller users as well. This would enable new users' types to connect in a system-friendly way, by specifying corresponding requirements for them and adapting to the state of technological development and system needs.
- › Deployment of DER increases the need for controllability. Grid codes can specify the type of VRE units that should adhere to controls and the power reduction and power restoration ramps for VRE.
- › Controllability requires communication interfaces, and grid codes can specify protocols and standards for the same. However, a minimum of interfaces and protocols should be required from distributed resources to keep costs down.
- › In this context, real-time Internet-based communication is becoming more relevant for power system operation, control and monitoring. Therefore, cybersecurity is one of the most critical factors for security of electricity supply and will become even more important in the future. Grid codes are evolving towards recommending standards and improving cybersecurity in power systems.
- › The inclusion of rooftop solar PV and storage and EVs at the low voltage grid has pushed the need for including LVRT from generators connected to low voltage grids. However, the low voltage parameters are less strict than those for medium or high voltage grids, and there is no requirement to support the voltage.
- › High voltage ride through (HVRT) is not very common in grid codes yet. With increasing VRE it is expected that this requirement related to the VRE remaining connected during over voltage will be more commonly implemented.
- › So far, storage is treated differently in various grid codes, either as a generation asset abiding by the minimum requirements applied to generators or as an IBR mainly focusing on its controllability and operation, whereas in some grid codes it has its own requirement depending on its size.
- › EVs categorised as demand (V1G) and generation (V2G) have specific requirements in regulations with regard to their state of charging, particularly pertaining to the ability to access charging flexibility in the future.

Grid code requirements worldwide have been continuously refined and extended over the past years, and new requirements have been developed and introduced. This chapter discusses development trends observed across leading grid codes to adapt to further increasing VRE penetration, and to the accompanying transformative trends of decentralisation, digitalisation and electrification of the end-use sector. The most significant changes encompass the requirements for DER and demand response. Also, grid codes start addressing the grid-forming capability of inverters, which can be the key to achieving 100% VRE systems as they can operate in stand-alone mode.

The evolution of grid code requirements can be divided into three extension dimensions, as illustrated in Figure 12: i) extending requirements, previously only applicable to larger users, to smaller users as well; ii) enabling new user types to connect by specifying corresponding requirements for them; and iii) adapting to the state of technological development and system needs by requiring newly developed functionality.

Figure 12 **The current (non-exhaustive) trends of technical requirements in grid connection codes**



3.1 CONTROLLABILITY

Controllability requirements are increasingly being extended towards applying to rooftop solar PV and other small DER.

There are two main facets of active power controllability for power plants: the first is the capability to reduce power output; the second is the capability of increasing power output upon request. VRE generation must be capable of both, to the extent possible without mandating the addition of energy storage. Grid code requirements therefore specify power

reduction capabilities and minimum power restoration ramps for VRE generation. In practice power system operators can impose an upper limit for power injection on a VRE generation facility, and the facility will adhere to this limit as quickly and accurately as required. When power output has been reduced during a disturbance without an externally signalled limit, units must return to the pre-fault operating points quickly to avoid undue impact on the system's frequency regulation. This ability to reduce VRE power output and eventually also control ramping rates is critical to congestion management and to maintaining frequency stability.

In some jurisdictions there have been discussions on also requiring minimum power output (firm capacity) from VRE generation under certain conditions. However, the imposition of such requirements is a rare exception and should be seen as a barrier to VRE adoption. VRE power plants cannot readily provide firm power output regardless of weather conditions without significant additional energy storage. Due to the high additional investment needed for storage, any storage requirement must be weighed against other ways of accessing flexibility and maintaining the power balance in the corresponding system, and it should be explicit if it is necessary (IRENA, 2020b).

While the VRE share is still low in a system, active power management capabilities from VRE generators may not be needed. However, this changes quickly with increasing VRE penetration. There is therefore no downside to making this a requirement from the beginning. It should also apply to DER at all voltage levels, possibly with an applicability threshold in the low kilowatts range.

In both examples (Germany and IEEE Std 1547-2018), the specifications also enable the system operator to use not only reactive power, but also active power management for voltage control purposes in the low voltage system, although this functionality is not activated by default.

Efficient use of DER controllability of any kind is only possible through remote management, which requires communication interfaces and control system integration.

Box 4 **Grid codes for remote control in China and Germany and the IEEE Standard**

China

According to Chinese energy storage connection code GB36547-2018, the system operator can send set-points and should work for suitable voltage management.

Germany

According to the German grid code for connection to the low voltage grid, new PV facilities with less than 30 kW capacity that cannot be controlled remotely have to limit their output to 70% of rated power. Remote control of active power output at the request of the system operator is required for all DER rated above 100 kW connected to the grid (VDE FNN, 2018a). The renewable energy law specifies similar requirements, but since 2021 puts the remote control threshold at a power rating of 25 kW (EEG (2021). Temporary curtailment for system management reasons is associated with full financial compensation for the energy not fed into the grid. This ensures that network security management does not adversely affect the incentives to install further VRE capacity.

IEEE Std 1547-2018

The current version of IEEE Std 1547 (IEEE Standards Association, 2018a) specifies a requirement for all conformant DER to respond to (local and/or remote) control signals limiting the active power. There is no DER size threshold for this requirement.

3.2 COMMUNICATION INTERFACES AND INTEGRATION

There are many different methods through which remote monitoring and control of DER can be implemented. However, the necessity of potentially having to implement several different communication interfaces and protocols can drive cost upwards for DER manufacturers. It is therefore beneficial to VRE integration if only a minimum number of standardised interfaces and protocols are required to be implemented, and these requirements should be harmonised across jurisdictions as much as possible. The IEC 61850 family of standards is commonly seen as a potential solution to this issue.

Harmonisation of communication interface requirements and control system integration remain a challenge in systems where they were not specified at the earliest VRE integration phases. While Italy has settled on mandating support for communication based on the IEC 61850 set of protocols early on, countries like Germany or the United States need to maintain the various DSOs' ability to continue running their diverse existing communication systems, and therefore the exact communication interfaces to be supported by new DER need to be agreed with the local DSO.

IEEE Std 1547-2018 specifies that conformant DER must implement at least one of three listed protocols: SEP2 (IEEE Std 2030.5), DNP3 (IEEE Std 1815) or SunSpec Modbus (over Ethernet or RS-485). However, it also leaves room for further protocols to be agreed between the involved parties, so that IEC 61850 or other protocols can be used as well (IEEE Standards Association, 2018a).

In Germany, the grid connection rules published by the Forum Network Technology/Network Operation in the Association for Electrical, Electronic & Information Technologies (VDE FNN) do not specify any required communication interfaces, and specifying them is left to the individual system operators for their own individual connection rules. While the most commonly used communication standards for DER are still IEC 60870-5-101/104, there is also a trend towards increasing use of IEC 61850 (DENA, 2018). Bidirectional communication to enable both control and monitoring is required for all facilities larger than 100 kW. Any new DER installation above 7 kW is required to communicate through a smart meter gateway (SMGW), which provides a secure data communication channel to the system operator for energy management (EEG, 2021; Förderer *et al.*, 2019). VDE FNN has published a specification of functional requirements for the on-site control box to be connected to this interface, and this specification relies on IEC 61850 for communicating with the operator (VDE FNN, 2018c). Multiple communication protocols can be supported between the control box and the individual DER units; one of the most commonly supported protocols is EEBUS (Swistec GmbH, n.d.).

In China, the communication between DER connected at medium voltage level and the system operators must meet the requirements of relevant standards, including both remote monitoring and control signals. The Chinese communication protocol standards DL/T 634.5.101 and DL/T 634.5.104, which are adopted from IEC 60870-5-101/104, can be applied. DER and microgrids connected at the low voltage level can communicate using a wireless or optical fibre public network, but information security protection measures must be in place.

Since setting up dedicated (physically separate) communication networks for power system monitoring and management is infeasible if these functions need to reach down into the low voltage system, Internet-based communication is becoming more and more relevant for power system operation. This is another reason why cybersecurity has already become one of the most critical factors for the security of electricity supply today and will become even more important in the future (Döring *et al.*, 2018).

Box 5 Cybersecurity

The term cybersecurity refers to information security in communication networks. Information security comprises confidentiality, integrity and availability of any data (the so-called CIA triad).

Figure 13 CIA triad



Confidentiality means that information is only available to authorised parties. If this is not guaranteed, then malicious third parties can use the information to inflict damage on infrastructure/equipment, businesses and humans.

Integrity means that the information itself is not modified while it is stored or transmitted. Only when the information being read/received is the same as that being written/sent is it possible that the data are interpreted correctly. Unauthorised parties must be prevented from modifying or removing any data.

Availability ensures that the authorised parties are able to access the information when needed. This implies sufficient degrees of reliability both for data storage and data transmission, even in the case of third-party interference attempts or accidents.

The multitude of hardware, software and organisational controls available to achieve these high-level requirements on the smart grid implementation level has been collected and categorised in several standards already. A good example of this is NISTIR 7628 (National Institute of Standards and Technology, 2014b). However, new security measures as well as new potential attacks continue to be developed as operational complexity increases, and the field is evolving rapidly.

Connection grid code usually do not attempt to address cybersecurity aspects directly, although they may be considered when choosing the required protocols.

Grid codes offering support on cybersecurity issues

Still, stakeholders such as generation facility owners are well advised to assess their cybersecurity levels and implement controls to mitigate the most important risks. One tool providing support with this is the Distributed Energy Resources Cybersecurity Framework. It offers a web application that can prioritise recommendations based on the user's input (Powell *et al.*, 2019).

In the United States, the Framework and Roadmap for Smart Grid Interoperability Standards (National Institute of Standards and Technology, 2014a) lays out the standardisation landscape for smart grid interoperability, including standards for cybersecurity. Knowledge sharing on this issue is also supported by the US Department of Energy through its smartgrid.gov platform (smartgrid.gov, n.d.).

Recommendations from the European Commission highlight the need for a methodical, sector-based line of cybersecurity defence for the energy system – particularly the electricity grid. This is necessary because of real-time requirements, a combination of both conventional and modern technologies, and the multiple consequences of disruptions. For these reasons, authorities foresee an increased necessity for regulation, enhanced knowledge and information exchange, certification and standardisation, and cybersecurity skills development (Erbach and O’Shea, 2019). The European Agency for Network and Information Security (also known as Agency for Cybersecurity) supports co-ordination and collaboration on cybersecurity between agencies and institutions in the EU member states and offers corresponding recommendations (ENISA, n.d.). A new network code on cybersecurity is under development by ENTSO-E and the newly created EU DSO entity. Interim reports on the development of the grid code recommend setting up an early warning system for the energy sector in Europe, cross-border and cross-organisation risk management, minimum security requirements for critical infrastructure components, a minimum protection level for energy system operators, a European energy cybersecurity maturity framework, and supply chain risk management (Erbach and O’Shea, 2019). Further support to system operators is provided by a non-profit organisation called the European Network for Cyber Security (ENCS, n.d.).

Box 6 Cybersecurity for wind power plants

The increasing reliance for dynamic operation of wind systems based on both internal plant data and external information requires network communication capabilities. Strategies for strengthening the cybersecurity of the intercommunication between the grid and wind plants are of unqualified importance because cyberattacks can cause major disruption to grid reliability by causing failures in both the software and hardware of wind turbines and the grid.

Cyber threats to wind energy technology have already occurred. Since wind-specific cybersecurity standards and grid codes do not exist, wind plants rely on general standards and grid codes that do not align exactly with the nature of wind technologies, thus creating a gap in the knowledge needed to provide extensive cybersecurity to such energy plants.

Some of the strategies stakeholders can follow to increase cybersecurity throughout the supply chain of the wind industry are network segmentation, developing cyber asset lists, creating a cyber emergency response plan, specifying concrete and clear supply chains, and performing cyber hygiene. This is an ongoing research field, and current best practices are expected to change exhaustively as more wind renewable is added to the energy mix (US Department of Energy, 2020).

As is generally the case in system planning and organisation, the more proactive and communicative the stakeholders, the better the chances to develop an extensive and comprehensive cybersecurity framework. It is in the interest of all – developers, investors, operators, government officials and policy makers – to broadly engage and share information, perform maintenance services, and perform best practices for a better, long-term, cyber-resilient VRE integrated energy system.



Photo: Stephan Langhans / Shutterstock

3.3 LVRT REQUIREMENTS IN LOW-VOLTAGE DISTRIBUTION GRIDS

Until recently, LVRT requirements were specified in grid codes only for DER connected at medium voltage or higher level. The latest generation of grid codes now requires LVRT capabilities from all DER, including those connected to low voltage distribution grids. There is no reason why these units should be exempt from such a requirement – the vast majority of DER connected at the low voltage level is solar PV (and other inverter-based technology such as batteries), and implementing LVRT capability is not very challenging with this technology. In addition, disconnecting significant amounts of solar PV at undervoltage events can endanger system reliability.

In contrast to the LVRT requirements specified for medium and higher voltage connections, the LVRT envelopes for low voltage do not extend down to zero residual voltage. According to the German low voltage grid code, synchronous machines do not need to ride through voltage dips below a residual voltage of 30% of the nominal voltage. For non-synchronous generation, the limit is 15% of the nominal voltage. Another example is the Japanese grid code for residential applications of PV, which lowered the threshold of residual low voltage in 2016 from 0.30 per unit to 0.20 per unit for 1 second. In addition, the PV system should recover more than 80% of the power output in 0.2 seconds (Iwamura *et al.*, 2018).

Another difference between the LVRT requirements at low voltage and higher voltage levels is that at low voltage there is generally no corresponding requirement to support the voltage by injecting reactive or active current during LVRT events. In fact, for residual voltages below 80% of the nominal voltage, non-synchronous generation and storage units are required to stop injecting any active or reactive current into the grid (VDE FNN, 2018a).

IEEE 1547-2018 does not consider the voltage level of the connection point in the specification of its LVRT requirement. Instead, the DER performance is to be selected among three predetermined LVRT envelopes (with increasing strictness amongst them) by the authority governing interconnection requirements (operator, utility or regulator, depending on the jurisdiction). The selected profile can be chosen by the authority according to the type of DER technology connected to the system and the stability needs of the power system (IEEE Standards Association, 2018a).

3.4 HVRT REQUIREMENTS

Unlike LVRT, which is a mandatory basic requirement in almost every international and national grid code, HVRT has seen comparatively less emphasis in the grid codes. HVRT requirements identify the performance of the generation asset during a voltage rise. Traditionally, HVRT has been stipulated in DER integration with medium and low voltage systems, such as IEEE 1547 and in Germany's VED-AR-N 4110/4105. For DER, overvoltage may occur in several situations, such as line-to-ground faults and fault clearance, during large-scale tripping of generation or load, or during the transient periods by switching on large capacitor banks.

The FRT specifications determine the performance of the generator during faults. They are specified in terms of the tripping voltage threshold and clearing time and are indicative of the robustness of the DER. According to IEEE 1547-2018, the default clearing time of DER under 1.2 per unit (p.u.) of nominal voltage is fixed at 0.16 second, while the clearing time varies between 1 second and 13 seconds when the voltage is lower than 1.2 p.u. In the medium and low voltage power system of Germany, DER are required to remained connected for 0.1 second under 1.25 p.u. and 5 seconds with 1.2 p.u. overvoltage (IEEE Standards Association, 2018b).

But with significant shares of renewable energy, especially wind, being connected through the transmission system and replacing the inertial contribution to system stability, the need for HVRT implementation and its discussion in grid codes is gaining momentum. Once the fault is cleared, for example in large wind farms, there is usually a transient period of high voltage. These high voltage excursions vary in duration and impact. Overvoltage occurrences like these, can be caused by increased reactive current injection during grid faults from renewable generators. Similarly, active currents injection may induce comparable actions in grids with relevant resistive characteristics.

In 2011, Northwest China Grid suffered a large-scale trip accident of 598 turbines and lost about 840 MW of wind power. During the first phase of this accident, 274 turbines disconnected from the grid due to voltage dip, and the excess reactive power made the voltage swell. Then another 324 turbines tripped due to their lacking the capability to resist such overvoltage. A similar German accident in 2012 resulted in the loss of about 1.7 gigawatts (GW) of wind power and caused the 420-kilovolt (kV) transmission network to increase considerably, up to 435 kV, for approximately three minutes.

To promote large-scale integration of wind and solar energy, grid codes solve this problem by stipulating the generating unit's HVRT specifications. The HVRT specifications are clarified in Table 4 for the listed countries. Australia, China and Spain have the most stringent regulations requiring a wind power plant and PV system to withstand a voltage swell of 130% of rated grid voltage. In the United States, the Western Electricity Coordinating Council (WECC) grid code requires that the wind turbine remain connected under the voltage of 1.2 p.u. for 1 second.

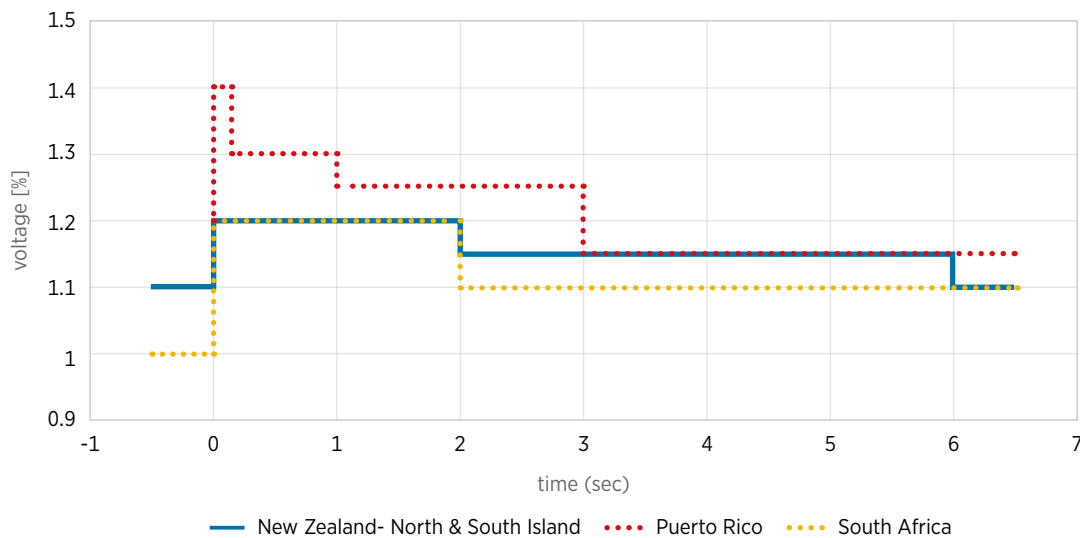
Table 4 HVRT requirements in selected countries

National grid codes	Fault	
	Vmax (p.u.)	Tmax (ms)
Australia	1.3	600
China	1.3	500
Denmark	1.2	100
Germany	1.2	100
Italy	1.25	100
Spain	1.3	250
United States	1.2	1000

Note: Vmax = maximum voltage; Tmax = maximum time; ms = milliseconds.

For system restoration under HVRT, it is imperative to have dynamic grid support during voltage swell. The capability of generating units to support the voltage by supplying reactive power at the time of the fault while using the same or less reactive power post-fault clearance is essential. In Denmark, Germany and Spain, the grid codes specify that the reactive current can only be injected outside the dead band (between 0.90 p.u. and 1.10 p.u. of the nominal voltage) by 10%. To avoid adverse outcomes, it is advisable for the renewable power plant to avoid reactive current absorption after the fault clearance.

Figure 14 HVRT curves in selected grid codes



Source: Hagh and Tohid (2018)

Figure 14 indicates the HVRT curves from selected grid codes and how long they stay connected during a voltage rise from a nominal value of 1 p.u.

3.5 REQUIREMENTS FOR STORAGE AND OTHER CONSUMER-PRODUCER CONNECTIONS

Due to the increasing decentralisation of the power system through the integration of battery storage, solar PV and battery combinations, and consumers with micro-CHP generators, the distinction between power generating and consuming grid users is blurring. It has therefore become relevant to specify technical requirements in grid codes for such combined consumer-producer connections. Similar to existing grid codes, the new grid codes covering these technologies do not distinguish between the many individual asset types but try to specify the requirements in a technology-neutral manner as far as possible. Such technology-neutral requirements help avoid introducing technical barriers for individual technologies, allowing users to adopt the most economically efficient technical solution to suit their needs and business cases.

Currently, the European grid connection network codes do not set any requirements for energy storage systems. The Grid Connection European Stakeholder Committee believes that a simple approach should be adopted in so far that an electricity storage module is the same as a power generating module. Therefore an electricity storage module will have to meet the same requirements as a power generating module when operating in both a generating mode and consumption mode, with specific additional requirements added where necessary (ENTSO-E, 2020b).

However, several member states have developed their own strategies to deal with storage. Therefore, different approaches are followed. For example, Belgium groups storage with power park module technology (wind parks or solar parks) for some requirements, but it also has a specific grid code section regarding storage (except pumped hydro) that covers frequency, robustness and LVRT, voltage stability, and reactive power capacity (Service Public Fédéral Economie P.M.E. Classes Moyennes et Energie, 2019).

Finland established its own specifications for storage, taking into account the goals of the European grid connection network codes. The requirements are specific for storage connected through power electronics and include controllability, operating frequency and voltage ranges, RoCoF, FRT, fault behaviour, protection, recovery after voltage disturbances, active power control, reactive power capacity, voltage control and reactive power control, commissioning testing, modelling requirements, and the compliance process. They also mention that large storage systems (types C¹⁰ and D¹¹) should agree bilaterally with the TSO on the capabilities for black start and anti-islanding (Fingrid, 2020).

Both Belgium and Finland follow the approach of classifying the storage facilities in types A through D as it is done for generators in the European grid code according to the maximum active power they are technically capable of injecting into or absorbing from the grid (see Chapter 6, Section 1 for more information on these types) (Service Public Fédéral Economie P.M.E. Classes Moyennes et Energie, 2019; Fingrid, 2020).

Great Britain considers that energy storage is a subset of power generation modules and therefore must abide by the minimum requirements applied to generators. The definition for electricity storage includes synchronous and non-synchronous technology, but such technology should be controllable in its injection/absorption of electricity and other functionalities as demanded from power generation equipment. Flywheels shall only fulfil the aforementioned requirements if their input/output of electricity can be operated in a controllable manner (Ofgem, 2020; National Grid ESO, 2021a).

The German rules for low voltage DER connections distinguish among facilities for EV charging, storage, consumption and generation. In addition, the rules include another category for mixed facilities that combine assets of numerous types at medium and higher voltage levels. The distinction does not extend to separate technical connection requirements among generation, storage and mixed facilities: while active power is injected into the system, the conditions specified for generators always apply (VDE FNN, 2018b). Similarly, IEEE 1547-2018 does not refer to generator facilities specifically, but to DER in general – any facility that is able to export active power into the power system, regardless of how it is composed internally. Controllable loads do not fall under this definition of DER.

10 Type C: The connection point's voltage level is less than 110 kV, and the grid energy storage system's rated capacity in production mode is at least 10 MW but less than 30 MW.

11 Type D: The connection point's voltage level is at least 110 kV, or the grid energy storage system's rated capacity in production mode is at least 30 MW.

The Chinese technical rules for connecting energy storage systems, GB36547-2018, mainly consider the power control and adaptability. This code covers the integration of energy storage in generation side and transmission side for any storage capacity, and at consumer side only when the storage capacity is higher than 5 MW, to support the power dispatch. In the newly revised version, the charging/discharging transfer time is designed at millisecond scale, showing the fast response potential of inverter-based energy storage.

Box 7 European grid code for demand side flexibility

Ongoing development for a network code on demand side flexibility is being done at the European level. The code aims to “better define and clarify the concept of ‘demand side flexibility’ and set up clear roles and responsibilities for all stakeholders” (European Commission, 2020). Current consultative processes suggest “that the network code should incentivise market-based flexibility procurement and support the creation of transparent and non-discriminatory flexibility markets at distribution and transmission levels. It should encompass all sources of flexibility, including storage and aggregation. Overall, stakeholders stress that the network code should be technology neutral”. (*European Commission, 2020*)

In order to effectively reduce the barriers to scale up demand side flexibility, Europe’s association for smart energy, SmartEN, suggests that the network code should also provide increased transparency on the needs of the grid, interactions between market participants and a market-based approach to all flexibility purchasing. The network code should also come with a cost-efficient solution for the integration of renewable energy sources and an increase in electrification as an alternative to grid reinforcement (SmartEn, 2020).

EV charging is notable because the storage units are not connected to the facility permanently. The implemented functionality therefore may not include the discharge and/or export of active power into the power system.

3.6 REQUIREMENTS FOR EV CHARGING

Due to the rapidly increasing numbers of EVs and the high charging power of each vehicle compared to normal household connections, recent grid codes have adopted requirements for EV charging as well. Similar to permanent storage and other consumer-producer connections, EV charging facilities usually need to fulfil the requirements applicable to generators while exporting active power into the grid.

At the European level, the expert group consultation organised by ENTSO-E concludes that the connection network codes assume that EVs (V1Gs and V2Gs) fall within the scope of the connection network codes but do not require special treatment. A V1G would fall within the scope of demand (as codified under Demand Connection Code) and a V2G would fall under the scope of generation (codified under Requirement for Generators) (ENTSO-E, 2020b).

For example, the German rules for facilities connected to the low voltage system specify that charging facilities for EVs, while in discharging and therefore exporting mode, must be able to ride through the same kind of voltage dips as generators without disconnecting from the system (VDE FNN, 2019). Charging facilities with an active power rating above 100 kW, like storage, must have interfaces suitable for bidirectional communication enabling remote control and remote monitoring.

Australia is undergoing revisions to its national standard – specifically AS4777.2 – to extend requirements for EVs so the full potential of vehicle-to-grid services is available. In this respect, EV charging stations need to fulfil requirements set for inverters, which include electrical safety, power quality, voltage support, demand response modes, anti-islanding requirements and withstand of grid conditions (FRT). An ongoing pilot project called the REVs project will validate a vehicle-to-grid charger against the AS4777 standard (Jones *et al.*, 2021).

Electromobility is expected to represent a significant share of power consumption in future power systems, and therefore the flexibility provided by co-ordinated charging is expected to be useful in accommodating VRE integration. In power systems where hardly any conventional power plants with synchronous generators are left to balance the variability, the inverters built into vehicle chargers and storage might need to have further capabilities beyond LVRT and remote controllability. One category of functions for inverters that has been under heavy discussion over the past few years is grid-forming capability.

3.7 GRID-FORMING CAPABILITIES OF INVERTERS

The continuing transformation of power sectors worldwide towards renewable energy-based systems corresponds to a transformation to more IBRs. There is an increasing need for technologies that will allow AC grid operation without any synchronous machines.

Traditional inverter systems used in most grid-tied power electronic applications (both VRE and high voltage direct current, or HVDC) operate basically as a current source and hence rely on an external voltage source to provide a frequency reference. Such inverters can be set up to provide some degree of voltage and frequency support such as droops (e.g. $P(f)$, $Q(U)$) or FFR; however, they cannot operate as stand-alone units. These inverters are commonly referred to as **grid following**. Other terms are also sometimes used in literature, e.g. grid feeding or grid supporting.

Grid following inverters are able to respond to control signals or changes in voltage and frequency very quickly (within a few milliseconds). However, their response can never be instantaneous (like the inherent behaviour of synchronous machines), because it relies on measuring the voltage angle and frequency using a phase locked loop. They do not inherently stabilise the grid during events like load steps or short circuits – the grid supporting functions must be programmed into the controls explicitly. Due to their inability to operate without any external voltage reference, it is not suitable to have all inverters equipped with such control schemes. The active power injection provided by grid-forming inverters is now commonly termed virtual inertia, for this functionality is not the same as synthetic inertia provided by grid following wind turbines or FFR provided by other types of grid following IBRs. It does not require frequency measurement and in that way is more similar to the inherent inertial response of synchronous machines. For high instantaneous inverter penetration, which will occur more frequently with the rising share of renewables, other inverter control designs are needed. Inverters designed to operate without external voltage reference are called **grid forming**. There are multiple technical concepts available to implement the relevant inverter controls (MIGRATE Consortium, 2019; Lin *et al.*, 2020). Such inverters are able to respond instantaneously and can thereby inherently contribute to stabilising the grid. The main reasons why such inverters are not widely deployed yet are:

- The functionality is not needed at low VRE penetrations.
- The fraction of resources required to have grid-forming capability for stable operation at high instantaneous VRE penetrations is not clear yet.

- The instantaneous response of each grid-forming unit implicitly requires a limited amount of energy storage, not inherently available in wind and solar generation systems, making them more expensive.
- The instantaneous response capability makes it necessary to at least slightly increase the power rating to be able to absorb fast load spikes, again making the system more expensive.
- A higher power rating may also be needed to support the provision of short circuit current during faults and other events that may require overcurrent capability beyond the rated current.
- There is no established standard on what grid forming actually is or what it is expected to do. This is still an area of active research, and only few original equipment manufacturers offer commercial-grade grid-forming inverters.

Retrofitting existing grid-following inverters to grid forming is usually not possible for wind and solar applications. Whether it can be done at reasonable cost for existing battery storage applications depends on the installed inverters and the specific grid-forming functionality desired.

Battery storage inverters offering grid-forming functionality are already available on the market (ESIG, 2021). However, as of May 2021, there were no grid code requirements mandating such capabilities for grid connected facilities yet.

Studies published by the University of Strathclyde together with British TSO National Grid ESO have shown that stable operation of the British system at 100% inverter penetration would be possible with only 10% of units equipped with grid-forming functionality. Other sources put the estimate more conservatively at 30%, which roughly corresponds to the minimum amount of synchronous generation currently necessary in systems like Ireland's. Rising VRE shares in many countries along with the availability of grid-forming technology have started an ongoing discussion about grid code requirements for grid-forming capability. Grid-forming inverters will be needed to regularly operate entire synchronous areas at 100% VRE penetration. A number of small, megawatt-scale island power systems run on grid-forming inverters as of 2021, such as Graciosa in Azores, Portugal; Saint Eustatius in the Caribbean; and Tetiaroa in French Polynesia (Schömann *et al.*, 2019), and the technology has long been established in kilowatt-sized off-grid systems. The technology has not yet seen a large-scale rollout in large power systems though, equipment manufacturers are only slowly adapting, and 100% VRE penetration is still only a somewhat distant future scenario in most power systems (Urdal, Ierna and Roscoe, 2018; Ndreko, Rüberg and Winter, 2018). Most recently the Australian Energy Market Operator (AEMO) announced the world's largest grid-forming battery, with construction on its 250 MW/250 megawatt hour (MWh) big battery to begin later this year at Torrens Island, just north of Adelaide in South Australia.

As of 2021, grid-forming capability is not required from inverter-based generators in any grid code. Great Britain's National Grid ESO undertook a first step in this direction by publishing first drafts of a grid code specification for grid-forming inverters in 2020. When integrated into the grid code, this will be a non-mandatory specification that outlines technical requirements for potentially installed grid-forming inverters, but does not generally require the functionality itself (National Grid ESO, n.d.). The idea is to enable the introduction of a market for grid-forming ancillary services, for which the grid code requirements specify the underlying technical conditions (National Grid ESO, 2021b). The specification is written in such a way that both synchronous machines and inverter-based generation are enabled to provide the grid-forming service.

04 ANCILLARY SERVICES



KEY TAKEAWAYS OF THIS CHAPTER:

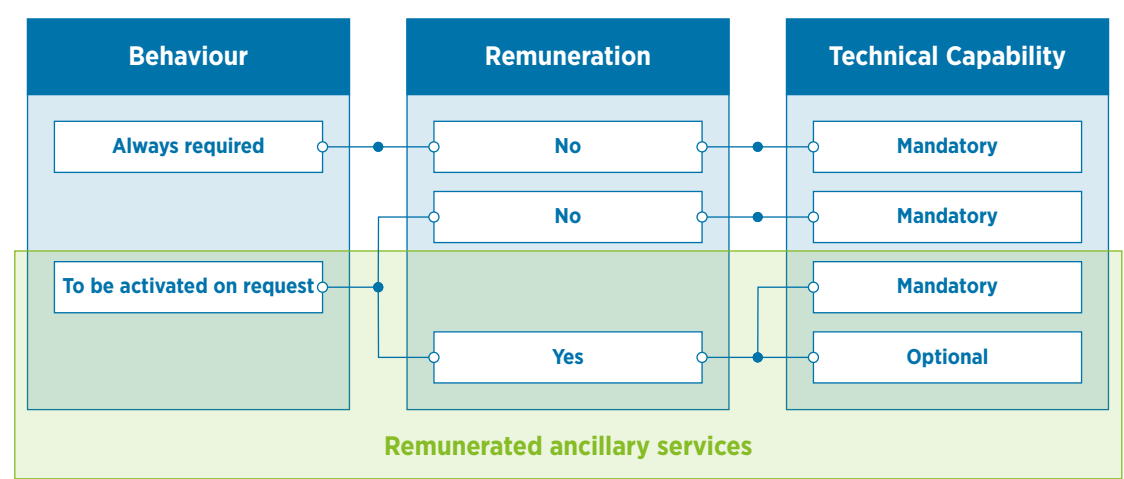
- › Ancillary services are necessary to keep the power system going. They can be mandatory, remunerated, required on grid codes or agreed on bilateral agreements. This depends on the system and can be specified by grid codes. Ancillary services have increased with higher penetrations of VRE. Remunerated ancillary services contribute significantly to the economic viability of flexibility provider projects.
- › Initial concerns about power systems becoming unstable due to VRE have largely abated after the successful large-scale VRE rollout and higher instantaneous penetration of VRE achieved in many systems. Inertia and limits on non-synchronous penetration have been dealt with through several strategies such as inertia floors, incentives for synchronous generator upgrades and multi-stage frequency control.
- › FFR has been receiving much attention in recent years, as this service directly addresses the inertia-related RoCoF issue and is provided almost exclusively by inverter-based generators and battery storage systems.
- › Requirements for grid-forming inverters in grid codes are needed sooner rather than later. There is some debate on whether the functionality should be mandatory and if so, for which installations.
- › Black-start provision entrusted with synchronous generation units has to be revised due to fossil fuel-based power plants being decommissioned early. VRE resources with active power controllability and storage with grid-forming inverters are an important enabler for VRE-based black-start plans. In systems with high shares of DER, effective communication in real time is key to providing black-start capability.
- › Flexibility from small-scale grid users can be accessed through aggregators or virtual power plants. In this sense, communication and control interfaces in DER again are key.



Photo: chuyuss / Shutterstock

In the bulk power systems of the past, system operators procured ancillary services from transmission-connected conventional power plants to manage system stability. In modern and sustainable power systems, the same services can also be provided by VRE generation, storage and other grid users. The design of ancillary service markets has evolved as well to help system operators integrate VRE by addressing the variability and uncertainty introduced. One set of innovative ancillary services addresses flexibility issues, remunerating those services related to rapid ramping requirements, frequency regulation and so on. Another set of innovative ancillary products allows new market participants to offer such services: wind turbines can be utilised to provide inertial response, solar PV can offer reactive power support and other DER can help increase market liquidity across different trading time frames (IRENA, 2019d). The grid codes and their requirements not only ensure appropriate behaviour of grid users during normal operation and during disturbances, but can also define the technical capabilities required as the basis for contributing such remunerated services procured by the system operator. This distinction of capabilities and behaviour from system services is illustrated in Figure 15.

Figure 15 Distinction of capabilities, behaviour and provision of ancillary services



This chapter briefly discusses ancillary service markets and looks into specific services around frequency control: inertia management and FFR. Grid-forming services from inverters are on the horizon as a new service, and these are expected to also impact the black-start service. The chapter finishes with a look on the solutions that allow contributions from small-scale grid users (DER).

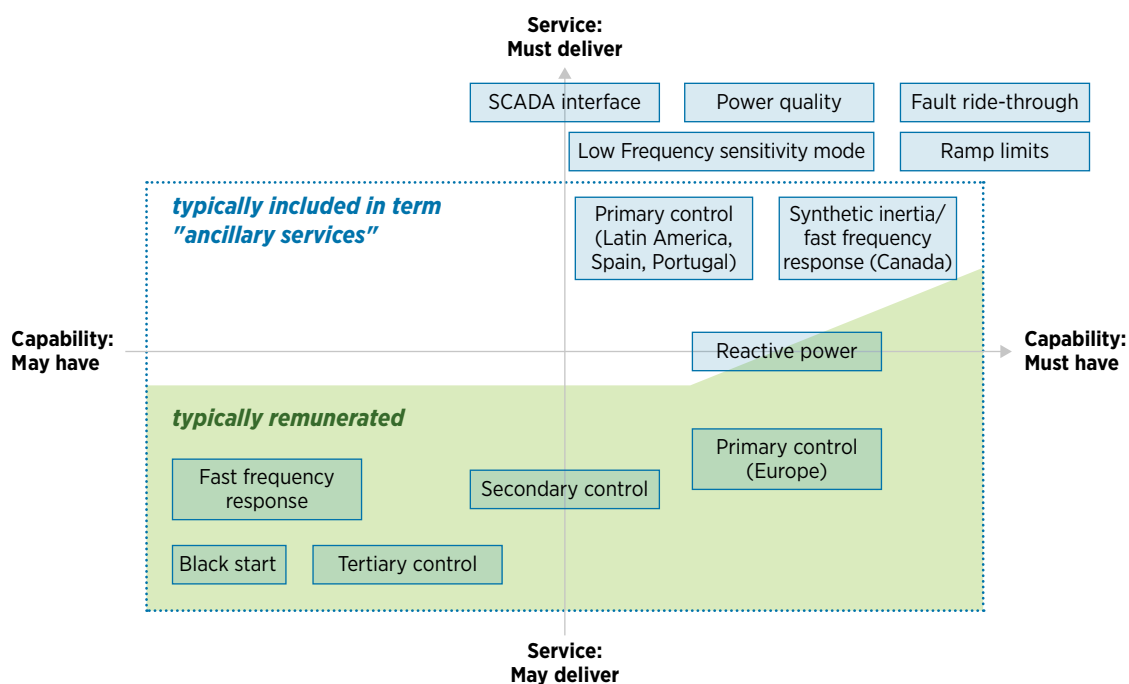
4.1 ANCILLARY SERVICES AND GRID CODES

The definition of ancillary services is a somewhat debated issue, as it can refer either to all services outside of bulk active power generation required to keep an AC power system running and stable, or to a subset of these services. EURELECTRIC (Eurelectric Thermal Working Group, 2004) coined the following definition in 2000, which has since been generally used in European systems:

- **System services** are all services provided by some system function (such as a system operator or a grid/network operator) to users connected to the system.
- **Ancillary services** are services procured by a system functionality (system operator or grid/network operator) from system users in order to be able to provide system services. (Preotescu *et al.*, 2020)

No strict line can be drawn between grid code requirements and ancillary services. Generally, grid codes may require the capability to provide ancillary services, but the actual activation of services should be subject to a procurement scheme. Services that are mandatory and unremunerated should strictly speaking not be considered ancillary services. However, reactive power is unremunerated and mandatory in many countries and generally considered an ancillary service, while for example FRT is almost always required, never remunerated, and usually considered a safety feature and not an ancillary service. Figure 16 provides an overview of ancillary services and other services, according to the capabilities and obligations to provide the services.

Figure 16 Overview of ancillary services and other services



Requirements for the capability to provide ancillary services are routinely found in grid codes to ensure the availability of generating units to provide them upon request. System operators tend to require capability for those ancillary services in grid codes deemed crucial especially in emergency situations and may have to be engaged outside of the market.¹² In these cases, grid code requirements also ensure the availability of enough market participants in all cases.

¹² Some services may be crucial to system stability, but the necessary capacity and the cost of capability do not justify a mandatory requirement for all generators. No definitive line can be drawn here as practice varies by system operator and service.

Examples include the following:

- Most grid codes require the capability to provide reactive power from all generators, but depending on country and region, actual delivery may be a remunerated service that is only activated on request.
- Requirements for all generating units above a certain size to be capable of providing primary reserve are found in many transmission codes. The actual delivery of the service is, however, allocated through balancing markets in most unbundled systems.

Both, although common, are somewhat controversial, especially as some countries such as Spain have mandatory provision rules for primary reserve, and reactive power is often considered as an unremunerated, mandatory ancillary service (ENTSO-E WGAS, 2017).

ERCOT requires frequency containment response capability on all generation. It must be activated at all times, but there is no requirement to reserve capacity for provision of this service unless it is offered into the ancillary service market. This way VRE generation can respond to overfrequency events whenever in operation and underfrequency events whenever curtailed. This is not a remunerated service.

Other ancillary services may not be addressed in the grid code at all. For example, the capability to provide frequency restoration reserve is often not required. To access the corresponding balancing markets, generators have to undergo additional prequalification procedures set out in additional documents. The same procedure is applied to new ancillary services such as FFR, ramping products or additional inertial response.

In Uruguay, according to regulations, secondary and tertiary reserve are included in the market regulation as a product. Despite that, given that most thermal units and all hydro units belong to the state-owned company, these services have been implicitly remunerated in the electricity tariff. VRE generators still do not have the opportunity to offer these kinds of reserves because they are not included in the regulations. Including these would imply changes in the rule for dispatching VREs, as currently these kinds of generation have zero variable cost assigned by decree and the generation must be determined directly from the available resource at any time.

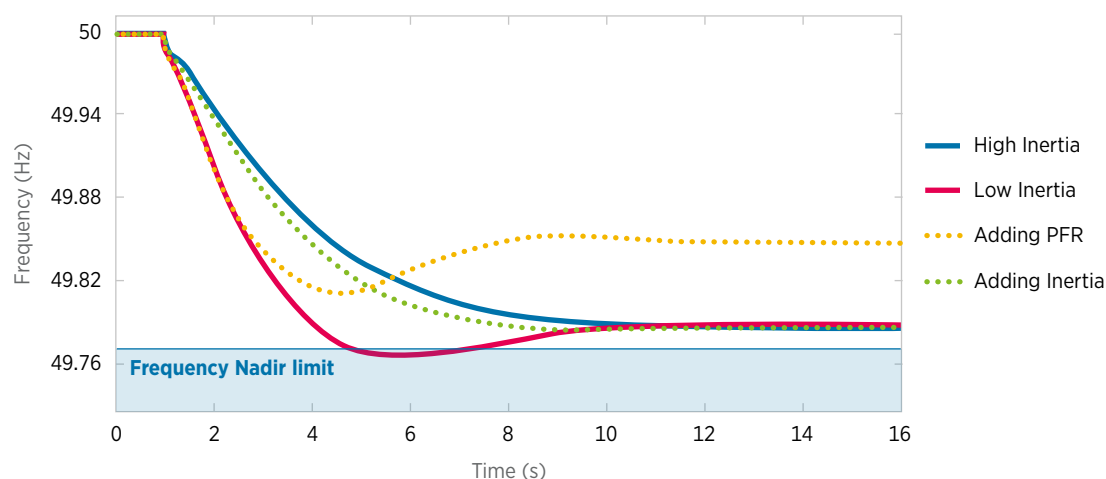
In the case of Honduras, ancillary services comprise rules for the provision of frequency control (primary, secondary and tertiary), automatic and manual disconnection of loads, voltage control and reactive power injection/withdrawal capabilities, and black-start capabilities. This technical norm takes into consideration the fact that energy storage installations can provide primary and secondary frequency control. The norm also imposes some requirements to variable renewable energy (wind and solar PV), such as the obligation to provide some levels of primary and secondary frequency control, minimum reactive power capability, high and low voltage ride through, and dynamic reactive current (Norma Técnica de Servicios Complementarios, 2021). Another technical norm for consumer-producers connected to the distribution system (primary and secondary voltage levels) is under evaluation by the national regulatory entity (Comisión Reguladora de Energía Eléctrica, or CREE) (La Gaceta, 2020).

Remunerated ancillary services contribute significantly to the economic viability of flexibility provider projects. A comprehensive discussion and framework on the case of storage can be found in IRENA (2020a).

4.2 INERTIA MANAGEMENT

Inertia management is becoming increasingly important in high VRE power systems, as inertia in the system decreases with rising penetration of non-synchronous generation, shown in Figure 17. This figure shows the comparison between the responses to a frequency excursion of two systems: a low and a high inertia system. System operators hence have to either ensure that a certain minimum amount of inertia is always present in the system or provide alternative means to limit frequency deviation during low-inertia situations, like adding primary frequency response (PFR) or adding inertia, as shown in Figure 17. With some notable exceptions, this issue is currently generally not subject to grid code requirements, but almost entirely addressed through operational constraints and/or ancillary services.

Figure 17 **Impact of system inertia on frequency response after an event**



Source: Rezkalla, Pertl and Marinelli (2018)

The inertia issue has been known and discussed since the first introduction of inverter-based generation decades ago. Initial concerns about power systems becoming unstable already at, by today's standards, relatively low non-synchronous penetration levels have largely been dispersed after the successful large-scale VRE rollout. Between 5% and 30% of non-synchronous penetration continue to circulate as the "stability limit" for a synchronous system, especially in areas and countries with little VRE experience. However, VRE integration in systems in South and West Australia, Ireland and Texas has shown that system stability can be ensured at higher instantaneous penetration levels of 50-70%, and various small island systems have even gone up to 80-90% of non-synchronous penetration without encountering severe stability issues.

Notably, inertia and limits on non-synchronous penetration are issues that need to be addressed at the synchronous system level. The focus is therefore currently on synchronously independent systems. Individual countries in Europe, like Denmark, regularly reach or exceed 100% non-synchronous penetration of load, but these are connected to the much larger Central European synchronous system, in which overall non-synchronous penetration remains relatively low. As VRE penetration levels continue to rise across larger areas, inertia will eventually become an issue there as well, and inertia management procedures established in synchronously independent systems will provide valuable experience.

The case of Ireland shows that non-synchronous penetration up to 50% of load could be realised without inertia becoming a major issue. However, inertia issues were anticipated during the first All-Island Grid Study in 2008, with the study predicting at least some RoCoF issues beyond 50% instantaneous penetration. Ireland has raised the limit on non-synchronous penetration (in its case including wind power, HVDC interconnectors and a very low share of PV) to 65% over the years and is set to achieve 70% to 75% by the end of 2021. This penetration level can likely be achieved with the general traditional power system structure based on using synchronous generators as the main providers of stability and some added services that will be described in the following sections. A major paradigm change will be required to go beyond this level, according to Irish TSO EirGrid¹³ (EirGrid/SONI, 2021; Nedic and Bell, 2008).

As of 2021, EirGrid had undertaken the following measures to mitigate inertia issues and raise the permissible non-synchronous penetration level:

- Continuously estimating and monitoring system inertia.
- Introduction of an inertia floor (minimum system inertia limit), which was lowered from 25 000 MW-s to 23 000 MW-s over time, based on monitoring of the largest credible contingency in real-time.
- Incentives for synchronous generators to decrease their minimum continuous operating level (lowest active power output at which the plant can operate stably), to make way for more VRE generation without having to disconnect synchronous generation (and, hence, reduce inertia), through the remunerated ancillary service of SIR.
- Introduction of a multi-stage frequency control and reserve ancillary service suite including FFR which can react to RoCoF or underfrequency events within 0.5-2 seconds.

4.3 FAST FREQUENCY RESPONSE (FFR)

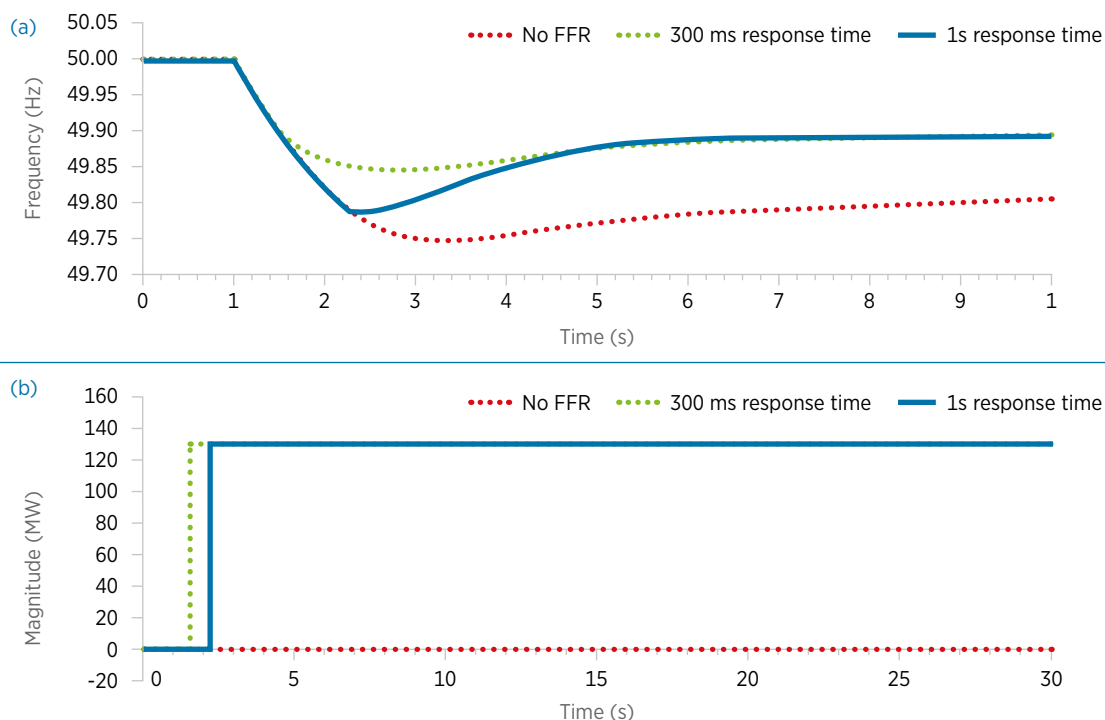
System operators in Australia, Great Britain and Texas (United States) have implemented similar measures that differ in minor technical details only. While inertia floors and reduction of minimum stable output still rely on synchronous generators, recently FFR has been the subject of heightened interest. This is because FFR addresses the inertia-related RoCoF issue directly. In addition, it is supplied by battery storage systems and inverter-based generators and possibly from load resources with underfrequency relays. In other words, FFR allows for a faster response to match faster RoCoF operations.

The service now implemented as FFR has been discussed among power system and renewable energy experts for more than a decade, initially using the terms “virtual inertia”, “synthetic inertia” or “emulated inertia.” With the introduction of FFR in a number of systems worldwide, these terms have largely fallen out of favour or have shifted in meaning to describe the inertial response of grid-forming inverters, but all describe the behaviour that is now required from units providing FFR.

¹³ With previous predictions from power system experts over the past three decades ranging from a non-synchronous penetration limit from 15% to 50%, which have all been exceeded quite easily, this number should also be examined carefully. However, EirGrid has now gathered more than 20 years of VRE experience and conducted extensive research on the issue taking into account that vast operational experience; hence, this number can be expected to be slightly more reliable than previous predictions.

The general idea behind this function is to provide a very fast active power response from IBRs to measured frequency deviations. This response is not inherent, as inertial response of synchronous generation, but is faster and therefore supplements inertial response from synchronous generators in improving initial RoCoF and frequency nadir¹⁴ after a generation trip. With the adequate software controls, this functionality can be provided by any IBR with surplus primary energy available, such as batteries or VRE operating at curtailed power setpoints.

Figure 18 **Impact of 140 MW of FFR (from battery units) on system frequency in the Irish power system**

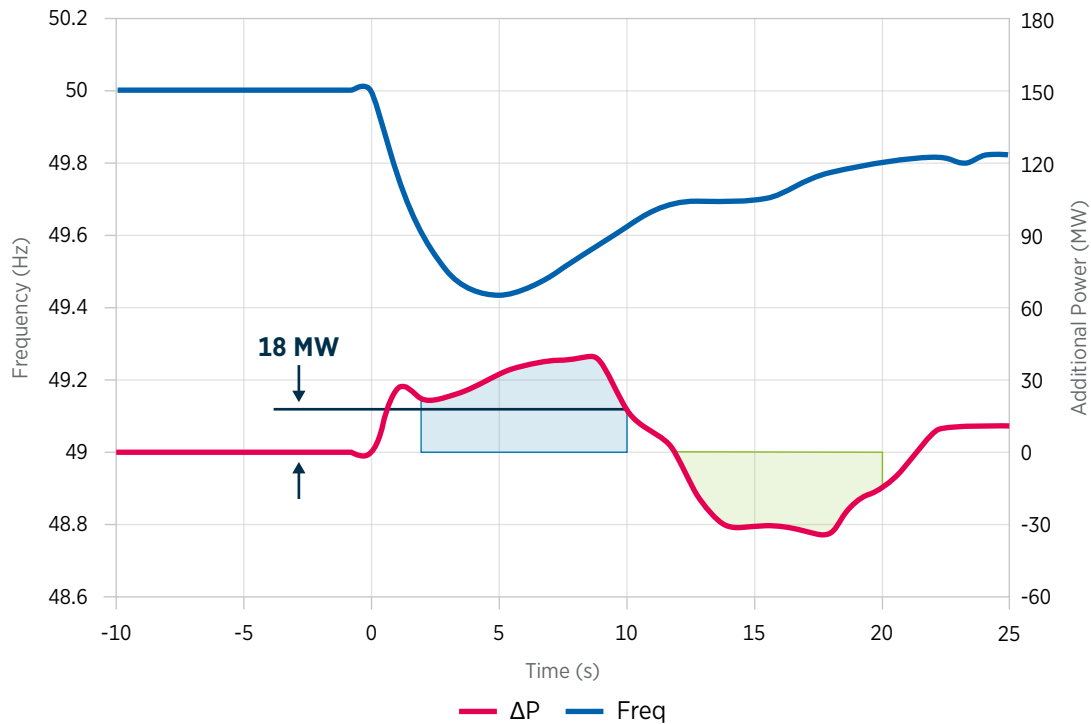


Source: Deegan *et al.* (2019)

This behaviour could also be provided by non-curtailed wind turbines by making use of the actual rotational inertia of the rotor, which is present but usually fully decoupled from the grid by the power electronic converter. With the corresponding software controls implemented, this inertia can be accessed and a response to the grid provided within between 0.5 seconds and 2 seconds. Unlike actual grid coupled inertia, the increase in power output can be sustained for several seconds independent of the further frequency trace. However, the entire reaction comes at the cost of slowing the rotor down from its optimal rotational speed. As this energy needs to be recovered to return to the pre-fault active power output, wind power plants at wind speeds lower than rated wind speed exhibit reduction in output power below the initial state a few seconds after the power increase that is the “synthetic inertia” response (Figure 19). Above rated wind speed, there is normally extra power available in the wind and cut by pitch control. This primary source of power can be used to speed up the turbine back to optimal speed. There is no reduction in active power output as seen from the grid.

¹⁴ The frequency nadir is the lowest frequency measured during a low-frequency event (typically caused by an unforeseen power plant outage). For a given event (loss of a large generator), the resulting nadir indicates the performance and adequacy of the frequency containment reserves.

Figure 19 Wind turbine FFR provision and recovery period



Note: According to Irish FFR requirements, the area shaded in green may not be larger than the area shaded in blue.

Source: Deegan *et al.* (2019)

Inertia-based FFR from wind turbines can be useful in high VRE power systems. At low inertia levels and subsequently high RoCoF at imbalances, it is typically not the amount of available primary reserve that is the limiting factor, but the response speed. Inertia-based FFR provision from wind turbines may increase the amount of primary reserve needed, as it will have to cover the post-event output reduction of the wind power plants on top of the initial imbalance. Its response, however, does not need to become much faster, as the initial frequency deviation is contained or slowed down by the inertia-based FFR from VRE.

Requirements for wind power plants to possess this functionality have not been widely introduced, with the notable exemption of Canadian public utility HydroQuébec, which introduced the requirement as early as 2005. The requirement for generators (RfG) as part of the EU Network Codes also allows TSOs to implement this requirement (non-mandatory), but gives no further specifications, and no European TSO has introduced it so far. Canadian experience showed that synthetic inertia from wind power plants can contribute significantly to system stability, but also revealed some issues with the post-event output power dip (which was eventually limited through a revised requirement) and compliance testing for the functionality. TSOs in Australia, Great Britain and Texas therefore opted against any unified requirement and for procurement of inertia-based FFR as a remunerated ancillary service, using the terms “fast frequency response,” “firm frequency response” and “dynamic containment” (St. John, 2020; Miller and Pajic, 2016; Hydro-Quebec-TransÉnergie, 2009; ENTSO-E, 2017b).

FFR procurement is technology neutral, and tenders have been won mainly by battery units, but also by some wind power plants. System operators such as ERCOT and AEMO procure this in day ahead or real time markets.

Table 5 Inertia-based FFR and other FFR requirement examples

	Inertial response, Hydro Québec grid code requirement	Fast frequency response, ancillary service procured by EirGrid
Capacity per unit	6% of rated capacity	≥ 1 MW, capacity bid
Activation mode	Trigger based, capability for both step and proportional response required	Trigger based, step response
Response speed	≤ 1.5 seconds	0.3-2 seconds (higher remuneration if faster)
Sustain time	9 seconds	8 seconds
Post-event active power reduction limit	No more than 20% of rated capacity	Energy lost in 10-20 second time frame after event must be smaller than additional energy provided in 2- 10 second time frame

Source: Hydro-Quebec-TransÉnergie (2009), EirGrid/SONI (2020, 2019)

4.4 GRID-FORMING INVERTERS

To allow higher penetration of IBRs and approach a 100% power electronic penetration in power systems, the introduction of a grid-forming ancillary market is proposed and under discussion. According to a recent ENTSO-E report, a grid-forming power plant/power park module:

"shall be capable of supporting the operation of the AC power system (from EHV [extra high voltage] to LV [low voltage]) under normal, disturbed and emergency states without having to rely on capabilities from SGs. This shall include the capabilities for stable operation for the extreme operating case of supplying the complete demand from 100% converter-based power sources. (ENTSO-E, 2020c)"

Based on this definition, the requirements listed below could be necessary for future grid code development for power park modules with grid-forming inverters (ENTSO-E, 2020c):

- creating (forming) system voltage
- contributing to fault level (short circuit power)
- contributing to total system inertia (limited by energy storage capacity and the available power rating of the Power Park Module or HVDC converter station)
- supporting system survival to enable the effective operation of low frequency demand disconnection for rare system splits
- acting as a sink to counter harmonics and inter-harmonics in system voltage
- acting as a sink to counter any unbalance in system voltage
- preventing adverse control system interactions.

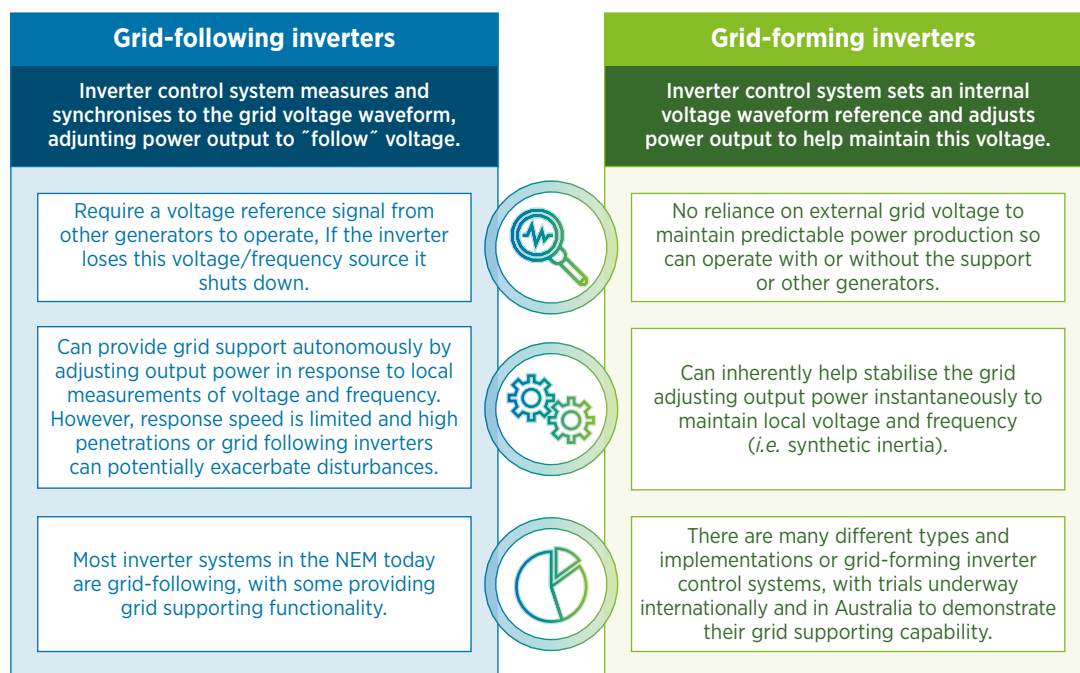
An initial national draft grid code requirement concerns the capability of operating as a voltage source behind a reactance over a frequency band of 5 Hz to 1 kHz (kilohertz). This relates to paid for, not mandatory, capability (National Grid ESO, 2019a).

Since it has the voltage source characteristics, a grid-forming inverter would contribute to the system strength of the power system. The grid-forming inverter should limit the impact of a grid fault and avoid the risk of immediate voltage collapse. Research shows that grid-forming inverters should inject current under low impedance faults. Obviously, this current is limited by the inverter's overcurrent capacity. Recent research on grid-forming inverters focuses on their different aspects, and one such aspect is the speed of current delivery where the time of delivery specified for 100% IBR penetration is specified as 5 milliseconds.

Resonance due to the power electronic equipment is highlighted as one of the major concerns when considering higher penetration of IBRs. The connection of the converter to the network results in new resonant points determined by the interaction between the converter impedance and grid impedance. To avoid the impact of such resonance, the grid-forming inverters should be able to provide damping to the identified potential resonant frequencies.

Figure 20 provides a comparison between existing grid-following invertors and future capabilities that may be offered by grid-forming invertors.

Figure 20 **Grid-following vs. grid-forming inverters**



Source: AEMO (2021)

As described in Chapter 3, Section 7, grid-forming capability from inverters can provide a solution for the inertia issue in the medium or long term, but this has not been reflected in grid codes or ancillary service markets to a great extent so far. Essentially, this is a chicken-and-egg problem: the functionality cannot be made to be required before it is available, and manufacturers avoid the cost of developing this before it becomes clear this will be required in a given country at a given time. The impact on the manufacturing costs of corresponding generation units also needs to be considered. Depending on the detailed specification of the functionality, certain generation technologies may become more expensive.

However, there seems to be a general consensus among grid code experts from TSOs and academia that requirements for grid-forming inverters in grid codes are needed sooner than later. There is still some debate on whether the functionality should be mandatory for the above-mentioned reasons. Procurement of the necessary capacity through markets is under discussion, with potential grid code requirements serving as prequalification for market access (Urdal, 2020; Lin *et al.*, 2020).

The proposed minimum specification required for the provision of grid-forming capability in the United Kingdom's National Grid

- Must have internal voltage source behind reactance
- Maintain synchronism and stability
- Supply RoCoF Response Power, damping, fast fault current injection, control based real and reactive power
- Control power with bandwidth <5 Hz to avoid oscillations
- Operate at a minimum short circuit level
- Must stably inject current for balanced and unbalanced faults
- Demonstrate all attributes of performance for grid forming inverters via type tests and simulation models

Source: National Grid (2021b)

4.5 BLACK-START CAPABILITY

Black-start capability describes the capability of a generator to start without outside power supply and energise the grid or part of the grid to resume operations after a blackout. Generators with this capability are present in every power system, as even well-interconnected systems may not always be able to rely on outside help in case of a blackout. However, black-start capability is neither needed nor required from all generators in a system, and hence, it is only very rarely specified as a grid code requirement.¹⁵ TSOs ensure the availability of enough black-start capable units through bilateral agreements or open tenders (Elia, 2018).

Black-start plans have so far relied almost exclusively on synchronous generators, with common black-start units being hydro or gas turbine power plants that can then be used to start up larger coal or gas fired units. Especially in power systems mainly relying on coal as a primary resource, black-start capability is also often provided from power plants that can sustain islanded operation, supplying only their auxiliary consumption, for some hours after an outage of the grid (“houseload operation”). With rising VRE shares in the system, black-start plans relying on synchronous generators have come under pressure, and operators often have to revise their plans for the following reasons:

¹⁵ Exceptions can be found in codes applicable to small island systems, such as the Philippines, which sometimes contain a requirement for black-start capability for all synchronous generators above a certain size.

- Increasing numbers of conventional power plants are decommissioned early or not replaced after regular decommissioning, as they are no longer needed. This can also affect black-start capable units, as black-start capability is usually only a secondary or tertiary source of income.
- Conventional power plants capable of running in houseload operation for limited amounts of time. Houseload units are typically baseload units that are assumed to be almost always online. Increasing VRE shares reduce baseload demand and hence often force former baseload units into cycling operations, meaning that they will sometimes be switched off if they are not able to sell electricity in the market. Houseload units may therefore not be reliably online during high VRE periods, or must be assigned a costly must-run constraint outside the market (Cherevatskiy, 2011).

Almost all currently installed VRE capacity is equipped with grid-following inverters, which are inherently not capable of black start. VRE resources that offer some degree of active power controllability can be part of currently standing black-start plans, but only as secondary resources that can be reconnected early during the restoration process after the initial re-energisation of grid areas by conventional black-start units. Such procedures are in place or under investigation at multiple European TSOs, most notable Great Britain's National Grid ESO, which published a review of British non-synchronous generation with regard to their role in future black-start plans in 2019 (National Grid ESO and TNEI Services Ltd, 2019).

Recently published trial runs have however shown that large wind power plants can also be used as initial black-start units if equipped with the corresponding equipment – either with diesel generators on site, or grid-forming batteries inside the plant, or with at least part of the wind turbines equipped with grid-forming capability themselves (the latter being the most common approach as of 2021) (renews.biz, 2020; 50Hertz Transmission GmbH, 2020). Large wind and solar power plants equipped accordingly could play a significant role in future black-start plans, potentially providing the services that can no longer be provided from houseload units during high VRE periods (Egan, MacLeod and Cowton, 2015; Midtsund *et al.*, 2016).

Decentralisation of electricity generation leads to a reduction of the number of large, transmission-connected generators, which are the primary resource in most black-start plans. Strategies for black start from distributed generators connected to distribution grids have therefore been discussed for a long time, especially in countries that rely on a high share of distributed generation such as Denmark, Germany or Great Britain. Those have been largely theoretical in nature or focused on pilot projects for a long time, but British regulator Ofgem has recently approved funding for British TSO National Grid ESO to develop black-start plans based on distributed resources (National Grid ESO, 2019b; Ofgem, 2018). National Grid's strategy focuses on starting the grid from small synchronous generators, as these make up the majority of British distributed generation capacity, and using IBRs in the second stage when individual portions of the grid have been energised (National Grid ESO and TNEI Services Ltd, 2019). This concept was proven in Denmark's Cell Project a decade ago (Cherevatskiy, 2011; Ackermann *et al.*, 2008), but National Grid is now advancing it due to the fact that its black-start capacity procurement cost has steadily risen over the past years because large generators increasingly rely on the capability payments as their market income lowers.

The project was expected to advance to the demonstration stage in 2021. National Grid has identified the following main challenges in the meantime (National Grid ESO and TNEI Services Ltd, 2020):

- There are no consistent communication interfaces with distributed generators.
- Resilient and secure operational communications will have to be established with a high number of stakeholders.
- Staff training will be required as participation of distributed resources in black start is a completely new operational strategy.

These findings relate directly to grid code requirements for distributed generators. Black-start capability itself is technically unproblematic in small synchronous machines. The prime movers can usually be started manually or from batteries, but the capability needs to be required to ensure that it is available in all generators. Requirements for communication interfaces are even more important, not only for synchronous generators, but all distributed resources. National Grid is currently in the process of developing new and appropriate functional specifications (National Grid ESO and TNEI Services Ltd, 2020).

Black start from distributed resources is by no means easy. It is definitely complicated both by the demand for resilient real-time communication for a high number of stakeholders as well as technical parameters, such as the initial energisation of higher voltage levels, which requires high inrush currents (Howitt, 2020; Cherevatskiy, 2011). Quick restoration of distribution grid cells and hence supply to paying customers is however possible, and such self-supplying cells can be reconnected much more easily to the higher voltage levels after they have been re-energised. System operators are therefore well advised to draft appropriate technical rules for distributed generators that facilitate such operations, even if the need has not yet arisen, to avoid technical issues and potentially costly retrofitting schemes further down the line.

Black start solely from IBRs is only possible with a certain share of inverters possessing grid-forming functionality to act as “anchor generators” for initial re-energisation much the same way that distributed synchronous units are set to do in the strategies developed in the Cell Project and currently by National Grid. This therefore directly relates to the potential requirements for grid-forming functionality discussed in Chapter 3, Section 7 and Chapter 4, Section 4, with the possible addition of a black-start requirement because not all grid-forming inverters are inherently capable of that. Due to the higher voltage and frequency flexibility of inverters compared to synchronous generators, some aspects of black starting from lower voltage levels may however be significantly easier when using only IBRs (Jain *et al.*, 2020). There are a few applications by General Electric in which grid-forming batteries were used instead of diesel generators in black-start. This is a step in the direction of black starting grid-forming batteries (Rao *et al.*, 2021).

4.6 LEVERAGING FLEXIBILITY FROM SMALL-SCALE GRID USERS

While small-scale users are often theoretically suited to provide flexible behaviour, an inherent issue is that their small scale and large numbers often make this flexibility uneconomical to access and use. Traditional integration approaches largely treat distributed generators, especially those connected to the low voltage level such as rooftop PV, as a negative load and hence non-dispatchable and non-flexible. Constraints appear at high shares of distributed generation, when the traditional integration approach may be obliged to operate flexibly. This could be even more likely to occur with the integration of consumer-producer options and demand-side management.

The use of distributed resources (which include generators, storage and demand-side options) in wholesale power markets requires aggregation, as numbers in the thousands or millions of small bidders would be economically unfeasible. The much-discussed introduction of local flexibility markets to address the need for flexibility at the distribution level may allow resources to participate directly. However, from the system point of view, these markets are also only a mechanism of aggregation. The most common approaches for distributed resources to access wholesale markets or ancillary service markets are through inclusion in virtual power plants or aggregators (for more information on aggregators, see IRENA [2019b]). Unlike feed-in tariff systems where distributed resources sell whatever production is available in the market at whatever price they receive, aggregators go a step beyond and may include bidirectional communications, with resources being signalled to generate or consume within specific time periods to optimise the overall revenue of the virtual power plant.

Retailers have the opportunity to serve as aggregators by assisting their customers in valuing their flexibility service providers for DSOs and TSOs and/or for their flexibility as balancing service providers for TSOs. However, doing so may result in the sale of less volume for retailers. This has resulted in the emergence of new entrants focusing on the aggregation business. Europe's Directive (EU) 2019/944 mandates the development of an enabling regulatory framework for independent aggregators to function next to retailers in all countries. Aggregators will play a significant role in achieving the goals of the European Green Deal, not least because the Commission has identified demand-side flexibility as a key area in which new network codes might be required (Meeus *et al.*, 2020).

Similar to the provisions for retailers, aggregators also have to provide data to their customers, enable switching and provide clear terms and conditions in their contracts. The future of retail markets is very much an open issue.

Technical requirements for such market-based arrangements have in most cases not been within the scope of grid codes, but rather are subject to either bilateral agreements between resources and aggregator, or to overarching energy and energy market regulation.¹⁶ Because grid codes should enable and facilitate market integration of VRE and distributed resources, it is however a good idea to set up technical requirements for communication and control interfaces in distributed generators, the lack of which was also identified in projects dealing with black start from distributed resources (see Chapter 4, Section 5).

Internet-based communications are an alternative to classic communication interfaces, which do not always allow for the real-time communication necessary for frequency control services but can enable a higher degree of flexibility within the energy-only market at little additional cost or complexity. However, Internet-based communications require attention to cybersecurity concerns. Blockchain technology is furthermore expected to be capable of inducing a paradigm change in electricity trading, with peer-to-peer trading and decentralised marketplaces decoupled from the wholesale energy-only market (IRENA, 2019c; Andoni *et al.*, 2019).

¹⁶ One example of the latter is an addendum to the German Renewable Energy Law stating that PV units above 30 kW peak must be remotely controllable – this requirement was introduced not because of need from DSOs, but to facilitate market integration.

05 GRID CODE COMPLIANCE MANAGEMENT



KEY TAKEAWAYS OF THIS CHAPTER:

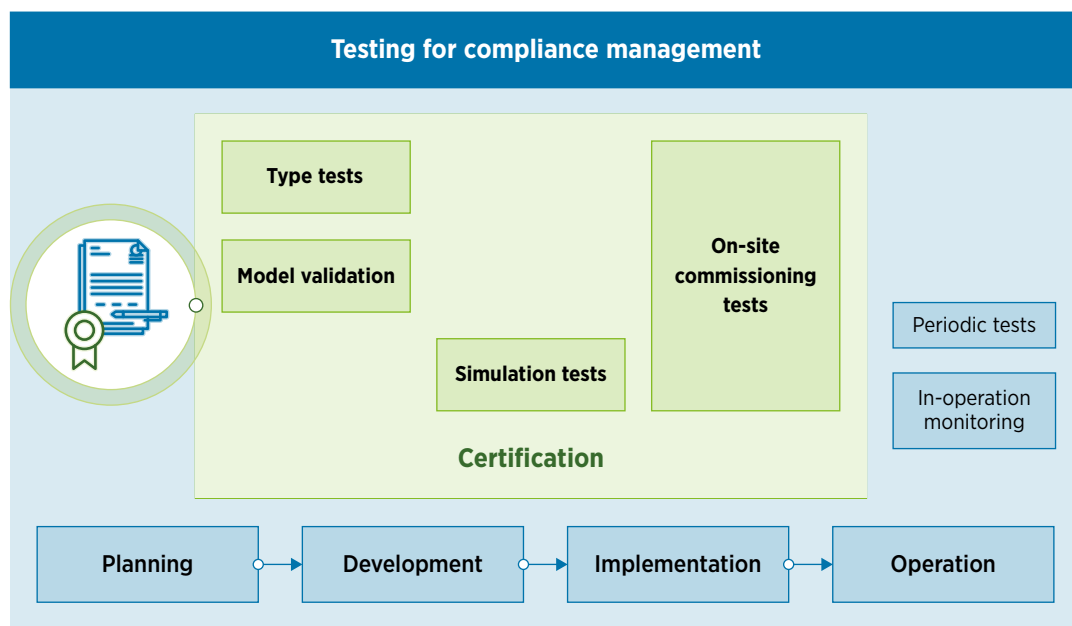
- › Grid code compliance tests should be made wherever reasonable in the planning, development, implementation and operation phases of each asset type and each facility.
- › Grid code compliance can be best achieved if all available test strategies are combined: type tests by independent testing bodies, on-site commissioning tests run for each individual project implementation, simulation tests in the design and connection phases of a VRE project, and in-operation monitoring.
- › Certification schemes are a good way to increase the level of trust because they enforce transparent and independent compliance assessment. There are several IEC and IEEE series of standards that specify the testing, modelling and validation specifications for investigating behaviour at the facility level and issue facility certificates.
- › It is important that the grid code requirements not only reflect the needs of the power systems in their present state but also anticipate future development. In case the requirements of a system change over time and grid codes are updated, the cost of upgrades should not fall entirely on existing grid users. However, when system security is at risk, compromises can be made to reach agreement on the burden of the cost.
- › Retrofitting schemes represent a compromise and require careful deliberation. It is a good idea to limit retrofitting schemes to the minimum required upgrade measures and not to demand a full upgrade to the latest grid code requirements.
- › Grid code compliance rules need to be formulated with consensus from all stakeholders. Achieving high levels of compliance is essentially a collaborative effort among equipment manufacturers, project developers and power system operators.

Only through efficient stakeholder participation can a reasonable compromise between desirable behaviour and corresponding implementation and verification efforts be found. Until independent certifications are available, temporary measures can be taken such as accepting manufacturer declarations and/or certificates issued in other countries. With DER installed in very high numbers and across a wide range of technologies, locations and sizes, ensuring the compliance of each facility with the technical requirements from a grid code is a significant challenge. This chapter discusses the available solutions and briefly presents ongoing work in international standardisation aimed at contributing new solutions.

5.1 BASIC COMPLIANCE ENFORCEMENT APPROACHES

Successful compliance enforcement implies compliance verification, which in turn relies on testing. Where and how can compliance tests be conducted? The answer is that tests should be made wherever reasonable in the planning, development, implementation and operation phases of each asset type and each facility (see Figure 21).

Figure 21 Grid code compliance testing in the project lifecycle



Type tests are important for any mass-produced equipment. Equipment manufacturers that provide consistent quality in their production processes only need to prove grid code compliance for an individual specimen of each product type. If the tested specimen passes the test successfully, then the manufacturer can guarantee that all products of the same type meet the corresponding technical requirements and issue a corresponding declaration. Type tests can also be performed by independent testing bodies to achieve higher confidence and verifiability. Such independent entities should apply standardised and transparent processes. Product certification according to a given set of standards and rules follows this transparent third-party verification scheme.

On-site commissioning tests are performed when the construction work has been completed and the connection of the new facility to the power system is about to be activated. Instead of testing an individual specimen of a mass product, on-site testing refers to tests that are always run for each individual project implementation. It is desirable to keep the amount of testing on this level to the minimum due to its high cost (testing compliance with every single requirement on-site is prohibitively expensive), but it should never be omitted completely because it is the only practical way to test the entire plant behaviour at the connection point to the grid and detect some local implementation mistakes, and it ultimately provides the highest level of trust.

Simulation tests help bridge the gap between type tests and on-site tests because neither is suitable to comprehensively test all functionality required by the grid codes. For example, in a VRE project consisting of many individual generators, compliance with requirements applicable at the point of interconnection to the power system cannot be verified in type tests of individual equipment. On the other hand, testing the fault response of an entire VRE power plant may have an undesirable impact on the operation of the power system to which it is supposed to be connected, since any testing procedure with impact on voltage or frequency will affect the power quality of other grid users in the vicinity. To avoid omitting a corresponding test completely, simulation tests can be used. Such tests can be conducted in the design and connection phases of a VRE project. To make simulations reasonable, accurate and reliable, the simulation models and their expected functionality must be specified and their performance must be verified. In countries where the corresponding specifications and requirements have been developed, simulation tests are successfully used to complement type tests and on-site tests.

After the connection has been activated and the facility is in operation, **periodic tests** can be performed to verify that the performance does not degrade over time. Such tests can detect issues accidentally introduced during maintenance and repair work or software updates. Data gathered during such tests can also be used for verifying and maintaining simulation models.

In-operation monitoring is based on the analysis of operational performance data, which can cover both normal operating conditions as well as response to disturbance events. Since the behaviour during events of abnormal voltage and frequency as specified in the grid code is particularly important for maintaining system stability, post-fault performance evaluation is a useful tool to assess actual compliance. If it turns out that the facility's performance failed to meet the requirements, the facility owner will usually be required to rectify this within a reasonable time interval, or pay a fine or cease to operate temporarily if that is not possible.

Certification schemes consist of a strict division of responsibilities and draw upon detailed standards and rules for the pre-commissioning compliance verification steps. While introducing further complexity, they help co-ordinate equipment verification with simulation tests and on-site tests in a way that is more cost-effective than relying on any single test category alone to achieve similar levels of confidence in grid code compliance.

5.2 STRATEGIC VERIFICATION MANAGEMENT CONCEPTS

Achieving high levels of compliance is essentially a collaborative effort between equipment manufacturers, project developers and power system operators. Their individual perspectives need to be considered when designing a compliance management framework and assigning the proper responsibilities. Therefore, the highest compliance levels are achieved with processes that combine multiple approaches, avoiding structural barriers to VRE integration through the disadvantages and deficiencies of each individual approach alone. The addition of certification bodies as a separate role increases transparency and reliability in each step and thereby raises the level of confidence.

The certification approach is usually applied on the generating unit level and at the facility level. The idea behind this is to create, on the unit level, validated simulation models that can then be used on the facility level to demonstrate performance aspects in simulations that cannot easily be verified in on-site tests. Validating the simulation models relies on extensive type tests and specification of model characteristics and accuracy. A number of standards have been developed in different countries to specify the corresponding tests and rules. These often make use of the testing, modelling and validation specifications provided by the IEC 61400 series of standards for wind turbine generators: IEC 61400-21 specifies tests for different functions and components, IEC 61400-27-1 describes dynamic simulation models for wind turbine generators and power plants, and IEC 61400-27-2 provides validation procedures for the simulation models. By making use of the validated generating unit models, certification bodies can investigate the behaviour on the facility level and issue facility certificates based on this.

The certification bodies do not perform the corresponding type tests themselves during unit certification. Testing institutes have been introduced as specialised entities providing grid code compliance testing and measurements on the unit level for equipment manufacturers. This is useful because several tests require dedicated, expensive equipment that individual manufacturers may not be able to afford on their own, like special containers with power hardware to conduct FRT tests.

Certification schemes have been used for grid code compliance in Germany and Spain for more than ten years already, with the corresponding specifications being further refined and updated multiple times. However, on the international level, comprehensive standards for the certification of VRE power plant connection with regard to grid code requirements are only starting to appear.

In Europe, the EU NC RfG (EU Network Code Requirements for Generators) establishes high-level compliance procedures that include compliance testing and compliance simulations for specified technical requirements. (The technical requirements are described in more detail in Chapter 6, Section 1). The compliance rules allow for the use of equipment certificates issued by an authorised certifier for the compliance demonstration. Neither the requirement specifications nor the compliance rules in the RfG are however sufficiently detailed and precise to directly serve as the basis for certification. There is hence a clear gap to be filled by a standard that reflects the requirements from the RfG and provides the additional details needed for exactness and verifiability. This is where the EN 50549 standards come in.

The European standards EN 50549-1 and EN 50549-2 from 2019 capture the connection requirements used by the states implementing the RfG for generation units connected to the low voltage and medium levels, respectively. These standards indeed go beyond the RfG in that they specify all requirements necessary to operate a generation unit in parallel to the distribution grid, and not only the requirements given in the RfG. For example, they describe reactive power control modes and capabilities for the smaller generator classes, which are not covered by the RfG. They also include electricity storage in their application scope. Where the RfG only describes validity ranges for parameters, the EN 50549 standards also provide default values to be used in the absence of system operator instructions. The EN 50549-1/2 standards are thus offered to serve as reference for national RfG implementations. In addition, a new standard, EN 50549-10, is in preparation to specify the tests needed to prove compliance with EN 50549-1/2 and thereby also with the RfG. This will pave the way to an RfG-compliant equipment certification process.

Other work in international standardisation of grid connection requirements (equally aiming at facilitating equipment certification) has been picked up by the IEC standardisation organisation through its IECRE effort. ENTSO-E has been involved in both the EN 50549 and IECRE standardisation efforts to ensure complementary approaches and avoid incompatibilities.

DER certification with regard to IEEE Std 1547-2018 will be possible soon. The corresponding tests, testing procedures and evaluations are specified in IEEE 1547.1-2020 and form the basis for the UL 1741 SB product standard, published in September 2021 (QualityLogic, 2021).

Equipment and facilities designed and certified to meet the requirements of a specific grid code usually cannot easily be modified to follow different rules. What should be done if the requirements of a system change over time and grid codes are updated?

5.3 APPLICATION OF NEW REQUIREMENTS TO EXISTING GRID USERS

The requirements applicable to a grid user facility should remain the same as they were when the permission to connect was granted unless the facility has undergone a significant modification/modernisation that may enable a new connection agreement and/or compliance with newer requirements. This approach allows investors to make reasonably accurate cost projections over the lifetime of their projects and is therefore a prerequisite to making the investment happen. However, if the connection requirements applying to existing assets never change, while the rules for new assets become stricter, it could result in delaying the replacement of old with newer, more advanced technology. A balance needs to be struck between the two extremes. Existing assets should be treated differently from new assets to some extent. However, if existing assets are significantly refurbished, they can be considered new or, in exceptional circumstances, existing assets can be forced to comply with new rules.

Since this means that facilities cannot easily be upgraded during their lifetime, it is very important that the grid code requirements not only reflect the needs of the power systems in its present state, but in fact anticipate future development and ensure that the needs will be met in the medium-term future, when significant amounts of additional VRE capacity will be installed.

Such anticipation of future system needs can fail. In this case, it is possible that upgrading existing generation facilities to support new functions or different characteristics will become necessary to maintain system security. However, facility owners should never be required to pay arbitrary amounts for necessary upgrades if this is not connected to additional benefits. This still leaves multiple ways of implementing retrofitting schemes:

- Minor upgrade costs that do not significantly affect operating costs can still be required to be paid for by the facility owners. In this case, it is a good idea to have transparent criteria for what upgrade cost level is considered acceptable and what is unacceptable.
- The upgrade cost could be paid for by the system operator, who in turn could recover the cost through an increased network charge, resulting in a higher electricity price for consumers.
- If not all facilities need to be upgraded, a new remuneration scheme can be put in place that offers additional income for facilities implementing an upgrade. Examples for such remuneration schemes are increased feed-in tariffs or a new ancillary service market.

- If only a few facilities need to be upgraded, bilateral arrangements between the system operator and the facility owners can be agreed to resolve the problem.

More variations can be thought of in which the costs are shared. For example, the upgrade costs to be borne by the facility owners could be capped, with the remaining costs to be covered by the system operator.

In any case, it is a good idea to limit retrofitting schemes to the minimum required upgrade measures and not demand a full upgrade to the latest grid code requirements for all facilities, as this would further increase the cost of the retrofitting action. To limit the societal cost, the schemes should also only apply to the smallest set of facilities required to restore system safety. Determining this set is also a challenge, however: some facilities might not be capable of upgrading, and verification of the modified behaviour after the upgrade has been applied at the facilities can be difficult. If not properly monitored, there might even be uncertainty about the installed capacity fleet and its precise behaviour before the retrofitting scheme is started. Retrofitting schemes therefore always represent a compromise and require careful deliberation (Burges, Doering and Kuwahata, 2014).

The EU NC RfG addresses the application of technical requirements to existing facilities in Article 4. TSOs desiring to implement such an application are required to conduct a sound and transparent quantitative cost-benefit analysis to justify the necessity to the regulatory authority.

5.4 RECOMMENDATIONS ON COMPLIANCE ENFORCEMENT AND VERIFICATION

The best ratio of achievable grid code compliance and verification cost can be achieved if all test categories discussed above are combined in a co-ordinated fashion: type tests, on-site tests, simulation tests and in-operation monitoring.

Compliance verification schemes are an important reason why all relevant stakeholder groups need to be involved in designing the corresponding rules. Only through efficient stakeholder participation can a reasonable compromise between desirable behaviour and the corresponding implementation and verification effort be found.

Certification schemes are a good way to increase the level of trust because they enforce transparent and independent compliance assessment. Because setting up a certification scheme is a complex process and may be unfeasible on a per-country level for smaller countries, active participation in international standards development, including certification standards, is a good idea. This may take time, though, since international standardisation necessarily requires many international stakeholder to achieve consensus on suitable methods, processes and requirements.

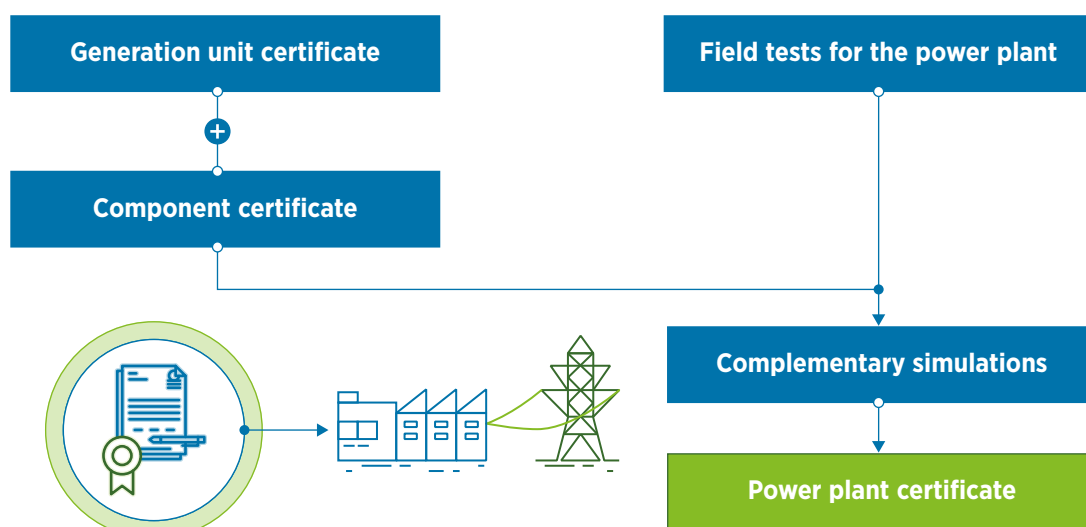
Besides certification along national rules and standards, there is currently only one international certification option for DER that is suitable for moderate to high shares of VRE. This is IEEE Std 1547-2018 (IEEE Standards Association, 2018a) together with IEEE 1547.1-2020 (IEEE Standards Association, 2020) and UL 1741 SB.

In the meantime, until manufacturer-independent certification is available, temporarily accepting manufacturer declarations and/or certificates issued in other countries (if the corresponding requirements match the system needs) can be a reasonable approach. As soon as certification is available, proper certificates should be required.

Regarding the technical requirements of the EU NC RfG, ENTSO-E provides guidelines for setting up compliance schemes. This includes guidance on which function is suitable for the different kinds of verification, such as testing or simulations (ENTSO-E, 2017a). The implementation status of the RfG in European countries is tracked closely by the European Commission (European Commission and FGH GmbH, 2021), which provides a detailed review on which non-exhaustive requirements have been implemented in which way in the member states. A couple of other sources provide overviews of the implemented compliance schemes (Holzapfel and Hinzer, 2020; Schowe-von der Brelie *et al.*, 2019; Ulvgård and Gehlhaar, 2019; Bründlinger *et al.*, 2018).

For example, Spain created a national technical standard for the conformity assessment regarding the certification structure for new power generating modules. The general process can be seen in Figure 22. The standard first states the process for the manufacturers to obtain the generation unit and component certificates. This will be done by authorised certifiers. Afterward, the power generating module should be simulated. If all requirements are fulfilled, then the module will obtain its certificate (Villanueva *et al.*, 2020).

Figure 22 **General scheme of conformity assessment**



Based on: Villanueva *et al.* (2020)

India has ambitious VRE integration plans and is therefore also addressing the compliance verification issue. In 2019, the Central Electricity Authority amended the regulations regarding the requirements for grid connectivity. According to the experience observed, it was necessary to include a dedicated testing and certification procedure to verify compliance (BS *et al.*, 2019). The procedure includes testing, measuring, recording and data post processing. The testing is usually carried out according to IEC 61400-21, FGW TR/3. For the compliance certification together with the CEA, DNVGL-SE-0124 will be used (Kunjumon, Wehrend and Gehlhaar, 2019).

06 REGIONAL GRID CODES AND INTERNATIONAL CO-OPERATION



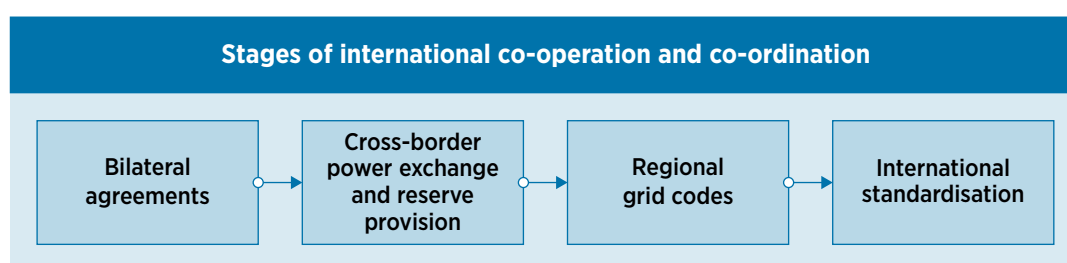
KEY TAKEAWAYS OF THIS CHAPTER:

- › The main purpose of regional grid connection codes is to facilitate international power trade. They also ensure competitiveness in regional markets between assets connected to one grid that also have the potential to sell their energy and services in neighbouring markets.
- › Harmonised requirements facilitate the regional sharing of flexibility and thereby contribute to a successful energy transition. This may allow equipment manufacturers and project developers to provide equipment compliant with these requirements at lower costs in the medium term owing to economies of scale. It will enable fair competition within regional markets and hence more market efficiency and lower consumer prices.
- › Technical requirements for generators are included in most regional codes but allow considerable freedom for the individual TSOs or member states to choose exact parameters. Regional connection network codes often focus heavily on ensuring operational security but focus somewhat less on actual harmonisation of technical requirements.
- › In the United States and the European Union, efforts focus heavily on operational security and power system stability in the regional market and co-ordination among TSOs. Harmonisation can be difficult to achieve due to differences in the acceptable ranges of parameters within each individual system, but RfGs and IEEE standards can guide TSOs on the allowable range of parameters and can be technology neutral.
- › Minimum regional requirements, such as those in the European Union, allow the national system operator in each country to choose the exact requirements it needs or even to impose stricter ones. These requirements are intended to ensure that generators connected in all EU countries fulfil a minimum set of requirements.
- › In Central America, the regional technical and market rules have evolved over time from a set of purely market-oriented rules into a full and legally binding regional grid code. These rules govern market transactions, inter-operator co-ordination and technical requirements for market actors, including generators, and currently include requirements for VRE. When the national and the regional grid codes have a similar requirement, the stricter requirement prevails.
- › In the case of small islands, the development of an aligned grid code for countries within the same region, with exact parametrisation left to the local operators, could allow equipment manufacturers and project developers to provide suitable equipment compliant with these requirements at a lower cost in the medium term owing to economies of scale.

- › Nationally customised implementation of international or regional grid codes will always be necessary, as regulation applicable to larger areas cannot capture the specific characteristics of each market and power system in full detail without becoming overly bulky and prescriptive. This is especially true for local issues like voltage control or market-specific issues like the handling of distributed generation, the overall share of which in power supply varies greatly by country.
- › Co-ordination between international equipment standards and grid codes continues to be an important point. In case of conflict, a decision about whether an applicable standard or a grid code requirement should prevail needs to be arrived at on a case-by-case basis. Local authorities' support of international participation in the development of standards is key for international standards to represent and cover any power system condition.

Each country developing its own set of completely independent connection requirements provides full control of grid code conditions and system characteristics, but it also requires a lot of effort. Co-operation with others to share resources is often better, especially for small countries. Where they manage to both co-ordinate rules and harmonise requirements, the result will be improved market access for manufacturers of modern and advanced equipment, safer regional operation, and easier adoption of high VRE penetrations. Co-operation and co-ordination can go through different stages (Figure 23).

Figure 23 **Stages of international co-operation in power systems**



Based on: Villanueva *et al.* (2020)

In the context of regional markets, having regional grid connection codes is important to ensure competitiveness in regional markets between assets connected to one grid that have the potential to sell their energy and services in neighbouring markets.

Historically, regional and international co-operation and co-ordination on matters relating to power system operation and security were mostly organised through bilateral negotiations and agreements between the power utilities of neighbouring countries or supply areas. The nature of such co-operation evolved from agreements on mutual assistance in emergency cases in order to increase security of supply, to bilateral trade of power to optimise net benefit, mostly conducted in the form of long-term contracts. The situation changed significantly with the liberalisation and unbundling of power sectors in Europe and North America in the late 1990s and early 2000s.

The shift towards open electricity markets along with the introduction of increasing shares of VRE generation introduced a greater need for cross-border trading and inter-TSO co-ordination, which gave rise to the introduction of regional grid codes in some cases.

One of the earlier examples of a regional grid code is the Nordic grid code, published in 2004 (Nordel, 2004, 2007). The Nordic grid code is a collection of national rules and agreements between the TSOs of Denmark, Finland, Norway and Sweden, which had introduced the world's first international electric power exchange, Nord Pool, in 1996. Inter-TSO co-ordination in the region was governed by the association of Nordic transmission grid operators, Nordel, from 1998. The Nordic grid code focused on collecting and harmonising the technical requirements and operational procedures of the Nordel TSOs.

The Nordic grid code has since been superseded by the EU Network Codes, which were signed into European law in 2016 and apply in all EU member states. These follow a similar approach but are much more extensive and are described in detail in Section 1 of this chapter. Similar efforts are underway in Central America, South and Southeast Asia, and several African regions, which are described in sections 3 and 4 of this chapter. The commonality between most of these regional efforts is that their main purpose is the facilitation of international power trade. Market rules and inter-TSO co-ordination in operation and planning are hence the focus of most existing frameworks. Technical requirements for generators are included in most regional codes, but leave considerable freedom to the individual TSOs or member states to choose the exact parameters. Regional connection network codes often focus heavily on ensuring operational security, but somewhat less on actual harmonisation of technical requirements.

The lack of harmonised technical requirements is receiving criticism, especially from equipment manufacturers, who largely still have to set up their products' capabilities individually for each jurisdiction. Manufacturers generally have great interest in having technical requirements harmonised across large markets so that solutions can be provided more cost efficiently due to economies of scale. In this regard, further international harmonisation of technical requirements will be an important contribution to fair competition within regional markets and hence more market efficiency and lower consumer prices.

This issue is especially important in small power systems and markets, which inherently have low market power and are therefore not in a situation to drive development of new functionality. It is greatly beneficial for operators of small systems to get together and harmonise their rules either regionally or globally in the wider context of VRE development.

6.1 THE EU NETWORK CODES

The framework commonly known as the EU Network Codes contains eight main documents, only four of which are currently considered to be actual network codes, with the remaining four having the status of guidelines (Table 6). The entire framework was developed by ENTSO-E in co-ordination with the European Agency for the Co-ordination of Energy Regulators between 2009 and 2015, signed into European law in 2016, and entered into force in 2016 and 2017 (Meeus and Schittekatte, 2018). It is important to notice that this co-ordination effort was greatly facilitated by European Union structures having been in place for decades before.

The entry into force was followed by an implementation process in which the national TSOs had to adapt their rules to be compliant with the provisions set out by the EU Network Codes.

Table 6 EU Network Codes

Connection	Operation	Market
Demand Connection Code (DCC)	Emergency and Restoration (ER)	Forward Capacity Allocation (FCA)
High Voltage Direct Current Connections (HVDCC)	Operation	Electricity Balancing (EB)
Requirements for Generators (RfG)	No more than 20% of rated capacity	Capacity Allocation & Congestion Management (CACM)

● Network Codes. ● Guidelines.

For the three Connection Codes, the implementation process was finished by the end of 2019, while for some of the other codes, the process will continue until 2022.

The three Connection Network Codes (CNCs), and among those especially the RfG, are the most relevant for this report, as these focus on connection requirements for different generator classes. They have been developed with the objective of ensuring operational security and power system stability in the regional market, *i.e.* synchronous areas of Europe, and hence specify a set of minimum requirements for each generation class that need to be fulfilled in every member country. A certain degree of harmonisation of requirements is inherent in this approach but did not constitute the main focus. The challenges of applying a set of technical requirements to users connected to different power systems across an entire continent, and the solution approach chosen in the EU Network Codes, are outlined below using the EU NC RfG as the example most directly applicable to renewable generation.

One of the key challenges in applying similar sets of requirements to all generators in the European Union is the fact that there are five synchronous systems of different sizes. Frequency stability functionalities may be required from smaller generators if the synchronous system is smaller, as the individual generator has a higher impact on overall system stability. The RfG address this by specifying four generator size classes, types A through D. Each type has to fulfil a certain set of requirements, with Type A requirements being the simplest and Type D requirements the strictest. The maximum size thresholds among the types are determined based on the synchronous system the generator is connected to (Table 7).

Table 7 Capacity thresholds for power-generating modules of four types, depending on the synchronous system they are connected to

Type	Baltic	Continental Europe	Great Britain	Ireland	Nordic
A	0.8 kW	0.8 kW	0.8 kW	0.8 kW	0.8 kW
B	0.5 MW	1 MW	1 MW	0.1 MW	1.5 MW
C	10 MW	50 MW	50 MW	5 MW	10 MW
D*	15 MW	75 MW	75 MW	10 MW	30 MW

* Units connected to a voltage level of 110 kV or higher are always Type D, regardless of capacity.

With this strategy in place, a 10 MW wind power plant in the smaller Irish synchronous system has to fulfil the same requirements that only generators of 75 MW and above would have to fulfil when connected to the much larger Continental synchronous system, accounting for the higher system impact of individual units in smaller systems. Key requirements for different generator categories are given in Table 8.

Table 8 **Main requirements in the EU NC RfG and where they apply**

	Type A	Type B	Type C	Type D	
Frequency range	X	X	X	X	
LFSM-O	X	X	X	X	
LFSM-U			X	X	
LVRT		X	X	X	
Dynamic fault current		X	X	X	
LVRT to 0 voltage				X	
Protection co-ordination		X	X	X	
FSM			X	X	
Black start			(X)	(X)	Non-mandatory
Island operation			(X)	(X)	Non-mandatory
Fault recorder			X	X	
Simulation models			X	X	
Voltage ranges				X	
Reactive power		(X)	X	X	Type B: synchronous only

The second major challenge in developing regional requirements is that, even with increasing inter-TSO co-ordination in the regional market, technical requirements still need to be tuned to the needs of the individual system. Frequency control mechanisms and requirements should be (but are not always) harmonised within each synchronous system. Voltage control and protection are however local issues and are addressed differently by each TSO. The RfG address this issue in two stages:

- Most requirements in the RfG allow for parametrisation by the individual TSOs. Acceptable parameter ranges are often specified instead of fixed parameters.
- The requirements are minimum requirements and non-exhaustive, which means that each TSO could specify additional and/or stricter requirements.

EU regional grid code ensures that generators connected in all EU countries fulfill a minimum set of requirements, crucial to system stability and security of supply, while enabling higher VRE shares.

This gives TSOs a lot of freedom to choose the parameters that work best in their system but does not achieve a full harmonisation of requirements (see Table 9). For example, manufacturers of wind turbines know, by way of the RfG, that all wind power plants above the Type B threshold have to be FRT capable, but the actual FRT envelopes may still be different in each country or for each TSO.

Table 9 EU NC RfG parameterisation of non-exhaustive requirements

Implementation detail of key technical requirements	TSO parametrisation required	TSO degree of freedom
Frequency range	Underfrequency duration can be extended by TSO, rest is fixed	Low
LFSM-O	Droop and threshold frequency to be chosen, max/min ranges given	Medium
LFSM-U	Droop and threshold frequency to be chosen, max/min ranges given	Medium
LVRT symmetric	Envelope given, times and voltage values to be chosen, max/min ranges given	Medium
LVRT asymmetric	Subject to TSO parameters	High
Dynamic fault current	Subject to TSO parameters	High
Protection co-ordination	Subject to TSO parameters	High
FSM	Detailed set of parameters given, narrow max/min ranges given	Low
Fault recorder	Subject to TSO parameters	High
Simulation models	Subject to TSO parameters	High
Voltage ranges	Undervoltage duration can be extended by TSO, rest is fixed	Low
Reactive power	Maximum ranges given	High

This may not be the full harmonisation desired by the manufacturers and project developers, but it is already a major step forward from the pre-EU Network Codes era, when requirements varied even more wildly. Further harmonisation is on the agenda in European Stakeholder Committee discussions that are working on the second iteration of the EU Network Codes.

National implementation has been successfully executed (ENTSO-E, 2020a).¹⁷ However, different countries have chosen different approaches of implementation, a degree of freedom that was explicitly granted under the codes and the corresponding law. The Connection Codes define the requirements for grid users non-exhaustively, giving each legislation and TSO the freedom to define additional requirements, and leaving considerable freedom in the exact choice of requirement parameters. The structure of national or TSO-specific grid code documents is also not prescribed. Most European TSOs opted for a revision of their respective grid codes to align them with the requirements set out in the European codes. Some (such as the Kingdom of the Netherlands), however, have chosen to directly use the Connection Codes as nationally applicable documents (which would have been the default prescribed by the European Union in case of no action)

¹⁷ Updates on national implementation and the applicable national documents of member states can be accessed at www.entsoe.eu/active-library/codes/cnc/.

and only specify additional requirements and parameter clarifications where needed (Ministerie van Binnenlandse Zaken en Koninkrijksrelaties (Kingdom of the Netherlands), 2021; ENTSO-E, 2020a).

The implementation structure and the degrees of freedom given to TSOs concerning technical parameters clearly show that a harmonisation of connection codes was not the primary objective of the EU Network Codes. Instead, a more high-level approach is taken, which is intended to ensure that generators connected in all EU countries fulfil a minimum set of requirements that are crucial to system stability and security of supply and hence grant the proper functioning of the electricity market and enable higher VRE shares to fulfil the European Union's emission targets. This is sufficient from a system operator perspective, but has been criticised by manufacturers that still have to comply with slightly different rules and navigate a multitude of differently structured grid code documents. The considerable TSO co-ordination that has taken place on the European level also supported harmonisation, especially (but not only) for parameters related to frequency. The Implementation Guidance Documents are products of such TSO co-ordination at the ENTSO-E level (ENTSO-E, 2021).

Acknowledging the increasing decentralisation trend and high share of DER that will be connected in the future in the European grid, the European Clean Energy Package maps out several necessary actions. Of primary importance is the formation of the EU DSO entity, which will boost efficiencies in the electricity distribution networks and assure collaboration between ENTSO-E and TSOs. This entity is expected to play a substantial part in preparing and executing new network codes, relevant distribution networks (Meeus *et al.*, 2020).

6.2 CO-ORDINATION EFFORTS IN NORTH AMERICA

Transmission systems in Canada and the United States are operated by a variety of different independent system operators (ISO) or regional transmission operators (RTO), which usually fulfil the role of both a power system operator and a market operator but may not actually own the grids (there may therefore be separate transmission companies focusing on maintenance and asset management). Subtransmission and distribution grids are operated by a variety of different grid operators and utility companies. Market and ownership structures vary widely for the same historic reasons that can be observed in Europe. In this regard, the power system structure and the grid code landscape related to it are as fractured and uneven in North America as they are in Europe, despite the fact that only two (albeit heavily federalised) countries are involved here.

The North American Electric Reliability Corporation (NERC; until 2007, it was known as the North American Electric Reliability Council) is a non-profit association of network operators analogous to ENTSO-E in Europe that is tasked with assuring reliability of the bulk power system (transmission level). NERC, operating through eight regional entities, is therefore responsible for the development of technical standards and guidelines to facilitate inter-ISO/RTO co-ordination and ensure the functioning of the electricity market. There are currently 102 NERC standards that are applicable to North American power systems, given in Table 10.

Table 10 Applicable NERC standards for RTOs/ISOs

Section	Acronym	Number of standards
Resource and Demand Balancing	BAL	8
Critical Infrastructure Protection	CIP	16
Communications	COM	2
Emergency Preparedness and Operations	EOP	6
Facilities, Design, Connection and Maintenance	FAC	9
Interchange Scheduling and Co-ordination	INT	2
Interconnection Reliability Operations and Co-ordination	IRO	12
Modelling, Data and Analysis	MOD	12
Nuclear	NUC	1
Personnel Performance, Training and Qualifications	PER	4
Protection and Control	PRC	20
Transmission Operations	TOP	4
Transmission Planning	TPL	3
Voltage and Reactive	VAR	3

These form a framework of rules comprising 1 952 pages in the 2021 iteration and are comparable to the previously described EU Network Codes in both volume and objective. Similarities with the EU Network Codes are the following:

- Both sets of rules focus heavily on operational security and inter-TSO co-ordination, while the harmonisation of technical requirements for connections is only a side focus.
- Minimum requirements are set out, individual TSOs are allowed to choose the exact requirement parameters and/or impose stricter requirements.
- The application of requirements to different synchronous areas is accounted for through regional variances (see Table 11 for an example).

Concerning technical requirements for generators, the NERC Reliability Standards also contain a much smaller number of items than the EU NC RfG, focusing only on requirements crucial to system stability at the synchronous system level:

- Frequency and voltage operational envelopes (PRC 024).
- FRT and dynamic reactive current contribution (PRC 024).
- Primary frequency control requirements, only applicable to ERCOT as the smallest and most frequency-sensitive synchronous system (BAL-001-TRE). Recent FERC Order 842 requires all new resources connected to system to be capable of PFR with defined deadband and droop and to have this capability enabled.
- Requirements for power system stabiliser operation, only applicable to WECC as the largest synchronous system, which is prone to oscillatory stability problems (VAR-501-WECC-3.1).

Those requirements are largely technology neutral. All other technical requirements for synchronous generators, and IBRs are generally left up to the individual ISO or RTO. For

Table 11 **Frequency range requirements and minimum operation times for generators connected to different synchronous systems as an example of regional variance in the NERC Reliability Standards**

	Quebec	WECC	ERCOT
>66.0	Instantaneous trip		
≥63.0	5 seconds		
≥61.8			Instantaneous trip
≥61.7		Instantaneous trip	
≥61.6		30 seconds	30 seconds
≥61.5	90 seconds		
≥60.6	660 seconds	180 seconds	540 seconds
59.4 - 60.6		Continuous operation	
≤59.4	660 seconds	180 seconds	540 seconds
≤58.5	90 seconds		
≤58.4		30 seconds	30 seconds
≤58.0			2 seconds
≤57.8		7.5 seconds	
≤57.5	10 seconds		Instantaneous trip
≤57.3		0.75 seconds	
≤57.0	2 seconds	Instantaneous trip	
≤56.5	0.35 seconds		
<55.5	Instantaneous trip		

IBRs there are also a number of other guidelines outside of the NERC Reliability Standards framework.

For IBRs, NERC has followed a different approach from ENTSO-E in that it tends to largely rely on interconnection standards developed by international standardisation organisations – in its case, mainly IEEE. The two main standards that cover a scope similar to connection grid codes are IEEE 1547 for DER, and IEEE P.2800 (currently under development, expected to be approved in 2022) for transmission-connected IBRs. Both of those include the typical generator requirements that were compiled and developed with the involvement of grid operators and other power system stakeholders over a long period of time (NERC, 2019).

The use of IEEE 1547-2003 in the United States was mandated by the US Federal Energy Policy Act of 2005 (Basso, 2014). Authorities governing interconnecting requirements (AGIR; these may be grid operators, utilities or regulators, depending on the jurisdiction) are then required to comply with these rules. They may still publish their own grid codes, but they need to be compliant with the standards as well. In this regard, IEEE 1547 and IEEE P.2800 take on a role very similar to that of the EU NC RfG in Europe. IEEE 1547 has been regularly updated and the changes implemented by the respective operators. The amendments have been published every two to three years since 2003, and IEEE 1547-2018 is the current version¹⁸ set to be fully rolled out by 2022. In the operational recommendations of NERC, IEEE1547-2018 will be elevated to de facto grid code status in the region of applicability. Similar developments can

¹⁸ This 2018 version includes significant revisions from the previous (2003) version, recognising significant technology developments as well as the much greater role that DER may play in power system reliability.

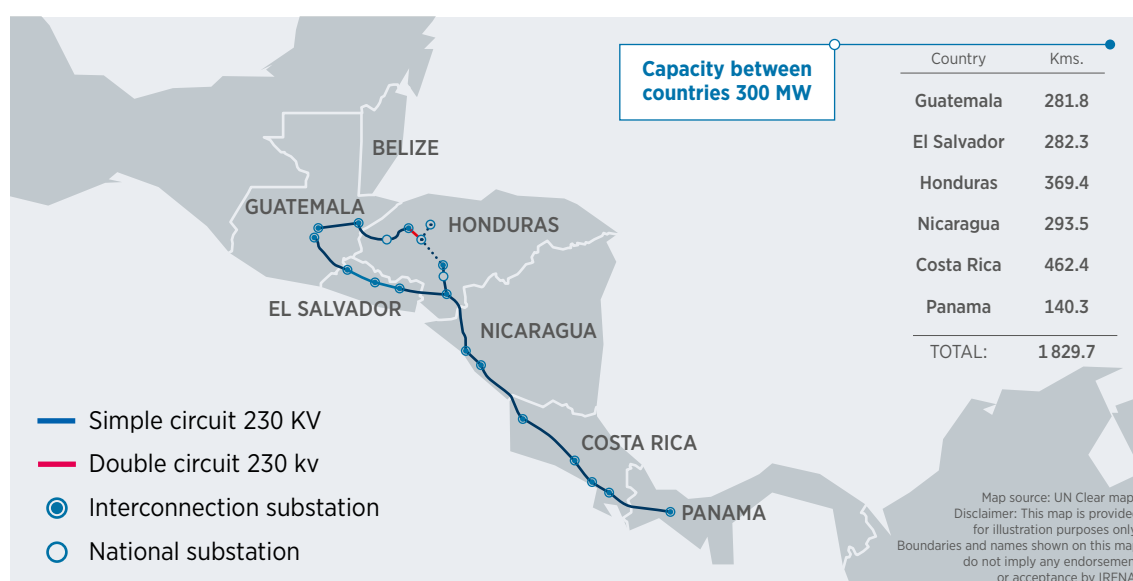
be expected for IEEE P.2800, while a NERC Reliability Guideline governing IBRs connected to transmission grids is already in place (Boemer *et al.*, 2019; NERC, 2019, 2020).

With this NERC recommendation, IEEE1547-2018 (all distributed resources) and IEEE P.2800 (transmission connected IBR) will be regional grid codes for North America, with the main area of applicability being the United States, but both documents are clearly designed to go beyond this scope. Both contain, as stated by the US Interstate Renewable Council, “a menu with options that need to be selected dependent on technology, location and other factors” (Lydic and Baldwin, 2019). Due to the combination of that with more concise and detailed requirements compared to the EU NC RfG, both standards can clearly be recommended as options for internationally standardised technical requirements for generators.

6.2 CO-ORDINATION EFFORTS IN CENTRAL AMERICA

The first regional effort in Latin America and the Caribbean is the interconnection of six countries of Central America through the Regional Transmission Grid (Red de Transmisión Regional, RTR). Along with the physical interconnection of the individual power systems, a regional market (Mercado Eléctrico Regional, MER) was established, governed by CRIE (Comisión Regional de Interconexión Eléctrica) as the regional regulator. The operation of each electric system and the corresponding market is performed by each national system operator, respectively (system operator and market operator) (Montecinos *et al.*, 2021). Each of the six countries is a balancing area. However, the regional operator entity is in charge of supervising and co-ordinating all of the operators in the region and establishing minimum technical requirements to be fulfilled (Ente Operador Regional, 2021).

Figure 24 **The Regional Electric System interconnecting Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua and Panama**



Source: INDE (2020)

Note: For real time regional interconnecting electricity system for Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua and Panama see: www.enteoperador.org/.

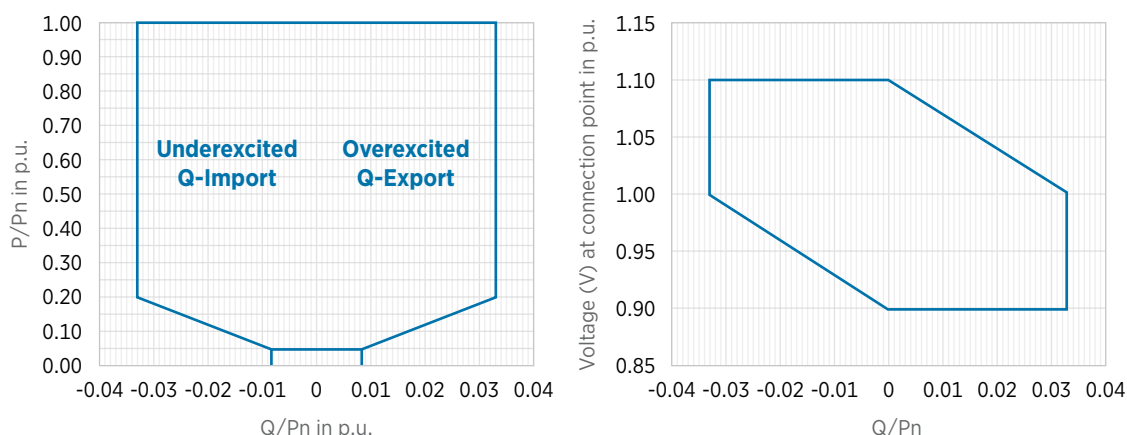
Furthermore, the regional operator entity is in charge of overseeing any exchanges among the systems such as those for power plants that sell to consumers in different systems and verifying that each country has enough reserves to comply with regional performance indices.

Technical and market rules are set out in the RMER (Reglamento del Mercado Eléctrico Regional), published by CRIE (CRIE, 2020). This document is maintained and regularly updated based on proposals from the regional operator entity and/or consultation with the national utilities system operator and market operators and other stakeholders. It has over time evolved from a set of purely market-oriented set of rules into a full and legally binding regional grid code, governing market transactions, inter-operator co-ordination and technical requirements for market actors, including generators.

Since 2018, the RMER has included minimum requirements for VRE generators above 5 MW, which apply to all such generators connected to the transmission system in member countries. National system operator and market operators or utilities are however allowed to impose stricter rules if they deem it necessary to do so (CRIE, 2018, 2020). Prior to 2018, technical requirements were formally established for conventional synchronous generators only, and each country had its own VRE requirements. These requirements include:

- Telemetry and forecasting: Requirements for a weather station and for real-time data to be provided to the system operator to enable it to have a generation forecast.
- Limited frequency sensitivity mode: The RMER states this should be established regionally by each power system based on its local analysis.
- Primary reserves: Wind and PV power plants must contribute to primary regulation. This can be done by operating in curtailed mode, through a substitute generator or through storage.
- Voltage control and reactive power supply: The minimum requirement is established by the regional operator entity (see Figure 25), but a stricter behaviour can be imposed by the national operator. Other requirements are:
 - At least 50% of the reactive power range has to provide dynamic support for voltage control.
 - The dynamic characteristic for voltage control will be defined by the system operator.
 - Control modes that need to be included are voltage control through reactive power, fixed reactive power, voltage control according to local voltage measurements, fixed reactive power output according to the active power output and fixed power factor.
- LVRT: VRE power plants must withstand voltage dips of 0.0 per unit for at least 150 milliseconds and remain connected for at least 2 000 milliseconds until a 0.9 per unit voltage is obtained.
- HVRT: VRE power plants must withstand 120% of the nominal voltage for up to 2 seconds.

Figure 25 Minimum requirement for reactive power capacity for all generation plants connected to the RTR



Source: CRIE (2020, pp. 214 and 215)

- Fault behaviour: VRE power plants must provide reactive current during faults. The amount will be determined by the national system operator. This current should have priority over the active power.

Currently, each system has its own rules and requirements according to the needs of its control areas. For Guatemala, the national grid rules focus more on distributed generation due to its popularity, whereas in El Salvador the focus is on the utility scale requirements. On the other hand, Costa Rica has technical requirements from the system operator that are included as part of the interconnection agreement to all generators. Costa Rican technical requirements were approved with the national regulator, Autoridad Reguladora de los Servicios Públicos (ARESEP). Finally, Panamá has a specific grid code dedicated to wind energy and another one for solar PV, including distributed generation.

The system operator and market operators are responsible for implementing the requirements imposed by the regional operator entity. Whenever there is a similar requirement between the national ones and the regional ones, the stricter requirement is the one that prevails. As the interconnection of these systems is quite recent, the push towards a harmonisation of requirements in the region is still ongoing.

Further co-ordination efforts in the Americas are currently beginning, most notably those related to the Caribbean. In this case, a potential harmonisation of grid codes is not driven by the fact that these countries are interconnected and need to operate in a co-ordinated way, like in Central America, but by the need for an increase in market power of small systems. The power systems in Caribbean countries are mostly located on islands and operate synchronously and independently, theoretically allowing each grid operator or utility to draft and enforce its own rules, which is also the current state of affairs there. However, power systems are small and have low market power, and the individual systems generally exhibit very similar properties. Small island systems also require special characteristics from generators, especially in matters relating to frequency control because inertia is low and the frequency sensitivity of the systems is high. Interest in the integration of VRE resources is also high, as wind and PV have developed a significant cost advantage over the oil-based generation that dominates these systems. That cost advantage could however be quickly diminished if significantly different advanced functionalities were required in each of the small grids. Aligning grid code requirements, potentially with exact parametrisation left to the

local operators, would avoid this issue and also put the Caribbean power system operators in a better position to drive technological development. As of 2021, these efforts were, however, in a state of initial discussion (CEPAL, 2016). Similar efforts are under consideration for island nations in Southeast Asia, as described in the following section.

6.4 OTHER CO-ORDINATION EFFORTS

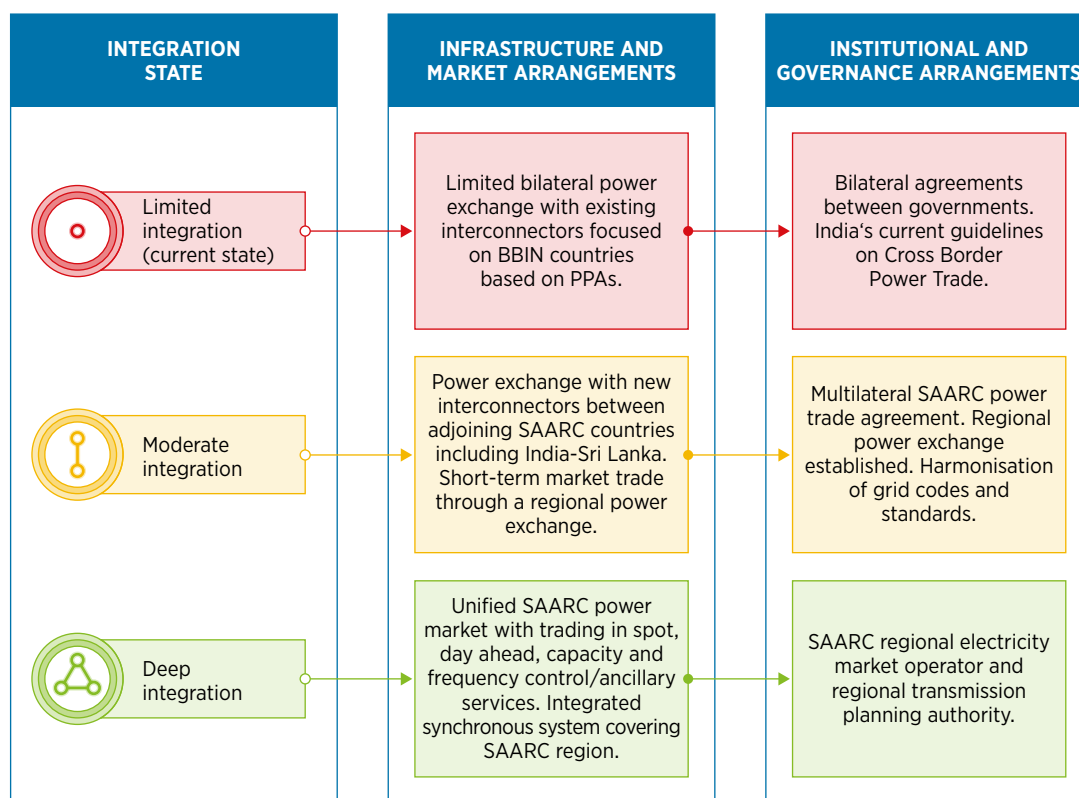
The facilitation of cross-border power trading has also been widely accepted as an important step towards reliable and cost-efficient power supply outside of Europe and North America. Especially in developing regions, the grids of neighbouring countries are still often not or only weakly interconnected. Because some countries may have a surplus of resources (especially hydro potential in tropical areas), while their neighbours have a deficit or have to rely on more costly generation resources (often oil), the mutual benefit from interconnections and cross-border power trades has been obvious for a long time. It has however been hindered by political issues in many cases, such as a heavy focus on self-reliance and mistrust of neighbours – issues that still persist to some degree in developed regions as well. With progressing economic and human development, the topic has however risen to the forefront in recent years, and a number of efforts are currently underway to develop regional frameworks to facilitate international co-operation and markets:

- the Greater Mekong Subregion (GMS) regional grid code to be applicable to the power systems of Cambodia, China, Lao People's Democratic Republic, Myanmar, Thailand and Viet Nam (Greater Mekong Subregion Secretariat, 2021)
- grid code harmonisation efforts within the concept of the South Asian Association for Regional Cooperation (SAARC) energy ring since 2004, which includes Afghanistan, Bangladesh, Bhutan, India, the Maldives, Nepal, Pakistan and Sri Lanka (SAARC, 2015; Batra and Panda, 2019)
- the development of a regional grid code for the Southern African Power Pool (SAPP) driven forward by the Southern African Development Community (SADC) including 17 Southern African countries (The World Bank and SAPP, 2020).

Among those, the GMS regional grid code has progressed the furthest so far, with drafts published in 2018 and the documents in the process of formal enforcement by the respective countries. The others are still in the development or tendering phases. All of these efforts are focused heavily on the establishment of regional power markets and the facilitation of cross-border trading, similar to the initial motivation behind the EU Network Codes. The SAARC and SAPP efforts in particular have so far mainly addressed inter-TSO co-ordination on operational and planning matters, with the harmonisation of technical requirements for generators playing a secondary role at best. As VRE has started to become a cost-competitive alternative to large-scale conventional generation, this can however be expected to change quickly.

The SAARC cross-border interconnections of national power grids include regional interconnection between India-Bangladesh, India-Bhutan and India-Nepal. These four

Figure 26 Steps in developing grid integration in SAARC



Note: BBIN includes Butan, Bangladesh, India and Nepal

Source: UN ESCAP (2018)

countries are actively participating in an electricity market and will be synchronously connected to each other in the future, looking to explore the renewable potential from India. Power system regional integration can take various forms, from bilateral trade to a fully integrated subregional energy market. Each participating country must establish its optimal integration level by weighing and evaluating questions of risk and benefit, sovereignty, and investment (Figure 26) (UN ESCAP, 2018).

SADC has recently tendered consultancy services for the development of its regional code with the issues of VRE and technical requirements explicitly addressed (The World Bank and SAPP, 2020), and a full set of requirements is already included in the GMS regional grid code (Greater Mekong Subregion Secretariat, 2021).

The latter document draws quite heavily from the EU Network Codes in both structure and content, but has been adapted to apply to the local context, considerably shortened and simplified, and integrated a few updates that may also be seen in future iterations of the EU Network Codes. This code contains a set of connection conditions for power-generator facilities, HVDC systems and demand facilities. Key differences in the connection codes include the following:

- The different generator type thresholds for different synchronous areas have been removed, which is sensible because all member states are part of the same synchronous system.
- All generators and HVDC systems of Type B upwards are explicitly required to be capable of

providing primary reserve, with the requirement settings being taken from the most recent Danish grid codes (this functionality is only required from Type C and D in the EU NC RfG).

- The requirements for non-synchronous generation are given in the HVDC connection code instead of the RfG, presumably due to the comparability of inverter technology.

Considering that the published document is a draft, all requirements are still subject to change, and the implementation and performance of the rules remains to be seen.

6.5 THE ROLE OF INTERNATIONAL STANDARDS IN VRE INTEGRATION INTO POWER SYSTEMS

The development of technical equipment generally relies on requirements and guidelines set forth in national and international technical standards, and generation equipment (including VRE) is no exception to this rule. The standards applicable to the design, installation and commissioning of generating equipment therefore often impact grid code requirements, for example frequency and voltage ranges, which can largely be traced back to synchronous generator standards developed decades ago. Similarly, grid code requirements impact equipment standards as new functionalities are required. This bidirectional relationship is subject to heated discussion in some cases, as equipment manufacturers prefer to see the standards they have been using reflected in grid code. On the other hand, power system

Table 12 **IEC and IEEE product specification standards relevant to power systems and VRE integration**

Standard	Content	Standard	Content
IEC 60034	Rotating electrical machinery	IEC 61215	Terrestrial PV systems
IEC 60044	Instrument transformers	IEC 61400	Wind turbine design
IEC 60045	Steam turbines	IEC 61730	Construction of PV systems
IEC 60076	Power transformers	IEC 61868	Insulating mineral oils
IEC 60143	Series capacitors for power systems	IEC 61869	Instrument transformers
IEC 60044	Voltage and current transformers	IEC 62052	Electricity metering equipment
IEC 60308	Hydraulic turbines	IEC 62548	Solar PV arrays
IEC 60358	Coupling capacitors	IEC 62934	Grid integration of renewable energy generation
IEC 62052	Electricity metering equipment	IEEE 112	Induction motors
IEC 62053	Static meters for AC active energy	IEEE 115	Synchronous machines
IEC 60076	Power transformers	IEEE 421	Synchronous machines
IEC TS 61836	Solar PV energy systems	IEEE 929	Solar PVs

operators may want to impose more stringent requirements that would better reflect today's and tomorrow's systems, which may require a revision of those standards. However, while grid codes are binding laws, following standards is to a certain extent voluntary.

Table 13 **International communication and power system design standards commonly referenced in grid codes**

Standard	Function	Content
IEC 60617	Terminology	Graphical symbols for diagrams
IEC 60050	Terminology	International electrotechnical vocabulary
IEEE 1159	Data, broadcasting, communication	Power quality monitoring
IEC 60870	Data, broadcasting, communication	Telecontrol tasks
IEC 62056	Data, broadcasting, communication	Electricity metering exchange
IEC 61970	Data, broadcasting, communication	Energy management system application programme interface
IEC 61724	Data, broadcasting, communication	PV system performance monitoring - Guidelines for measurement
IEC 61727	Data, broadcasting, communication	PV systems - Characteristics of the utility interface
IEC 61850	Data, broadcasting, communication	Communication networks and systems in substations - Part 3: General requirements
IEC 61968	Data, broadcasting, communication	Application integration at electric utilities
IEC 60071	Standard practices	Insulation co-ordination
IEC 61188	Standard practices	Design and use of printed boards
IEC 62058	Standard practices	AC electricity metering
IEC 61936	Standard practices	Erection of power installations
IEC 62053	Standard practices	AC electricity metering
IEC 62054	Standard practices	Electricity metering
IEC 62305	Standard practices	Protection against lightning
IEEE 142	Standard practices	Grounding in power systems
IEC 61140	Standard practices	Protection against electric shock - Common aspects for installation and equipment

The aforementioned equipment standards, the most important ones of which are listed in Table 12, generally describe the behaviour of generating units on the grid only at a high level, if at all, and often leave enough room to implement new functionality. These standards are also regularly referenced in grid codes, particularly when it comes to issues related more to unit design than to operation, such as power quality requirements.

Table 14 **International interconnection standards**

Standard	Content
IEC 62257	Microgrids
IEC 62786	DER interconnection with the grid
IEEE 1547-2018	Interconnecting distributed resources with electric power systems
IEEE P.2800*	Connection of IBR to bulk energy systems (transmission)
EN 50549	Interconnection for generators up to Type B according to the EU Network Codes RfG, including EU NC RfG compliance certification

* Not yet approved; expected in 2022.

While technical requirements for generators are sometimes decoupled from product standards, communication in power systems is generally governed by international standards, ensuring the interoperability of different actors. The same is true for general power system design. The relevant standards are given in Table 13.

There is another set of standards with a much closer relationship to technical requirements and power system operation: interconnection standards for generators (Table 14). These often not only contain typical grid code requirements such as FRT, operating ranges and communication requirements, but are in some cases so detailed that they can be used in lieu of a separate grid code. In this regard, some of these standards represent grid code harmonisation efforts of their own. Prime examples of such structures can be traced back to the situation in the North American grid, where they are generally applied as well (see Chapter 6, Section 2). These particular standards, IEEE 1547-2018 for distributed generators and the upcoming IEEE P.2800 (expected in 2022) for transmission-connected IBR, will be very useful especially for smaller countries just starting out with grid code development, as they can be used either as a basis or directly as a grid code.

6.6 RECOMMENDATIONS ON FORMULATING REGIONAL GRID CODES

International co-operation and standardisation involve co-ordination among a large number of different stakeholders from different countries and power systems. This leads to the main single drawback of such undertakings, which is that they typically require much time and effort to develop and implement. This is also the major reason why regional grid codes are not yet as widespread as they probably should be. However, regional grid code co-ordination is greatly facilitated by the presence of international co-operation and governance structures already in place. This is clearly visible in Europe, where the EU Network Codes, which represent the most advanced regional grid code effort as of today, were successfully implemented through the structures of the European Union, which had been established for decades before.

Further development of international harmonisation of grid codes is recommended for the following reasons:

- Small countries or power systems have little overall market power and hence usually cannot require any functionality from generators that is not already required in some larger systems. Small independent systems in particular may require special functionalities related specifically to frequency and active power control, and from much smaller units that would be considered distributed resources in larger systems. This can only be done to the full extent and at reasonable cost if requirements are at least somewhat harmonised between different island systems with comparable characteristics.
- For larger, interconnected systems it is very sensible to harmonise at least the requirements related to frequency and active power control across the entire synchronous system. This is not primarily for economy of scale, but for overall predictable behaviour of the system during frequency disturbances and therefore increased system security. Harmonised requirements facilitate the regional sharing of flexibility and thereby contribute to a successful energy transition.
- Even for larger systems, harmonised requirements may allow equipment manufacturers and

project developers to provide suitable equipment compliant with these requirements at a lower cost in the medium term owing to economies of scale.

International co-ordination and exchange of experience is furthermore also crucially important for the development of suitable national and power system specific grid codes. Mistakes made in one area do not have to be repeated by everyone else; instead, lessons learnt by one operator should be considered by others. National grid codes, or at least nationally customised implementation of international or regional grid codes, will always be necessary, as regulation applicable to larger areas cannot capture the specific characteristics of each market and power system in full detail without becoming overly bulky and prescriptive. This is especially true for local issues like voltage control, or market specific issues like the handling of distributed generation, the overall share of which in power supply varies greatly by country.

Great caution should however be taken to not get caught up in a dynamic where national grid codes are leading the way and regional codes are always lagging. This can easily happen and in fact has already happened to some degree with the EU Network Codes, development and implementation of which took the best part of a decade and which therefore do not fully represent the current state of the art anymore. It should however be noted that these presented an initial effort, and future revisions of this regulation are expected to be quicker and more frequent. This is similar to national grid codes, which tend to be revised more frequently after an often time-consuming inception of the first code.

Co-ordination between international equipment standards and grid codes continues to be an important point. When these conflict, the applicable standard or grid code requirement that should prevail needs to be decided on a case-by-case basis. International interconnection standards such as IEEE 1547 and IEEE P.2800 on the other hand present full sets of grid code requirements and can therefore either fulfil the function of regional grid codes or be used as national grid codes directly.

To adopt good standards, it is important that members from several system operators are active in the standard's development. When this is the case, a whole view of possible operating conditions is at hand when defining a standard. Otherwise, there is a risk that standards will not be applicable in some specific systems, requiring a revision of the standards, which may take a long time. Therefore it is key that local authorities support international participation in the development of standards.



Photo: Singkham / Shutterstock

07 GUIDANCE FOR DESIGNING GRID CODES

This section provides an overview of which kinds of connection requirements are appropriate in power systems at different stages of the VRE integration process. Where possible and applicable, the requirements themselves should be drawn from international standards such as the latest editions of EN 50549 or IEEE 1547. When looking at regulation, the European grid codes are probably the best developed. Leading stakeholders from any country should join the corresponding standardisation efforts to ensure that their particular needs are adequately addressed.

7.1 POWER SYSTEM ARCHETYPES

Achieving significant levels of VRE is a challenge in any power system, because VRE technology has become competitive only recently. In many countries the capacities are ramped up quickly. Examples from several countries illustrate that high shares of VRE are already possible with the technology available today.

Table 15 VRE shares in selected systems

System	Approximate peak load (GW)	Annual VRE electricity share (%)	Maximum VRE share of hourly demand (%)	Year
California (CAISO)*	50	22.6	62.6	2018
Costa Rica	1.7	13.3	35	2020
Denmark	6	51	157	2018
Germany	81	32.8	93	2020
Great Britain**	55	21	67	2018
Ireland & Northern Ireland**	6.5	30.8	85	2018/2019
South Australia	3	50	142	2018/2019
Texas (ERCOT)**	74.8	23	66.5	2020/2021
West Australia***	4	20	65.6	2021

* CAISO = California Independent System Operator.

** Island system with limited interconnectivity.

*** Island system with no interconnectivity.

Given the wide variety of country power systems, how should their grid codes be designed to facilitate VRE adoption? What requirements and parameters are important, and which aspects could be neglected in a given situation? We discuss these questions based on three different power system archetypes and look at them at three different stages of their VRE integration process. Considering that many countries operate multiple power systems to supply geographically separate areas, we also add further country-level advice to account for the need to design grid codes that cover more than a single system.

Table 16 **Selection of power system archetypes**

System archetype	Interconnection with neighbouring systems	Grid structure	Predominant existing generation resource
Large System	Weak	Short-distance transmission	Coal and gas
Medium System	Weak	Long-distance transmission	Hydropower and fossil fuels (coal/gas/heavy fuel oil)
Type Small	None	Island	Diesel and heavy fuel oil

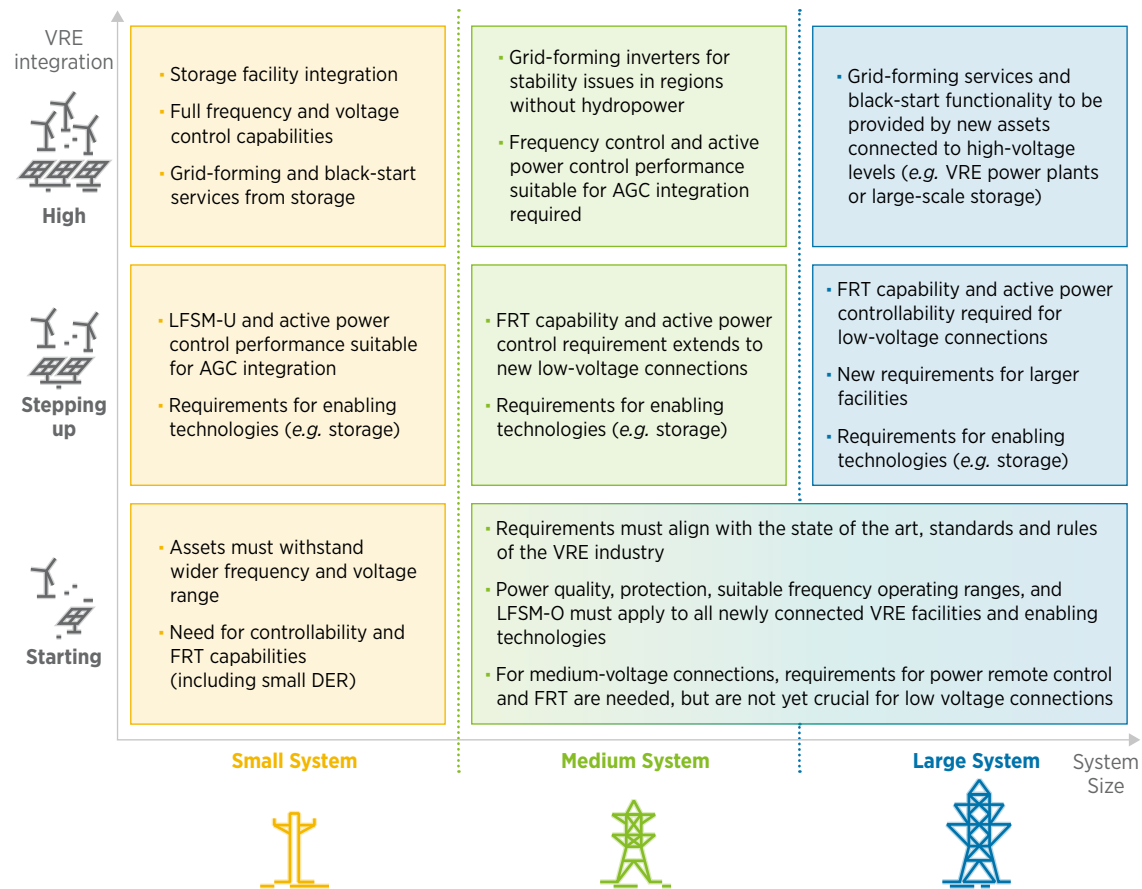
An overview of the main characteristics of the three selected archetypal power systems is given in Table 16. Since the discussion first focuses on power systems, we can assume that each of the selected cases has no or only weak interconnectivity to neighbour systems. In comparison to systems with strong interconnection ties, this represents the more challenging situation because fewer resources can be shared with neighbours. The assumed grid structures of the archetypes are related to the predominant existing generation resources – fossil fuel-based generators are commonly located close to the demand centres. This is less the case with hydropower. Therefore, the archetype with a share of hydropower generation features a grid with long-distance transmission between the hydropower resources and the demand centres.

The archetypes have not been designed to match any existing systems. However, they aim to capture the most common typical cases in developing countries, where more guidance on designing grid codes for scaling up VRE is usually needed. Systems with very high shares of hydropower are not covered, because their VRE adoption process is less challenging – they do not have major shares of fossil-fuel-based power plants to replace, and hydropower often provides the needed flexibility to accommodate VRE fluctuations. However, hydropower plants have relatively low inertia and relatively slower PFR, often leading to low inertia issues.

Grid code designers and policy makers aiming to facilitate VRE adoption in more challenging situations should be able to find similarities between their systems and the archetypes to extract the relevant recommendations for their systems.

Appropriate grid code requirements and parameters must be determined considering the generation mix, size of the power system, and the existing interconnection capacity.

Figure 27 **Grid code formulation guidance according to grid size and VRE integration level**



Note: AGC: Automatic generation control; DER: Distributed energy resources; FRT: Fault ride through; LFSM-O: Limited frequency sensitive mode for overfrequency; LFSM-U: Limited frequency sensitive mode for underfrequency; VRE: Variable renewable energy

7.2 STARTING THE VRE INTEGRATION PROCESS

Large and Medium systems

Countries with minimal VRE capacity within their power system that intend to kick off the capacity build-up process should not make the mistake of imposing lax connection requirements in the beginning. As in all other phases of VRE integration, the requirements should be oriented towards state-of-the-art VRE industry standards and rules in the countries that have already achieved significant VRE integration. These countries' standards and rules incorporate experiences from past successes and failures and have been developed over the course of many years with input from all relevant stakeholders.

Starting with up-to-date best industry practices is beneficial because once VRE integration gains traction and higher penetration levels are reached, there will be less old (*i.e.* with insufficient functionality) capacity in the system that can prevent reaching higher levels quickly. It will also be less likely that costly retrofitting is needed later on.

Basic requirements such as power quality, protection, suitable frequency operating ranges and LFSM-O need to apply to all newly connected VRE facilities and enabling technologies. It is not yet important that the smallest units connected to the low voltage distribution system be capable of active power remote control and FRT, but for connections at medium voltage level they should already be required.

An example for starting the VRE integration is Colombia. The country's power mix is dominated by hydropower and had no wind power connected until recently (less than 1% in 2018). Since there is not much experience with VRE, the requirements on the grid code are based only on studies. Therefore, one of the crucial next steps is to monitor and assess the performance of current requirements and eventually revise and amend the grid code if needed.

Since Colombia is starting with integration of variable renewables, preparatory work is ongoing to ensure the correct integration of the new power plants. The work includes running grid studies, identifying suitable connection points and transmission needs – there are plentiful wind and solar resources, but the best sites are not located close to the load centres. Colombia has the advantage of having hydropower readily available to provide the flexibility needed to integrate the planned VRE. Furthermore, Colombia is assessing different strategies to incentivise the start of variable renewables: incorporation of an intraday market, balancing markets for system services, improving generation forecasts, optimisation of reserves and dispatch.

Among the best practices Colombia is adopting is the inclusion of new technical requirements – like FFR – in its grid code since the beginning of the integration process, foreseeing a high VRE penetration and a reduction of the system's inertia.

Small systems

When connected to smaller systems, DER of any given size can have an early and significant impact on system performance. Since small systems are unable to share resources over greater distances, they tend to be less robust when failures and generator outages occur. Facilities connected to smaller systems should be able to withstand wider frequency and voltage fluctuations than larger systems, and controllability and FRT capabilities should be needed even for small DER on the low voltage level at the initial VRE integration stage.

7.3 STEPPING UP VRE INTEGRATION

Large systems

Once an initial share of VRE penetration is reached, it becomes important to start preparing the power system for higher shares. For VRE connections, requirements previously only applicable to larger facilities should be applied to new small facilities. For example:

- FRT capability and active power controllability should be required for new facilities connected to low voltage distribution systems.
- It is advisable for new requirements to be introduced for larger facilities, such as LFSM-U, or for enhancing controllability requirements to enable AGC integration.
- Grid code requirements should apply to enabling technologies such as storage or other producer-consumer users to facilitate their integration. If enabling technologies are installed from the initial stage of VRE integration, grid codes should apply from the beginning.

Medium systems

Systems with significant shares of flexible hydropower resources have less pressure to introduce advanced VRE flexibility measures and supporting enabling technologies early. They should also extend FRT capabilities and active power controllability requirements to new low voltage connected VRE facilities.

In the case of systems with reduced hydro capacity, if VRE starts developing far away from demand centres, weak grid/voltage stability and long-distance power transfer/voltage stability issues will arise. The former can be solved having VRE controls designed for low grid strength (low short circuit ratio) and the latter can be resolved through transmission reinforcements.

In Australia, a certain level of system strength is required by the system operator, and this has to be ensured by transmission service providers, who in turn may require VREs developing in the area to provide it or install additional transmission assets to achieve it. New VREs in Australia are also required not to reduce system strength at the interconnection point below a required level, which in turn may necessitate additional equipment to be installed by VREs.

Small systems

Small systems without flexible non-variable renewables need to introduce the most demanding requirements first, for all sizes of user facilities. Once some initial VRE integration is reached, appropriate requirements for new facilities already include LFSM-U and active power control performance suitable for AGC integration. Grid code requirements should explicitly apply to enabling technologies, especially storage.

7.4 GRID CODE REQUIREMENTS FOR HIGH VRE SHARES

Large systems

Due to their sheer size, large power systems previously relying mostly on fossil fuels require much more time and effort to convert to high VRE shares than smaller systems. Nevertheless, conventional power plants can only be fully replaced in the power system if all necessary functions and services can be delivered from sustainable resources. Therefore, grid-forming services and black-start functionality will need to be provided by non-conventional facilities such as VRE power plants or large-scale storage. The corresponding technical requirements should be specified in the grid codes. Since it is not necessary that all user facilities across all sizes and voltage levels provide this functionality, imposing such requirements only on facilities connected to the highest voltage levels and/or beyond a certain size threshold is useful. It is also possible to specify these requirements outside the grid code by requiring them only as a prerequisite to getting access to a corresponding service market.

Medium systems

Similar to the situation at the medium VRE integration step, the presence of hydropower in the system allows for a less aggressive introduction of further advanced grid code requirements. Continuous availability of hydropower will often offer more economical provision of black-start and grid-forming services than requiring these functional capabilities from VRE power plants and/or battery storage facilities. However, even in Type Medium systems targeting

high VRE shares, the grid codes must require frequency control support through FSM and active power control performance suitable for AGC integration, and they should explicitly facilitate the integration of enabling technologies.

When integrating high shares of VRE in systems without large hydro, grid-forming inverters should be considered to solve stability-related issues and reduced VRE curtailment.

Small systems

Particularly in small systems, storage facilities will be needed to achieve high annual electricity shares of VRE. Grid codes need to require full voltage and frequency control capabilities from the storage plants and should also require the capabilities to provide black-start and grid-forming services from them. Leaving significant portions of the requirement specification to market-based processes may be possible but may also be unfeasible in small systems due to the organisational overhead of running dedicated power markets or service markets.

7.5 COUNTRY GRID CODES FOR MULTIPLE SYSTEMS

As highlighted above, appropriate grid code requirements and parameters must be determined for each synchronous power system, and the size of the power system is a major factor in identifying the parameters. This creates a challenge when preparing a grid code for multiple systems, because distinguishing applicability based on the voltage level of the connection point and the power rating of the connected facility is not enough. The synchronous system where the facility is to be connected must be considered as well, which can be done in any one of these ways:

- The grid code splits the connection requirements into different sections, one section for each synchronous power system.
- In the specification of each connection requirement, different parameters are listed for each of the relevant synchronous power systems.
- Instead of referring directly to size thresholds, the connection requirements are specified as applying to facility type classes, where the facility type class delineation can be defined separately for each synchronous power system.

The third approach is the one taken in the European Network Code RfG (Chapter 6, Section 1). It separates generation modules into classes A to D and defines the requirements for each of them. They are separated by facility size thresholds, and countries have some freedom to choose thresholds. The main factor influencing them is the considered synchronous system.

The Mexican grid code combines all three approaches. It separates the generation power plants into classes according to size (A to D), similar to the European approach. However, since each of the four systems has very different characteristics, there are also differences in the parameters for LFSM per power system. The frequency ranges are wider for the two island systems. Furthermore, the operation parameters of each system are different, such as reserves needed. Some sections are only applicable to certain power systems. For example, the Baja California System is interconnected with the California System in the United States, and therefore there are extra requirements defined by WECC that power plants need to comply with (Comisión Reguladora de Energía, 2016).

One related question is how the connection requirements need to change when the system size changes, for example when two or more previously separate systems get interconnected. This case is rarely problematic, because the larger system size facilitates sharing of reserves and usually makes the system more robust. Therefore, there is no need to adopt stricter requirements after such a system extension. Potentially more challenging is the opposite case: a permanent system split. It decreases the system sizes and therefore tends to necessitate stricter connection requirements in each of the separated parts. Planning such a permanent system split should involve a careful risk analysis and may require retrofitting of existing user facilities to maintain the same level of system reliability in each system.

Box 8 Island nation examples: Indonesia and the Philippines

Co-ordination and harmonisation efforts can be observed in the Philippines and Indonesia. Both are island nations comprising hundreds of different islands of different sizes. In the case of Indonesia, the vast majority of the more than 600 different power systems are operated by national utility PLN, while Philippine grids are operated by separate distribution companies. In both cases however, connection requirements and operational strategies differ greatly from one island to the other, making widespread integration of VRE difficult in an area where it has the greatest economic advantages – diesel-based small power systems. Efforts are undertaken in both countries to harmonise nationally applicable rules.

The Philippines published its Small Grid Guidelines in 2013, but they mainly contained requirements for grid operators and conventional generators (Philippine Distribution Code Distribution Management Committee, n.d.). VRE deployment in these systems was addressed in a 2018 government circular (Republic of the Philippines Department of Energy, 2018), but no harmonised technical requirements have been published to date. However, the requirements imposed on synchronous generators and the structure that addresses the commonalities and differences between individual small grids can be used as a template for future grid code development in such areas.

Indonesia's small grids are theoretically subject to the applicable national distribution code and an additional Renewable Energy Connection Guideline, but neither document addresses the additional functionalities required for generators. Increased interest from private sector independent power producers (IPPs) in Indonesia's island systems, and the obvious benefits that could be obtained from VRE generation as the cheapest available resource, have pointed out the need for harmonised rules. National utility PLN is currently revising its distribution code, and a small grids section addressing special requirements for VRE in island systems is expected to be part of it (Energynautics GmbH, 2020).

If implemented successfully, both cases could be a valuable resource in developing internationally harmonised island grid codes in areas like the Pacific Islands or the Caribbean in the future.



7.6 REGULATORY MEASURES TO SUPPORT NATIONAL POLICIES AND LEGISLATION

Regulation around VRE integration is not limited to defining connection requirements for grid user facilities. Policy makers will want to address many other relevant aspects, including:

- Clear definition of roles and responsibilities of actors in the power sector. System operators, responsible for system security and stability, must have the means to take on this responsibility. For example, they must be authorised to refuse connection if conditions are not fulfilled by the user. If the costs for upgrading or extending existing grid infrastructure are shared between parties, the cost allocation and corresponding rules and criteria must be clearly defined in the regulation.
- Due to the transformation of the power system, responsibilities are not necessarily static and may change over time. Distribution system operators previously had only very limited responsibility for managing user behaviour; however, the introduction of DER and their activation towards providing system services is changing that. Distribution operators need to be given the right to intervene locally, and they need to acquire the technical and operational capacities to handle this successfully and reliably. It is also important that collaboration and co-ordination between system operators are strengthened.
- In systems where service markets are used to allocate ancillary services, the market access rules often need to be reviewed to make sure that the markets are accessible to VRE, storage, and flexible consumption. This does not have to be with direct access; participation through aggregators and virtual power plants is an alternative.
- A clear pathway for the system transformation is very important for system planning. Upgrading and extending grid segments as new DERs are getting connected can be very inefficient if no optimisation is carried out across multiple projects and years. Therefore, system extension obligations need to provide the system planners with the necessary freedom to carry out such optimisation. This necessity extends beyond just new lines, substations and transformers, and also relates to reactive power compensation and voltage stability management. In the future, such optimisation will need to cover system adequacy and infrastructure beyond the power sector and may also integrate heating and mobility sector planning.
- Non-technical factors are the biggest barrier to VRE adoption. They include not only investment resources, but also knowledge and local expertise. In any system that already has some level of VRE penetration there is also local experience and implementation knowledge that should be used and expanded upon. Stakeholders and working groups assessing the progress so far and developing new rules need to be open to new contributors to learn. Identification of gaps and weaknesses in existing rules should not be limited to the grid codes but comprise the wider framework of roles and responsibilities.
- A very important part of sharing VRE integration knowledge and reducing implementation costs consists of international standardisation and harmonisation of requirements for connection, operation and planning. With engineering costs being one of the biggest cost drivers in designing power systems, successful standardisation not only of equipment, but also on the system level, will be key to achieving successful VRE adoption.

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GLOSSARY

Term	Description
Active power	The part of alternating current power that can perform work.
Alternating current (AC)	Electrical current that changes direction along a power line with periodic frequency (typically 50 Hz or 60 Hz) in a sinusoidal wave.
Ancillary services	Services provided by system actors that may build on grid code requirements and may or may not be monetarily rewarded (e.g. contributions to voltage and frequency control).
Black start	The process of energising an electricity system without any pre-existing electricity supply. Black-start capabilities are necessary for system restoration after blackouts of the entire system.
VRE curtailment	The reduction of the active power output of a VRE generator below the maximum it could produce in the prevailing conditions (wind, irradiation, temperature, rain, etc.).
Direct current (DC)	Electrical current along a power line that does not change flow direction in steady state.
Distribution system	Electrical power network operating at voltages below transmission system voltage; typically operated by a DSO.
Distribution System Operator (DSO)	Network operator in charge of the lower voltage levels. Responsible for operation, maintenance and planning of (parts of) the electrical power distribution network.
Fast Frequency Response (FFR) (inertia-based)	Response of power converter relating to system frequency change on power imbalance, with details to be specified in grid code. The purpose is to imitate to some extent the response of a rotating electrical machine. Previously referred to as “virtual inertia” or “synthetic inertia.”
Fault Ride Through	The ability of a generator to stay connected to the grid during a fault. Usually this refers to Low Voltage Ride Through (Under-voltage Ride Through) and High Voltage Ride Through (Over-voltage Ride Through).
Feeder	A distribution network power line that distributes electricity from a connection point with the transmission (or sub-transmission) network to connected electricity consumers and/or lower-level distribution systems.
Feed-in-tariff	Conditions of financial return to VRE operators for providing electrical energy to the power system.
Flicker	Variations in voltage magnitude that would cause a light bulb to flicker.
Frequency	In an AC power system, the inverse of the time period of one cycle of the fundamental sine-wave of the voltage.
Grid operator	Entity responsible for supervising grid operation including asset management, safety, system balancing and other system services.

Harmonics	Oscillations in the voltage occurring at integer multiples of the system frequency.
High voltage	Voltage level typically above 100 kilovolts; e.g. 110 kilovolts. Voltage levels above 200 kilovolts or 300 kilovolts are often referred to as extra-high voltage.
Instantaneous penetration of VRE	For a particular point in time, the fraction of the electrical load covered by VRE.
Interconnected system	A system connected to other systems through AC (alternating current) lines.
Inverter	Power electronic device to convert DC power to alternating current power.
Low voltage network	AC (alternating current) electricity network with rated voltage typically below 1 kilovolt, e.g. 110 volts, 230 volts or 400 volts (according to IEC standards).
Low Voltage Ride Through (or Under-Voltage Ride Through)	The ability of a facility or unit to stay connected to the grid when the voltage falls below standard limits during a fault.
Medium voltage	Voltage level typically in the range of tens of kilovolts, e.g. 10 kilovolts, 20 kilovolts or 30 kilovolts.
Network operator or System operator	Responsible for operation, planning and maintenance of (a part of) the electrical power network.
Nominal frequency	The design frequency for the alternating current in a power system. A country's nominal frequency is typically either 50 Hz or 60 Hz. In stable operations, the system frequency should remain close to the nominal frequency.
Nominal voltage	The design voltage for a part of the power network. In stable and secure operations, the system voltage for this part of the network should remain within a set range around the nominal value.
Operating reserve	Reserved active power capacity that can be called upon in real time from operating generators, demand or storage in the case of a power deficit or surplus.
Plant operator	Entity responsible for supervising generator operation.
Point of common coupling	A defined point on the connection between the user facility and the grid operator, at which the facility must meet the electrical performance criteria specified in the grid code. For example, this could be the lower (or higher) voltage busbar of a grid coupling transformer that connects a plant to the grid.
Primary energy source	Energy source converted by a power plant to produce electricity, e.g. wind, solar radiation, biomass, coal, gas, oil, water.
Primary (operating) reserve	Operating reserve provided by power plants already connected to the grid and running at reduced power output. Also called primary reserve. Typically, in traditional systems, the minimum allocated primary operating reserve should be the power of the largest power plant in the synchronous system.

Prosumer (Producer-Consumer)	A party connected to the power system operating at some time as a generation plant and at other times as a load. (Examples: Private house with rooftop PV, industrial facility with a wind farm and a battery electricity storage system connected to it.)
Ramping	The change in active power output over a defined time period.
Ramp rate	The rate at which a generator changes its active power output.
Rate of change of frequency	The rate (measured in hertz per second) at which the system frequency (measured in hertz) changes.
Reactive power	The part of the alternating power responsible for building electromagnetic fields around components. Reactive power cannot perform work; it is used to control the system voltage.
Reversed power flow	Classical distribution systems only connected consumers. The power was therefore supplied via the transformer from the next highest voltage level, and the direction of the power flow was always the same. Connecting numerous small generators next to consumers can mean local generation exceeds local demand, so that the direction of the power flow in the distribution system can be reversed. Power then flows via the transformer to the higher voltage level.
Synchronously independent area, or synchronous area /zone/system	An alternating current power system that regulates its own frequency.
Synthetic inertia	Term referring to the same functionality as – but increasingly replaced with – Fast Frequency Response.
Transmission system	System designed for long-distance electricity transmission; usually operates at hundreds of kilovolts.
Transmission system operator (TSO)	Responsible for operating the transmission system. The TSO is usually responsible for overall power system stability, including a constant frequency.
Unbundling	The separation of transmission, distribution, supply and generation infrastructure ownership in the power system. This separation facilitates the introduction of market competition among generators and suppliers by preventing grid operators as monopolists from intervening in the market.
Variable renewable energy	Energy from generators such as wind turbines and solar panels whose power output varies with the weather.
Vertically integrated utility	A utility that owns and operates both transmission and generation infrastructure, possibly also distribution and retail.
Virtual inertia	Term previously used for FFR, later for inertia provided by grid-forming inverters. Using this term is discouraged due to this ambiguity.
Voltage control	The ability of a generator to contribute towards keeping the voltage between regulated limits. Generators contribute to voltage control by adjusting their reactive power output.

