Balance of Power

Designing operational practices for balancing power systems and electricity markets with growing penetrations of renewable energy

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I, AUTHORNAME confirm that the work presented in this thesis is my own. Where information has been derived from other sources, I confirm that this has been indicated in the thesis.

Abstract

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Acknowledgements

0.1 First paper

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0.2 Second paper

The authors would like to thank:

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Abbreviations and Nomenclature

AC	Alternating Current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	Automatic generation control
BESS	Battery energy storage systems
BRP	Balancing responsible party
BSP	Balancing service provider
CCGT	Combined-cycle gas turbine
DC	Direct current
DR	Demand response
ENSTO-E	European Network of Transmission System Operators for Electricity
ESB	Energy Security Board
IBR	Inverter-based resources
ISO/RTO	Independent System Operator/Regional Transmission Organisation
FCS	Frequency control services
FCAS	Frequency Control Ancillary Services
FERC	Federal Energy Regulatory Commission
FFR	Fast frequency response

Gas-Steam	Gas-powered steam turbine
Hz	Hertz
mHz	Millihertz
ISP	Integrated System Plan
LOR	Lack of reserves
MSL	Minimum stable level
MW	Megawatts
NEM	National Electricity Market
NER	National Electricity Rules
NOFB	Normal operating frequency band
NSW	New South Wales
OCGT	Open-cycle gas turbine
OFGS	Over-frequency generation shedding
PASA	Projected Assessment of System Adequacy
PFR	Primary frequency response
PV	Photovoltaic
QLD	Queensland
RERT	Reliability and Emergency Reserve Trader
RoCoF	Rate of change of frequency
SA	South Australia
SDP	Synthetic daily profile
SFR	Secondary frequency response
SO	System operator
TAS	Tasmania
TFR	Tertiary frequency response
TNSP	Transmission Network Service Provider

TSO	Transmission System Operator
UC-ED	Unit commitment and economic dispatch
UFLS	Under-frequency load shedding
UK	United Kingdom
US	United States
UFLS	Under-frequency load shedding
VIC	Victoria
VPP	Virtual power plant
VRE	Variable renewable energy

1 | Introduction, with a citation

1.1 Background

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1.2 Summary of chapters

This is a brief outline of what went into each chapter, and a section which shows how to reference headers (which are labelled automatically for you). This chapter, Section 1, shows how to use citations and how to reference section headers. Section 2 shows how use and reference equations. Section 4 is the FCAS paper. Section **??** shows how to use, reference, and resize pdf and jpg figures. Section 5 shows how to use and reference tables. Section 6 is truly revolutionary (but shows nothing functional). **Appendix 1** shows how to add chapters which are not numbered, and has to be referenced manually, as does **Appendix 2**.

2 | Literature review

2.1 Introduction

2.2 Outline of literature review

2.3 Power systems

Given the welfare and economic benefits associated with electricity access, many 20$^{\text{th}}$ century states constructed large bulk *power systems* to leverage investment & operational economies of scale. These systems sought to efficiently deliver active power (i.e. power that does work) to numerous electricity end-users (*demand* or *loads*) from electricity suppliers (*generators*) across vast distances. A typical power system configuration is presented in Figure 2.1. Generators supply the system with alternating current (AC) power either through a direct electromagnetic connection or through a power inverter interface (which converts the direct current, or DC, produced by the generator to AC). AC power is then efficiently transmitted over long distances through a high voltage *transmission* system. As transmission lines approach load centres, voltages are stepped down to make power delivery to the houses and businesses connected to the lower voltage *distribution system* safer (Masters, 2004).

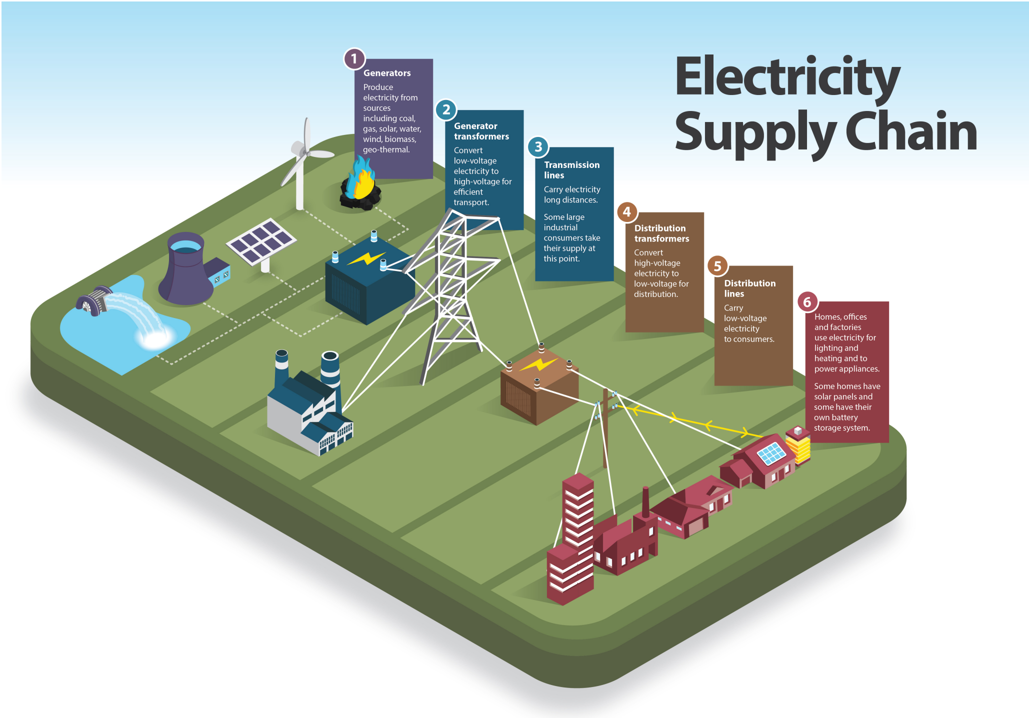

Figure 2.1: Conventional bulk power system, including generation, transmission, distribution and industrial, commercial and residential end-users (loads). Source: Australian Energy Market Operator (2023).

2.3.1 Synchronous and control areas

A network area that is operated at a (constant) nominal AC frequency is known as a *synchronous area*. During stable operation, AC frequency should be close to the system's nominal value and more-or-less uniform across the synchronous area. A *control area*, on the other hand, is a network area in which a *system operator* (SO) is responsible for maintaining a balance between supply and demand for electrical power. Whether the term "power system" refers to a synchronous area or a control area is often dependent on context — in particular, the relationship between the two in the jurisdiction in question. In eastern and southern Australia, the National Electricity Market's (NEM) single control area consists of two synchronous areas (see Section 4.6 for further detail). In contrast, other jurisdictions have a single synchronous area composed of several electrically-connected control areas demarcated by political rather than physical boundaries. For example, continental Europe is a single synchronous area consisting of many national or trans-national control areas, and the continental United States has three synchronous areas (two of which extend into Canada) with over 60 control areas (North American Electric Reliability Corporation, 2023; Schittekatte and Pototschnig, 2022)

2.4 Power system operations

In broad terms, *operating* a power system involves the direction or control of *power system resources* — generators, loads, network elements and energy storage resources (which can act as both a generator and a load). In practice, however, power system operation is inseparable from the economic objective imposed upon SOs: minimise system costs (or under some market paradigms described in Section 2.5, maximise the value of trade) whilst 1) continuously maintaining a balance between active power supply & demand and 2) ensuring that system resources & the system itself are operated within their respective technical envelopes (Wood et al., 2014). The latter constraint implies *stable* & *secure* operation and is a prerequisite for the former constraint, which more-or-less corresponds to *reliable* operation[1].

Noting that planning & investment have a large bearing on the manner in which a power system is operated (and vice versa), Figure 2.2 presents a high-level overview of power system phenomena and processes, services & markets

[1]The term *balancing services* is used in European systems, whereas the term *operating reserves* is widely used in North America.

that are most pertinent to active power balancing in operational timeframes, with those discussed in detail within this thesis highlighted in bold red text.

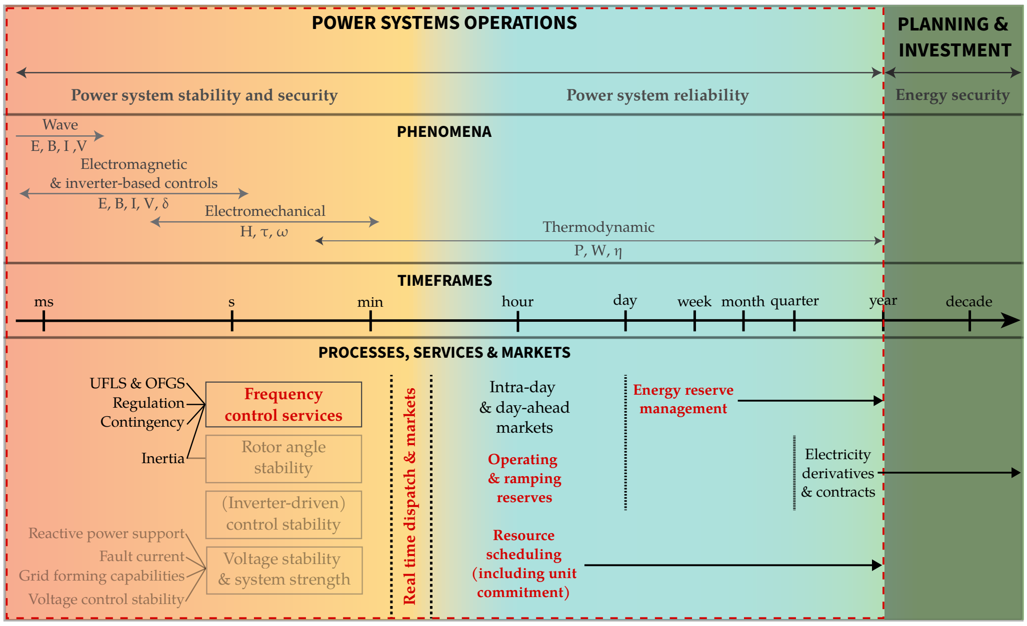

Figure 2.2: A high-level overview of power system concepts, phenomena and processes, services & markets relevant within operational timeframes (bounded by the red dashed box). All non-faded text in the bottom section indicates a process, service and/or market related to active power balancing. All bold red text in the bottom section indicates a process, service and/or market related to active power balancing that is discussed in detail in this thesis. Timeframes, phenomena and stability categories were adapted from Machowski et al. (2020) and Hatziargyriou et al. (2021). The figure concept and layout was inspired by a similar figure presented in Wilson (2020).

2.4.1 Phenomena in operational timeframes

As shown in Figure 2.2, power system operations is concerned with phenomena that dominate on timescales ranging from a few milliseconds to several months (Hatziargyriou et al., 2021; Machowski et al., 2020):

1. *Electromagnetic* phenomena arise from the coupling of electrical and magnetic fields within *synchronous machines* (generators and motors that rotate at a speed proportional to AC frequency) and between power system resources. They occur on the timescale of milliseconds to seconds. Controls

for *inverter-based resources*, which have a power electronic inverter interface to the wider power system, also operate in this timeframe.

2. *Electromechanical* phenomena are slower (seconds to minutes timescale) and arise as a result of electromagnetic fields interacting with rotating masses and mechanical forces. These typically occur in motors and generators.

3. *Thermodynamic* phenomena are slower still. They encompass chemical fuel conversion & heat transfer processes in boilers. These phenomena occur over multiple timeframes, from seconds to minutes to hours. I will also extend this category to include the dynamic behaviour of the primary energy sources for hydroelectricity and *variable renewable energy* (VRE), which primarily refers to wind and solar photovoltaic (PV) generation.

2.4.2 The need for system balance

2.4.2.1 Synchronism

Following synchronisation, generators (e.g. turbines) and loads (e.g. motors) that rotate at a speed proportional to the power system frequency are known as *synchronous machines*. As shown in [eq:synch_speed], the *synchronous speed* is dependent on the number of poles of the machine and the power system frequency (**Grainger1994?**).

$$N_s = \frac{120f}{P}$$

where N_s is the synchronous speed in revolutions per minute, P is the number of magnetic poles and f is the electrical frequency in Hz.

Power system frequency control is required for the stable operation of a synchronous area. Should synchronous machines be exposed to high RoCoFs and sufficiently serious frequency deviations, they may experience equipment-damaging vibrations (**Ulbig2014?**) or suffer from pole slipping due to a loss of synchronism (**DGAConsulting2016?**). As such, if frequency control services are insufficient in their response, *under-frequency load shedding* (UFLS) relays or *over-frequency generation shedding* (OFGS) relays, and frequency-sensitive equipment protection relays are used as emergency frequency control schemes and equipment protection measures, respectively (**Eto2018?**; **AustralianEnergyMarketCommission2019?**).

The activation of these schemes is undesirable, particularly as UFLS is reflected in power system reliability metrics. Moreover, the presence and configuration of these schemes in the power system means that if frequency deviations are sufficiently large, a cascading series of trips and faults may aggravate the active power imbalance and lead to power system black-out and collapse (**Ulbig2014?**; **Hartmann2019?**).

2.4.3 Threats to system balance

As highlighted in [eq:swing_area], the AC frequency of a power system can deviate from its nominal value when there is an imbalance between power supply and demand in the synchronous area. Active power imbalances are the result of power system *variability* and *uncertainty*.

2.4.3.1 Variability

Variability refers to expected or forecast fluctuations in the balance of active power supply and demand (**Ela2011?**). Sources of variability include fluctuations in load, oscillatory active power output from synchronous generators and changing weather conditions (e.g. cloud cover, wind speed) that may affect the active power output of VRE (**Ela2011?**; **Bloom2017?**; **Riesz2015a?**).

2.4.3.2 Uncertainty

Uncertainty refers to unexpected fluctuations in the balance of active power supply and demand (**Ela2011?**). Power system uncertainty encompasses the unanticipated behaviour of generators, loads and network elements. This includes unexpected outages (known as *contingency events*) and weather forecast errors that lead to VRE generation forecast error (**Ela2011?**; **Riesz2015a?**)

2.5 Operational paradigms

Synchronous areas can be subdivided into *control areas*, which are typically demarcated by the network boundaries of separate electric utilities or electricity markets (**Grainger1994?**; **Elgerd1971?**). Within a control area, the control of AC frequency is the responsibility of a system operator.

2.5.1 Vertically-integrated

Historically, this configuration enabled economies of scale in both asset investment and operation to be achieved by electric utilities, particularly regulated monopolies that owned and operated most, if not all, of the generation, transmission and distribution infrastructure within a power system and were responsible for the retail of electricity to the end-user (these regulated monopolies are known as vertically-integrated utilities) (**Masters2004?**).

2.5.2 Restructuring and the emergence of wholesale electricity markets

In mandatory pool markets, the system operator commits and dispatches individual generators (and, in some cases, loads) in the day-ahead and real-time markets, respectively, based on economic optimisation processes that incorporate transmission constraints and stability and reliability requirements. These processes are *security-constrained unit commitment* (SCUC), which is executed in the day-ahead market, and *security-constrained economic dispatch* (SCED), which is executed just prior to the relevant real-time market interval. In many mandatory pool markets, SCED and SCUC co-optimise the provision of energy and frequency control services

It should be noted that these processes are not exclusive to mandatory pool markets and could be used by vertically-integrated utilities to efficiently schedule resources in the power system (**Grainger1994?**).

2.5.2.1 Electricity industry restructuring

Beginning in the early 1990s, perceived inefficiencies and overspend by monopoly electric utilities, advancements in small low-upfront cost gas turbine technologies and the successful liberalisation of other industries such as airlines and telecommunications prompted many countries to restructure their electricity industries (**Weigt2009?**; **Miller2017?**). A common feature of this process across power systems was the implementation of a wholesale market for electricity, where generators compete for the opportunity to supply electricity and earn revenue through an auction-based mechanism (**Milligan2017?**).

2.5.2.2 Electricity market structures and features

2.5.2.2.1 System operator In restructured electricity industries, the implementation of wholesale markets was accompanied by the creation of an independent power system operator to operate the transmission network, manage and administer the electricity market, maintain short-term power system *reliability* (the ability to meet demand with supply) and *security* (the ability to operate the power system within a defined operating envelope), and carry out longer term planning functions (**Sioshansi2006?**; **Hogan2008?**). These entities may own transmission infrastructure as a regulated monopoly, as is the case with the various Transmission System Operators (TSOs) in Europe, or be independent of any infrastructure ownership, such as the Independent System Operators (ISOs) and Regional Transmission Operators (RTOs) in North America and the Australian Energy Market Operator (AEMO).

2.5.2.2.2 Market models The restructuring process proceeded differently across jurisdictions, resulting in the implementation of different wholesale market mechanisms. However, at a higher level, electricity markets worldwide have generally converged towards two main market models which are distinguished by the degree of centralisation of market operations and the role of the system operator (2):

1. Decentralised *bilateral markets*, in which suppliers enter into contracts with buyers either directly or through intermediaries (**Barroso2005?**). Whilst scheduling and dispatch is managed by market participants, intended energy schedules (i.e. net contract positions) are submitted by market participants ahead of time to the system operator, who is responsible for determining the requirement for and procuring frequency control services (known as balancing services in bilateral markets) (**Hirth2015?**). This model is the dominant market model in Europe.

2. Centralised *mandatory power pool markets*, in which offers to generate are aggregated into a single supply curve and are cleared against a demand forecast (one-sided pool) or against an aggregated demand curve constructed from potential buyers (two-sided pool) by the system operator (**Barroso2005?**). In these markets, locational marginal prices for energy and frequency control services are produced by centralised optimisation processes run by the system operator that consider the physical constraints of the transmission system (**Cramton2017?**). The Australian National Electricity Market (NEM) and the ISO/RTO markets in North America have adopted this type of market model.

The difference between these mechanisms is whether real-time generation instructions (*dispatch*) or scheduling decisions (an outcome of *unit commitment* processes) are determined centrally by the system operator or are decentralised, with decisions made by market participants. It is important to note, however, that the adoption of one model does not preclude the integration of aspects of the other. Bilateral contracts (in the form of derivatives) are often used as hedging instruments in mandatory pool markets and several bilateral markets, such as those in Europe, have associated voluntary power exchanges that are essentially power pools (**Barroso2005?**).

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Mandatory power pool and physical bilateral market models. Reproduced from

2.5.2.2.3 Market platforms Whilst other commodity markets are settled continuously or sequentially, reliability and security considerations and concerns have led to electricity markets being divided into discrete *platforms* (**Isemonger2006?**). Platforms are formal sub-markets for energy that are settled at different times. A platform implemented by all electricity markets is a real-time, or spot, market. Where implemented, additional platforms involve trade for one or more real-time market intervals but are each settled at different times ahead of the spot market. These additional platforms can reduce uncertainty for the system operator and provide market participants with a formal market mechanism for managing risk (**Isemonger2006?**; **EnergySecurityBoard2020c?**).

The number and type of platforms a particular market implements is often related to its market model. European bilateral markets often have a real-time market, a day-ahead market and intra-day markets, where day-ahead commitments may be traded continuously between market participants (**Ahlqvist2018Central-Markets?**). In contrast, however, it is practical to limit the number of platforms in a mandatory pool market due to the inflexibility of commitment 'contracts' determined by computationally complex optimisation processes (**Isemonger2006?**; **Ahlqvist2018Central-Markets?**). North American ISO/RTO markets have two platforms - a financially binding day-ahead market and a physically and financially binding real-time spot market (**Cramton2017?**). The Australian NEM is rather unique amongst mandatory pool markets as it only has a single platform - the real-time spot market. This arrangement means that while dispatch is centralised, participants manage the commitment of their generation portfolio with the assistance of pre-dispatch forecasts provided by AEMO (**Riesz2016a?**).

2.6 Balancing processes and mechanisms

2.6.1 Inherent inertial response

Synchronous machines convert electrical energy to mechanical energy, or vice versa, through the interacting magnetic fields of the rotor and the stator (**Chapman2011ElectricFundamentals?**). In a synchronous generator, this interaction produces an electromagnetic torque (T_e) on the rotor that opposes the mechanical torque (T_m) supplied by a prime mover (4). From [eq:swing], which is known as the *swing equation*, we can see that if a generator is at synchronous speed (i.e. steady state) and there is a transient increase in the electrical load of the power system (equivalent to an increase in P_e), the rotor of a synchronous generator will begin to decelerate as its stored kinetic energy is converted to electrical energy (**Grainger1994?**; **Elgerd1971?**). When this electromechanical response is observed across synchronous machines, the decrease in rotor speed will result in a decrease in the synchronous area's AC frequency as per [eq:synch_speed]. The inverse is true for a decrease in electrical load - the synchronous area's AC frequency will increase. These inherent responses describe a synchronous machine's *inertial response*.

$$J\omega_{sm}\frac{d\omega_{sm}}{dt} = P_m - P_e$$

where ω_{sm} is the rotor shaft velocity, J is moment of inertia of the rotor, P_m is mechanical power due to T_m and P_e is electrical power due to T_e.

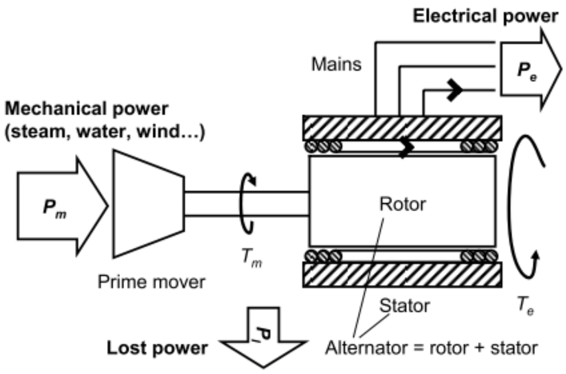


Figure 2.3: Mechanical power applied to the prime mover results in a mechanical torque T_m on the rotor of a synchronous generator. This is opposed by an electromagnetic torque T_e that is produced from the interaction of the rotor and stator magnetic fields. Source: (**Rebours2009?**).

2.6.1.1 Active power imbalance and RoCoF

We arrive at the relationship between the active power imbalance ($P_{gen} - P_{load}$) in a power system and AC frequency in [eq:swing_area] by extending the dynamics of the swing equation from a single synchronous generator to all synchronous generators in the synchronous area (**Tamrakar2017?**). [eq:swing_area] demonstrates that the rate of change of frequency (*RoCoF*) is proportional to the active power imbalance and inversely proportional to the system's inertia constant, H. [eq:swing_area] is primarily concerned with synchronous generators, not loads, as the rotors of the former store more kinetic energy due to a larger physical mass and higher rotational speeds (**Ulbig2014?**; **Denholm2020?**).

$$\frac{2H}{f}\frac{df}{dt} = \frac{P_{gen} - P_{load}}{S_{g,total}}$$

where H is the inertia constant of the synchronous area ($H = \sum_g H_g$, where $H_g = \frac{J_g \omega^2}{2S_g}$), f is the AC frequency, $\frac{df}{dt}$ is the rate of change of frequency or RoCoF, $S_{g,total}$ is the total apparent power of synchronous generators, and P_{gen} and P_{load} are the system's total power supply and total power demand (including losses), respectively.

2.6.2 Load damping response

Another inherent electromechanical response is that of frequency-dependent loads, which include machinery driven by induction motors (**AustralianEnergyMarketOperator2019l?**). The power consumption of frequency-dependent loads decreases with lower frequencies and increases with higher frequencies. This is known as *load damping*, as the response reduces the imbalance in active power supply and demand and hence dampens the change in AC frequency as described in [eq:swing_area] (**Denholm2020?**). However, load damping is diminishing in power systems around the world as a growing share of load is coupled to the power system through power electronic controllers, which enable loads to operate independently of the power system frequency (**Undrill2018?**).

2.7 The role of frequency control services

As discussed in 2.4, SCED is executed by vertically-integrated utilities and in mandatory pool electricity markets to ensure that active power supply and demand is efficiently balanced subject to network constraints and system security and reliability requirements. Between, and potentially across consecutive SCED processes (dispatch intervals) and unit commitment schedules, *frequency control services* are used by the system operator to manage both small and large instantaneous active power imbalances that may arise due to variability and uncertainty.

2.8 Conventional frequency control scheme and services

Power system operators typically employ a hierarchical and sequential control scheme to contain AC frequency within as narrow a band as possible, particularly during contingency events (**Undrill2018?**; **Ela2011?**). This control scheme involves the use of generation or load units with reserve capacity that provide frequency control services (**Ela2011?**). For these units to mitigate power system frequency deviations, they must have reserve capacity in the form of *headroom* (the ability to increase active power output) to respond to an under-frequency event, *footroom* (the ability to decrease active power output) to respond to an over-frequency event, or both (**Eto2010a?**). Under-frequency events are generally of greater concern to the system operator (e.g. loss of large generator). The various frequency control services differ based on their purpose, activation method, response time and control method (5). In the following subsections, we outline frequency control services that are common in many power systems.

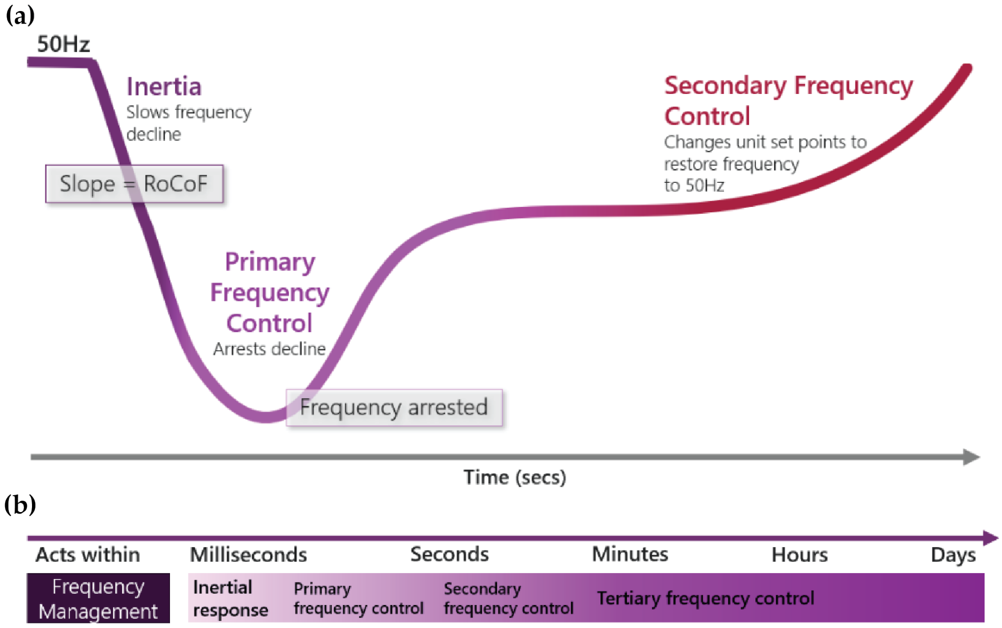


Figure 2.4: (a) A trace of power system frequency with corresponding frequency control services following a loss-of-generation contingency event. (b) The timeframes over which the various frequency control services are provided. Source: (**AustralianEnergyMarketOperator2020l?**).

2.8.1 Inertial response

As discussed in 3.3.1, synchronous machines have an inherent inertial response to AC frequency deviations that must be considered in the frequency control strategy of a power system. For a a given active power imbalance, the inertia constant of the synchronous area, H, determines the magnitude of the initial RoCoF following a contingency event (see [eq:swing_area]) and the speed at which the power system can be returned to the nominal frequency (**Ulbig2014?**; **Hartmann2019?**).

2.8.2 Primary frequency control

The aim of primary frequency control (PFC) is to arrest the frequency deviation through the autonomous response of generators and frequency-responsive demand-response to locally-measured frequency deviations that exceed a certain control dead-band (**Ela2012b?**; **Wang2003?**; **AustralianEnergyMarketOperator2019e?**). For generators, this is achieved through *droop control*, in which a deviation from synchronous speed corresponds to a change in the active power output of a generator according to its droop characteristic (6, from A to B along L_0) (**Eto2018?**; **Ela2012b?**). Droop control is implemented through the turbine governors of synchronous generators or the inverter control system for IBR (**Undrill2018?**). Provided there is a sufficient amount of PFC reserve to arrest the system frequency, the speed of PFC determines the *frequency zenith* or *frequency nadir*, which are the maximum or minimum system frequency, respectively, following an active power imbalance event (**Eto2010a?**). PFC can be activated in response to small (tight dead-band) or contingency (wide dead-band) imbalance events and should ideally be sustained until secondary frequency control can take over (**Eto2018?**).

2.8.3 Secondary frequency control

Secondary frequency control (SFC) replaces PFC and can consist of either or both of a synchronous area secondary control system known as an *Automatic Generation Control* (AGC) or unit-level load controllers (the latter is illustrated in 6) (**Undrill2018?**; **Eto2018?**; **Undrill2019?**). The most common strategy is for a synchronous area AGC to implement proportional-integral control on the Area Control Error (ACE) with a tie-line bias (**Machowski2020?**; **Ela2011?**). To minimise ACE and return the power system to its nominal frequency, the AGC sends signals to SFC units every 4 to 10 seconds to adjust their active power output in response to a frequency deviation (**Eto2018?**). When used to respond to smaller imbalance events, SFC is typically known as *regulation* (**Ela2011?**; **Hewicker2020?**).

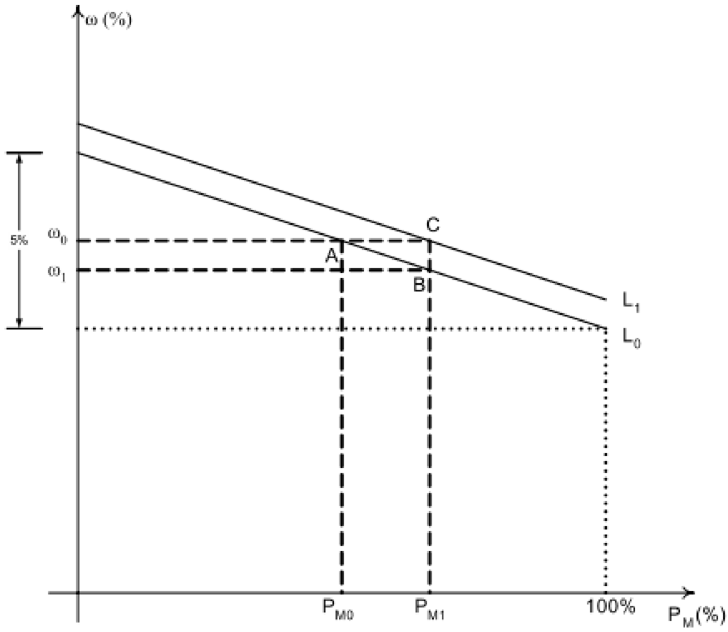


Figure 2.5: Behaviour of a synchronous generator with a turbine governor providing PFC and responding to SFC. L_0 is the initial droop characteristic. The generator is initially operating at point A with an active power output of P_{M0}. System frequency (and hence the synchronous sped of the turbine) decreases from ω_0 to ω_1 and the turbine governor responds by moving the turbine along the droop characteristic to point B, thus increasing its active power output to P_{M1}. Following this, SFC changes the reference speed setpoint of the governor, moving the droop characteristic to L_1 and returning the system to frequency ω_0. Source: (**Wang2003?**).

2.8.4 Tertiary frequency control

Tertiary frequency control (TFC) is intended to replace PFC and SFC. TFC is typically used as a margin of safety in systems where relatively infrequent unit commitment or rescheduling processes may be required to correct an active power imbalance (**Hewicker2020?**). Some systems, such as the NEM, do not procure TFR and instead rely solely upon a SCED that is frequently executed

(**Billimoria2020?**).

2.8.5 Dispatch and unit commitment

2.8.5.1 Security-constrained economic dispatch

SCED aims to determine the minimum cost operating configuration for committed generation such that a short-term forecast or actual demand can be met subject to subject to network constraints and stability and reliability requirements (**Grainger1994?**; **Wood2014?**). As generators typically submit offers for generation (and in some cases, frequency control) as piecewise linear cost functions, the SCED problem is less computationally complex than SCUC and can be solved using linear programming techniques (**Wood2014?**). For a given real-time market interval, SCED produces a set of physically and financially binding dispatch instructions, which include generation setpoints and enablement for frequency control services, and locational marginal prices for energy and frequency control services (**Cramton2017?**). In multi-platform markets such as the ISO/RTO markets, SCED is considered a sub-problem of unit commitment and is run for every real-time market interval (5-15 minutes) (**Wood2014?**; **InternationalRenewableEnergyAgency2019?**). In single-platform markets, such as the NEM, market participants manage their own unit commitment and SCED is the only market process that produces a binding schedule (**AustralianEnergyRegulator2016?**).

2.8.5.2 Security-constrained unit commitment

The aim of SCUC is to determine the minimum cost subset of generation that should be committed (i.e. synchronised and ready to deliver power to the power system) to meet a demand forecast for a set of future market intervals subject to network constraints and stability and reliability requirements (**Wood2014?**). SCUC is a computationally complex non-linear problem in many electricity markets because it considers non-convexities such as start-up costs and minimum operating costs in addition to an offer for energy (**Cramton2017?**; **Isemonger2009?**). The outcomes of solving this problem are an ahead schedule, which is often only financially binding, and locational marginal prices for energy and frequency control services for a future set of market intervals, such as the next day when SCUC is executed in day-ahead markets. SCUC can be beneficial for market participants that wish to hedge their production or consumption (**Isemonger2006?**). Furthermore, it offers certainty around power system outcomes to the system operator, and around market outcomes to generators that have long lead times and significant costs associated with commitment (e.g. baseload coal power plant) or generators that primarily consider opportunity costs, rather than marginal costs, when determining whether it is profitable to provide energy (e.g. hydroelectric power plants, battery energy storage systems) (**Wood2014?**; **Cadwalader1998ReliabilityPricing?**).

2.8.6 Longer-term scheduling

2.9 Emerging challenges in power system operations

2.9.1 Inverter-based resources and frequency control

Inverter-based resources (IBR) include variable IBR (solar PV and Type III and Type IV wind turbines (**Wu2018?**)), BESS and high voltage direct current (HVDC) links that connect to a power system through power electronic devices. The impacts of variable IBR on frequency control are of particular interest to system operators and market designers as many power systems are currently experiencing high instantaneous penetrations of variable IBR (in excess of 50%) and because many more are expected to do so in the future (**AustralianEnergyMarketOperator2019?**; **IRENA2020?**).

2.9.2 Challenges posed by inverter-based resources

High penetrations of IBR in power systems pose challenges to frequency control due to their characteristics, particularly in islanded power systems or weakly-interconnected control areas that cannot rely on a wider synchronous area for frequency control services (**Hodge2020?**). These include (**Kroposki2019?**):

2.9.2.1 Interface to power system

As IBR interface to a synchronous area through inverters, they are not electromagnetically coupled to the power system and therefore do not exhibit the inherent inertial response of synchronous generators. This has two main implications. The first is that reduced inertial response may affect power system stability during transients (e.g. rotor angle stability) (**Tielens2016?**), and the second is that a lack of inertia in the power system can lead to higher RoCoF and therefore more severe frequency nadirs or zeniths and the tripping of emergency protection schemes that would otherwise not occur in high inertia systems (**Machowski2020?**; **Ulbig2014?**; **Hartmann2019?**; **Dreidy2017?**).

2.9.2.2 Variability and uncertainty

The aggregate degree of power system variability and uncertainty is likely to increase with higher penetrations of variable IBR (**Riesz2015a?**; **AustralianEnergyMarketOperator2020b?**). Variability not only encompasses active power output variability during a dispatch interval, which depends on the primary energy source and plant location and configuration, but also includes large ramps due to the correlated active power output of variable IBR over longer timeframes (**Keeratimahat2019a?**; **AustralianEnergyMarketOperator2020d?**). Power system uncertainty will depend on the accuracy of weather and generation forecasting, generator reliability and may also be a function of the degree of visibility and control a system operator has over IBR, particularly distributed energy resources such as rooftop solar PV and electric vehicles (**AustralianEnergyMarketOperator2020d?**; **Wurth2019?**; **AustralianEnergyMarketOperator2020m?**).

2.9.3 Provision of frequency control services

The presence of synchronous machines and grid-following inverters makes inertial response and frequency control necessary for secure and stable operation of a power system. At high instantaneous penetrations, low short-run marginal cost IBR may displace synchronous generators that have traditionally provided inertial response and frequency control services, and the load damping response may be minimal (**Riesz2015a?**; **Tielens2012?**). In these cases, the instantaneous inertia constant of the system may be low and IBR may be needed to assist in frequency control (**Hartmann2019?**; **Tielens2012?**). Through their inverter control system, IBR are able exercise rapid and precise control of their active power, within the constraints of primary or stored energy, to provide what is known as *fast frequency response* (FFR) (**Machowski2020?**; **Hodge2020?**).

2.9.3.1 Fast frequency response

FFR can generally be provided within a matter of milliseconds to provide a sustained active power response similar to PFC or to mitigate high RoCoF events (**AEMO2017a?**; **Miller2017?**). In response to an under-frequency event, a sustained active power raise response, similar to PFC, can be achieved by implementing frequency droop control in the inverter of a BESS, or that of a variable IBR that has been *deloaded* to provide headroom. Wind turbines can be deloaded through pitch angle or over speed control, whereas solar PV is typically deloaded through over-voltage control (**Dreidy2017?**; **Tielens2012?**; **Fernandez-Guillamon2019a?**). A sustained lower response can be delivered by operating an inverter control system at an off-maximum power point to reduce the IBR's active power output.

High RoCoF can be mitigated by FFR that is delivered through processes and controls that mimic the inertial response of a synchronous generator (**Eriksson2018?**). Inertia-based FFR (otherwise known as *synthetic inertia* in the literature) is provided by extracting the kinetic energy from a wind turbine rotor to rapidly inject active power (**Miller2017?**) into the power system. FFR from *virtual inertia*, on the other hand, is provided as the result of implementing the dynamic model of a synchronous machine to some degree within an inverter control system (**Tamrakar2017?**; **Anderson-Cook2013?**). As FFR requires some form of measurement and is not inherent, it cannot be considered to be a direct substitute for inertial response (**Miller2017?**; **AEMO2017a?**).

2.10 Procurement of frequency control services

As highlighted by (**Ela2012b?**) and (**Billimoria2020?**), frequency control services are typically procured through a combination of market-based mechanisms, such as remunerative schemes or contract or spot markets, and regulatory mechanisms, such as connection requirements or system operator intervention.

2.10.1 Market-based mechanisms

2.10.1.1 Suitability of markets

Many restructured electricity industries have developed competitive *ancillary services* markets that enable frequency control services to be procured alongside *primary* markets for energy and/or capacity provision. Competitive markets are a suitable mechanism for procuring frequency control services as AC frequency is a global parameter and, as such, frequency control services can be provided by any capable resource within a synchronous area (**Billimoria2020?**; **Hirst1998?**). This supports greater participation and competition in frequency control markets. Furthermore, frequency control services and energy are essentially the same commodity (active power) but differentiated by their delivery methods, with the former providing reserve capacity that responds in the event of a frequency deviation and the latter providing sustained delivery of active power during a market interval. Given that these products are related, there are benefits related to reducing overall system costs, incentivising frequency control provision and improving trade outcomes for market participants by *co-optimising* markets for energy and frequency control services (**Ela2016?**).

2.10.1.2 Opportunity costs and co-optimisation

To provide raise frequency control services, generation must allocate reserve capacity, which may be at the expense of profitable energy provision (**Raineri2006?**). As such, participation in ancillary services markets often entails an *opportunity cost* to market participants. While frequency control services markets are often co-optimised with energy markets to ensure that power system energy supply and security requirements are met at the lowest cost to the system, participant opportunity costs can be accounted for in two ways in mandatory pool electricity markets:

1. In *partially co-optimised* frequency control services markets, perceived opportunity costs are incorporated into bids by market participant. The procurement of frequency control services and energy is co-optimised by the system operator in SCUC and/or SCED, thereby minimising overall costs to the system (**Isemonger2009?**).

2. In *fully co-optimised* frequency control services markets, market participants submit bids for energy and frequency control services provision. The system operator then determines a price for frequency control services that is the sum of the bid offer and the opportunity cost of that resource forego-ing provision of energy or other services. The system operator can then co-optimise all bids and costs in SCUC and/or SCED so as to simultaneously maximise profit for market participants whilst minimising overall costs to the system (**Ela2012a?**; **IntelligentEnergySystems2010a?**).

2.10.1.3 Potential benefits of market-based mechanisms

Compensation for frequency control services addresses the externality of providing ancillary services, particularly if the compensation is aligned with a market participant's opportunity costs (**Rebours2007b?**). Furthermore, if compensation is delivered through market-based mechanisms and if these mechanisms are designed well, frequency control services can be procured at least cost to the system from resources that are best placed to provide them within an operational timeframe (*productive* efficiency) and spur efficient investment in frequency control capabilities by market participants into the future (*dynamic* efficiency) (**Thorncraft2007?**; **Riesz2015b?**; **Biggar2014TheMarkets?**; **AustralianEnergyMarketCommission2020a?**).

2.10.1.4 Challenges in frequency control services markets

Frequency control services markets face both existing and emerging challenges to achieving productive and dynamically efficient outcomes. The main challenges being faced in these markets are outlined below:

2.10.1.4.1 Product design and fungibility. Products in existing frequency control services markets generally reflect the capabilities and requirements of conventional frequency control provided by synchronous generators (**EU-SysFlex2019?**). As frequency control abilities and needs have changed over time, various jurisdictions have considered or created additional frequency control services. These include ramping products, which have been implemented in some ISO/RTO markets in response to increasing variability and uncertainty (**Ela2019?**; **Ela2017?**), FFR products to mitigate RoCoF (**Ela2019?**; **Fernandez-Munoz2020?**) and TFC or operating reserves where operating reserve margins are a concern to the system operator (**EnergySecurityBoard2020?**).

Furthermore, there are trade-offs associated with the separation and *fungibility* of both existing and new frequency control products. Market-based mechanisms will work best when a particular frequency control product is a fungible and well defined, or "discrete", commodity supplied by various providers (**Gimon2020?**). With a sufficiently large market, prices should reflect the costs incurred by various providers to provide such a service (**Ela2012b?**). This, however, ignores the wide "spectrum" of technical capabilities of power system resources with respect to frequency control.

Understanding the trade-offs in creating fungible new products is important to frequency control service market design. For example, while a new product may value and incentivise the provision of a particular frequency response (**Ela2012b?**), a market may not deliver a net benefit if there is limited competition or the costs and complexity of administering a market are significant (**Rebours2007b?**; **Ela2019?**).

2.10.1.4.2 Price formation. Price formation is an unresolved issue within frequency control services market design. Ideally, the price of provision should be explicit, transparent and recognise the true value of the service alongside any opportunity-costs incurred by the supplying participant. There are three main issues that hamper efficient price formation and hence productive and dynamically efficient market outcomes:

1. Frequency control products are arbitrarily defined by a system operator and often procured in a single-sided market due to the *public good* nature of frequency control (**Billimoria2020?**; **Pollitt2019a?**). As such, the true value of these services to power system users is not recognised (**Rebours2007b?**).

2. Furthermore, in co-optimised markets, there is a tension between the relatively low opportunity costs of existing synchronous generation providing frequency control services and the strong price signals needed to incentivise new capabilities, particularly from high capital, low operating cost inverter-based resources (**Ela2019?**).

3. Some products, such as inertia, may be 'lumpy' in their provision and inseparable from other system security products (**Billimoria2020?**; **EnergySecurityBoard2020?**).

2.10.1.4.3 Cost allocation. In many mandatory pool markets, the cost of frequency control services procured by the system operator is allocated to loads, even though the deviation of generation may cause the need for procurement in the first place (**Milligan2011a?**). Australia's NEM has a 'Causer Pays' cost allocation framework in place for frequency control services procured for contingency response and regulation, though the mechanism for the latter suffers from a lack of transparency, complexity and fundamental design flaws (**Riesz2015b?**; **AustralianEnergyMarketCommission2020?**; **AustralianEnergyRegulator2020?**). Cost allocation could provide disincentives for undesirable behaviour, such as deviation from SCED dispatch instruction, and create counter-parties for hedging frequency control services price risk and therefore assist in price formation (**Thorncraft2007?**). As the power system continues to transition, it may be possible to allocated costs based on a 'User Pays' framework, whereby power system resources that impose frequency zenith, nadir or RoCoF limits pay for frequency control services (**AustralianEnergyMarketCommission2020a?**).

2.10.1.4.4 IBR participation. IBR cannot or do not participate in many frequency control services markets. Historically, literature has focused on the impact of variable IBR on frequency control-related integration costs and how these costs can be minimised (**Ela2011?**; **Riesz2015b?**). However, for reasons discussed in 5 and as demonstrated by variable IBR frequency control trials (**AEMO2018d?**; **Loutan2017?**) and the provision of frequency control services by BESS (**AustralianEnergyMarketOperator2018i?**), there is both a growing need for and benefit to IBR providing frequency control services. In markets such as Australia's NEM, many IBR can participate in frequency control services markets but choose not to as their business models rely on revenue from energy provision and the opportunity-cost of participation is too high (**AEMO2018d?**). An active area of interest is designing frequency control services markets and the revenue earned within them to incentivise IBR participation and investment in frequency control capabilities, particularly as system security requirements change over time and as high instantaneous IBR penetrations are often associated with low energy prices (**Ela2019?**; **EnergySecurityBoard2020?**).

2.10.2 Regulatory mechanisms

Regulatory mechanisms, such as equipment technical standards, grid codes and system operator intervention, were used by monopoly electric utilities and system operators to procure sufficient frequency control response prior to implementation of frequency control services markets. Even now, regulatory mechanisms are used in conjunction with market-based mechanisms to procure frequency control services. In fact, the processes of designing and regulating market rules are in and of themselves regulatory mechanisms (**Sioshansi2006?**).

2.10.2.1 Potential benefits of regulatory mechanisms

Regulatory mechanisms are ideal for mandating basic frequency control capabilities as a condition for access or where markets may be difficult to design or suffer from major flaws such as a concentration of market power, oversupply of a product or the issues discussed in 6.1.4 (**Ela2012b?**).

2.10.2.2 Shortfalls of regulatory mechanisms

It may be difficult for regulatory mechanisms to ensure that sufficient frequency control services can be procured in power systems and electricity markets that are rapidly facing more power electronic-based control systems, lower levels of operational inertial response and higher variability and uncertainty of different scales and nature. Prescriptive regulatory mechanisms, such as grid codes, are often only updated after a number of years to reduce the compliance burden placed on connecting generators and loads. As such, they are slow to respond to changing frequency control capabilities and requirements. This delay can make new standards and requirements reactive rather than proactive. For example, AEMO can only review generator technical performance standards every 5 years (**AustralianEnergyMarketCommission2018?**), a timeframe in which the solar PV capacity installed in the NEM has more than tripled (2014-2019) (**AustralianPVInstitute?**).

2.10.2.3 Regulatory requirements as a solution to market failures

Regulatory mechanisms are being increasingly used in power system jurisdictions where frequency control services markets have failed to incentivise or procure or appropriate capabilities and services, or where there is significant uncertainty around frequency response from generation. For example, several power systems, including the Australian NEM, have mandated some degree of PFC provision from connected generators in their grid codes or market rules (**AustralianEnergyMarketCommission2020?**; **Roberts2018?**). Similarly, frequency response has also been specified as a requirement for new generation (primarily IBR) to access and connect to the NEM and ISO/RTO markets in the U.S. (**AustralianEnergyMarketCommission2018?**; **FederalEnergyRegulatoryCommissionFERC2018?**).

2.10.2.4 Role of regulatory mechanisms

Though processes across several jurisdictions are underway to address frequency control services market deficiencies (e.g. the Australian NEM's post-2025 market design project (**EnergySecurityBoard2020?**), the Electric Reliability

Council of Texas' (ERCOT) Nodal Protocol Revision Request (**Ela2019?**) and the EU-SysFlex project (**EU-SysFlex2019?**)), there has been relatively little work around what role regulatory mechanisms may play, how they interact with market-based mechanisms and the relative benefits and costs of further frequency control services marketisation, both now and into the future.

2.11 Designing frequency control arrangements

Designing frequency control arrangements is a control, regulatory and market design problem which has become more complex in recent years due to electricity industry restructuring and growing penetrations of IBR (**VanderVeen2016?**).

2.11.1 Outcomes of good design

It is important to define desired outcomes of the design process. Below, we present three outcomes that have previously been proposed for designing ancillary/system services arrangements (including frequency control arrangements) by (**Rebours2007b?**) and the (**AustralianEnergyMarketCommission2020a?**).

1. **Effectiveness**. This entails both sufficient quantity and performance of procured frequency control services to ensure that power system security requirements are met.

2. **Efficiency**. Efficient frequency control arrangements will procure services at the lowest cost to the system, both now (productive efficiency) and

into the future (dynamic efficiency). Furthermore, efficient arrangements should also procure the right mix of services according to user and/or system needs (*allocative efficiency*).

3. **Minimising procurement costs and complexity**. Procurement and verification of delivery of frequency control services may involve significant costs associated with facilitation and monitoring. This could include metering equipment, IT systems and additional staffing costs. Complex procurement arrangements may also have unintended and unforeseen consequences on processes and markets that interface with these arrangements, such as the energy market and other ancillary services markets.

2.11.2 Complexity of the design process

Designing frequency control arrangements is a complex exercise in managing interrelated and interacting capabilities, mechanisms and objectives (7). The frequency control *capability* of a power system is distinct from its *performance*, with a *control strategy* defining how the former translates to the latter. The frequency control capability of a power system is determined by the physical characteristics and configuration of generators, loads and network elements within a synchronous area.

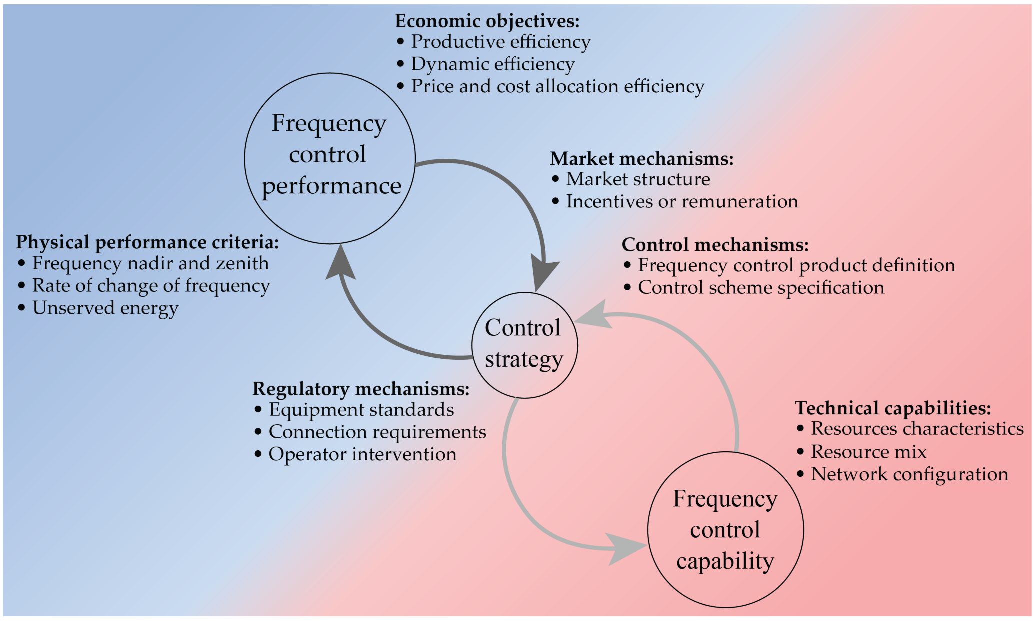


Figure 2.6: A diagrammatic depiction of the complexity involved in designing power system frequency control arrangements.

Frequency control services from capable resources are often mandated through connection requirements or power system operator intervention (see 6.2), incentivised through remunerative schemes, or procured through a contract or spot market (see 6.1) (**Billimoria2020?**). Together with the control specification of frequency control products, these mechanisms define a power system *control strategy* that dictates how capable system resources respond to deviations, and therefore determine the frequency control *performance* of a power system. The outcomes that define frequency control performance can be divided into physical performance criteria, which describe the effectiveness of frequency control services provided, and economic objectives, which relate to the productive, dynamic and price and cost-allocation efficiency of the arrangements.

2.11.2.1 Interactions between capability, strategy and performance

These three design layers often interact. Technical capabilities may guide the design of the control strategy, and therefore the mechanisms that define frequency control performance. An example of such a process is the PJM Interconnection (an RTO) implementing a high frequency AGC signal designed for BESS providing fast regulation frequency control services (**Benner2015?**; **Brooks2019?**). Similarly, deficiencies in performance can be addressed through modifying the control strategy to procure additional or more suitable frequency control capability. The California and Midcontinent ISOs have introduced ramping products to address increasing variability and uncertainty in their power systems (**Ela2016?**; **Ela2017?**).

2.11.3 Diversity of design outcomes

The design process has and will most likely continue to proceed differently across jurisdictions due to the diversity of both the technical capabilities of resources within power systems (see 4 and 5) and the different structures and features of various electricity markets (see 2) (**Rebours2007b?**). Existing frequency control arrangements across the world have been reviewed and compared extensively in the literature (**Rebours2009?**; **Ela2011?**; **DGAConsulting2016?**; **Hewicker2020?**; **Rebours2007a?**; **Rebours2007?**; **Zhou2016?**; **ReishusConsultingLLC2017?**; **Banshwar2018?**).

2.11.4 Design principles and considerations

Previous literature has explored the key design considerations for frequency control arrangements. (**Rebours2007b?**) outline design principles for power pool markets related to the frequency control services procurement, price formation, cost-allocation and market structure, which includes how frequency control services are offered, remunerated and cleared in markets, in addition to market operation and regulation. (**VanderVeen2016?**) build upon the work of (**Rebours2007b?**) to provides a more comprehensive treatment of frequency control arrangement design variables and performance criteria. The key contribution of (**VanderVeen2016?**) is that they explore some of the trade-offs between performance criteria when designing frequency control services markets. However, as they focus on the design challenge in European bilateral markets, some of these trade-offs are not relevant to or present in mandatory pool markets.

Both (**Rebours2007b?**) and (**VanderVeen2016?**) emphasise that good design will lead to efficient and effective frequency control arrangements. However, (**VanderVeen2016?**) focuses solely on market design whilst (**Rebours2007b?**) assesses various competitive procurement options but only briefly discusses the relative merits of compulsory provision of frequency control services through regulatory mechanisms. The work from these authors concentrates on achieving economic efficiency but pays relatively little attention to the technical capabilities of power system resources and the design of and interactions between frequency control products.

2.11.4.1 Holistic design

(**Ela2012b?**), (**Billimoria2020?**) and (**MacGill2020a?**) recognise that power system frequency control arrangements are typically composed of a mixture of market-based mechanisms and regulatory mechanisms that are compatible with the physics and control needs of the power system. The challenge here is determining the appropriate combination of these options for procurement, and the most suitable control mechanisms that account for both frequency control capabilities and the physical performance required by a power system. This can only be achieved by considering the interactions, or *interfaces*, between mechanisms within a power system's frequency control strategy.

2.11.4.2 Interfaces

The concept of interfaces in electricity industry decision-making is distinct but coupled to the frequency control arrangement design layers discussed above. Interfaces were first formalised by (**Thorncraft2007?**), specifically with relation to the security decision-making interface between commercial decision-making processes (i.e. processes within market-based mechanisms) and the technical and physical processes and the requirements of the power system (i.e. frequency control capability and physical performance) (**Thorncraft2009?**).

2.11.4.2.1 Security decision-making interface. The security decision-making interface includes system operator processes in integrated markets (e.g. SCUC and SCED) which co-optimise the provision of energy and frequency control services (**Chow2005?**). Literature has explored enhancing unit commitment and economic dispatch processes for frequency control through frequency response constraints (**Ela2014?**; **Doherty2005?**; **Teng2015?**; **Mancarella2017a?**) and, more recently, inertia constraints (**Gu2020?**; **Johnson2020?**). However, these studies implicitly assume that existing security decision-making processes and frequency control products are adequate and efficient, and will therefore perform well.

2.11.4.3 Interfaces between mechanisms in the frequency control strategy

Interfaces change over time and with technological innovation (**Thorncraft2009?**). The arrival of highly-controllable loads and IBR in the power system warrants the consideration of a *control system* process that is separate from physical characteristics and processes (8).

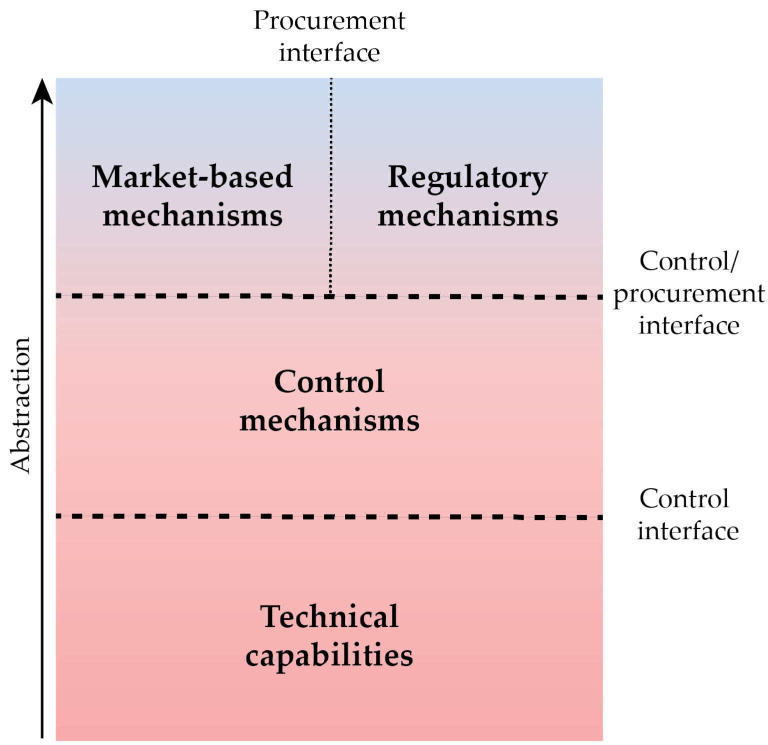


Figure 2.7: Interfaces between the frequency control capability and the mechanisms within the frequency control strategy of a power system.

2.11.4.3.1 Interface between control and procurement mechanisms. Some literature has begun to explore the interface between control mechanisms and market-based mechanisms. (**Garcia2019a?**) explore the impact of interchangeability between FFR and PFC on total system frequency control services costs. (**Badesa2020?**) outlined an optimisation framework that enables inertia, a reduction in contingency size and multi-speed PFC to be procured based on RoCoF and frequency nadir constraints and, more significantly, priced with a view of incentivising faster PFC and synthetic/virtual inertia provision from IBR. However, these studies do not consider how control mechanisms might interface with other regulatory mechanisms, such as equipment performance standards.

2.11.4.3.2 Interface between procurement mechanisms. In framing the design challenge for power system security services in the NEM, (**MacGill2020?**), (**Billimoria2020?**) and (**Skinner2020?**) acknowledge that there is a choice between, or potential combination of regulatory mechanisms and market-based mechanisms for procurement, with the latter two exploring the various advantages and disadvantages of each option. In particular, (**Billimoria2020?**) explores various procurement models and how regulatory and market-based mechanisms may interact within them. However, these procurement models are highly generic and further work is required to determine how existing and emerging control mechanisms might be structured in each of the models. Furthermore, there is a need to understand how these procurement models might interface with and integrate into existing and emerging market processes if an optimum for the entire system is to be achieved (**MacGill2020?**).

2.12 Conclusion

Frequency control is vital to the secure operation of a power system. The inherent characteristics and control systems of IBR differ from those of synchronous machines and this poses both opportunities and challenges to frequency control arrangements in mandatory pool markets with growing instantaneous penetrations of IBR. The frequency control performance of a power system is highly influenced by the frequency control strategy, which consists of the control mechanisms, electricity market design and the regulatory mechanisms that are in place, and the frequency control capability of its resources. Determining the appropriate combination of these mechanisms will require examining the interfaces between market-based, regulatory and control mechanisms and identifying the benefits, costs and trade-offs associated with particular design choices. This will enable electricity market designers to make an informed choice in implementing effective and efficient frequency control arrangements in low-carbon electricity markets.

3 | Research framework

4 | Frequency control arrangements: insights from the National Electricity Market

4.1 Link to thesis

This para will link this chapter (paper) to the broader thesis.

4.2 Abstract

For restructured electricity industries undergoing energy transition, designing effective and efficient frequency control arrangements is a complex and ongoing task that requires appropriate configuration of controllers, generator technical connection requirements, market arrangements and wider policy settings. In this paper, we provide an overview and assessment of these arrangements in Australia's National Electricity Market - a useful case study given its long-standing frequency control ancillary services markets, yet recent challenges in maintaining secure frequency control. We assess the performance of these evolving arrangements in delivering improved frequency control outcomes, with particular regard to growing renewable penetrations and evident tensions between mandatory requirements and market-based incentives. Based on this as-

sessment, we draw out four key insights on designing frequency control arrangements as power system capabilities and needs change: 1) Understanding control action interactions, 2) Implementing efficient price formation and cost-allocation mechanisms, 3) Monitoring and assessing service provision to better align participant remuneration with service quality, and 4) Considering both regulatory and market mechanisms and their consequences and interactions. In particular, we discuss the trade-offs between effective and efficient outcomes, and provide arguments for more robust and forward-looking frequency control arrangements during energy transition.

4.3 Introduction

As a consequence of growing momentum to address global warming and continually declining technology costs, many power systems around the world are undergoing an energy transition in which significant capacity additions of variable renewable energy (VRE) and other inverter-based resources (IBR) are being accompanied by the progressive retirement of existing fossil fuel generation (International Energy Agency, 2021). Such power systems are currently experiencing or expected to soon experience high instantaneous penetrations of VRE (i.e. beyond 50% of grid demand being met by VRE at any given time), which can pose technical challenges to the stable and secure operation of a power system (Kenyon et al., 2020; Kroposki et al., 2017; Meegahapola et al., 2021). While several of these challenges have technological solutions of various maturities, configuring mechanisms in an effective and efficient manner across power system design layers, which span from how resources are controlled to how grid codes and markets are designed, remains an open and significant challenge.

In this article, we focus on one aspect of power system security: control of AC frequency. Maintaining frequency near the nominal value of a power system (either 50 or 60 Hz) is contingent on the ongoing balance of active power supply and demand within a synchronous area (Grainger, 1994). Power system frequency deviations are a consequence of instantaneous supply-demand imbalances, which typically occur as a result of system variability (predictable changes in supply or demand, such as fluctuations and ramps of generation or load) and uncertainty (unpredicted changes in supply or demand, such as forecast errors or unplanned outages) (Ela et al., 2011). System operators (SOs) achieve short-term active power balancing using reserve capacity. Whilst there are many names for these reserves[1], this article will focus on a common subset that responds to and mitigates frequency deviations over short timeframes (milliseconds to minutes). We will refer to such reserves as *Frequency Control Services* (FCS). If FCS are insufficient or inadequate, the system frequency may deviate beyond acceptable system limits and lead to equipment damage, load shedding, generator trips and cascading failures that lead to blackouts (Kirby et al., 2002; Ulbig et al., 2014).

In electricity industries with competitive markets for energy and FCS, frequency control arrangements consist of control, regulatory and market-based mechanisms (Mancarella and Billimoria, 2021). Control mechanisms specify the technical requirements for FCS. Regulatory and market-based mechanisms are used by the SO to:

1. Mandate or incentivise participant behaviour in the energy market that facilitates system balancing. This includes enforcing dispatch compliance or penalising participant portfolio imbalances; and

[1]The term *balancing services* is used in European systems, whereas the term *operating reserves* is widely used in North America.

2. Procure FCS from capable resources (i.e. generators, loads and network elements).

Regulatory FCS procurement mechanisms are often mandatory and include equipment standards, connection requirements and SO intervention, whereas market-based FCS procurement mechanisms are often voluntary and include remunerative schemes and contract or spot markets. Together, these mechanisms dictate the physical effectiveness and productive, dynamic, price formation and cost-allocation efficiencies of FCS provision and procurement. Well-designed arrangements should be effective and efficient, where *effectiveness* entails sufficient and robust frequency response to meet physical power system requirements and *efficiency* relates to frequency response being provided at low cost, both now and into the future (Y. Rebours et al., 2007; van der Veen and Hakvoort, 2016).

As power systems transition towards higher instantaneous penetrations of VRE and IBR, SOs are likely to face the following challenges to short-term system balancing that may require existing frequency control arrangements to be revisited:

- VRE adds variability and uncertainty to a power system, particularly if similar technologies are situated within close proximity of one another (i.e. correlated production and/or forecast errors) (Australian Energy Market Operator, 2020a; Keeratimahat et al., 2021). Furthermore, unless an appropriate response is incorporated and enabled in their control systems, VRE and other IBR do not provide FCS. In jurisdictions that do not require, incentivise or allow VRE and IBR to provide FCS, the displacement of synchronous machines in dispatch has led to lower availabilities of resources that provide FCS (Australian Energy Market Operator, 2020b; Denholm et al., 2020; Milano et al., 2018) .

- In jurisdictions with competitive markets for energy and FCS, there is a tension between achieving economically efficient markets and the redundancy, certainty and control afforded to the SO. While the societal and economic costs of power system failure are often very large, it may be difficult for the SO to justify the cost of mitigation measures when they are ongoing or significant and when the joint probability of events or failures is low. The uncertainties associated with energy transition and the impacts of global warming are likely to present additional challenges. Power system security measures may need to be implemented rapidly and be both robust to a range of futures and resilient in the face of shocks, such as severe weather events (Eggleston et al., 2021; Prakash et al., 2021).

In this paper, we provide insights and recommendations on designing more effective and efficient frequency control arrangements based on experience from the Australian National Electricity Market (NEM). The NEM is currently experiencing relatively high system-wide instantaneous VRE penetrations (just over 60% in 2021) and is expected to experience penetrations as high as 75-100% by 2025 (Australian Energy Market Operator, 2021a, 2021b). Though the NEM's frequency control arrangements were once arguably world-leading (Riesz et al., 2015; Thorncraft and Outhred, 2007), the speed at which system capabilities and needs are changing and the removal of mandatory requirements in 2001 as a part of a paradigm shift from obligation to remuneration for FCS have exposed design issues. In attempting to address these issues, the NEM's rule makers have placed FCS obligations on generators and transmission network operators and have undertaken reforms to the NEM's energy and FCS markets, including introducing a new market to procure emergency fast frequency response (FFR) from IBR. Whilst the NEM is an electrically-isolated power system with a relatively simple energy-only market, the insights and recommendations from this paper are likely to be relevant to other power systems and interconnections as their existing conventional generation retires and VRE deployment levels increase.

This paper offers three contributions to the literature. First, we provide a high-level overview and comparison of the key features of frequency control arrangements in North America and Central and Western Europe, and provide a review of the most prominent challenges to designing effective and efficient frequency control arrangements and the potential solutions discussed in the literature. Second, we provide a comprehensive update to previous literature on frequency control in the NEM (Riesz et al., 2015; Thorncraft et al., 2008; Thorncraft and Outhred, 2007). Our analysis benefits from recent experience in the NEM that encompasses deteriorating frequency performance, the reintroduction of mandatory requirements and integrating higher shares of VRE. While several of these aspects have been discussed independently in the literature, this paper seeks to provide a structured and holistic analysis of developments in the NEM and their implications for frequency control arrangement design. Third, this article advocates for designers placing a greater emphasis on delivering forward-looking frequency control arrangements during energy transition through the implementation of more robust regulatory mechanisms and ensuring that market-based mechanisms are capable of supporting FCS investment. As highlighted in the following sections, these design features have received surprisingly little attention in the literature.

The rest of the chapter is structured as follows. In Section 4.4, we provide an overview of typical frequency control arrangements, with a focus on restructured electricity industries in North America and Europe, and the main challenges faced in their design. We describe the NEM, its frequency control arrangements and the specific challenges posed by increasing penetrations of VRE and other IBR in Section 4.6. In Section 4.7, we analyse the performance of the NEM's frequency control arrangements in responding to the challenges explored in Section 4.4, with primary frequency response and regulation (secondary frequency response) services in the NEM as case studies. Based on our analysis, we conclude by offering four key insights to operators, regulators and market-bodies that include understanding control action interactions; ensuring that arrangements are capable of supporting investment in FCS capability; monitoring, assessing and remunerating FCS performance; and considering both regulatory and market-based mechanisms in the design of effective and efficient frequency control arrangements.

4.4 Context

4.4.1 Conventional frequency control schemes

SOs employ hierarchical and sequential frequency control schemes. In most power systems, such schemes implicitly include inertial response and explicitly define FCS such as primary frequency response (PFR), secondary frequency response (SFR) and tertiary frequency response (TFR). In general, once frequency has deviated from the system nominal value, synchronous machines provide an inertial response that is inherent and immediate in slowing the rate of change of frequency (RoCoF). Within seconds, generators and/or loads provide autonomous and decentralised control action through PFR (Eto et al., 2018; Machowski et al., 2020). PFR arrests the frequency deviation to enable the slower and more centralised control actions of SFR and TFR to return the power system frequency to its nominal value (Ela et al., 2012b; Eto et al., 2010). Should system frequency continue to rise or fall beyond the system's allowable limits, emergency protection schemes such as under-frequency load shedding (UFLS) and over-frequency generation shedding (OFGS) relays may be triggered. In some systems, RoCoF relays are also used to prevent high RoCoFs from tripping or damaging equipment and to contain frequency nadirs and zeniths (Akram et al., 2020; DGA Consulting, 2016; Miller et al., 2017a).

4.4.2 Procurement of frequency control services

Except for inertial response from synchronous machines, the SO procures FCS capacity from capable resources within its control area and, in the case of SFR and TFR, activates FCS energy if necessary. In electricity industries where the SO owns most if not all the generation assets (i.e. a vertically-integrated utility), the SO is able to jointly schedule generation and FCS capacity with knowledge of the condition of the system and the status and cost structures of their plant. However, many electricity industries have undergone some degree of restructuring, which has created a greater role for competitively-oriented decentralised decision-making (van der Veen and Hakvoort, 2016) . The diverse outcomes of restructuring processes and differences in technical characteristics (e.g. capabilities of resource mix and network topology) have led to a wide range of frequency control arrangements across power systems (Poplavskaya and de Vries, 2019; Y. Rebours et al., 2007) , which have been reviewed and compared extensively within industry and academic literature (Banshwar et al., 2018; Brooks and Lesieutre, 2019; Ela and Hytowitz, 2019; Hewicker et al., 2020; Lopez et al., 2020; Ocker et al., 2016; Y. G. Rebours et al., 2007a, 2007b; Reishus Consulting LLC, 2017; Zhou et al., 2016).

In restructured electricity industries, the provision of more passive FCS (e.g. ride-through capabilities) is usually mandated by regulatory mechanisms such as connection agreements and grid codes, whereas FCS that require additional response capabilities or impose opportunity-costs on suppliers are procured and remunerated by the SO through market-based mechanisms. In Section 4.4.3 & Section 4.4.4, we provide an overview of typical features[2] and key developments in market-based mechanisms for procuring FCS in North America and Central and Western Europe, respectively. These regions best represent the two prevailing short-term wholesale electricity market models: central dispatch markets, in which the SO issues dispatch instructions, and decentralised or self-dispatch markets, in which resource dispatch is managed by market participants (Ahlqvist et al., 2018). Given that FCS and energy are partially substitutable goods, the characteristics of short-term wholesale electricity markets heavily influence the design of FCS arrangements and thus these regions provide an interesting contrast. However, despite their differences, the SO plays a central role in both of these regions as they determine the area demand for FCS capacity, activate FCS energy as required and are ultimately responsible for ensuring that the power system is balanced and securely operated.

[2]We note that there are numerous differences between jurisdictional arrangements and terminology in each of these regions. For a more general overview of potential procurement models, refer to Billimoria et al. (2020).

4.4.3 North American markets

In North America, central dispatch wholesale electricity markets are operated by an Independent System Operator (ISO) or Regional Transmission Organization (RTO) and are distributed across three synchronous areas. These markets consist of two short-term centralised platforms: a day-ahead market and a real-time market. In the day-ahead market, the SO solves a security-constrained unit commitment problem using supply offers (single or three-part) and demand bids (quantity or price-quantity) to produce day-ahead locational marginal prices and a financially-binding hourly schedule. In the real-time market, the SO solves a security-constrained economic dispatch problem (typically every five minutes) using generator price-quantity offers and a demand forecast to produce real-time locational marginal prices and a set of physically and financially binding dispatch instructions. Thus, each short-term market is cleared to maximise social welfare whilst respecting network and system security constraints (Chow et al., 2005; Cramton, 2017).

Except for Frequency Responsive Reserves (i.e. PFR), operating reserves (i.e. FCS capacity) are explicitly procured by placing an obligation on load-serving entities to self-provide or purchase their share from SO-run FCS markets (Ela et al., 2012b; Zhou et al., 2016). These FCS markets are usually integrated into day-ahead market and, in most jurisdictions, the real-time market. Standard products in North American markets include Regulation (i.e. SFR during normal operation), Spinning and Non-Spinning Reserves (i.e. TFR deployed following an event) (Ela and Hytowitz, 2019; Hewicker et al., 2020; Zhou et al., 2016). Participants can submit offers for FCS in addition to offer for energy. Unit commitment and economic dispatch permit co-optimisation of energy and FCS procurement. From the perspective of the SO, co-optimisation ensures that the total system cost of achieving an energy supply-demand balance is minimised alongside FCS requirements, subject to network and system security constraints. From the perspective of participants, co-optimisation leads to an FCS price that not only reflects the price offer of the marginal resource, but also any ”profit” it forgoes in the energy market (assuming supplier offers reflect their short-run marginal costs) (Ela et al., 2012a; Isemonger, 2009). As such, ISO/RTO FCS markets can compensate opportunity-costs related to the day-ahead and/or real-time market but only allocate costs to load-serving entities through a procurement obligation.

Though North American FCS markets have predominantly procured and remunerated FCS capacity, ISO/RTOs (except Texas’ ISO, ERCOT) were ordered to also remunerate Regulation providers for the quantity of energy provided whilst accurately following control signals by the Federal Energy Regulatory Commission’s (FERC) Order 755 (Commission, 2011). As such, Regulation providers offer a quantity of capacity, a price for capacity and a price for ”mileage”, which is the energy delivered. Remuneration for Regulation takes performance (the ability of a resource to follow the ISO/RTO’s control signals) into account, though how this is implemented varies between ISO/RTOs (Ela and Hytowitz, 2019; Fernández-Muñoz et al., 2020). A notable example is the PJM RTO, which uses both a standard SFR control signal (RegA) and faster SFR control signal (RegD) intended for battery energy storage systems (BESS). PJM determines how interchangeable a resource’s RegD provision is with RegA provision (the marginal benefit factor) to clear the Regulation market and calculates a performance score for use in market clearing and settlement. However, according to the independent market monitor, the omission of the marginal benefit factor from market settlement has led to perverse market outcomes (Brooks and Lesieutre, 2019; Monitoring Analytics, 2021).

4.4.4 European markets

Most of the electricity markets of Central and Western Europe are self-dispatch and consist of two short-term platforms: the day-ahead market and the intraday market, which can be continuous, composed of frequently-run discrete auctions or a combination of the two. Each of these platforms is coupled across the majority of market zones in Europe, with a single price coupling algorithm used to simultaneously clear zonal day-ahead markets and a single order book compiled to match cross-zonal intraday orders (EPEX Spot, n.d.; NEMO Committee, n.d.). In contrast to North American electricity markets, the market operator is responsible for market operation and is distinct from the Transmission System Operator (TSO). Generation and load are managed by Balancing Responsible Parties (BRP), which must submit binding operational schedules to the TSO ahead of delivery (often by the day prior to delivery). As BRPs become aware of potential deviations closer to real time (e.g. improved forecasts), they are able to adjust their submitted schedules (i.e. remain "balanced") through trades on the intraday market (Lago et al., 2021; Müsgens et al., 2014). BRPs face financial repercussions if they are imbalanced via an imbalance price and, in some jurisdictions, are legally obliged to be balanced (ENTSO-E WGAS, 2021).

Following gate-closure of the intraday market, residual imbalances are primarily addressed by FCS (known as balancing services) procured by the TSO. Standard FCS in Europe include Frequency Containment Reserve (i.e. PFR), automatic Frequency Restoration Reserves (i.e. SFR), and manual Frequency Restoration Reserves and Replacement Reserves (i.e. both TFR), with minimum technical requirements for each specified by the European Network of Transmission System Operators for Electricity (ENTSO-E) (European Network of Transmission System Operators for Electricity, 2013). Depending on the FCS product and the jurisdiction, TSOs may distinguish between FCS capacity (balancing capacity) and the delivery of FCS energy (balancing energy). The provision of one or both is mandated in some cases, but where both are procured competitively, Balancing Service Providers (BSP) typically submit separate offers for FCS capacity and FCS energy (Abbasy, 2012). FCS capacity markets are often cleared days to months in advance of real-time whereas the FCS energy market, which effectively constitutes merit-order or pro rata activation of capacity for FCS energy provision, is cleared within an hour or minutes of real-time (ENTSO-E WGAS, 2021; Ocker et al., 2016; Poplavskaya and de Vries, 2019). FCS capacity costs are typically allocated to power system users via a grid tariff. FCS energy costs are typically allocated to BRPs based on their schedule deviations and an imbalance price, which may differ from the FCS energy price paid to BSPs (Hirth and Ziegenhagen, 2015; Vandezande et al., 2010). As such, European FCS markets generally disincentivise causers of imbalance through the imbalance price, which may also recover or reflect the cost of FCS energy. However, since FCS capacity markets are typically decoupled from and cleared ahead of short-term energy markets, perceived opportunity-costs based on expected short-term energy market prices must be internalised within participants' FCS offers.

Given the relatively high degree of interconnection between transmission systems in Central and Western Europe, cross-TSO initiatives are in place and being expanded to address imbalances and share FCS across the Continental Europe synchronous area. When sufficient cross-TSO transmission capacity is available, initiatives currently in place enable participating TSOs to jointly procure Frequency Containment Reserve capacity, net imbalances (i.e. reduce the demand for SFR by aggregating individual control area imbalances) and jointly procure automatic Frequency Restoration Reserve capacity and energy (European Network of Transmission System Operators for Electricity, 2020). Further efficiency gains are expected following the implementation of integrated market platforms for imbalance netting and balancing energy for SFR and TFR. The implementation of these platforms is mandated by the European Commission's European Balancing Guideline and requires certain FCS product definitions and market features to be harmonised across the balancing energy markets of participating TSOs (50hz, 2017; European Commission, 2017).

4.5 Designing frequency control arrangements

As with any policy problem, designing frequency control arrangements in restructured electricity industries requires design principles, variables and performance criteria to be established. The public good characteristics of frequency control have heavily influenced arrangement design principles across jurisdictions, such as the common preference for the SO to centrally coordinate FCS procurement and activation (Müsgens et al., 2014; Y. Rebours et al., 2007). In contrast, though some design variables are common, others may only apply to particular systems based on their resource mix, network topology and/or market design. Y. Rebours et al. (2007) discuss design variables for central dispatch markets related to the following arrangement features:

1. FCS procurement;

2. Price formation, which when efficient should lead to FCS prices not only reflecting the true cost of the service, but also its true value to the system; and

3. Allocation of the cost of FCS.

Similarly, Abbasy (2012) discusses the main design variables applicable to European self-dispatch markets. van der Veen and Hakvoort (2016) build upon this work to provide a more comprehensive treatment of design variables in self-dispatch markets. Y. Rebours et al. (2007), Abbasy (2012) and van der Veen and Hakvoort (2016) all propose some variation of effectiveness and efficiency as performance criteria, with van der Veen and Hakvoort (2016) analysing the various trade-offs between and within each criterion.

Despite the well-defined nature of the design problem, there are several challenges to achieving effective and efficient arrangements. In Section 4.5.1 & Section 4.5.2, we present the most prominent challenges and their treatment in the literature.

4.5.1 The influx of VRE and other IBR in power systems

As discussed in Section 4.3, VRE adds variability and uncertainty to power systems which, at the very least, can lead to increased procurement and activation requirements for PFR and SFR during normal operating conditions (Ela et al., 2011). Three proposals to address this issue and thus reduce FCS requirements with growing penetrations of VRE have been discussed in the literature. The first is to shorten energy market trading/dispatch intervals (Ocker and Ehrhart, 2017; Riesz and Milligan, 2015) and the time between market gate closure and dispatch (Katz et al., 2019), thereby enabling scheduling based on up-to-date system conditions and forecasts. The second is to increase coordination between control areas within a synchronous area by netting imbalances (King et al., 2011), jointly procuring and dispatching FCS (Scherer et al., 2013) or aggregating them into a single market region (Milligan and Kirby, 2010; Riesz and Milligan, 2015). These two proposals alone have delivered significant system savings in Germany despite growing penetrations of VRE (Hirth and Ziegenhagen, 2015; Ocker and Ehrhart, 2017). The third is for the SO to determine the required quantity of FCS capacity (*dimensioning*) using dynamic and probabilistic approaches (as opposed to static and deterministic) that adequately reflect current or expected power system conditions and an acceptable level of risk, such as a reliability standard (De Vos et al., 2019; Holttinen et al., 2013; Ortega-Vazquez et al., 2020).

In recent years, SOs have become increasingly concerned with growing penetrations of asynchronous IBR leading to higher RoCoFs and fewer resources offering conventional FCS (Denholm et al., 2020; DGA Consulting, 2016; Hartmann et al., 2019). However, VRE and other IBR are able to provide tunable conventional FCS, FFR and/or an inherent response that strongly resembles the inertial response of synchronous machines[3] if this is facilitated by arrangement design (Fernández-Muñoz et al., 2020; Mancarella and Billimoria, 2021; Miller et al., 2017b). Following a contingency event in a low-inertia power system, rapid FCS from IBR can mitigate higher RoCoFs, which when unabated can lead to deeper

[3]The terms *virtual, emulated and synthetic* inertia have been used in the literature to refer to a proportional active power response to RoCoF. However, these terms do not distinguish whether the inverter control scheme provides an inherent response (i.e. from inverters operated as a voltage source which are commonly referred to as *grid-forming inverters* (Cherevatskiy et al., 2020; Lin et al., 2020)) or a controlled response following frequency measurement (Eriksson et al., 2018; Tielens and Van Hertem, 2016).

frequency nadirs and zeniths and the subsequent activation of UFLS or OFGS (Australian Energy Market Operator, 2017a; NERC Inverter-Based Resource Performance Task Force, 2020; Tielens and Van Hertem, 2016).

4.5.2 Achieving economic efficiency

Achieving short-run efficiency entails supplier costs being reflected in their offers and adequately propagated to FCS prices, and the SO assigning at least some portion of FCS costs to system users that create a need for procurement or activation. A widely used pricing approach in ISO/RTO co-optimised FCS markets is a marginal price which incorporates the marginal resource's short-term market opportunity-costs and their offer, which could reflect potential mileage or wear-and-tear costs (Frew et al., 2021a; Zhou et al., 2016). Though improving cost-allocation has been repeatedly proposed in North American literature (Ela et al., 2012a; Isemonger, 2009; Milligan et al., 2011), FCS costs are predominantly socialised across loads based on demand or consumption. In Europe, however, much attention has been given to FCS market pricing, scoring (the order in which offers are selected) and cost-allocation. Specifically, literature on European FCS markets has explored whether pay-as-bid or uniform pricing better facilitates suppliers revealing their true costs (Hirth and Ziegenhagen, 2015; Müsgens et al., 2014; Ocker et al., 2018), the particular offers scoring should consider (Ehrhart and Ocker, 2021; Müsgens et al., 2014) and the design of imbalance prices to sufficiently incentivise short-term balancing (Hirth and Ziegenhagen, 2015; Papavasiliou, 2020; Vandezande et al., 2010). Regardless, both European and North American literature suggest that increased competition in FCS markets is a priority. This could be facilitated by enabling distributed and utility-scale VRE and IBR to qualify for FCS provision, reducing minimum offer quantities, separating raise and lower (positive and negative) products and increasing market clearing frequency and the time resolution of FCS products (Frew et al., 2021a; Hirth and Ziegenhagen, 2015; Lago et al., 2021; Poplavskaya and de Vries, 2019). Despite the typically "shallow" nature of FCS markets (i.e. additional supply can significantly reduce prices (Riesz and Milligan, 2015)), dynamic efficiency has received considerably less attention. Notable exceptions include Papavasiliou (2020) and Frew et al. (2021a), who briefly discuss the potential for FCS scarcity pricing to better reflect the true value of system reliability and support investment in FCS.

An additional challenge in implementing efficient FCS markets involves the trade-offs that must be considered. As outlined in Section 4.3, some mechanisms that improve efficiency may come at the expense of visibility, control and redundancy afforded to the SO, which typically does not own any FCS-capable assets. The former is typically achieved using market-based mechanisms and the latter through regulatory mechanisms. Ela et al. (2012b), Billimoria et al. (2020), Mancarella and Billimoria (2021) and Lal et al. (2021) discuss several prerequisites for implementing market-based mechanisms and stress that balance between market-based and regulatory mechanisms may be required. However, achieving this balance can be challenging due to the asymmetry between the risk of an event and its consequences, and that between the benefits of market efficiency and the cost of resilient and robust mitigation measures (Lal et al., 2021; Mancarella and Billimoria, 2021). Another trade-off is the arbitrary definition of FCS products. Market-based mechanisms will work best when FCS are "discrete" commodities and fungible. However, this ignores the wide "spectrum" of resource technical capabilities. Favouring fungibility may obscure physical and control interdependencies between FCS and restrict or fail to incentivise higher quality provision, thereby leading to an inefficient overall outcome (Gimon, 2020; MacGill and Esplin, 2020).

4.6 Frequency control arrangements in the Australian National Electricity Market

4.6.1 Overview of the NEM

The NEM consists of five regions corresponding to the eastern and southern Australian states of New South Wales (NSW), Queensland (QLD), Victoria (VIC), South Australia (SA) and Tasmania (TAS) (Figure 4.1). In 2020, the NEM serviced a total electricity consumption of approximately 190 TWh/year and a peak demand of approximately 35 GW across a 'stringy' network over 5000 kilometres long with relatively weak interconnection between regions through interconnectors (Australian Energy Regulator, 2021; MacGill and Esplin, 2020). As high voltage DC transmission connects the island of Tasmania to the mainland state of Victoria, the NEM consists of two synchronous areas operated at a nominal frequency of 50 Hz: the mainland states and Tasmania. Due to the large distances involved, the NEM is not electrically connected to other markets.

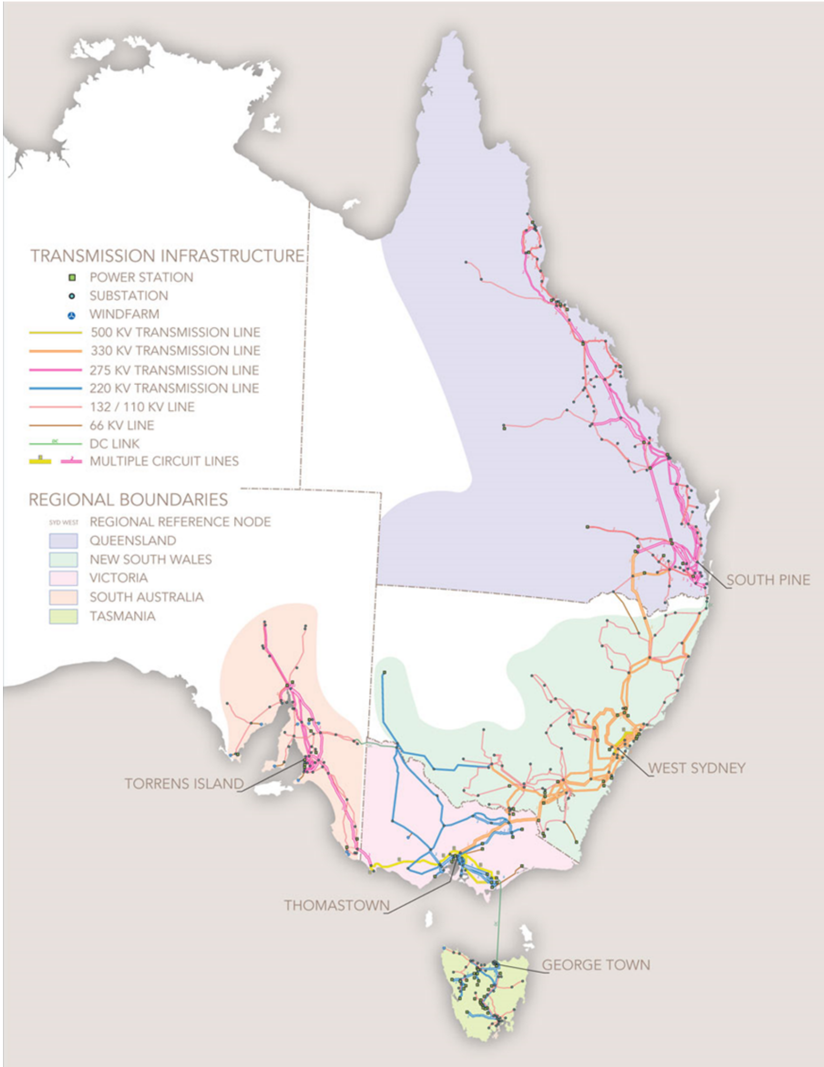


Figure 4.1: Regions/states and transmission in the NEM. Source: Australian Energy Market Commission (n.d.a)

The NEM is a single platform (real-time) energy-only market with no explicit capacity mechanisms. Unit commitment is managed by market participants, who must submit resource-specific offers for energy and Frequency Control Ancillary Services (FCAS) capacity in price-quantity pairs the day before delivery. These offers are subsequently used in a pre-dispatch process, which provides forecasted market information (e.g. generation and demand, interconnector flows, prices, etc.) to market participants. While prices in submitted offers are fixed, participants may change the energy volumes in their offer up to a few minutes before the delivery dispatch interval commences. As the NEM is single-sided, security-constrained economic dispatch is run every five minute to meet forecast demand at least cost, subject to network and security constraints. Much like ISO/RTO markets, energy and FCAS markets are co-optimised with respect to technical feasibility and cost (Australian Energy Market Operator, 2021c, 2017b). Real-time dispatch produces zonal marginal prices for energy and FCAS, which form the basis for market settlement in each of the NEM's regions.

4.6.2 FCAS markets

The NEM's competitive FCAS markets consist of eight separate raise and lower FCAS products that can be classed as regulation FCAS or contingency FCAS, with the former responsible for control when frequency is within the normal operating frequency band (NOFB) and the latter for when frequency deviates outside the NOFB after an event (see Table 4.1). This is similar to arrangements in many ISO/RTO markets, where FCS are divided into event and non-event reserves (Ela et al., 2011).

Security-constrained economic dispatch includes system-wide and regional FCAS requirement constraints. Regulation and contingency FCAS are typically procured for and from all regions of the NEM in the absence of binding local constraints. Local requirements for FCAS procurement apply to Tasmania and to the other regions of the NEM if they experience network constraints, are at risk of separation or when islanded[4] (Australian Energy Market Operator,

[4]From 2015-2019, the Tasmanian and mainland contingency FCAS markets were separated on average for 40% of the time due to the technical limitations of the high voltage DC interconnector (GHD Advisory, 2019). However, if the interconnector flow is within the appropriate operating envelope, NEM-wide FCAS procurement is possible as the interconnector's frequency controller

2015a, 2010). Prices are calculated for each region of the NEM based on the sum of the shadow prices of local and system-wide constraints and FCAS costs are allocated to market participants based on a ”Causer Pays” principle, which bears similarities to imbalance penalties in European markets (Australian Energy Market Operator, 2015b). FCAS providers are paid for enablement (capacity provision) regardless of whether their capacity is activated (Australian Energy Market Operator, 2015b; Riesz et al., 2015; Thorncraft and Outhred, 2007).

For a resource to provide FCAS, it must meet pre-qualification criteria and undergo a registration process. Historically, FCAS was provided by thermal generation (predominantly coal and some gas), hydropower generation and some large loads, such as hydropower pumps and an aluminium smelter, as only resources associated with wholesale energy market participants were permitted to offer FCAS. In 2017, the first battery energy storage system (BESS) in the NEM began to offer FCAS and market reform enabled demand response (DR) aggregators to offer contingency FCAS without participating in the energy market (Aurecon, 2019; Australian Energy Market Commission, 2016). In recent years, new FCAS market entrants have included several DR aggregators, new BESS, distributed PV-battery virtual power plants and wind farms (the latter two through trials) (Aurecon, 2019; Australian Energy Market Operator, 2021d; Australian Energy Regulator, 2021). However, these new entrants tend to offer smaller volumes and there are still relatively few FCAS providers in the NEM, with no single FCAS product having more than 30 providers across the system or 8 providers in any one region (Australian Energy Regulator, 2021).

enables FCAS transfer between the mainland and Tasmania (Australian Energy Market Operator, 2017c).

Table 4.1: Frequency control ancillary services in the National Electricity Market. Sources: Thorncraft and Outhred (2007), Riesz et al. (2015), Australian Energy Market Operator (2017a), Australian Energy Market Operator (2010), Australian Energy Market Operator (2015a), Australian Energy Market Operator (2015b), Australian Energy Market Operator (2020c).

Product	Control action	Procurement	Timeframe
Regulation (raise & lower)	Centralised control through AEMO Automatic Generation Control (AGC), which adjusts unit set points	Minimum capacity enablement with dynamic additional reserve setting based on time error for every dispatch interval	Unit set points adjusted by AGC every 4-s over dispatch interval
6-s contingency (fast raise & lower)	Decentralised control response to locally-measured frequency, typically delivered through droop settings in governors or inverters or frequency-responsive loads (raise only)	Capacity enablement based on size of largest generator (raise) or load block (lower), minus assumed load relief for every dispatch interval	Full response delivered by 6-s after frequency has left NOFB and orderly transition to 60-s service
60-s contingency (slow raise & lower)			Full response delivered by 60-s after frequency has left NOFB and orderly transition to 5-min service

Product	Control action	Procurement	Timeframe
5-min contingency (delayed raise & lower)	Response pre-configured by AEMO but triggered in response to locally-measured frequency. Typically consists of unit control systems increasing or decreasing set points with sustained frequency deviations	Capacity enablement based on size of largest generator (raise) or load block (lower), minus assumed load relief and corresponding Regulation FCAS procurement for every dispatch interval	Full response delivered by 5-min after frequency has left NOFB and sustained until frequency returns to NOFB or 10-min has elapsed

4.6.3 NEM operation and governance

The Australian Energy Market Operator (AEMO) is responsible for the operation of the market and power system in the NEM in accordance with the National Electricity Rules (NER). They act as a single buyer of dynamically-determined volumes of FCS. The Australian Energy Market Commission (AEMC) is responsible for making or amending rules for the NEM. Both AEMO and the AEMC provide operational and strategic advice to the Energy Security Board (ESB), which is responsible for coordinating market oversight and longer-term reform such as the ongoing post-2025 NEM market design framework. As the market regulator, the Australian Energy Regulator (AER) monitors compliance with and enforces the NER.

4.6.4 Challenges to frequency control posed by VRE and IBR

The rapid pace at which IBR have entered the NEM was preceded by the exit of FCAS-capable synchronous generation (Figure 4.2). Many of these IBR do not currently offer FCAS or any meaningful frequency response to deviations other than the most extreme. Furthermore, though updated equipment standards require distributed IBR to ride-through and/or respond to certain frequency deviations, some inverter models have been found to be non-compliant and there is still a significant number of legacy systems in the NEM (Australian Energy Market Operator, 2021e; Stringer et al., 2020).

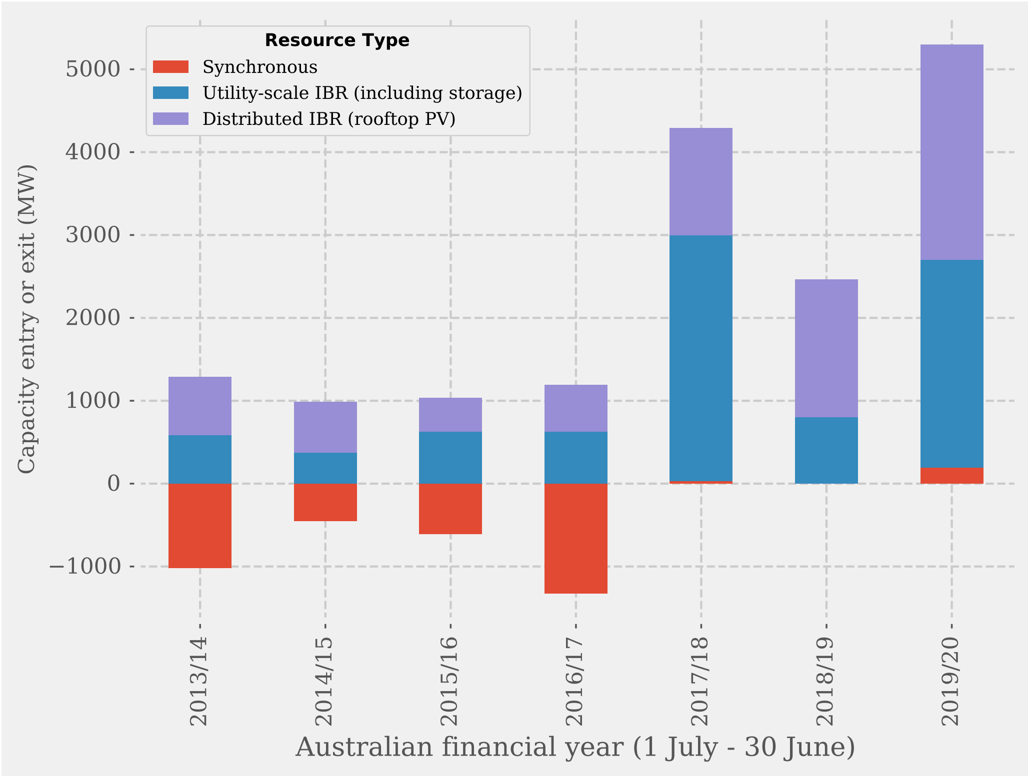


Figure 4.2: Entry (of IBR) and exit (of synchronous generation) capacity in the NEM between Australian financial years 2013/14 and 2019/20. Data source: Australian Energy Market Commission (2020a).

The challenges that VRE and other IBR pose to frequency control have been exacerbated by the NEM's network topology. Limited interconnection between regions reduces the NEM's cross-regional balancing capabilities and increases the likelihood of synchronous area separation following power system events, a consequence of which is that local requirements for FCAS may apply (Australian Energy Market Operator, 2019a). Furthermore, correlated variability and uncertainty can arise from intensive development of similar utility-scale VRE in areas with good wind or solar resources (as might occur in the Renewable Energy Zones identified by AEMO's least-regrets transmission planning study (Australian Energy Market Operator, 2020d)). This is also an issue at the distribution level given the significant installed capacities of rooftop solar PV located within proximity of one another in suburban areas (Australian Energy Market Operator, 2021f).

4.6.5 Features of NEM frequency control arrangements

Below, we highlight some noteworthy features of the NEM's frequency control arrangements that complement or contrast previous analyses in Thorncraft and Outhred (2007), Riesz et al. (2015) and Thorncraft et al. (2008).

4.6.5.1 Control mechanisms:

- There is no explicit TFR FCS in the NEM. Security-constrained economic dispatch is run every five minutes and is expected to relieve PFR and SFR and address supply-demand imbalances (Australian Energy Market Operator, 2020c).
- PFR from contingency FCAS is only required to respond to frequency deviations outside the NOFB (50 ± 0.15 Hz). When FCAS markets were implemented in the NEM in 2001, mandatory PFR around a tight deadband of $\pm$ 50 mHz was removed from the NER (Australian Energy Market Operator, 2019b). Since then and prior to 2020, there was no explicit procurement or requirement for tight-deadband PFR provision within the NOFB. The decline in the provision of tight-deadband PFR in the NEM is discussed further in Section 4.8.
- The mainland synchronous area is controlled as one balancing area by AEMO's AGC (i.e. no tie-line biased SFR) despite limited interconnection between adjacent regions (Australian Energy Market Operator, 2018a). AGC control performance is discussed further in Section 4.9.

4.6.5.2 Market-based mechanisms:

- There are relatively few limits imposed on FCAS participation. FCAS can be provided by any technology through variable, switched or hybrid controllers (Australian Energy Market Operator, 2020e). Furthermore, regulation and contingency FCAS products are unbundled into raise and lower services, and contingency FCAS products are unbundled based on response time. All of these features improve the potential for participation and competition in FCAS markets, though market participants can and often are enabled to provide multiple FCAS.
- FCAS unbundling has enabled a 'Causer Pays' cost allocation framework. Raise contingency FCAS costs, which are incurred as insurance for the failure of a generator, are distributed amongst generators in proportion to their generation in the trading interval. Similarly, lower contingency FCAS costs are distributed amongst loads based on their consumption in a trading interval. A complex methodology is used to calculate monthly, portfolio-wide Causer Pays contribution factors (outlined in Australian Energy Market Operator (2018b) and summarised in Riesz et al. (2015)) that determine how regulation FCAS costs are allocated to market participants. We discuss the issues associated with this methodology in Section 4.9.
- The NEM co-optimises FCAS that respond within similar timeframes. In the absence of constraints, the volume of 5-minute delayed contingency FCAS procured is reduced by the volume of regulation FCAS enabled (Australian Energy Market Operator, 2010).

4.6.5.3 Regulatory mechanisms:

- Connecting utility-scale generators negotiate the frequency response capability of their plant between a minimum access standard and an automatic access standard, the latter guaranteeing network access to the applicant. A suite of generator standards for frequency response were added to the NER in October 2018 and apply to any newly-connecting generation. These standards include minimum frequency disturbance ride-through times, automatic generation output reduction following extreme over-frequency events and the capability to operate in a frequency response mode with a proportional response[5] (Australian Energy Market Commission, 2018a).

- Transmission Network Service Providers (TNSPs) are required to address any inertia shortfalls identified by AEMO within the NEM region in which they build, maintain, plan and operate the transmission network. AEMO's assessment considers whether an islanded region can be securely operated following a contingency event. Shortfalls can be reduced by special protection schemes (e.g. disconnection of load following interconnector trip) and the provision of FFR, but they must ultimately be met by providers of inertial response (Australian Energy Market Operator, 2020g, 2018c).

[5] In addition to these standards, newly-connected generation may install a synchronous condenser under the 'do no harm' requirements outlined in the NER if they are determined to have an adverse impact on system strength. Particularly when fitted with a rotating mass or flywheel, these synchronous condensers can also provide inertial response (Australian Energy Market Operator, 2020f).

4.7 Insights from the National Electricity Market

In light of existing challenges and those posed by energy transition, effective and efficient frequency control arrangements should enable sufficient FCS to be procured across timeframes and strike the appropriate balance between efficiency and robustness. In the following sections, we review issues associated with two core elements of the NEM's frequency control hierarchy (i.e. PFR and SFR), assess their physical and economic performance and outline reform underway. Drawing on developments in the NEM and our review of arrangements in North America and Europe, we then discuss the merits and flaws of regulatory and market-based mechanisms with respect to sufficiency and efficiency. We conclude by offering insights that could serve as design principles for jurisdictions revisiting their frequency control arrangements during energy transition.

4.8 Declining tight-deadband primary frequency response

When FCAS markets were implemented in 2001, mandatory tight-deadband PFR was superseded by two types of PFR: voluntary PFR within the NOFB and competitive procurement for PFR outside the NOFB in the form of contingency FCAS (Australian Energy Market Operator, 2019b).

As such, the NEM's frequency control scheme deviated from what has been argued to be international best practice as it only explicitly specified and procured wide-deadband PFR (i.e. deadband of $\pm$ 150 mHz) (Australian Energy Market Operator, 2019b). In contrast, ENTSO-E specifies that PFR providers have a deadband no greater than $\pm$ 10-15 mHz depending on the control area

(European Network of Transmission System Operators for Electricity, 2013) and FERC Order 842 mandates all newly-connecting generation in US interconnections to operate frequency-responsive control equipment with maximum deadbands of $\pm$ 36 mHz (Federal Energy Regulatory Commission, 2018).

In recent years in the NEM, the lack of an incentive or requirement for tight-deadband PFR and perceived disincentives to its provision (through Causer Pays contribution factors discussed further in Section 4.9) has led to many synchronous generators that once provided tight-deadband PFR to widen deadbands or install control systems that block or dampen PFR from the speed governor within the NOFB (Australian Energy Market Commission, 2020b). Furthermore, many VRE generators were deployed in the NEM and connected with inverter control systems that were unresponsive to any frequency deviations other than the most serious.

The extent to which tight-deadband PFR provision had declined in the NEM and the consequences of this became clear to AEMO following a major power system incident on the 25th of August 2018 (Australian Energy Market Operator, 2019c). Prior to the event, the QLD region was exporting $\sim$ 900 MW to the rest of the NEM. Around 13:11:41, lightning strikes at the QLD-NSW interconnector resulted in the QLD region being separated from the rest of the NEM with excess supply. The SA region was exporting $\sim$ 200 MW prior to the event and following QLD's separation, this increased by more than 200 MW in response to under-frequency. The sudden increase in active power flow triggered an emergency scheme that disconnected SA from the NSW-VIC synchronous area, resulting in local over-frequency.

There were diverse responses from various generators following the double separation event. While many synchronous generators provided some form of PFR though not enabled for FCAS, their response was withdrawn by their load controllers in several cases so that the unit could return to its dispatch target (e.g. green and pink lines in top frame of Figure 4.3). Wind and solar farms were either unresponsive, tripped due to protection settings in their inverters, or reduced their active power output in line with performance standards negotiated in their connection agreements (middle and bottom frames in Figure 4.3). AEMO attributed slow frequency recovery and under-frequency load shedding in NSW and VIC to insufficient PFR from generators and a lack of appropriate contingency FCAS within the islanded regions. Over 50% of fast and slow raise contingency FCAS needed in NSW-VIC was enabled in SA and QLD, whilst QLD had no lower FCAS enabled to respond to over-frequency[6] (Australian Energy Market Operator, 2019c).

[6] AEMO is currently investigating appropriate regional requirements for FCAS, particularly for contingency FCAS in the terminal regions of QLD and SA (Australian Energy Market Operator, 2020h, 2019d).

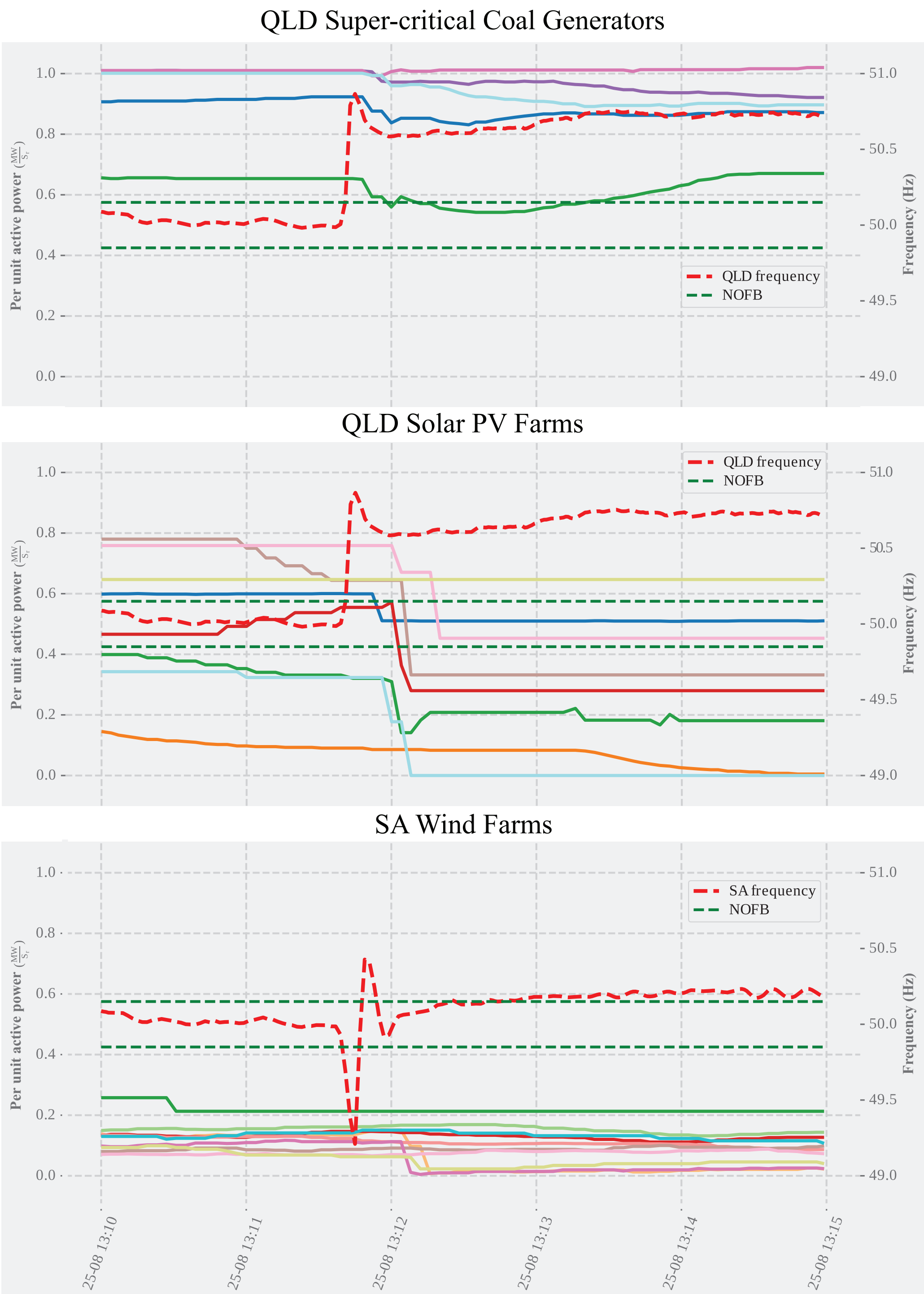


Figure 4.3: Active power output of QLD super-critical coal generators (top), SA solar PV farms (middle) and SA wind farms (bottom). The response of an individual generator is denoted by solid lines (obtained from 4-second AEMO SCADA data using NEMOSIS (Gorman et al., 2018)). None of these generators are enabled for FCAS. The red dashed line in each frame is the regional frequency as measured by high-speed (1-second) phasor measurement units.

Prior to this incident, deteriorating control of frequency within the NOFB was of concern to AEMO and the AEMC, and trials and investigations were recommended to inform the design of an incentive for tight-deadband PFR provision (Australian Energy Market Commission, 2018b). However, this separation event demonstrated the "urgent need for regulatory changes to arrest the ongoing decline in frequency performance in the NEM" and to enhance "the resilience of the NEM to similar major disturbances", with AEMO submitting a rule change proposal for all capable generators in the NEM to provide mandatory PFR with a maximum deadband of $\pm$ 0.015 Hz (i.e. 10% of the NOFB) (Australian Energy Market Operator, 2019b).

This rule was initially incorporated into the NER in 2020 as a temporary arrangement through the addition of a "sunset" after three years to demonstrate the AEMC's commitment to investigating incentives or market-based mechanisms for tight-deadband PFR (Australian Energy Market Commission, 2020b, 2020c). AEMO has specified PFR settings, including maximum droop and response time, but is unable to require generation to reserve headroom for PFR (Australian Energy Market Operator, 2020i).

4.9 Performance and efficiency issues of regulation services

For SFR provided by regulation FCAS within the NOFB to be effective, the dynamics of the system need to accommodate slower SFR control action and the centralised secondary controller (in the NEM, AEMO's AGC) needs to be properly configured. Prior to the introduction of mandatory PFR in the NEM, AEMO observed no significant improvement in NOFB frequency stability despite several increases in the minimum volumes procured for regulation FCAS in 2019

(Australian Energy Market Operator, 2019b). This is likely due to:

- A lack of fast and decentralised tight-deadband PFR supporting slower SFR;
- Inappropriate control signals being calculated within the AGC due to the use of rate limiters to account for ramping constraints, signal filtering and generator controller models that do not accurately reflect a unit's frequency response (DIgSILENT, 2017). The latter is the consequence of an absence of control coordination between market participants and AEMO; and
- Variable communication delays between individual unit controllers and AEMO's AGC system, and disparate response times from generators.

Furthermore, the control of all mainland regions as one balancing area can be problematic in the event of separation. AGC control of regulation FCAS enabled in islanded regions may exacerbate local frequency deviations when responding to the AGC frequency reference. This was the case during the double separation event on the 25$^{\text{th}}$ of August 2018, in which the AGC instructed raise regulation FCAS generators in QLD and SA to respond to under-frequency in the AGC frequency reference despite local over-frequency (Figure 4.4). Such incorrect control action can occur until AEMO is able to manually reconfigure the AGC to treat each island as a control area - a process which can take up to 15 minutes (Australian Energy Market Operator, 2019c) .

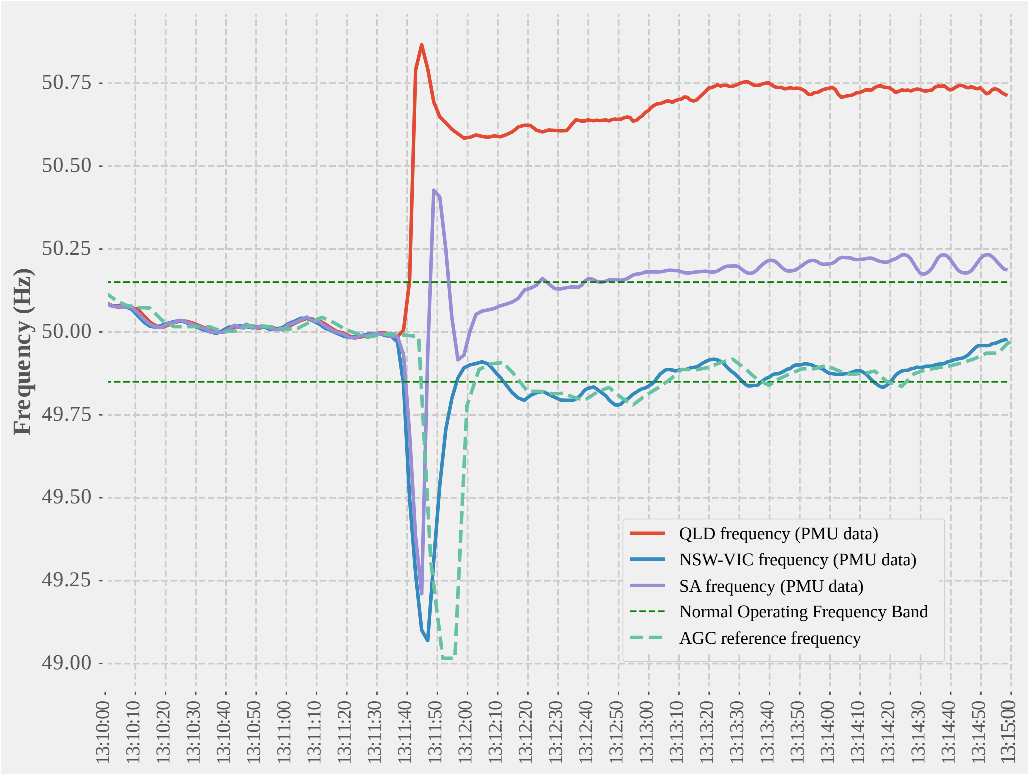


Figure 4.4: Regional phasor measurement unit frequency data and AGC reference frequency data from AEMO's NSW control centre (obtained using NEMOSIS (Gorman et al., 2018)) during the power system event on the 25th of August, 2018. Note that the AGC reference frequency deviates in the opposite direction to local frequency in QLD and SA.

Over time, inefficiencies in regulation FCAS procurement and cost-allocation have also become apparent. Regulation FCAS procurement in the NEM is dynamic beyond a minimum volume, but the dynamic component is based on the system time error (Australian Energy Market Operator, 2015a). Time error control is largely unnecessary as modern clocks no longer rely on power system frequency to keep the time (Y. Rebours et al., 2007). Furthermore, whilst AEMO is required to control the NEM within certain time error limits, these have been relaxed in recent years (Australian Energy Market Commission Reliability Panel, 2017). Given that time error is no longer prioritised as a control objective, dynamic regulation FCAS procurement based on better measures of sustained frequency deviation (e.g. mean absolute error as suggested by Riesz et al. (2015)) and/or a modelled distribution of potential intra-dispatch ramp uncertainty may be more suitable.

Regulation FCAS costs are allocated to market participants based on their contribution factor, a calculation which represents the extent to which the participant has contributed to the need for regulation FCAS through a deviation from a dispatch trajectory. Though the calculation methodology assigns weights to a generator or load's dispatch trajectory deviation based on the AGC regulation direction and mileage requirement every 4 seconds, the disincentive for dispatch deviation suffers from a disconnect to causation. This is because the contribution factors of a generator or load are averaged over a 5-minute dispatch interval, summed over a 28-day period and then within a market participant's portfolio (Australian Energy Market Commission, 2018b; Australian Energy Market Operator, 2018b; Australian Energy Regulator, 2020).

Much like portfolio-based balancing in Europe, the aggregation of contribution factors enables a market participant to offset antagonistic deviations with assisting deviations (from the provision of tight-deadband PFR) across its resources and time. However, the complexity and opacity of the methodology and cost-allocation process has contributed to the withdrawal of tight-deadband PFR in the NEM. Several generators disabled governor response in the NOFB in the belief that dispatch adherence alone will minimise Causer Pays liabilities (DIgSILENT, 2017).

4.10 NEM assessment and outlook

Though the introduction of competitive FCAS markets in 2001 initially resulted in significantly lower FCAS prices in the NEM (Riesz et al., 2015; Thorncraft and Outhred, 2007), volume-weighted average FCAS prices, particularly those for raise regulation and contingency services, have increased relative to the volume-weighted average energy price since 2016 (Figure 4.5). Furthermore, the increases in minimum regulation FCAS volumes and reductions in assumed load relief in 2019 have raised the procured volumes of regulation and contingency FCAS, respectively. Together, these factors have contributed to higher NEM-wide FCAS costs (Australian Energy Market Operator, 2019e). While quarterly FCAS costs were less than 1% of quarterly total NEM costs in 2015, 50% of all quarters from 2017 to 2020 had FCAS costs that were between 1-2% of total NEM cost (Australian Energy Regulator, 2021).

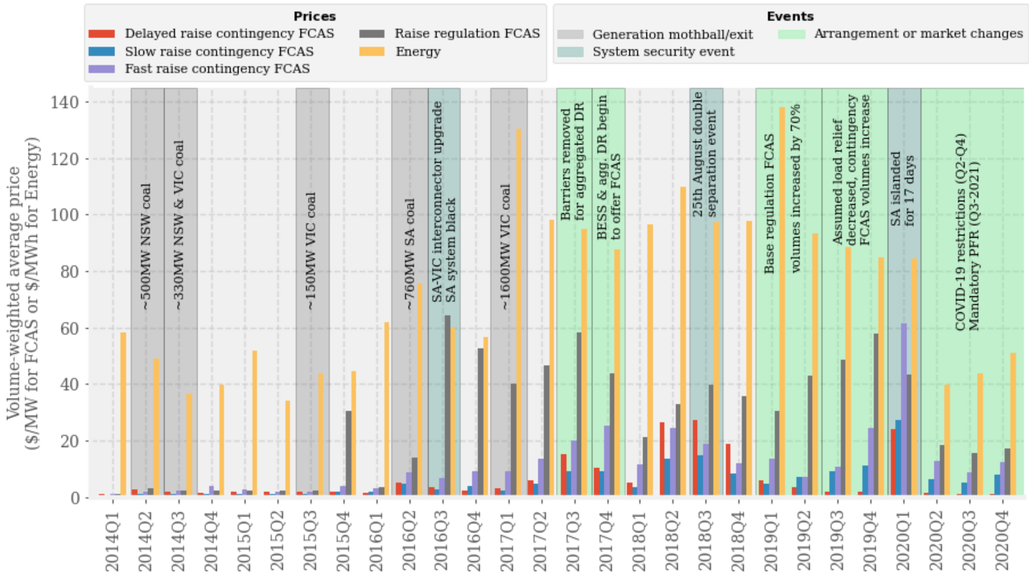


Figure 4.5: Events and volume-weighted NEM-wide average quarterly prices for energy, raise regulation FCAS and raise contingency FCAS in the NEM. The entry of new albeit smaller FCAS providers in 2017 was preceded by the retirement of several large thermal generation. Q1 2020 FCAS prices were high due to local procurement in the SA region, which was islanded for approximately two weeks. Note that while average energy prices fell in Q2-Q4 in 2020 to levels previously seen in 2014-2015 (due to lower demand during COVID-19 lockdowns), FCAS prices remained relatively high. Five-minute price and volume data obtained using NEMOSIS (Gorman et al., 2018).

Prior to the implementation of mandatory PFR, higher NEM FCAS costs were arguably not accompanied by an improvement in frequency control performance. Alongside deteriorating frequency control performance within the NOFB (Figure 4.6), AEMO has expressed a loss of confidence in the NEM's resilience to complex power system events, such as the double separation incident on the 25th of August 2018 (Australian Energy Market Operator, 2019b). These events are typically more severe than the 'credible' contingency events (i.e. N-1 contingency) that dictate the volume of contingency FCAS procured.

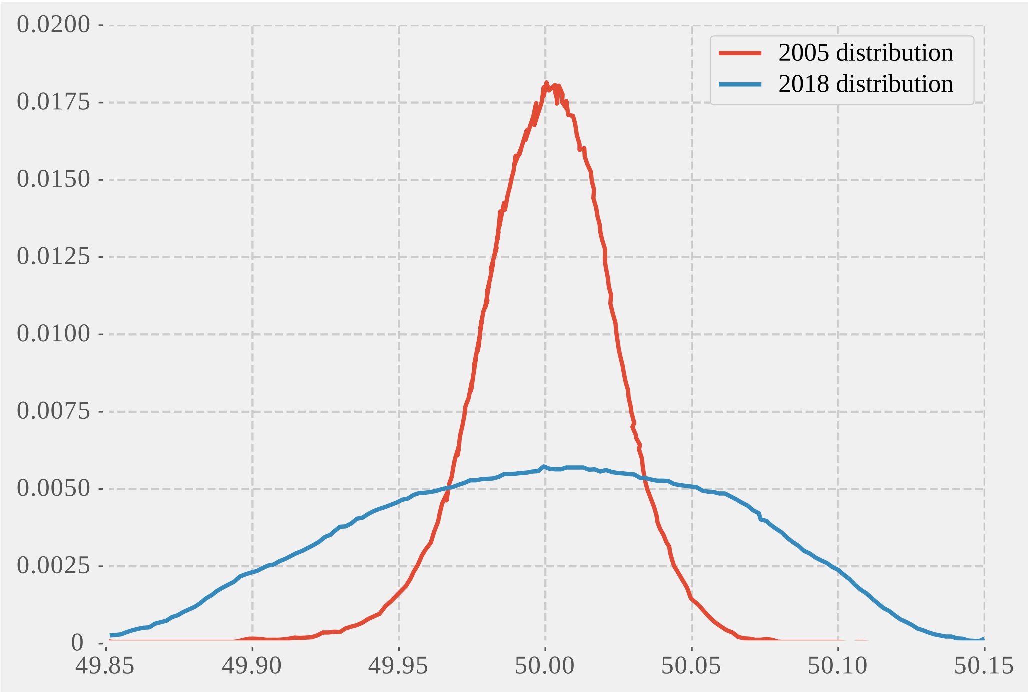


Figure 4.6: Normalised distribution of mainland frequency within the NOFB in 2005 and 2018. Reproduced from (Australian Energy Market Operator, 2019d)

Since the implementation of the mandatory PFR, settings specified by AEMO have been applied to a majority of large synchronous generators ($>$ 200MW) and some smaller synchronous generators. Despite the absence of requirements for maintaining headroom and/or footroom, preliminary analysis by AEMO[7] suggests that mandatory PFR has delivered better control of frequency within the NOFB (see Figure 4.7) and reduced excursions beyond the NOFB (Australian Energy Market Operator, 2021f). As a result of this initial success and further technical advice provided by AEMO, the AEMC has indicated that it intends to retain mandatory PFR at a tight-deadband following the "sunset" of the initial rule (Australian Energy Market Commission, 2021a).

[7]The ramp rate used in dispatch by AEMO is the lesser of a telemetered rate or a ramp rate submitted in a resource's offer for energy, and was obtained using NEMOSIS (Gorman et al., 2018).

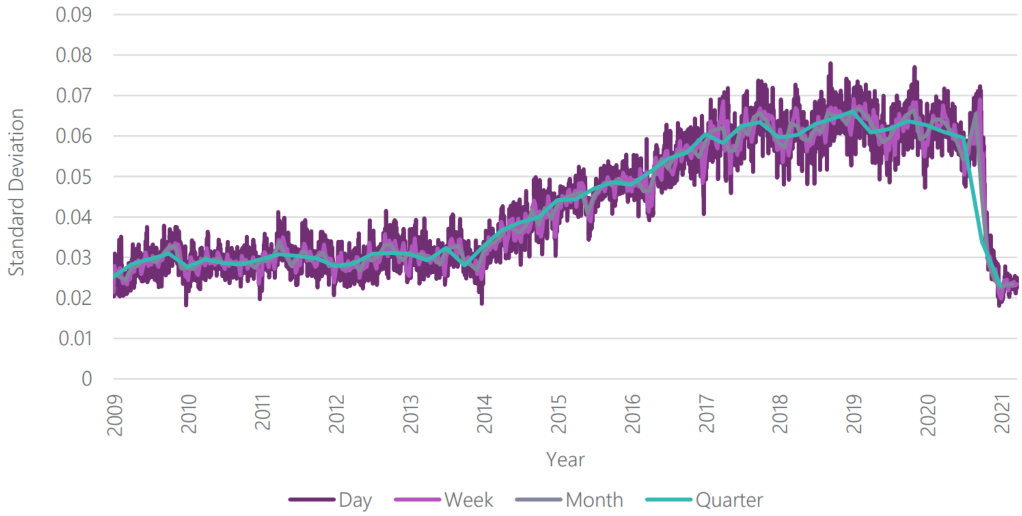


Figure 4.7: Standard deviation of mainland frequency grouped by each day, week, month or quarter from 2009 to 2021. Some initial PFR setting changes were made in late September 2020 and many generators moved to final settings in late October 2020. Source: Australian Energy Market Operator (2021f).

However, this initial success may be a result of the headroom maintained by these generators for risk management purposes (e.g. defending contract positions) and any headroom made available to the system through the displacement of more expensive synchronous capacity by VRE. Given that several large synchronous generators are expected to retire in the coming decades (Australian Energy Market Operator, 2020d), continuing to rely on this "free" headroom (and any available footroom) into the future may reduce the potential resilience benefits of widespread, tight-deadband PFR and place a greater burden on generators that do reserve headroom and hence respond. The AEMC is proposing to address this issue by paying resources that provide assisting tight-deadband PFR ("double-siding") (Australian Energy Market Commission, 2021a).

Presently, several other operational and market changes are being considered or implemented with the goal of improving the effectiveness of arrangements in the NEM. AEMO is investigating the use of dispatch constraints to (Australian Energy Market Operator, 2021g):

- Procure contingency FCAS volumes based on system inertia;
- Apply regional contingency and regulation FCAS requirements; and
- To limit the amount of switched contingency FCAS procured. Switched FCAS has a number of limitations compared to governor-like control (Australian Energy Market Operator, 2020b).

These additional constraints will likely improve the effectiveness of frequency control arrangements but may lead to higher FCAS costs. In addition to these procurement changes, the AEMC has made a rule to introduce raise and lower contingency markets for FFR by October 2023, each with a likely response time of 1 second (Australian Energy Market Commission, 2021b; Australian Energy Market Operator, 2021h). Whilst AEMO has highlighted that potential stability issues and interconnector maloperation will need to be managed (e.g. through delivery caps or provision constraints) (Australian Energy Market Operator, 2021i), these FFR markets, along with the ESB's proposals for short-term scheduling and/or procurement of inertial response (Energy Security Board, 2021), will likely improve AEMO's operational toolbox for managing a low-inertia NEM.

4.10.1 Reactive regulatory requirements

Despite a broad set of FCS markets, there is a high degree of reliance on regulatory mechanisms in the NEM. Performance standards and mandatory PFR enforced by connection requirements in the NEM have recently been aligned with international grid-codes (Roberts, 2018). As argued by TNSPs and AEMO during the mandatory PFR rule change process, near-universal widespread provision of frequency control should lead to relatively low costs for individual participants and be outweighed by greater visibility and certainty for AEMO alongside the system-wide benefits of improved physical frequency control performance (Australian Energy Market Operator, 2019b; Dillon, 2019; Hopwood, 2019).

Regulatory mechanisms are ideal for mandating basic FCS capabilities as a condition for access, which may reduce the need to procure more specialised FCS, or where FCS faces significant barriers to efficient price formation or unbundled procurement. The latter reasons are particularly pertinent in the NEM. Current FCAS prices do not appear to be incentivising FCS provision from the vast majority of VRE generators, which have business models centred around energy provision (Australian Energy Market Commission, 2021c; Meegahapola et al., 2021). Furthermore, procuring inertial response is challenging due to its inseparability from system strength provision and unit commitment costs (Billimoria et al., 2020). With respect to these challenges, regulatory mechanisms in the NEM have assisted in ensuring some level of frequency response from most power system resources (e.g. mandatory PFR) and improving the ability of AEMO and TNSPs to coordinate the procurement of essential but "lumpy" FCS (e.g. inertia shortfall mechanism).

While mechanisms such as mandatory PFR are likely to improve the robustness of frequency control arrangements, it may be difficult for other regulatory mechanisms to keep in step with changing physical performance requirements in systems rapidly facing higher penetrations of VRE and IBR. Regulatory mechanisms are often only updated after a number of years to reduce the burden placed on connecting resources. As such, they are slow to respond to changing capabilities and requirements. This delay often makes new standards and requirements reactive rather than proactive. For example, AEMO can only review utility-scale generator technical performance standards every 5 years (Australian Energy Market Commission, 2018a), a timeframe in which the solar PV capacity installed in the NEM has more than quadrupled (2015-2020) (Australian PV Institute, n.d.).

Additional concerns with regulatory mechanisms include poor dynamic efficiency and opaque costs(Riesz et al., 2015). In the absence of remuneration or incentives, particularly those that are linked to the quality of frequency response, there is no incentive to innovate or invest in higher-quality frequency control capabilities (Meegahapola et al., 2021). Furthermore, cost opacity may lead to FCS provision costs being internalised within other prices (e.g. energy) by participants and prevent the implementation of imbalance or dispatch non-conformance disincentives through cost-allocation mechanisms.

4.11 Preference for market-based arrangements

Since the establishment of the NEM, a competition norm has been established, with markets being viewed as a key driver for delivering the National Electricity Objective of "efficient investment in, and efficient operation and use of electricity services" (Haines and McConnell, 2016; MacGill et al., 2020). This norm has pervaded all levels of participation and governance in the NEM. Generator owners opposed the mandatory nature of the mandatory PFR rule change on the basis that a lack of remuneration was against market principles and that it would lead to economically inefficient outcomes (Rolfe, 2019; Scott, 2019; Skinner, 2019). AEMO did not include a headroom requirement in its proposal, making the mandatory PFR rule change more palatable to market bodies and participants. The AEMC, who have expressed a clear preference for market-based approaches (Australian Energy Market Commission, 2018b), included a "sunset" clause in their initial decision to implement mandatory PFR. Furthermore, a market for FFR will be implemented in 2023 and the ESB's post-2025 market design process is considering new system services markets for inertial response and TFR (Energy Security Board, 2021, 2020).

If incentives or remuneration are designed correctly, markets can drive short-run efficiency. Where required, they can also support investment in FCS capability and assist a power system in achieving dynamically efficient frequency control arrangements. However, in some cases, simply introducing new FCS markets may serve as 'patchwork' solutions to existing control deficiencies and market failures. These deficiencies and failures could be partially addressed by improving FCS cost allocation processes, verifying FCS performance and linking incentives to higher quality provision.

As discussed in [Section 4.4), efficient Causer Pays cost-allocation mechanisms in FCS markets could provide suitable disincentives for dispatch non-conformance or imbalances. In the NEM, the aggregation of regulation FCAS Causer Pays contribution factors over time and a portfolio has resulted in a blunt frequency performance market signal. The solution to this problem may not be as simple as strengthening disincentives (e.g. as proposed by Hirth and Ziegenhagen (2015) and Papavasiliou (2020)) for resource-based cost-allocation processes as potential exposure to high instantaneous FCS costs may lead to participants curtailing or decommitting flexible resources rather than providing an assisting frequency response. This has been observed in the NEM when local constraints have resulted in regulation FCAS (Australian Energy Market Commission, 2018b) and contingency FCAS (Australian Energy Market Operator, 2020j) price spikes. The AEMC has proposed a compromise to this problem by shortening the settlement period for regulation FCAS Causer Pays to 5 minutes but only allocating the costs of regulation FCAS capacity that is activated by AEMO (i.e. the cost of any unactivated capacity is socialised across power system users) (Australian Energy Market Commission, 2021a).

An alternative to Causer Pays is to allocate costs based on needs ('User Pays'), such that connected equipment imposing RoCoF or frequency constraints pay for FCS. 'Users' of frequency control currently include synchronous machines and IBR that have not been configured to ride-through higher RoCoFs and greater frequency deviations. Following more extreme frequency deviations, the former may suffer equipment damage whereas both have the potential to trip (DGA Consulting, 2016; Miller et al., 2017a). A User Pays approach to cost-allocation could encourage resources to be more resilient to frequency deviations and thereby reduce system FCS costs (Lal et al., 2021), particularly if a significant proportion of connected equipment are IBR that can be configured to ride-through such disturbances.

Beyond choosing who costs should be allocated to and what an appropriate granularity for cost-allocation might be, market designers should ensure that the chosen methodology is transparent, can be understood by participants and that any calculations can be replicated using accessible data. If appropriate design choices are made, efficient cost-allocation could create counter-parties for financial instruments that hedge price risk (Skinner et al., 2020; Thorncraft and Outhred, 2007). FCS derivatives may drive investment in FCS capabilities by supporting business models in which FCS is a major revenue stream (this is currently the case for utility-scale BESS, DR aggregators and virtual power plants in the NEM) and assist in FCS price formation (Billimoria et al., 2020; Pollitt and Anaya, 2019).

As in ISO/RTO Regulation markets, aligning FCS procurement and/or remuneration with performance essentially recognises that there is a spectrum of FCS capabilities. This recognition is lacking in the NEM, where battery energy storage systems are responding precisely and rapidly to AGC regulation signals but are being paid the same as thermal plant that provide lower quality regulation FCAS (Australian Energy Market Operator, 2018d). However, implementing performance-based design is contingent on the SO verifying FCS provision. While AEMO has outlined FCAS delivery measurement standards and verification principles (Australian Energy Market Operator, 2020e), delivery verification appears to be restricted to confirming contingency FCAS delivery following a power system event (to the authors' best knowledge). While a regular verification process does not appear to be in place for regulation FCAS, AEMO is proposing to specify minimum control requirements (e.g. response delay and ramp rate) and implement a regular testing cycle for resources registered for regulation FCAS (Australian Energy Market Operator, 2021j).

Market designers may also need to consider price formation in FCS markets to ensure that arrangements are at least capable of supporting investment during energy transition. As discussed by Hirth and Ziegenhagen (2015), VRE have low to no short-term energy market opportunity-costs when providing lower/negative FCS but can incur significant short-term energy market opportunity-costs when providing raise/positive FCS. The raise/positive opportunity-cost may be even higher if the SO requires additional curtailment to better ensure that FCS capacity is firm, which AEMO has required, or if the resource has entered into an energy off-take agreement, which is common in the NEM (Australian Energy Market Operator, 2018e). While co-optimised FCS markets mean that such opportunity-costs can be accounted for, FCS prices can be suppressed if large conventional generators with low to no opportunity-costs offer large volumes of FCS. Low prices can limit the incentive for high capital, low operating cost IBR to provide and invest in FCS capabilities. This may lead to a dynamically inefficient outcome as additional conventional generators are retired and limited FCS capabilities are offered by VRE and other IBR (Ela et al., 2019; Meegahapola et al., 2021). As discussed in Section 4.5.2, one potential solution to this issue is to strengthen scarcity pricing in FCS markets. The AEMC and ESB have discussed implementing system demand curves with scarcity pricing for all existing and proposed FCAS (Australian Energy Market Commission, 2020c; Energy Security Board, 2020). However, the shape of these system demand curves and how they account for interdependent or interchangeable FCAS will ultimately dictate their success.

4.12 Conclusion

Whilst recent years have seen increasing participation from demand response and IBR, energy transition and a pervasive competition norm have exposed design issues in the NEM's frequency control arrangements. As such, considerable attention and effort have been devoted to reforming the NEM's arrangements in the past two years.

From our review of North American and European frequency control arrangements and our analysis of the NEM's, we share four key insights below that could serve as design principles for operators, regulators and market-bodies attempting to design effective and efficient frequency control arrangements in restructured electricity industries during energy transition:

1. Control deficiencies may not be addressable through introducing new FCS. While this solution may address emerging needs (e.g. low-inertia operation), SOs and market bodies need to better understand the interdependency, interoperability and interchangeability between FCS and the interactions with other technical attributes of the power system (e.g. system strength) to ensure that frequency control is first and foremost effective. Once this has been achieved, the short-run efficiency of arrangements can be improved through mechanisms such as dynamic and probabilistic dimensioning and co-optimising the procurement of interchangeable FCS.

2. Given the pace and scale of energy transition, a dynamically efficient outcome in some power systems may require additional investments in FCS capability. FCS prices can be strengthened through scarcity pricing, which may better reflect the system's preference for security and reliability. Such pricing mechanisms are complementary to appropriate and efficient cost-allocation based on causation or needs. Both efficient price formation and cost-allocation will improve the potential for FCS derivatives, which may assist in providing price signals for investment.

3. SOs should systematically and frequently verify FCS delivery, where relevant, and withhold or penalise remuneration when delivery is deemed to be insufficient. If such monitoring is in place, FCS remuneration can be performance-based to drive the provision of high quality FCS. Perfor-

mance monitoring would also enable the SO to assess FCS arrangements and identify any deficiencies in control action or procurement.

4. During energy transition, a suitable set of frequency control arrangements will most likely involve a combination of market-based and regulatory mechanisms. Frequency control is a power system public good and achieving frequency stability requires a degree of coordination and cooperation between resources. These characteristics make it difficult to establish complete markets for FCS, and an emphasis on market solutions may obscure these characteristics to market participants and undermine effective control. In contrast, regulatory mechanisms may prove to be more robust and resilient in the face of uncertainties, particularly those that are exogenous to the power system (e.g. climate risk). Regardless of whether arrangements are skewed towards market-based mechanisms or regulatory mechanisms, designers should be more forward-looking and avoid assumptions regarding the provision of FCS capability over time, particularly when there is a pervasive competition norm and effective frequency control relies on sequential and hierarchical control actions.

5 | Quantifying reserve capabilities: an Australian case study with increasing penetrations of renewables

5.1 Link to thesis

Link to the rest of the thesis

5.2 Abstract

Across several power systems with market frameworks, policy-makers are proposing that balancing flexibility requirements emerging during energy transition be addressed through new reserve product markets. However, these may introduce additional costs, constraints and complexity and even encroach upon the functions of existing operational practices. Thus, policy-makers need to assess and compare flexibility design options, and quantifying system flexibility capabilities based on current and expected resource mixes can assist in achieving this. In this article, we offer a practical method to quantify the time-varying spectrum of upwards and downwards flexibility capabilities in systems, and subsequently apply it to historical and projected resource mixes in two regions of

the Australian National Electricity Market. Our results suggest that with higher penetrations of renewable energy: 1) downwards flexibility margins can be exhausted around noon if wind and solar are unable or unwilling to provide it, 2) upwards flexibility becomes more scarce during morning and evening peak demand events and 3) a greater portion of upwards flexibility is provided by energy-limited resources. Given these trends, we recommend that policy-makers examine how existing operational practices can be augmented to elicit upwards flexibility provision, and that duration specifications and sustained footroom procurement be considered for reserve products.

5.3 Introduction

The reliable and secure operation of power systems is contingent upon locational and temporal balancing of active power supply and demand. As jurisdictions progressively decarbonise electricity supply through considerable capacity additions of variable renewable energy (VRE) and the retirement of carbon-intensive conventional generation, the nature of short-term risks to system balancing (i.e. those of concern over the range of seconds to days) is changing. The most notable of these short-term risks are (Ela et al., 2011):

- Power system *variability*, which includes expected changes in the supply-demand balance. Traditionally, variability has been associated with system load movements and fluctuations around pre-determined generator schedules. As energy transition proceeds, system operators (SOs) are becoming increasingly focused on managing variability that arises due to the presence of VRE. This includes the correlated ramping of neighbouring solar PV generation during sunrise and sunset, and that of wind generation following the arrival of a cold front (Australian Energy Market Operator, 2020a; Lew et al., 2013).

- Power system *uncertainty*, which encompasses unexpected changes in the supply-demand balance. Beyond demand and VRE generation forecast errors, uncertainty also includes singular or widespread outage events that could be the result of a sudden loss of primary energy availability, equipment malfunctions, or common mode failures either triggered by insecure system operation (e.g. significant frequency and/or voltage deviations) or exogenous events (e.g. extreme weather events) (Electricity Sector Climate Information Project, 2021; Matevosyan et al., 2021; Redefining Resource Adequacy Task Force, 2021).

Provided that it is sufficient, leveraging the active power balancing flexibility of a power system (defined by Heggarty et al. (2020) as a system's "ability to cope with variability and uncertainty") should enable these short-term risks to be managed. At a particular point in time, the total balancing flexibility *capability* of a power system is the sum of potential flexibility contributions from resources such as generators, flexible demand and energy storage. However, the flexibility that can actually be *deployed* at any given time and location is potentially limited by:

1. Physical, economic, social and environmental constraints on the operation of resources (Denholm et al., 2018; Gonzalez-Salazar et al., 2018);
2. Network topology, particularly if deploying a flexibility solution results in the violation of network constraints (Lannoye et al., 2015; Liu et al., 2021); and

3. Operational practices. These include protocols and tools used by the SO (which is ultimately responsible for maintaining supply-demand balance) and electricity market design in power systems with a market overlay (Ela et al., 2016).

Though it is well established that operational practices are crucial to "enabling" balancing flexibility provision (Hirth and Ziegenhagen, 2015; Hsieh and Anderson, 2017; Papaefthymiou et al., 2018), limited attention has been given to assessing the trade-offs between practice changes (Mays, 2021). A typical design choice in power systems with electricity markets is determining whether a balancing function should be performed by the SO, or partially delegated to market participants via market-based mechanisms. Proponents of market-based mechanisms argue that if they are well-designed, their benefit is twofold: appropriate incentives can unlock the efficient utilisation of latent flexibility from existing resources whilst encouraging investment in additional flexibility as a market-signalled need emerges. However, to some extent, desires to maximise market benefits and minimise market distortions need to be weighed against providing the SO with sufficient lead-time and levers to maintain system balance during both normal and extraordinary circumstances (Prakash et al., 2022; Roques, 2008).

Establishing markets for balancing reserves offers a compromise between SO control and market efficiency (Kristov et al., 2016; Ryan et al., 2014). These enable the SO to set a requirement for, competitively procure and then schedule system *headroom* (spare generation capacity and potential load curtailment) or system *footroom* (potential generation curtailment and load increase) with particular power, energy, ramping and quality-of-response (e.g. response time) capabilities

(Degefa et al., 2021; Ulbig and Andersson, 2015). Whilst tailored *reserve services* can be procured through tendering processes, zonal or system-wide markets for *reserve products* have become increasingly commonplace given that temporal balancing is of greater concern in meshed networks. Additionally, "commodification" of capabilities through products reduces complexity and enables the implementation of auctions, which can improve transparency and competition and be co-optimised with energy or other reserve product markets (Lal et al., 2021; Mancarella and Billimoria, 2021).

The changing nature of short-term risks to system balancing and the accompanying need for greater system flexibility is leading policy-makers to reassess the suitability of the reserve products available to their SOs (Energy Security Board, 2021; EU-SysFlex, 2019; Federal Energy Regulatory Commission, 2021). Reform of reserve arrangements can simply modify procurement practices or lead to a more significant restructuring of available products, which includes introducing new markets (Ryan et al., 2014). Particularly in their initial stages, reform processes tend to justify changes on the basis of how they might address potential threats to system balancing. This approach is appropriate and sufficient where reserve service provision entails specialised quality-of-response capabilities that cannot be provided effectively or efficiently through other means (e.g. high bandwidth control configurations required for fast frequency response provision). However, some reserve products may "compete" with other design options. For example, the purpose and timeframe of tertiary frequency control and ramping products overlap with those of dispatch processes. Where reserve arrangement reform encroaches on the functions of other processes and practices, quantifying system flexibility capabilities based on current and expected resources mixes can assist policy-makers in assessing flexibility design options.

Reserve products also impose tangible and intangible costs. Regardless of cost allocation mechanisms, procuring reserves typically raises system operation costs and thus prices paid by energy users (Hummon et al., 2013). Furthermore, even if they offer a solution to a system sub-problem, reserve products do not guarantee reliable operation of the overall system and may even hinder the implementation of other measures that can realise system flexibility (MacGill and Esplin, 2020; Papaefthymiou et al., 2018; Pollitt and Anaya, 2019). For example, valuing balancing flexibility on the scale of minutes to hours through reserve products could mean sacrificing the benefits of better reflecting the value of flexibility in energy prices:

1. For participants, energy market risk management is more straightforward than managing risk in reserve product markets. Short-term energy markets typically have greater depth and a broader range of associated technical or financial forward markets (Pollitt and Anaya, 2019).
2. Reserve product markets often have pre-qualification criteria and minimum offer quantities. As such, the participation of smaller demand-side and distributed energy resources (DER) in reserve product markets is often contingent on the involvement of an intermediary aggregator, which imposes additional transaction costs (Poplavskaya and de Vries, 2019). However, embedding the value of flexibility within the price for energy could simplify flexibility provision through market participation for these resources, particularly if policy-makers pursue dynamic retail pricing or nested distribution-level markets that interface with transmission-level markets (Hogan, 2019; Kristov et al., 2016; Mays, 2021).
3. The flexibility that the SO is able to procure through reserve products is restricted by their product specifications. Solely relying on reserve products

for flexibility may constrain operational outcomes. Such flexibility "discretisation" might also be reflected in the resources deployed in the system should reserve product markets influence investment decisions (Lal et al., 2021). Additionally, whilst reserve products can be tailored to a particular system's capabilities and needs, reserve sharing between SO jurisdictions is easier if technical specifications are standardised (Scherer, 2016).

Given these factors, quantification and comparison are therefore needed to assess the role of reserve products, particularly where (Ela et al., 2021; Y. Rebours et al., 2007):

1. Other operational practice or policy changes have the potential to deliver greater and/or more robust flexibility benefits without the additional costs, uncertainty and complexity of new markets; or
2. Current market design or exogenous resource adequacy policies (e.g. firming revenue guarantees or capacity markets) are driving sufficient investment in flexible resources.

A plethora of metrics that quantify different aspects of system balancing flexibility capabilities have been proposed in the literature (Heggarty et al., 2020; Lannoye et al., 2012a; Mohandes et al., 2019). Rather than solely quantifying flexibility capabilities, operational metrics typically compare short-term flexibility capabilities against a flexibility requirement that is set by one of the following or a combination thereof: rules-of-thumb, net load variability, net load forecast uncertainty and/or probabilistic VRE forecasts. While an SO can use these metrics to identify potential flexibility shortages (Zhao et al., 2016), dimension reserve products (Costilla-Enriquez et al., 2023; Dvorkin et al., 2014) or schedule resources (Nosair and Bouffard, 2015), they may be less useful to system designers assessing changes to practices that leverage decentralised decision-making (e.g. energy and reserve product markets). Broader planning-oriented flexibility capability metrics may be more suitable for such purposes. These include traditional resource adequacy metrics (Stenclik et al., 2021), "inflexibility costs" (e.g. additional system costs due to flexibility constraints as explored in Vithayasrichareon et al. (2017)) or "flexibility adequacy" metrics, such as the insufficient ramping resource expectation proposed in Lannoye et al. (2012b). In particular, Lannoye et al. (2012b) uses time-sequential power system operations data to explicitly calculate the balancing flexibility available after resources are dispatched, though valuable chronological information is lost when the time series generated in the study are converted into probability distributions to calculate the insufficient ramping resource expectation. By retaining a degree of this chronological information, our methodology aims to provide electricity industry stakeholders with a better understanding of the time-varying "spectrum" of system balancing flexibility capabilities, and thus assist them in assessing, comparing and designing potential operational practice changes to improve flexibility in power systems with a growing number of variable and energy-limited resources.

In this article, we offer a practical method for quantifying available reserves and footroom (the balancing flexibility that is available after resources are dispatched to meet system demand), and an example of how such quantification can inform flexible electricity market design. We provide simple extensions to the methodology developed by Lannoye et al. (2012b) that account for flexibility contributions from VRE and battery energy storage systems (BESS), and market participants' aversions to incurring cycling costs. We then use this methodology in a case study in which we quantify time-varying available reserves and footroom in real-world systems: two regions of the Australian National Electricity Market (NEM). Through a 2020 baseline and two 2025 scenarios, we test four key sensitivities in these two regions: the acceleration of large conventional generation retirement, the rate of deployment of VRE and storage technologies, contrasting resource mixes and operational constraints, and greater variability in operational demand. While previous studies have tested the impact of some of these sensitivities on the availability of total system headroom or existing reserve products (Frew et al., 2021b; Hummon et al., 2013; Tanoto et al., 2021), our analysis offers a perspective that is focused on quantifying a time-varying spectrum of flexibility capabilities and thus concerned with the *design* of operational practices in low-carbon power systems. Our analysis results highlight the underappreciated need to consider mechanisms for procuring footroom, and we proceed to discuss the implications of implementing new balancing products on operational outcomes. Though the NEM is unique in aspects of its operational practices and the balancing risks it faces, the methodology and findings from this study will become increasingly relevant in other jurisdictions given the accelerating deployment of VRE and storage and the progressive retirement of carbon-intensive conventional generation (International Energy Agency, 2021, 2019).

Section 5.4 provides an overview of how balancing flexibility is enabled and procured through the NEM's operational practices and market design. In Section 5.5, we describe a methodology to quantify available reserves and footroom across deployment horizons for various resource types. Then, in Section 5.6, we quantify the available reserves and footroom in two regions of the NEM for existing resource mixes in 2020 and potential resources mixes in 2025, with two scenarios for the latter. We then use the findings from this case study to explore the role of reserve products in securing balancing flexibility. We conclude by highlighting pertinent findings and recommendations to policy-makers in Section 5.7.

5.4 Flexibility in the National Electricity Market

The Australian National Electricity Market (NEM) is a short-term wholesale electricity market overlaid on a ~5000 kilometre long "stringy" network that services the majority of eastern and southern Australia (Australian Energy Market Commission, n.d.b). In 2021, it saw a peak demand of ~32 GW and total electricity consumption of ~204 TWh (Australian Energy Regulator, 2022). With no explicit capacity mechanisms or compulsory forward markets, the NEM solely consists of a zonal real-time platform, with market regions corresponding to the states of Queensland, New South Wales (NSW), Victoria, Tasmania and South Australia (SA). Interconnection between market regions is relatively weak and, due to the large distances involved, the NEM is not connected to other bulk power systems (Australian Energy Market Operator, 2019a).

In the subsections that follow, we describe the operation of the NEM with a focus on features and mechanisms that enable or explicitly procure balancing flexibility. In particular, we discuss current reserve arrangements in the NEM in Section 5.4.3 and the proposal to introduce an *operating reserve* product in Section 5.4.3.1. The policy debate surrounding the usefulness and design of this potential reserve product provides the primary motivation for our case study in Section 5.6.

5.4.1 Market design

5.4.1.1 Real-time markets

The NEM is a central dispatch market that is operated by the Australian Energy Market Operator (AEMO). On the day ahead of delivery, market participants are required to submit non-binding offers for each resource consisting of price-quantity pairs for energy and, optionally, Frequency Control Ancillary Services (FCAS) (described in Section Section 5.4.3) (Australian Energy Market Operator, 2021k). Energy offers can be priced as high as the market price cap (15,000 AUD/MW/hour during the Australian financial year of 2020-2021) or as low as the market floor (-1000 AUD/MW/hour). Negative pricing enables generators to express a preference to either remain online due to significant start-up/shut-down costs or to be dispatched as a price-taker when it is commercially favourable to do so (e.g. to receive remuneration from an offtake agreement). In theory, it also provides investment signals for flexible resources alongside a relatively high market price cap (Orvis and Aggarwal, 2018; Riesz et al., 2016).

On the day of delivery, co-optimised markets for energy and FCAS are cleared every 5 minutes through a security-constrained economic dispatch process, which produces zonal marginal prices for energy and FCAS. There is no formal gate closure in the NEM; participants are able to alter volumes (but not prices) in their offer up to tens of seconds before the delivery interval (Australian Energy Market Commission, 2015; Paul McArdle, 2021). In 2021, the market settlement period was changed from 30 minutes (the average of prices of the preceding six 5-minute intervals) to 5 minutes to better align settlement with dispatch and pricing (Australian Energy Market Operator, 2022a). Since resources are expected to linearly ramp between one dispatch target and the next, the dispatch process implicitly "procures" some flexibility to manage variability (Australian Energy Market Operator, 2021c; Ryan et al., 2014). As such, the NEM's dispatch is relatively fast and granular when compared to short-term electricity markets worldwide (Katz et al., 2019; Silva-Rodriguez et al., 2022).

The NEM's real-time market is also able to elicit balancing flexibility provision from a variety of resources:

- Unlike some North American markets that permit large proportions of the generation fleet to self-schedule (Ela et al., 2016; Orvis and Aggarwal, 2018), generation with a capacity above 30 MW is required to participate in the real-time market and receive dispatch instructions (Australian Energy Market Commission, 2017). This exposes larger utility-scale resources, which make up the bulk of the NEM's generation capacity, to price signals that somewhat reflect system balancing requirements.
- VRE forecasts used in dispatch can be generated by AEMO or provided by market participants; due to very late gate closure, both are able to incorporate telemetered operational data from the minutes preceding delivery (Australian Energy Market Operator, 2018f, 2016).
- In 2021, a wholesale demand response mechanism was implemented to enable larger loads (aggregated or otherwise) and virtual power plants (VPPs) to directly participate in the energy market[1] (Australian Energy Market Operator, 2020k).

[1]For all conventional resources, the distribution of offer prices resembles "hockey-stick" offer curves that are common in the NEM (Energy Synapse, 2020) and in other electricity markets (Hurlbut et al., 2004). Moreover, for most peaking conventional resources, energy is offered at or just above the strike price of cap options/futures (300 AUD/MWh).

5.4.1.2 Forward markets

In the NEM, forward energy markets are voluntary and primarily consist of the trading of electricity derivatives between market participants. Though market participants can contract over-the-counter, the majority of forward market activity occurs on two market exchanges for standard products for periods up to 3 years out (ASX Energy, 2021; Australian Energy Regulator, 2021). These standard products include quarterly or annual futures, which fix a price for an agreed quantity of energy, and caps, which are essentially call options that enable contract purchasers (typically electricity retailers) to pay no more than the strike price of 300 AUD/MWh for energy at the cost of a premium paid to the seller. Contract markets in SA are considered to be relatively illiquid compared to those in NSW, Queensland and Victoria (Australian Energy Regulator, 2022). Beyond enabling market participants to hedge real-time market price risk, products traded on the forward markets may 'discipline' market participants into offering balancing flexibility to the system. For example, a generating market participant that sells futures and caps is likely to retain some reliable generation capacity in reserve to avoid large payouts in the event of high real-time prices or the failure of their other plants (Riesz et al., 2016).

5.4.1.3 Limitations

Despite the arguably world-leading flexible design of its real-time markets, there are some notable limitations in the NEM and its associated forward markets:

- To date, the balancing flexibility offered by DER has primarily been leveraged through unremunerated, last-resort curtailment of distributed solar PV in SA by AEMO (Australian Energy Market Operator, 2021l) or through aggregated solar-battery VPPs. At the end of 2021, VPPs had a registered capacity of approximately 30 MW (Kuiper, 2022), a small percentage of the ~15 GW of distributed solar PV capacity installed in the NEM as of June 2022 (Australian PV Institute, n.d.).

- Aside from the procurement of footroom that is only deployed following frequency excursions (Section 5.4.3), there are currently no mechanisms in the NEM that remunerate resources for providing sustained downwards flexibility to the system.
- Standard derivative products have remained much the same for decades despite changes in the NEM's resource mix and market dynamics. In particular, the 300 AUD/MWh strike price of cap contracts does not necessarily reflect a resource's operating costs (e.g. the price of natural gas or the charging/pumping price for BESS/pumped hydro energy storage). While a demonstration project trialled a market platform for derivatives designed to be sold by flexible resources (e.g. a "Super Peak" contract that enables buyers to hedge morning and evening demand peaks), these are nascent products with small traded volumes to date (Renewable Energy Hub, 2021).
- AEMO has little visibility and no direct oversight over the voluntary forward markets, which are currently operated by the financial services sector. Moreover, even if AEMO did, it would likely be difficult for them to determine how portfolio-based contracting might influence the operation of particular resources (Australian Energy Market Commission, 2020d).

5.4.2 Ahead processes and operator intervention

Through several ahead processes, AEMO regularly publishes forecasted system and market information to assess power system reliability and assist market participant decision-making. The processes most relevant to operational decision-making include the near-term Projected Assessment of System Adequacy (PASA) and pre-dispatch simulations:

- Using forecasts for demand and VRE, a simplified set of forecasted network constraints and participant-submitted resource availabilities and energy constraints, the Pre-Dispatch PASA and Short Term PASA (run every half-hour and hour, respectively) both assess the maximum generation reserves available in each region for the next 7 trading days. PASA outputs include half-hourly available generation and system load forecasts (Australian Energy Market Commission, 2022; Australian Energy Market Operator, 2020l, 2012).
- Once day-ahead offers have been submitted by market participants, AEMO uses these offers in pre-dispatch processes alongside forecasts for constraints, demand and VRE. Pre-dispatch simulations then produce forecasts for dispatch conditions and regional prices for energy and FCAS. These are run every half hour at half-hourly resolution until the end of the next trading day (pre-dispatch) and at 5 minute resolution for the next hour (5 minute pre-dispatch) (Australian Energy Market Operator, n.d., 2021k). The potential impacts of demand forecast error on regional energy prices and interconnector flows are explored through a sensitivity analysis (Australian Energy Market Operator, 2021m).

Regional balancing stress is indicated by the level of in-market reserves, which is the total offered generation capacity in excess of forecast regional demand[2]. Should the Short Term PASA or pre-dispatch processes forecast in-market reserves below specific trigger levels, AEMO must issue market notices that declare forecast Lack of Reserve (LOR) conditions (Australian Energy Market Operator, 2021n). Trigger levels are set by the maximum of either deterministic generation contingencies (i.e. below N-2 for LOR1, below N-1 for LOR2 and no in-market reserves for LOR3), or a particular confidence level of a probability distribution of total forecasting errors generated by a Bayesian Belief Network, which is trained on historical forecast errors and power system conditions (Australian Energy Market Operator, 2018g).

The intention of these ahead process and LOR notices is to provide market participants with information that might elicit a response, such as shifting planned maintenance or rescheduling flexible resources in response to forecasted tight supply-demand balance conditions. However, if more severe LOR2 or LOR3 notices have been issued and AEMO deems that the market response is insufficient by a certain time, AEMO can intervene in the market by issuing directions (manual dispatch), activating emergency reserves procured through the Reliability and Emergency Reserve Trader (RERT) and/or instructing transmission network operators to shed load (Australian Energy Market Operator, 2021n, 2018g).

[2]This measure does not consider the horizon within which the capacity can be converted to generation (i.e. the reserve horizon).

5.4.3 Reserve products

Formal reserves arrangements in the NEM consist of eight FCAS and the Reliability and Emergency Reserve Trader (RERT). In each dispatch interval, FCAS are procured by AEMO from markets for raise (headroom) and lower (footroom) regulation FCAS, which are used to provide frequency control during normal operation, and three raise and lower contingency FCAS, which deliver their full response within 6 seconds, 60 seconds or 5 minutes following a major imbalance event. The volumes of FCAS procured for each dispatch interval are dynamically determined, with regulation FCAS procurement volumes dictated by power system time error and contingency FCAS procurement volumes typically corresponding to an N-1 contingency. In the absence of regional constraints, FCAS are procured for and from all regions of the NEM. While FCAS provides balancing flexibility through frequency-responsive headroom and footroom, they predominantly respond to intra-dispatch variability and uncertainty with the expectation that deployed resources will be relieved by 5-minute dispatch (Prakash et al., 2022; Riesz et al., 2015). 5 minute contingency FCAS is an exception, given that its response may be called upon for up to 10 minutes. 5 minute contingency FCAS is currently provided by a diverse range of resources (see Figure 5.1).

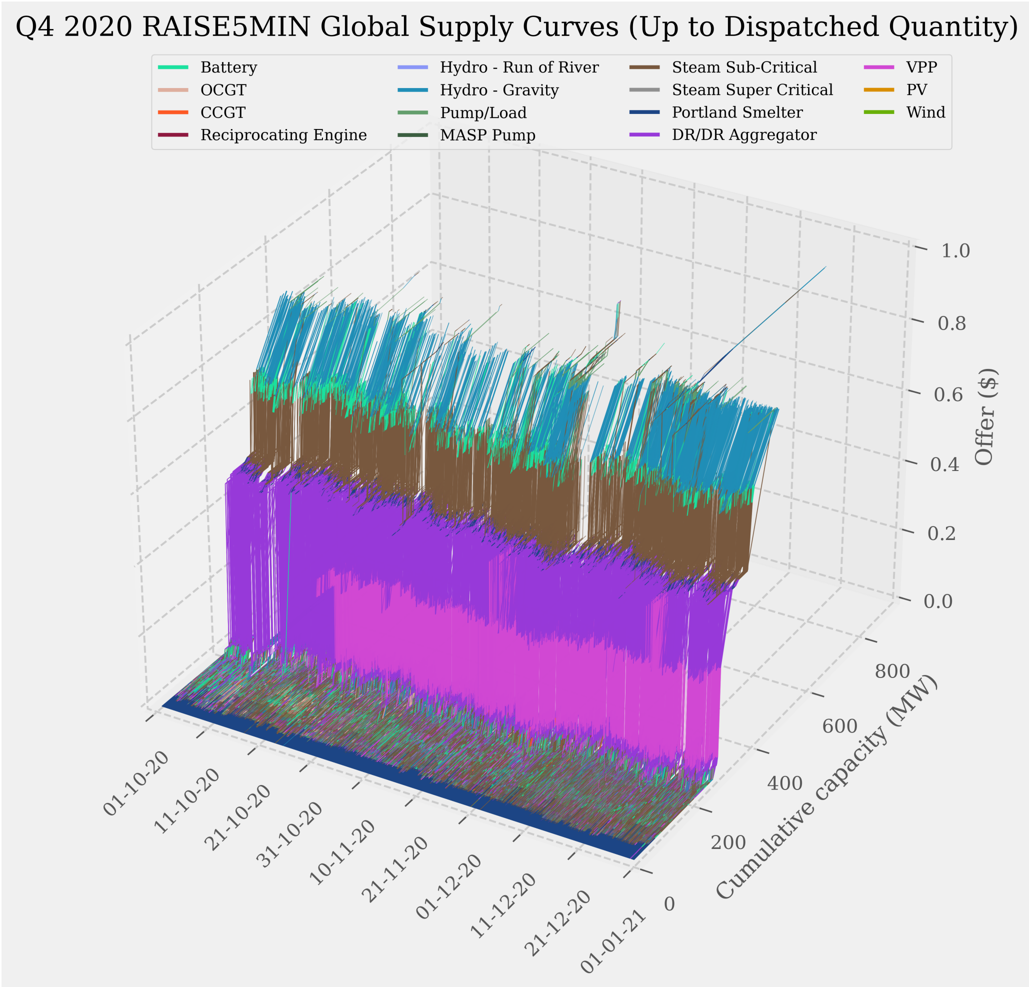


Figure 5.1: Q4 2020 global supply curves by resource type for the raise 5 minute contingency FCAS market. Each of the supply curves are truncated to the volumes of 5 minute contingency FCAS procured by AEMO across the NEM in that dispatch interval (NEM-wide mean of ~420 MW for Q4 2020). Providers include conventional steam and hydropower generators, an aluminium smelter, demand response (DR) aggregators, VPPs and BESS. As each supply curve is constructed from the offers of resources across the NEM (i.e. global), they do not reflect dispatch outcomes in the presence of regional constraints. Offer and dispatch data were obtained using NEMOSIS (Gorman et al. (2018)).

Through the RERT, AEMO can obtain last-resort reserves given between 1 week to 1 year of notice of forecasted in-market reserves shortfalls. While procurement practices vary depending on the notice time, RERT procurement consists of AEMO contracting with out-of-market resources. Following forecast or actual LOR2 or LOR3 conditions and an insufficient market response, AEMO is able to activate RERT reserves (Australian Energy Market Commission Reliability Panel, 2020; Australian Energy Market Operator, 2021o). The RERT provides AEMO with a last-resort mechanism to procure balancing flexibility prior to any potential load shedding. However, resources that provide reserves through the RERT are unable to participate in the real-time market for the duration of their contract. After RERT reserves are activated, market participants are remunerated based on counterfactual pricing (i.e. dispatch without RERT), thus maintaining scarcity pricing and potential signals for investment.

5.4.3.1 Operating reserves product

An inter-dispatch operating reserve product has been proposed in the NEM. It would enable AEMO to procure headroom, which would need to be available to the real-time market within the product horizon, in each dispatch interval. Horizons of 5 minutes and 30 minutes were proposed (Australian Energy Market Operator, 2021p; Energy Security Board, 2021). Market bodies and participants have raised several potential benefits of an operating reserve product:

1. It could address both inter-dispatch variability and uncertainty. Market bodies consider that the need to address the latter may be more material due to the growing impact of forecast uncertainty on system balancing and the potential for high impact, low probability power system events leading to extraordinary system imbalances (Australian Energy Market Commission, 2021c; Eggleston et al., 2021).
2. AEMO supports a 30+ minute horizon, as a longer timeframe product is likely to have a larger pool of providers and provide participants/AEMO with more lead time prior to any potential market intervention (Australian

Energy Market Operator, 2021p).

3. Through reserve constraints and potential scarcity pricing through an operating reserve demand curve (Hogan, 2013), the product could act as an energy 'price-adder'. This would enable real-time market prices for energy to better reflect consumers' preference for reliability (Cramton, 2017). Although the NEM's market price cap is high by international standards, it is generally well below the estimated value of short-term reliability for both residential and non-residential customers in the NEM (Australian Energy Regulator, 2019). A 'price-adder' could also provide sharper investment signals for flexible resources.

The assessment of reserve capabilities to justify this new product has been limited. AEMO has previously analysed ramping capabilities over timeframes greater than 30 minutes (Australian Energy Market Operator, 2020a), the total reserve capacity available within various timeframes across NEM regions and years (Australian Energy Market Operator, 2021p) and regularly forecasts in-market reserves (Section 5.4.2). However, these studies do not consider flexibility capability available *after* resources are dispatched, or do not explore the time-varying spectrum of this capability. Using the methodology outlined in Section 5.5, we incorporate these elements when quantifying balancing flexibility capabilities in NSW and SA to inform an assessment of the operational benefits of additional balancing products (Section 5.6).

5.5 Modelling Available Reserves and Footroom

To quantify balancing flexibility capabilities, we consider headroom and footroom that can be converted to stable active power output within a particular time *horizon*. We will refer to these as *available reserves* and *available footroom*[3], respectively. Though these metrics do not explicitly consider whether resources are frequency-responsive, how long a potential response can be sustained for and whether network constraints restrain flexibility provision, calculating these quantities is broadly useful for understanding the balancing flexibility that could be deployed in a meshed system within operational timeframes (minutes to hours).

5.5.1 Quantifying available reserves and footroom

At a given point in time and for a particular horizon, the available reserves and footroom that a resource can offer are dependent on its operational constraints, its synchronisation status and its active power output. The latter two can be obtained from historical data, or as the outputs of production-cost or market modelling.

Below, we outline a methodology for calculating system-wide available reserves and footroom (Section 5.5.1.5). We adapt the methodology proposed by Lannoye et al. (2012b) to calculate available reserves and footroom from conventional resources (coal-fired, hydro and gas-fired generation - Section 5.5.1.2), and propose simple extensions for calculating available reserves and footroom

[3]We use terminology consistent with Lannoye et al. (2015), which quantifies *available* flexibility considering resource operational constraints and *realisable* flexibility considering both network and resource operational constraints. These types of flexibility exclude transient power changes from phenomena such as inertial response.

provided by VRE (Section 5.5.1.3) and BESS (Section 5.5.1.4). The nomenclature used in these sections is described in Section 5.5.1.1.

5.5.1.1 Nomenclature

5.5.1.1.1 Indices and sets

$t \in \mathcal{T}$	Time periods, each corresponding to the the end of a 5-minute dispatch interval in the corresponding scenario year.
$h \in \mathcal{H}$	Set of (reserve) horizons (minutes).
$r_c \in \mathcal{R}_c$	Set of conventional resource units.
$r_v \in \mathcal{R}_v$	Set of VRE resource units.
$r_b \in \mathcal{R}_b$	Set of BESS resource units.

5.5.1.1.2 Time-varying resource parameters

$g_{r_c/r_v/r_b,t}$	Net generation (active power output) of unit at time t (MW).
$g^f_{r_v,t}$	Maximum generation of VRE resource unit based on primary energy availability, i.e. $0 \leq g^f_{r_v,t} \leq \overline{g}_{r_v,t}$ (MW).
$\overline{g}_{r_c/r_v/r_b,t}$	Maximum capacity of unit. Time-varying due to seasonal derating and partial/full outages (MW).

5.5.1.1.3 Static resource parameters

MSL_{r_c}	Minimum stable level of conventional resource unit r_c (MW).

$\mathrm{StartUp}_{r_c}$ Start-up ramp up rate of conventional resource unit r_c. Start-up is assumed to progress in a linear fashion (MW/minutes).

RampUp_{r_c} *Upper* ramp up rate of conventional resource unit r_c. See Section 5.6.2 for an explanation of *upper* ramp rates (MW/minutes).

$\mathrm{RampDown}_{r_c}$ *Upper* ramp down rate of conventional resource unit r_c. See Section 5.6.2 for an explanation of *upper* ramp rates (MW/minutes).

5.5.1.1.4 Computed quantities

$\mathrm{SUT}_{r_c,t}$ Start-up time for conventional resource unit , i.e. $\mathrm{SUT}_{r_c,t} = \frac{\mathrm{MSL}_{r_c} - g_{r_c,t}}{\mathrm{StartUp}_{r_c}}$ where $0 \leq g_{r_c,t} < \mathrm{MSL}_{r_c}$ (minutes).

$AR_{r_v,h,t}$ Available reserves from VRE resource unit r_v at time t for horizon h (MW).

$AR_{r_b,h,t}$ Available reserves from BESS resource unit r_b at time t for horizon h (MW).

$AR^{OFF}_{r_c,h,t}$ Available reserves from offline conventional resource unit r_c at time t for horizon h (MW).

$AR^{ON}_{r_c,h,t}$ Available reserves from online conventional resource unit r_c at time t for horizon h (MW).

$AR_{h,t}$ Reserves available to the system within horizon h at time t (MW).

$AF_{r_v,h,t}$ Available footroom from VRE resource unit r_v at time t for horizon h (MW).

$AF_{r_b,h,t}$ Available footroom from BESS resource unit r_b at time t for horizon h (MW).

$AF^{ON}_{r_c,h,t}$ Available footroom from online conventional resource unit r_c at time t for horizon h (MW).

$AF_{h,t}$ Footroom available to the system within horizon h at time t

5.5.1.2 Conventional resources

The quantities of reserves and footroom that can be made available by conventional resources are dependent on whether the resource is online (non-zero active power output) or offline.

A conventional resource unit is considered to be online if $g_{r_c,t} > 0$. The reserves that an online conventional resource unit can make available within the horizon h ($AR^{ON}_{r_c,h,t}$) is given by:

$$AR^{ON}_{r_c,h,t} = \begin{cases} \text{StartUp}_{r_c} \times h & 0 < g_{r_c,t} < \text{MSL}_{r_c}, h \leq \text{SUT}_{r_c,t} \\ \min(& \\ \quad (\text{MSL}_{r_c} - g_{r_c,t}) + \text{RampUp}_{r_c} \times (h - \text{SUT}_{r_c,t}), & \\ \quad \overline{g}_{r_c,t} - g_{r_c,t} & \\ ) & 0 < g_{r_c,t} < \text{MSL}_{r_c}, h > \text{SUT}_{r_c,t} \\ \min(\text{RampUp}_{r_c} \times h, \overline{g}_{r_c,t} - g_{r_c,t}) & g_{r_c,t} \geq \text{MSL}_{r_c} \end{cases} \tag{5.1}$$

The three conditions in Equation 5.1 reflect the following:

1. The unit is in its start-up sequence (i.e. $0 < g_{r_c,t} < \mathrm{MSL}_{r_c}$) and the reserve horizon (h) is shorter than or equal to the unit's start-up time $(\mathrm{SUT}_{r_c,t})$. In this case, the start-up ramp rate $(\mathrm{StartUp}_{r_c})$ dictates the quantity of reserves that the unit can provide.
2. The unit is in its start-up sequence and the reserve horizon (h) is longer than the unit's start-up time $(\mathrm{SUT}_{r_c,t})$. In this case, the quantity of reserves that the unit can provide is the minimum of the total unit ramping potential within the reserve horizon (at rate $\mathrm{StartUp}_{r_c}$ up to the unit's minimum stable level, and RampUp_{r_c} beyond it) and the unit's headroom.
3. The unit is operating above its minimum stable level. The quantity of reserves that the unit can provide is the minimum of the total unit ramping potential within the reserve horizon (at rate RampUp_{r_c}) and the unit's headroom.

The reserves that an offline conventional resource unit can make available within the horizon h is given by Equation 5.2, which has two conditions that resemble the first two conditions of Equation 5.1:

$$AR^{OFF}_{r_c,h,t} = \begin{cases} \mathrm{StartUp}_{r_c} \times h & g_{r_c,t} = 0, h \leq \mathrm{SUT}_{r_c,t} \\ \min(& \\ \quad \mathrm{MSL}_{r_c} + \mathrm{RampUp}_{r_c} \times (h - \mathrm{SUT}_{r_c,t}), & \\ \quad \overline{g}_{r_c,t} - g_{r_c,t} & \\ ) & g_{r_c,t} = 0, h > \mathrm{SUT}_{r_c,t} \end{cases} \tag{5.2}$$

To ensure that flexibility quantification only considers stable changes in active power output, footroom from conventional resource units is defined to be the maximum downwards flexibility they can provide without shutting down (i.e. down to their MSL). As such, footroom can only be provided by online units operating above their MSL (first condition in Equation 5.3):

$$AF^{ON}_{r_c,h,t} = \begin{cases} \min(\mathrm{RampDown}_{r_c} \times h, g_{r_c,t} - \mathrm{MSL}_{r_c}) & g_{r_c,t} > \mathrm{MSL}_{r_c} \\ 0 & 0 < g_{r_c,t} \leq \mathrm{MSL}_{r_c} \end{cases} \tag{5.3}$$

5.5.1.3 Variable renewable energy

Within the availability of their primary energy source and the timeframes of concern in this study, VRE are considered to be highly flexible (Holttinen et al., 2021; Nelson et al., 2018). Therefore, the provision of available reserves ($AR_{r_v,h,t}$) and footroom ($AF_{r_v,h,t}$) by VRE is not limited by ramp rates but rather by headroom and footroom:

$$AR_{r_v,h,t} = g^f_{r_v,t} - g_{r_v,t} \tag{5.4}$$

$$AF_{r_v,h,t} = g_{r_v,t} \tag{5.5}$$

In this study, $g_{r_v,t} < g^f_{r_v,t}$ can occur as the result of VRE curtailment due to oversupply.

5.5.1.4 Battery energy storage systems

BESS are also highly flexible and, unlike other resource types, can provide additional flexibility by switching from charging ($g_{r_b,t} < 0$) to discharging ($g_{r_b,t} > 0$), or vice-versa. This additional flexibility can be accounted for by including the maximum power capacity of the BESS ($\overline{g}_{r_b,t}$, which restricts BESS charging and discharging such that $|g_{r_b,t}| \leq \overline{g}_{r_b,t}$) in the equations for available reserves (Equation 5.6) and available footroom (Equation 5.7):

$$AR_{r_b,h,t} = \overline{g}_{r_b,t} - g_{r_b,t} \tag{5.6}$$

$$AF_{r_b,h,t} = \overline{g}_{r_b,t} + g_{r_b,t} \tag{5.7}$$

5.5.1.5 System-wide

At time t, the total reserves and footroom that can be made available to the system within the horizon h are given by Equation 5.8 and Equation 5.9, respectively:

$$AR_{h,t} = \sum_{r_c \in \mathcal{R}_c} (AR^{OFF}_{r_c,h,t} + AR^{ON}_{r_c,h,t}) + \sum_{r_v \in \mathcal{R}_v} AR_{r_v,h,t} + \sum_{r_b \in \mathcal{R}_b} AR_{r_b,h,t} \tag{5.8}$$

$$AF_{h,t} = \sum_{r_c \in \mathcal{R}_c} AF^{ON}_{r_c,h,t} + \sum_{r_v \in \mathcal{R}_v} AF_{r_v,h,t} + \sum_{r_b \in \mathcal{R}_b} AF_{r_b,h,t} \tag{5.9}$$

These equations are used to calculate system available reserves and footroom for all reserve horizons of interest ($h \in \mathcal{H}$) across all of the dispatch intervals in a given scenario year ($t \in \mathcal{T}$).

5.6 Case Study: Two Regions in the National Electricity Market

5.6.1 Scenarios

In this study, available reserves and footroom were quantified for NSW and SA in calendar year 2020 and for two resource mix scenarios in 2025 (see Table 5.1). The 2025 scenarios roughly correspond to the Central and Step Change scenarios in AEMO's 2020 Integrated System Plan (ISP) (Australian Energy Market Operator, 2020m), a least-regrets transmission planning study that incorporates scenario-based capacity expansion modelling (Australian Energy Market Operator, 2020d) [4].

Table 5.1: Scenarios simulated for NSW and SA.

Scenario	Description
2020	• Modelled using historical demand and existing resources – Synchronous units (gas-fired) must run for system strength in SA

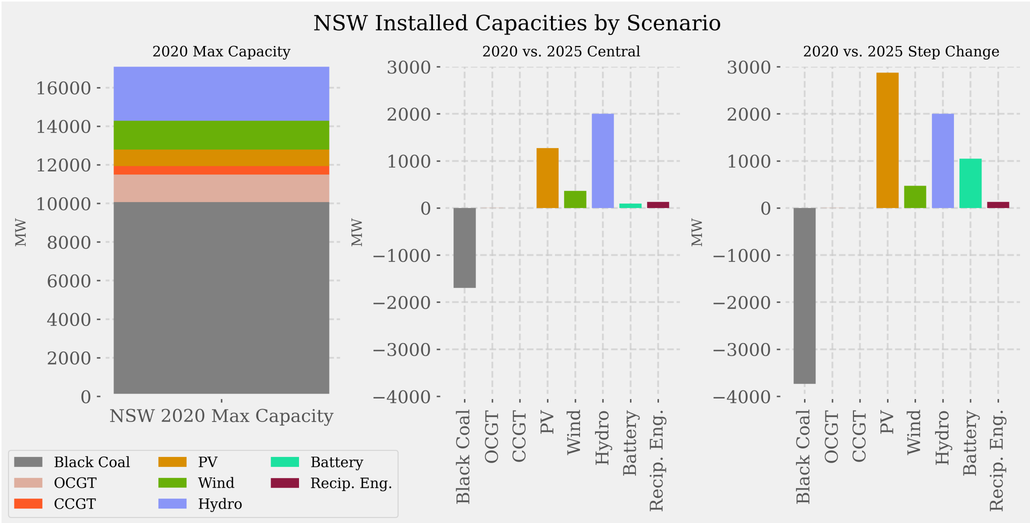
[4]The 2022 ISP was recently released (Australian Energy Market Operator, 2022b). For the planning horizon relevant to this study (i.e. to 2025), the 2022 ISP broadly reflects the outlook of its predecessor, with the exception that it draws on extensive consultation with electricity industry stakeholders in determining the Step Change scenario to be the most likely scenario.

Scenario	Description
2025 Central	• Based on existing policy settings at the time of 2020 ISP: – Moderate deployment of VRE and BESS – Distributed solar PV has moderate impact on operational demand – Thermal unit retirements in both states – Large hydropower capacity addition in NSW – Fewer synchronous units must run for system strength in SA
2025 Step Change	• More aggressive transition: – Large deployments of VRE and BESS – Distributed solar PV has greater impact on operational demand – Further thermal unit retirements in NSW – Large hydropower capacity addition in NSW – Fewer synchronous units must run for system strength in SA

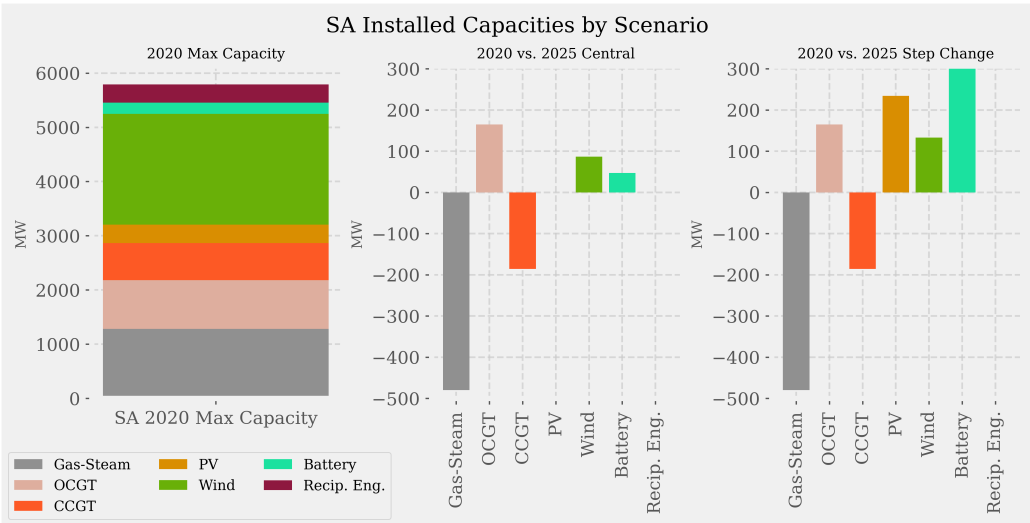
Modelling SA and NSW across these three scenarios enables four sensitivities to be explored:

1. **Conventional generation retirement**. For NSW, one coal-fired power station is retired in 2025 Central and two in 2025 Step Change. In SA, four gas-powered steam turbine (Gas-Steam) units and two combined-cycle gas turbine (CCGT) units are retired between 2020 and both 2025 scenarios.

2. **Increasing deployment of VRE and BESS**. Additional VRE and BESS capacity is deployed in both states between 2020 and 2025 Central in AEMO's 2020 ISP. In the 2025 scenarios for both states, a greater quantity of VRE (predominantly solar PV) and BESS is installed in the Step Change scenario than in the Central scenario. The addition of 2 GW hydro generation in NSW by 2025 reflects the expansion of the region's largest hydro scheme (Snowy 2.0). The capacity mix of each state in 2020 and the changes in the mix for each 2025 scenario are shown in Figure 5.2.
3. **Contrast in resource mix and thus operational constraints**. In NSW in 2020, coal-fired generation is a large proportion of the generation fleet and is complemented by hydro generation, gas-fired generation (CCGTs and OCGTs) and VRE. In SA in 2020, VRE (especially wind) is a significant portion of the region's generation fleet. SA's synchronous generation consists of gas-fired generation across the flexibility spectrum, some of which must remain online to ensure there is sufficient system strength in SA for secure operation.
4. **Greater variability in operational demand due to more distributed solar PV**. Operational demand is defined as the system demand that AEMO dispatches resources to meet (i.e. excluding demand met by DER). As the capacity of distributed solar PV in each region increases (i.e. from 2020 to 2025 Central to 2025 Step Change), operational demand in the middle of the day is eroded whilst ramping requirements in the morning (downwards) but especially the evening (upwards) increase. In other words, higher penetrations of distributed solar PV leads to a "deeper" duck curve (Australian Energy Market Operator, 2020h).



(a)



(b)

Figure 5.2: Capacity mix in NSW (a) and SA (b) in 2020, and additional deployments and retirements in 2025 Central and 2025 Step Change. 2020 resource mixes were adapted from AEMO's 2020 Inputs and Assumptions workbook (Australian Energy Market Operator, 2020n). 2025 scenario resource mixes were aligned with their namesake ISP scenarios (Australian Energy Market Operator, 2020m) and include committed generation (projects that are highly likely to proceed as they have acquired land, secured financing, set a firm construction commencement date and either finalised contracts for components or been granted planning approval) (Australian Energy Market Operator, 2022c).

5.6.2 Methodology

For each region and scenario, the available reserves and footroom in the system were calculated from the results of a year-long time-sequential market simulation implemented in the commercial electricity market modelling tool PLEXOS (Energy Exemplar, 2021). The PLEXOS market simulation consisted of a PASA phase to model maintenance and forced outages for conventional generation across the year, a Medium Term Schedule phase in NSW to schedule hydro generation according to monthly energy constraints, and a Short Term Schedule phase that carries out unit commitment and economic dispatch (UC-ED) at 5-minute resolution in daily steps[5].

Each existing coal-fired (NSW) and Gas-Steam (SA) unit was explicitly modelled to accurately capture the consequences of partial and full outages of large capacity units. For other resource types, the operational constraints and attributes of individual units were averaged and applied across all units of a resource type. This enabled clustered UC-ED and thus reduced the computational burden of the Short Term Schedule phase (Palmintier and Webster, 2014). For baseload conventional generation and gas turbines, ramp rates in each direction were separated into a *market* ramp rate, which was used in the PLEXOS market simulation, and an *upper* ramp rate, which was used to calculate available reserves/footroom (Section 5.5.1.2). A lower magnitude ramp rate in the market simulation (*market*) reflects participants' preferences to reduce cycling wear-and-tear due to demanding ramping during typical operation (especially for ageing assets) (Kumar et al., 2012), whilst using a higher magnitude ramp rate to calculate a resource's available reserves and footroom (*upper*) ensures that the total

[5]A 12 hour look-ahead was used in the SA model to avoid "end-of-horizon effects" (Barrows et al., 2020), such as end-of-day decommitment of gas-fired generation.

available flexibility of a resource can be utilised if needed in a system emergency.

Both NSW and SA were modelled assuming a copper-plate network with no interconnection to other regions (i.e. single bus with no network constraints). The Short Term Schedule mixed-integer linear program was solved using the CPLEX Optimizer (IBM, 2021) with a relative mixed-integer program gap tolerance of 0.07%. The generation and synchronisation status of each resource was obtained from the solution and used to calculate the available reserves and footroom for each 5-minute interval using the equations outlined in Section 5.5. A process flow diagram of the study methodology is shown in Figure 5.3.

In Appendix A, we outline our sources for key input data and assumptions (top row of Figure 5.3) and provide further details regarding how these data were used in the market simulation and/or the calculation of available reserves and footroom.

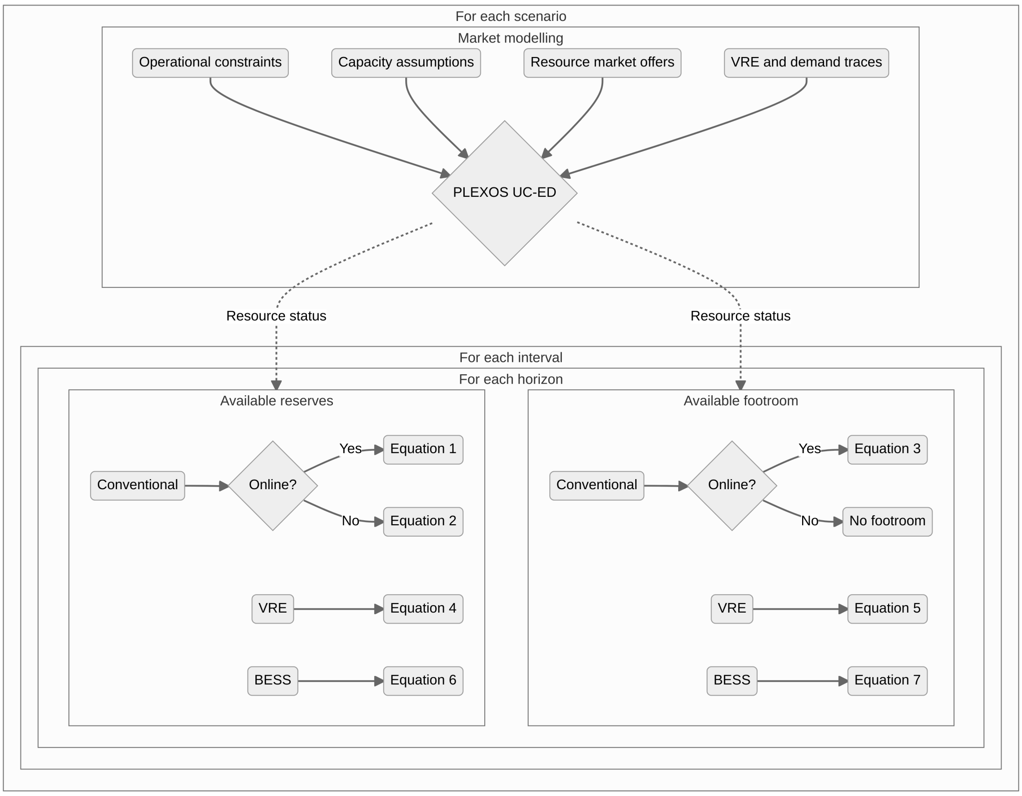


Figure 5.3: Process flow for modelling available reserves and footroom for each scenario in this case study.

5.6.3 Limitations

There are two important caveats to this study. The first is that this study models each region in isolation – that is, resources in other NEM regions can neither assist in meeting demand nor provide available reserves or footroom through cross-regional interconnectors. During typical operating conditions, it is likely that any headroom/footroom on interconnectors would mean that a greater quantity of reserves/footroom are available to a region, albeit at different horizons due to modified dispatch patterns. For example, the inclusion of interconnectors in the SA model between SA and VIC and SA and NSW[6] may in-

[6]At the time of writing, the interconnector between SA and NSW is under construction and due to commence operation in 2025/2026 (ElectraNet, Transgrid, n.d.).

crease the total available reserves/footroom in SA at the cost of a decrease in the reserves/footroom available within shorter horizons. This could arise from local mid-merit gas generators remaining offline in favour of inflexible but cheaper coal-fired generation in NSW and VIC.

However, modelling available reserves and footroom for isolated regions may provide a closer approximation to reality when balancing flexibility is scarce in a region. Under these circumstances, it is likely that interconnector flows will already be close to their limits. This will reduce or altogether prevent the available reserves/footroom provision from resources in neighbouring regions. Moreover, large interconnector flows may be prevented if there is a credible risk of regional separation (loss of synchronism between market regions due to interconnector circuit faults — a particular risk in the NEM due to limited interconnection between market regions); at present, AEMO co-optimises interconnector flow with regional FCAS procurement (Australian Energy Market Operator, 2010). An additional consideration is that if an operating reserve product is implemented to improve the NEM's resilience to supply-demand shocks, regional procurement requirements may also limit the available reserves/footroom that can be procured over an interconnector. As such, the modelling of isolated regions may approximate actual operation when reserves/footroom are scarce and thus most valuable to the system.

The second caveat is that this study does not explicitly model FCAS procurement. If headroom or footroom reserved for FCAS is unable to also provide available reserves or footroom[7], then modelling FCAS markets would reduce the reserves and footroom that are available within horizons less than or equal to

[7]Exclusive headroom procurement for an operating reserve service (i.e. inability to offer the same headroom in FCAS markets) is currently being considered (Energy Security Board, 2021).

5 minutes. However, the actual headroom/footroom reduction would depend upon the following factors:

- Whether regional FCAS procurement constraints bind for the modelled region. If they do not, multi-regional or NEM-wide FCAS requirements can be satisfied by procuring FCAS in other market regions.
- The degree to which headroom/footroom is "re-offered" across sequential FCAS markets. For example, a single resource enabled for 10 MW across the three raise contingency FCAS markets would withdraw less system headroom than three resources enabled for 10 MW each for a particular FCAS market.
- Headroom that is offered into the 6 second and 60 second raise contingency FCAS market may not reflect sustained power provision. For example, frequency response from a steam-powered turbine may draw on steam stored in a boiler; a sustained response would require a longer timeframe due to slower boiler dynamics.

5.6.4 Results and discussion

5.6.4.1 Synthetic daily profiles

Synthetic daily profiles (SDPs) were developed to quantify the time-varying spectrum of available reserves and footroom for each scenario. For a given horizon, the SDP value at a particular time is an aggregate value (mean or a specific percentile) calculated from the reserves/footroom available within that horizon at the end of that dispatch interval across all days in the simulated year. In other words, values from across the year for a given time of day are aggregated, and these are then “stitched” together to form a “synthetic day” curve for a particular horizon. Two aggregate values were calculated for each horizon curve:

1. The mean. This provides a picture of the average or “typical” availability of reserves and footroom at different times of the day for a particular scenario year; and
2. The bottom 1% (i.e. 1st percentile or 1-in-100 day lowest). This measure better reflects the availability of reserves and footroom when they are scarce and thus when they are most needed[8].

In addition to an infinite horizon (which corresponds to the maximum availability), curves were calculated for 1, 5, 15, 30 and 60 minute horizons. These horizons encompass the start-up times of hydro and flexible gas generation, and represent the likely timeframes over which the proposed operating reserve product will be required to respond.

5.6.4.2 Available reserve synthetic days

Mean and bottom 1% available reserve SDPs were generated for the NSW scenarios and for the SA scenarios (Figures 5.4, 5.5). The mean SDPs across scenarios suggest that, on average, NSW has more than 2 GW and SA more than 600 MW of reserves available within 5+ minutes. These levels of reserves:

1. Correspond to approximately 15% and 20% of peak demand in 2020 in

[8]More extreme percentiles (i.e. $< 1\%$) could better reflect the tight reliability standards adopted in many power systems - e.g. the NEM standard of a maximum expected unserved energy of 0.002% of the total energy demand of a NEM region in an Australian financial year (Australian Energy Market Commission Reliability Panel, 2022). However, the use of extreme percentiles would be more appropriate with a greater number of modelled days (i.e. several years).

NSW and SA, respectively. These 5+ minute "reserve margins" (i.e. 5+ minute reserves as a percentage of peak demand) are comparable to lower-end reserve margins anticipated for the summer of 2022 in North American jurisdictions (North American Electric Reliability Corporation, 2022).

2. Exceed the highest N-1 contingency in 2020 (i.e. highest LOR2 trigger level declared in the last run of Pre-Dispatch PASA prior to delivery — see Section 5.4.2) by approximately 225% in NSW and 170% in SA (Prakash, 2023).

Furthermore, with additional BESS and flexible gas resources expected to be deployed, the mean 5+ minute reserve margins of both regions are higher for most parts of the day in the 2025 Step Change scenario. Though the market simulation relied on perfect foresight (additional uncertainty may reduce reserve margins), these results suggest that reasonable quantities of reserves are available in each region within a 5+ minute horizon.

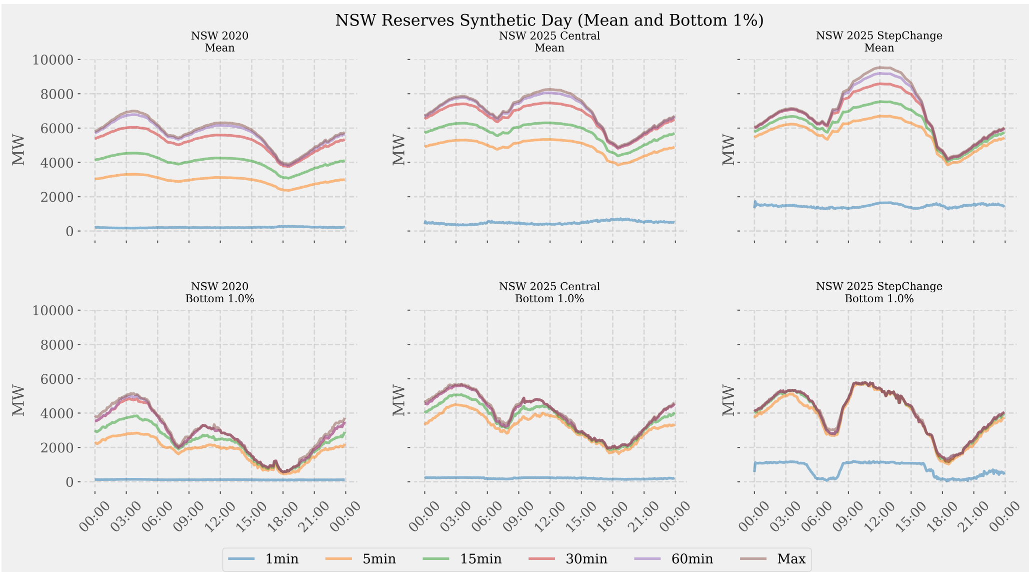


Figure 5.4: Mean (top row) and bottom 1% (bottom row) SDPs for available reserves in NSW in 2020 (leftmost column) and the two 2025 scenarios (rightmost columns).

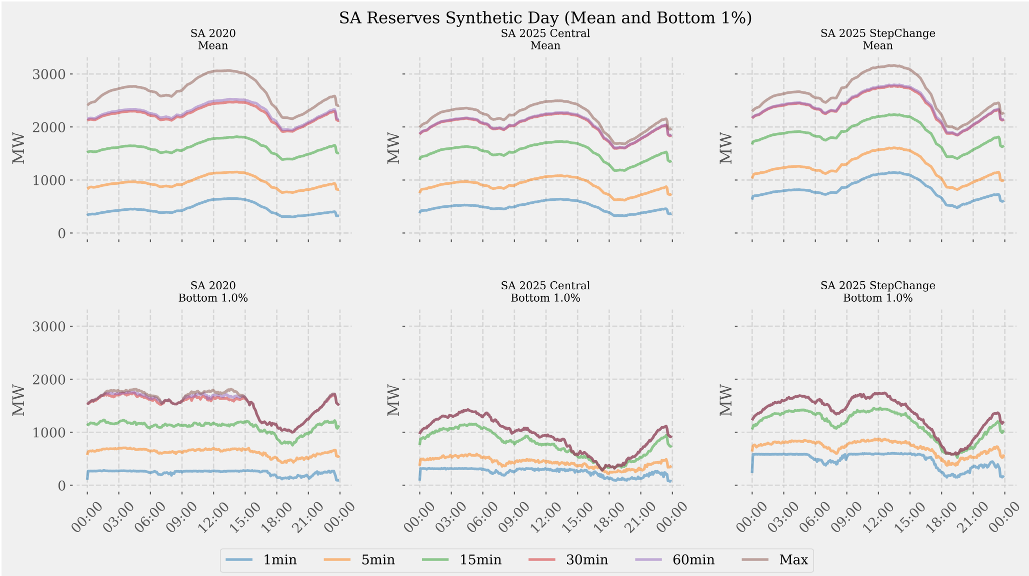


Figure 5.5: Mean (top row) and bottom 1% (bottom row) SDPs for available reserves in SA in 2020 (leftmost column) and the two 2025 scenarios (rightmost columns).

Across scenarios, the following trends are apparent in the SDPs:

1. From 2020 to the 2025 Step Change scenario, a midday peak in the mean available reserves SDPs becomes more pronounced. This can be attributed to the increasing displacement of conventional generation by lower-cost utility-scale solar PV in dispatch (an outcome observed by Hummon et al. (2013) and Tanoto et al. (2021)) and the progressive erosion of day-time operational demand due to higher penetrations of distributed solar PV. Particularly in SA, curtailed VRE and BESS also contribute to this reserve "surplus". BESS in particular are often charging during such periods of plentiful supply and low prices, and thus are able to offer up to double their active power rating as reserve (i.e. by switching from charging to discharging).
2. As is particularly clear in the bottom 1% SDPs for the 2025 scenarios, the availabilities of different reserve horizons tend to converge during periods

of lower reserves or "relative scarcity", which include peak demand events in the morning and evening. The convergence may be driven by the retirement of baseload conventional generation and higher ramping requirements in the 2025 scenarios requiring more flexible, mid-merit resources to be online prior to and during these periods.

From this analysis, we can also gain an insight into the supply-side dynamics of a potential operating reserve product market. The first trend suggests that as energy transition proceeds, a reserve surplus during the daytime could suppress the price of an operating reserve product (a dynamic that is further explored by Frew et al. (2021b)). Moreover, the convergence of availability across horizons during periods of "relative scarcity" suggests that relatively inflexible but cheaper resources are being preferentially ramped through dispatch at these times whilst more flexible but expensive resources are left in reserve. Since the majority of system headroom during these periods appears to be available within 5 to 15 minutes, operating reserves would likely be procured from these more flexible resources regardless of whether the product requires availability within 5 or 30 minutes. As such, concerns regarding limited providers of a 5-minute horizon product may also apply to a 30-minute horizon product during periods of relative scarcity (noting that several resource types in the NEM are already providing upwards flexibility within 5 minutes in the NEM, as shown in Figure 5.1).

5.6.4.3 Available footroom synthetic days

Two types of SDPs were constructed for available footroom: one for *firm* footroom and the other for total footroom. The former refers to potential footroom provision from conventional resources and BESS, whereas the latter also includes footroom that can be provided by curtailing VRE. Figures 5.6, 5.7 show mean and bottom 1% SDPs across NSW scenarios for firm footroom and total footroom, respectively. From the bottom 1% SDPs in Figure 5.6, it is clear that firm system footroom can become very low in NSW in 2025 as remaining baseload conventional generators are driven to operate closer to their MSLs. However, such concerns could be alleviated if VRE provide footroom (Figure 5.7). A similar result was observed for the SA region.

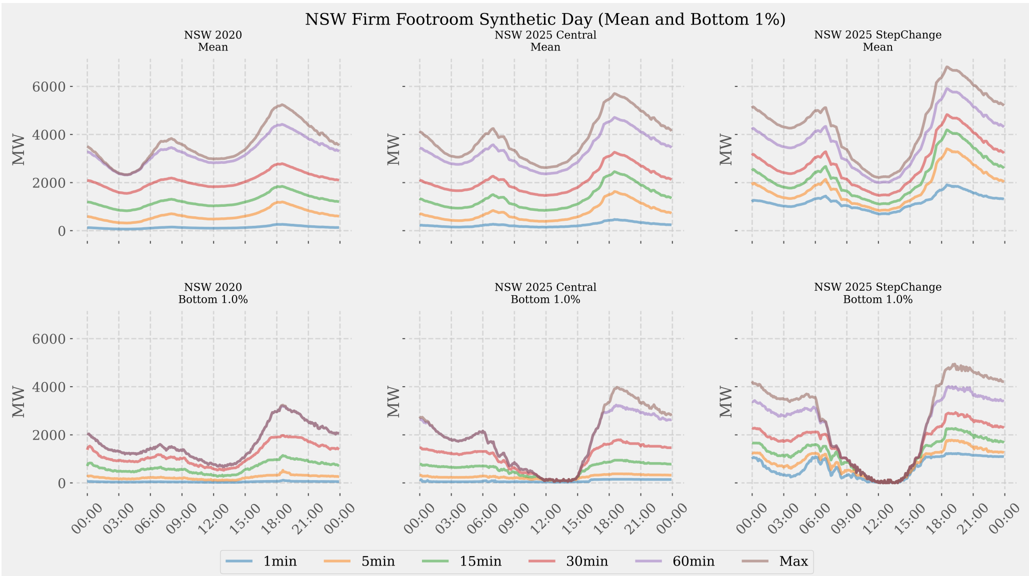


Figure 5.6: Mean (top row) and bottom 1% (bottom row) SDPs for available firm footroom (i.e. footroom provided only by “firm” resources: conventional and BESS) in NSW in 2020 (leftmost column) and the two 2025 scenarios (rightmost columns).

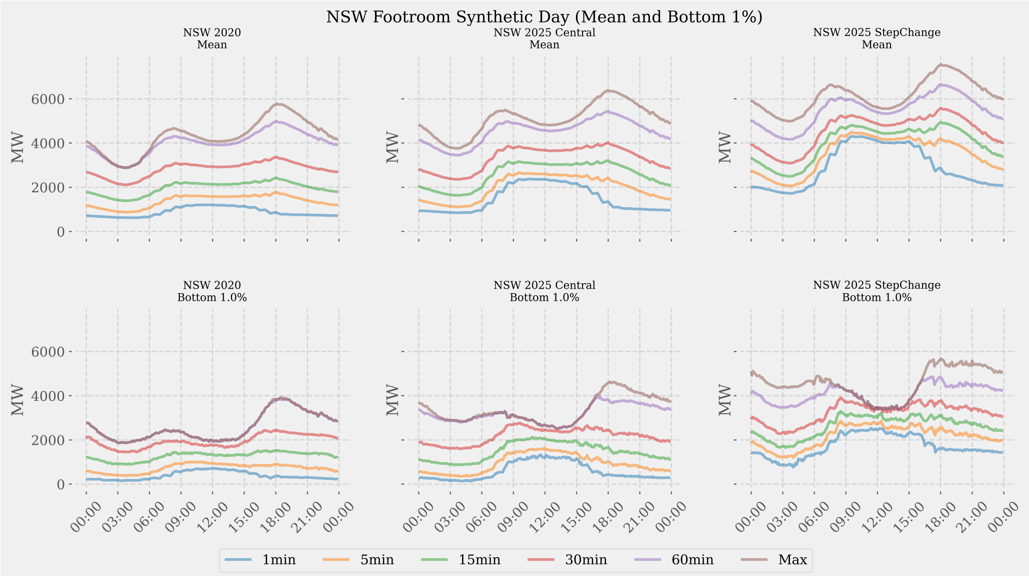


Figure 5.7: Mean (top row) and bottom 1% (bottom row) SDPs for available total footroom (including footroom that would be provided by curtailing VRE) in NSW in 2020 (leftmost column) and the two 2025 scenarios (rightmost columns).

The available footroom in the system is likely sensitive to extent of conventional generation retirements. Further retirements may enable remaining conventional resources to operate at a higher loading, thereby increasing the available footroom in the system. Regardless, given that each region appears to suffer a lack of *firm* footroom for several hours during the day in the 2025 scenarios explored in this case study, mechanisms for procuring sustained downwards balancing flexibility should be considered alongside those for procuring sustained upwards balancing flexibility. One simple option would be to implement an operating *footroom* product, which, if VRE are permitted to provide this service, can enable conventional generation to operate closer to their MSL and thus reduce system operating costs and carbon emissions (Nelson et al., 2018).

5.6.4.4 Short-term energy-limited reserves

While the available reserves metric does not consider the duration for which reserve deployment can be sustained, we can infer whether reserves are short-term energy-limited (i.e. with a duration no more than a few hours) based on their resource type. For this analysis, BESS reserve power was calculated based on the BESS's state of charge at the end of each dispatch interval and the requirement to sustain provision for 15 minutes. This duration is consistent with the BESS power and capacity that is reserved in SA for the possibility of loss of interconnection (Australian Energy Market Operator, 2020o). In addition, the maximum available price-responsive demand available in each state was added to the available reserves in each dispatch interval (assuming an emergency response time of 5 minutes) to gain a better understanding of the maximum potential contribution of demand response. This corresponded to ~60 MW in SA and ~290 MW in NSW, based on AEMO analysis and forecasts in Australian Energy Market Operator (2020n). Both BESS and DR can be considered to be short-term energy-limited reserve providers. Though conventional generation fuel constraints (e.g reservoir schemes and the gas system) were not modelled in this market simulation, the contribution of conventional resources was separated into those of thermal and hydro to assess the importance of the energy constraints on each resource type to available reserves in NSW.

Tables 5.2 and 5.3 show the median percentage across dispatch intervals in a scenario year of available reserves provided by a resources type for NSW and SA, respectively. Whilst hydro and thermal resources dominate 5 minute horizon reserve provision in 2020 in NSW and SA, respectively, short-term energy limited resources provide a greater proportion of reserves in this horizon in

2025. In particular, the median contribution of BESS to reserves available within 5 minutes is 16% for NSW and 40% for SA in the 2025 Step Change scenario. As the reserve horizon is extended to 30 minutes, a greater proportion of reserves are provided by conventional resources, which may be better positioned to sustain a response beyond the short-term[9]. These results indicate that as energy transition progresses, a trade-off between reserve deployment speed and duration develops. This trend reaffirms the value of the sequential and hierarchical approach to reserve product design and deployment that has been adopted in many jurisdictions (Prakash et al., 2022). Moreover, it should be noted that unlike other mechanisms for procuring balancing flexibility, reserve services and products can specify duration/energy requirements and thus ensure that flexibility provision is sustained.

NSW Resources	2020		2025 Central		2025 Step Change	
	5 min	30 min	5 min	30 min	5 min	30 min
BESS (15 min)	0%	0%	2%	1%	16%	14%
DR	9%	5%	5%	4%	5%	4%
Hydro	74%	43%	81%	60%	71%	61%
Thermal	18%	52%	12%	34%	8%	19%

Table 5.2: Median of the percentage of each resource type's contribution to reserves available within 5 minutes and 30 minutes in every dispatch interval for each NSW scenario year. The median percentages are not necessarily coincident (i.e. from the same dispatch interval) and therefore may not sum to 100%. Furthermore, some distributions are long-tailed, so a median does not capture occasional reserve provision by a resource type (e.g. VRE, for which all medians are 0%).

[9]In reality, conventional resources are also susceptible to fuel constraints, as highlighted by the events preceding the 2022 NEM suspension (Australian Energy Market Operator, 2022d). More sophisticated modelling of thermal coal availability, the gas system and hydro schemes, including their operation under different climate conditions, would be required to better understand the potential duration of available reserve provided by conventional generation.

SA Resources	2020		2025 Central		2025 Step Change	
	5 min	30 min	5 min	30 min	5 min	30 min
BESS (15 min)	14%	6%	24%	10%	40%	20%
DR	7%	3%	7%	3%	5%	3%
Thermal	71%	88%	61%	84%	45%	73%

Table 5.3: Median of the percentage of each resource type's contribution to reserves available within 5 minutes and 30 minutes in every dispatch interval for each SA scenario year. The median percentages are not necessarily coincident (i.e. from the same dispatch interval) and therefore may not sum to 100%. Furthermore, some distributions are long-tailed, so a median does not capture occasional reserve provision by a resource type (e.g. VRE, for which all medians are 0%).

5.6.5 The role of balancing products

It is unclear whether introducing an operating reserve product will deliver material operational benefits to the NEM in light of the revenue risks, complexity, and implementation and ongoing costs associated with a new market. Instead, existing mechanisms may be able to deliver sufficient upwards flexibility, particularly if they can be augmented:

1. Market participants with forward market obligations are strongly incentivised to offer balancing flexibility to the market. The premium payment offered to the seller, along with a strong financial incentive to perform during periods of system stress, means that derivatives such as cap contracts somewhat resemble pay-for-performance capacity remuneration mechanisms[10]. Participants would have further incentive if contracting were made mandatory (Mays et al., 2022), or if they increasingly resort to contracting to hedge pricing volatility that could occur as energy transition progresses (de Vries and Sanchez Jimenez, 2022).

2. Market and system information and forecasts (e.g. the NEM's ahead pro-

[10] However, derivatives are financial in nature and thus need not be "backed" by power system resources (i.e. they are not associated with any physical obligation).

cesses) may be critical to ensuring that market participants schedule resources to provide flexibility to the system. Future work should not only seek to improve their accuracy and their treatment of uncertainties, but also to understand how they shape participant decision-making and thus which enhancements could provide the most value.

However, there remain some operational benefits of additional balancing products. Nested distribution-level markets and/or real-time market scheduling of aggregated resources have the potential to better enable balancing flexibility from DER. However, a key insight from Section 5.6.4.4 is that consideration should be given to the duration of this flexibility. System stress could coincide with periods in which DER owners wish to use these resources for themselves (e.g. a heatwave or if they are exposed to real-time market volatility to some extent) (Roberts et al., 2020). In contrast, reserve products that specify response durations could provide the SO with certainty that flexibility is only procured from resources that are available for a minimum period of time. Any duration requirements would need to be balanced against the quantity and diversity of flexibility providers – primarily to ensure that product markets are competitive, but also because successive deployment of several short-term energy limited resources may be sufficient to meet system balancing needs over the course of a few hours. Furthermore, sustained footroom products might assist SOs in managing a lack of firm footroom (Section 5.6.4.3). Typically, energy prices rise when upwards flexibility is scarce, thereby compensating providers of upward flexibility. In contrast, downwards flexibility providers are not strictly compensated through energy pricing, as oversupply could lead to dispatch curtailing, rather than remunerating flexible resources. Though this might mean flexible resources avoid financial losses, it comes at the cost of footroom available to the system. Accordingly, an "operating footroom" product that remunerates downwards flexibility offers a solution to the tension between dispatch incentives and the need for system footroom.

5.7 Conclusion and policy implications

State-of-the-art resource adequacy assessments are closing the gap between traditional capacity adequacy assessments, which focus on capacity reserve margins during peak demand events, and flexibility adequacy assessments that often model chronological operations (Stenclik et al., 2021). Yet flexibility adequacy assessments alone do not necessarily offer a better understanding of *what type* of balancing flexibility a system has and might need, and *how* best to make it available to the system. As resource mixes change dramatically during energy transition, system designers, planners and operators should quantify balancing flexibility capabilities to gain an appreciation of the availability of different resource types to inform operational practice design.

By quantifying balancing flexibility "margins" in two sub-systems of the Australian National Electricity Market (Section 5.6), we identify potential balancing flexibility dynamics and trends in future power systems. Firstly, systems with high penetrations of distributed and utility-scale solar PV will likely have reserve "surpluses" around the middle of the day and periods of relative reserve scarcity during morning and evening peak demand events. In such systems, the periods when reserves are most valuable do not necessarily correspond to the periods during which it is most efficient to curtail renewable energy generation (due to oversupply or to obtain reserves). As such, a key recommendation for policymakers is to consider whether reserve product markets are needed to elicit sufficient balancing flexibility provision during these short periods of relative scarcity, or whether adjusting energy market settings, forward market obligations and/or market and system information processes can achieve this. Understanding the potential benefits of new reserve product markets is crucial because they can introduce additional costs, constraints and complexity whilst encroaching upon the functions of other operational practices. Secondly, our study highlights the importance of placing a greater emphasis on duration, as resources touted as essential future balancing flexibility providers (e.g. battery energy storage, demand response) may only be able to sustain a response for at most a few hours. Thirdly, we highlight the need to consider footroom and the benefits of enabling renewable energy to provide it. Footroom procurement and response duration specifications are underappreciated by prevailing market designs, and may be better addressed by policy-makers either modifying existing or creating new reserve product specifications.

6 | Final research study

6.1 Introduction

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6.2 Method

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6.3 Results

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6.4 Discussion

This is the discussion. Curabitur gravida nisl id gravida congue. Duis est nisi, sagittis eget accumsan ullamcorper, semper quis turpis. Mauris ultricies diam metus, sollicitudin ultricies turpis lobortis vitae. Ut egestas vehicula enim, porta molestie neque consectetur placerat. Integer iaculis sapien dolor, non porta nibh condimentum ut.

6.5 Conclusion

This is the conclusion to the chapter. Nulla sed condimentum lectus. Duis sed tempor erat, at cursus lacus. Nam vitae tempus arcu, id vestibulum sapien. Cum sociis natoque penatibus et magnis dis parturient montes, nascetur ridiculus mus.

7 | Conclusion

7.1 Thesis summary

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7.2 Future work

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A | Data and assumptions used in market simulation

A.1 Resource ramp rates

Separate upwards and downwards ramp rates were modelled for most resource types. For hydro generation and reciprocating engines, maximum upwards and downwards ramp rates were sourced from GHD (2018). For other conventional resources (coal-fired generation, Gas-Steam, CCGT and OCGT), ramp rates in each direction were further separated into a *market* ramp rate, which was used in the PLEXOS market simulation, and an *upper* ramp rate, which was used to calculate available reserves/footroom. For these resources, the market ramp rate was calculated using the unit ramp rates used most frequently in NEM dispatch[1] in 2020, and the upper ramp rate was calculated using resources' assumed maximum ramp rates in AEMO's 2020 Inputs and Assumptions workbook (for an example of a comparison, see Figure A.1.1) (Australian Energy Market Operator, 2020n). Additional resources in 2025 were assumed to have the same ramp rate characteristics as newer existing resources of the same technology type.

[1]AEMO is currently investigating appropriate regional requirements for FCAS, particularly for contingency FCAS in the terminal regions of QLD and SA (Australian Energy Market Operator, 2020h, 2019d).

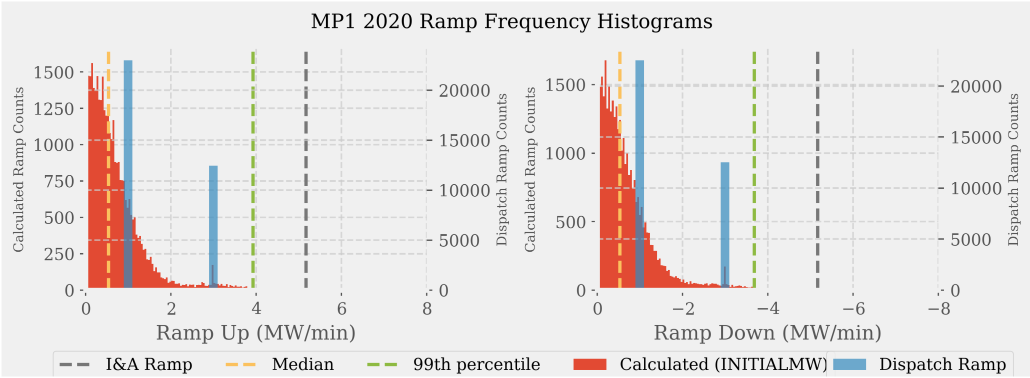

Figure A.1.1: Ramp rates observed (red) and used in dispatch by AEMO (blue) for a coal-fired unit in NSW in 2020. The green line denotes the ramp rate assumed by AEMO in its 2020 Inputs and Assumptions workbook and the 2020 ISP.

A.2 Unit commitment and cycling constraints

Many existing flexible conventional resources (OCGT, reciprocating engines and hydro generation) submit dispatch inflexibility profiles to AEMO that contain the resource's time to start up and reach MSL, the MSL itself, the time required at minimum loading and the time taken to shut down (Australian Energy Market Operator, 2021q). The most frequently offered fast start inflexibility profile of a resource in 2020 was obtained using NEMOSIS (Gorman et al., 2018) and used to calculate its start-up rate, minimum up-time, MSL and shutdown rate. The minimum down-time for these resources was chosen to be equal to the minimum up-time.

For the other conventional resources (CCGT, coal-fired generation and Gas-Steam), minimum up-times, minimum down-times and MSLs were obtained from AEMO's 2020 Inputs and Assumptions workbook (Australian Energy Market Operator, 2020n) and start-up rates were calculated based on hot or warm start times (i.e. depending on the start state of the resource after being offline for its minimum down-time) obtained from GHD (2018) or Aurecon Australasia (2020). The shut-down rates for these resources were calculated based on actual shutdowns, or those of similar technology types, observed in AEMO dispatch data that was obtained using NEMOSIS (Gorman et al., 2018).

BESS were dispatched by PLEXOS's arbitrage algorithm subject to charging and discharging efficiencies and maximum and minimum state of charge constraints that corresponded to those assumed within AEMO's 2020 Inputs and Assumptions workbook (Australian Energy Market Operator, 2020n). Given an assumed economic lifetime of 10 years (Australian Energy Market Operator, 2020n) and 3000 cycles (da Silva Lima et al., 2021) for lithium-ion BESS, a constraint of 300 cycles per year was applied to BESS in each scenario.

A.3 Partial and forced outages

Maintenance rates, forced outage rates (partial and full) and the corresponding mean time taken to repair were modelled for all conventional generation and were sourced from AEMO's 2020 Inputs and Assumptions workbook (Australian Energy Market Operator, 2020n).

A.4 SA synchronous generation requirement

At present, certain combinations of synchronous generators are required to remain online for power system security in SA. Should ahead processes indicate that the synchronous generation expected to be online and dispatched is inadequate to provide sufficient system strength in SA, AEMO will intervene in the market and direct additional synchronous generation online (Gu et al., 2019). The various sufficient combinations of synchronous generation in SA are outlined in Australian Energy Market Operator (2022e), with a decrease in requirements/increase in the allowable asynchronous generation level following the installation of 4 synchronous condensers (completed in 2021). To model these requirements, a must-run condition was imposed on 3 CCGT units and 1 Gas-Steam unit in 2020, and on 2 CCGT units and 1 Gas-Steam unit in the 2025 scenarios. These combinations reflect a subset of the sufficient combinations outlined in Australian Energy Market Operator (2022e).

A.5 Hydro generation monthly energy constraints

Run-of-river hydro generation and pumped hydro storage in NSW were aggregated and modelled as dispatchable generation with monthly energy constraints. These monthly energy constraints correspond to the average monthly inflows for the Snowy scheme (NSW and Australia's largest hydro scheme) across financial years 2011 to 2018 (obtained from Australian Energy Market Operator (2020n)). Though this model for hydro does not account for the additional generation that could be extracted from pumped storage, the application of monthly energy constraints could be interpreted as modelling one pattern of run-of-river hydro operation and/or enforcing the same reservoir level at the start and end of each month (and thus at the start and end of each year). Explicitly modelling reservoir schemes, inflows for individual hydro generators and pumping opportunities for pumped hydro storage are likely to improve the accuracy of the methodology proposed in this work for systems with significant shares of hydropower capacity.

A.6 Demand and VRE traces

Chronological demand traces at 5-minute resolution were used in the market simulation. For each region, historical operational demand for 2020 at 5-minute resolution was obtained using NEMOSIS (Gorman et al., 2018) and used as the demand trace for the 2020 scenario. AEMO ISP demand traces were available for each 2025 scenario at half-hourly resolution (Australian Energy Market Operator, 2019f); 5-minute resolution demand traces for each 2025 scenario were produced by scaling 5-minute historical operational demand by a corresponding half-hourly scaling factor, which was calculated as the ratio of the ISP scenario's 2025 demand trace to the ISP scenario's 2020 demand trace.

Half-hourly chronological solar PV and wind capacity factor traces were obtained from AEMO's ISP database for each 2020 scenario (Australian Energy Market Operator, 2019g) and for each 2025 scenario (Australian Energy Market Operator, 2020p). Generation traces were obtained by multiplying the capacity factor trace of a resource by its nameplate capacity. Capacities for existing and committed VRE plants were obtained from AEMO's 2020 Inputs and Assumptions workbook (Australian Energy Market Operator, 2020n) and any additional VRE capacity that was built out in the 2025 scenarios was assigned to AEMO-designated Renewable Energy Zones (for which capacity factor traces are available) based on the ISP's generation capacity outlook. The half-hourly generation traces for each resource and Renewable Energy Zone in a region were than aggregated and linearly interpolated for use in the 5-minute resolution market simulation.

A.7 Resource market offers

For all scenarios for a given region, one set of four static price-quantity pairs were used to represent each resource's offer in the market simulation. Except for hydro generation, offers were priced *a priori*. The type of the resource determined how each band was priced (price bands for each resource type are outlined in Table A.7.1) [2]:

- For wind and solar PV generators, the entire available forecasted energy was offered at the market floor price to ensure preferential dispatch of VRE where possible.
- For baseload conventional resources (coal-fired generation and Gas-Steam), the first band was priced at or close to the market floor price to ensure the resource's MSL would clear the market. The second band was priced close to the short-run marginal cost (SRMC) of the resource. The SRMC was calculated using the average heat rate, fuel price and variable operating and maintenance cost of each resource type obtained from Australian Energy Market Operator (2020n). The third band was priced at a premium relative to the resource's SRMC and the fourth band was offered at the market cap price.
- For peaking generation (OCGT and reciprocating engines), the first band was priced close to the SRMC of each resource, which was calculated in the same manner as for baseload conventional resources. The second and third band were offered at a moderate and higher premium relative to the

[2] The ramp rate used in dispatch by AEMO is the lesser of a telemetered rate or a ramp rate submitted in a resource's offer for energy, and was obtained using NEMOSIS (Gorman et al., 2018).

resource's SRMC, respectively. The fourth band was offered at the market cap price.

- Hydro generation offers were adjusted iteratively to align the proportions of annual generation and average market prices of the NSW 2020 scenario with those calculated from historical data.

Table A.7.1: Offers by resources type for NSW and SA across all scenarios. The market floor and cap prices used were -1000 AUD/MW/hr and 15,000 AUD/MW/hr, respectively.

Generator Type	Price Band 1 (AUD/MWh)	Price Band 2 (AUD/MWh)	Price Band 3 (AUD/MWh)	Price Band 4 (AUD/MWh)
Coal	Floor	30	50	Cap
CCGT	40/Floor (NSW/SA)	70	170	-
OCGT	100/175 (NSW/SA)	200/300 (NSW/SA)	500	Cap
Reciprocating Engine	175	300	500	Cap
Gas-Steam	Floor	90	190	Cap
Wind	Floor	-	-	-
Solar PV	Floor	-	-	-
Hydro	35	60	300	Cap

Calibration

Resource offer quantities were used to calibrate the 2020 simulation with historical generation patterns in each state. The quantity of energy in each price band was adjusted in an iterative process of offer adjustment and market simulation to ensure that the proportion of annual generation of a particular resource type in the simulated 2020 scenario was similar to the actual proportion of annual generation for that resource type in 2020. The combination of offer quantities that produced the closest proportions were retained and used for each state's 2020 and 2025 scenarios. The results of the calibration for NSW and SA are outlined in Table A.7.2 and Table A.7.3, respectively.

Table A.7.2: Percentage of annual generation by resource type for the simulated NSW 2020 scenario and for NSW in 2020 (calculated based on historical data obtained using NEMOSIS (Gorman et al., 2018)).

	Coal	Wind	Hydro	Solar PV	CCGT	OCGT
NSW 2020	82.9%	6.4%	4.5%	3.2%	2.4%	0.6%
Historical 2020	84.5%	6.6%	3.8%	3.3%	1.5%	0.3%

Table A.7.3: Percentage of annual generation by resource type for the simulated SA 2020 scenario and for SA in 2020 (calculated based on historical data obtained using NEMOSIS (Gorman et al., 2018)). Note that percentages may not sum to a total of 100% due to net storage in BESS.

	Wind	CCGT	Gas-Steam	Solar PV	OCGT	Reciprocating Engine
Historical 2020	43.7%	29.7%	15.1%	5.1%	2.3%	3.5%
SA 2020	45.6%	25.6%	16.8%	8.0%	2.3%	1.6%

B | Some more extra stuff

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