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Market design for system security in low-carbon electricity grids: From the physics to the economics

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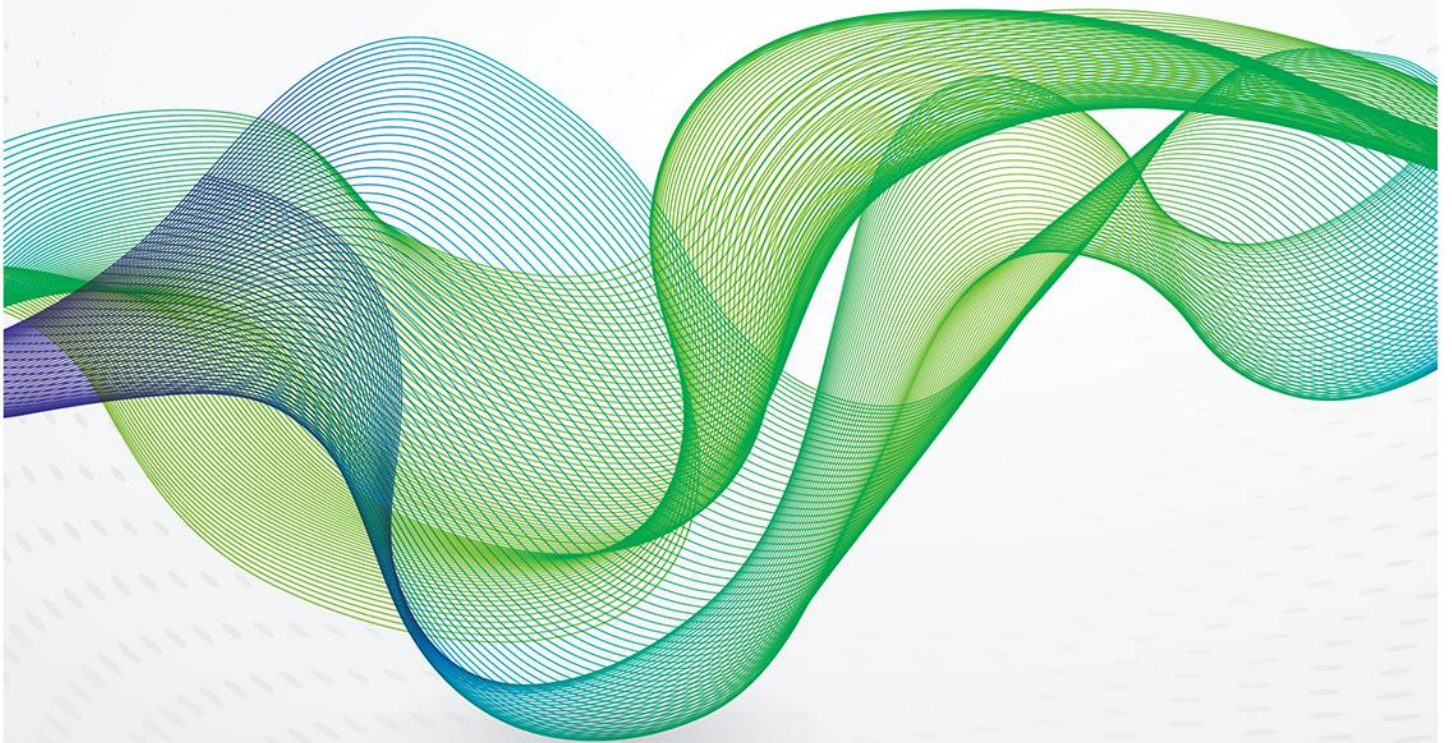
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Market design for system security in low-carbon electricity grids: from the physics to the economics

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Abstract

System security is a critical component of power system operation. The objective of operational security is to manage grid stability and to limit the interruption to customer service following a disturbance. The integration of inverter-based renewable generation technologies such as solar and wind in the generation mix has introduced new challenges for managing operational security. First, the intermittency inherent in renewable resources can impact on key power system parameters such as frequency and voltage. Second, renewables interface with the grid through power electronics rather than turbines, which means that the physical characteristics of turbine generation that have historically supported the stability of the grid are becoming scarce as the power system transitions away from fossil-fuel based thermal generation. In this paper, using public good theory, we provide an economic characterisation of the system services necessary for power system security. The analysis illustrates that, as opposed to a standard 'public goods' characterisation, system security products are better viewed as a basket of goods with differing economic characteristics that can also vary over space and time. The implications of these classifications for market design is analysed, including the inseparability of certain products, the binary or unit-commitment based nature of certain products, and the interactions between procurement mechanisms, network access rights and investment. Finally, we highlight five emerging models of market design for system security that reflect the nuances of economic characterization while respecting the physical characteristics of the grid.



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1. Introduction

A technological revolution is underway in most electricity systems around the world. Solar and wind generation technologies offer emission free energy at close to zero marginal cost. Coupling these technologies with storage and demand response allows for firmer sources of power and improved balance between power demand and supply. However, the integration of these technologies into the grid comes with new challenges for maintaining operational security.¹

Operational security relates to the ability of the power system to remain stable in the event of disturbances and keeping a system operationally secure is an everyday (and an every-minute) challenge. Recent events have underscored the criticality of system security – including the South Australia blackout, fault-driven disturbances in California, a regional blackout in the UK, and ongoing regional electrical separations within the National Electricity Market in Australia (AEMO, 2020a; National Grid, 2020a; NERC, 2019).

Renewable technologies have introduced two major issues of concerns for operational security. First, is the variability and uncertainty inherent in resources such as wind and solar, which can impact upon power system parameters such as frequency and voltage. The second concern relates to the way in which renewables interface with the grid – through power electronics rather than turbines. There are physical characteristics of turbine generation interfaced via synchronous machines that have historically supported the stability of the grid – such as inertia² and fault levels.³ With the phase-out of synchronous generation, grids around the world are experiencing challenges to maintain operational security.

To manage security when critical system services are scarce, operators may need to resort to interventions in the market, renewable curtailment, and potentially even delaying new connections to the network. This has the potential to slow down the investment in renewables, which is critical to the deep decarbonization of the electricity sector. On the other hand, new technology solutions are being developed that use the speed, precision and control of power electronics to better manage security issues. However, without appropriate policy and market frameworks there is little incentive for market participants to deploy these advanced functionalities.

System security is a multi-faceted concept and concerns many different aspects of power system physics. The challenge for policy makers and market designers is to develop cohesive economic and regulatory frameworks for operational security – and to manage integration within the broader market design for electric supply. An array of instruments is available to the policy maker, from regulation, mandatory licenses and markets (both organized and informal). An understanding of the economic characteristics of system security can inform the choice of which instrument or combination thereof is best suited for the security problem. We propose a bottom-up approach that begins with an understanding of the physics of electricity networks and translate this to an economic characterization. Indeed, it is these approaches that were the basis of foundational electricity market design in the first place (Joskow and Schmalensee, 1988; Schweppe et al., 1988). However, at that time markets for

¹ In this paper, we are mainly concerned with the challenge of operational security. There are also challenges relating to resource adequacy and system balancing under deep power system decarbonisation. While we will note linkages with these challenges, a review of the optimal market designs for latter is out of the scope of this paper. In general we will assume that the high level market design of optimal least-cost generator dispatch based on short run marginal cost (SRMC) pricing principles is taken as a given at least from the perspective of short term resource commitment, scheduling and dispatch.

² Mechanical energy stored in the rotating mass of the turbine which is released in the event of a disturbance. The primary effect of inertia is to resist the degradation of frequency, but it also affects transient and voltage stability.

³ Fault levels are an indicator of the maximum current that would flow to the fault at a specific node on the occurrence of a fault. There are often three sources of fault current: (i) large power plants via networks (i.e. system-derived fault current); (ii) embedded generators connected to the local network; and (iii) conversion of the mechanical inertia of the rotating turbine into electrical energy. Fault current is important to supporting power system stability in response to a fault.



energy and ancillary services were able to be designed around the assumption that connecting resources were primarily synchronous, as this was the predominant technology interface. With that assumption now challenged (and some would argue broken) frameworks for system security will need to adapt to the new emerging technology environment.

The novel contributions of this paper are as follows: (1) a cohesive framing of the system services value chain, from elementary services to system security products to power system security requirements; (2) an application of public good theory to a variety of system security products to understand their economic characteristics; and (3) the application of this characterisation to five emerging economic frameworks for security. In doing so we illustrate that the economic characterization of system security products is increasingly heterogenous. Indeed, rather than thinking of all system security products as pure public goods, they can be better thought of as a basket of goods with public and private qualities. This necessitates a nuanced approach to regulatory and market design that reflects the interplay between network access, resource control and system characteristics.

The paper is structured under three main parts. In Section 2 we will first outline the interactions between mechanics and electricity that have underpinned power system security to date. Then, we will highlight how the technology transition has fundamentally shifted the pillars of control that have underpinned power system security to date. In Section 3 we will begin the economic characterization by describing the system services value chain – from the operational elements and differing modes of control that go into creating different power system security products, to how they contribute to satisfying power system requirements. We then apply the perspective of public good theory to characterize these system security products. Next, armed with this lens, in Section 4 we set out five models for regulatory and market design and provide suitable pathways for policy in grids with differing technical characteristics and topologies. Finally, we provide some concluding remarks in Section 5.

2. Emerging system security issues in the energy transition

2.1 An overview of power system security and stability

The security of the power system refers to its ability to remain stable in response to disturbances. Thus, the security is intrinsically linked with the concept of power systems engineering concept of stability. Stability is important across many dimensions – temporally, spatially and across different parameters of the system (such as frequency, phase angle, voltage, active and reactive power). Any imbalance in one dimension or element of the power system can quickly affect others. In reality, the system and its resources are built in a way that means it is able tolerate some level of imbalance, as long as this is arrested, mitigated and rebalanced within a sufficiently short period of time. Events such as generator or load trips, transmission line outages or unpredicted changes in renewable generation happen as a matter of course. From time to time extreme events such as multiple disconnections, extreme weather and cascading failures can also occur. At a high level, the goal of operational security is to manage those imbalances to limit the interruption to customer service (Kirschen and Strbac, 2004; Stoft, 2002).

This involves handling the issue on multiple levels. First, to limit the risk and magnitude of those imbalances to within the operational tolerances of the system. Second, to ensure that there are sufficient emergency mechanisms to mitigate impacts when the tolerances are breached. Third, to recover the system effectively and expeditiously when there is an interruption to service. Finally, to ensure that the inevitable interactions between different aspects of security are manageable.⁴

⁴ While this paper only focuses on the aspects of system security that are relevant for economic characterization, there are excellent technical treatments of the issue. Interested readers are referred to fundamental texts such as Glover et al. (2010), Kundur (1994) and for technical analyses - Kroposki et al., (2017); Milano et al., (2018); Perez-Arriago and Batlle (2012) and CIGRE (2016).



The power system parameters, such as frequency and voltage, are important indicators of the aforementioned stability in the system. To date, much of the focus of operational security has been upon managing these parameters and on keeping the system resilient to disturbances that affect them. The disturbance events that affect these parameters can be exogenous or endogenous, in other words, they can be triggered by an event that is external to the power system (such as weather events) or by elements within the power system itself (such as a trip of a generation unit). Moreover, it is often not just one single cause that results in the system deviating from its balance state – one event can impact another element of the power system, which affects another, and so on (i.e. a cascading failure).

Increasingly, power system parameters can themselves interact with each other with adverse impacts. Take the case of ‘voltage dip-induced frequency dips’ or VDIFD – a phenomenon where a short temporary drop in the voltage magnitude induces a similar effect in the system frequency, which is observed more in systems with high renewable penetration (Rather and Flynn, 2015). In power systems with significant renewables, low voltage events can cause inverter-based resources (IBRs)⁵ to enter into an emergency control scheme (low voltage ride through) which limits their active power output for a short period of time. This loss of power can result in a frequency deviation, which must be managed in addition to the recovery of voltage.

Indeed, analyses of system blackouts illustrate that blackouts are often not triggered by a single cause or impact, but by multiple interactive factors that ultimately result in interruption to service (Dobson, 2016; Pourbeik et al., 2006; Yamashita et al., 2009). These interactional factors will have increased relevance in the power systems of tomorrow given the mix of different technologies and sources of supply. Monitoring and managing these interactions are essential to having a secure and resilient power system.

The goal of regulation and policy, in this context, is to develop mechanisms for the efficient management of power system security risks. This may involve both market instruments (such as spot markets or contracts) and non-market mechanisms (licenses, regulation).

2.2 Components of power system stability

The physics of legacy AC power systems rely upon interactions between the physics of mechanical systems of generators and the physics of electrical networks; for example, the mechanics required to keep all turbines spinning at the same speed and in synchrony with one other, to create a good high-quality AC signal. These electro-mechanical interactions have traditionally underpinned the stability of the system. As such there are direct relationships between the mechanical characteristics of turbines and electrical voltage and frequency.

In this section, we will explain the classical definition of stability and how that is changing with new technology entering the system. Kundur et al., (2004) provide the classic definition of the elements required for power system stability. They are: **(1) frequency stability** – the ability of a power system to keep frequency within reasonable bounds; **(2) voltage stability** – the ability to maintain steady voltages at all buses in the system; and **(3) angular stability** – the ability of resources in a system to maintain synchronism with the grid. While frequency is a system-level parameter, voltage and angular stability are more localized parameters. Frequency and voltage are well explained and understood in the power system literature. See Kroposki et al. (2017) and Milano et al. (2018) for excellent overviews of frequency and voltage concepts in a power grid.

Angular stability can be explained by analogy. Imagine two runners running one behind the other at the same speed, tethered by a rope. The rope needs to be pretty taut but can tolerate a little bit of slack. There is a natural harmony between the two. If the runners want to accelerate or decelerate, the rope

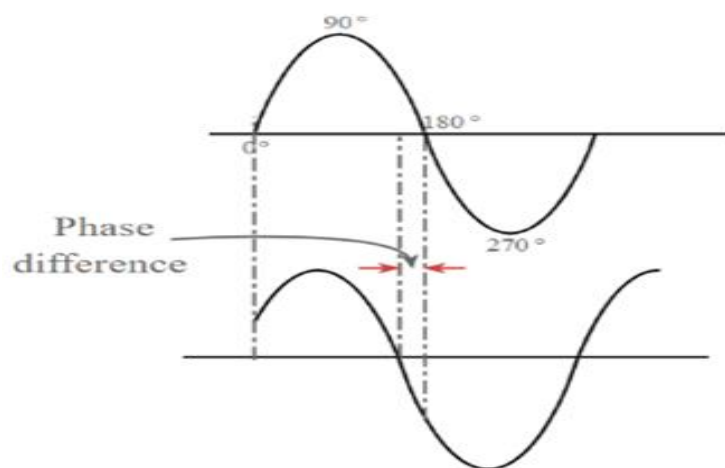
⁵ IBRs, such as photovoltaic, wind power and batteries, are resources that interface with the grid through inverters, rather than directly through the turbine shaft.



provides a natural impetus – in other words, one runner can pull the other along to the new speed, as long as this is slow and controlled enough for the other one to respond. Instability arises when either runner accelerates or decelerates too quickly – either there will be too much slack, or a runner will be jolted forward/backward. This can be triggered by events internal to the system (one or both runners fall out of synchrony) or external (a dog runs into the runner's path).⁶

For a turbine generator to generate electricity there is a small time delay between the rotation of the mechanical turbine and the electrical signal that interfaces with the grid. One is always slightly out of phase with the other (as depicted in Figure 1). This is known as the rotor or phase angle. In a synchronized system, the differences between the phase angles of the generators across the system must be kept within operational limits. Instability can result in a generator suffering damage or disconnecting from the system.

Figure 1: Phase angle



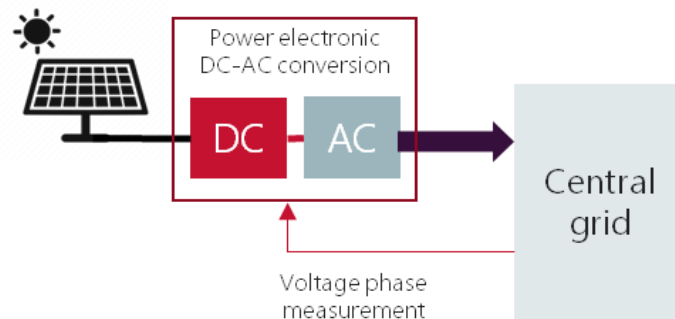
Source: adapted from Kundur (1994)

New technologies **interface** with the grid in a fundamentally different way from traditional generation sources. Traditional generation technologies are **synchronous**, which means that all mechanical rotating turbines are directly connected and synchronized with the grid, rotating with the same speed (for a frequency of 50 Hz this is 3000 rotations per minutes). By contrast, most IBRs are **asynchronous** because they have no rotating mass and connect to the grid via power electronic inverters, which convert DC electricity into grid-compatible AC electricity (Kroposki et al., 2017).

⁶ See also Basler and Schaefer (2005) for a technical overview of power system stability concepts.



Figure 2: Grid-following interface



Source: authors

The first generation of IBR use an industry standard control system, known as the phase-locked loop (PLL). As an IBR has no natural spinning mass, the PLL measures the phase of the voltage signal from the grid and then injects an AC voltage signal that matches the phase of the grid. This ensures that the signals are synchronized – they follow the grid signal ('grid-following' inverters) (Figure 2).

While PLL-based inverters can have a range of alternative control schemes that trigger under certain conditions (for example, to provide frequency or voltage support), they continue to rely upon stable measurements of voltage from the grid. At low levels of IBR penetration, this approach has worked soundly. At higher levels of IBR penetration (30–40 per cent are often seen as trigger points) this introduces new categories of security issues that are not seen in traditional grids and lowers the ability of IBR to provide voltage and frequency support to the grid (AEMO, 2019; Bakke et al., 2019).⁷

As long as we continue to have synchronous resources in the grid, classical components of stability will continue to have relevance. However, as grids continue to transition to an inverter-dominated model, it is evident that the characterization of stability is itself evolving to reflect the additional considerations relevant to IBR and its control systems (Farrokhhabadi et al., 2020). For the purposes of this paper, we have set aside a broad category of resource stability – which includes stability associated with synchronous generation (such as angular stability), as well as stability issues emerging as a result of higher IBR penetration.

2.3 Technology transition and integration

The security challenges associated with the grid integration of new technologies can be broadly categorized into the impacts of (i) variability and uncertainty and (ii) new technology interfaces between generator and grid.

While uncertainty has always been a factor in electricity market design since its inception (Schweppe et al., 1988), the nature of the uncertainty has changed. Power system operators must manage for the uncertainties introduced by more intermittent forms of generation, such as wind and solar, which for the purposes of security relate more to short timescales (minute or second timescales) and can impact upon system parameters such as frequency and voltage. These can include, for example, changes in wind or solar generation due to weather patterns or clouding. It can also include risks of greater correlation or co-movement between sets of resources.

⁷ These include classic voltage stability issues, but also new interactions between the grid and IBR control systems, and between IBRs – including previously unobserved interactions where IBRs oscillate with one another (Rehman et al., 2019; Wang and Blaabjerg, 2019).



Second, due to the link that existed between turbine mechanics and electric networks, there have been important physical characteristics of synchronous resources, which have traditionally supported the security of the system but are less available in the transition era. These include:

- **Inertia:** the spinning mass of rotating turbines have a store of kinetic energy, which is naturally and instantaneously released into the system if there is imbalance in demand and supply. Inertia naturally slows the rate at which system parameters (such as frequency and voltage) change in response to disturbances. This slows the rate of degradation of the parameters but also their recovery.
- **Fault current:** On the occurrence of a fault, synchronous resources will naturally and instantaneously inject high levels of current into the fault. This assists with limiting the rate at which voltage degrades during fault conditions. In other words, it keeps voltages 'stiff'.
- **Synchronization effect:** There is a natural synchronization effect between all generators connected within a network (i.e. to use the walking analogy used earlier, the rope that ties all participants together).

The electrical response that underpins these characteristics are inherent to the traditional synchronous generation technology and are a natural response to a power system disturbance. Operational control for AC grids has heretofore relied upon these characteristics to underpin system security (Milano et al., 2018). With the interface between generator and grid increasingly moving towards power electronic converters, these existing services are becoming scarce and result in weaker grids that are less resilient to disturbances.

Inverter control and systems technology are advancing at a rapid rate to meet the challenges of system security. IBRs are already capable of delivering rapid and precise frequency and voltage response services, by injecting or withdrawing active or reactive power into the system. This has been already implemented in some markets and is expected to be implemented in many others.

On a more fundamental level, there is also the development of new modes of control from IBRs that aim to resolve some of the interface issues between first-generation IBRs and the network. The approaches taken to meet the challenge vary from fitting new technology into existing modes of control, to creating entirely new operational paradigms more suited to an inverter dominated grid (Matevosyan et al., 2019). Research and development have been underway on classes of 'grid-forming inverters',⁸ which adopt new control schemes that have less reliance on grid measurements. There are many variations on 'grid-forming' control from those that try to mimic the full response of synchronous machines (virtual synchronous machines), while others adopt alternative control strategies (for example, virtual oscillators). However, it is still early days, and few have been piloted as of yet.⁹

What does this all mean for policy and market design? It is clear that electricity market design needs to be flexible and adaptable to reflect these ongoing changes in technology. This will inevitably involve trade-offs between maintaining existing control modes and using new models and technologies. Immediate risks to security may require a near-term reliance upon what operators know works. However, testing and piloting of new technologies on an ongoing basis is important to ensure that, once proven, new technologies can participate in the market without prejudice. An ideal approach is one that

⁸ The current generation of inverters operate as so-called 'grid-following' sources, meaning that they track the phase angle of the grid in order to synchronise their output. Grid following inverters are best viewed as a source of current, and are less able to assist in keeping voltages stiff at the connection point in the event of disturbances (such as faults). By contrast, the control schemes of grid forming inverters act as a voltage source, which allows them to contribute to keeping voltages stiff at the connection point.

⁹ There has been some piloting of grid-forming technologies on large-scale grids, including the Dalrymple ESCRI battery project in South Australia (<https://www.escri-sa.com.au/>). In many cases, these have focussed upon microgrids or smaller-scale islanded grids (Schomann, 2019).



effectively bridges the gap between the economics of service delivery and the engineering of resource control, though pragmatism may require operators and policymakers to favour one over the other at different times. The roles and incentives of decision makers and regulators in this domain must also be considered.

2.4 Power system requirements

Table 1 outlines the physical requirements for a secure power system and highlights the scarcities and phenomena emerging as a result of the transition away from legacy synchronous generation towards resources that are inverter-connected and variable in nature.

In the following sections, we will draw out the essential elements of frequency and voltage control that are important for economic characterization. However, a detailed treatment of engineering control applications for frequency and voltage under high IBR penetration is out of the scope of this paper. Interested readers are instead referred to the following resources: CIGRE, 2016; EPRI, 2019; Milano et al., 2018; Tielens and Van Hertem, 2016.

Table 1: Summary of technical power system requirements

Physical requirements		Parameter type	Emerging scarcities and concerns
Frequency stability	Inertia and primary response	System	<ul style="list-style-type: none"> Declining inertia affecting frequency response Reduced synchronous load affecting frequency damping More rapid frequency variation within periods Voltage induced frequency dips (VFID)
	Secondary response		
	Tertiary response		
Voltage stability	Static voltage control	Local	<ul style="list-style-type: none"> Declining fault levels affecting voltage stability Potential for increased voltage oscillation Voltage variations with intermittent resources Voltage waveform distortions from IBR Reduced inertia affecting voltage recovery
	Dynamic voltage control	Local	
	System strength and fault levels	Local	
Resource stability	Angular stability	Local	<ul style="list-style-type: none"> Declining inertia affecting angular stability Reduced synchronization effect Harmonic interactions between IBR units Delayed active power recovery in IBR dominated grids
	Resonance stability		
	Control systems stability		

Source: compiled from Kroposki et al. (2017); Milano et al. (2018); Shair et al. (2019); CIGRE (2016); AEMO (2018)

2.4.1 Frequency management and inertia

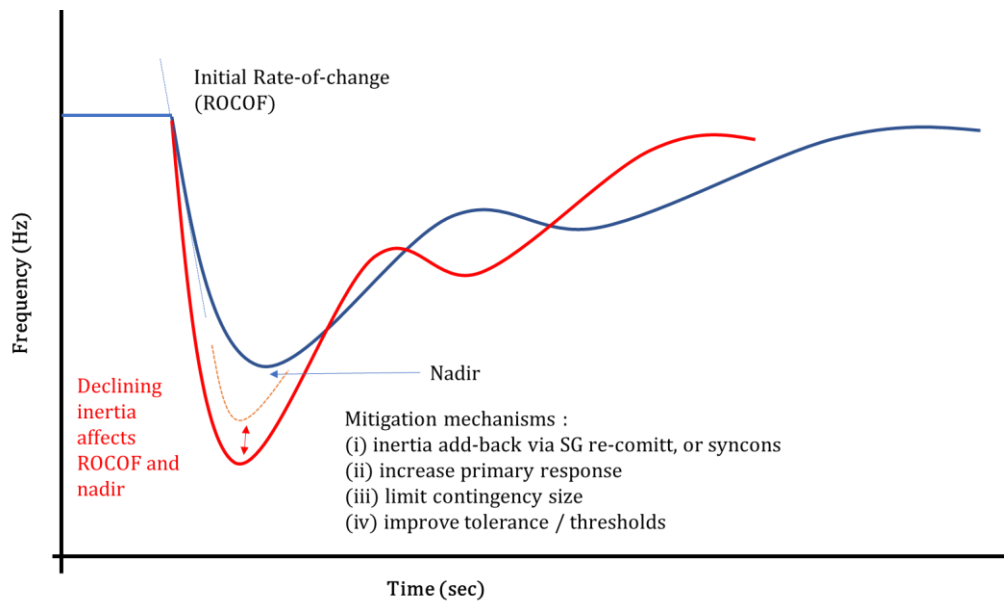
The incumbent approach to frequency management in response to a system event or contingency involves three stages: primary response (PFR) to arrest large frequency deviations and recover it to initially acceptable levels; secondary response (SFR) to regulate smaller deviations within normal operating levels; tertiary response (TFR) seeks to replace reserves that used to provide faster responses, to provide some measure of cushion.¹⁰ Some markets, such as the National Electricity Market of Australia (NEM), dispense with TFR reserves and instead rely upon the redispatch of the power system to keep the new balance in the power system. If frequency degrades past normal

¹⁰ As we outline below, a shift towards 100% IBR may entail new control modes. In the near term, inertia will continue to be a relevant parameter but may degrade in importance over time.



operating bounds, emergency control schemes (such as under-frequency load shedding) trigger to attempt to avoid cascading failure. In each case, frequency is controlled through injecting or withdrawing active power from the system.

Figure 3: Frequency response under contingency



Source: authors, adapted from Mancarella et al (2017)

The impacts of lower inertia on traditional frequency control have been well studied in recent years (Milano et al., 2018). Inertia reduces the instantaneous rate at which frequency changes (known as the rate of change of frequency, or ROCOF). It also affects how low the frequency gets (the nadir).¹¹ It also slows down the recovery of the system (Figure 3).

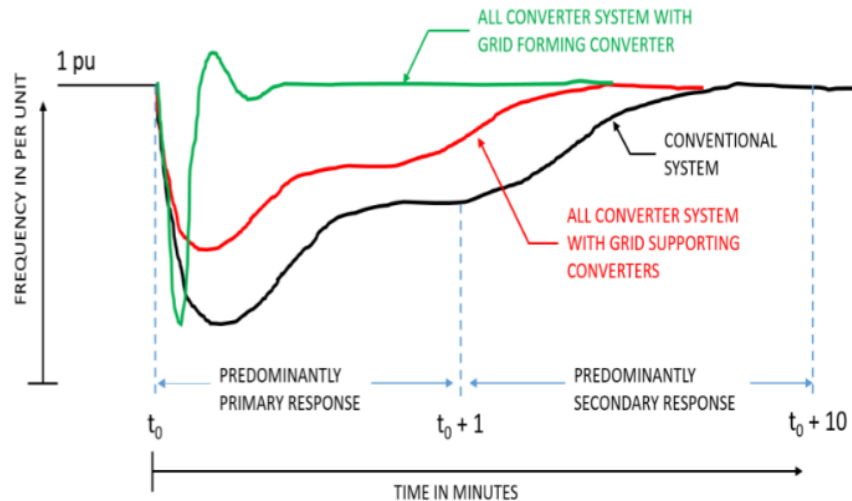
Frequency is a critical parameter for existing turbine generation and the network, and there are limits to the ROCOF and nadir that this equipment can handle. As such, the grid relies upon these measures being between viable operating bounds, or else risking cascading failure or equipment damage.

There are a range of operational levers and responses to deal with the loss of inertia, as a result of the retirement or reduced merit order dispatch of synchronous generation. First, and most obvious, would be to increase the level of inertia in the system. This can be done through re-scheduling synchronous generation (SG), by installing synchronous condensers ('syncons') to replace lost or retired SG, or to modify SG to allow operation in a synchronous condenser mode. 'Primary response, especially from fast-acting resources, can be used to substitute for and be co-optimised with inertia to control the nadir (Mancarella et al., 2017). This can be sourced either as reserve quantities based on triggers or through active control schemes, such as droop-based frequency control mechanisms (PFC). There is also active research and piloting of IBR control schemes that seek to mimic synchronous resources (so-called synthetic inertia or virtual synchronous machines) to provide as-close-to instantaneous inertial response' (Milano et al., 2018).

¹¹ In this section we mainly talk about an under-frequency event, for example in respect of a loss of a generation unit. Frequency operating frameworks must also cater to over-frequency events, such as the loss of load, and the same principles apply.



Figure 4: Constance frequency operating modes



Source: Ramasubramanian (2018)

A further opportunity lies in controlling the quantum of risk in the system. The amount of inertia or primary response is sized to cater for a particular risk level – usually the largest generator in the system. Thus control over the sizing of the contingency, by controlling the dispatch of the largest generator, has been argued to serve as a partial substitute (Badesa et al., 2018; Nedd et al., 2018; Püschel-Lovengreen and Mancarella, 2018, Mancarella et al., 2017). This latter approach assumes that the inherent risk in the system is correctly captured by the sizing metrics, which is appropriate for primary control that focuses upon unit contingency events. It has less application in respect of frequency dynamics that are affected by risks other than unit contingencies – for example in relation to generation variability.

The role of system thresholds is also important. The operational limits of the system (for example thresholds for ROCOF and nadir) are guided by the tolerance capabilities of the system within it. Synchronous machines that rely on granular control of large machinery have different tolerances to electrically coupled resources that convert from DC. Higher technical requirements can also impact the amount of inertia and frequency response that is needed.¹²

While the policy response to frequency challenges has focussed upon mitigating the impacts of technology changes to frequency sensitivity, it is also possible that the transition to an inverter-based grid requires new operational paradigms and ways of running the system. In a system with 100 per cent inverter-based generation, frequency may be a less relevant parameter. Different regimes may be required that continue to maintain power balance without the use of frequency as a control variable. Constant frequency operation is a proposed mode of operation where IBRs aim to maintain a constant frequency, rather than a bounded range, through controlled injections of active power (Figure 4). For an overview, see Ramasubramanian, (2018). For more detailed analysis, see Ramasubramanian et al (2018).

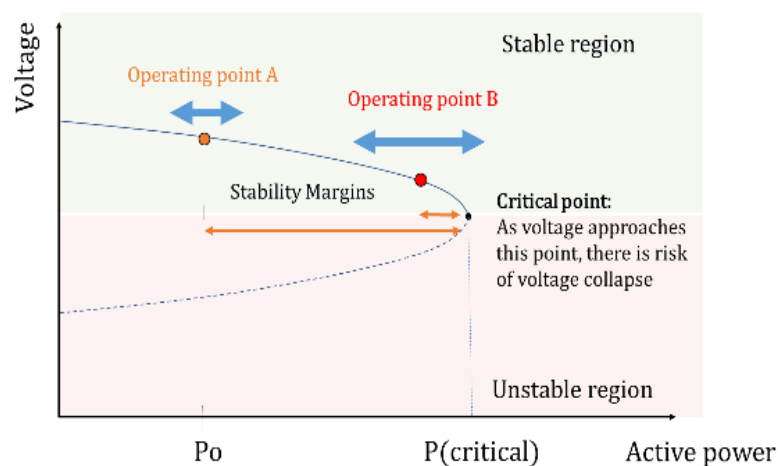
¹² EirGrid has a programme of work to transition grid code requirements for ROCOF from 0.5 Hz per second to 1 Hz per second (Eirgrid and SONI, 2018). National Grid in the UK is also undertaking changes to its distribution code relating to ROCOF relay settings (National Grid, 2020b).



2.4.2 Voltage stability and system strength in weak grids

Voltage is a local parameter and affects the operation of both synchronous resources and IBRs. In general, the relationship between voltage and power generation at a node is as per Figure 5. Voltage at every node needs to be operated above a critical point. Operating closer to the critical point makes the voltage more sensitive to changes in power flows, and more at risk of instability and collapse. As such, voltages are affected not just by the steady state operating point, but also by the variability of power flows. The addition of varying generation and load, such as from renewables, can thus impact upon the stability margin of voltage in certain locations around the grid (Pierrou and Wang, 2019).

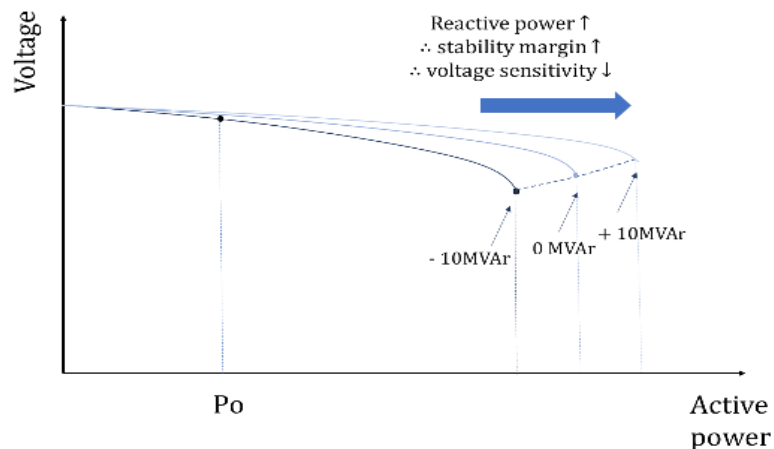
Figure 5: Voltage stability margins



Source: authors

Voltage control is achieved through managing the reactive power flows around the system (as shown in Figure 6). This is typically achieved through a combination of network control schemes and equipment at the node or regional level, or by changing the set-points of generators at different locations. Control schemes at the generator level can also assist with voltage stability.

Figure 6: Effects of reactive power on voltage



Source: authors

In addition to traditional voltage stability, an emerging concept is that of 'system strength'. A weak grid is one where the voltage is sensitive to changes in active power or reactive power (CIGRE, 2016; Dozein



et al., 2018). By contrast, a strong grid is one where the voltages are 'stiff' and exhibit much less sensitivity to power changes and to system events. There are physical characteristics of synchronous generators (and other resources, such as synchronous condensers) that have traditionally supported system strength. By contrast, IBRs have characteristics that have limited their ability to contribute to system strength (Gu et al., 2019a, 2019b; Shair et al., 2019). First, IBRs are limited in the amount of current they can inject during a fault. Second, and perhaps more fundamentally, the first generation of IBR technology (using PLLs protocol) themselves rely upon a 'stiff voltage' to synchronize with the grid. A large presence of online synchronous generators inherently slows the dynamic changes in the system, thereby allowing grid-following inverters to accurately track the grid voltage (Matevosyan et al., 2019). A weak grid is susceptible to a number of issues including: (1) mal-operation of fault-protection systems; (2) mal-operation of inverter control systems; (3) voltage oscillations following faults; (4) angular instability for synchronous generators; and (5) sub-synchronous control interactions between IBRs. With the retirement of synchronous fossil fuel generators, weak grid conditions are increasingly being observed, especially in areas of high renewable generation.

System strength is a complex issue and represents an interaction of many different factors. The inherent responses of synchronous resources, such as fault levels and synchronising power are important, as is the specific control systems employed by IBRs. System strength is also a very locational issue and depends upon many factors, including the combination and location of generators online, and the transmission configuration. There are some high-level metrics that provide high-level screening tools as to whether a system is strong (NERC, 2017; Wu et al., 2018). Often however, system operators need to undertake detailed and computationally intensive simulations to determine whether particular combinations of resources will give grid voltages that are sufficiently resistant to disturbances (Matevosyan et al., 2019).

In resolving near-term system strength issues, operators have looked towards re-scheduling synchronous generation, or installing synchronous condensers (Jia et al., 2018; Kenyon et al., 2020; Richard et al., 2019). In other cases, the tuning of inverter settings and constraints on IBRs has been utilized as alternative measures (Filatoff, 2020). Longer term, newer technology and control schemes (such as grid-forming inverters) are being considered (Matevosyan et al., 2019).

3. The economic characterization of system security

3.1 The system services value chain: elementary services, system products and power system requirements

In the sections above, we have described the technical challenges associated with power system security. In this section and hereafter, we begin to frame some of the economic characteristics of system security.

As a start, we think it is a helpful analogy in this situation to think about system security as a value chain. This allows us to understand what the 'raw materials' of power system security are, how they are packaged or segmented into different products or types of responses, and ultimately how those products combine in a manner that fulfils the needs of the users (see Figure 7).

What are the raw materials of power system security? The requirements for the control of frequency and voltage can be reduced at a fundamental level to four elementary services (Rebours, 2008). These are specified as:

- *upward active power – increasing injection or decreasing withdrawal of active power*
- *downward active power – decreasing injection or increasing withdrawal of active power*
- *upward reactive power – increasing injection or decreasing withdrawal of reactive power*
- *downward reactive power – decreasing injection or increasing withdrawal of reactive power.*



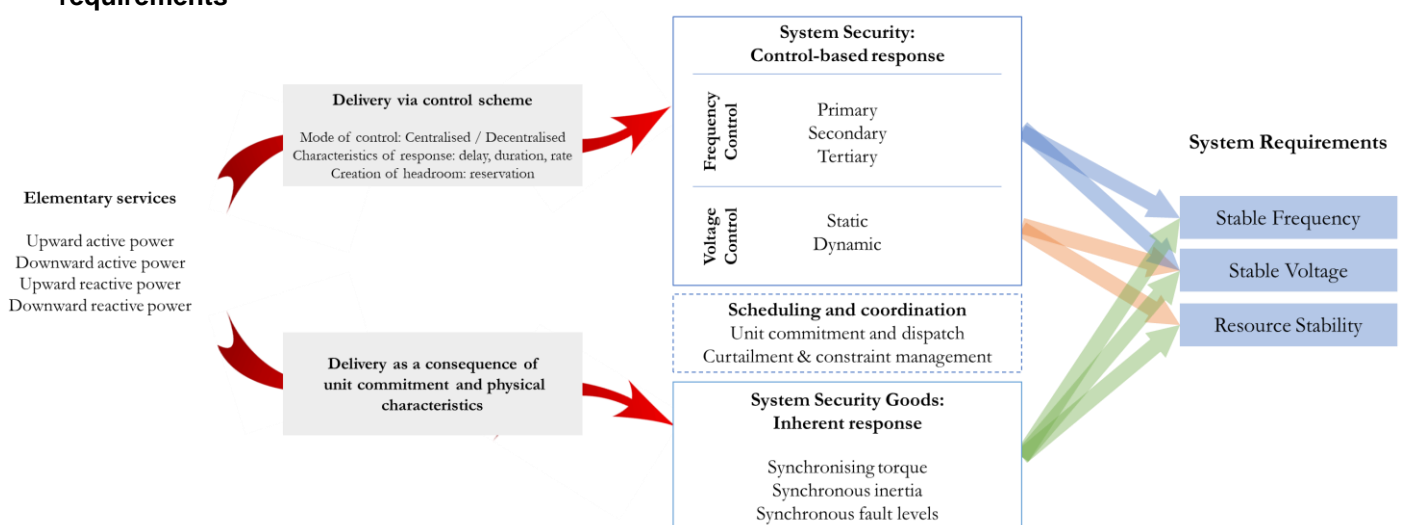
While the characterisation of these elementary services as it relates to concepts such as active power (frequency) or voltage (reactive) reserves is intuitive, this concept can also be extended to concepts such as inertia and system strength. As outlined in Section 2, inertia is stored energy released during disturbances. Fault levels relate to the natural injection of current (and hence power, either reactive or active) in response to system faults. More complex system strength phenomena also relate to the ways in which voltage-sources and current-sources inject or withdraw power in a network given either through control schemes or inherent physical responses.

A common approach then, in many market designs, is to designate a particular type of response, in other words, how active or reactive power is to be injected or withdrawn in the system. This has involved the creation of products based on a variety of factors, including: (i) what the triggering event is (if any); (ii) the quantity and quality of the response; (iii) the speed and duration of the response and (iv) notice times. Providers of these products must have the headroom or reserve to deliver these products, over and above what they may be delivering as part of energy dispatch.

These definitions are important determinants of efficiency and liquidity in these markets, which in turn influence system security (Oren, 2001). There is an inherent trade-off in the design of system service markets between homogenization of products to ensure competition, and product differentiation to meet system needs and optimize quality of delivery. Market designers have to decide upon the optimal balance between too many products and too few products (Pollitt and Anaya, 2019). Works such as Badesa et al (2020) and Greve et al (2018) suggest that artificial product boundaries can in some cases be replaced where all providers bid their technical characteristics (in addition to price and quantity), thereby allowing a market operator or co-ordinator to make optimal trade-offs between them.

However, there is also a distinction between those products which have a controlled actuation (i.e. via centralized or decentralized controllers) and inherent actuation (i.e. on the basis of the physical characteristics of the generator or resource). System strength and inertia from synchronous generators fall into the latter category. While control-based responses can be switched on or off, inherent responses are naturally provided when the resource is online. They are binary in nature and cannot be scaled up or down.

Figure 7: System security value chain – elementary services, system security products and requirements



Source: authors

Recent security outcomes have underscored the importance of inherent responses (inertia, system strength and synchronization effect) for system security. These inherent responses have unique



aspects which may create complexities for the design of economic products around these responses. These include (i) definability of the services, (ii) measurability and modelling of system impacts, (iii) unit commitment, and (iv) the inability to separate the delivery of different services.

Definability. Power system security in an asynchronous grid is very much an emerging area of research, and new dynamic behaviors are being observed every day. This has made the definition of power system requirements much more difficult, especially where a variety of factors interact in different ways. System strength is one such requirement. It is not clear if it is a power system requirement or a product. Also, we do not know whether a response type for individual providers can be defined in a common, consistent and effective way.

Measurability and modelling. There is also the challenge of measuring and modelling dynamic interactions. This is important for product quantification and for understanding trade-offs between the quantity of the product and other power system factors. For example, deriving constraint equations under security constrained unit commitment and dispatch (SCUC/SCED) market designs requires a clear mathematical relationship between variables such as the online status of synchronous units and the dispatch (in MW) of generators in the network. This means that there needs to be clear metrics for the security condition you are constraining the system for. While this may be carried out for some of the new system requirements such as for co-optimization of inertia and frequency response (Mancarella et al., 2017) it is challenging for other emerging security phenomena, such as low system strength in areas with plenty of renewables. In fact, while there are some standardized metrics for system strength (including a range of metrics that are modifications or adaptations of the short circuit ratio or SCR), there is a question of whether these metrics adequately capture the phenomenon. Although they may be sufficient for planning and connection processes, it is not clear if they are adequate for dispatch and scheduling. On the other hand, detailed transient simulations provide a better and more accurate understanding of whether the system is resilient to certain events or contingencies (such as faults). However, they are computationally intensive and sensitive to many factors. In markets such as the NEM where system strength is already a scarcity, operators have resorted to creating a schedule of generator configurations that provide comfort around system strength sufficiency (Ela et al., 2019). Ultimately, a set of viable parameters suitable for commitment and dispatch is required and should emerge as more is understood about the phenomena.

Unit commitment. Inherent response products are typically binary responses, in other words, they are based on whether the unit is synchronized to the system. The unit provides its full response if it is synchronized, and zero if it is not. These responses do not scale up or down with the level of generation, which is important for approaches to commitment and dispatch. Unit commitment creates non-convexities in dispatch optimization,¹³ which makes locational marginal pricing less meaningful. Some designs have adopted linear relaxations of the integer products to obtain meaningful pricing of inertia (Badesa et al., 2020). In other markets, the challenges of revenue inadequacy flowing from centralized unit commitment have relied upon 'uplift and clawback' side-payment frameworks, and upon alternative price formations for energy (such as convex-hull approximations) to minimize those uplift payments (Gribik et al., 2007). However, it is questionable whether energy price formation is an appropriate tool when the services being delivered are not always linked to the delivery of active power (for example, a synchronous condenser).

Separability. Particularly for inherent response products, there is an inability to separate the delivery of different services. For example, if online, a synchronous generator will provide both inertial, fault level and system strength contributions. This is of relevance when the products have fundamentally different economic characteristics. Simultaneous delivery must also be reflected in how these products are priced.

¹³ With a convex optimization, there can be only one optimal solution, which is globally optimal, whereas non-convexity causes multiple feasible regions and multiple locally optimal points within each region.



3.2 An economic characterization of system security and services

The electricity system is not unique in its need to manage security and quality of service (Pollitt and Anaya, 2019). Economic frameworks should guide how the comprehensive needs of the power system are met. Electricity and other essential infrastructure goods can be usefully assessed through the perspective of public good theory. In this section, we draw upon the rich body of literature in public good theory to appropriately characterize system security and the products required to deliver system services.

3.2.1 The nature of goods

The modern identification of a public good, and its distinction from a private good, is based on characteristics of excludability and rivalry (Table 2). A pure public good is one that clearly exhibits properties of (i) non-excludability and (ii) non-rivalry, while a private good is clearly excludable and rival. A good is excludable if the users of the good can be easily excluded from the enjoyment of the good (where the marginal cost of exclusion is low). Rivalry pertains to jointness of use. A rival good is one where the consumption of the good by one person diminishes the ability of others simultaneously to consume the good – where the marginal cost of extending the use of the good to a new user is high (the marginal cost of extension). Non-rival goods can be enjoyed by multiple users without diminishing its value.

Table 2: Classification criteria for different types of goods

		Rivalry	
		Non-rival	Rival
Excludability	Excludable	Club goods	Pure private goods
	Non-excludable	Pure public goods	Common pool resources (CPR)

Source: Ostrom (1990)

Seminal works by Ostrom (2003, 1990, 1977), Buchanan (1965) and others identified additional classifications that do not neatly fall into the classification of a pure private or public good. Ostrom's Nobel Prize winning work developed the notion of a common pool resource (CPR) – a good that is rival but not excludable. Furthermore, goods that are not rival but are excludable are termed as a club or toll goods.

CPRs are subject to the tragedy of the commons. This is a phenomenon where individual users acting in their own interests are incentivized to exploit a resource. Uncontrolled, this can lead to overexploitation of the resource to the detriment of the entire user group.¹⁴ This is particularly relevant for aspects of electricity service as it relates to the utilization rates of resources (static efficiency) and the incentive to invest in new capacity (dynamic efficiency) (Kiesling, 2008).

Few, if any, goods are perfectly non-rival. At some thresholds of supply, congestion begins to occur and one person's use of a good begins to impact its enjoyment by others. There is a category of goods known as congestible common pool resources, which initially behave like public goods when there is excess capacity. However, as more users are added, congestion starts to occur and the good becomes increasingly rival. A common example of this is a toll road/highway which is initially non-rival when there is excess capacity, but congestion effects and rivalry will begin to appear as the number of users increase. The concept of CPRs has been previously applied to different aspects of the

¹⁴ A common example of the tragedy of the commons is environmental air quality or emissions, where the marginal cost of emissions on an individual is very low and there is no direct incentive not to emit. If all individuals act in their interests the cost on society as a whole is nevertheless significant.



electricity sector, such as networks (Kiesling and Giberson, 1997; Kiesling, 2008; Künneke and Finger, 2009), community energy (Gollwitzer et al., 2018; Wolsink, 2012) as well as to other energy infrastructure (Hallack and Vazquez, 2014).

3.2.2 Characterising products for system services

In this section, we apply the framework in Section 3.2.1 to characterize power system security goods. We note that the characterization of a set of goods is not static nor universal – it reflects the system of property rights surrounding the good. Goods may also be transformed based on the legal, regulatory and market framework in place on a jurisdictional basis (Cornes and Sandler, 1996).

We also draw a distinction between the characterization of the power system requirements themselves and the products required to deliver those requirements. Traditionally, electricity economists tend to classify ‘power system requirements’ (in other words, a stable voltage or frequency) as public goods based on a view of the system-wide nature of security phenomena – that all consumers in a certain area of the network face the same voltage and frequency conditions (Joskow and Tirole, 2007; Toomey et al., 2005).

This, however, does not imply that system service products that deliver these power system requirements are also necessarily public goods. Non-public goods can be used to deliver public goods (Hogan, 1996). The characterization of system services products thus requires an assessment of the technical characteristics of these goods and the regulatory frameworks underpinning them.

For clarity, we define the users or beneficiaries of system security to include all participants in the power system, including consumers and suppliers of energy, as all benefit from a stable grid within which to consume or deliver the electric commodity. For example, a generator benefits from a more stable grid through reduced equipment stress and unit trips.

First, we analyse the characteristic of excludability. The physical provision of many system service products is naturally non-excludable in that it is difficult to exclude a particular user from the benefits of the product. Any generator or load connected to the grid will obtain the benefit of most system services like inertia, frequency or voltage services. This renders them susceptible to free-rider issues and necessitates a cost allocation framework that allocates liability for the costs of system services to the users of the services (Rebours et al., 2007).

The issue of rivalry is more nuanced. Rivalry is important as it has impacts upon incentives for efficient contracting and investment. As outlined above, rivalry can be assessed by understanding the marginal cost of extension. The marginal cost of extension is defined as the societal costs of extending the particular system service to a new user. For a non-rival good, the marginal costs of extension will be low, and vice versa. The broader literature suggests that all goods will have some degree of rivalry, and our assessment of system service products suggests this may also be the case. For policy makers, the question is whether the degree and nature of the rivalry is trivial, or whether it is significant enough to reframe our view of how property rights for that product should be governed. Ultimately, we are trying to get an understanding of whether competitive consumption of the product is practical and feasible.

There are three types of costs that are particularly relevant to system security services (Kaye et al., 1995): (1) availability cost, the sum of each provider’s cost of being available to deliver the service; (2) response cost, the expected cost of actually responding to an event; and (3) expected outage costs, the expected system costs of a security-related outage. Expected outage costs can be thought of as the unit cost of outage (VOLL may be a good estimate) multiplied by the probability that a system will collapse. Thus, the rivalry of a service can be assessed by examining the impact of a new user of the service on these costs.

A complicating issue is that the users of system service products are increasingly heterogenous. For example, a user of system services may be a new residential customer, commercial customer or a new renewable generator. As such, it may be hard to pinpoint the characteristics of the ‘marginal user’. This



is increasingly important in a system security context. Whether a new user is variable or dispatchable, synchronous or non-synchronous is relevant to understanding whether they will impact the value/costs of system security. Are there easily identifiable parameters or characteristics of the user which directly relate to the valuation of the product? Presumptions on typical user characteristics may be more justifiable in local or regional settings. For example, where the grid configurations or resource characteristics lend themselves more readily to certain types of users (for example, high wind or solar resource regions may better justify a presumption that new users will have 'typical' characteristics or interfaces with the grid)

Inertia and primary frequency response

Let us examine inertial and primary frequency response (PFR) products, which aim to keep frequency within operating bounds in response to contingency events.

Given the availability of a certain quantity of inertia and PFR, the addition of a new user of inertia and PFR services is unlikely to impact availability costs, as the latter primarily relates to the opportunity cost of providing reserve. Response costs are also unlikely to be significantly impacted, as they relate to the cost of energy generated or consumed while responding to a contingency event. Assuming that the unit costs of outage remain constant, outage costs are only affected if the addition of a marginal new user will affect the probability of system collapse. The amount of PFR and inertia is typically sized such that the frequency parameters (such as ROCOF and nadir) will remain within tolerance threshold in the event of the largest system contingency (typically the loss of the largest unit). Thus, a new user would only increase the probability of collapse (and thus be considered rival) if that user is necessarily larger in size than that of the existing largest contingency. Given the new user is a marginal addition, this is unlikely to be the case. As such, inertial and primarily response products are best classified as non-rival public goods (Greve et al., 2018).

Secondary frequency response

Secondary frequency response (or frequency regulation) aims to manage smaller frequency deviations that occur in the normal course of operations. Providers reserve a quantity of active power for the dispatch interval, and control schemes (typically an automatic generation control or AGC scheme) will then adjust the active power of those providers during the dispatch interval to respond to the instantaneous imbalance between power supply and demand.

Certain sub-classes of users (such as renewables) are more intermittent and uncertain, and their addition in a system can lead to greater and more frequent power imbalances (Apostolopoulou et al., 2016; Nguyen and Mitra, 2016) in the system. This is likely to result in larger and more frequent adjustments of power from regulation reserve providers, implying higher response costs from the addition of such users.

However, given that frequency is a system-wide parameter, rivalry would only emerge for the system as a whole if there is a strong homogeneity between users of the system. In essence, this would only occur if there is a case to suggest that the archetypal user has these characteristics (for example, highly intermittent or uncertain). This may be possible on a regional basis but would be difficult to establish for electricity systems as a whole. All this suggests that non-rival and public good characterization may be appropriate for secondary frequency products. Nevertheless, this does leave open the question of whether frequency response frameworks should consider the need for additional mechanisms to manage the effects of 'causers' of system variability.

Tertiary frequency response

We also assess the class of reserves known as tertiary frequency reserves, sometimes called operating reserves or replacement reserves. These are reserves of active power designed to replace primary or secondary frequency response beyond the dispatch interval. As with other frequency response products, these for the most part may be thought of as non-rival, though aspects of rivalry can emerge through, for example, new users adding to the variability of generation or load patterns. However, as



with other frequency products, given TFR is a system-wide (active power) service, this element can be disregarded.

What sets this type of product apart from the other reserves is the possibility of exclusion through curtailment. This product can be seen as a form of insurance against reliability-driven curtailment (Hirst and Kirby, 1999). These scheduled reserves are available for dispatch in later intervals to deal with uncertainties, such as ramping events (Zhou and Botterud, 2014). Given that this type of reserve has been developed for periods longer than a dispatch interval, it may be possible to curtail users that do not wish to pay for the product via the concept of priority curtailment (Chao et al., 1988; Mou et al., 2019; Wilson, 1997). In other words, users that are unwilling to pay for dynamic operating reserves can be curtailed in favour of other users when such uncertainties arise. This ensures that they do not obtain the benefit of the additional reliability reserve. This also relates to the concept of differentiated reliability, which is very much aligned with the customer's rights to independently procure some service – a typical example is a microgrid, which can guarantee levels of self-security (Martínez Ceseña et al., 2018).

Combined with the non-rival characteristic, the excludability of this type of product implies that a characterization as a club good might be appropriate.

Voltage control

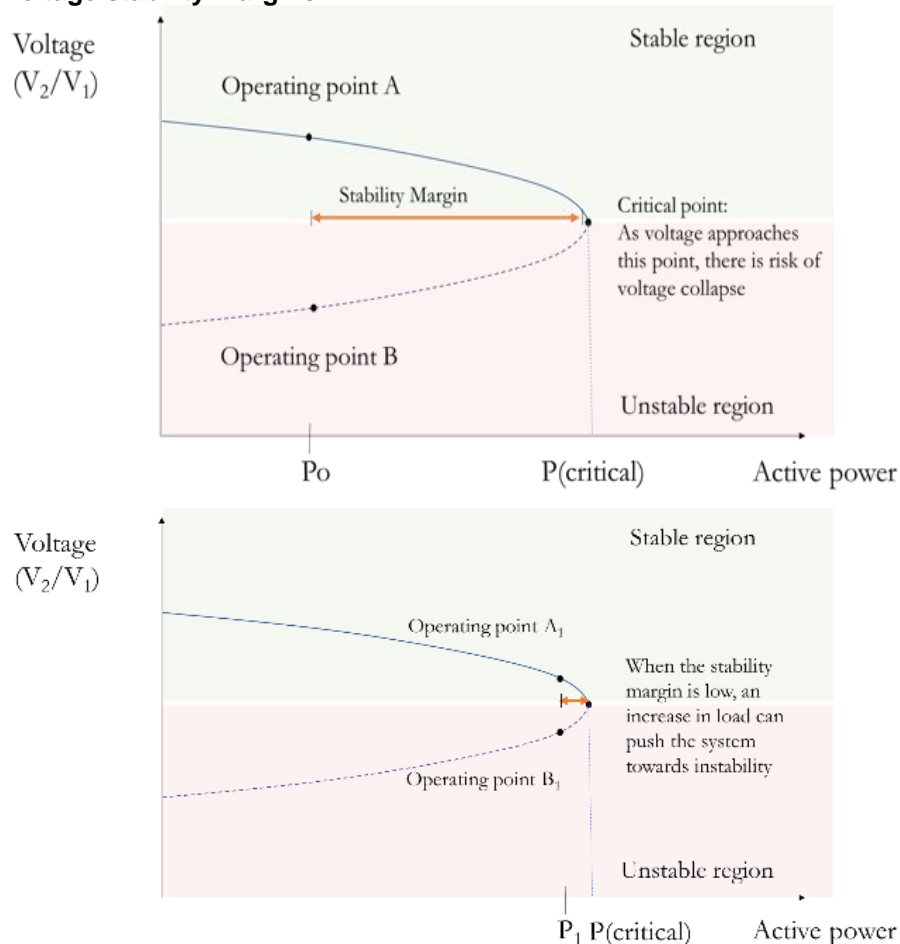
In the absence of incentives and/or regulations for both static and dynamic voltage control for users, and given a certain quantity of existing voltage products, characteristics of rivalry can emerge on a local level. As voltage is a local parameter, homogeneity between users in a particular region may be more common. For example, in a region of the grid with high wind or solar resources it may be acceptable to suggest that the typical user of the system is a variable energy resource.

Rivalry for static voltage control can emerge where the addition of users in a local area can adversely affect absolute voltage levels. Examples include high rooftop solar penetrations in local regions resulting in over-voltages at times of high solar export (Meegahapola and Littler, 2017; Watson et al., 2016), or uncontrolled electric vehicle charging resulting in under-voltages (de Hoog et al., 2015; Sun et al., 2020). Rivalry in the more dynamic aspects of voltage control can also be illustrated. For a given dynamic voltage response, users that have increasingly intermittent usage or generation profiles can affect voltage deviations.

If there is a high stability margin in the local grid, the marginal addition of users is unlikely to have a significant impact on the likelihood or severity of outages. However, at certain points of congestion the concepts of rivalry could become increasingly relevant. As such, as grids approach congestion, particularly at the distribution level, the addition of users will begin to adversely impact likelihood of instability and severity of impact. This would increase expected outage costs and imply high marginal costs of extension. This is illustrated in the voltage stability curve in Figure 8. Similar considerations may be drawn for distribution networks with respect to the concept of “hosting capacity”, which may effectively limit the ability of a new user to connect to the network or limit its capacity because it might breach voltage limits (unless curtailment is carried out at given times). In a system with a high stability margin and operating well in the stable region, an additional user will have little effect on voltage stability. However, when a system is approaching its limits, additional active power can push the system towards the critical point and at risk of voltage collapse. This would tend to support a congestible CPR classification.



Figure 8: Voltage stability margins



Source: authors

Whether a congestible CPR characterization is more appropriate than a standard public good approach depends on the congestion in the system, the homogeneity of users and whether there is a risk of depletion and overuse if the rivalry aspects are not recognized. This suggests that the classification of voltage products as a congestible CPR may be more applicable in some situations (such as DER in weak networks) and less so in others (such as a transmission grid with high diversity of users).

Fault levels and system strength

There are certain aspects of system strength that can also be usefully thought of as congestible CPRs. Synchronous fault levels, for example, demonstrate rivalry characteristics as the network becomes increasingly congested, supporting a characterization as a congestible CPR. In this situation, we can clearly define a user of a product as non-synchronous. A synchronous resource would be a provider of the product by virtue of its inherent fault-current response characteristic.

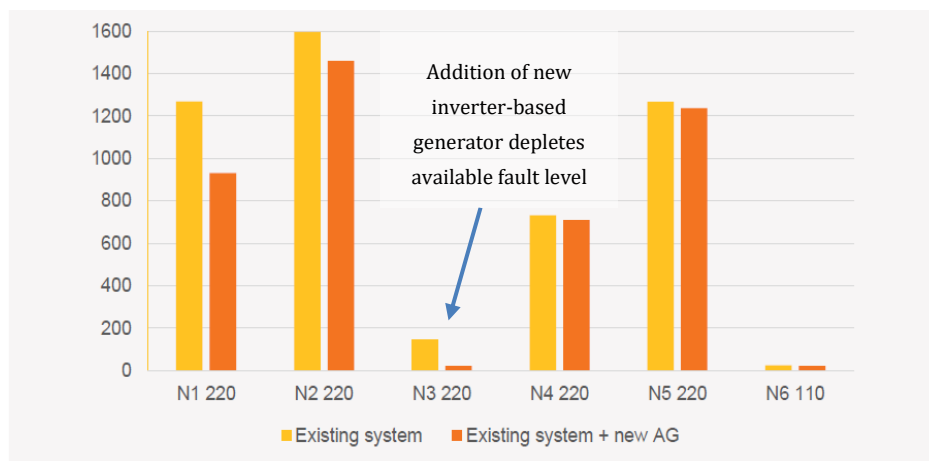
In order to ensure that voltages are stable in response to faults, there needs to be sufficient fault-level contributions from synchronous resources to every node in the network. The available fault level (AFL) methodology set out in (CIGRE, 2016) characterizes a synchronous resource as a source of fault level, and non-synchronous resources (such as first-generation IBRs) as a sink for fault levels. It is important to note that available fault levels at a particular node are affected not just by the resources at the node, but by resources in the surrounding area as well (based on their electrical distance from the node).



When there are high available fault levels at nodes in a region, the addition of a new IBR user (fault level sinks) would have little effect as the system is strong and resilient to faults. However, as IBR penetration grows, available fault levels would continue to deplete and, at some point, the addition of a new user could push the level beyond the threshold required for stability (Figure 9).

An example is provided in AEMO (2018), illustrating that adding a new inverter-based generator in the Tasmanian network would deplete available fault levels at particular nodes (such as N3). For other nodes, however, there are still excess fault levels, and this addition would not cause a concern (such as N4, N5). This suggests that fault levels are increasingly rival where the network is congested and supports the treatment of this system service as a congestible CPR.

Figure 9: Depletion of fault levels through the addition of new inverter based generator



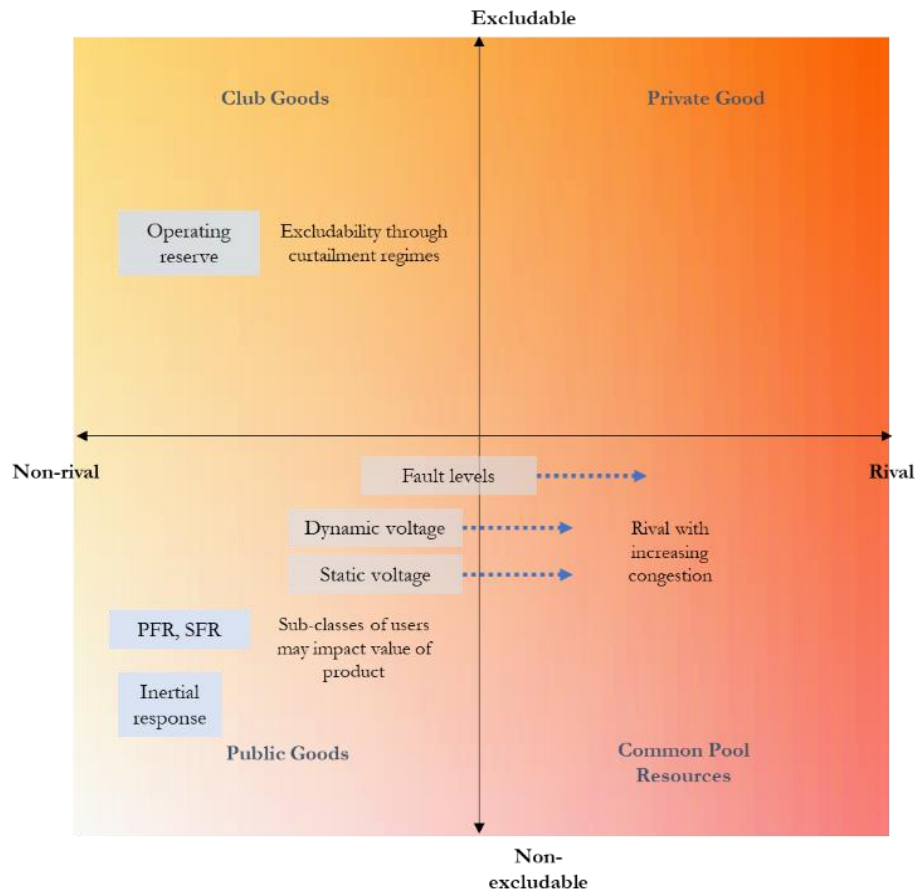
Source: AEMO (2018)

The 'basket of goods' for system security

As the analysis above shows, while traditional analyses of system security parameters have tended to adopt a broad 'public goods' characterisation, a detailed analysis of the system service products underpinning the delivery of a secure system is in actuality a **basket of goods** with differing characteristics (Figure 10). Some services, such as inertia and frequency response, may be considered to have limited rivalry and strong public good characteristics, though subsets of users could still affect the quality of service. Operating reserves (or tertiary frequency response) may have similar non-rival characteristics but may be excludable with curtailment schemes – implying potentially a club good classification. Other products, such as fault levels and voltage products, may have more direct rivalry qualities, especially when approaching congestion points – supporting a classification as a congestible CPR. These characteristics may also change over time, given technology changes and a practical appreciation of what constitutes the 'marginal user'. This multiplicity of economic characteristics has important implications for market design, as we shall outline in Section 3.4.



Figure 10: Spectrum of classifications of system security products



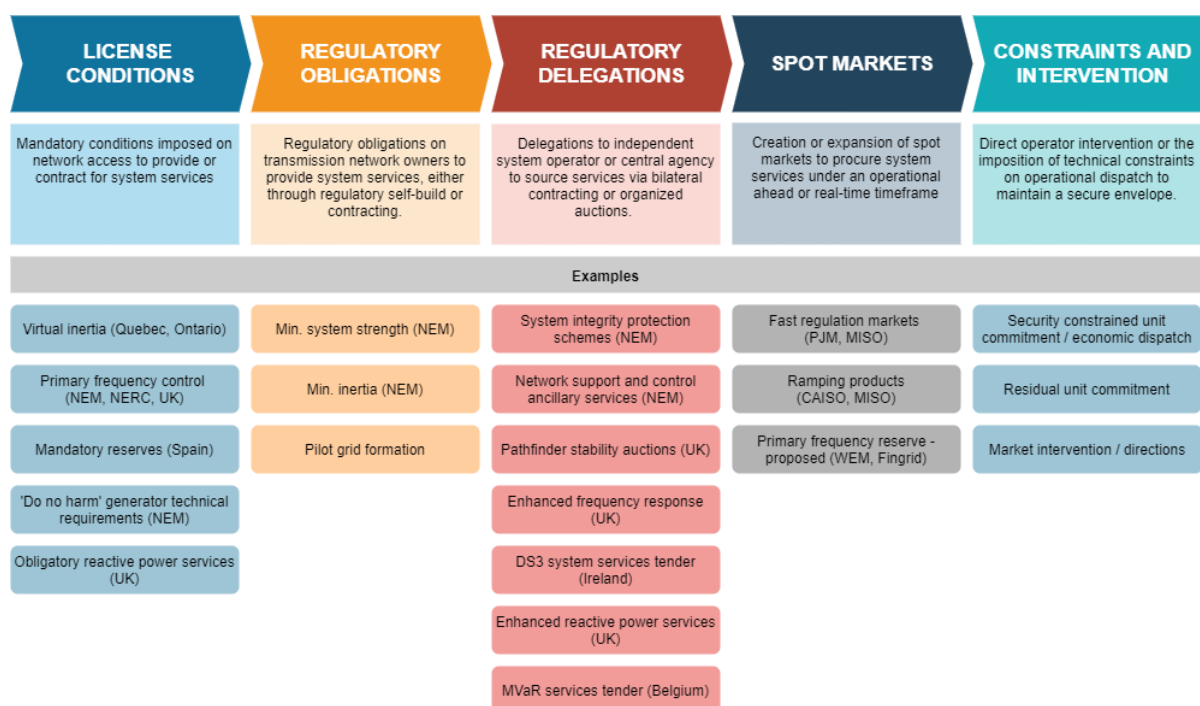
Source: authors

3.3 Developments in regulation and market design

On a global level, there is an increased recognition of the importance of operational security in a decarbonized grid. Work has been progressing over a number of years to identify and quantify the technical scarcities that have emerged (EU-Sysflex, 2019; Milano et al., 2018). Given the complexity underpinning the management and control of operational security, a combination of market-based instruments (MBIs) and non-market-based instruments (NMBIs) have been adopted to govern and manage emerging power system security issues. These include, as per Figure 11: (1) the imposition of **mandatory license conditions** on network access; (2) **regulatory obligations**, imposed upon regulated network utilities – procured either through self-build into the regulated asset base or, in some cases, contracting; (3) **regulatory delegations** imposed on independent system operators (ISOs), government agencies or other regulatory institutions to source and procure system services through bilateral contracting or centralized auctions/tenders; (4) the creation, expansion or modification of **spot markets** to procure system services, or to obtain additional operational flexibility to manage scarcities; and (5) the imposition of **operational constraints** and **market interventions** upon merit-order dispatch.



Figure 11: Market and non-market mechanisms for system services



Source: authors, compiled from EU-Sysflex (2019); Rebours et al. (2007); Zhou et al. (2016)

3.4 Implications of classification for market design

Our analysis in Section 3.2 above illustrates the complex and diverse nature of property rights that the different security products exhibit within the power system. This makes the job of creating a cohesive procurement framework for system services complex and intricate. We highlight some important considerations for designing frameworks based on the analysis above.

3.4.1 Inseparability of certain system security goods

Complex situations arise where products have different characterizations but are inseparable. This can commonly occur for inherent response products. For example, the provision of inertia and fault level by a synchronous generator are inseparable. It is not possible to deliver inertia without delivering fault level, and vice versa. However, inertia and fault levels can have different economic characterizations. While inertia can be classified as a public good, fault levels have congestible CPR aspects to them. It would also mean that how one good is procured affects the other, especially where responsibility for procurement is disparate. For example, in a CPR, users have incentives to deplete the resource. This is relevant not just for the CPR, but also any inseparable public goods. The 'tragedy of the commons' in fault levels should thus be considered for any procurement of synchronous inertia. In these situations, it may be relevant to consider whether the characteristics and configuration of the grid mean that one security phenomenon dominates or is more critical than the other.

3.4.2 Integration of access frameworks and market design

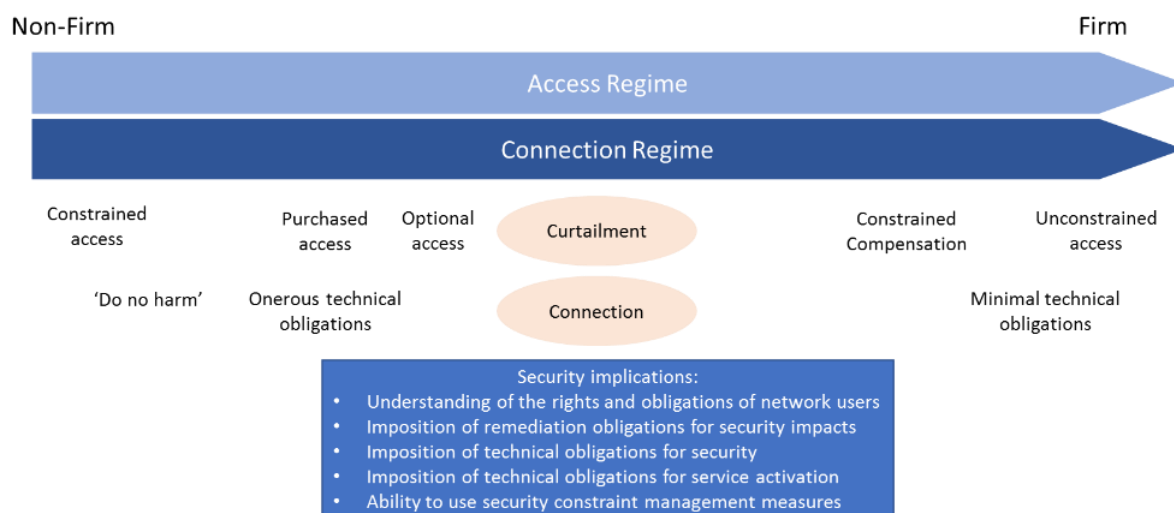
The regime of rights to connect to and access the network is directly relevant to how aspects of security can be treated. Access regimes range on a spectrum from firm to open (non-firm) access (see Figure 12). Firm regimes provide generators with stronger rights to connect to the network and to be dispatched (subject to merit-order). They may receive compensation if these rights are curtailed, for example



constrained-on or constrained-off payments if they are constrained.¹⁵ Non-firm arrangements provide constrained rights of access and dispatch, and the impacts of curtailment are borne by the resources themselves. Within this spectrum, there are also variants such as optional firm access, which may give participants choice to pay for different levels of network access or financial hedging of network risk.

Applying constraints upon system resources is an important tool in managing many aspects of security, including voltage, dynamic stability and system strength. A less firm regime would give an operator more leeway to constrain generators for system security, because the property right does not guarantee firm dispatch. Operators can still apply constraints in firmer access regimes but may be limited in the extent of the constraint, and the need to provide compensation. This may suggest that in firmer access regimes, the constraints are better viewed as an economic good given the nature of the property right. See for example congestion management products in the UK (National Grid, 2020b).

Figure 12: Spectrum of access regimes



Source: authors

3.4.3 Understanding the incentives for investment

Connection regimes also determine the obligations of a resource in respect of connecting to a system. What are the obligations of a connection-seeking generator that would harm system security in an area on its connection? Certain jurisdictions have 'do no harm' regimes that require such resources to incorporate measures to remediate any harm before being permitted to connect (AEMC, 2018). These 'do no harm' provisions have the effect of mitigating the rival aspects in a CPR regime (for example, removing the fault-level contribution rivalry) and have two major implications.

First, within the CPR they create the incentive for investment by users themselves. As network access is linked to the security impacts of the connection, new projects may decide to remediate the adverse impacts of its connection through additional investment in assets, equipment and control schemes. For example, many renewable projects in the NEM have installed synchronous condensers in order to secure network connections (Gu et al., 2019a; O'Reilly, 2019). While this is positive in that it generates investment, it does not guarantee that such investment is system optimal. Each generator would only

¹⁵ Constrained-on or constrained-off payments are paid to compensate the generator for revenue that it may otherwise have been able to make in the electricity market but has been constrained for an operational security reason. If the generator reduced output when the electricity price was above its offer price, it receives a constrained-off payment. On the other hand, if the generator increased output when the energy price was below its offer price, it receives a constrained-on payment.



consider the minimum investment required to secure access. More efficient alternatives, for example through better siting or sizing of synchronous condensers, cannot be realized through assessing generator access applications individually. However, while better co-operation between projects may allow for more efficient investment, holdout and competitive issues may limit this (Ostrom, 1990). There is thus a rationale for the establishment of platforms that facilitate better co-ordination and collective action (Steins and Edwards, 1999). Certain aspects of system security that are inherently local (for example, aspects of voltage control and system strength) may lend themselves well to platform arrangement-making under certain conditions.

Second, by dampening the rivalry aspects, CPR goods can be treated more like public goods. This allows any residual procurement of these goods to be managed through existing market-based or non-market-based instruments to source public goods. This also means that goods that were inseparable but had different degrees of rivalry (such as fault levels and inertia) could be treated together. This may also create the case for the procurement of 'super-products' – where multiple products can be clubbed and procured together, an example of which is the recent Stability Pathfinder procurement by National Grid of a synchronous product comprising inertia and fault level (National Grid, 2019).

In the absence of rivalry, there are also questions as to whether short-term markets for public goods can create efficient investment signals on their own. Long-term hedging and contracting incentives are important for investment. While a short-term service spot market provides scarcity pricing signals, in the absence of rivalry it does not create any incentive for participants to hedge (Pollitt and Anaya, 2019). Hence investment is reliant upon a volatile revenue stream, which may be more difficult to justify for a long-duration asset. This approach may be practically justifiable where services are 'ancillary' and represent a top-up to generators' existing energy revenue base. However, it may not be justifiable in a dynamic where the investment case for new assets is heavily reliant upon 'system service' revenues. In those situations, a paired long-term 'public' procurement framework may be required as a complement to short-term markets. This could be implemented on a centralized or on a decentralized basis.

4. Emerging design models for operational security

In this section we highlight the implications of system service characterization on viable models of market design for system services. Both centralized models and decentralized models for system services are reviewed, including: (1) comprehensive central procurement; (2) decentralized procurement via cost or quantity allocation; and (3) decentralized access-driven procurement. In addition, two hybrid extensions are also assessed: (4) hybrid decentralized/centralized procurement; and (5) decentralized procurement with facilitated co-ordination. Key elements of each model are summarized in Table 3. While this paper provides high-level commentary on generalized design models, we recognize that underlying each of these models are a set of granular design specifications and requirements. A detailed design review of these specifications and integration with the design of system balancing and resource adequacy frameworks is an area for future research.



Table 3: Summary of system service procurement models

	Central procurement	Decentralized procurement via cost/quantity allocation	Decentralized procurement via network access	Hybrid centralized-decentralized procurement	Decentralized procurement with facilitated co-ordination
Design	Centralized	Decentralized	Decentralized	Hybrid	Hybrid
Quantification of services	Central	Central	Central with connecting resource	Central with connecting resource	Local platform
Procurement responsibility	Central agency	Market participants	Connecting resources	Connecting resources and central agency	Connecting resources
Character of goods	Public	Public	CPR	CPR	Complex CPR
Renewable objectives	System-wide integration policies	System-wide integration policies	Limited to none	Minimum levels	Strategic regional objectives
Access frameworks	Firmer access	Firmer access	Constrained access (do no harm)	Constrained access (do no harm)	Mixed
Operational scheduling/dispatch	Unconstrained or constraint compensation	Unconstrained or constraint compensation	Constrained dispatch	Constrained dispatch	Constrained dispatch
Procurement – long term	Central mechanism	Decentralized procurement via cost or quantity allocation	Individual connecting resource	Individual connecting resource with public procurement	Regional co-ordinated procurement
Examples	EirGrid DS3, National Grid UK	US markets – certain aspects	NEM	NEM	REZs in NEM/ERCOT

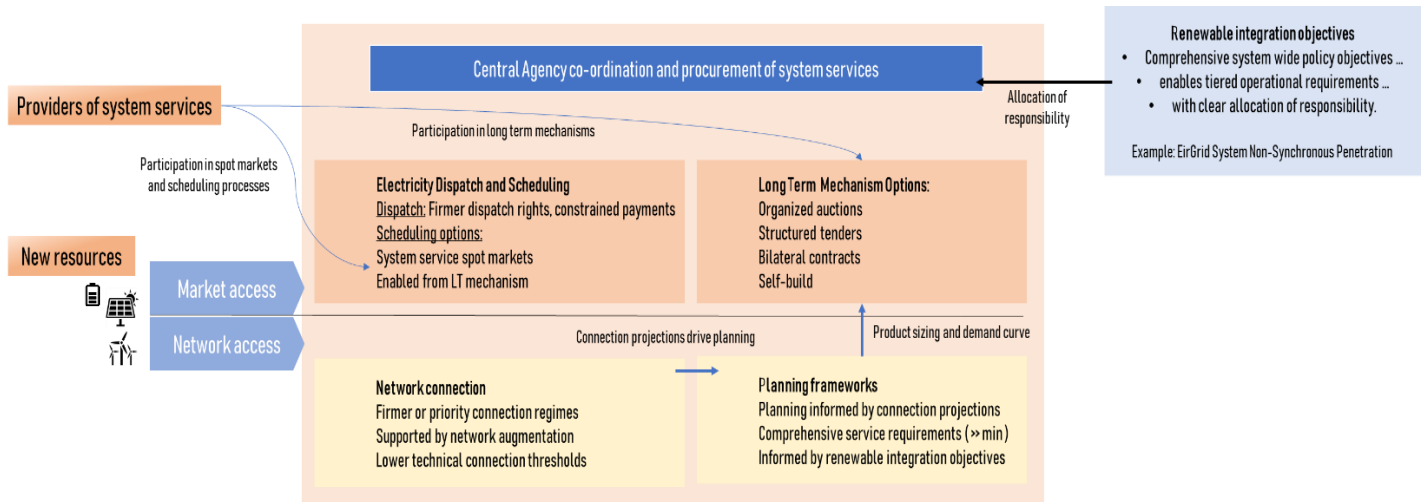
Source: authors

4.1 Comprehensive central procurement (CP model)

In this model, centralized procurement is the predominant approach to the procurement for system services (see Figure 13). The obligations for procuring the range of system services are placed upon one or more central agencies with responsibility for managing security across the power system. These agencies then procure system services on both a short-term and long-term basis.



Figure 13: Central procurement (CP model)



Source: authors

Procurement responsibility: Responsibility for procuring system services is delegated to a central agency with system-wide security obligations. Delegations to multiple central parties may also be possible under this model, but boundary issues would need to be considered. In this vein, incentive compatibility is critical. How is the central agency motivated to make cost-effective and efficient decisions around procurement, on cost, quantity and quality of products procured? How does the model guard against over-procurement of products? An ISO, while independent, has limited direct pecuniary incentives (Billimoria and Poudineh, 2019). On the other hand, a regulated network has asset-based revenue incentives for self-build that may conflict with other procurement options (such as contracts). Procurement responsibility should be complemented by performance measurement/monitoring regimes, and performance incentives (penalties and rewards) supporting socially optimal decision-making (Joskow, 2008a).

Dominant service characterization: This approach is well suited to power systems where the relevant scarcities in system security relate to goods that are predominantly of a 'public good' nature. For example, in meshed networks with system-wide scarcities such as inertia. CPR system services could also be incorporated (but are less suited), with the implication being that the system will absorb the cost of 'harm' caused by rivalrous extension. Access frameworks and renewable integration objectives should support this.

Procurement mechanisms – operational scheduling and dispatch: Multiple options are available. Economic products may be created with spot markets providing scarcity price signals. Alternatively, the system operator may choose to commit specific resources out of merit order, under uplift or other compensation frameworks. Services could be scheduled operationally, based on the terms of long-term mechanisms and contracts.

Procurement mechanisms – long-term mechanisms: As outlined in Section 3.4, spot markets on their own may not be sufficient to support investment in 'public good' system services, and require long-term mechanisms (Pollitt and Anaya, 2019). Long-term procurement by the responsible central agency could be in the form of self-build (via a regulated monopoly), contracting or via organized auctions. Given the multiplicity of system service providers and offerings, the justification for exclusive regulated monopoly is not immediately apparent. Existing regulated networks could, however, tender to provide services as part of a centralized auction. One of the benefits of this model is its ready acceptance of inseparable goods under a contracting or tender framework (National Grid, 2019). This would allow



contracting with resources that provide both inertia and system strength contributions, for example. Procurement would, however, need to be responsive to market shifts, and thus medium-term options should also supplement the long-term mechanism.

Planning frameworks and renewable integration objectives: Central decision-making is guided by system-wide renewable integration policy objectives, such as the System Non-Synchronous Penetration (SNSP) objective in Ireland (Eirgrid and SONI, 2018), which is able then to inform more granular operational requirements. Integration objectives that are framed across multiple horizons provide a policy pathway, enable long-term decision making by the central agency and support long-term investment by industry. There is an underlying principle (either explicit or implied) in this model that enabling this type of generation is socially beneficial. In the absence of this principle, an operator could always achieve system security by curtailing dispatch for non-synchronous generation or limiting its network access. To date, non-synchronous technology has been mainly applied to lower-carbon forms of generation – such as wind and solar.

Access and dispatch frameworks: Access regimes for network connection and dispatch would support these system-wide objectives, by providing firmer access and dispatch rights for non-synchronous and variable renewables. Firmer dispatch could be enabled through priority scheduling, or constrained payments. While there are still technical standards governing network access, additional capabilities beyond minimum technical requirements would be treated as the provision of a service rather than part of the grid connection. Contrast the specification of post-fault active power recovery and dynamic reactive power capabilities as a DS3 service in Ireland with ‘do no harm’ technical standards for the same in the NEM. This model is also possible in an access regime that is less firm; however, the public agency would need to appropriately weigh trade-offs between constraining resources and procuring services, for both short-term and long-term mechanisms. Conflicts between renewable integration objectives and constrained dispatch would also need to be resolved, especially if security requirements based on operating reserves and inertia constraints may lead to renewable curtailment, even under a co-optimised dispatch environment (Mancarella et al., 2017).

Quantification of system services: Central agencies would size the quantity of system services. Firmer access rights drive system augmentation in a planning context, which then allow the central agency to size product requirements and create a demand curve. Renewable integration objectives would support the central agent moving beyond ‘minimum’ levels of procurement, to source a comprehensive range and quantity of services and allow industry to develop scalable business models around these objectives. The quantification process needs to be responsive to market and connection trends, which may be practically difficult. Auctions or other co-ordinated market platforms could be used to allow more transparent pricing of services.

Price formation and cost allocation: Short-term price formation in spot markets, possible though the binary nature of certain services, would need to be dealt with. Long-term price formation could be guided by contractual revenue streams that reflect cost structures. However, the central nature of procurement would imply a ‘one-sided’ market (Rebours et al., 2007). Given centralized procurement, this model does not rely upon cost allocation to incentivize provision of system services.

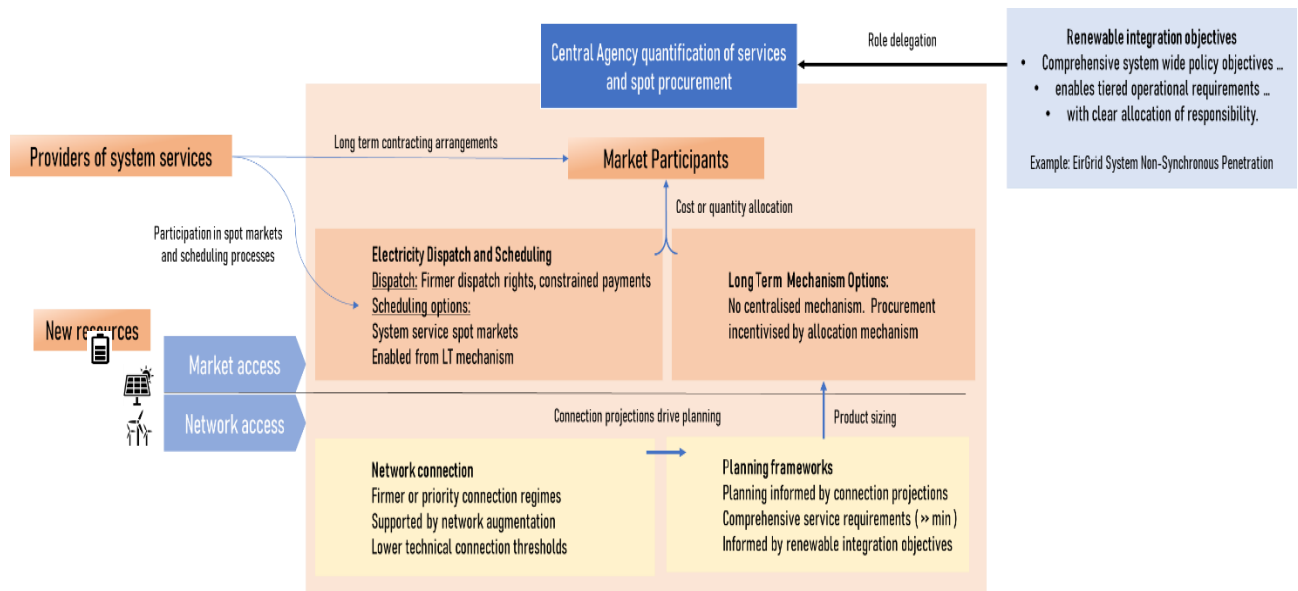
Examples: Examples of this model include the EirGrid DS3 System Services programme in Ireland, and the sourcing and procurement of system services by National Grid in the UK (see Eirgrid and SONI, 2018; National Grid, 2020b for further details).

4.2 Decentralized procurement via cost or quantity allocation (DP-CQ model)

This model shares many characteristics with the CP model, including centralized planning and firmer access regimes. The key difference is that instead of a central agency being responsible for procurement, it is decentralized and delegated to market participants through cost or quantity allocations (Figure 14).



Figure 14: Decentralized procurement via cost or quantity allocation (DP-CQ model)



Source: authors

Procurement responsibility: Responsibility for procuring system services is delegated to market participants through cost or quantity allocations. Quantity allocations (analogous to reliability obligation schemes) impose obligations upon market participants (it could be retailers, generators or both) to procure a certain minimum quantity of services (for example, a retailer could be required to procure the availability of a certain quantity of inertia, concomitant with their load). The participant would then decide how to procure those services. By contrast, the design could rely upon the allocation of the costs of system services upon market participants to drive procurement. A market participant would be incentivized to enter into longer-term contracts with system service providers to hedge or offset these costs. The methodology could be based on 'causer-pays' or 'beneficiary-pays' or be smeared more generally across participants. Whichever approach is adopted, mechanisms that are simple, clear and transparent are more conducive to enabling risk transfer, contractual liquidity and market depth.

Dominant service characterization: As with the CP model, this approach is also better suited to system-wide public goods. More locational services could also be incorporated, but this may increase the complexity of allocation frameworks.

Procurement mechanisms – operational scheduling and dispatch: For models that rely on cost allocation, short-term mechanisms to procure system services would be required with some framework for payment or compensation for resources required to be enabled for these services (though a market framework itself is not mandatory). These costs of spot procurement would then be allocated to market participants. Quantity allocation processes do not rely upon spot prices for allocation, though can co-exist with them.

Procurement mechanisms – long-term mechanisms: Cost allocation frameworks rely upon the allocation of short-term costs to indirectly drive long-term procurement. Participants seeking to hedge their cost exposures would contract with service providers or self-build. Quantity allocation frameworks would more directly incentivize long-term procurement, by obligating participants to procure a certain quantity of services much like a capacity obligation mechanism. The design would also have to set out the implications of the failure to procure the required quantities, and a central procurement may still be required as a backstop, in the event that insufficient quantities are procured in the decentralized process.



Planning frameworks and renewable integration objectives: As with CP, a central planning process would guide granular system requirements, supported by system-wide renewable integration policy objectives.

Access and dispatch frameworks: As per the CP model.

Quantification of system services: While procurement is decentralized, central agencies would continue to have a role in the quantification of system services. In cost allocation mechanisms, the central agency would determine the quantity of services to be procured in the spot, and an allocation methodology for those costs across market participants. For quantity allocation mechanisms, the central agency would (in addition to spot procurement) determine the total quantities that need to be procured by market participants in the long-term mechanism, with an allocation framework to then determine how much each participant is responsible for.

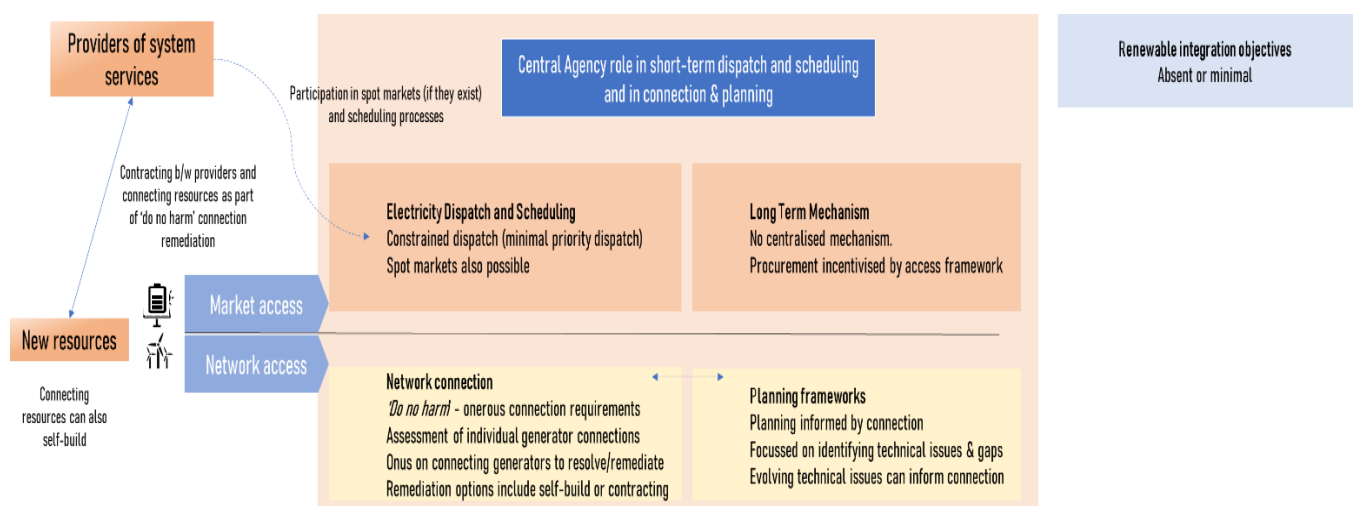
Price formation and cost allocation: Cost allocation requires some form of pricing or costing for short-term procurement of services. Long-term price formation would be guided by price risk in short-term markets. Quantity allocation requires long-term price formation guided by the long-run marginal cost of system service resources, in a similar manner to resource adequacy capacity mechanisms (Joskow, 2008b).

Examples: Elements of this model are common in US markets such as ERCOT, which seek to allocate the cost of ancillary services to market participants. Market participants are then incentivized to contract for the relevant services in ahead timeframes.

4.3 Decentralized access-driven procurement (DP-A model)

This model incentivizes decentralized procurement through network access regimes. It relies upon a more stringent connection and access process that requires participants to mitigate or eliminate the system security risks of their connection (Figure 15).

Figure 15: Decentralized access-driven procurement (DP-A model)



Source: authors

Procurement responsibility: The procurement responsibility in this model is housed in generators or resources that are seeking connect to the network. Generators that do not mitigate the adverse security impacts of their connection.



Dominant service characterization: Relative to other models, this model tends to support power system configurations where scarcities are emerging in system services that are akin to common pool resources with strong rivalry characteristics. For example, power systems with long-string or parallel topologies (and with large electrical distances between power system resources and loads) that are subject to locational system strength or voltage stability issues. The rivalry effect creates the impetus for a decentralized approach to system service procurement.

Procurement mechanisms – operational scheduling and dispatch: This model works best in a framework of security-constrained dispatch. In other words, energy dispatch is subject to operational constraints, and there are no payments for being constrained on or off. This model is also consistent with the establishment of spot markets for system services, but co-optimized with generator dispatch (Badesa et al., 2020; Püschel-Lovengreen and Mancarella, 2018).

Procurement mechanisms – long-term mechanisms: There is no formal long-term mechanism. This model relies upon the network connection process to drive the necessary contracting and/or investment.

Planning frameworks and renewable integration objectives: In these regimes, renewable priority is not common, and legislated system-wide renewable integration objectives are absent or minimal. The underlying principle is one of security-constrained access and dispatch, and there is no established regulatory objective for higher levels of renewable generation. Environmental or renewable energy objectives would be dealt with outside of electricity market design. While there is still a central planning process, this process serves as a guide to other institutions (such as networks) and is based on an estimate of generator connections and retirements.

Access and dispatch frameworks: The network connection and access regime for new generators is underpinned by a principle of 'do no harm', which requires the generator to remediate any adverse impacts of connecting the resources. This translates into stringent requirements around the provision of frequency control, voltage control and system strength (AEMO, 2018). Remediation of adverse impacts necessitates either self-investment in additional assets, equipment or capabilities (such as synchronous condensers, grid forming inverters subject to technical viability), along with operational measures (such as appropriate control system tuning) or contracting with other providers of the service. The latter could take the form of contracts with nearby synchronous generation to access system strength. On a practical level, the mechanism would need to ensure that the synchronous generator is online in either generator or synchronous condenser mode when the new asynchronous generator is generating. One of the concerns is the potential for inefficient investment in the absence of co-ordination between new connecting generators (as previously highlighted in Section 3.4). Furthermore, in the case of security phenomena that are emerging and not fully understood, there is a risk that the connections process does not anticipate the totality of the impacts upon security. This may leave the system vulnerable to unanticipated conditions without any means of remediation. To mitigate this challenge, hybrid regimes (as described below) establish backstop centralized mechanisms to deal with unanticipated security impacts. Alternatively, the ISO could just constrain those resources down until issues are resolved. This, however, could be seen as harsh given that the generator has already been granted network access, and may dampen the impetus for new investment.

Quantification of system services: The quantification of system services required for the connecting generator is negotiated as part of the network connections process and supported by a centralized planning process. Parties wishing to connect would agree requirements with the system operator or planner, based on the technical characteristics of the connection and their expected adverse impacts on system security. These impacts would be informed by technical modelling exercises.

Price formation and cost allocation: This model can co-exist with short-term price formation in spot markets. This model does not rely upon cost-allocation to incentivize provision.

Examples: Elements of this model are consistent with the NEM's do no harm regime, though the NEM's current design is more akin to a hybrid model (outlined in Section 4.4.1).

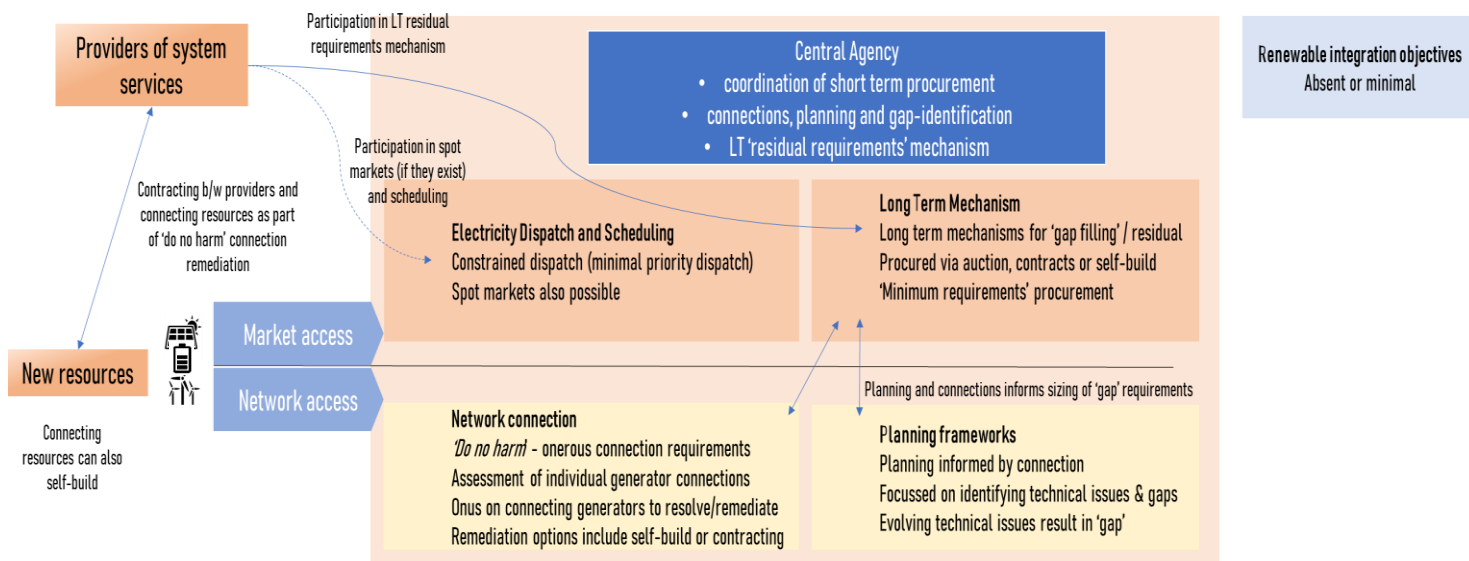


4.4 Hybrid arrangements

4.4.1 Hybrid decentralized/centralized procurement (HD-C model)

This model works as an extension to the DP-A model (see 4.3) seeking to mitigate the risk of inadequate access-driven procurement and investment. This model adopts a hybrid of public and CPR models to deliver system security (Figure 16). In this model, CPR goods are regulated through strong constrained access regimes, while public procurement is utilized to provide residual services and to fill gaps.

Figure 16: Hybrid decentralized/centralized procurement (HD-C model)



Source: authors

Procurement responsibility: Under this model, the responsibilities and obligations for procuring system security services is split between new connecting generators and central agencies. Connecting generators have the same responsibility as the DP-A model. The central agency is responsible for (1) procuring services that are unable/unlikely to be procured through access frameworks and (2) residual procurement of services for security conditions that were not anticipated in connection processes. These responsibilities may be split across multiple central agencies. For example, currently in the NEM, the procurement of system services is split across the ISO and network operators.

Dominant service characterization: This model caters for goods with a variety of characteristics. CPR-type goods could be dealt with in access frameworks, while public goods are supported through the centralized procurement process.

Procurement mechanisms – operational scheduling and dispatch: Central operators are charged with the responsibility for the scheduling of required services in operational timeframes, either with or without formal spot markets for those services. In the absence of a spot market, a unit commitment with side-payments would seek to ensure that the right mix of resources are online. As per DP-A model, constrained dispatch would apply.

Procurement mechanisms – long-term mechanisms: There is a formal centralized mechanism for the procurement of (1) residual quantities of system services that were not procured as part of connection access (for example, if unanticipated system strength issues emerged after network connections) and (2) system services with public good characteristics. Formal approaches could involve contracting, organized auctions or regulated self-build. Agencies that are subject to asset-based economic regulation may be naturally incentivized towards asset buildout, though this could be



balanced by regulatory performance incentives schemes. Regulations could also mandate specific procurement mechanisms (for example, requiring network owners to contract rather than self-build).

Planning frameworks and renewable integration objectives: As per the DP-A model, this model is suited to regimes with limited formal renewable integration objectives. Planning process would aid the quantification of residual system services procurement.

Access and dispatch frameworks: As per the DP-A model, network access is underpinned by a principle of 'do no harm' with procurement of rival CPR goods driven by the need to remediate adverse security impacts. As with DP-A, there is a risk that the connection process does not capture all system security impacts, but this would then be dealt with by a centralized procurement process.

Quantification of system services: The quantification of residual amounts is based on a planning process, which aims to identify 'gaps' in provision. Once a gap is identified, a central agency is responsible for procuring that quantity. Gap identification under such a scenario is an inherently complex issue as it requires the central planner to estimate synchronous generation commitment and retirement. In a market where generator entry and exit are unregulated, this could complicate the quantification exercise. The absence of renewable grid integration objectives also limits the quantities to the 'minimum amounts' required to meet gaps. Conflicts between the timeframes involved may also arise. For example, the timeline for the assessment of gaps and subsequent procurement or buildout can be quite extended. As an example, the process of gap identification to deployment of synchronous condensers to resolve South Australia system strength/inertia issues is estimated to take three years. By contrast, changes to commercial commitment patterns for synchronous generation can happen very quickly. This may require a more flexible and adaptive planning and quantification process.

Price formation and cost allocation: As per the DP-A model.

Examples: The primary example of this model is the current arrangements in the National Electricity Market of Australia, relating to 'do no harm' network access and minimum system strength and inertia procurement requirements.

4.4.2 Decentralized procurement with facilitated co-ordination (HD-FC model)

One of the questions posed upon a decentralised model of procurement is whether individual obligations to remediate harm results in the most optimal investment. Indeed, there is a risk of un-coordinated or sub optimal (highlighted in Section 4.3) procurement when each individual connection request is treated on its own. The incentives for co-ordination among participants are limited also by the competitive dynamic of the connection queue. The question is therefore whether there are models that improve the optimality of investment by providing for facilitated co-ordination processes and services.

The literature on common pool resources introduces the concept of a 'nested platform', which we consider has applicability to the system security products with complex CPR characteristics. In essence, with the aim of a nested platform is to provide facilitated co-ordination for collective action by participants in the common pool (Figure 17).

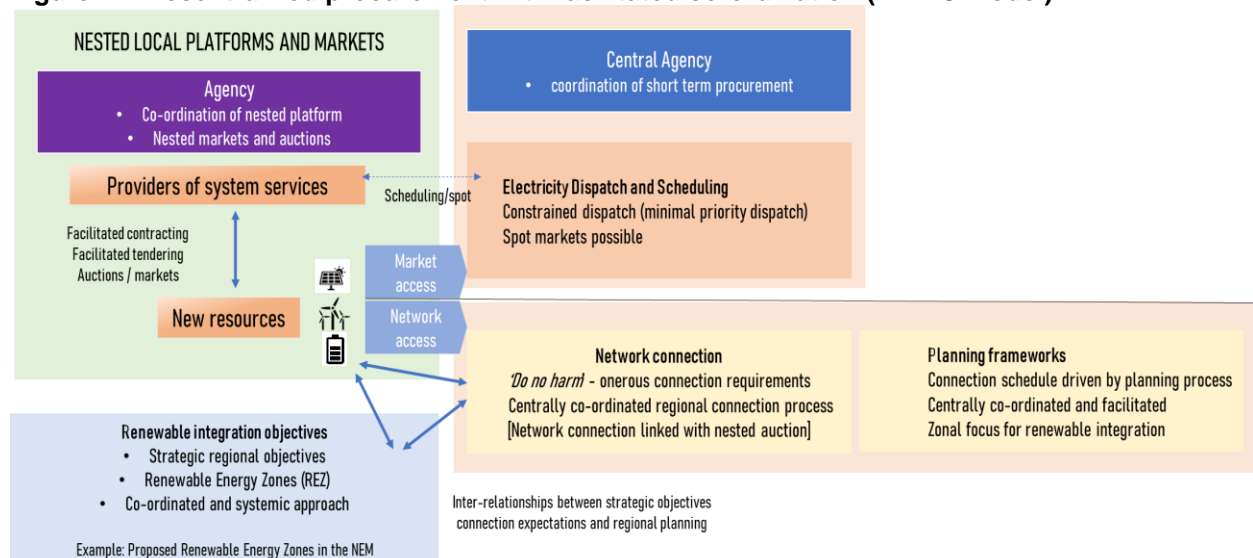


Nested platforms for complex CPRs

Steins and Edwards (1999), define complex, multiple-use CPRs as resources that are used for different types of purposes by different stakeholder groups and managed under a mixture of property rights regimes. The authors proposed the establishment of 'nested platforms' for resource use negotiation to co-ordinate collective action for complex CPRs. Nested platforms are those that operate within higher-level decision-making frameworks. Platforms emerge when stakeholders experience the negative impact of their own and others' use of a resource and become aware of the need for collective action and decision-making. Nested platforms operate within a boundary area where the boundaries are often negotiated, rather than hard delineations. The co-ordination services in nested platforms can extend from common learning and knowledge sharing, local appropriation and provision frameworks (Cox et al., 2010), to the establishment of local nested markets (Ploeg et al., 2012; Polman et al., 2010).

Thus, the idea is that local platforms would be established (where system characteristics allow) to facilitate co-ordination and collective action to manage security issues. These platforms would offer services that include enhanced local planning, aggregated connection access and potentially matching services between connecting resources and system security product providers. This notion also seems to underlie the development of regional renewable energy zone (REZ) frameworks in the Electric Reliability Region Council of Texas (ERCOT) and the National Electricity Market of Australia (AEMO, 2020b; Matevosyan and Du, 2017).

Figure 17: Decentralized procurement with facilitated co-ordination (HD-FC model)



Source: authors

Procurement responsibility: The procurement responsibility in this model remains with generators or resources seeking connect to the network. However, a central party would facilitate improved co-ordination between connecting generators and system service providers.

Dominant service characterization: This model supports goods with complex CPR characteristics. That is, CPRs where there are complex and multiple uses and a mixture of property right regimes. An



example of goods where nested platforms may prove useful is system strength – which involves multiple facets and interactions (sometimes countervailing) between generation levels, resource characteristics and grid topologies.

Planning frameworks and renewable integration objectives: Under open-access planning system planners must base plans for network and system augmentation upon forecasts of connection requirements. Connections are also treated on an individual basis, with connection queues based on order of applications application. This model is distinguished by a co-ordinated approach to system planning, connection and system service procurement. This model represents a shift from traditional approaches, where a co-ordinated planning process facilitates connection and procurement of system services. Planning would drive a co-ordinated process of access and system service provision.

Underlying this revised approach, rather than having broad-brush renewable policy targets, system planners and governments would approach renewable integration policy on a more strategic basis. This would involve greater focus upon regional characteristics that would naturally lend themselves to renewable energy deployment – in other words, renewable energy zones. This would then involve a public-private partnership (PPP) between central agencies and the regional industry consortium to co-ordinate and facilitate integration in those regions. The PPP would appoint a regional platform co-ordinator (delegated either to existing institutions or new) to implement the strategy.

Access and dispatch frameworks: As with the DP-A model, strong ‘do no harm’ generator technical standards could apply to new connections but this model could also work in the context of firmer connection regimes. Non-firm constrained dispatch would be expected to apply to constrain down generators based on their impacts, as required. This is essential to ensuring that generators that adversely impact security ‘feel the pain’, thus driving the impetus for collective action and co-ordination.

Quantification of system services: Due to the complexity of quantifying the requirements for certain system services (such as system strength), system planners will create a regional integration plan. This planner could be an ISO, or another institution appointed by the industry consortium. This planner would draw upon input from generators or projects intending to connect in the area. However, such intentions could be firmed up by requiring a security deposit or funds that would contribute to planning at the regional level. This would allow the planner to get greater certainty on which projects are ‘serious’. The planner would then establish a framework for minimum technical requirements (which may be in excess of grid requirements) and for the provision of system services. Critical to this would be to understand the treatment of this plan in terms of operational constraints.

Procurement mechanisms – operational scheduling and dispatch: As per the DP-A model. An important facet here is security-constrained dispatch, which would apply to constrain generation to mitigate security impacts.

Procurement mechanisms – long-term mechanisms: Informed by the regional planning exercise, the platform co-ordinator would then create a procurement framework. The long-term mechanism would take the form of an auction with bids for access rights from connecting generators and offers of supply of system services from providers. Depending on technical capabilities, participant projects may both bid to connect and offer to supply. The platform co-ordinator would specify technical requirements and facilitate the auction, including the specification of acceptable bids and offers. A range of technical pre-approvals would need to be undertaken prior to the auction, which would ensure that only serious and technically viable projects participate in the auction. It would also encourage simultaneous co-ordination of land acquisition, planning approvals and financing. Auctions could be undertaken on a forward basis to provide construction and implementation lead time. Such a system could be adapted from natural extensions to financial transmission rights (FTRs) in markets with locational marginal pricing (LMP). The auctions could be run on a periodic basis to enable future new entrants and reflect changes to existing connection plans, as well as allow new technical services as they develop.



Price formation and cost allocation: Short-term price formation could continue to apply as per DP-A models. However, long-term price formation could consider the regional benefits of opening up regional energy zones for development. As part of this, the platform could also establish the allocation of these societal costs to future new entrants in the zone.

Examples: There are elements of this model that align with proposed renewable energy zone (REZ) co-ordination in the NEM, as well as strategic transmission augmentation for competitive renewable energy zones (CREZ) in ERCOT (AEMO, 2020b; Matevosyan and Du, 2017). A practical example of regional co-ordination is the resolution of voltage stability issues emerging from a group of renewable facilities in Western Victoria in the NEM. Facing their generation being constrained down, the consortia co-ordinated, together with the ISO and equipment manufacturers, to develop a technical solution that resolved the issue (Filatoff, 2020). Nested platforms could provide and expand the co-ordination area while respecting the specific technical issues emerging in each region of the grid.

5. Summary and conclusions

Operational security relates to the ability of the power system to remain stable in the event of disturbances. The growth of renewables, such as solar and wind, in the generation mix has resulted in an increased recognition of the importance of operational security in future decarbonized electricity grids. On the one hand, the intermittency inherent in renewable resources can impact on key power system parameters such as frequency and voltage. On the other hand, renewables interface with the grid through power electronics rather than turbines, which means characteristics of turbine generation that have historically supported the stability of the grid are becoming scarce. Therefore, the electricity market and regulatory frameworks need to adapt to cater for the system security requirements of future decarbonized grids.

While traditionally system security parameters such as voltage and frequency are characterized as public goods, a detailed analysis of the system service products show that it is a basket of goods with differing characteristics. Some services, such as inertia and frequency response, may be considered to have limited rivalry and strong public good characteristics, though subsets of users could still affect the quality of service. Operating reserves (or tertiary frequency response) may have similar rivalry characteristics but may be excludable with curtailment schemes – implying a club good classification. Other products, such as fault levels and voltage products, may have more direct rivalry qualities, especially when approaching congestion points – supporting a classification as a congestible common pool resource (CPR). These characteristics may also change over time given technology changes and a practical appreciation of what constitutes the ‘marginal user’. This multiplicity of economic characteristics has important implications for market design.

The diverse nature of property rights that the different security products exhibit within the power system makes the job of creating a cohesive procurement framework for system services complex and intricate. For example, the provision of inertia and fault level by a synchronous generator are inseparable. It is not possible to deliver inertia without delivering fault level, and vice versa. However, inertia and fault levels can have different economic characterizations. This brings up the question of whether the characteristics and configuration of the grid mean that one security phenomenon dominates or is more critical than the other.

Given the complexity underpinning the management and control of operational security, a combination of market-based and non-market-based instruments have been adopted to govern emerging system security issues. These include: mandatory license conditions for network access by generators or other resources; regulatory obligations imposed on regulated networks; regulatory delegations imposed upon independent system operators (ISOs), government agencies or other regulatory institutions to source and procure system services; the creation, expansion or modification of spot markets; and finally the imposition of operational constraints and market interventions upon merit-order dispatch. For example, the regime of rights to connect to and access the network is an important instrument in how aspects of



security can be treated. Access regimes range on a spectrum from firm to open (non-firm) access. Less firm regimes may give an operator more leeway to constrain generators for system security purposes. Connection regimes, on the other hand, determine the obligations of a resource in respect of connecting to a system. Certain jurisdictions have 'do no harm' regimes that require connection-seeking resources to incorporate measures to remediate any harm before being permitted to connect.

Given the characterization of system security products and available instruments, at least five emerging model of market design for system services can be identified (Table 4). These includes: (1) comprehensive central procurement; (2) decentralized procurement via cost or quantity allocation; (3) decentralized access-driven procurement; (4) hybrid decentralized/centralized procurement; and (5) decentralized procurement with facilitated co-ordination.

Centralized procurement (CP) is the predominant approach to the supply of system services. The obligations for procuring the range of system services are placed upon one or more central agencies with responsibility for managing security across the power system. These agencies then procure system services on both a short-term and long-term basis.

Decentralized procurement via cost or quantity allocation shares many characteristics with the CP model, including centralized planning and firmer access regimes. The key difference being that instead of a central agency being responsible for procurement, responsibility for procurement is decentralized and delegated to market participants through cost or quantity allocations.

Table 4: Advantages and disadvantages of system service procurement models

		Advantages	Disadvantages
Central procurement		<ul style="list-style-type: none"> • Consistency with legacy approaches • Singular line of responsibility • Opportunity for co-ordinated whole of system assessment • Caters to level of risk aversion • Transparency of price signals 	<ul style="list-style-type: none"> • Need for incentive alignment of public or quasi-public parties • One-sided competitive tension • Assessment of connection dynamics and trajectory
Decentralised	<i>Cost or quantity allocation</i>	<ul style="list-style-type: none"> • Clear allocations can facilitate contracting • Market driven contracting and investment 	<ul style="list-style-type: none"> • Ability to procure CPRs unclear • Fairness of allocation methodologies
	<i>Network access</i>	<ul style="list-style-type: none"> • Timeliness of procurement • Market driven contracting and investment • Outcomes-linked procurement 	<ul style="list-style-type: none"> • Risk of sub-optimal investment • Lack of local co-ordination • Lack of price transparency • Management of emerging conditions
Hybrid	<i>Centralised-decentralised</i>	<ul style="list-style-type: none"> • Avenue to rectify emerging system conditions • Management of inseparable goods 	<ul style="list-style-type: none"> • Boundaries of responsibility • Dulling of market incentives
	<i>Nested platforms</i>	<ul style="list-style-type: none"> • Opportunity for improved coordination • Facilitation of trade and contracting • Regional planning and assessment 	<ul style="list-style-type: none"> • More complex, and nuanced implementation • Varying needs across locations • Need for geographical delineation

Source: authors



Decentralized access-driven procurement incentivizes decentralized procurement through network access regimes. It relies upon a more stringent connection and access process that requires participants to mitigate or eliminate the system security risks of their connection.

Hybrid decentralized/centralized procurement works as an extension to the previous model, seeking to mitigate the risk of inadequate access-driven procurement and investment. This model adopts a hybrid of public and CPR good models to deliver system security. In this model, CPR goods are regulated through strong constrained access regimes, while public procurement is utilized to provide residual services and to fill gaps.

Finally, decentralized procurement with facilitated co-ordination model seeks to improve the optimality of investment by providing for facilitated co-ordination processes and services through nested platforms. These services include enhanced planning and connection support, matching services and potentially orchestration, co-ordination and clearing of auctions for access.

The management of power system security is increasingly important as we seek to decarbonise the electricity system. Yet, the physical characteristics of security are complex, multifaceted and interactive. A bottom up assessment of the physics delivers important insights on economic characteristics and provides pathways for holistic market and regulatory reform.



6. Appendix A: Examples illustrating the rivalry properties of system security services

We assess the rivalry of a particular system security product (or set of products) by examining the marginal cost of extension – which is the social cost of extending an existing quantity of product to a new user. As per Kaye et al (1995), the social costs S of a set of substitutable system services can be obtained as per (1) as the sum of the system (i) availability cost (A) and (ii) response cost (R) and (iii) outage costs (C). Thus $S = A + R + C$.¹⁶ There are stochastic elements to these costs, as R and C depend upon the type and severity of contingency that occurs.

We break these cost components down further:

- *Availability costs, A can be thought of as the sum of each participant's costs associated with their offered quantity.*
- *Expected response costs, R are the sum of each providers' expected response cost given the occurrence of contingency (the sum of the actual response costs weighted by the probability of the contingency occurring)*
- *Expected system collapse costs, C are the sum of the costs of outage weighted by the probability of an outage*

Given the provision of a particular quantity of the product, the marginal cost of extension MC_E can thus be assessed as the increase in social costs S from the addition of a marginal user.

$MC_E = \Delta S = \Delta A + \Delta R + \Delta C$ given a marginal user addition $\Delta p \Rightarrow MC_E = dS/dp$

6.1 Rivalry properties: Inertia and frequency response

Let us take the case of inertia and frequency response – the characteristics of which can be illustrated by examining the classical swing equation (Kundur, 1994). Assume that a power system, with multiple generators operating at the same frequency, is subject to a loss of generation (or gain in demand) the frequency evolves over time in the following manner (see Figure 18):

Figure 18: Frequency response - swing equation

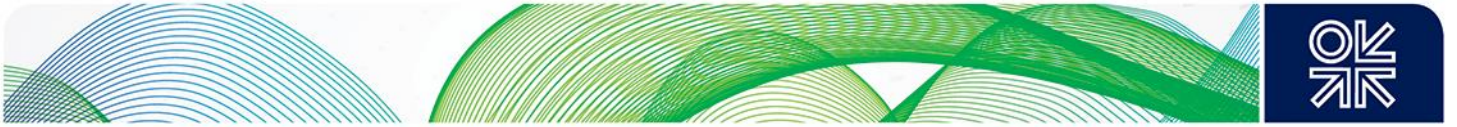
The swing equation:

$$A \quad \frac{\partial f}{\partial t} = [-\Delta P_{LOSS}(t) + \Delta P_{FR}(t) - f \cdot D \cdot P^D] \times \frac{2f_0}{H} \quad (1)$$

B Power lost minus...
 C Power delivered by frequency reserves
 D Power delivered by damping (generation/load)
 E Multiplied by a factor that includes base frequency f_0 and system inertia H

Source: Kundur (1994), Püschel-Lovengreen and Mancarella (2018)

¹⁶ We note that quantifying these probability distributions are inherently complex and is the subject of ongoing research especially given the potential interactions between different products. Hence this paper does not propose to pre-emptively quantify these probabilities, but more to provide a contextual appreciation of the physical-economic interactions in an environment of uncertainty.



In general the rate of change of frequency over time $\frac{\partial f}{\partial t}$ is equal to the active power lost as a result of the disturbance $P_{LOSS}(t)$ minus the power delivered by frequency response $\Delta P_{FR}(t)$, minus the power delivered by damping, either from load or generation ($= f \cdot D \cdot P^D$), divided by the total system inertia (H) and multiplied by 2 times the base frequency (i.e. 50Hz).¹⁷

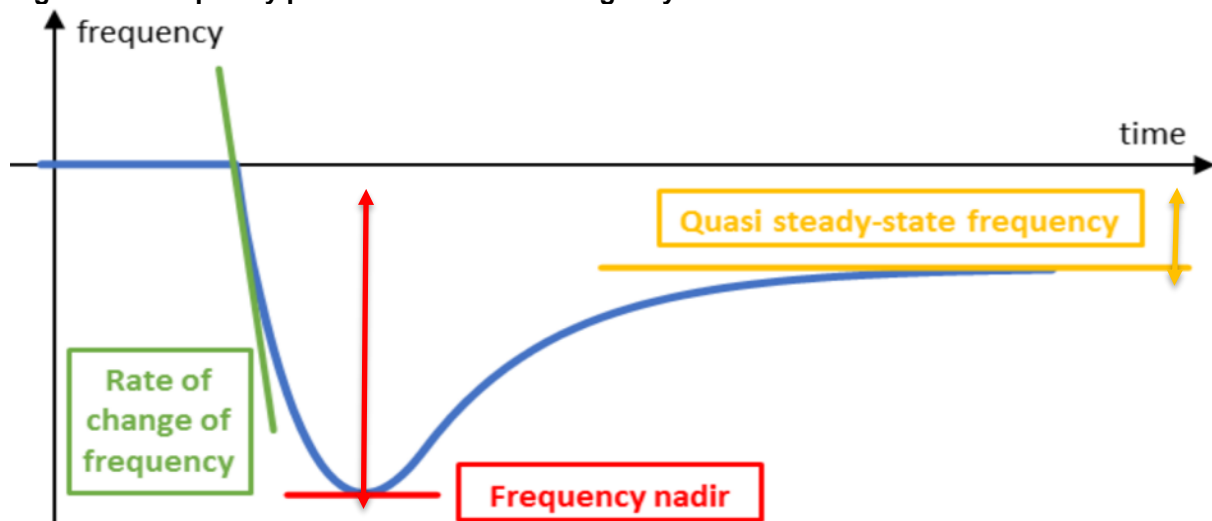
We analyse frequency response from the perspective of two different risks.

- I. *First by examining impacts of large instantaneous contingencies such as the loss of losses of power from a trip of a unit*
- II. *Second the impact of smaller common disturbances in frequency from the mismatches between active power injection and withdrawal.*

With respect to (i) the frequency response of a power system in response to a contingency is broken down into three important parameters (see Figure 19):

- *The initial Rate of Change of Frequency (ROCOF) in response to a frequency event.*
- *The frequency Nadir is the maximum frequency degradation that is reached during the event.*
- *The Quasi steady-state frequency (QSSF) is an acceptable frequency range under normal operating conditions.*

Figure 19: Frequency parameters under contingency



Source: Püschel-Lovengreen and Mancarella (2018)

The equations for these parameters are provided below (Püschel-Lovengreen and Mancarella, 2018), where G is the aggregated primary frequency reserve provision rate (MW/s).

$$ROCOF = \left. \frac{\partial(\Delta f)}{\partial t} \right|_{at t=0} = \frac{\Delta P_{LOSS}}{2 H \times f_0} \quad (2)$$

¹⁷ In this paper we primarily talking about the situation of a frequency decline for simplicity, but the principles here apply to a frequency increase as well (relating to the loss of load rather than generation).



$$Nadir = \frac{\Delta P_{LOSS}}{D.P^D} + \frac{2G.H}{(D.P^D)^2} \ln \left(\frac{2G.H}{D.P^D \Delta P_{LOSS} + 2G.H} \right) \quad (3)$$

$$QSSF = \left. \frac{\partial(\Delta f)}{\partial t} \right|_{at \ t \rightarrow \infty} = \frac{\Delta P_{FR}(t) - \Delta P_{LOSS}}{D.P^D} \quad (4)$$

If the goods are rival, then there will be a social cost to extending the inertia and frequency response services to a new user. We make the assumption that primary frequency reserves are only triggered based on frequency deviating outside of a predefined normal operating bound – see for example Mancarella et al (2017). The quantity of these frequency reserves will typically be sized to incorporate the maximum foreseeable loss in the system (usually the largest single unit or sometimes the multiple large units).

Given a set quantity of reserve provided is provided the availability costs A are unlikely to be affected by the addition of a user. Hence it is the impact upon response costs R and outage costs C that would be most relevant. Outage C costs would be expected to increase where the addition of a new user increases the risk or probability of outage, such as through a larger ROCOF or nadir. This would only occur if the new user is larger than the maximal contingency size that the system is designed to protect against. By definition, for a marginal user this cannot be the case. This suggests that inertia and frequency response in non-rivalry properties as it relates to instantaneous contingencies.

With respect to smaller disturbances (ii) we would not expect $\Delta P_{FR}(t)$ to be triggered and thus frequency would be managed through frequency damping control systems (for example droop-controllers such as those on governors), frequency regulation services or natural damping from load. We term this secondary frequency response.¹⁸ The quantity of these products is determined though control damping ratios set at the asset level, or in the case of frequency regulation dispatch a particular quantity of power is reserved based on the expected supply-demand imbalance. The providers of this response then dynamically adjust their active power injection or withdrawals based on metrics that describe the instantaneous power imbalance. Droop controllers often use a local measurement of frequency while centralised frequency regulation often uses the area control error which is the measured difference between scheduled and instantaneous electrical generation within a control area on the power grid.

In assessing marginal costs of extension, there is potential for higher response costs if the addition of the marginal user increases the potential for demand supply imbalances within the dispatch interval—for example if the new user has variable or intermittent power generation or use (Apostolopoulou et al., 2016; Nguyen and Mitra, 2016). Whether the ‘common’ marginal user in a system has those characteristics will depend upon the system in question. However, given the potential for a mix of variable and dispatchable energy sources in the future, we that consider system-wide frequency metrics are best considered non-rival (Greve et al 2018).

6.2 Rivalry properties of fault levels (system strength)

The rivalry properties of fault levels (being one aspect of system strength) can be illustrated using the simplified scenario outlined in (CIGRE, 2016) and (AEMO, 2018).

In this scenario one measure of system strength is the available fault level (AFL) at a node, which is calculated based on the methodology in (CIGRE, 2016). Under this analysis only a synchronous unit (such as a synchronous generator or synchronous condenser) is able to contribute to system strength.

¹⁸ We note that however that nomenclature and definition of primary and secondary frequency response can vary between markets. We have adopted this classification based on risk categorisations.

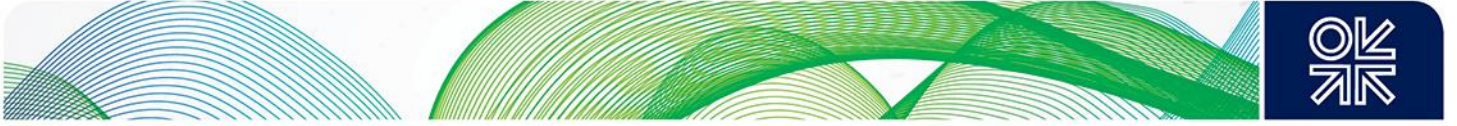
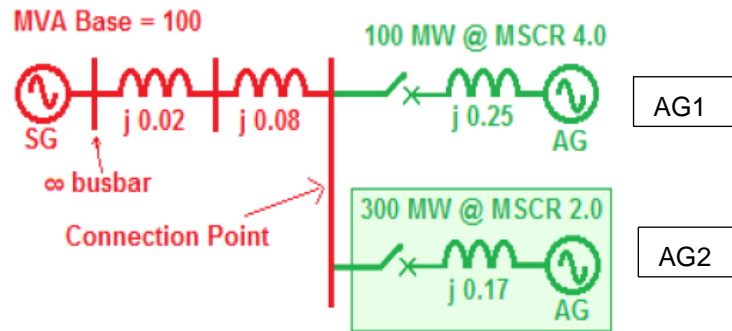


Figure 20 illustrates the impact on system strength of a new user connecting to a network. In this case a new user is an inverter-based or asynchronous generator (AG2 shaded in green). The network has an existing asynchronous generator AG1 of 100MW and a synchronous generator (SG) of 100MVA.

Figure 20: The impact on fault levels of a new user connecting to a network



Source: AEMO (2018; CIGRE (2016)

Following the steps in CIGRE (2016), the fault level contribution provided by the SG is calculated as (using Kirchhoff's Law):

$$Fault\ Level_{provided} = C_{SG}^{MVA} \times \frac{V^2}{Z} = 100MVA \times \frac{1}{j0.02 + j0.08} = 1000MVA$$

Where C_{SG}^{MVA} is the rated capacity of the SG in MVA, V is the voltage (per unit) at the node (assumed to be 1), and Z is the combined impedance of network and the internal impedance of the generator.¹⁹

This means that there is 1000MVA of fault level contributed by the SG. However, the existing AG2 consumes a portion of this fault level. The required fault level for the existing AG1 is based on its minimum short circuit ratio (MSCR) rating and is calculated as:

$$Fault\ Level_{consumed\ by\ AG1} = MSCR \times C_{AG1}^{MW} = 4 \times 100MW = 400MVA$$

Where C_{AG1}^{MW} is the rated capacity of AG1 in MW.

This means that the available fault level (AFL) for any new AG wishing to share the connection point is:

$$AFL = Fault\ Level_{provided} - Fault\ Level_{consumed\ by\ AG1}$$

$$AFL = 1000MVA - 400MVA = 600MVA$$

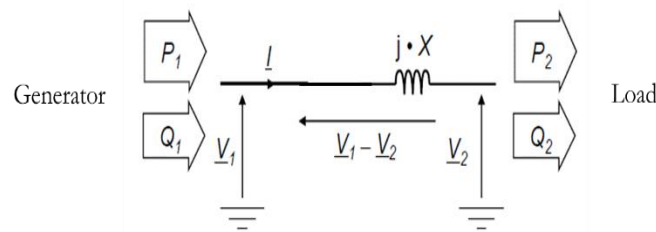
The AFL can be considered to be the system strength capacity at the node and must exceed a minimum level (AFL_{MIN}) for the system to be considered 'strong' (AEMO, 2018). When AFL is high, the addition of a new generator does little to impact system strength. However, when AFL is low the addition of a new can significantly deplete the available capacity. For example, an AG with a 300MW and an MSCR of 2 would deplete all of the AFL. Given a network with such fault levels, the marginal addition of a new user at this location would result in negative AFL and likely increase the risk of system instability and hence outage costs C. This suggests that fault levels become increasingly rival as the network gets increasingly congested, suggestive of qualities consistent with a congestible CPR.

¹⁹ Sub-transient reactance

6.3 Rivalry properties of voltage control

In this section we provide a simplified illustration of rivalry properties of voltage using a simple static stability example involving a generator and load connected by a transmission network, as provided in (Rebours et al., 2007) (Figure 21). In this example, we ignore the resistance of the line.

Figure 21: Simple two bus example – static voltage stability



Source: Rebours et al (2007)

Where P_1 , Q_1 , V_1 are the active power, reactive power and voltage of the generator, P_2 , Q_2 , V_2 are the active power, reactive power and voltage at the load. X is the impedance of the transmission line. The relationship between voltage, the active power (P_2) and reactive power (Q_2) of the load is provided as²⁰:

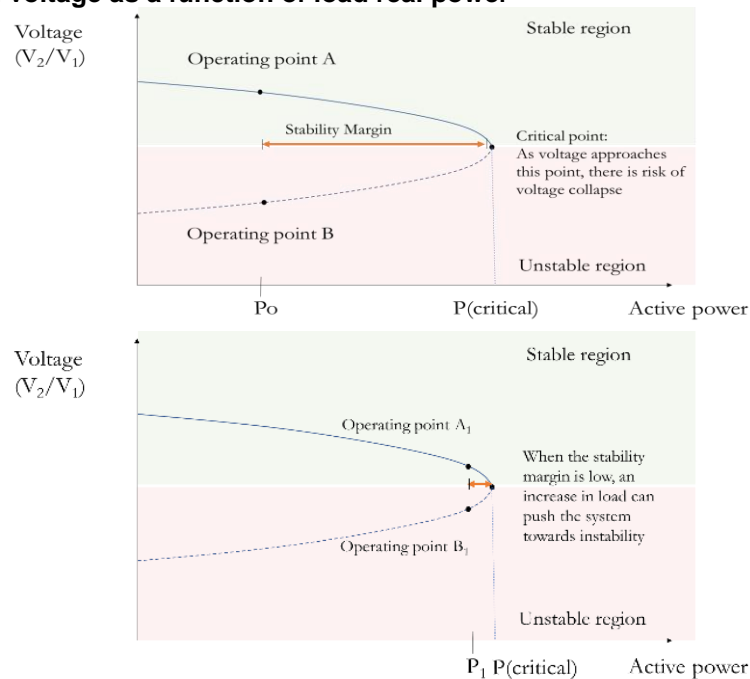
$$\left[\frac{V_1 V_2}{X} \right]^2 = [P_2]^2 + \left[Q_2 + \frac{V_2^2}{X} \right]^2$$

This is reflected in the power-voltage (P-Q) curve in Figure 22 below which presents load voltage as a function of load real power. For a static load P_0 as shown in the figure, two operating points (A) and (B) are possible. Point (A) represents low current high voltage solution and is the desirable operating point, while point (B) represents high current low voltage solution. Operation at point B is possible, is unstable due to low voltage and high current condition. Power systems are operated in the upper stable region of the curve. There is also a critical operating point at which the stable and unstable regions coincide, and the system is at risk of voltage collapse. The stability margin is an indication of how far away from the critical point the system is operating at.

²⁰ This assumes an ideally stiff load, meaning that the power demand of the load is independent of voltage and is constant. This presumes there is sufficient system strength in the network.



Figure 22: Load voltage as a function of load real power



Source: authors

The rivalry aspects of the system under congestion can be illustrated as follows. At a point P_0 and the system operating at 'point A' where there is a large stability margin, if the load is increased then from the curve it can be seen that the voltage will drop. This is a perfectly normal response of the system.

However, if the load is at point P_1 (operating point of A_1) with a very small stability then an increase in load will likely push the system towards the critical point and at risk of voltage collapse. This means that during congestion (or when the system is reaching certain limits) expected outage costs C would increase and the use of the voltage service becomes increasingly rival. In this example the stability margin can be increased by the load injecting more reactive power into the system. This is the basis upon voltage control services are activated to improve the voltage stability characteristics of the system (Figure 23). While real-world systems are much more complex, the broader principle remains instructive.

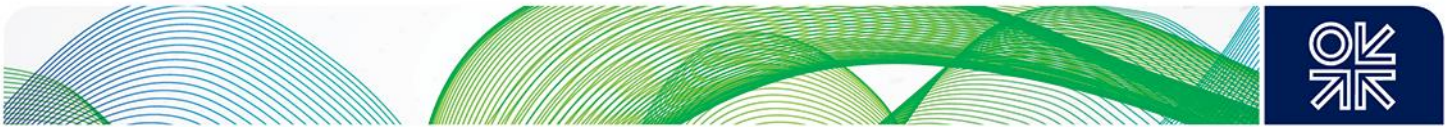
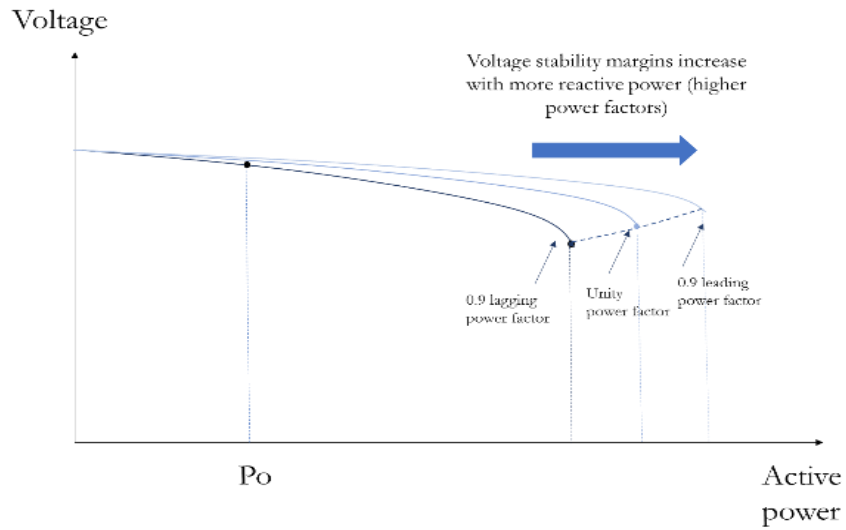


Figure 23: Impact of increased reactive power on voltage stability curves



Source: authors



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