Insights on designing effective and efficient frequency control arrangements from the Australian National Electricity Market

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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 assessment, 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 enable participant remuneration based on service quality, and 4) Considering both regulatory and market mechanisms and their consequences and interactions. In particular, the Australian experience highlights how the pursuit of efficiency through market-oriented arrangements can create tensions with regulatory requirements that, in some cases, may prove to be more effective and resilient.

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The final article (which includes changes in response to reviewer feedback) is available online here.

List of Abbreviations and Nomenclature

AC	Alternating current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
DC	Direct current
ENSTO-E	European Network of Transmssion 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

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FERC	Federal Energy Regulatory Commission
FFR	Fast frequency response
Hz	Hertz
mHz	Millihertz
MW	Megawatts
NEM	National Electricity Market
NER	National Electricity Rules
NOFB	Normal operating frequency band
NSW	New South Wales
OFGS	Over-frequency generation shedding
PFR	Primary frequency response
PV	Photovoltaic
QLD	Queensland
RoCoF	Rate of change of frequency
SA	South Australia
SFR	Secondary frequency response
SO	System operator
TAS	Tasmania
TFR	Tertiary frequency response
TNSP	Transmission Network Service Providers
UFLS	Under-frequency load shedding
UK	United Kingdom
US	United States
UFLS	Under-frequency load shedding
VIC	Victoria
VRE	Variable renewable energy

1. Introduction

As a consequence of growing momentum to address global warming and continually declining technology costs [1, 2], 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 displacement and retirement of existing fossil fuel generation [3]. 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 [4, 5]. 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 [6, 7, 8].

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 [9]. Power system frequency deviations are a consequence of instantaneous supply-demand imbalances, which typically occur as a result of the variability and uncertainty of generation and load [10]. System operators (SOs) achieve short-term active power balancing using reserve capacity [11]. 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, frequency may deviate beyond acceptable system limits and lead to equipment damage, load shedding, generator trips and cascading failures that lead to blackouts [14, 15].

In electricity industries with competitive markets for energy and FCS, frequency control arrangements consist of control, regulatory and market-based mechanisms [8]. Control mechanisms specify the technical

[1] The term *balancing services* is used in European systems [12], whereas the term *operating reserves* is widely used in North America [13].

requirements for FCS, whereas regulatory and market-based mechanisms are used to procure FCS from capable resources (i.e. generators, loads and network elements). Regulatory procurement mechanisms are often mandatory and include equipment standards, connection requirements and SO intervention, whereas market-based mechanisms are often voluntary and include remunerative schemes and contract or spot markets. Together, these mechanisms dictate the physical effectiveness and productive, dynamic and price formation and cost-allocation efficiencies of FCS provision and procurement. Well-designed arrangements should be effective and efficient, where the former entails sufficient and robust frequency response to meet physical power system requirements and the latter relates to frequency response being provided at low cost, both now and into the future [16, 17].

Designing frequency control arrangements has become more complex over the past three decades. Many electricity industries have undergone some degree of restructuring, which has created a greater role for competitively-oriented decentralised decision-making [17]. The diverse outcomes of these restructuring processes and differences in the technical capabilities of resources have led to a wide range of frequency control arrangements across power systems [18], which have been reviewed and compared extensively within industry and academic literature [10, 18, 19, 20, 21, 22, 23, 24, 25]. As such, the design problem can be complex as some system-specific arrangements may be required. Further complexity has been introduced by increasing penetrations of VRE and IBR. Conventional frequency control arrangements are being revisited as power systems transition towards greater levels of variability and uncertainty and towards a greater proportion of resources whose behaviour is dictated by control system design rather than inherent electromagnetic phenomenon such as inertial response [6, 26, 27, 28].

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 50% in 2020) and is expected to experience penetrations as high as 75-100% by 2025 [29, 30]. Both 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 the NEM's frequency control arrangements, which were once arguably world-leading [31, 32]. However, demand response and some utility-scale and distributed VRE and IBR can and do offer FCS, and rule makers are adapting the NEM's market design to harness advanced capabilities, such as fast frequency response (FFR), from these resources [33].

Though 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. Based on our assessment of frequency control arrangements in the NEM, we offer four key insights to operators, regulators and market-bodies that include understanding control action interactions, promoting 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 during energy transition. Our analysis benefits from experience in the NEM that encompasses deteriorating frequency performance, the reintroduction of mandatory requirements and integrating higher shares of VRE. As such, it complements, or altogether contrasts, previous literature on frequency control in the NEM [31, 32, 34].

The rest of the paper is structured as follows. In Section 2, we provide a brief overview of typical frequency control arrangements in restructured electricity industries and the main challenges faced in their design. We outline the NEM's frequency control arrangements and its noteworthy features in Section 3. In Section 4, we analyze the performance of the NEM's frequency control arrangements in responding to the challenges explored in Section 2, with primary frequency response and regulation (secondary frequency response) services in the NEM as case studies. Based on our analysis, we conclude by identifying four key insights from the Australian experience that may assist in improving the efficiency and effectiveness of frequency control arrangements both in the NEM and in restructured electricity industries with competitive markets for FCS.

2. Context

2.1. Conventional frequency control schemes

SOs typically 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 [35, 36]. 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 [37, 38]. 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 [39, 40, 41].

2.2. Procurement of frequency control services

Restructured electricity industries with competitive markets for energy differ in their approaches to procuring FCS. Whilst some FCS may be mandated by regulatory mechanisms such as connection agreements, many restructured electricity industries have elements of competition in the procurement of FCS. In electricity industries with decentralised or self-dispatch (e.g. European markets), FCS markets are decoupled from energy market platforms. Balance responsible parties are incentivised to balance their energy portfolio through mechanisms that allocate the cost of FCS [17, 22]. The SO procures FCS days, weeks or months in advance to address residual imbalances through bilateral contracts or tendering processes [25, 42]. In electricity industries with centralised unit dispatch (e.g. North American ISO/RTO markets), an area or system-wide requirement for FCS is determined by the SO, who is responsible for system security. Typically, FCS markets are co-optimised with the day-ahead and/or real-time energy markets and load-serving entities are responsible for purchasing or self-providing their share of FCS [20].

2.3. Challenges in designing frequency control arrangements

Previous literature has explored the key design considerations for frequency control arrangements. Rebours et al. [16] outlines design principles for centralised 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.

van der Veen and Hakvoort [17] build upon this work to provide a more comprehensive treatment of frequency control arrangement design variables, performance criteria and the trade-offs between these, with a focus on the design challenge in European bilateral markets. Both Rebours et al. [16] and van der Veen and Hakvoort [17] emphasise that good arrangement design may lead to efficient and effective frequency control arrangements but focus on economic efficiency.

Ela et al. [38], Billimoria et al. [6] and Mancarella and Billimoria [8] recognise that frequency control arrangements are typically composed of a mixture of market-based and regulatory mechanisms for procurement that are compatible with the physical needs of the power system. However, finding the 'best' combination of these options is challenging due to:

1. The trade-off between efforts to improve the economic efficiency of FCS provision, and the degree of visibility and immediate control available to the SO [16]. In many jurisdictions, a system requirement that is determined by the SO is met by market participants who offer limited reserve capacity with assumed response capabilities. However, the actual response provided by a market participant may deviate from that assumed. Furthermore, in the case of complex faults or events, the SO may have a limited set of emergency tools beyond UFLS, OFGS and RoCoF relays to respond to supply-demand imbalances that exceed an "efficient" system requirement;

2. The trade-offs associated with the fungibility of FCS. Market-based mechanisms will work best when FCS are "discrete" commodities and fungible. However, this ignores the wide “spectrum” of technical capabilities of resources. Favouring fungibility may restrict or fail to incentivise higher quality provision and thus may lead to an inefficient overall outcome [43, 44];
3. The public good characteristics of power system frequency. The introduction of competitive markets can hamper the coordination and cooperation required to provide effective frequency control. Furthermore, where FCS markets have been implemented, these characteristics have implications on FCS price formation and cost allocation [6, 16], and therefore the efficiency of FCS markets;
4. The overlap between energy and FCS provision. The latter has traditionally been considered a capacity mechanism that is *ancillary* to the former. This may be reflected in the price of FCS relative to the price of energy; and
5. The pace of the energy transition that is being observed in power systems around the world. VRE and other IBRs are asynchronous and offer both challenges and opportunities to conventional frequency control arrangements designed for power systems historically dominated by synchronous generators. Such challenges include efficiently managing the variability and uncertainty of VRE [10, 32, 45], and operating power systems with higher RoCoFs due to reduced system inertial response and with fewer resources offering conventional FCS [27, 39, 46, 47, 48]. However, if their control systems are configured appropriately, IBR also offer opportunities such as tunable FFR and an inherent response that strongly resembles the inertial response provided by synchronous machines[2] [28, 56, 57]. Following a contingency event in a low-inertia power system, these rapid responses can mitigate higher RoCoFs, which when unabated can lead to deeper frequency nadirs and zeniths and the subsequent activation of UFLS or OFGS [54, 58, 59].

3. Frequency control arrangements in the Australian National Electricity Market

3.1. 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 1). In 2019, the NEM serviced a total electricity consumption of approximately 206 TWh/year and a peak demand of approximately 34 GW across a 'stringy' network over 5000 kilometres long with relatively weak interconnection between regions through interconnectors [44, 60]. 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.

The NEM is a single platform (real-time) energy-only market with no explicit capacity mechanisms. Unit commitment is managed by market participants, who submit offers for energy and Frequency Control Ancillary Services (FCAS) in price-quantity pairs. Security-constrained economic dispatch is run every five minute to co-optimise the provision of energy and FCAS with regards to technical feasibility and cost [62, 63]. This process produces zonal marginal prices for energy and FCAS.

3.2. FCAS Markets

The NEM's competitive FCAS markets consist of eight separate 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 2). This is similar to arrangements in many ISO/RTO markets, where FCS are divided into event and non-event reserves [10].

Regulation and contingency FCAS are typically procured for and from all regions of the NEM in the absence of binding network constraints. Local requirements for FCAS procurement apply to Tasmania and

[2]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* [49, 50, 51, 52]) or a controlled response following frequency measurement [53, 54, 55].

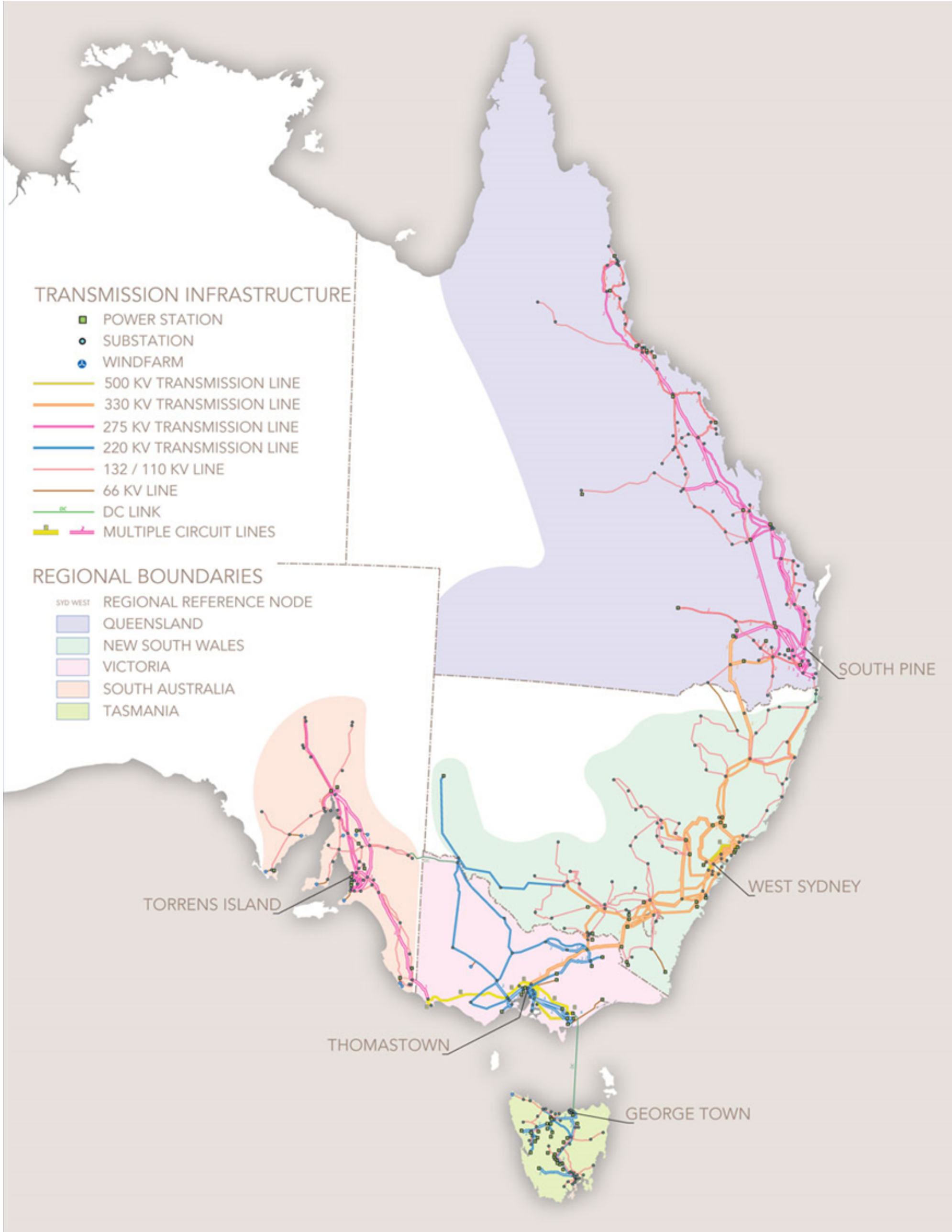

Figure 1: Regions/states and transmission in the NEM. Source: Australian Energy Market Commission [61].

to the other regions of the NEM if they experience network constraints, are at risk of separation or when islanded[3] [66, 67]. FCAS providers are paid for enablement (the capacity to respond to frequency deviations) regardless of whether FCAS is required and delivered [31, 32, 68].

[3]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 [64]. However, if the interconnector flow is within the appropriate operating envelope, NEM-wide FCAS procurement is possible as the interconnector's frequency controller enables FCAS transfer between the mainland and Tasmania [65].

Table 2
Frequency control ancillary services in the National Electricity Market. Sources: [31, 32, 58, 66, 67, 68, 69]

Product	Control Action	Procurement	Timeframes
Regulation (raise & lower)	Centralised control through AEMO Automatic Generation Control, 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 seconds over dispatch interval
6-second 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 seconds after frequency has left NOFB and orderly transition to 60-second service
60-second Contingency (slow raise & lower)			Full response delivered by 60 seconds after frequency has left NOFB and orderly transition to 5-minute service
5-minute 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 deviation	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 minutes after frequency has left NOFB and sustained until frequency returns to NOFB or 10 minutes has elapsed

3.3. 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 and seek as best possible to allocate costs to market participants based on a 'Causer Pays' principle [68]. 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.

3.4. Features of NEM frequency control arrangements

Below, we highlight some of the noteworthy features of the NEM's frequency control arrangements that complement or contrast previous analyses in [31], [32] and [34].

3.4.1. 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 [69].
- 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 ± 50 mHz was removed from the NER [70]. 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 4.1.
- 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 [71]. AGC control performance is discussed further in Section 4.2.

3.4.2. Market mechanisms:

- There are relatively few limits imposed on FCAS participation. FCAS can be provided by any technology through variable, switched or hybrid controllers [72]. 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. For example, large or aggregated loads participate in all three raise contingency FCAS markets.
- 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 [73] and summarised in [32]) that determine how regulation FCAS costs are allocated to market participants. We discuss the issues associated with this methodology in Section 4.2.
- 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 [66].

3.4.3. Regulatory mechanisms:

- Connecting 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[4] [75].
- 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 [76, 77].

4. Insights from the National Electricity Market

4.1. 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 [70].

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 ±150 mHz) [70]. In contrast, ENTSO-E specifies that PFR providers have a deadband no greater than ±10-15 mHz depending on the control area [78] and FERC Order 842 mandates all newly-connecting generation in US interconnections to operate frequency-responsive control equipment with maximum deadbands of ±36 mHz [79].

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 4.2) has

[4] 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 [74].

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 [80]. 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 [81]. Prior to the event, the QLD region was exporting ∼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 ∼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 2). 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 2). 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[5] [81].

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 [84]. 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 ±0.015 Hz (i.e. 10% of the NOFB) [70].

This rule was incorporated into the NER in 2020 as a temporary arrangement, with 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 [80, 85]. AEMO has specified PFR settings, including maximum droop and response time, but is unable to require generation to reserve headroom for PFR [86].

4.2. 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 [70]. 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 [87]. 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.

[5] AEMO is currently investigating appropriate regional requirements for FCAS, particularly for contingency FCAS in the terminal regions of QLD and SA [29, 82]

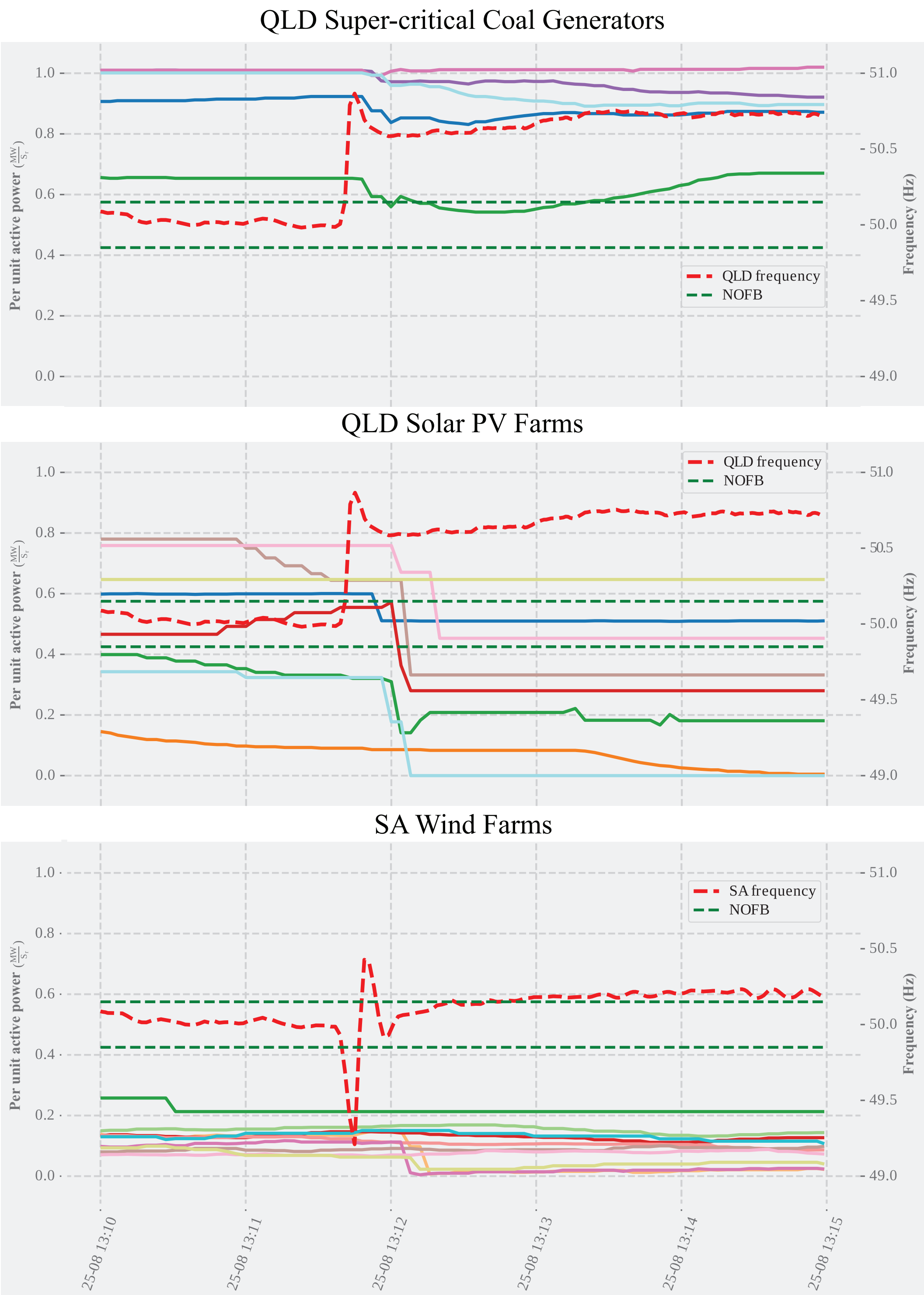

Figure 2: Active power output of QLD super-critical coal generators (top), SA solar PV farms (middle) and SA wind farms (bottom). The response of an individual generator is denoted by solid lines (obtained from 4-second AEMO SCADA data using NEMOSIS [83]). None of these generators are enabled for FCAS. The red dashed line in each frame is the regional frequency as measured by high-speed (1-second) phasor measurement units.

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 25th 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 3). 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 [81].

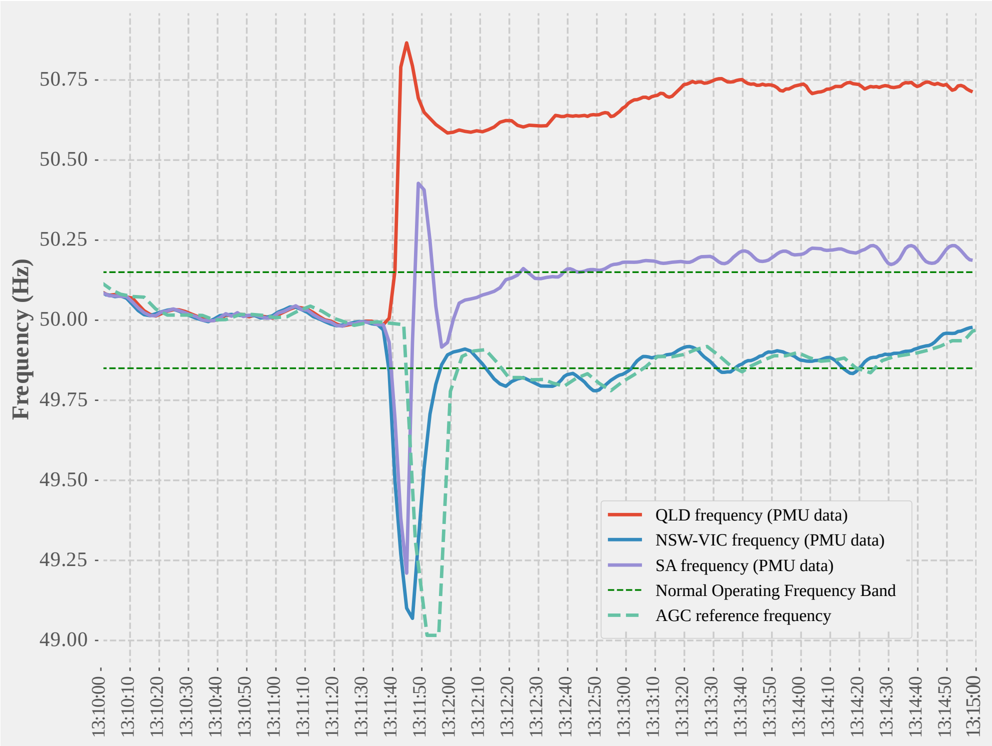

Figure 3: Regional phasor measurement unit frequency data and AGC reference frequency data from AEMO's NSW control centre (obtained using NEMOSIS [83]) during the power system event on the 25th of August, 2018. Note that the AGC reference frequency deviates in the opposite direction to local frequency 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 [67]. Time error control is largely unnecessary as modern clocks no longer rely on power system frequency to keep the time [16]. Furthermore, whilst AEMO is required to control the NEM within a certain limit of time error, time error limits have been relaxed in recent years [88]. Given that time error is no longer prioritised as a control objective, forecast uncertainty, inherent variability and better measures of sustained frequency deviation (e.g. mean absolute error as suggested by Riesz et al. [32]) may be more suitable for dynamic regulation FCAS procurement.

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 [73, 84, 89].

The aggregation of contribution factors enables a unit to offset antagonistic deviations with assisting deviations due to the provision of tight-deadband PFR. 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 have disabled governor response in the NOFB in the belief that dispatch adherence alone will minimise Causer Pays liabilities [87]. It is likely that a complete redesign of regulation FCAS Causer Pays is necessary to better align (dis)incentives with cost-causation and frequency control performance.

4.3. NEM assessment and outlook

Though the introduction of competitive FCAS markets in 2001 initially resulted in significantly lower FCAS prices in the NEM [31, 32], 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). 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 [90]. While quarterly FCAS costs were less than 1% of quarterly total NEM costs in 2015, 75% of all quarters from 2017 to 2019 had FCAS costs that were between 1-2% of total NEM costs [60].

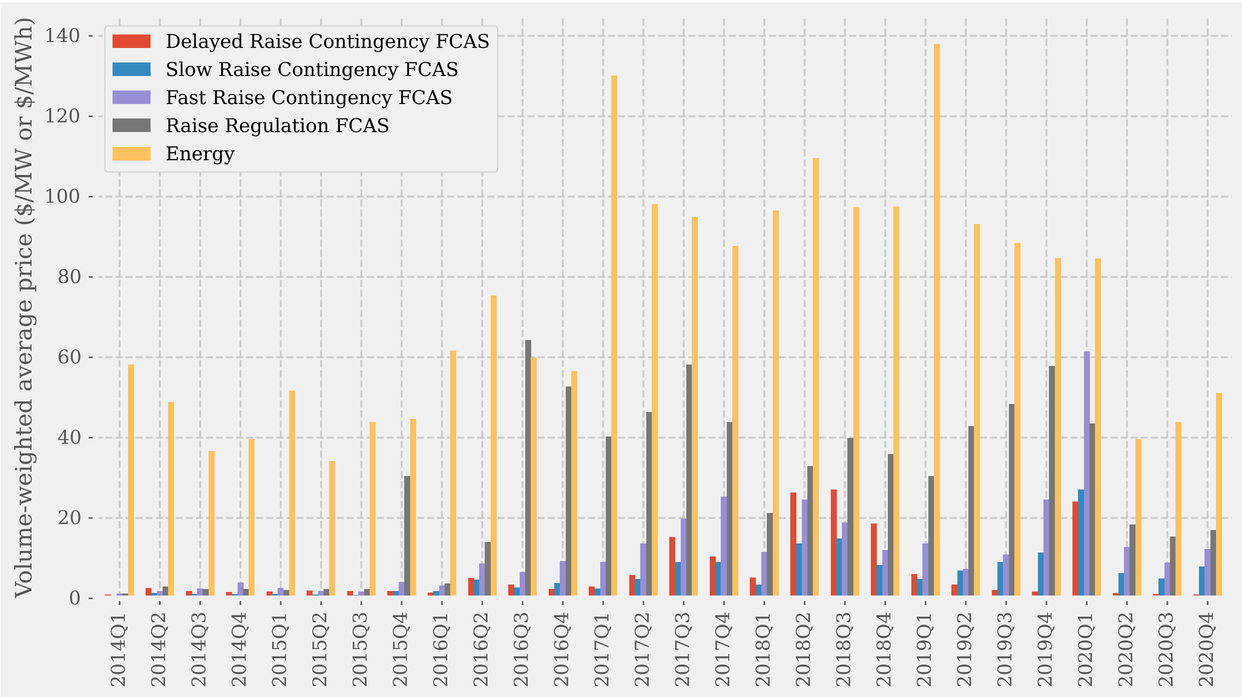

Figure 4: Volume-weighted NEM-wide average quarterly prices for energy, raise regulation FCAS and raise contingency FCAS in the NEM. Q1 2020 FCAS prices were high due to regional procurement in the SA region, which was islanded for approximately two weeks. Note that while average energy prices fell in 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 [83].

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 5), 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 25^{th} of August 2018 [70]. These events are typically more severe than the 'credible' contingency events (i.e. N-1 contingency) that dictate the volume of contingency FCAS procured.

Since the implementation of the mandatory PFR, settings specified by AEMO have been applied to the governors of large synchronous generators (>200MW). Despite the absence of requirements for maintaining

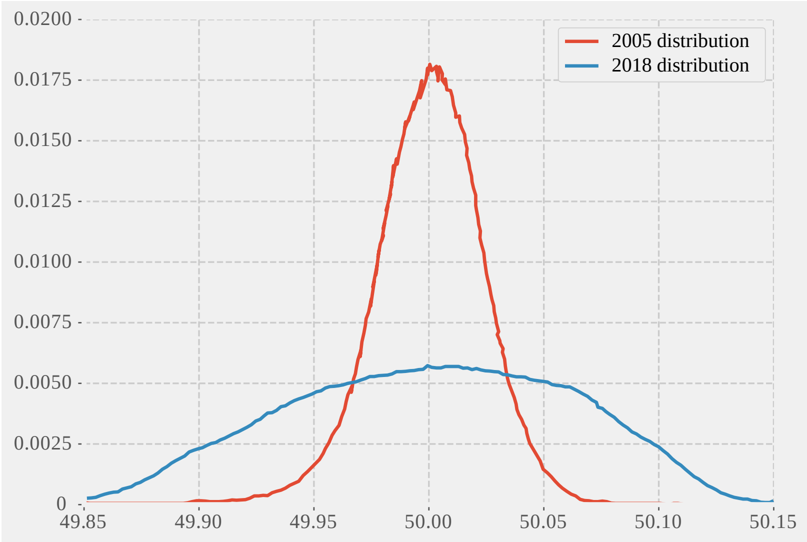

Figure 5: Normalised distribution of mainland frequency within the NOFB in 2005 and 2018. Reproduced from [82]

headroom and/or footroom, preliminary analysis by AEMO[6] suggests that mandatory PFR has delivered better control of frequency within the NOFB (see Figure 6) and reduced excursions beyond the NOFB [91].

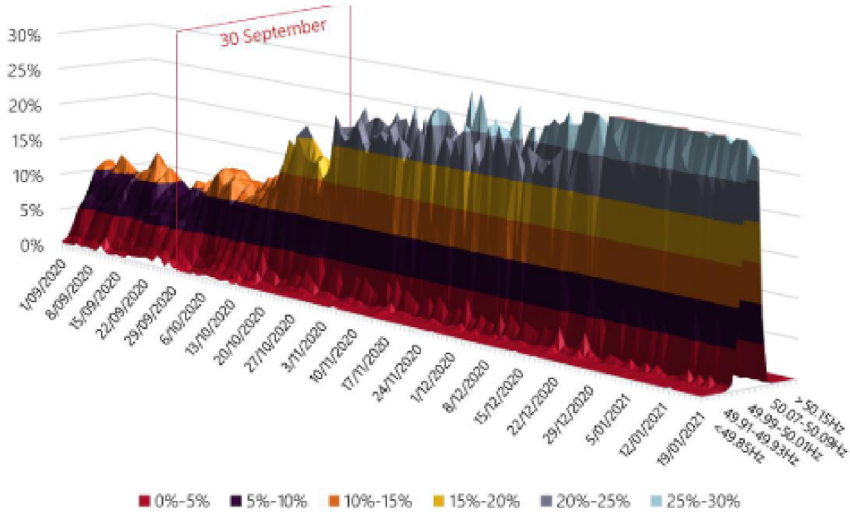

Figure 6: Daily frequency distributions from 1st of September 2020 to 20th of January 2021. Some initial PFR setting changes were made in late September 2020 and many generators moved to final settings in late October 2020. Source: Australian Energy Market Operator [91].

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 [92, 93]. Given that several large synchronous generators are expected to retire in the coming decades [94], continuing to rely on this "free" headroom

[6] We note that AEMO is currently preparing a more comprehensive assessment of the various costs and benefits associated with mandatory PFR [85], though it has yet to be implemented for VRE as inverter control system software changes are being trialed [91].

(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.

Presently, several operational and market changes are being considered for FCS in the NEM. AEMO is investigating the use of dispatch constraints to [95]:

- 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 [96].

These additional constraints will likely improve the effectiveness of frequency control arrangements but may lead to higher FCAS costs. Furthermore, the AEMC has made a draft rule to introduce raise and lower contingency markets for FFR by mid 2024, each with a likely response time of 1 second [33, 97]. Whilst AEMO has highlighted that potential stability issues and interconnector maloperation will need to be managed (e.g through delivery caps or provision constraints) [91], these FFR markets, along with the ESB's proposals for short-term scheduling and/or procurement of inertial response [98], will likely improve AEMO's operational toolbox for managing a low-inertia NEM.

4.4. 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 [99]. 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 [70, 100, 101].

Regulatory mechanisms are ideal for mandating basic FCS capabilities as a condition for access or where FCS faces significant barriers to efficient price formation or unbundled procurement. The latter reasons are particularly pertinent in the NEM. Whilst IBR such as battery energy storage systems, distributed PV-battery virtual power plants and one wind farm are currently providing FCAS in the NEM [102, 103, 104], current FCAS prices do not appear to be incentivising frequency control from the vast majority of VRE generators which have business models centered around energy provision [7, 93]. In such cases, regulatory requirements can assist in ensuring adequate frequency response from power system resources. In addition, the NEM's shortfall mechanism enables the procurement of inertial response, which is difficult to price due to its inseparability from system strength services and unit commitment costs [6].

However, it may be difficult for regulatory mechanisms to ensure that physical performance requirements are met in systems rapidly facing more power electronic-based control systems, lower levels of operational inertial response and higher variability and uncertainty of different scales and nature. 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 generator technical performance standards every 5 years [75], a timeframe in which the solar PV capacity installed in the NEM has more than quadrupled (2015-2020) [105].

Additional concerns with regulatory mechanisms include poor dynamic efficiency and opaque costs. 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 [7]. Furthermore, cost opacity may lead to FCS provision costs being internalised within other prices (e.g. energy) by participants and prevent the implementation of disincentives through cost-allocation mechanisms.

4.5. 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" [106, 107].

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 [108, 109, 110]. 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 [84], included a sunset clause in the final rule change. Furthermore, within a suite of rule changes proposals submitted to the AEMC [85, 93, 111] and the scope of the ESB's post-2025 market design process [98, 112], several new system services markets for inertial response, FFR, PFR and TFR are being considered.

If incentives or remuneration are designed correctly, markets can spur investment in high-quality FCS capability and assist a power system in achieving a dynamically efficient outcome. However, in some cases 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.

Efficient Causer Pays cost-allocation mechanisms in FCS markets could provide suitable disincentives for undesirable behavior, such as deviation from dispatch targets. 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 disaggregation as potential exposure to high instantaneous FCS costs may lead to participants curtailing or decommitting resources rather than providing an assisting frequency response. This has been observed in the NEM when regional constraints have resulted in regulation FCAS [84] and contingency FCAS [113] price spikes.

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 [39, 40]. A User Pays approach to cost-allocation could encourage resources to be more resilient to frequency deviations and thereby reduce system FCS costs, 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 [31, 114]. FCS derivatives can support business models in which FCS is a major revenue stream, assist in FCS price formation and drive investment in FCS capabilities [6, 115].

While many FCS markets compensate capacity and/or delivery, few align enablement or compensation with performance. Examples of such alignment include the PJM Interconnection, where each part of the offer and the remuneration for regulation services is adjusted by a unit's performance score [23], and in the UK, where remuneration for Enhanced Frequency Response may be penalised or altogether withdrawn due to poor performance [28]. Such market features should not only incentivise higher quality frequency control performance, but also potentially reduce procurement requirements and improve FCS cost efficiency [7].

Performance-based design 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 [116]. However, the implementation of performance-based remuneration is contingent on the SO verifying FCS provision. While AEMO has outlined FCAS delivery measurement standards and verification principles [72], it is unclear whether AEMO or the AER is systematically verifying FCS delivery or monitoring whether resources are able to comply with their enabled offers (aside from considering technical feasibility in dispatch)[7].

An outstanding challenge in FCS markets is the issue of price formation. Ideally, the price of provision should be explicit, transparent and recognise the true value of the service alongside any opportunity-costs

[7]Only one FCAS non-compliance penalty has been issued by the AER (to the authors' best knowledge). However, the instances of non-compliance that triggered the penalty (incorrect frequency response settings) were self-reported by the market participant [117, 118].

incurred by the supplying participant. Achieving this through FCS market design is challenging due to the somewhat arbitrary distinction between FCS products and their centralised procurement, which is a result of the public good characteristics of frequency control [16, 119],

In markets such as the NEM where FCS are co-optimised with energy, the opportunity-cost of FCS provision may be a component of FCS prices [92, 120]. Since the procured volume of FCS is equivalent to a vertical demand curve, prices will be suppressed if several synchronous generators offer these services at low prices and their opportunity-costs are relatively low [120, 121]. This will limit the incentives for provision and investment in FCS capability, particularly for high capital, low operating cost IBR [7, 122]. This issue may be resolved by strengthening scarcity pricing in FCS markets through system demand curves. The AEMC and ESB are currently considering implementing such curves for all existing and proposed FCAS [85, 112]. However, the shape of these system demand curves and how they account for interdependent or interchangeable FCAS will ultimately dictate their success.

5. 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. Regulatory mechanisms have been implemented or reintroduced to address performance issues and increasing costs, but have been constrained by rule makers in favour of introducing new FCS markets and minimising the impact to existing energy and FCS markets.

From our analysis of the NEM, we share four key insights below that may assist operators, regulators and market-bodies in achieving effective and efficient frequency control arrangements during energy transition, both in the NEM and other power systems with competitive markets for FCS:

1. Control deficiencies may not be addressable through introducing new FCS. While these solutions may address emerging needs (e.g. low-inertia operation), SOs and market bodies need to better understand the interdependency, interoperability and interchangeability between FCS to ensure that frequency control is first and foremost effective. Once this has been achieved, the efficiency of arrangements can be improved through mechanisms such as dynamic procurement and co-optimising the procurement of interchangeable FCS.
2. FCS prices should as best possible reflect the true value of the services both now and into the future to incentivise investments in FCS capability. Strengthening scarcity pricing by better reflecting the system's preference for security and reliability can achieve this. 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 provide price signals for investment in FCS capability.
3. Participants in FCS markets should not be remunerated unless delivery of, or the ability to deliver a service is deemed sufficient. SOs should systematically and frequently verify FCS delivery, and where possible, the ability to deliver FCS. If such monitoring is in place, FCS remuneration can be performance-based to drive the provision of high quality FCS. Performance 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. Regardless of whether arrangements are skewed towards market-based mechanisms or regulatory mechanisms, designers should avoid assumptions regarding the provision of FCS capability over time, particularly when there is a pervading competition norm and effective frequency control relies on sequential and hierarchical control actions.

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CRediT authorship contribution statement

Abhijith Prakash: Conceptualization, Methodology, Data curation, Formal analysis, Visualization, Writing - original draft. **Anna Bruce:** Conceptualization, Methodology, Validation, Resources, Writing - review & editing, Supervision, Project administration. **Iain MacGill:** Conceptualization, Methodology, Validation, Resources, Writing - review & editing, Supervision, Project administration.

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