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The Levelised Cost of Frequency Control Ancillary Services in Australia's National Electricity Market

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1. Introduction

As with many of the world's major power systems, Australia's National Electricity Market (NEM) is experiencing a rapid supply-side adjustment. Policy discontinuity associated with Australia's 20% Renewable Energy Target and the disorderly exit of ~5000MW of aging coal plant produced sharply rising spot and forward electricity prices. A surge of investment in variable renewable energy (VRE) followed. Over the period 2016-2021 more than AUD[1]$26.5 billion in utility-scale plant commitments across 135 projects were made, totalling 16,000MW. Simultaneously, households added 8,000MW of rooftop solar PV behind the meter. In a power system with a ratcheted peak demand of 35,000MW, the addition of 24,000MW of variable renewable resources over a five-year window could only be described as an *investment supercycle* (Simshauser and Gilmore, 2022).

Accompanying the supercycle and the notable change in the plant mix was a sharp deterioration in power system Frequency. Historically, the large fleet of (synchronous) coal, gas and hydro generators would ensure that the NEM's primary commodity, electrical energy, was delivered at the appropriate Frequency (50Hz) through a series of 5-minute spot markets for Frequency Control Ancillary Services (FCAS). NEM markets for FCAS are co-optimised with the spot electricity market, and were historically highly successful at delivering low cost Frequency management. Indeed, it could be argued that FCAS prices in most wholesale markets around the world were inefficiently low in the early stages of reform (Newbery, 2016). In the NEM, FCAS markets had been negligible in value, typically comprising less

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♥ Powerlink Queensland. The usual caveats apply.
[1] Unless otherwise stated, all financials are expressed in Australian Dollars. At the time of writing, AUD/US = 0.73, AUD/£ = 0.53 and AUD/€ = 0.62.

than 0.5% of total annual electricity market turnover. The reason for these low prices was that all operational coal, gas and hydro plant had excellent FCAS supply capability, vastly exceeding real-time operational demand under most conditions.

But the disorderly exit of ~5000MW of coal plant and reduction in operating duties of gas plant meant the supply of FCAS diminished sharply – especially in NEM regions such as South Australia. Simultaneously, rising variable solar/wind resources[2] led to increasing demand for Frequency management duties. With falling supply and rising demand, the value of FCAS Regulation and FCAS Reserves increased markedly.[3] The changes were very material – FCAS Regulation costs from 2003-2015 averaged ~$1.60 per MW per hour but surged to $26 during 2016-2021, while FCAS Reserve jumped from $4/MW/hr to $23.[4] Given the task of decarbonisation, this trend is unlikely to be unique to Australia.

A notable feature of the NEM's investment supercycle was trivial interest shown in new fast start open cycle gas turbines (OCGT)[5]. The supercycle delivered just ~670MW of OCGT plant (and ~1000MW under development). An extensive European literature[6] finds rising levels of VRE and associated merit order effects have made gas plant increasingly unprofitable. This *known trend from Europe* may well be impacting Australian investment perceptions. Conversely, disorderly exit of coal plant has served to reverse the NEMs earlier episodes of VRE-induced merit order effects, thus pointing to reasonable entry conditions for flexible GT plant.

In contrast to GTs, the supercycle has delivered 1,400MW of utility-scale battery commitments with another ~3,000MW permitted and a further 8,100MW in various stages of development (i.e. total ~12,500MW). Underpinning battery investment momentum is the fact that they are ideally suited to FCAS duties, and, FCAS prices are currently elevated for reasons outlined above.

In our experience[7], generation investment decisions made inside utility boardrooms invariably place considerable reliance on forward market prices, or where these do not exist, price forecasts from structural models of the power system, to identify project specific revenues in portfolio expansion plans. Specifically, a GT investment case would rely on NEM forward market prices which place a clear value on capacity for three-years ahead through the traded price of $300 Cap derivatives (i.e. one-way CfD with a $300/MWh strike price). Extending observed forward market data then arises through price forecasts. Structural models or alternate stochastic approaches are invariably used for investment commitments and portfolio expansion plans under uncertainty (Simshauser, 2020).

But how might a firm replicate such frameworks for a battery investment? Various studies have analysed optimal battery sizing for arbitrage activity given recent and expected spot electricity market conditions, starting with McConnell et al., (2015). Yet in our experience, arbitraging spot electricity prices, even in an energy-only market with a VoLL of $15,000/MWh, provides a necessary but grossly insufficient revenue stream vis-à-vis utility-scale battery investments. Quantitative analysis across multiple international markets by Lazard (2021) shows spot market arbitrage typically contributes ~40% of requisite revenues. The practical evidence from the NEM is that the overwhelming majority (i.e. > 60%) of battery revenues are *currently* derived from FCAS Regulation and FCAS Reserve duties (ARENA, 2021), or other *revenue stacking* alternatives.

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[2] To be clear, while it is technically plausible for VRE generators to provide FCAS, it has thus far been most unusual for wind or solar plants to do so.
[3] In certain locations, other desirable features of a good quality power supply also deteriorated, viz. inertia and system strength with the exit of synchronously coupled coal generators and entry of asynchronous (electronically connected) VRE plant.
[4] Both metrics cited are for 'raise' duties.
[5] Four small open cycle gas turbine (OCGT) investments with installed capacity of 670MW were made. Three of these investments were made by merchant stochastic generators to 'firm' their VRE capacity, and one by a traditional vertical energy retailer.
[6] See for example Traber and Kemfert (2011); Hach and Spinler (2016); Praktiknjo and Erdmann (2016); Höschle *et al.*, (2017); Bublitz *et al.*, (2019); Milstein and Tishler (2019); Gugler *et al.*, (2020); Liebensteiner and Wrienz (2020).
[7] One of the NEM's batteries and two of the NEM's GTs were originated by the authors during 2018-2020.

However, FCAS Regulation and FCAS Reserves are 5-minute spot markets with no visible forward market. Furthermore, there no framework or basis for which to derive a forecast of spot FCAS prices. The absence of a framework for forecasting FCAS prices therefore appears to be highly problematic, particularly given most NEM portfolio expansion plans that we are aware of include some form of battery storage.

Thus is the purpose of this article. We aim to develop a framework for long run equilibrium prices through developing *Levelised Cost of Frequency Control Ancillary Services* (LCoFCAS) metrics for the various product lines, drawing on the principles outlined in Psarros et al., (2018). Just as plant entry costs provide guidance to equilibrium spot electricity prices over the cycle, so too can LCoFCAS guide long run equilibrium pricing in competitive FCAS spot markets because in an efficient market, spot prices are mean reverting and must ultimately converge to underlying costs.

The principle that underpins our work is that FCAS provision has an opportunity cost given such duties are co-optimised with the NEM's spot market for electricity. Accordingly, we start by dissecting the underlying cost of reserving capacity for FCAS Regulation and FCAS Reserve duties from various technologies, including the incumbent coal fleet, batteries and VRE.

Our findings are important. They show that while the cost of FCAS initially rises due to increasing quantities required, unit prices are likely to decline over time as technologies move down their experience cost curves. We also find long duration batteries that currently exist in Australia's NEM will be better suited to delivering FCAS Regulation, whereas short duration batteries will be better suited to FCAS Reserve duties. Ultimately, capacity reserved for FCAS duties incurs genuine opportunity costs from making headroom available or from being activated during inopportune moments. Therefore, we consider it *unlikely* that FCAS prices will fall to negligible levels in equilibrium.

This article is structured as follows. Section 2 provides a primer on FCAS and a review of relevant literature. Section 3 develops a normative approach to short-run pricing of FCAS. Sections 4 and 5 contrast our normative values with market results. Policy implications and concluding remarks follow.

2. FCAS Primer and Review of Literature

A distinguishing characteristic of electrical energy is its moment-by-moment requirement to match supply and demand. Maintaining continuous electrical flows through a large, interconnected power system requires extraordinary levels of coordination (MacGill, 2010). While real-time power (MW) is the primary commodity, an array of other services *auxiliary* to its supply are required to ensure an accurate voltage (required by consumer appliances) and stable Frequency[8] (required by synchronous generators) (Stoft, 2002; Pollitt and Anaya, 2021).

Our analysis is focused entirely on Frequency Control Ancillary Services or *FCAS*, which are required to ensure a reliable and high-quality power supply (Ela *et al.*, 2012). Any supply-demand imbalance on the power system is first signalled by adverse deviations in Frequency.[9] Frequency instability is an outcome and an indicator of, a disturbance event (Agranat, Macgill and Bruce, 2015). Market prices will therefore lag, not lead, Frequency deviations.

2.1 Management of Power System Frequency & NEM Market Design

By way of brief background, power is generated at a single synchronised AC Frequency measured in cycles per second or Hertz (Hz). In the NEM, thermal generators synchronise to the grid at 50 cycles per second (50Hz) meaning the fleet of turbines all rotate at exactly the

[8] Frequency is the rate at which Alternating Current alternates. In the NEM, AC completes one cycle 50 times per second (50 Hertz). Other markets such as the USA operate at 60 Hertz.
[9] It is also signalled by Voltage but this article is focused on Frequency.

same speed (i.e. 50 cycles x 60 seconds = 3000RPM for large steam turbines). It is vitally important that Frequency is maintained as close to 50Hz as possible. Material deviations in the demand-supply balance, even for a few seconds, can send Frequency outside tolerable limits, at which point generators disconnect themselves to avoid damage (Simshauser, 2017).[10] In extreme cases this may culminate in the collapse of a power system (Green and Staffell, 2016).

To manage Frequency, modern power systems use a combination of responses which are sometimes referred to as Primary, Secondary and Tertiary responses[11]. The terminology we use are FCAS Reserves (Primary) and FCAS Regulation (Secondary). There is no uniform design for FCAS across markets internationally. The management of Frequency has historically been defined according to the response speed and capability of the local fleet of conventional generators (Neuhoff, Wolter and Schwenen, 2016).[12]

Australia's NEM is somewhat unique amongst restructured electricity markets with its centrepiece being a single platform involving a real-time mandatory energy-only gross pool spot electricity market and eight[13] FCAS spot markets, co-optimised across five imperfectly interconnected regions with 5-minute dispatch resolution and settlement (MacGill, 2010). A single Market Operator coordinates all regions and markets, and again uniquely, without any formal day-ahead market[14] or organised capacity market (Riesz, Gilmore and MacGill, 2015). Generators manage their own unit commitment and other inter-temporal scheduling constraints, including how they offer their generation into the spot electricity market and spot FCAS markets.

The FCAS spot markets are organised into FCAS Regulation and three FCAS Reserve markets for raise and lower services[15], viz.

1. FCAS Regulation (raise / lower),
2. 6-second FCAS Reserves (raise / lower),
3. 60-second FCAS Reserves (raise / lower), and
4. 5-minute FCAS Reserves (raise / lower).

FCAS Regulation duties (secondary response) are supplied by generators to the Market Operator using Automatic Generation Control, which involves the real-time altering of MW output in line with small demand fluctuations in between 5-minute dispatch intervals. FCAS Regulation duties maintain Frequency within a tight range (50Hz +/- 0.015Hz) under system normal conditions, that is, 99+% of time (see Figure 1).

FCAS Reserve duties (Primary response) are supplied by resources on a contingent basis, and effectively translate into withholding capacity (most of which has historically been "spinning"). FCAS Reserves are then physically called upon to active duty during non-trivial supply- or demand-side shocks, viz. from the unexpected breakdown of a large generator, network element or block-load. These large system shock events require a more substantive response than FCAS Regulation because Frequency will deviate well beyond the Normal Operating Band (i.e. 50Hz +/- 0.015Hz) – the most common occurrence involving the loss of a large generating unit (Simshauser, 2017). Such an event will typically see Frequency fall to ~49.5Hz, as Figure 1 illustrates.

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[10] As (Agranat, Macgill and Bruce, 2015) note, low Frequency events can lead to the overheating of generators.

[11] Sometimes known as spinning reserve because it was typically provided from already online (spinning), but this no longer reflects the reality of provision from the demand side, inverter-based resources, etc.

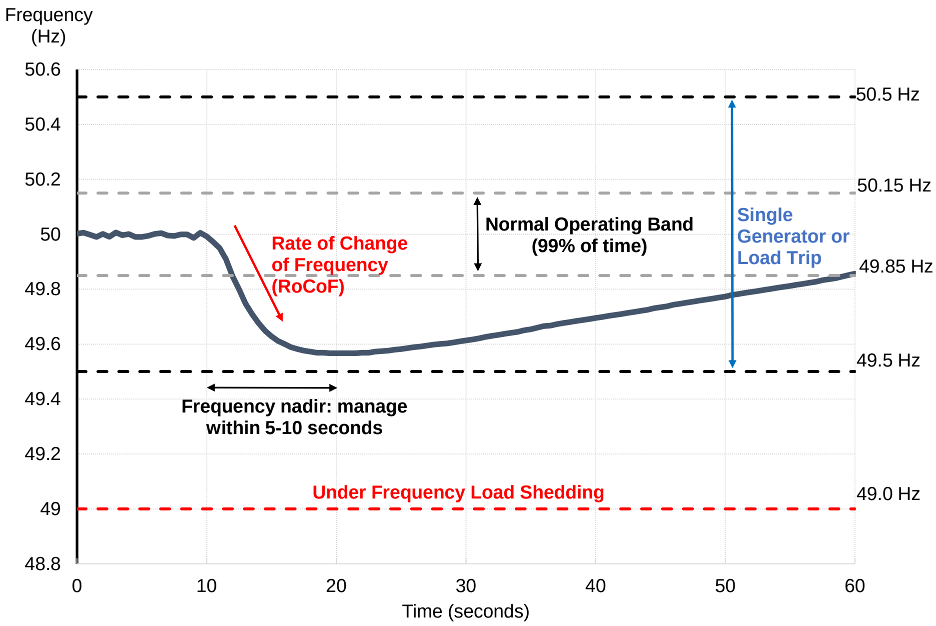
[12] Different markets define contingency reserves differently depending on the type of installed capacity, the nature of events they are required to respond to and the timeframes over which they respond and how such services are activated (Riesz, Gilmore and MacGill, 2015). For example, (Rivard and Yatchew, 2016) note that in Ontario, contingency reserves (known as operating reserves) are organised into 10-minute synchronised, 10-minute non-synchronised, and 30-minute non-synchronised reserves.

[13] Soon to be ten, with the introduction of a 0.5-2 second Fast Frequency Response FCAS Reserves market in 2023, that was proposed and designed by the authors.

[14] Although the Market Operator does produce a continuously updating 40hr pre-dispatch forecast.

[15] That is, the 8 markets comprise both (1) raise, and (2) lower markets for each of the 4 services.

Figure 1: Frequency deviation – loss of a large generating unit



Source: Simshauser (2017).

When a supply-side disruption occurs, the speed that Frequency falls (i.e. *the Rate of Change of Frequency or RoCoF*) is crucially important (Keeratimahat, Bruce and Macgill, 2016). The slower the RoCoF, the easier deviations are to arrest (Agranat, Macgill and Bruce, 2015). Synchronous generators have a store of kinetic energy due to the rotational momentum in their rotors. NEM coal generators, which weigh between 106-233t+[16], are spinning at 3000RPM and electrically coupled to the power system, means that rotation Frequency has some initial *Inertia* (Simshauser, 2017). Some new *grid forming* inverters also deliver an inertia-like response proportional to the RoCoF. Any change to Frequency from a disturbance event will first meet resistance from this passive physical response (Riesz, Gilmore and MacGill, 2015). Inertia services are valuable for maintaining Frequency but historically has been supplied in such abundance that no formal market was considered necessary.

A rapid response is required to arrest Frequency decline. Minimum Frequency must be achieved within 5-10 seconds in order to avoid system collapse (Ela *et al.*, 2012). In the NEM, apart from inertia and FCAS Regulation, the first *market response* comes from 6-second FCAS Reserves. Synchronous generators usually have store of excess steam and latent energy in boilers which can be released to give an initial boost of output (essentially additional output not associated with 'additional fuel' to boilers). 6-second resources are deployed without Market Operator intervention to enable an orderly transition to 60-second[17] FCAS Reserves, which further stabilise Frequency and enable an orderly transition to 5-minute FCAS Reserves (Riesz, Gilmore and MacGill, 2015). These collective resources are intended to restore the system back to its nominal 50Hz Frequency over a 5-minute window (see Figure 1).

If Frequency falls below 49Hz then automated non-price load shedding occurs, known in Australia as *Under Frequency Load Shedding* or UFLS (Simshauser, 2017). Load shedding occurs in order to avoid the collapse of a power system.[18] An applied example is presented in Figure 2. Here, Frequency in the NEM's Queensland region plunges to 48.5Hz following the

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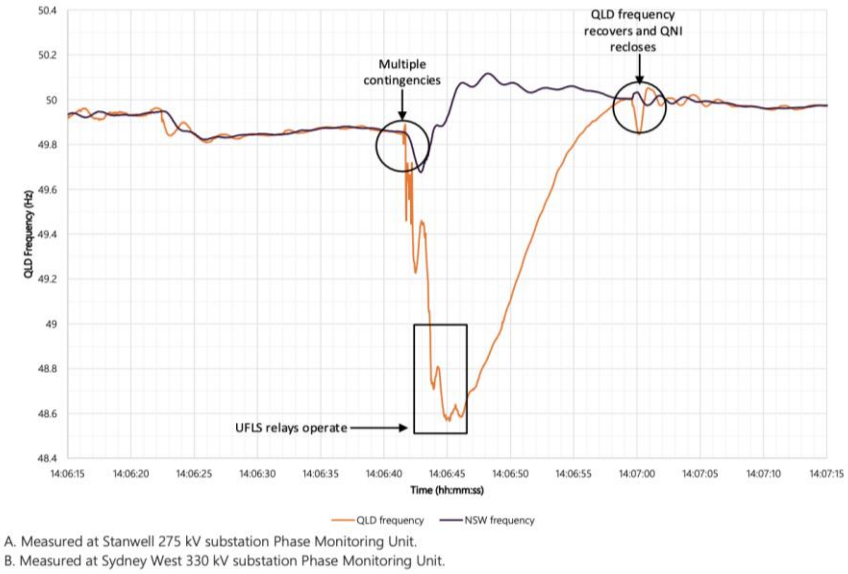
[16] The rotating mass of Queensland 350MW generators are 106t (i.e. High & Intermediate Pressure turbine 16t, Low Pressure turbine 50t and generator 40t). The rotating mass of the 500MW generators in Victoria and 660MW generators in New South Wales are 217.5t and 232.8t, respectively.

[17] 6-second & 60-second FCAS are usually operated by governor response or load shedding, and are triggered by Frequency moving outside the normal operating band.

[18] In the NEM, non-price load-shedding or Under Frequency Load Shedding, a highly automated sub-second event, can generally be relied to arrest a 'Rate of Change of Frequency' (RoCoF) of up to 3.5Hz per second. In 2016, South Australia experienced a RoCoF of 6.25Hz per second which resulted in a system collapse.

loss of multiple coal and VRE generators (totalling 3000MW) during a single event. UFLS relays were triggered at 49Hz, and the Frequency nadir is achieved within 5 seconds after shedding ~2100MW of load (i.e. 3000 – 2100 = 900MW of generation, which was either spinning or exporting power to neighbouring regions just prior to the event).

Figure 2: Loss of multiple generators in the NEM's QLD region (25-May-2021)
Qld region frequency vs adjoining NSW region frequency (interconnector disconnects)



Source: AEMO.

As noted earlier, the NEM's design and associated spot markets have been highly successful at reducing FCAS costs prior to VRE entry. Procurement over 5-minute intervals with short gate closure periods delivered efficiency compared to long-duration procurement contracts (Müsgens, Ockenfels and Peek, 2012).

The large number of FCAS spot markets contrasts with other markets such as Great Britain, which have been reducing over time (Pollitt and Anaya, 2021). However in the NEM, FCAS Reserve markets are aligned and complementary such that in most periods the same physical resource delivers each of the three FCAS Reserve markets. Rationalising the number of FCAS markets in the NEM was recently considered, but the analysis found this may reduce participation, at least based on historical offers. The NEM's spot market approach (*cf.* weekly or monthly auctions) may also help to make very granular markets more feasible.

2.2 Impacts of VRE

A challenge of rising VRE is how Frequency is to be managed as coal plant exits. This changing plant mix means the inherent supply of inertia and of FCAS plant is falling (MacGill, 2010; Hogan, 2013; Green and Staffell, 2016). Recall that VRE plant connect asynchronously to the power system with power electronic interfaces, and are *not* physically coupled to system Frequency. Consequently, VRE plant do not provide inertia during Frequency deviations (Agranat, Macgill and Bruce, 2015), nor are they designed to undertake FCAS duties (MacGill, 2010). As the supply of inertia falls with exiting coal plant, the NEM's existing quantities of FCAS Regulation and the speed of 6-second FCAS Reserve may become inadequate to arrest Frequency deviations, and consequently, a greater array of FCAS services may be required (Pollitt and Anaya, 2021; Simshauser and Gilmore, 2022).[19]

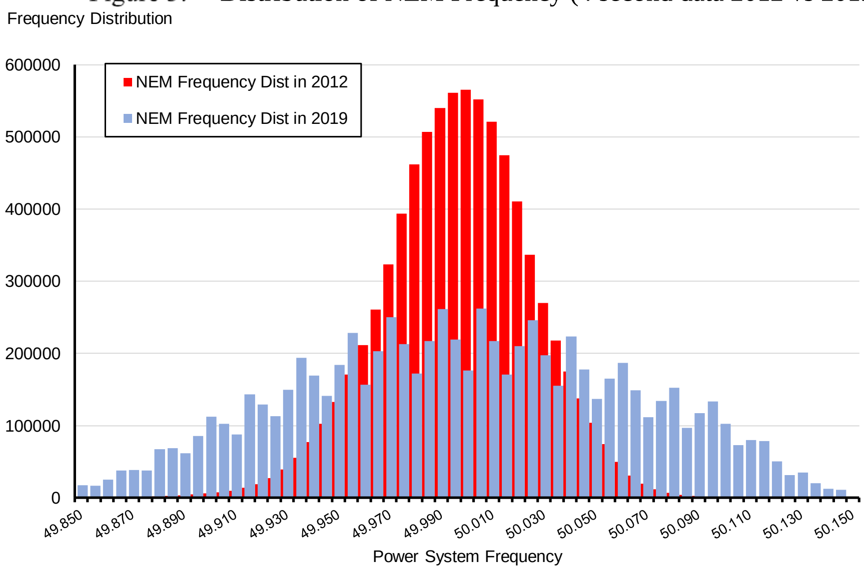
Changes also extend to likely FCAS quantities demanded by the Market Operator. The NEM's FCAS quantities were initial set in 2004 and were maintained at the same levels for

[19] Indeed, the authors originated a NEM Rule Change proposing an additional FCAS market for Fast Frequency Response, viz. ½ second FCAS Reserves (see also Agranat, Macgill and Bruce, 2015).

well over a decade during which the NEM had virtually no VRE. Administratively determined FCAS Regulation quantities had been set to +/-130MW (i.e. raise/lower services). FCAS Reserves then comprised a further ~620MW under system normal conditions (i.e. a total FCAS suite of 750MW, equivalent to n-1 given the largest NEM generating unit is 750MW[20]). Counterintuitively, FCAS quantities were held constant well into the investment supercycle in spite of sharply rising levels VRE capacity and output, and exiting synchronous coal plant.

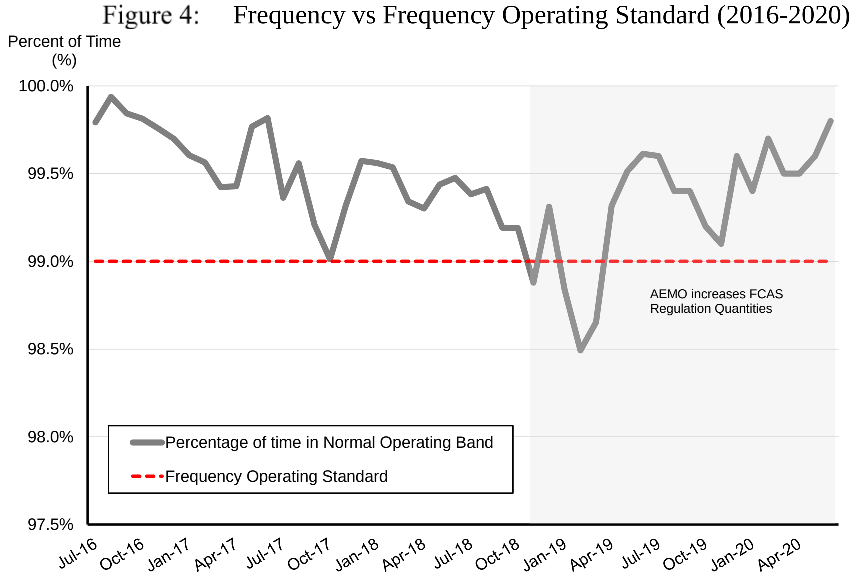
Unsurprisingly, the distribution of Frequency began to disperse (see Fig.3) and eventually in aggregate, breached the NEM's Frequency Operating Standard, that is, to maintain Frequency within the so-called 'Normal Operating Band' of 50Hz +/-0.015Hz for > 99% of time (see Fig.4). FCAS quantities demanded by the Market Operator were (*finally*) reviewed from 3 October 2018, rising from a minimum of 130MW to 220MW (and at times to as much as 400MW) as highlighted in Fig.5.

Figure 3: Distribution of NEM Frequency (4 second data 2012 vs 2019)



Source: Reliability Panel

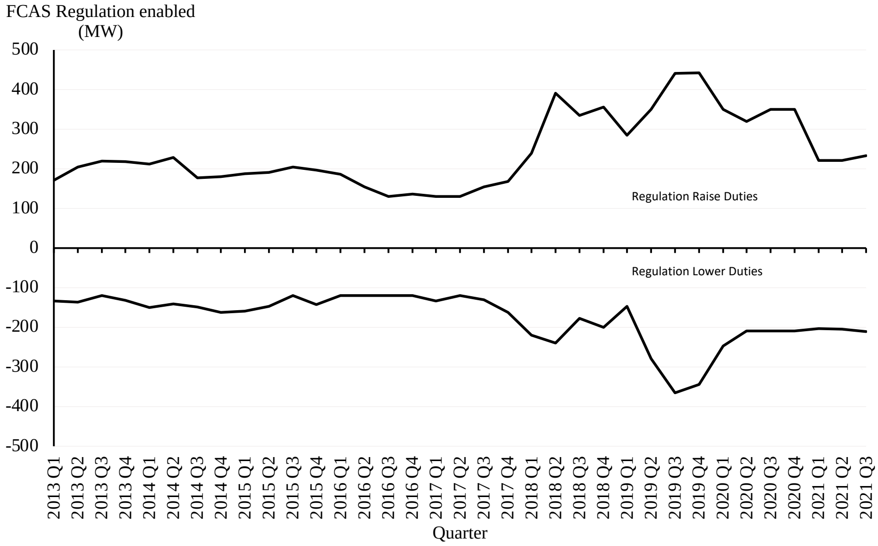
Figure 4: Frequency vs Frequency Operating Standard (2016-2020)



Source: Reliability Panel

[20] Minus a small amount of load relief from synchronous loads

Figure 5: 90th Percentile Demand for FCAS Regulation (2013-2021)



Source: AEMO.

As markets incorporate increasingly high shares of renewable generation and synchronous thermal plant closes faster FCAS services, particularly delivered by batteries, can be expected to play a critical role. Across markets, PJM implemented fast ramping FCAS Regulation in 2012 (with several subsequent revisions), the UK a implemented a 1-second Enhanced Frequency Response market and Ireland is procuring very fast (150ms-2 minutes) Frequency response from batteries and responsive loads, as recommended through its DS3 work program to deliver 70%+ renewables[21]. Very fast markets seem likely to become ubiquitous, though the PJM experience (e.g., exhausting energy-limited resources leading to deteriorating Frequency, or fast signals opposite to slower signals) highlights the need for careful design in the face of rapidly changing technology and requirements. Understanding the capability and cost of storage resources will be an important input to market design.

2.3 FCAS prices

As noted earlier, historically the supply of FCAS Regulation and FCAS Reserves were dominated by coal, gas and hydroelectric plant. And because the supply of FCAS was ostensibly a by-product of the production process, FCAS prices appeared inefficiently low even in equilibrium conditions (Newbery, 2016), representing as little as 0.5% of NEM turnover or $1.6 – 4.0/MW/h[22]. But with falling supply and rising demand, FCAS prices have become a hallmark of the NEMs transitioning plant stock, rising to $23-26/MW/h. And, batteries are now beginning to deliver a larger share of the FCAS product suite.

While investors can readily undertake back-casts of potential revenues for future power projects using historical prices, investment cases for batteries will require forward projections of all markets and services (for a broad overview, see Weron, 2014). Modern structural power system models which combine the principles set out in Calabrese (1947), Boiteux (1949), Berrie (1967) and Booth (1972) depend heavily on the input assumptions (capital costs, fuel prices, plant availability, plant entry and exit). Pricing is impacted by dynamics on multiple timescales (Zhu *et al.*, 2017) and is non-linear, driven by behavioural choices of participants with diverse goals and incentives.

Historically at least, forecasting the price of FCAS Regulation and FCAS Reserves was more complex than forecasting spot electricity prices. The supply curve for electricity production is strictly upward sloping given the usually diverse range of plant technologies setting base,

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[21] https://www.eirgridgroup.com/how-the-grid-works/ds3-programme/

[22] In QLD, NSW and VIC, the spot electricity market had typically comprised > 99.7% of total revenues. FCAS raise services in SA were the first to rise sharply, and formed a surprisingly large 5-7% of market revenues by 2017. The point being that FCAS raise services provided by thermal plant have almost no value until plant exit, at which point they become extremely valuable.

intermediate and peaking prices based on observed marginal running costs. In an oversupplied wholesale market comprised of synchronous plant, the FCAS supply curve, being a joint product, had close to zero marginal costs (hence prices clearing at $1.6-4.0/MW/h on average from 2003-2015).

However, with synchronous plant withdrawing, these dynamics are changing. At the highest level, the market value of FCAS Reserves should reflect the opportunity cost of withdrawing resources from the spot electricity market, which in turn depends on the generation mix, its flexibility, and expected utilisation (Hirth and Ziegenhagen, 2015; Aasgard and Roti, 2016).

The most theoretically straightforward approach is to develop an objective function which minimises total system costs subject to various constraints (Doorman and Nygreen, 2002; Fosso and Belsnes, 2004). In practice, simulations will require unit commitment decisions and an input quantity of FCAS Reserves to procure. Furthermore, aside from absolute supply costs, the slope of supply curves also contributes to the opportunity costs of reserve provision (Just and Weber, 2008). Attarha, Scott and Thiébaux (2020) also consider how network constraints and competing value stacks in the Australian context need to be incorporated into bidding. Finally, market design settings also impact FCAS market prices (Gan and Litvinov, 2003).

2.4 Levelised cost approach

The logical alternative to price forecasting is to focus on underlying costs in equilibrium. This may not have been plausible in the era of markets comprised of synchronous plant in an oversupplied state (as outlined above in Section 2.3). But with the exit of coal plant and the rising requirement for FCAS duties, cost-based estimates are becoming tractable as our analysis in Section 4 subsequently reveals.

For investment in renewable plant, Levelized Cost of Energy (LCoE) calculations can be used, albeit care is required. LCoE is defined as the discounted cost of supply divided by the discounted quantity of power produced (Roth and Ambs, 2004). LCoE is of course imperfect because it is sensitive to discount rates and resource assumptions used (Aldersey-Williams and Rubert, 2019), and such calculations treat technology output as homogeneous products as if governed by the law of one price (Joskow, 2011; Mills, Wiser and Lawrence, 2012; Edenhofer *et al.*, 2013). In real-time, the law of one price does apply; output from wind and solar are good substitutes for thermal generation. However, when demand is higher than forecast, all else equal, dispatchable generators increase output and receive a higher average price. Conversely, stochastic generators rarely reduce output in periods of oversupply, and hence sell disproportionately at lower prices (Hirth, Ueckerdt and Edenhofer, 2016; Simshauser, 2018).

Nonetheless as a metric, LCoE is useful because average dispatch-weighted prices over the business cycle must invariably converge to long-run average costs of an efficient capital mix (Nelson, 2018). And while actual prices can be impacted by transient market power (raising prices above efficient levels), or by "two-step pricing[23]" (lowering prices below efficient levels), mispriced products will inevitably regress to true cost over time.

Psarros et al., (2018) introduced an equivalent concept of a Levelised Cost of Reserves, defined as the discounted cost of delivering primary reserves divided by the discounted quantity of reserves delivered. While previous authors such as Kempton and Tomić (2005) have considered the underlying cost of provision in the context of profitability assessments, a Levelised cost of Reserves, or more specifically, a Levelised Cost of FCAS (LCoFCAS), provides a valuable benchmark for investment analysis and policy makers.

[23] Two-step pricing occurs when investors expect higher revenues in the long run, and so choose a lower price in the short run. See Jenkin *et al.*, (2019) and Simshauser and Gilmore, 2020).

3. Normative approach to modelling short- and long-run FCAS prices

Before considering the long-run cost of FCAS, it is helpful to define a normative approach to the short run pricing of Regulation and Reserve duties. Following Gan and Litvinov (2003) and Müsgens et al., (2012), any generation technology (i.e. coal, battery, renewables) that curtails output in the spot electricity market to provide headroom in FCAS markets misses out on the wholesale market price P_E, but avoids marginal running costs MC.[24]

3.1 FCAS from coal plant

For a generator that offers no FCAS and produces G into the electricity market where spot prices P_s are above its marginal running costs MC, net market revenue over period Δt would be:

$$\text{Revenue with no Reserve duties} = (P_s - MC) \times \text{MW} \times \Delta t \tag{1}$$

For a generator that provides (raise) Reserve duties at a price $\overline{P_R}$:

$$\text{Revenue with Raise duties} = (k_R \times (P_s - MC) + \overline{P_R}) \times \text{MW} \times \Delta t \tag{2}$$

The critical parameter here is k_R – the expected utilisation of plant Reserves (for raise duties), defined as average MW per MW of activation. Note that for $k_R = 100\%$, the resource is indifferent to energy production or reserve duties (it will deliver and be paid for its energy in either case), while for $k_R = 0$ the cost of reserve duties is the simple opportunity cost of lost energy revenue *minus* avoided marginal running costs. The general breakeven Reserve price is given by solving when revenue streams are equivalent with or without Reserve duties.

When $P_s < MC$, an inflexible thermal generator would lower production output to its *minimum stable load* and would freely make the balance of productive capacity available for Reserve duties, but would incur net costs of $(MC - P_s) \times k$ based on expected utilisation of Reserves[25]. Symmetric arguments can be made for either of raise or lower services. Therefore, in the short-run an economically efficient raise and lower Reserve offer (P_R and P_L) would be given by:

$$P_R = \begin{cases} (P_s - MC) \times (1 - k_R), & P_s \geq MC \\ (MC - P_s) \times k_R, & P_s < MC \end{cases}$$

and

$$P_L = \begin{cases} (P_s - MC) \times k_L, & P_s \geq MC \\ (MC - P_s) \times (1 - k_L), & P_s < MC \end{cases} \tag{3}$$

Note this assumes the generator has the freedom to dispatch into either a raise or lower Reserve market. If there are network or economic constraints, more specific calculations may be needed.

In order to solve for Eq.(3), a value for k_R is required, which can be imputed from historic NEM data. Utilisation varies but within a narrow range as illustrated in Fig.6. For example, over 2021, $k_{act\%}$ increased but $k_{util\%}$ decreased, leaving their product k_R flat.

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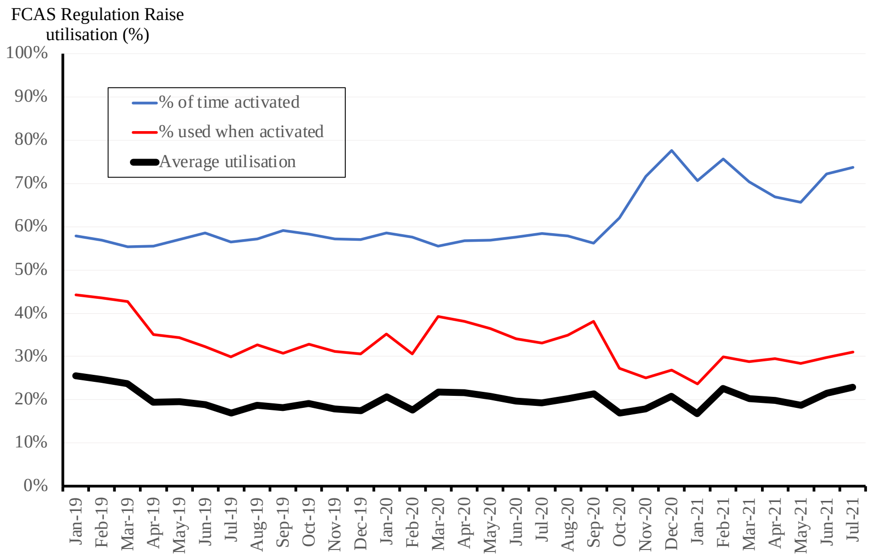
[24] Note that MC would typically be the marginal running cost of the unit, but may also incorporate an opportunity cost. For example generation from an energy limited resource may mean lost production at some future higher price period, such that the effective marginal "cost" (lost revenue) of running in the short-term may be higher than fuel costs alone.

[25] Note that the NEM's real-time market means short-run reserve pricing reflects marginal costs, with any must-run costs effectively sunk; those costs must be recovered through prices set by more expensive generators, if possible, or through market power. Grids with organised forward markets may incorporate financial losses for a unit's must-run component into reserve pricing, as described in (Müsgens, Ockenfels, & Peek, 2014), resulting in slightly different formulations than presented in this paper. (Hirth & Ziegenhagen, 2015) derive a similar formula applying only to contingency (spinning) reserves, with minimum load losses pro-rated across the service.

Figure 6: Monthly FCAS Regulation Raise activation% and utilisation% in the NEM



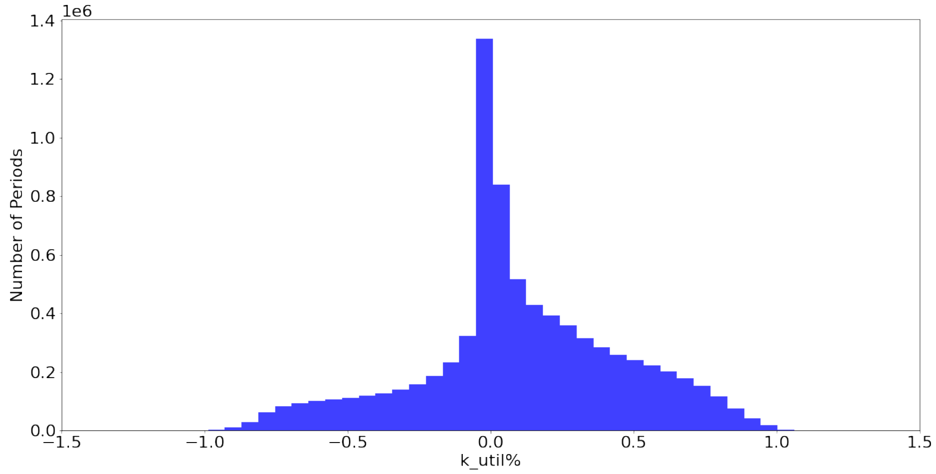
For our purposes we draw on the data in Tab.1, which presents an analysis of NEM 4-second Frequency Regulation data for the 2020 calendar year. Regulation raise duties were required during 62% of 4-second intervals, and Regulation lower duties were required in 31% of intervals. The average *utilisation* of raise was 18.7%. Accordingly, we will adopt these values in all subsequent analyses.

Table 1: Regulation FCAS utilisation parameters for the NEM (Cal 2020)

	k_act%	k_util%	k_R
FCAS Reserve (Raise or Lower)	0.026%	~2%	~0
Theoretical FCAS Regulation (perfectly symmetric system)	50%	20-40%	10-20%
Raise Regulation utilisation	62%	30%	18.7%
Lower Regulation utilisation	31%	27%	8.5%

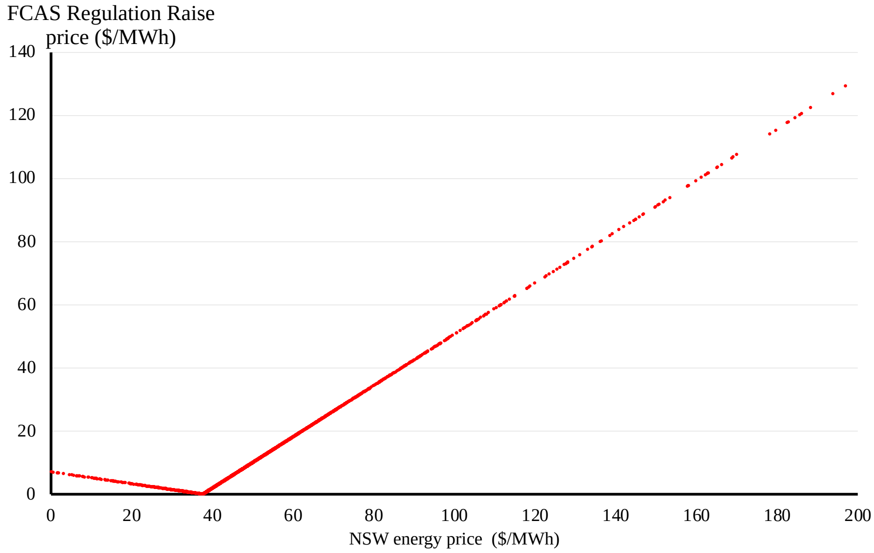
It is also worth noting that the demand for FCAS Regulation is currently biased towards *raise* duties, as Fig.7 clearly illustrates.

Figure 7: Distribution of FCAS Regulation in the NEM CAL-20. % utilisation of Raise (positive) and Lower (negative) enabled MW



Given a value for k_R of 18.7% from Table 1 and an estimated marginal running cost for NSW coal generators of $MC = \$38/MWh$[26], Eq.(3) collapses down to the trajectory of FCAS Regulation (raise) prices (y-axis) for any given spot electricity price (x-axis) in Fig.8.

Figure 8: Theoretical model of FCAS Regulation Prices in the NSW region



Finally are the relative values for FCAS Reserves. Unlike FCAS Regulation which is a continuous active duty, FCAS Reserve duties are designed to be a form of Reserve which is only activated in response to a material Frequency disturbance (>0.15Hz). Consequently, in this instance $\mathrm{k}_{\mathrm{act\%}} \approx 0$. When called upon, utilisation of FCAS Reserves depends on both droop settings, and the severity of any Frequency deviation. In a practical sense, $k_{util\%}$ for FCAS Reserves is typically be less than 2%. Therefore, $k_R = k_L \approx 0$ for FCAS Reserve duties and short-run pricing will simply depend on the difference between the marginal running cost of the unit and the energy price.

3.2 FCAS from Batteries

Delivering FCAS Contingency (primary response) or FCAS Regulation (secondary response) is ideally suited to utility-scale batteries. Lithium-Ion batteries in particular can follow targets or undertake proportional response duties to local Frequency changes virtually instantaneously. The LCoFCAS for delivering FCAS Regulation services from a dedicated, grid-scale battery, based on projected capital costs in year *y* is given by:

$$\mathrm{LCoFCAS}_{REG,y} = \frac{\text{Total capital and operating costs of battery in year } y}{\text{Lifetime provision of Regulation services}} \tag{4}$$

Building on the work of Psarros et al., (2018) we derive the LCoFCAS for the simultaneous provision of both raise and lower Regulation, with symmetrical enablement in both services[27]. In this article, we focus on grid-scale lithium-ion batteries, but this approach could be applied to any energy-limited storage technology (including distributed or embedded storage). The general equation is given by the carrying cost of a battery, plus annual operating costs:

$$LCoFCAS_{REG,y} = \frac{C_y + \frac{(1+\xi)\times C_{y_{rp}}}{(1+i)^{y_{rp}}} + \sum_{j=y}^{y+l} \frac{\left(OM_j \times H + E_{ch,j} \times 8760 \times k_R \times CF_j \times (1/e-1)\right)}{(1+i)^j}}{\sum_{j=y}^{y+l} \frac{8760 \times CF_j}{(1+i)^j}} \tag{5}$$

[26] Based on an average Newcastle coal price of USD66/t over calendar year 2020 with energy content 23GJ/t, an average 10GJ/MWh heat rate, and applying a 90% netback adjustment.

[27] Batteries are well suited to offering both Raise and Lower services simultaneously (and symmetrically) around a setpoint of 0 MW. This can be done continuously with limited impact on state of charge, allowing batteries with limited headroom to

Table 2: Battery model parameters for Eq.(5)

	Description	Value for modelling
$E_{ch,j}$	recharging costs in year *j*	$30/MWh off peak
CF_j	% of hours delivering the service	100%
k_R, k_L	Average Raise/Lower utilisation (kWh/kW/hour)	38%,20%
ξ	Premium on cell capex for repowering	25%
OM_j	Battery fixed O&M ($/kWh-nameplate/y) in year *j*	$5/kWh-nameplate
i	Pre-tax cost of capital	6%
L	Useful life	15 years
W	Warranted throughput (lifetime kWh/kW-nameplate)	4300[28]

Eq.(5) and the associated values presented in Tab.2 capture the capital cost of the battery (plus ongoing capex works) along with the discounted costs of O&M and roundtrip losses, divided by utilisation. Annual capex is parameterised as $C_y = C_{bop,y} + C_{cells,y} \times H$, where H is the hours of storage and $C_{bop,y}, C_{cells,y}$ represent annual capital works ($/kW). The lifetime of the cell is $l = \max\left(L, \frac{W \times H}{8760 \times k_R}\right)$, defined by the lesser of the cell life (which is based on warranted throughput W, the lifetime kWh per kWh-nameplate) and the calendar life (nominal life of the cells and balance of plant L (Dubarry, Qin and Brooker, 2018)).

Charging costs during FCAS Regulation lower duties are assumed to be offset (and, indeed, surpassed) by revenues from FCAS Regulation raise duties. However, the roundtrip battery efficiency losses as well as current Frequency bias in the NEM lead to stored energy being exhausted over time without being replenished through the natural provision of lower duties. Therefore, some off-peak charging needs to be included. This is assumed to be in off-peak (i.e. high VRE) times[29] at $30/MWh (noting any results will *not* be sensitive to this assumption). To allow for this recharging, portfolios of FCAS Regulation providers would need to allow for approximately two hours of reduced lower but increased raise duties. Given the former will likely be readily available from an excess of market sources (e.g., curtailment of wind, solar) this is not considered further in the LCoR analysis.

The $LCoFCAS_{REG,y}$ is a function of the hours H of storage. Greater hours means a higher capex but allows for a longer effective battery lifetime[30] and hence potentially a longer capex recovery period for the BoP. The optimal hours of storage for given inputs can be determined through an iterative optimisation to minimise$LCoFCAS_{REG,y}$.

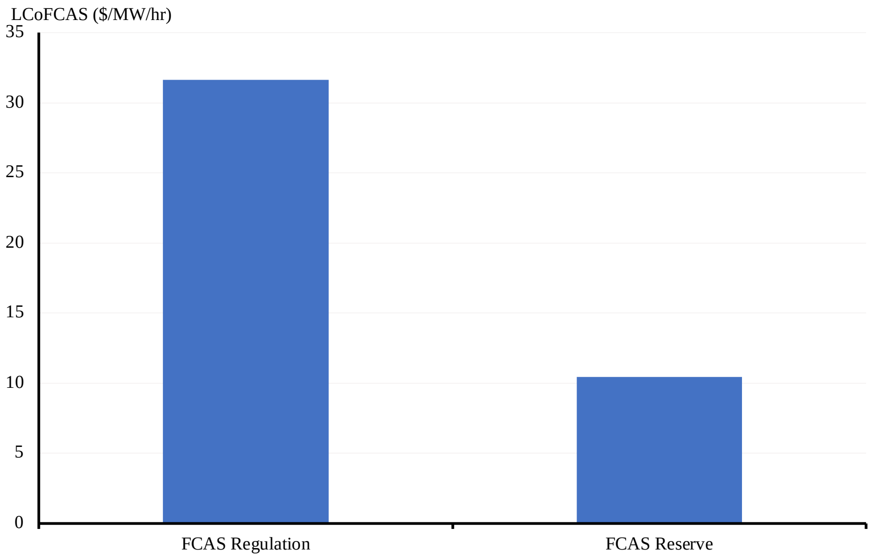
Current battery capex costs are around $1100/kW for a two-hour battery (the typical sizing for recent NEM batteries) and $850/kW for a one-hour battery (Graham *et al*. 2020). Based on the assumptions of Tab.2, the provision of FCAS Regulation would cost approximately $30/MW/hr and $10/MW/hr for FCAS Reserve, as shown in Fig.9. Note that this is for the simultaneous provision of both raise and lower duties.

[28] Lithium-ion batteries are typically warranted for "1 cycle per day", allowing for degradation in stored energy capacity over time. The figure in Tab.2 is based on an average of one cycle per day with a 3% degradation in stored energy year on year, over 15 years. While batteries may last beyond their warranted cycles, this is not typically included in the initial business case.

[29] Specifically, when the opportunity cost of charging is low – this could be off-peak energy or high Raise value periods.

[30] Because more hours means more available cycles for the same MW nameplate

Figure 9: LCoFCAS from batteries (simultaneous Raise and Lower provision)



3.3 The normative value of FCAS from VRE

Historically VRE have been passive price taking plant, operating on a run-of plant basis and supported by long-term Power Purchase Agreements with reduced scheduling obligations. However, rising shares of renewable generation have led to a tightening of technical requirements. In the NEM, this includes lower short-circuit current requirements, requirements for complementary inertia and/or system strength provision, and, most relevant to this article, the mandatory *capability* for delivering Frequency response (Appendix II provides further detail).

Therefore, while we have not historically observed VRE plant undertaking FCAS duties there is no technical reason as to why they could not do so in the future. Modern wind and solar farms are flexible[31] and could physically deliver both FCAS Reserves and FCAS Regulation if sufficient headroom was made available. For a raise response, this means deliberately curtailing potential output to some lower production setpoint.

In the short-run, the cost of providing Reserves follows Section 3.1 but with low or sub-zero marginal running costs (i.e. if the opportunity cost of production under a run-of-plant Power Purchase Agreement is taken into account). With this in mind, Reserves from VRE plant are likely to be more expensive than existing thermal plant, particularly a coal plant with $MC = \$38/MWh$.

Fundamentally, Reserve duties supplied by VRE plant are not free. In the long-run, the LCoFCAS from a VRE plant must be linked to its PPA, which in turn is usually linked to its LCoE. For a fixed nameplate MW of VRE capacity to be offered into an FCAS market over the *long-run*, the project must be indifferent to the FCAS and energy market revenue streams. The short-run pricing formulas for $LCOR_R$ presented in Section 3.1 would apply in any given dispatch interval, and assuming equilibrium pricing in both the energy and FCAS markets can be generalised[32] to link the LCoFCAS and LCoE, such that:

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[31] AECOM (2017) (link) suggests that wind ramp down rates are limited to 20% per second; this would still allow a wind farm to deliver the 6-second Lower Contingency FCAS service.

[32] Ignoring the time value of money, if g_t is the economically efficient energy dispatch in each period t and $P_{E,t}$ is the energy price, in equilibrium $LCOE = \frac{\sum_t P_{E,t} \times g_t}{\sum_t g_t}$. If a fixed percentage of the available output $r_t = \alpha \times g_t$ is instead dispatched into the Raise reserve market in all periods, receiving a price $P_{R,t}$, the $LCOR_R$ can be expressed as $LCOR_R = \frac{\sum_t P_{R,t} \times r_t}{\sum_t r_t} = \frac{\alpha \sum_t (P_{E,t} - M) \times (1-k) g_t}{\alpha \sum_t g_t} = (LCOE - M) \times (1 - k)$.

$$LCoFCAS_{VRE,Raise} = (LCoE_{VRE} - MC_{VRE}) \times (1 - k) \quad (6)$$

This approach simply sets a benchmark long-term price if reserves must be sourced from VRE projects. The volume of reserves offered will vary with the underlying resource, meaning future reserve markets might ultimately have periods of under- and over-supply just as in the energy market. Eq.(1)-(6) would therefore apply in the short-run. An analogous approach to lower reserves also applies:

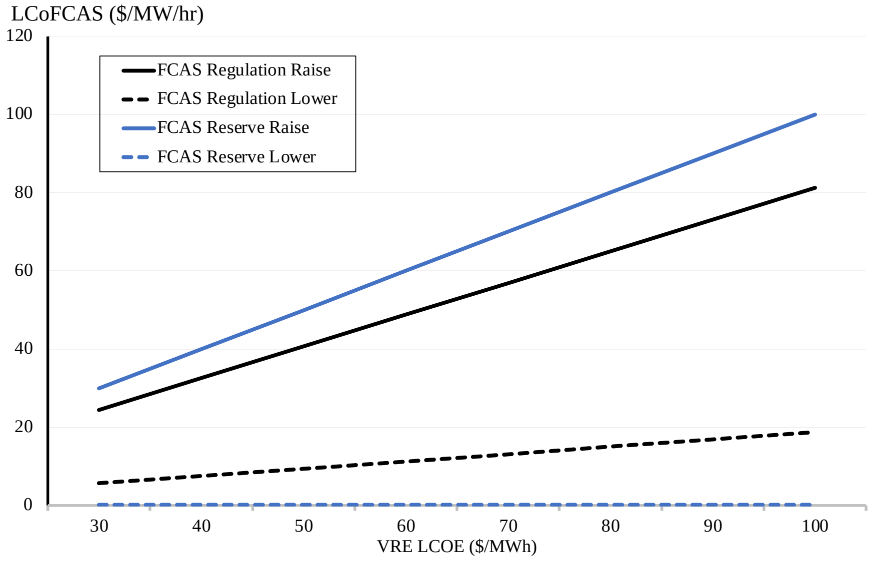
$$LCoFCAS_{VRE,Lower} = (LCoE_{VRE} - MC_{VRE}) \times k \quad (7)$$

Typical projections of the future LCoE of wind and solar are $45-60/MWh and $35-50/MWh respectively (Graham *et al*. 2020). Assuming no marginal running costs and *k*~20%, the LCoFCAS Regulation raise duties provided by these projects would commence at $24+/MW/h for VRE for the lowest cost VRE projects, as the solid line series in Fig.10 illustrates (with VRE LCoE measured on the x-axis, and LCoFCAS Regulation presented on the y-axis). The current mandatory capability requirements in the NEM to provide narrow-deadband primary Frequency response (locally sensed) does not include a headroom requirement, meaning that unless a VRE project is already curtailed it will not be required to deliver a response. Therefore, the market signals and associated prices will still drive behaviour.

Lower reserves from VRE would of course be available at a lower opportunity cost (from $6+/MW/h), reflecting the average amount of lost revenue from being turned down. Again, this is illustrated in Fig.10 (dashed line series).

For FCAS Reserves Raise duties, *k*≈ *0* (low utilisation) and again assuming no marginal running cost the $LCoFCAS_{R,VRE}$ is simply $LCOE_{VRE}$. That is, a revenue adequate project must ultimately be paid the same average price for its *reserved* energy as it would if it had offered that energy at market prices. This is relatively expensive compared to resources with non-zero marginal running costs, where the opportunity cost of turning down is lower. Conversely, FCAS Reserve lower duties can in principle be provided for free, subject to ramp rate constraints, noting these Reserves will only be available when a VRE project is generating.

Figure 10: Projected LCoFCAS from VRE as a function of LCOE

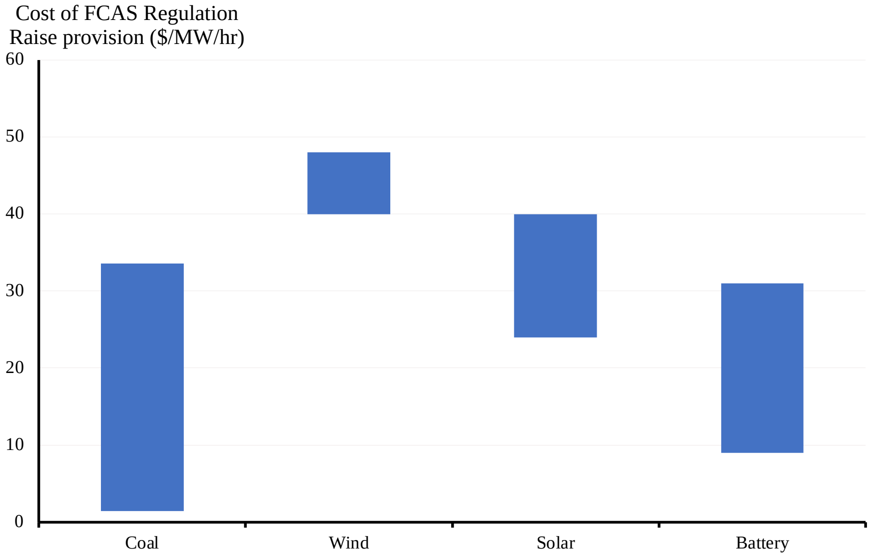


3.4 Comparison of FCAS Regulation duties

Fig.11 summarises the previous analysis of FCAS Regulation by focusing on raise duties (which we find are more challenging to deliver). The bars show indicative LCoFCAS ranges from batteries via Eq.(5), and from wind and solar via Eq.(6) based on cost estimates from

Graham *et al*. (2020). As a benchmark, we also plot the indicative short-run cost range of provision from existing coal units for wholesale prices of $50-80/MWh, consistent with Graham *et al*. (2020) estimate of firmed VRE costs).

Figure 11: Comparison of projected costs of FCAS Regulation Raise duties



Given the comparative results in Fig.11, we will dispense with any further analysis of solar and wind vis-à-vis FCAS duties. Our analysis from here on will focus specifically on provision from coal and batteries, and the change in observed FCAS prices over time.

4. FCAS Regulation prices vs theoretical benchmarks

Having established the theoretical framework for providing FCAS duties, we now consider their applicability to the NEM given the rapidly changing plant stock, and the likelihood that prices will reflect opportunity values of reserved capacity.

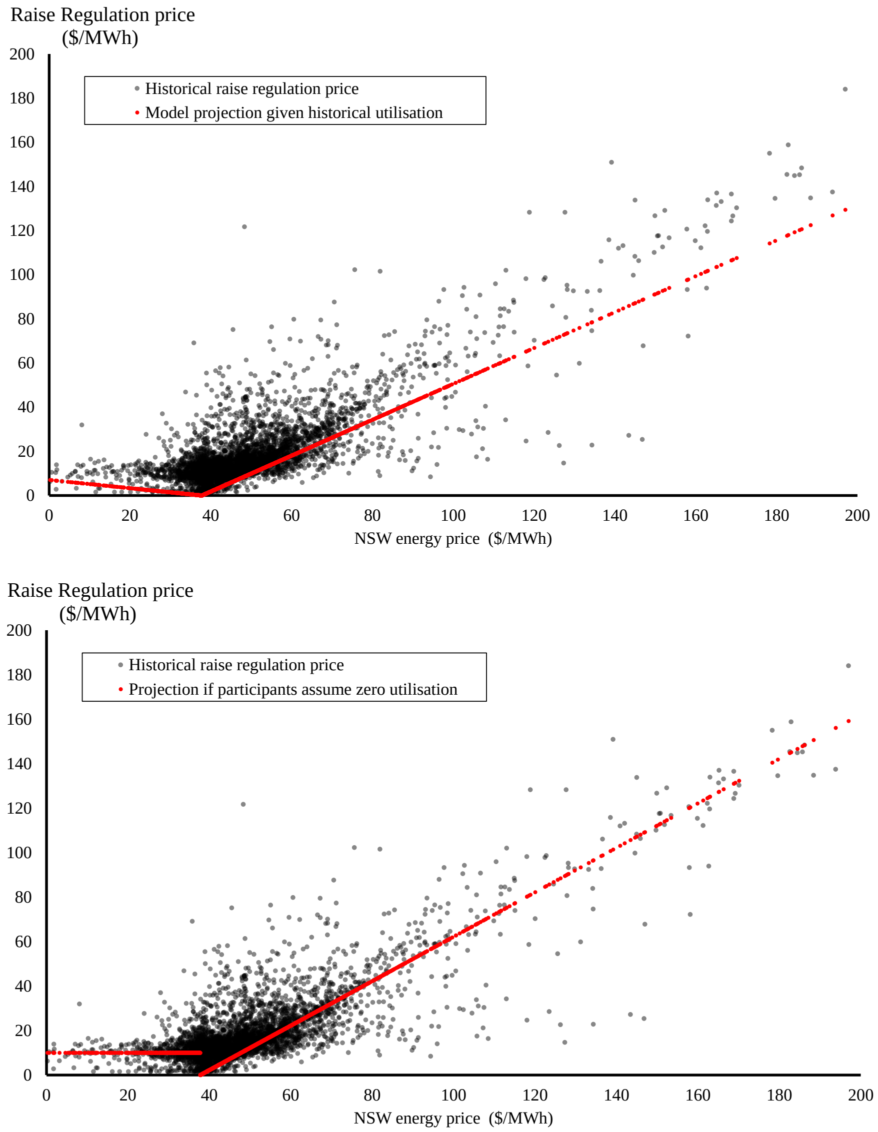
4.1 Coal plant FCAS Regulation duties vs observed market prices

Fig.12 shows historical 2020 FCAS Regulation prices for the NSW region of the NEM for trading intervals where black coal are setting FCAS prices, versus the corresponding energy price in that interval. This analysis is based on *"price setter"* data published by the Market Operator for each five-minute dispatch interval.

Our red-line forecast is the theoretical prediction based on Eq.(3) and values in Tab.1, assuming fuel costs of 90% of the annual average Newcastle coal export price[33] and plant heat rates of 10 GJ/MWh. We see a strong qualitative, but imperfect quantitative, fit to the data. Our second chart in Fig.12 demonstrates a better fit by assuming $k = 0$ (i.e. offers assume no Regulation utilisation) and a common floor price offer of $10/MWh. We interpret this as conservative FCAS offer pricing strategy by generators, such that they are not "out of pocket" if there is low Regulation utilisation. Some periods may also be due to the way the NEM dispatch engine trades-off offers between energy and Reserve markets, such that differences in offers (without any consideration of utilisation) drives prices.[34]

[33] The 90% net back calculation allows for transport costs from the mine to the export terminal.
[34] We would argue that participants *could* offer lower prices into the reserves market if sufficient additional competition existed. With this caveat, we expect this approach could be used to project future FCAS prices from various sources (with different values of M). This approach can also be adapted to changed market conditions, such as carbon constraints increasing the marginal running costs of coal generators which, counterintuitively, reduces the cost of reserves (units are more willing to withhold energy with higher marginal running costs).

Figure 12: Historical FCAS Regulation Raise prices versus theoretical model



4.2 Provision of FCAS Regulation duties from batteries

When we combine the variables set out in Tab.1-2 and Eq.(5) with a forecast of battery costs (with battery cell costs projected to fall by ~50% by 2030; see Appendix I[35]), a forecast for the LCoFCAS Regulation (i.e. both raise and lower duties) can be derived. This is shown in Fig.13 as the line series, commencing from 2022 through to 2035 on the x-axis. This cost estimate is for continuous provision of FCAS Regulation, both raise and lower duties.

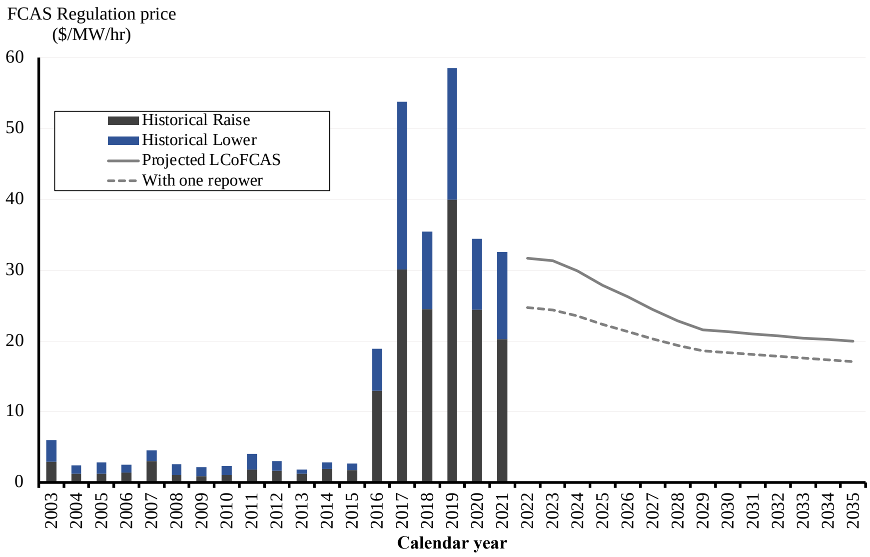
Historic FCAS Regulation prices have also been included in Fig.13 as the bar series, and span the period 2003-2021. The step-up in FCAS Regulation prices following the disorderly exit of coal plant is very apparent, from 2016 onwards.

In our LCoFCAS Regulation forecast (i.e. line series), the optimal sizing of a battery was determined for each year in order to minimise costs. Based on today's costs, FCAS Regulation can be delivered from a battery for ~$30/MW/h, falling to ~$20/MW/h by 2030 if cost reductions eventuate.

Our view is that LCoFCAS can be further reduced if cells are replaced (allowing longer-life BoP to be reused). This is captured as the 'Repowering' dotted line series in Fig.13.

[35] Just as technology costs are critical in determining future spot prices, so too are technology costs critical inputs to FCAS prices. For this purpose we have drawn on results contained in (Graham *et al.*, 2020).

Figure 13: Projected LCoFCAS Regulation from grid-scale batteries



Recent (bundled) time-weighted FCAS Regulation prices have settled at an average of $32-59/MW/hour. This is consistent with near-term projections of the cost of provision from batteries in the NEM. If battery costs continue to fall and wholesale prices converge to underlying costs, the existing FCAS Regulation prices can be expected to reduce substantially.

The average storage capacity of deployed NEM batteries is currently ~1.4 hours with most new entrants now opting for 2 hours of storage, perhaps reflecting the higher arbitrage value (per MW-installed) of short-duration storage. This aligns with purely technical studies that have focussed on revenues ($/kW) from price-taking resources in the energy arbitrage market, which favour short duration storage (Gilmore *et al.*, 2015; Engels, Claessens and Deconinck, 2019).

However, our analysis tends to suggest that batteries will benefit from higher hours (i.e. ~3-4 hours) of storage given that FCAS markets are significantly more important to project economics. This can be understood by recognising that dedicated FCAS Regulation providers would currently deliver, *on average*, +5.25 MWh/MW/day of raise response – therefore the warranted daily cycle will need to be close to this average result. Alternatively, more frequent cell replacement could be undertaken as cycles are exhausted[36].

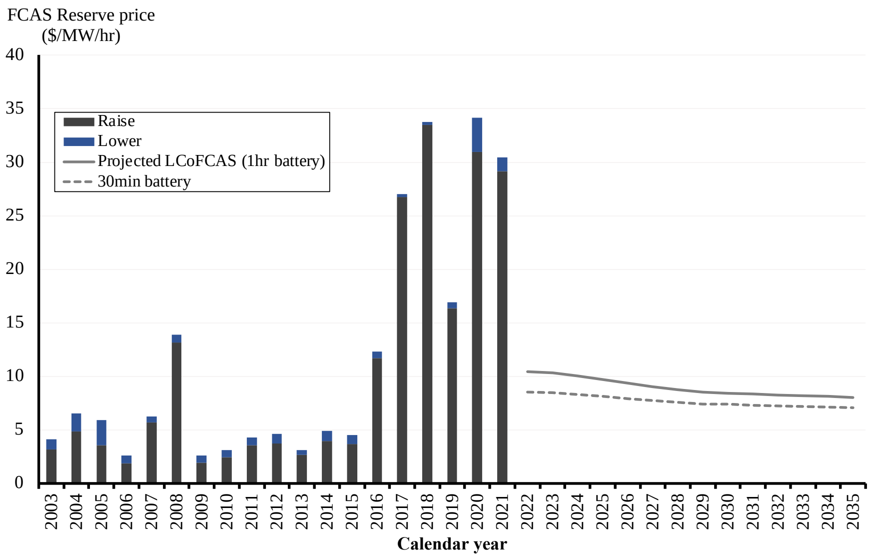
5. Provision of FCAS Reserve duties from batteries

To first approximation, the expected average utilisation $k_{reserves} = k_{util\%} \times k_{act\%} \approx 0$ and under these conditions Eq.(6) effectively collapses down to the carrying cost of a battery[37]. The required stored energy depends on the maximum response times specified in the service. In the NEM, FCAS Reserves must be capable of sustaining a response of up to 30 minutes. Publicly available cost projections for very short duration batteries are limited, so we present results for both the estimated cost of an optimal 30 minute battery and a more typical 1 hour duration battery. When we apply Eq.(6), we assume the battery is able to offer its full nameplate capacity into each of the NEM's FCAS Reserve markets[38] outlined in Section 2. All other assumptions are as per Tab.2. Our forecast results are illustrated as the line series in

[36] Note our analysis excludes the possibility that shallow cycling duties extends the available cycles (Kempton and Tomić, 2005).
[37] This is similar the carrying cost of an open cycle gas turbine being a proxy for historical $300 cap prices, which act as a proxy for operational reserve capacity (Simshauser & Gilmore, 2020).
[38] In practice, most providers offer into multiple reserve markets in the NEM and future batteries would likely do the same. The response able to be registered in each NEM FCAS Reserve market depends on the droop setting of the battery (change in output over change in frequency); faster droop settings allow for more response to be registered. A droop setting of 0.7% is sufficient to allow full participation in each market. Currently, some batteries in the NEM are restricted to 1.7% droop, preventing full utilisation in the fastest FCAS markets. If applied to future batteries, this will result in higher costs to consumers in the long run.

Fig.14 for years 2022-2035 by again relying on technology cost assumptions in Appendix I. Historical FCAS Reserve prices are also presented as the bar series, from 2003-2021.

Figure 14: Projected LCoFCAS Reserves from grid-scale batteries



As noted in Fig.14 our projected $LCoFCAS_{con}$ for utility-scale batteries continuously delivering bundled raise and lower services equates to $8-$10/MW/hour, with costs projected to fall to $7-$8/MW/hour by 2030 if projected battery cost reductions are realised. This is much more gradual than projected reductions for FCAS Regulation duties, as FCAS Reserves from batteries do not benefit from reduction in cell costs.

We believe utility-scale battery investors in the NEM should anticipate significant reductions in earned FCAS Reserve prices relative to current levels. Indeed if current prices persisted, a dedicated, short-duration battery could comfortably be financed on FCAS Reserve revenues alone. To be clear, any plant undertaking FCAS Reserve duties must also withdraw its capacity from active duty in all other markets, including the spot market for electricity and FCAS Regulation.

6. Policy implications and concluding remarks

There are a series of important implications arising from Sections 2-5, as follows:

1. The microeconomic reform of wholesale electricity markets that occurred throughout the 1990s dealt with a universal problem – oversupplied markets. In an environment in which the entire plant stock was capable of supplying FCAS duties as a joint product of the electricity production process, FCAS markets were heavily oversupplied. Consequently, with the marginal cost of providing FCAS typically being zero (in oversupply), FCAS prices cleared at almost inefficiently low levels (i.e. $1.6 - $4/MW/h) even in equilibrium. It is perhaps not surprising that literature on FCAS pricing prior to the past five years has been virtually non-existent (*cf.* literature on wholesale electricity prices and wholesale market design).

2. The disorderly exit of coal plant in Australia's NEM, and the sharp rise in asynchronous VRE plant meant that the inherent supply of FCAS was falling while the demand for FCAS was simultaneously rising. These conditions led to a market rebalancing, and in consequence, reserving capacity to undertake FCAS duties suddenly converted to non-zero marginal costs, with prices subsequently surging to $23+/MW/h.

3. Our analysis of NSW FCAS Regulation prices in Fig.12 showed an opportunity cost has emerged, although as Fig.13 very clearly showed, this is a relatively new phenomenon, arising as it did from 2016 onwards. And recall that 2016-2017 formed an important crescendo of disorderly coal plant exit (Simshauser and Gilmore, 2022).

4. Policy makers will need to be mindful of allowing reserve markets to be priced appropriately. Where mandatory requirements reduce the need for market procurement, this will distort market prices. However, the management of Frequency Control shouldn't be subject to 'a taking' simply because resources are *currently* available and can be compelled to provide it. This has been the recent case in Australia, where a primary frequency response has been mandated from all resources (albeit without a headroom requirement) as outlined in Appendix II. While Frequency Control is valuable, it is not costless as Figs.13 and 14 show. Ultimately, an unpriced service will lead to overconsumption, undersupply, or both. This has been observed recently in the Australian market where the lack of price signals for system strength and inertia has led to shortfalls that have threatened grid security. This is not a market failure per se, but clear examples of missing markets. Recognising this issue, in consultation with two of the authors, the rule maker exempted batteries from the obligation unless otherwise generating, and so avoiding the cost of continuously providing FCAS Reserve or Regulation as quantified in Section 3.2 and Appendix II.

5. Conversely, as a consequence of point (3) above, it would seem FCAS duties undertaken by mid-merit coal plant are now setting prices well above the efficient level, with batteries able to respond to the FCAS markets at well below prevailing prices as Fig.13-14 tend to suggest.

6. A large number of potential battery entrants are responding to these elevated prices. It is also possible under the circumstances that inefficient over-investment occurs, whereby the supply of batteries well-outstrips demand for services. This would of course depress future FCAS prices, but we would suggest on a transient basis. Strong growth in battery storage will be required to manage a 100% renewable energy grid, and consequently this dynamic should drive prices back towards equilibrium. And even in oversupply, FCAS Regulation duties are not costless. Batteries developed have an opportunity cost – providing FCAS Regulation consumes cycles, reducing their lifetime.

7. Revenue stacking is an important value driver for battery storage. Switching between arbitrage, FCAS Regulation, FCAS Reserve, responding to new markets like Fast Frequency Response, or more localised services such as managing episodes of high volts, underwriting protection schemes to reduce network constraints, or providing system strength (through grid forming inverters) will, we believe, become increasingly common for current and future batteries. Investors will be aware of these various revenue sources, and prices in each market will ultimately reflect costs as supply is reconfigured.

Finally, we note that the price of reserving capacity for FCAS duties are becoming increasingly connected with spot electricity prices. Our view is that they will continue to going forward. As a consequence of this, total revenues will not simply be the sum of an arbitrage calculation, and a LCoFCAS calculation. The highest value period in each market will likely coincide. Supply-side resources will therefore need to optimise their participation across these increasingly connected markets.

A natural next step would be to convert the LCoFCAS into a revenue forecast for each service. But as with converting an LCoE into market prices for spot electricity, the translation is unlikely to be simple. First, markets are rarely in equilibrium, and the benchmark technology is likely to fall in cost – and nor will batteries be the only resource providing FCAS duties in the future. What our approach does provide is an *a priori* cap on time-weighted average costs of FCAS duties, as a way to calibrate stochastic price distributions. More granular forecasts of FCAS prices can and should be benchmarked against these curves to ensure short-run assumptions are consistent with long-run costs.

7. References

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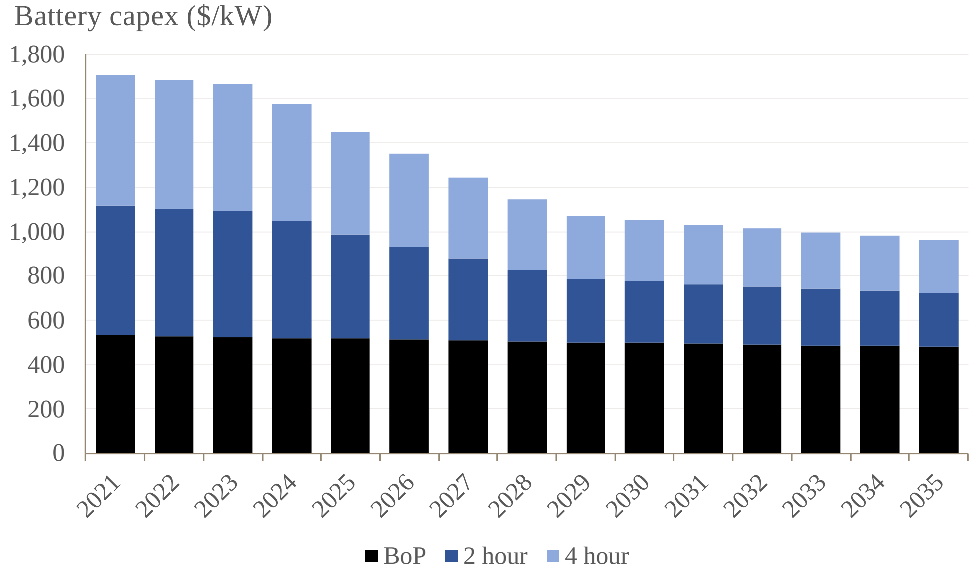
APPENDIX I – Battery cost projections

We consider a future cost scenario broadly based on Graham *et al.*,(2020) whose work also underpins forecasts by the NEM market operator. We linearise the projected costs into a fixed Balance of Plant (BoP; $/kW) cost plus a component that scales with hours of storage. Costs for a two (four) hour battery decline from $1,100/kW ($1,700/kW) in 2021 to $700/kW ($960/kW) in 2035. Note that the projections assume only modest reductions in $/kW costs over time, with most cost reductions being for the cells. An additional $70/kW in connection costs was also applied.

Figure 15: Projected capital costs for grid-scale batteries



Source: Graham et al (2020)

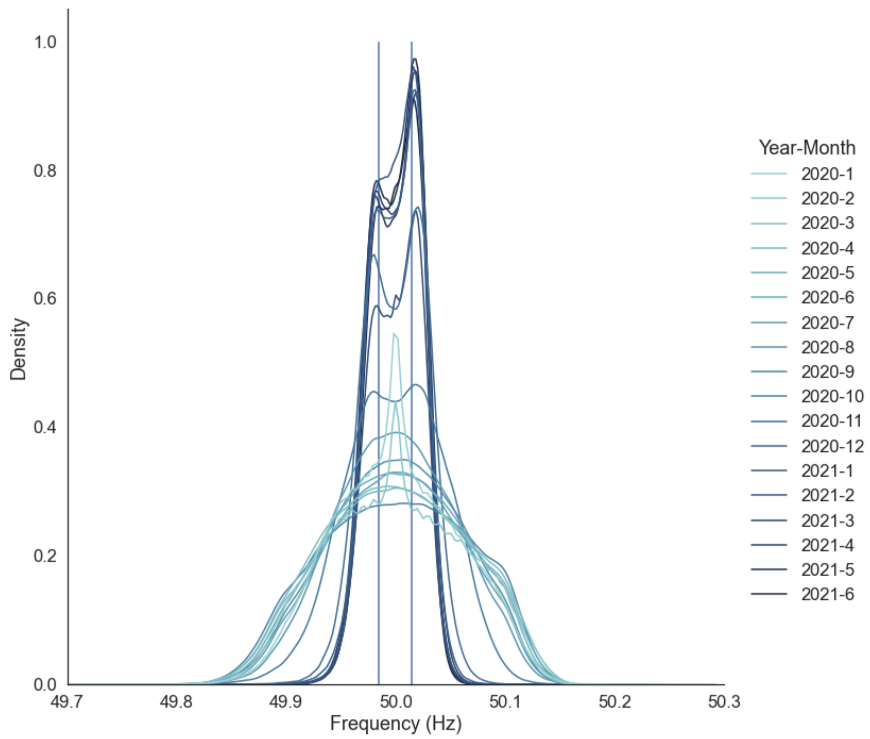
APPENDIX II – Temporary Mandatory Primary Frequency Response

Underlying costs of Frequency Control cannot be avoided. However, FCAS Regulation may be exchangeable for other forms of Frequency Control. With rising levels of VRE relative to synchronous generation, a requirement for additional quantities and services is, we believe, entirely predictable. We noted in Section 2 that the NEM's so-called *Normal Operating Band* for Frequency is 50Hz +/-0.15Hz, and the *Frequency Operating Standard* specifies the power system should be maintained within this Band >99% of time.

Perhaps unsurprisingly given the results in Fig.3-5 in Section 2, a "mandatory" Primary Frequency Response (mPFR) requirement was originated by AEMO and accepted by AEMC as it became clearer that the distribution of the power system's Frequency was deteriorating (Simshauser and Gilmore, 2022). Subsequent to the implementation of a NEM Rule on mPFR in mid-2020, all capable generators were required to enable a Frequency Response with a +/- 15mHz deadband, and with a droop curve of no more than 5%. To explain this in simple terms, all generators with the ability to automatically respond and stabilise any small Frequency deviation were obliged to do so, albeit without any requirement to retain available headroom[39]. And being mandatory, no compensation is payable.

When combined with an expanded FCAS suite, the mPFR Rule had the desired effect on the relative distribution of the NEM's Frequency, as Fig.16 illustrates. Note the NEM's distribution of power system Frequency has narrowed significantly since mid-2020 when the Rule was implemented.

Figure 16: Distribution of power system Frequency (50Hz)



The mPFR requirement has been imposed for a period of three years, with the intention being that this represents sufficient time for the development of a sustainable market solution. The most obvious problem with the transient mPFR is that services are mandated, free of charge. And as is commonly understood in economics, a mispriced product will be overconsumed and eventually, undersupplied. In this instance, the mPFR Rule ignored the fact that there is a non- trivial opportunity cost of supply. And because the Rule mandates all generators that can supply must supply, the relative cost and suitability of generating units over others (vis-à-vis PFR duties) is ignored.

[39] By headroom, we mean capacity, either up or down, as well as stored energy.

A utilisation factor for mPFR can be calculated. Tab.3 shows the battery cycles that would be consumed by a 1-hour battery delivering mPFR over time based on the historical Frequency distributions and modelling the battery with a 1.7% droop. Over time, the share of mPFR undertaken by the hypothetical battery reduces, as more units have been enabled for mPFR and the Frequency distribution narrows. The long-term trend seems to be 3-4% of warranted cycles are being consumed through mPFR.

Table 3: Primary Frequency Response utilisation parameters (2020-2021)

Year	Month	Cycles	% of monthly warranted cycles
2020	January	4.84	16%
	February	5.16	17%
	March	5.93	20%
	April	5.65	19%
	May	5.51	18%
	June	4.82	16%
	July	4.56	15%
	August	5.21	17%
	September	5.96	20%
	October	3.45	12%
	November	1.61	5%
	December	1.16	4%
2021	January	1.04	3%
	February	0.88	3%
	March	1.16	4%
	April	1.04	3%
	May	1.08	4%
	June	0.95	3%

The challenge with mPFR is that it is indifferent to adjusting zero marginal running cost VRE plant and high cost thermal plant. That is, the mPFR policy does not distinguish between the opportunity cost of turning down a high marginal running cost gas plant, and a zero marginal running cost wind plant. This represents an area for the policymakers to refine over the three-year window.