Article Title: Power System Stability in the Transition to a Low Carbon Grid: A Techno-Economic Perspective on Challenges and Opportunities

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Abstract

Increasing power system stability challenges are being witnessed worldwide, while transitioning towards low-carbon grids with a high share of power electronic converter (PEC)-interfaced renewable energy sources (RES) and distributed energy resources (DER). Concurrently, new technologies and operational strategies are being implemented or proposed to tackle these challenges. Since electricity grids are deregulated in many jurisdictions, such technologies need to be integrated within a market framework, which is often a challenge in itself due to inevitable regulatory delays in updating grid codes and market rules. It is also highly desirable to ensure that an economically feasible optimal technology mix is integrated in the power system, without imposing additional burdens on electricity consumers. This paper provides a comprehensive overview of emerging power system stability challenges posed by PEC-interfaced RES and DER, particularly related to low inertia and low system

strength conditions, while also introducing new technologies that can help tackle these challenges and discussing the need for suitable techno-economic considerations to integrate them into system and market operation. As a key point, the importance of recognising the complexity of system services to guarantee stability in low-carbon grids is emphasised, along with the need to carefully integrate new grid codes and market mechanisms in order to exploit the full benefits of emerging technologies in the transition towards ultra-low carbon futures.

Keywords: Distributed energy resources (DER), electricity markets, frequency stability, power electronic converter (PEC), renewable energy sources (RES), system inertia, system strength, voltage stability.

1. INTRODUCTION

The need to fight climate change, and the emergence of cost-effective new technologies, are causing electrical power systems worldwide to rapidly evolve towards a distributed energy resources-driven, complex cyber-physical architecture. A low-carbon grid will, in fact, be more and more characterised by power electronic converter (PEC)-interfaced renewable energy sources (RES) and distributed energy resources (DER) (including energy storage and flexible loads, such as electric vehicles), smart-grid technologies (e.g., smart meters, substation automation, microgrids, Internet of Things), distributed energy trading/management platforms (e.g., peer-to-peer energy trading, virtual power plants, etc.) and bidirectional power flows, as illustrated in Figure 1. It is envisaged that the interdependent nature of these technologies will create complex interactions between conventional and new generation technologies (Meegahapola & Flynn, 2015), both in terms of investment decisions and operational practices, and will change the characteristics of the existing power grid. As already witnessed in a few countries with a high share of renewables, for example Australia, UK and Ireland, the systemic interdependency between conventional and new technologies is creating complex dynamic interactions (Bloom et al., 2017) that call for radically new control and operating procedures in order to maintain grid stability, and hence security and reliability.

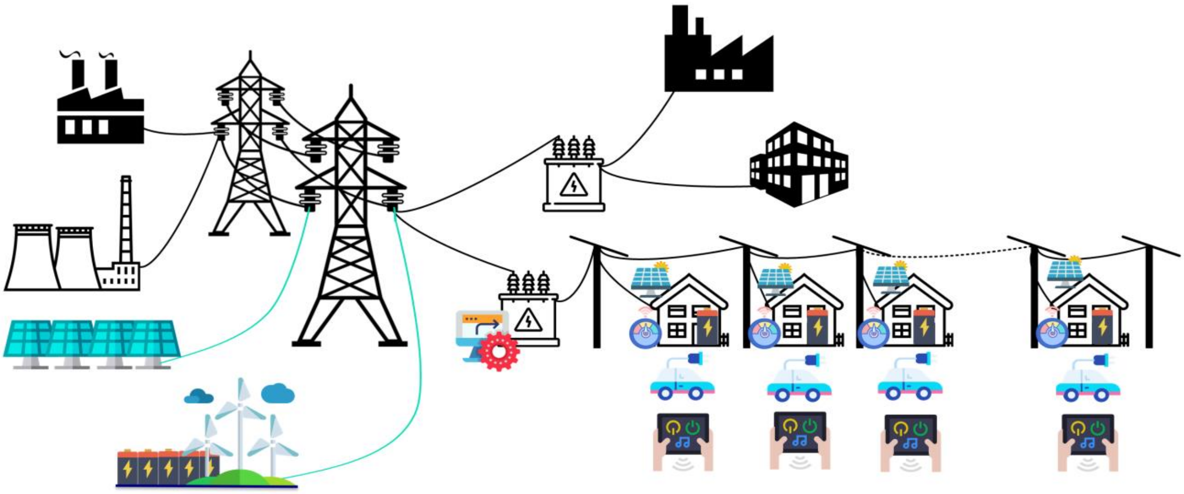


Figure 1. A power grid under transformation.

Among those key factors driving grid transformation, PEC-interfaced RES and DER are playing a significant role in changing grid dynamics, particularly, with respect to the instantaneous generation mix of the power grid, with implications for system inertia (stored energy in synchronously rotating masses), short-circuit strength (fault-level), and reactive power reserve (NERC, 2015). In fact, in conventional power grids, synchronous generators, besides providing continuous voltage regulation (via their automatic voltage control loops and using their available reactive power capability[1]), provide a natural response during frequency excursions (commonly known as an “inertial” response) and inject high short-circuit currents following a fault, as their stator windings are directly coupled to the grid. However, with an increasing share of PEC-interfaced technologies, synchronous generator-based power stations are gradually being displaced, leading to a (significant) reduction in stored energy capacity, short-circuit strength, and the ability to regulate frequency and voltage. All these factors directly affect power system stability, which is defined as the ability of power grids to regain and maintain system parameters within an acceptable range after being subjected to large or small gradual changes/ disturbances (Kundur, 1994).

Moreover, unprecedented growth in DER, particularly small-scale photovoltaic (PV) systems (<100 kW) and electric vehicles (EVs), is resulting in greater uncertainty in generation and load demand profiles, which can require additional reserves in order to maintain grid stability, due to the possibility of temporarily losing GW-level generation within a few minutes during uncertain (cloudy) weather conditions (X. Chen et al., 2020), changeable human behaviour (Pratt & Erickson, 2020), and cascading DER trips initiated by transmission level faults (AEMC, 2019; AEMO, 2019a; National Grid ESO, 2019). In Germany, for example, 49 GW of solar photovoltaic (PV) generation capacity was installed by the end of 2019, with over 52% of the systems noted as small scale systems (< 100 kW), and more than 98% of them connected to the low-voltage (LV) grid (Wirth, 2020). A similar trend in small-scale solar-PV system integration can be seen in Australia, where over 10 GW of small-scale solar-PV systems are currently (early 2020) being integrated[2] (Clean Energy Council, 2020). Therefore, the uncertainty driven by these highly weather-dependent renewable energy technologies is growing each day, requiring more fast responding energy resources to cope with potential stability challenges. Furthermore, as power grids are moving towards 100% renewable based power grids (basically 100% PEC-interfaced renewables), stability challenges are expected to dramatically escalate in the next few years (Hodge et al., 2020).

Electricity grids are deregulated in many jurisdictions worldwide, and hence electricity markets are required to support the essential activity of balancing system generation against the load demand on a second by second basis and across longer time scales. Some of these markets may operate in time intervals as short as 5-15 minutes, trading *energy* as the primary commodity. Other market products may also be defined to provide various *security services* to maintain grid stability and system reliability

[1]Available reactive power capability is constrained by the synchronous generator rating, active power capability and limits imposed by the excitation system, such as field current limit and over/under excitation limit (Kundur, 1994).

[2]These new energy technologies, which are distribution network-connected, also introduce voltage control issues in the LV and MV networks, which can also have consequences for the wider power grid in terms of requiring more network support services and localised control capabilities.

(Billimoria et al., 2020). These markets are commonly known as ancillary services, or system services, markets (e.g., for frequency control, it is possible to mention frequency control ancillary services (FCAS) market in Australia (AEMO, 2015a), flexible ramping product (FRP) in California (California ISO, 2016), DS3 system services in Ireland (EirGrid, 2017), fast frequency response (FFR) in ERCOT (ERCOT, 2016), and enhanced frequency response (EFR) in GB (National Grid, 2016)). These services are procured by existing (e.g. synchronous generators) and emerging technologies, such as battery energy storage systems (BESS) and demand response (DR). Inevitably, these ancillary services need to evolve against the background of a fundamental low-carbon power grid transformation.

The new technologies that are being introduced to tackle power grid stability challenges with an increasing share of PEC-interfaced resources must be effectively integrated within the incumbent market framework to exploit the economic benefits of low-carbon power grids. Therefore, it is imperative to fully characterise the capabilities of these emerging technologies in order to efficiently deploy them in an electricity market environment. Concurrently, the new technologies must adhere to the existing regulatory rules and grid-codes. Therefore, these complex interrelationships must be recognised to effectively address the stability and dynamic challenges that are emerging in low-carbon power grids, as shown in Figure 2.

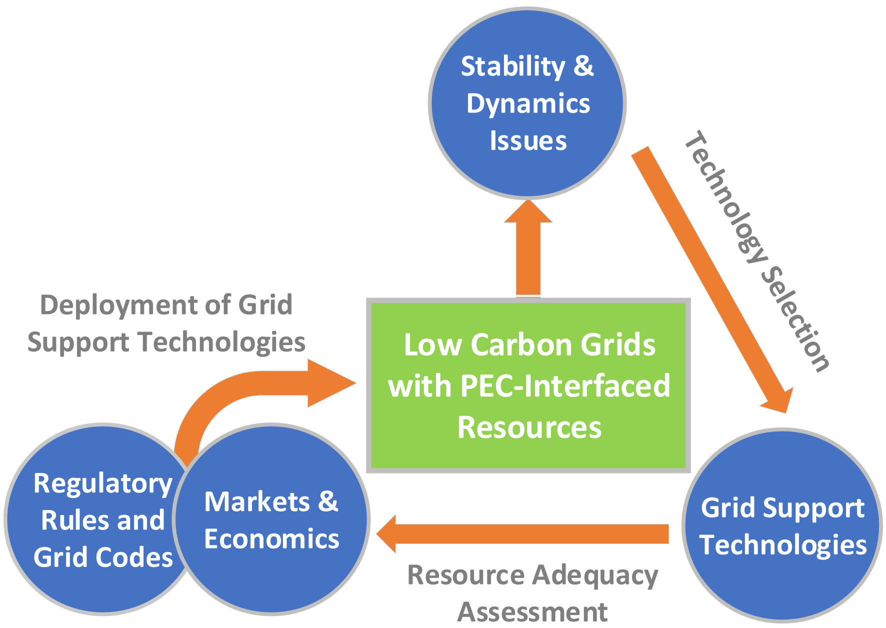


Figure 2. Grid-support technology deployment to address stability and dynamics challenges in low-carbon power grids.

The main objectives of this paper are to shed light on critical factors which affect the dynamics and stability of a transforming power grid, and to evaluate how emerging technologies could be deployed and incentivised to improve grid stability and security, considering the integration of grid codes and market mechanisms. This paper also discusses a potential framework that could be used to identify the most suitable technologies to address system stability issues during the system planning stage, which would facilitate power utilities in procuring an optimal mix of new technologies to address emerging security challenges in the presence of high share of PEC-interfaced renewable generation.

2. Stability Challenges with High Shares of Renewable Energy Sources

2.1 Frequency stability: conventional synchronous vs. PEC-interfaced technologies

The system frequency has traditionally been maintained by conventional synchronous generators, which provide a *natural* response during frequency excursions (i.e., inertial response), and also provide a *controlled* response (e.g. governor response and automatic generation control (AGC)) to recover the frequency back to a steady-state condition (EPRI, 2019). Inertial response is the instantaneous, natural (physical) response of the synchronous generator to a system frequency variation. On the other hand, governor response only becomes effective after several seconds (depending on the underlying plant technology, e.g., hydro, steam or gas turbines), due to delays associated with the overall control system and the plant dynamics. Hence, the inertial response provided by the synchronous generators during the initial few seconds following an event is a vital component of the overall frequency response to maintain system stability, particularly, since it is effectively the only means to reduce the initial severity of the frequency excursion before a governor response can act. The inertial response, ΔP_{gen} from a synchronous generator (Fox et al., 2014) is given by:

$$\Delta P_{gen} = \left(\frac{-E_{gen}}{f_0} \right) \times \frac{df}{dt}$$

where E_{gen} is the stored (rotational) energy of the generator, f_0 is the nominal system frequency and df/dt is the rate-of-change-of-frequency (ROCOF). The inertial response thus proportionally depends on the ROCOF [Hz/s] and the system stored energy capacity (in [GWs] or [MWs]) (Fox et al., 2014), which is often called the 'system inertia' (AEMO, 2018). However, in order to affect the system frequency, this stored energy capacity should be tightly coupled with the electrical dynamics of the system, which is what happens if the energy resource-grid interface is achieved through synchronous generators. Synchronous generators are, in fact, the dominant source of this response, which is why E_{gen} is also commonly referred to as 'synchronous inertia'. Overall, synchronous inertia possesses unique and key attributes that should be highlighted, namely, the fact that its response is inherent and autonomous (so requiring no trigger or control action), instantaneous (which is highly beneficial for extreme frequency events), and self-stabilising and proportional to ROCOF.

The "classical" concept of inertia in a power system dominated by synchronous generators is associated with the rotational energy available from rotating masses – such as a power plant, g – that are connected to the main synchronous grid, and the *inertial constant*, H_g, is often a convenient way to represent the normalised stored rotational energy of a particular machine:

$$H_g = \frac{E_{rot,g}}{S_g} = \frac{1}{2}\frac{I_g \omega^2}{S_g} [\text{MWs/MVA}]$$

where I_g is the power plant moment of inertia [kg m^2], ω is the rotor synchronous speed [rad/s], S_g is the machine rating [MVA], and $\frac{1}{2} I_g \omega^2$ represents the machine rotational energy [MJ] (or [MWs]). While different power plants are characterised by different inertial constants (accounting for both multi-stage turbines and generators), typical values are in the region of 1-10 MWs/MVA, with hydro plants and open cycle gas turbines typically exhibiting lower values and combined-cycle gas turbines typically higher ones (see (Bollen & Hassan, 2011; ERCOT, 2018a)) for inertia constant values for different plant models).

The system rotational energy, E_{sys}, for an entire power system can therefore be defined as;

$$E_{sys} = \sum_{i=1}^{n} H_g S_g [\text{MWs}]$$

where the sum is applied to all n machines that are operationally connected to the synchronous system[3] It is intuitive that the larger the rotational energy of a system, the greater will be its "inertia", that is, the greater will be its opposition to changing conditions, and, in particular, to changes in the system frequency (which is the main state variable in this context), as elaborated below.

The fundamental frequency dynamics of a power system can be conveniently described according to a so-called system frequency model (Bevrani, 2009), which considers a simplified single busbar (copper plate) system representation of the aggregate frequency response of all online generators (which are assumed to provide frequency control via governor droop feedback speed control) as well as the "damping" effect of some loads, e.g. pumps and fans, whose power consumption depends on the frequency (Bevrani, 2009). Such an approach assumes that the system frequency is the same everywhere, which is generally a reasonable assumption. However, during system disturbances, individual generators (and loads) or groups of generators (and loads) may swing against each other, resulting in low-frequency oscillations superimposed on the fundamental frequency signal. Neglecting such oscillations, the resulting fundamental supply-demand power balance dynamic equation following a generation contingency[4] ΔP_{GT} can be expressed as:

$$2E'_{sys}\frac{\partial \Delta f(t)}{\partial t} = -\Delta P_{GT} + D.P_D.\Delta f(t) + \sum P_g$$

where E'_{sys} is the post-contingency[5] system rotational energy (including the inertial contribution from the demand side and synchronous generators embedded in the distribution network) [MWs], D is the load damping factor (in [%/Hz]), P_D is the demand level [MW], $\Delta f(t)$ is the frequency drop [Hz], and

[3] These include inertia from loads such as induction motors, etc.

[4] The same principles apply to a generic contingency, such as an interconnector loss or demand loss.

[5] That is, discounting the inertia contribution that may have been lost with the tripping generator or load group

$\sum P_g$ is the aggregate generator response [MW] (summed over all generators[6] that actively respond to an event by adjusting their output). Figure 3 represents the relationship between the system stored energy capacity (i.e. inertia measured in [GWs]) and the *initial* ROCOF (Hz/s) under different (instantaneous) system contingencies for a system with a maximum load ($Pmax$) equal to 2000 MW.

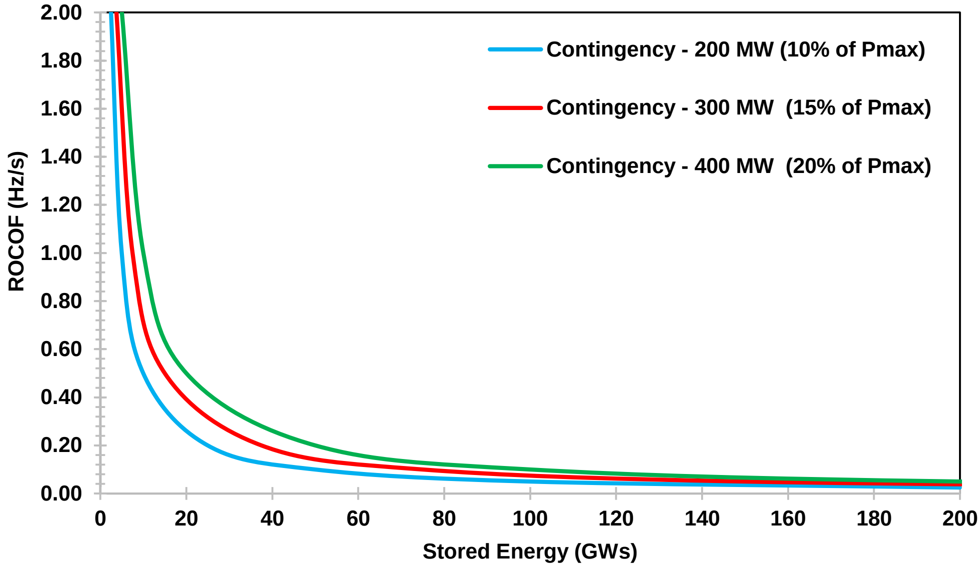


Figure 3. System stored energy vs. initial ROCOF under different contingency values.

According to Figure 3, increased stored energy capacity clearly helps to reduce the initial ROCOF following a contingency. The maximum ROCOF threshold could be used to determine the minimum inertia requirement for the largest infeed loss that may occur in the system. For example, in the context of Figure 3, if the loss of the largest infeed to the system is 10% of the maximum load, and the ROCOF threshold of the system is 0.5 Hz/s, then the system requires a minimum of 10 GWs stored energy capacity to maintain frequency stability. The stored energy capacity of the system varies from one dispatch interval to another, depending on the number of synchronous generators that are online during the dispatch interval and their respective inertia. For example, the stored energy capacity of the Nordic power grid in 2020 was anticipated to vary between 124–305 GWs (the installed capacity of the Nordic power grid was approximately 98 GW, with a minimum and a maximum and load were 29 GW and 71 GW respectively) (Fingrid, 2019; Ørum et al., 2018), while in the ERCOT system in 2019 the stored energy capacity has varied between 134.5–400 GWs (system load was 29.883 GW during the minimum stored energy capacity) (Matevosyan, 2020). The two systems are characterized by very different generation mixes, with, in particular, a much larger wind and solar-PV generation capacity installed in ERCOT.

On the contrary, PEC-interfaced sources (e.g. most wind turbines and solar-PV systems) do not provide a similar *natural* response during frequency excursions (see below for further discussion). Therefore, displacing individual conventional synchronous generators with PEC-interfaced

[6] The same applies, and can be readily extended to, an “equivalent” active generation response as from an energy storage plant, load disconnection, etc.

renewables causes a reduction in the online stored energy capacity, leading to a higher initial ROCOF during frequency excursions, assuming that the magnitude of the generation contingency is unchanged. For example, in South Australia the stored energy capacity can fall below 2 GWs in certain dispatch intervals with high production from PEC-interfaced generation, which might create serious frequency issues in the case that South Australia were to become islanded from the rest of the Australian system (DGA Consulting, 2016). It should also be noted that larger systems tend to have larger (MW) generators, and hence they are more susceptible to larger contingencies. On the other hand, for a given contingency size (e.g., largest generator), smaller systems with lower inertia may generally experience greater frequency stability issues. Hence, the link between ROCOF and system size, and displacement of conventional generation due to RES, is somewhat complex and not straightforward to generalise.

Various methodologies have been proposed to determine the minimum inertia requirements for power grids with a high share of PEC-interfaced RES (AEMO, 2018). The minimum inertia requirement is often calculated based on the assumption of a minimum ROCOF withstanding capability, mainly focused on generation. However, this can be a very subjective measure, which depends on system protection settings and plant auxiliary protection settings, (historical) grid code requirements, largest plausible infeed loss, and the system stored energy itself (including a load contribution). It is also sometimes claimed that the phase-locked loops (PLLs) of grid-following PEC-interfaced RES can encounter issues during high ROCOF periods (Sun et al., 2019). Attempts are also being made to identify suitable substitutes for inertia, for instance via pre-programmed synthetic responses that could be provided by some PEC-interfaced technologies (known by different technical terms, such as synthetic inertia, emulated inertial response, fast frequency response (FFR), etc.). Three main techniques are proposed within the literature, and indeed commercial offerings implemented by OEMs (Meegahapola, Sguarezi, et al., 2020), to achieve a fast frequency response; 1) *response based on frequency error (Δf)* ,2) *response based on ROCOF (df/dt),* 3) *fixed trajectory response (fixed trapezoidal response) when the frequency excursion exceeds a certain threshold* (Ruttledge & Flynn, 2016). By providing a very fast active power response – in the same timescale as an inertial response (basically, sub-second response) – these technologies can help to stabilise the system frequency during frequency excursions (Ruttledge et al., 2013; Tan et al., 2017). It should be noted, however, that despite usage of the term "inertia" in the names of the programmed responses, the response provided cannot be considered equivalent to that from a synchronous machine, particular for smaller systems, or when the share of PEC-interfaced RES is high. In fact, because “artificial” inertia is triggered by a control signal and is therefore of a discrete nature, there will always be certain delays associated with such responses (distinct from the “natural”, continuous inertial response obtained from synchronous machines), compounded by the fact that, since it is based on a controlled rather than physical response, it may also carry some degree of unreliability. On the other hand, it should be noted that control systems can be triggered to provide large step changes within a few hundreds or even tens of milliseconds, much faster than synchronous generators, subject, of course, to equipment physical and thermal limitations.

In addition to an inertial response, conventional generators also generally provide a primary (e.g. governor-based) and secondary (e.g. AGC-based) frequency response following frequency excursions in order to assist frequency restoration. In a similar manner, PEC-interfaced generators can be programmed to provide a primary frequency response; however, similar to conventional generators, RES-based PECs need to be operated below their maximum power point (i.e. de-loaded operation) in order to provide such a response in the case of an under-frequency event (Tan et al., 2016), and there is an open economic and environmental argument as to whether it is appropriate to pre-curtail renewable generation for stability related services.

On the other hand, a counterargument is that renewable energy curtailment might take place in any case due to security constraints (AEMO, 2020d; EirGrid, 2019), and RES should contribute to ancillary services, as with all other generation technologies. In a well-designed and competitive market environment (see below), market prices should drive behaviour towards the optimal trade-off between energy and reserve provision from different technologies, including RES. PEC-interfaced battery systems (Dozein & Mancarella, 2019) and hydrogen electrolysers (Zhang et al., 2017) can also provide a primary and secondary frequency response, as well as FFR. The response time of PEC-interfaced batteries and electrolysers[7] is, in fact, significantly smaller (e.g., 100-200 ms) in comparison to conventional (steam thermal) synchronous generators (e.g., 2-3 s), and hence the system frequency excursion could be arrested relatively quickly, as if there was some inertial response. For example, in Ireland fast responding frequency regulation products have been introduced to the electricity markets (e.g., fast frequency response (FFR)), and the equipment providing these services are required to inject active power across a 2-10 s timeframe (EirGrid, 2017), although faster responses are incentivised. Similar FFR and primary frequency response features may be exhibited by grid-scale and even household PV systems, if the PEC interfaces are properly designed (e.g., equipped with FFR schemes) and a response is suitably incentivised.

2.2 Voltage Stability: Fault levels and reactive power support

In addition to frequency stability support, synchronous generators traditionally contribute to voltage control requirements by injecting/absorbing reactive power, and they also contribute to the fault level of the grid by injecting high short-circuit currents (up to 6-8 times the nominal current). Although PEC-interfaced resources are also capable of injecting/absorbing reactive power (i.e., volt-var control) (Kabiri et al., 2015; Meegahapola et al., 2013), and regulating their active power output (i.e., volt-watt control) based on local voltage measurements, it is only relatively recently that they have started to be actively deployed in this manner in utility networks (IEEE 1547, 2018). Substantial benefits have been demonstrated when volt-var control strategies are deployed in solar-PV systems for voltage control, such as their potential to increase the hosting capacity of distribution networks with large PV shares (Kabiri *et al.*, 2015; Procopiou & Ochoa, 2017). On the other hand, other forms of less sophisticated protection schemes, e.g., PV tripping in the case of over-voltages, have been mandated for a long time, for instance, since 2005 in Australia (AS 4777.3—2005, 2005). Significant benefits from such

[7] Particularly polymer electrolyte membrane (PEM) water electrolysers.

schemes have also been witnessed in the recent separation event in Australia in August 2018 (Dozein et al., in press). Therefore, these protection schemes would also actively contribute to voltage control under excessive voltage rise in feeders, besides system-wide emergency events.

Recent amendments to DER standards, such as IEEE 1547, helpfully now require PEC-interfaced DER to provide reactive power under certain operating conditions (e.g. DER should be able to inject 44% of the nameplate apparent power rating when generating more than 20% of the active power rating) (IEEE, 2018). In addition, PEC-interfaced RES and DER only provide a small contribution to system fault level, by injecting a short-circuit current similar to the nominal value. In conventional power systems dominated by synchronous generators, reactive power support and fault-level are closely related concepts, as an important measure of the "stiffness" of the system voltage to a small, or large, system perturbation. In fact, low system short-circuit strength, normally also accompanied by scarce reactive power capability, would result in voltage control and synchronisation issues. Most remotely located PEC-interfaced RES are adversely affected by the low short-circuit strength of the local network (NERC, 2017), which is typical of long sub-transmission and distribution feeders in rural areas where there is sufficient space (and resource) to install RES such as wind and solar farms. Short-circuit strength is typically determined for a specific location, and when a new generator is connected, the strength of that location is usually represented through a relative metric. Specifically, short-circuit strength is typically measured by the short-circuit ratio (SCR) or stiffness ratio, defined for a DER connected to a specific busbar as the ratio between the short-circuit capacity (measured by MVA) at the point-of-common-coupling (PCC) of the DER and the MVA rating of the DER.

However, as argued in several studies (Dozein et al., 2018), the SCR does not fully capture the electrical strength of a location, as there could be control interactions associated with small-scale PEC-interfaced RES. Hence alternative formulae have been defined by power utilities to measure the short-circuit strength (NERC, 2018). For example, General Electric (GE) has proposed a composite SCR (CSCR), which takes into account all electrically close power electronic converters (see Table 1) (NERC, 2018). Both conventional and contemporary approaches (with DER/PEC-RES) used for SCR calculations are summarised in Table 1.

Table 1: Conventional and Contemporary Short-Circuit Ratio Calculations

Method	Formula	Description
Short-Circuit Ratio (Conventional Approach)	$\text{Short-circuit ratio}\,(SCR) = \left(\frac{S_k}{S_{DER}}\right)$	S_k is the short-circuit capacity (measured by MVA) at the point-of-common-coupling (PCC) of the DER and S_{DER} represents its MVA rating.
Composite SCR (CSCR)	$Composite\,Short-Circuit\,Ratio\,(CSCR) = \left(\frac{Composite\,SC\,MVA}{\sum ConverterMW\,rating}\right)$	Composite short-circuit (SC) level is determined as short-circuit level at busbars with the same voltage level, assuming they are all interconnected. The contribution from DER converters are ignored for composite

		SC level calculation and determined under low realistic load conditions.
ERCOT's Weighted Short-Circuit Ratio (WSCR) (NERC, 2015)	$\text{Weighted Short-Circuit Ratio}\,(WSCR) = \left(\frac{\sum_{i=1}^{N} S_{SCMVAi} * P_{RMWi}}{\left[\sum_{i=1}^{N} P_{RMWi} \right]^2} \right)$	S_{SCMVAi} is the short circuit capacity at bus *i* before the connection of non-synchronous generation (DER/ PEC-RES) plant *i*, and P_{RMWi} is the MW rating of non-synchronous (DER/ PEC-RES) generation plant *i* to be connected. *N* is the number of DER/ PEC-RES fully interacting with each other.

Dynamic reactive power compensation devices, such as static-var compensators (SVCs) and static-synchronous compensators (STATCOMs), are employed in power grids to improve voltage stability in network regions with low short-circuit strength (Dozein et al., 2018). Synchronous condensers have also been proposed and implemented for similar reasons (ElectraNet, 2019; Marken, 2013). Moreover, some system operators are procuring reactive power via ancillary services markets (e.g. steady state reactive power (SSRP) and dynamic reactive response (DRR) in Ireland (EirGrid, 2017), and network support and control ancillary services (NSCAS) in Australia (AEMO, 2015a)) to maintain the voltage stability of the grid.

2.3 Characterisation of electricity grid stability

Three system parameters, namely system inertia/stored energy capacity, short-circuit strength and reactive power reserve are noticeably affected by the presence of PEC-interfaced resources, thus affecting frequency and voltage stability, as shown in Figure 4.

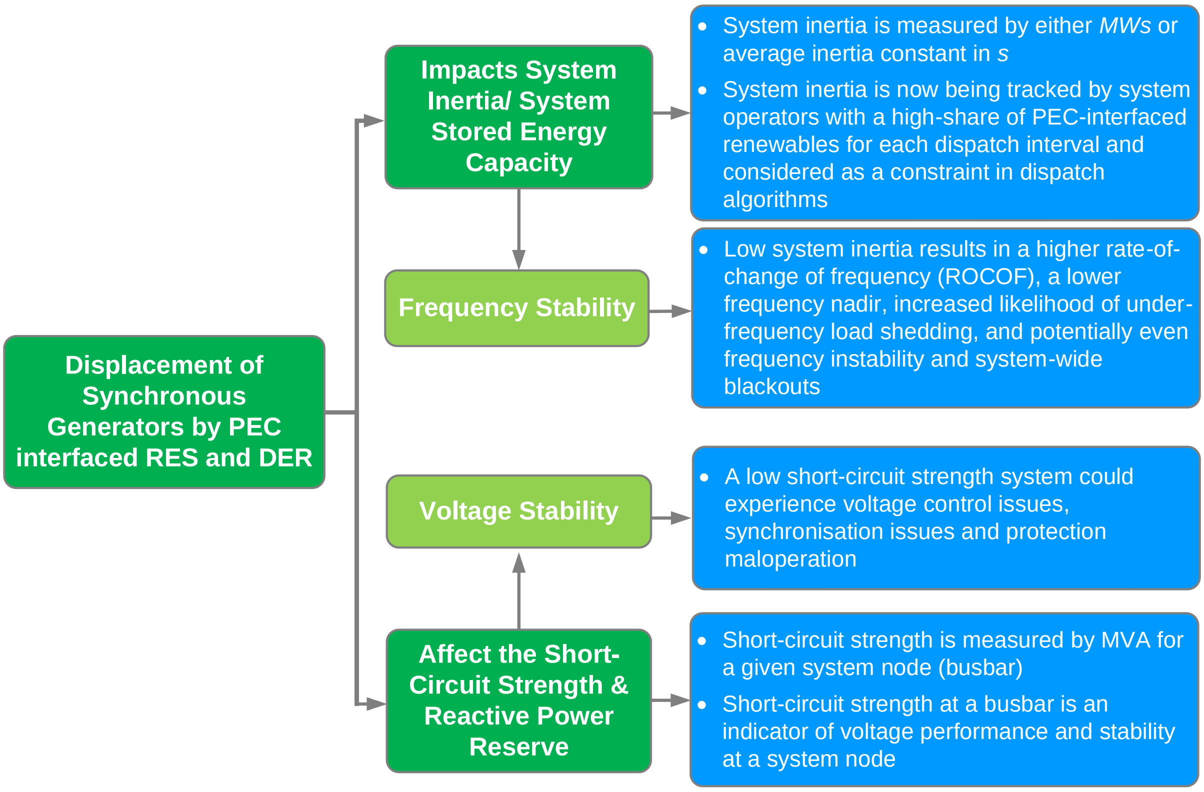


Figure 4. Main power grid stability challenges and associated characterisation factors.

Short-circuit strength indicates the stiffness of the system voltage to changes in local demand, while system inertia indicates the (dynamic) stiffness of the system frequency to changes in system demand. For example, a reduction in system inertia will contribute to frequency stability issues, as it could result in higher ROCOF changes and larger frequency excursions (i.e., for under-frequency/over-frequency events, lower/higher frequency minimum/maximum, technically indicated as “nadir”/”zenith”). Therefore, there is the increased possibility of triggering system protection (e.g., tripping of an interconnector), and under-frequency load-shedding or over-frequency generation shedding schemes. In some cases, existing synchronous generators might also suffer from very high ROCOF (e.g. in the order of 3-4 Hz/s) and disconnect from the network to avoid potential instability and excessive electro-mechanical stresses (Hartmann et al., 2019). Moreover, ROCOF protection has also been associated with ancillary systems to the electrical grid, e.g. upstream gas network depressurisation stations, which can then adversely affect (gas) power plant operation. In contrast, low short-circuit strength can result in issues related to voltage stability, synchronisation, and system protection (NERC, 2017). Although such issues are normally conventionally confined to a local area, they are now being widely observed in larger network regions (e.g., greater part of South Australia) with a high share of PEC-interfaced renewables (ElectraNet, 2019). The term “system strength” is also often used to characterise a network region or node having a low SCR (i.e., systems with SCR < 3 (IEEE PES TDC, 1997)); in recent years this term has often been used to indicate a measure of short-circuit strength and voltage performance (AEMO, 2020c). Since synchronous generators are major sources of both system inertia and short-circuit strength, displacement of synchronous generators by PEC-interfaced renewables has major implications on both frequency and voltage stability. Therefore, there is a strong coupling between synchronous inertia and short-circuit strength in synchronous generator dominant power grids.

As previously mentioned, a fast-frequency response from PEC-interfaced resources can be used to improve the overall system response during the first few seconds after a disturbance. These responses are deemed to (temporarily) restore the lost inertia in the system due to RES integration, and, as aforementioned, various system operators have conducted studies to determine the minimum stored energy capacity to maintain system frequency stability (AEMO, 2018). However, fast-frequency response strategies alone do not assure a robust system in terms of overall stability, as they may not directly improve system strength. Therefore, more integrated system planning approaches involving comprehensive stability studies (e.g., voltage, transient and frequency stability) with emerging technologies (considering capability vs. limitation matrices) are required to ensure the overall stability of future, low-carbon grids. An example of such an integrated system planning approach is presented in Section 4.3.

2.4 Challenges posed by high shares of small-scale PEC-interfaced DER

One of the emerging threats for power systems is the growing volume of small-scale PEC-interfaced DER installed at consumer premises. In particular, small-scale solar-PV systems, located on domestic rooftops, and commercial installations are becoming increasingly common, and some regions (e.g. South Australia) have experienced instantaneous power shares of 77% of the total demand from rooftop solar-PV during low demand periods (Macdonald-Smith, 2020; Parkinson, 2019). These small-scale units tend to be unobservable and uncontrollable from a system operator's perspective, and they may adversely respond to local weather conditions (e.g. significant drop in active power output during weather events, such as fast-moving clouds and storms) and variations in local electrical network conditions (e.g. voltage, frequency), in case also due to the propagation of the effects of outages in the transmission network. A short-term solar power forecasting system[8] has been implemented by AEMO to gain some level of visibility of power generation from these small-scale solar-PV units, which assists towards making informed operational decisions for high solar-PV generation periods (AEMO, 2020a). Also, emerging VPP commercial schemes could be employed to control these small-scale solar-PV units as a single generation source (AEMO, 2020b), as discussed in Section 3.4.

Power variations due to disturbances can be basically categorised into four types; *1) voltage dips, 2)Voltage swells/spikes (Key et al., 2020), 3) frequency excursions,* and *4) phase-angle jumps due to network configuration (e.g. switching of devices)* (AEMO, 2019b). Based on the severity of these incidents, various protection devices in the network may activate, isolating generating plants and local regions in the network. For example, during frequency excursions, under-frequency, ROCOF and vector-shift relays could operate based on their proximity to the fault location.

[8] Forecasting system has a 30 min resolution up to 40 hours ahead for pre-dispatch, and the forecast is based on numerical weather prediction data, output measurements from selected households from PvOutput.org and aggregate kW capacity by installed postcode available from Clean Energy Regulator.

Major stability threats posed by small-scale DER include:

1) Significant localised drop in power output due to sudden weather variations (e.g. cloud cover effects, thunderstorms);

2) Disconnection and significant power output reduction due to transmission network faults;

3) Voltage control and management issues;

4) Protection issues due to reverse power-flow;

5) Unbalance issues due to increased loading on individual phases.

Issues (1) and (2) outlined above would result in a significant (short-term) power output reduction, and could thus lead to frequency stability issues, especially in relatively small regions (such as in Western Australia or Ireland). Significant weather variations/events could result in high ramp-up/-down rates, but the system operator could mitigate such variations using reserve capability from conventional units. The impact of severe weather events driving reductions in output from PEC-interfaced renewable generation, as well as the impact of transmission network outages on tripping of small-scale DER, have been seen, for example, in the 2018 system separation in Australia (AEMO, 2019a) and in the 2019 Great Britain (National Grid ESO, 2019) blackout. There are, therefore, concerns that the adverse impacts originating from issues (1) and (2) may become unavoidable in some cases, and work is in progress to enhance the resilience of more fragile, low-carbon grids (AEMC, 2019; Mancarella & Billimoria, 2021).

Although issues (1) and (2) have a direct impact on system level stability, issues (3)-(5) could also trigger system level stability concerns. For example, the propagation of low voltages (i.e. issue (3)) in proximity to the fault origin could result in the disconnection of these units, potentially resulting in a major generation deficit across the network. In some cases, small-scale DER will reduce their power output, depending on the severity of the voltage dip and/or frequency excursions. These issues have been observed during disturbances occurring in the Australian eastern seaboard grid (AEMO, 2019a). In addition, significant generation from small-scale PV units could result in reverse power-flows in LV/MV networks (issue (4)), which could trigger protection schemes, leading to significant generation deficits in the network. Similarly, severe unbalance caused by significant loading on individual phases (due to single-small-scale PVs) could trigger protection schemes in substation transformers (e.g. negative sequence over-current protection). Furthermore, following sudden loss of a significant load (e.g., due to a load rejection event), solar-PV units could experience over-voltages, leading to their subsequent disconnection due to over-voltage protection operation (Key et al., 2020). Therefore, an anticipated increase in the volume of small-scale PEC-interfaced DER strongly indicates that additional control measures should be introduced, either through new grid-code requirements and/or market mechanisms (Billimoria et al., 2020). These requirements can be determined via integrated system planning approaches, similar to the model presented in Section 4.3.

2.5 Other Stability Issues

It has been discussed above how synchronous generator-based power plants, besides being the traditional energy source, also contribute to system inertia (rotational energy), voltage support, fault level, etc. Other important features include synchronising torque, ramping and reserve capability, black start capability, etc. (IEEE PES PSDPC, 2014) They are also likely to provide the location for power system stabilisers, which help to dampen out low frequency oscillations in the system (Pal & Chaudhuri, 2005). So, while the focus here has been on the loss of rotational inertia, system strength and reactive power reserve associated with the displacement of conventional generators, there are many other factors which can come into play, such as decentralisation of energy resources, sub-synchronous control interactions (SSCI) (Flynn et al., 2017), (Meegahapola, Bu, et al., 2020), and ramp up/down capability (IEEE PES PSDPC, 2020).

Amongst several general considerations concerning system stability, the location of displaced generation, in particular, can be extremely important. In fact, there has always been a desire for generation plant to be distributed around the system, and, where possible, in proximity to the load, in order to support voltages across the system, maintain transmission line flows within operational limits, ensure that the system is robust against network faults, line outages, system splits, etc., and where bottlenecks exist, locate flexibility and energy sources on either side of the constraint(s). Maintaining synchronising torque (linked to angular stability) (Kundur, 1994), achieving adequate fault level (for activation of protection devices), etc. may also require that generators are suitably distributed, or that a certain volume of operational active and reactive power capability, with a certain response speed, is maintained in particular locations. The potential for system splits can also encourage a regional approach to the location of generation plant around a system. While non-synchronous generation, PEC-interfaced technologies, and other operational mechanisms can assist here, it is essential to recognise that a broader perspective (e.g., response time, duration, quantity, trajectory of the response) needs to be adopted as more and more synchronous generation is displaced, and those traditional sources of energy and a number of stability services are lost.

It is finally worth mentioning that relatively new forms of control interaction-driven stability issues, such as sub-synchronous oscillations and resonance issues (Meegahapola, Bu, et al., 2020), are becoming increasingly evident when synchronous and PEC-based technologies interact, especially in weaker grids. In particular, the complex control architectures associated with PEC-interfaced sources can be heavily affected by the challenges associated with a decreasing number of conventional synchronous generation to provide stable voltages (essential for PLL control and operation of most current RES technologies) under low system strength conditions (Sun et al., 2019). Therefore, increasingly so, rigorous studies must be conducted using electro-magnetic transient (EMT) programs, in order to identify those operating conditions which can lead to destabilising control interactions (which could later form inputs to operational constraints for generation dispatch algorithms or market framework). Specific market related aspects related to these services are discussed in Section 4.

3. EMERGING TECHNOLOGIES AND STRATEGIES FOR IMPROVING POWER GRID STABILITY

New technologies are emerging to help tackle the challenges posed by high shares of PEC-interfaced renewables in the power grid. Some of these new technologies are already showing promising performance (e.g. FFR from BESS), while others are approaching commercial viability for future large-scale implementation (e.g. FFR from PEM electrolysers). Potential options include enhanced PEC control schemes, larger-scale BESS, demand response schemes (DRS), virtual power plants (VPP), hydrogen electrolysers (HE), and flexible network technology (FNT). Also, while synchronous condensers (SCs) are a well-known and mature technology for providing reactive power, they have recently re-emerged as a key technology to improve short-circuit strength; hence, their role in the context of tackling emerging challenges in low-carbon grids dominated by PEC-interfaced renewables will be discussed.

3.1 Enhanced PEC Controls

Among the various proposed enhanced control schemes for PEC-interfaced generation, FFR schemes (e.g. based on the system frequency error or ROCOF) and grid-forming converters represent the leading technologies.

FFR schemes can either mimic a frequency response (active power injection in response to a frequency event) similar to a conventional synchronous generator (e.g. *df/dt*-based, as mentioned above) or be pre-programmed to follow a specific characteristic during frequency excursions (e.g. they may be Δf-based) (Ruttledge & Flynn, 2016). FFR capabilities are now available with the majority of PEC-interfaced wind generators, and they are mostly based on Δf-based droop schemes and fixed trapezoidal response (N. Miller et al., 2017; N. W. Miller & Sanchez-gasca, 2008). As the energy is extracted from the rotational masses of the wind turbines (if no pre-curtailed or operating at maximum output), there are some limitations on the amount of energy that they can provide during a frequency excursion, while the energy recovery phase should be carefully managed to avoid any second frequency dip (Kang et al., 2016). Moreover, PEC-interfaced wind turbines can also offer a primary frequency response if there is an available energy reserve, i.e. power output has been curtailed beforehand (N. W. Miller & Sanchez-gasca, 2008), as mentioned in Section 2.1: Frequency stability. However, some PEC interfaced sources, such as solar-PV systems, are not able to directly provide either FFR or primary frequency response services, unless they are operating at a sub-optimal operating point (i.e., operating at a point lower than maximum power with a reserve (Xin et al., 2013)) or equipped with energy storage systems, such as batteries or super-capacitors.

PEC technology can generally, and fundamentally, be divided into two types; 1) grid-following (GFL) converters (current source converters which follow the grid voltage angle, usually by PLL controllers) (Pattabiraman et al., 2018), and 2) grid-forming (GFM) converters (voltage source converters which "form" the grid voltage, phase-angle and frequency) (Matevosyan et al., 2019). The capabilities and characteristics of these two technologies are summarised in Table 2.

Table 2: GFM vs. GFL Characteristics and Capabilities

	Grid-Forming (GFM) Converter	Grid-Following (GFL) Converter
Source Characteristics	Controllable voltage source behind a coupling reactance	Controllable current source with high output impedance
Islanded Operation Capability	Can be operated in the absence of the main grid, and is black start capable	Cannot operate without the main grid, and is not capable as a black start source.
Damping Performance	Provides natural damping to system frequency oscillations	Requires additional control scheme to achieve damping
Synchronisation Capability	Ability to self-synchronise to the grid via fast current regulator	A PLL is required to synchronise to the grid
Energy Source Requirement	Capability strongly influenced by the energy source characteristics (e.g. ramp rates)	Low dependency on the energy source characteristics

The vast majority of existing RES-based converters are of the GFL type, which, in most cases, could be retrofitted with the above mentioned enhanced FFR schemes, etc. A number of options exist for the control design of GFL converters, including operating them more or less similar to synchronous machines, also known as virtual synchronous machines[9] (D'Arco et al., 2015). GFL converters may also suffer from PLL instability issues under weak-grid conditions (i.e., under low SCR<3) (Sun et al., 2019); hence, GFM converter technology could potentially offer much more robustness and stability support under weak grid conditions.

Grid-forming (GFM) converter technology is also gaining popularity with power system operators in recent years, as a potential means of future-proofing systems towards scenarios where PEC-interfaced generation (based on GFL converters) is dominant, or where system splits could result in a very high share of PEC-interfaced generation in a given sub-system, leading to weak grid conditions across the entire network. The fundamentals of grid-forming technology are relatively well understood from a research perspective. However, from a power system operator's perspective, and for actual implementation, the formal requirements for GFM technology are still evolving, considering the need to better understand the challenges posed by PEC-interfaced RES for large-scale, real networks under a wide range of potential operational conditions. Hence, while GFM converters are, in principle,

[9] Virtual synchronous machine technique has also been involved to provide some of the capabilities / services of GFM converters, such as islanded operation and black start capabilities (ABB-ElectraNet, 2020).

already capable of offering some, if not all, of the above services (i.e. FFR and dynamic reactive response), they too present limitations, e.g., in terms of the availability of the energy buffer (i.e., state of charge, available MWh) and the ability to handle high currents for short durations (subject to GFM design) (Matevosyan *et al.*, 2019). Hence, further studies are required to robustly define the enhanced capabilities that would be required to stabilise operation in low grid strength conditions, and to determine suitable routes for procurement, e.g. through upgraded grid codes or new system service arrangements. There is, of course, an associated cost incurred, both in terms of technology development and equipment hardware. The ways in which these services could be procured within an electricity market framework is discussed in Section 4.

Certain requirements must be met by GFM converters in order to be capable of responding to stability issues in PEC-interfaced RES-dominated grids (Matevosyan et al., 2019)**:**

1) Operate as an AC voltage source, behind an impedance, under normal operation to provide the grid voltage reference;

2) Provide specific services during transient conditions while operating as an AC voltage source behind an impedance;

3) Operate autonomously under the absence of the main grid during network faults (i.e., islanded operation);

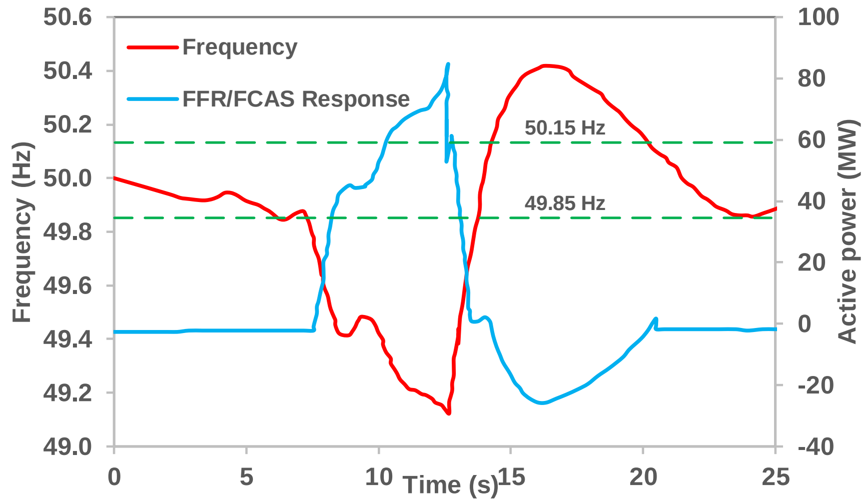
4) Contribute to system strength by improving system stiffness to voltage variations;

5) Ability to self-synchronise to the grid via fast current control loops;

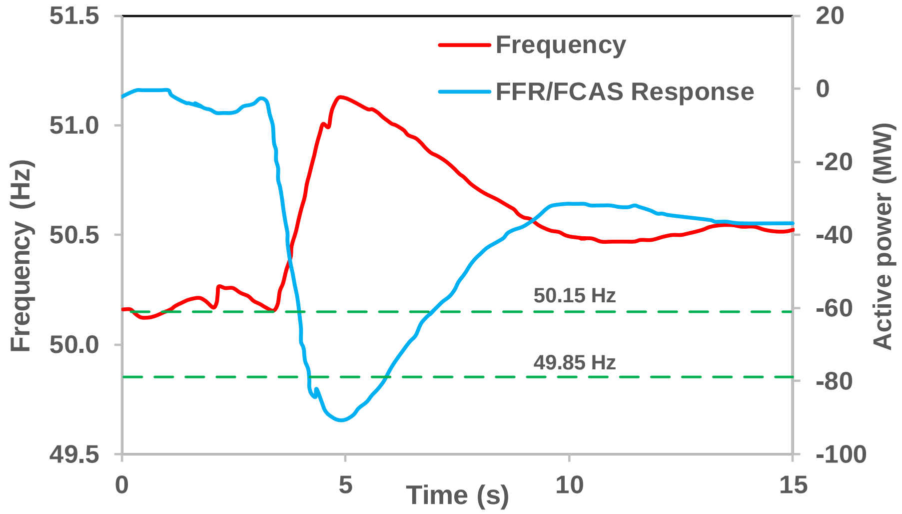
6) Provide black start and system restoration services to the grid.

3.2 Utility-Scale PEC-Interfaced Battery Energy Storage Systems

Battery energy storage systems (BESS) are the most prominent large-scale (>10 MW) PEC-interfaced energy storage technology integrated into power networks today. A utility-scale BESS can provide both frequency and voltage support to the grid during contingencies, and can also act as an energy balancing resource. Its main advantages lie in its ability to operate in four quadrants (i.e., ability to absorb/inject active and reactive power) and to achieve fast response times (typically between 100–150 ms) during system contingencies, enabling high flexibility to provide grid services (Dozein & Mancarella, 2019). For example, the 100 MW/130 MWh Hornsdale power reserve (based on Li-ion batteries) in South Australia is well-known around the world for successfully providing support services in low-inertia power conditions, with 70% of its capacity reserved for providing FFR services to the national electricity market (NEM) of Australia, while the remaining capacity participates in the traditional energy market (Aurecon, 2020). Similarly, a 11 MW / 5.5 MWh BESS installed in Co. Kerry, Ireland can deliver both active and dynamic reactive power for grid services, and can respond within 150 ms (Statkraft, 2020). Therefore, BESS are proven technology for delivering ancillary services for grid stability services (see the South Australian Hornsdale power reserve (HPR) response to extreme system events, shown in Figure 5).



(a)



(b)

Figure 5. HPR responses for system events; a) Low frequency event on 25th August 2018, b) High frequency event on 31st January 2020 (Aurecon, 2020).

As shown in Figure 5(a), HPR rapidly responded to the low frequency event by injecting active power soon after the local frequency fell below the low frequency deadband (49.85 Hz), and subsequently absorbed active power soon after the local frequency exceeded the high frequency deadband (50.15 Hz), and, finally, the active power output settled close to zero soon after the frequency recovered to the nominal operating frequency band. Similar behaviour can be seen from the high frequency event (see Figure 5(b)), in which a higher rate of active power absorption can be seen when the frequency drifts beyond the high frequency deadband.

BESS devices, and more in general demand response via small-scale BESS (< 10 kW), can also help to alleviate network constraints, and offer respite against immediate network upgrades, which may further impact on revenue streams and help identify optimal placement locations (Martínez Ceseña et al., 2015). The front-end of the BESS is a converter system that can either operate under GFL or

GFM modes with enhanced FFR functions. However, if the BESS were to consist of multiple small-scale PECs, operating all of them as GFM-type could be challenging, due to potential control interactions between individual PECs in close proximity. In addition, GFM converters have exhibited some interactions with nearby conventional synchronous machines due to their fast response times (Tayyebi et al., 2019). Therefore, detailed simulation studies are required before fully deploying them in power networks. The required MVA rating, required energy capacity (MWh), converter technology (i.e. GFL or GFM), optimal location and interactions with other devices are primary factors which need to be examined before deploying BESS in the grid. Furthermore, actor participation (either in the energy or ancillary services market) can be highly influenced by MVA rating, energy capacity (MWh), and the PEC technology deployed in BESS, as well, of course, as the potential revenue streams associated with the individual markets.

3.3 Demand Response Schemes

Demand-side response is another emerging strategy that could be more widely adopted to promote flexibility in the load-demand balance (Losi et al., 2015). Demand response schemes (DRS) have been adopted by power utilities for decades for peak-shaving and shifting load demand to achieve economic benefits. Typically, control signals are sent to customer premises, enabling the electrical demand to be reduced by either adjusting the power output of flexible loads or switching them off. Subscribed customers are subsequently paid for their reduced demand, so that, effectively, a distribution network market can be established by distribution system operators where customers trade their operational demand against network investment (Schachter et al., 2016). More recent advanced options include post-contingency DRS that limit the impact on end-user customers while bringing substantial benefits in terms of deferring network asset investment at minimum or even lower risk (Martínez Ceseña et al., 2016). At the distribution utility level, demand response can also be achieved by lowering the voltage in distribution feeders, and thereby reducing the demand based on conservation voltage reduction (CVR) principles. Some utilities who have previously implemented advanced dynamic voltage management schemes are currently trialing the provision of frequency regulation services (ARENA, 2019). For example, utilities are trialing control of the voltage level in distribution networks (while maintaining voltage within stipulated limits) to increase / decrease active power demand in the network during frequency excursions, and thereby provide frequency support services (AEMC, 2018; Ma et al., 2013). More specifically, when the network voltage is lowered (via tap changing transformers), the load demand could be reduced, which would support system frequency enabled DRS to participate in the frequency regulation market. Therefore, DRS are likely to play an increasingly key role in participating in ancillary services markets in the near future.

3.4 Virtual Power Plants

A virtual power plant can be defined as a group of prosumers, potentially connected at different network nodes, which act in a coordinated manner to operate and respond in a manner similar to a large generator unit. The VPP concept is based on prosumers connected to distribution networks, which have either PEC-interfaced generation, storage systems (e.g. BESS) or controllable loads (e.g. EVs). The prosumers participating in the VPP scheme may receive control signals from a central controller which dispatches energy or other services to the network. VPPs can operate in a number of electricity markets, trading energy, ancillary services and other products (including financial products), similar to, or even better than, traditional synchronous generator-based power plants (Wang et al., 2020). In Australia, a number of trials are currently underway to apply VPP technology to provide contingency FCAS services to the network (AEMO, 2019d). In this way, many aggregated small-scale DER could effectively be used as a substitute for synchronous generators, not only for energy purposes, but also to provide fundamental system services. Recent developments are also looking into the possibility of creating "hybrid" virtual power plants from an aggregation of multi-energy resources, such as those based on electricity and hydrogen, to provide simultaneous network, system and market services (Naughton et al., 2020).

3.5 Synchronous Condensers

Synchronous condensers are not a new technology; however, their role have been redefined to overcome the challenges associated with low short-circuit strength and reduced system inertial response. Modern synchronous condensers can also deliver dynamic reactive power and they, possibly in conjunction with a flywheel, are capable of releasing stored rotational energy for a short time period (a few seconds), and they can contribute to short-circuit currents (Palone et al., 2019). Several countries and regions, such as Denmark, Germany, Texas and South Australia are currently installing a number of synchronous condensers in close proximity with wind and solar-PV generation plants (ElectraNet, 2019; Yang, 2017). However, although synchronous condensers could assist with multiple stability issues, there is the concern that they could increase the likelihood of sub-synchronous oscillations, due to control interactions with closely sited wind and solar-PV plants (ERCOT, 2018b). Therefore, rigorous electromagnetic transient studies must be performed with high fidelity models under a range of system conditions prior to installing synchronous condensers in weak power networks.

3.6 Hydrogen Electrolysers

Hydrogen is gaining great interest as a potential energy vector that can support whole-system decarbonisation (COAG Energy Council, 2019). One of the most promising options is to use electricity to split water and produce hydrogen (and oxygen) in hydrogen electrolysers (HEs). In particular, if the electricity comes from renewable energy, the produced hydrogen is basically emission-free (hence so-called "green hydrogen") and can be utilised for multiple purposes, including decarbonisation of the transport sector and gas/heating sectors. In the latter case, injection of green hydrogen into the gas network (so-called "power-to-gas") has the potential to provide power system operational flexibility and storage options in both the short term (Clegg & Mancarella, 2015) and long term (Clegg & Mancarella, 2016). Furthermore, electrolyser stations have the potential to provide several frequency control ancillary services while supporting grid operation (Mazza et al., 2018). In particular, PEM electrolysers could provide post-contingency fast frequency response with a speed (almost) compatible with BESS, indicatively within 1-2 seconds. Furthermore, hydrogen electrolyser PEC interfaces can potentially also allow reactive power control, which can untap the provision of multiple grid services and participation in multiple markets (Naughton et al., 2020). Given the expected growth in the number of electrolysers, particularly for green hydrogen production, and their operational flexibility, there is a great opportunity for this technology to become an important provider of balancing services, and different ancillary services, particularly relating to frequency control.

3.7 Electric-Vehicles to Grid (V2G)

Electric Vehicle (EV) can be considered as a mobile battery and once the EVs are connected to the grid via a home charging unit or charging station, they can be utilised to provide grid support ancillary services (Denholm et al., 2015; González-Romera et al., 2015). These EV based technology is commonly known as the vehicle-to-grid (V2G) technology. These grid support services include voltage control and frequency control services both under steady-state and contingency conditions. To facilitate V2G services, advanced charging units (bi-directional charging units) and algorithms (which could monitor voltage and frequency and dispatch active and reactive power once they exceed a pre-defined threshold) are utilised to provide these services. The EV charging stations should be sited and sized considering system stability issues (B. Zhou et al., 2016), so that the V2G based ancillary services could be procured to effectively to enhance system stability. The charging and discharging levels for the vehicle battery system (i.e., minimum and maximum state-of-charge (SoC)), charging rate (A/s), aggregation requirements, voltage and frequency thresholds to trigger these services, and economic incentives are the major factors which must be considered when deploying V2G technology for providing ancillary services support to the grid.

3.8 Flexible Network Technologies

There are various flexible network technologies (FNT) that are opening up new avenues for network operators and planners, allowing them to take a more *active* approach towards providing stability services by using corrective, real-time control and thus to integrate additional volumes of renewables in a secure manner. FNT approaches that are becoming increasingly important include : (i) new controllable and flexible technologies, such as flexible AC transmission systems (FACTS) (Pipelzadeh et al., 2017) and high-voltage DC (HVDC) systems (Y. Chen et al., 2018; Junyent-Ferr et al., 2015), that can rapidly control power flows across the network pre- and post-contingency; (ii) system integrity protection schemes (SIPS) that can enforce rapid increase/reduction of power in importing/exporting areas after an outage occurs by, for instance, curtailing generation and/or demand through suitable “inter-trip” schemes (Rodrigo Moreno et al., 2013); and (iii) various wide-area monitoring and control equipment supported by ICT technologies that will increase the capability of system operators to monitor and control electricity assets in real time and across wider areas through advanced and pervasive ICT (Rodrigo Moreno et al., 2017). These approaches, coordinated with generation real-time (re)dispatches, allow delivery of ancillary services (e.g. response and reserve services) to be more cost-effective and secure, without worsening post-contingency congestion, voltage problems and instabilities (e.g., transient stability issues). For instance, various SIPS options are already available, and more are currently being discussed in Australia. Examples include inter-trip options that could shed load/generation in the case of interconnector trips and the risk of regional islanding with high ROCOF (e.g., in South Australia (AEMO, 2015b)). Inter-trip schemes may also be considered to address controller instability following a network outage (e.g., in North-West Victoria) (AEMO, 2019c); however, such options should be considered carefully and balanced against the risk (e.g., in terms of frequency stability) emerging from sudden resource disconnection.

3.9 Other Emerging Techniques

Smart meters are being rolling out by power utilities in customer premises in order to capture energy demand and other electrical parameters at regular intervals (e.g. 5 min and 15 min intervals). Such data are currently being used by some power utilities to build data-based models to observe feeder voltages and energy consumption in real-time (Lave et al., 2019). These data-driven models, which have already been adopted by the system operator in Australia to dynamically size operating reserves (Fahiman et al., 2019), can, and will, be integrated into DRS and VPP portfolios, with the potential to effectively provide frequency support services to improve system stability. Distribution grid-based energy trading platforms (e.g. peer to peer energy trading between consumers and prosumers) are also now emerging (AEMO-ENA, 2019), potentially leading to ancillary service markets being implemented within these distribution grids, especially via VPP schemes (Wang et al., 2020). More systematic monitoring of consumption via smart meters and relevant data-driven modelling can also introduce new options to provide system and local network support via “differentiated reliability” schemes from the demand side (Y. Zhou et al., 2016). Finally, it is increasingly envisaged that intelligent market dispatch engines which could co-optimise energy, reserve, contingency size, and interconnector flows (Püschel-Løvengreen et al., 2020) will play a more crucial role in guaranteeing the secure and resilient operation of low-carbon, interconnected power systems.

4. DEPLOYING OPTIMAL EMERGING TECHNOLOGY IN A TECHNO-ECONOMIC FRAMEWORK

4.1 Market Frameworks for Ancillary and Stability Services: Are they effective?

Since the inception of electricity markets, ancillary service requirements have typically been defined based on conventional power plant characteristics. Consequently, system operating boundaries have been regularly augmented following the definition of new ancillary market products. For example, Australia’s National Electricity Market (NEM) was created in 1998, with tight governor deadbands mandated until 2001. At this time, governor response was removed as a requirement, and the nominal operating frequency band (NOFB) was relaxed to +/-150 mHz from +/-100 mHz, with a frequency control ancillary services (FCAS) market introduced (two regulation and six contingency markets). Initially, synchronous generation capacity was dominant, with only an insignificant share of PEC-interfaced RES connected to the NEM. Until approximately 2014-2015 there were no major (negative) impacts of the new arrangements, since synchronous generators continued to be the dominant technology, despite a growing share of PEC-interfaced RES. However, with the more recent retirement of high inertia coal-fired power plants, system frequency regulation has been dramatically affected(J.S. Bryant et al., 2021). The effects of increasingly poor frequency regulation can be observed from the large increase in FCAS regulation cost since 2015 (see Figure 6). Similar issues have been observed in the Argentinian and ERCOT power grids [19], which again reflects the need to augment system operational rules (e.g. tight governor deadbands) and develop new requirements, and potentially market products, which support grid stability with increasing shares of PEC-interfaced RES and DER.

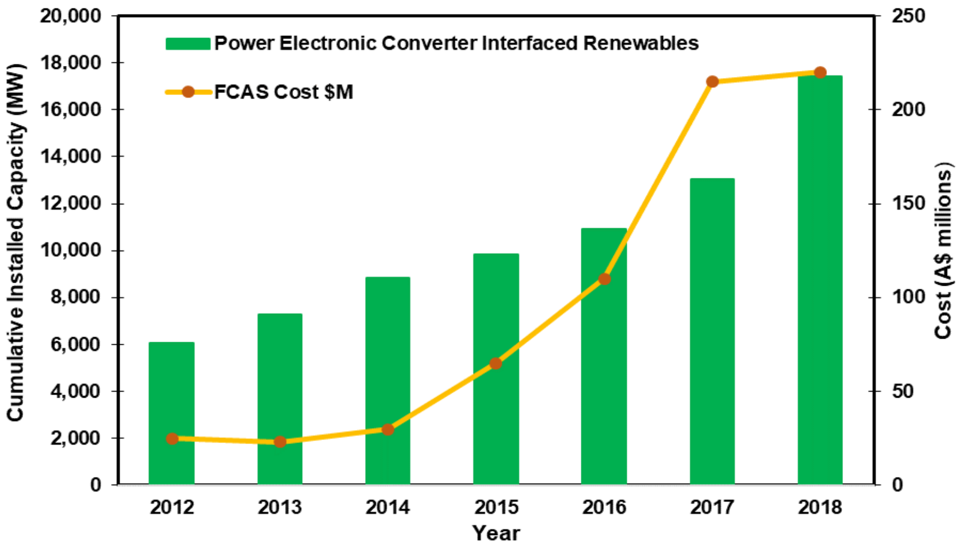


Figure 6: Cumulative installed PEC-interfaced RES in Australian Eastern Seaboard Grid and FCAS cost.

Other than the FCAS market, there are additional non-market ancillary services in the NEM, as in other jurisdictions worldwide, including services for voltage control, network loading control, and transient and oscillatory stability. These services also require revision (e.g. detail specifications and minimum requirements) in order to address the relevant needs associated with increasing volumes of PEC-interfaced renewable generation.

To give another example, in Ireland fourteen different ancillary services products were introduced in 2015 to maintain system stability with a high share of renewables. These services include synchronous inertial response, FFR, contingency reserve products, ramping products, steady-state and dynamic reactive power products (EirGrid, 2017). However, it is essential to assess the economic feasibility of these market products against the technical value they deliver to the network, particularly from operational stability and longer-term investment viewpoints. In this line, it is also important to account for the increased transactions costs, driven by more numerous and complex ancillary services markets. In GB, for example, National Grid was motivated to rationalise and simplify the ancillary services markets (National Grid, 2017, 2018). Hence, these products could be regularly redefined (annual or biannual basis) to ensure optimal technical-economic outcomes[10].

4.2 Approaches to Deploy New Technologies

Over reliance on new technologies may incur additional costs (e.g. capital investment on high fidelity wide-area monitoring system, over supply of niche services) to power utilities, and hence care needs to be applied when adopting new technologies while optimising the utilisation of existing assets. Also, emerging technologies present certain pros and cons, as summarised in Table 3. All plausible avenues should be investigated before fully embracing new technologies which may improve system stability and reliability, while maintaining system economic considerations. In addition, a deregulated environment would tend to imply that a wide range of technologies will likely be installed by a wide range of actors, in a diverse set of locations, for a multitude of reasons.

Table 3: Capabilities, opportunities, limitations and challenges of new technologies

Emerging Technology	Capability/ Opportunity	Limitations/ Challenges
PEC-interfaced Energy Storage Systems (e.g. BESS)	FFR; fast system active and reactive power balancing resource; voltage support	Uncertainty in lifetime, might need to be replaced after 7-8 years, if it is a BESS
Demand Response Schemes	Frequency support; system-level and local network capacity support	Availability subject to (time-dependent) load characteristics
Virtual Power Plants (VPPs)	Aggregated response can be achieved through geographically distributed DER; can avoid network constraints, as the responses are aggregated; revenues from different markets can be stacked to reduce costs and increase competitiveness	Availability subject to prosumer energy requirements, which need to be accurately forecasted; need to be carefully coordinated with local network conditions
Synchronous Condensers	Can provide reactive power, short-circuit current, and (natural) inertial response	May pose oscillatory stability issues interacting with local PECs; increasing cost due to increasing utilisation

[10] For a comprehensive overview of the new technical requirements, and regulatory and market options to ensure stability and security in low-carbon grids, the reader is referred to (Billimoria et al., 2020).

Hydrogen Electrolysers	Can provide active power flexibility, FFR, other FCAS, and potentially reactive power	Cost still high; response availability linked to downstream hydrogen process, often requiring a hydrogen buffer; hydrogen markets still in their infancy
Electric Vehicle to Grid (V2G)	Similar services provided by ESS can be delivered without requiring a dedicated specific structure (i.e., home chargers and charging stations could be used)	High uncertainty on the availability of the required capacity to deliver grid support services
Flexible Network Technology and New Techniques	Can provide great flexibility at relatively low cost; fast installation	Operational risk may be hard to assess in some cases; may require more field experience

System operators, regulators and policy makers can promote emerging operating and investment strategies and new technologies in several different ways, depending on the urgency of system (future) needs, favoured historical practices for implementing new requirements, and the diversity of (existing) available service providers. Such mechanisms range from regulated mandates to market-driven approaches, with various degrees of liberalization observed worldwide while also depending on the specific services to be provided (Skinner et al., 2020). Acknowledging that markets work best for system-wide services (e.g., frequency control), mandates may be better justified for localised needs (e.g., voltage control). In addition, although regulations and markets can, in theory, deliver the same solution under ideal assumptions, in practice, both approaches present imperfections (JOSKOW, 2010) and thus jurisdictions implement tailor-made solutions that depend on how large those imperfections are likely to be, and which option can be more effectively managed. Furthermore, jurisdictions exhibit large differences in terms of their political economy arena, constraining the implementation of market rules to what is politically feasible and acceptable in their regions (R. Moreno et al., 2010).

1. Mandates, via Grid Codes and Standards: Existing grid codes and standards can be augmented to suit (or simply avoid any disadvantage to) new technologies, and new rules can be introduced to accommodate these new technologies. The key benefit of mandating via grid code and standards is that it reduces complexity and transaction costs, while also reducing additional operational costs (e.g. cost of compliance testing) for the power utility. Although grid code requirements may or may not be compensated, it is important to consider that new technologies might need some form of compensation/payments, in addition to the direct benefits that the provider can internalise when selecting innovative technologies to meet grid code requirements. Compensation may be provided to enable such services, e.g., tuning and retrofitting existing control systems, establishing communication and monitoring protocols, etc. Questions can arise regarding the backdating of new requirements, and the ability of existing installations to be conveniently and economically retrofitted. In addition, such an approach does not necessarily promote innovation, and will likely result in grid code requirements being met but not exceeded. Mandates can also be applied directly toward the need for new investments, forcing, through a regulated, mandated investment plan, the installation of a given volume of capacity of a particular technology across the system, which will be remunerated at a regulated charge. The California Public Utility Commission, for example, mandated that the three major utilities invest in a total of 1325 MW of energy storage capacity by 2020 (Kaun, 2013, pp. 10-12–007).

2. Supply of the services directly, via purchase agreements: Some services could be directly procured from service providers via tenders or bilateral purchase agreements, which can be undertaken through mid or long-term contracts between the network operator and provider. Here, the key challenge is to justify the need for a purchase agreement, rather than using short-term market mechanisms (described next). Purchase agreements, however, can generally be justified if the benefits of market conditions, in the short-term, are unattractive due to, for instance, market power/concentration. In general, long-term contracts can be justified as a way to hedge against volatile prices in short-term markets of ancillary services (as operators purchase services through contracts with relatively fixed prices), promote cost-effective investments in key innovative technologies (stabilizing revenue streams for investors), mitigate market power (since, through contracts, market participants sell volumes at fixed prices), and improve the contestability of the electricity market (due to reduced barriers to entry that challenge incumbent participants).

3. Short-term market-based procurement mechanisms: Auctions, which typically take place days, weeks and even months ahead, or co-optimised with energy, can be enhanced to consider bids from innovative technologies. In effect, the market design of ancillary services has been historically biased towards generation-type and transmission-connected resources, ignoring, for instance, services from technologies such as batteries, demand-side response and DER that can certainly provide system-level services (Inzunza et al., 2016; Y. Zhou et al., 2018). Under this approach, though, revenue stacking may become a serious challenge for market participants who provide, for example, system-valuable FFR services (as, ideally, they need to provide additional services to make their investments profitable (Rodrigo Moreno et al., 2015; Strbac et al., 2017)) due to the need to coordinate bids to supply multiple services in various electricity markets that are not necessarily compatible with the revenue stacking concept. Also, if the prices of ancillary services are too low and/or volatile, they may fail to be sufficiently attractive to promote new investments (Papavasiliou & Smeers, 2017).

4. Define new market services and allow new (and existing) technologies to compete in markets: In order to preserve stability under certain operating conditions some premium services (e.g. ultra-fast frequency response via supercapacitors) can be introduced via an ancillary services market, with new service providers actively bidding to provide the requested ancillary services. Such an approach can promote innovation, particularly if payments are related to performance, e.g. volume supplied, speed of response. However, there is also the danger that if the anticipated payments for the new service(s) are not seen to be sufficiently rewarding, and/or are too volatile to be propagated to the long-term (Papavasiliou & Smeers, 2017), then there will be a lack of necessary investment, which may put system security at risk.

In addition to the above, governmental policy may introduce various support mechanisms to push forward technologies in the early stages of real-world deployment and promote their commercial viability. However, prior to implementing new security rules, or new system security related market products, system operators should optimise the utilisation of existing assets in order to improve system stability and reliability, and, ultimately, the energy cost to consumers. It is also important that if prior "future-proofing" measures have previously been introduced to a system then these should be fully exploited, before additional future proofing measures are seen to be necessary.

For example, synchronous generator frequency deadbands (DBs) play an important role in system frequency regulation, such that they could be optimised to provide improved frequency response with a high PEC-interfaced RES share (J.S. Bryant et al., 2021). Such an approach is illustrated by the frequency response plots shown in Figure 7 for various scenarios, which are simulated on a two-bus test system consisting of two 500 MVA synchronous generators, each having a capacity of 400 MW. The system serves a 500 MW load demand (2 × 250 MW supplied by each generator) and the system has a 6000 MWs stored energy capacity (synchronous inertia).

The system frequency response is evaluated for a 10% load increase (50 MW) event at t = 1 s under several scenarios, including different generator governor DBs (based on frequency error) and RES share levels. With the system comprised of 50% RES active power capacity, one of the 500 MW synchronous generators is replaced by a 500 MW PEC-interfaced wind farm (producing 250 MW). In this case, the PEC-interfaced RES provides FFR based on frequency error (i.e. $\Delta f \times K$) (N. W. Miller & Sanchez-gasca, 2008). Figure 7 illustrates the frequency response for the various scenarios for a 50 Hz system.

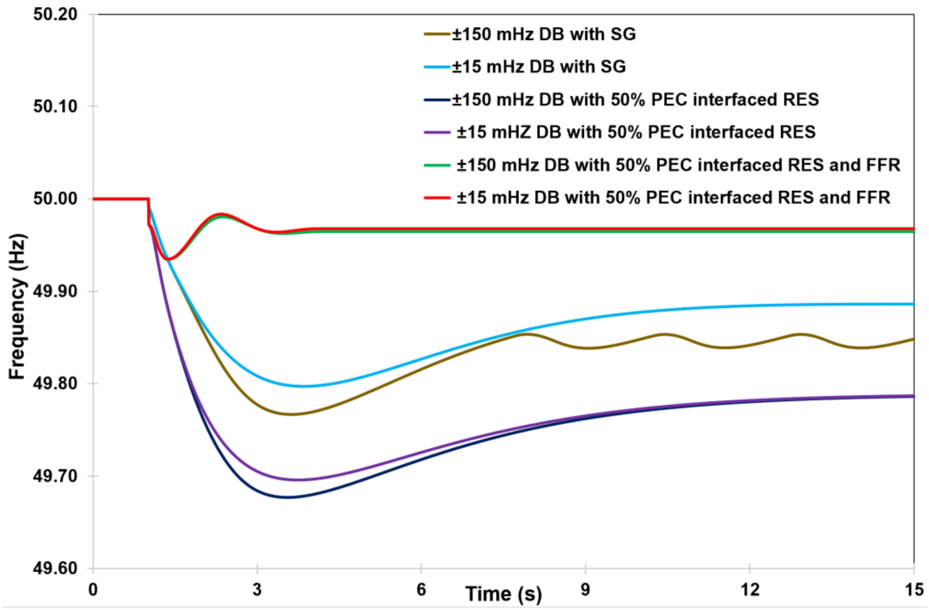


Figure 7. System frequency variation during a 10% load disturbance under different scenarios.

As illustrated in Figure 7, when transitioning from a scenario with only synchronous generation to cases with 50% of the production coming from PEC-interfaced RES (PEC-interfaced wind generators), the system frequency response deteriorates, resulting in a comparatively low frequency nadir (minimum frequency level). When the PEC-interfaced RES is equipped with FFR capability the initial system frequency nadir is significantly higher (e.g. improved by 0.26 Hz for the ±150 mHz scenario with 50% RES). It can also be noted that tighter governor DBs, e.g. 15 mHz relative to 150 mHz, can improve the frequency response by encouraging an earlier generation response. The FFR services, in this example, are provided from the stored rotational energy of the wind generators, and following this energy release, the wind turbines speed up (recovering lost energy) in order to return to their optimal speed, which causes the system frequency to slowly reduce again. Moreover, when wider governor DBs are used it can lead to a chattering effect around the frequency deadband (e.g. 150 mHz, as the governor response is delayed for the frequency excursion). Clearly, based on this simple example, it is essential to define additional rules when FFR services are procured from wind generators in order to avoid a second frequency dip, as above, during the recovery stage. For example, grid codes (ancillary services) could define the rule to delay the recovery phase or define a maximum allowable ramp-rate for the recovery phase.

4.3 Integrated System Planning and Operation Techniques

In most electricity market frameworks, PEC-interfaced RES and DER are yet to be fully integrated, particularly due to increasing evidence of stability issues, in spite of the increasing cost of ancillary services (Bloom et al., 2017; Jack Stanley Bryant et al., 2019): this is a key indication that both grid code and market mechanisms need to be updated, particually to deal with new system services requirements (Skinner et al., 2020). For systematic adaptation of ancillary services within a critical transition phase, however, it is desirable to have systematic techno-economic guidelines and frameworks, as every power system presents unique characteristics in terms of generation mix, network topology, etc. An example of an integrated system planning framework that could be adopted to systematically evaluate the optimal technology mix, while also potentially ensuring system security, is shown in Figure 8. However, of course, other similar, hybrid approaches could be considered, also depending on the specific market design and regulatory setup (see for example in (Billimoria et al., 2020)).

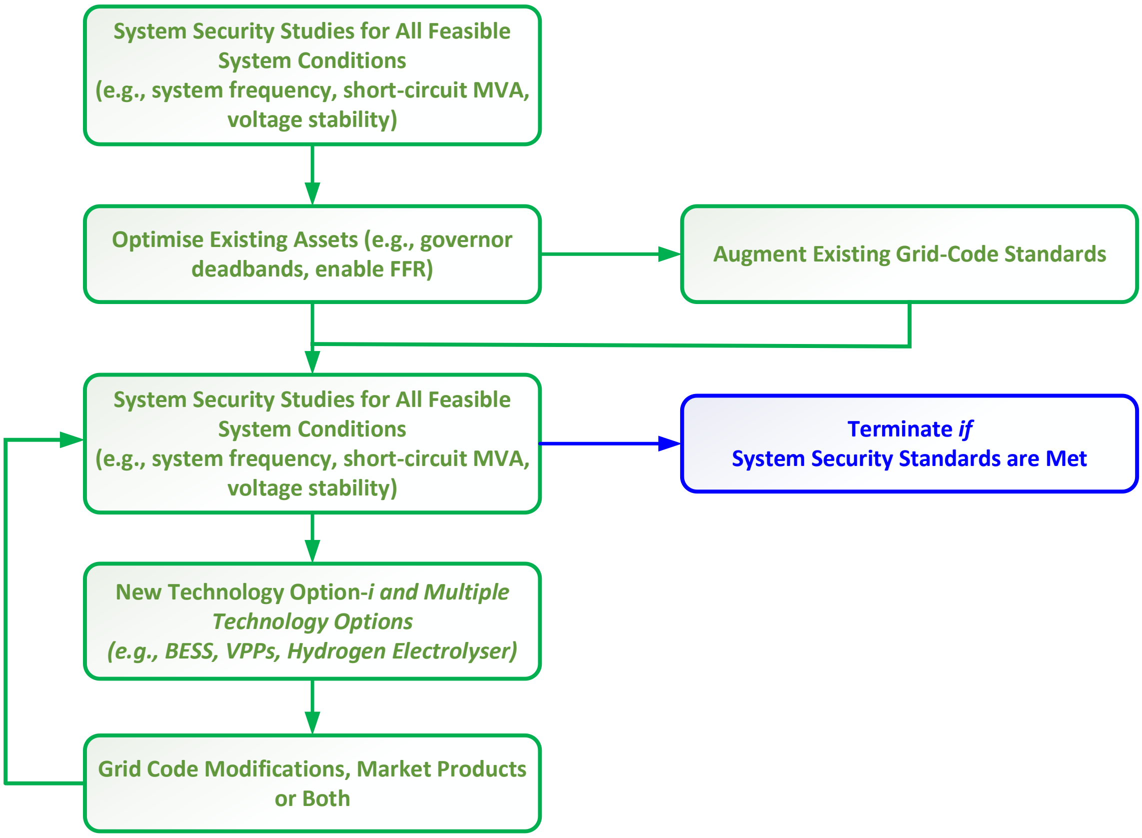


Figure 8. Example of integrated system planning and technology selection framework.

Power system operators should conduct comprehensive security studies, considering all feasible current and future generation scenarios for a network, under normal and other feasible, e.g. maintenance outage periods, conditions. The selection of scenarios, however, does need to balance their likelihood of occurrence against the (later identified) cost of mitigation actions and also the cost of inaction. These scenarios could be produced considering historical data driven approaches, using techniques, such as principal component analysis (PCA), for wind scenario variations based on historical wind data (Burke & O'Malley, 2011). Security studies could include stability studies (voltage, frequency small-signal stability, etc.), network transfer capability studies and contingency analysis (e.g., n-1 security studies). If security studies indicate adverse stability outcomes, then the system operator could analyse various possibilities to optimise various existing system assets (e.g. synchronous generator governor dead-bands, FFR from wind and solar farms) prior to considering new technology options. If wide-scale network asset optimisation indicates positive stability outcomes, then the system operator could augment existing grid codes to mandate these changes for existing assets, while factoring in the implementation cost, and impacts on equipment lifetime and plant availability. For example, system operators should assess the possibility of enabling FFR, and other services, from PEC-interfaced RES and DER. The majority of newer wind and solar generators possess this capability; however, settings are not enabled in the majority of cases, as there is no mandatory requirement (set by some grid codes) or no financial incentive (system service). However, if network asset optimisation leads to stability improvements which are confined to a specific region, then these asset improvements could be encouraged via ancillary market products, while also incorporating locational incentives.

Consequently, grid codes should be carefully augmented to enable such capabilities, acknowledging lessons learnt from deploying these capabilities in some jurisdictions (EirGrid, 2017). In parallel, new technologies must be systematically evaluated via in-depth system security studies in order to optimally align new investments in electricity networks. A capability chart, like the example shown in Figure 9, could be used for identifying appropriate technologies to fulfill stability requirements, and mitigate any potential instability scenarios. The vertical axis of Figure 9 represents the contribution to frequency regulation by a particular technology, while the horizontal axis represents the contribution to voltage regulation by a particular technology. For example, if a system security study indicates a shortfall in both system inertia and voltage regulation for a particular region, then the most suitable technology could be BESS. However, it must be noted that appropriate PEC (i.e. GFM) technology has to be employed by the BESS to deliver these services. Furthermore, selection of appropriate technology to tackle stability challenges may not only be limited to the frequency and voltage regulation capability of a particular technology, but may also be constrained by other factors, such as capital investment of the asset, return on investment, network constraints (line ampacity and substation transformer capacity), remote and local RES production, etc.

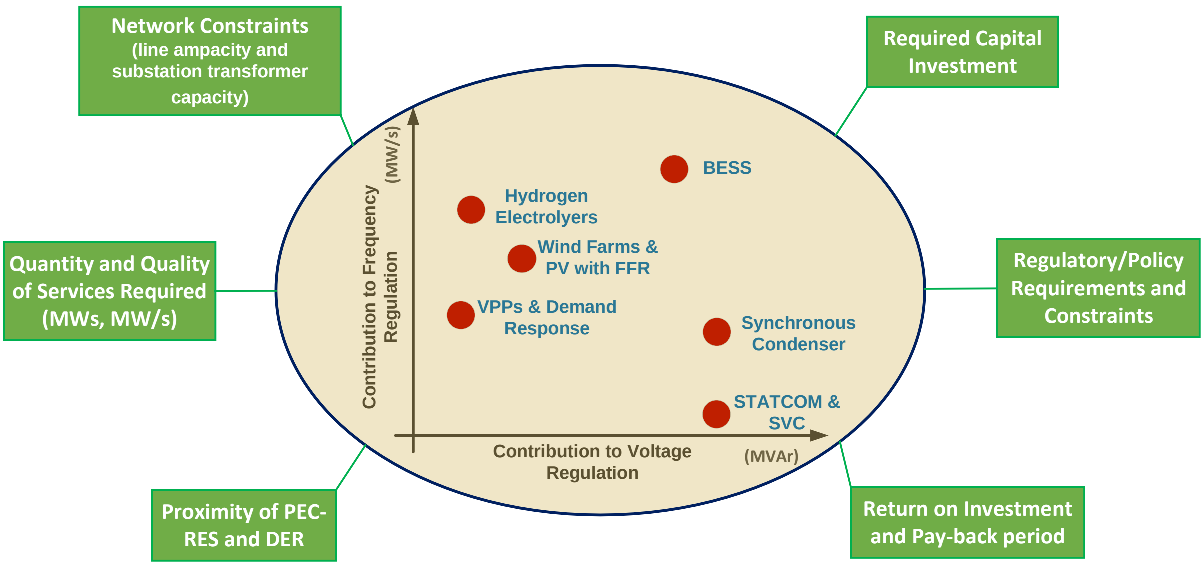


Figure 9. Capability chart of various technologies.

Such studies would enable feasible technology options to be identified for a network, and hence investors who wish to participate in ancillary services markets could make more informed decisions (e.g. appropriate technology selection ratings and optimal locations for various new technologies) at the early planning stage of their investment. In addition, such studies could enable existing asset owners to optimise their assets. For example, wind farm capabilities could be exploited by retrofitting conventional wind generator systems with controllers incorporating enhanced capabilities (e.g., FFR) to suit the generation mix of the power network, and these requirements could be imposed via augmented grid code rules and appropriate market incentives.

5. Conclusion

Rapidly evolving power grids require new technologies to ensure and maintain system stability, and thereby security and reliability, recognising that while PEC-interfaced RES-based generation and DER offer many benefits, they can also present a range of operational and stability issues. Particular concerns are associated with systems with low inertia (stored rotational energy), and where RES generation is connected in areas with low short-circuit capacity and/or a lack of locational reactive power reserves. New technologies, and new system operating mechanisms, are emerging, which can be deployed to tackle these developing challenges; however, system operators require systematic methodologies to effectively deploy them within an existing electricity market and regulatory framework. More importantly, not all technologies need to be deployed via markets, as some of them can be mandated via grid codes or similar mechanisms. For example, while premium services (e.g. ultra-fast frequency support) could be implemented via an electricity market framework, they could also be contracted via purchase agreements, and hence technology developers could be encouraged to provide such services in sufficient volume to electricity markets, thus decreasing investment risk in new technologies.

New important techno-economic challenges that are emerging are associated with inherent difficulties in dealing with complex physical system requirements - and then market products – in low-carbon grids with increasing shares of PECs, but still with a large presence of synchronous machines. These difficulties in dealing with the “new physics” of low-carbon grids justify the so-called “bottom-up” approach “from physics to economics” to define new market and regulatory requirements, services and products (Billimoria et al., 2020; Mancarella & Billimoria, 2021). Examples of such issues are: difficulty in defining physical features of low-carbon grids (e.g., “system strength” is related to network impedance, voltage/reactive power control, synchronising torque, inertia, and short-circuit current – it is not straightforward to even “define” in a clear but comprehensive manner); inseparability of certain services (e.g., a synchronous generator provides fault current, but also inevitably inertia, thus affecting other markets/products); integrality constraints (e.g., a synchronous condenser can only provide none, or all, of its inertia and fault-current capacity when off or on, respectively, thus leading to “binary” or “integer” service provision that is not easy to incorporate within market solution algorithms); non-intuitive stability characteristics of complex hybrid (continuous-discrete) dynamical systems (e.g., synchronous and PEC-based technologies); and difficulty in defining whether all security services are actually "public goods", as historically thought, or whether some of them may have different economic properties (e.g., provision and access to some services may become increasingly "contentious" due to system congestion). Extensive work is needed to address these issues and is the object of ongoing research studies and regulatory and market design efforts worldwide.

Data availability statement

Data sharing is not applicable to this article as no new data were created or analyzed in this study.

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