Submission

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Subject System services rule changes

Overview:

Infigen Energy (Infigen) welcomes the opportunity to make a submission. Infigen delivers reliable energy to customers through a portfolio of wind capacity across New South Wales, South Australia, Victoria and Western Australia, including both vertical integrated assets and PPAs. Infigen also owns and operates a portfolio of firming capacity, including a 123 MW open cycle gas turbine in NSW, a 25 MW / 52 MWh battery in SA, and will soon take ownership of 120 MW of dual fuel peaking capacity in SA. Our development pipeline has projects at differing stages of development covering wind, solar and batteries and we are also exploring further opportunities to purchase energy through capital light PPAs. This broad portfolio of assets has allowed us to retail electricity to over 400 metered sites to some of Australia's most iconic large energy users.

Our submissions provides high level feedback on the motivations, benefits, and drivers of the package of rule changes. Based on the AEMC's questions, we have not provided detailed discussion on the mechanisms, which we assume would take place in a subsequent round of consultation. The key points of our submission are:

- Continued interventions in the NEM threaten future investment, while the lack of a decarbonisation plan makes timing new investment to unforecasted coal closures challenging. Similarly, there are new modes of failure that may have not yet been identified, and could be addressed through a formal mechanism. Operating Reserves provides a framework for addressing key stakeholder requirements, and should be implemented quickly.
- Infigen supports the key elements of the TransGrid proposal to address system strength. System strength is best described as a system service, and the expected cost of under-procurement is significantly higher than the cost of over-procurement – Infigen therefore supports a forward looking procurement scheme that will minimise project delays and costs to consumers. We note, however, that a scheme should impose central planning by proxy. The Hydro Tasmania proposal for dispatching additional system services through constraints is worthy of further consideration.

- Infigen supports the rapid development of a Fast Frequency Response service, noting that multiple AEMO publications, including the Renewable Integration Study, have highlighted the value of FFR.
- Infigen considers that current market signals are effective for delivering reserves for *typical* variability, including the daily solar and load ramp. Given that future market resources are certain to be highly flexible, we do not see a need for ahead commitment of capacity that risks transferring inflexibility costs to consumers.
- Implementing an alternative to the Mandatory Primary Frequency Response rule should be progressed quickly by the AEMC to ensure that sufficient resources are available even as the market transitions. The critical first step is for the Reliability Panel and AEMO to work together on a revised Frequency Operating Standard.

In considering these rule changes, we note that the NEM has recently seen significant investment – over 40% of investment since NEM start occurred in the past 3-4 years, with the number of projects per year well above historical rates. At the same time, aging coal plants have closed with very little notice. This has presented a "rate of change" problem, where system headroom and previously "free" services have been eroded, while new modes of failure have emerged. While the NEM remains highly investable and the energy only market continues to function well[1], it is very likely that new, unforecasted system security problems (including further as-yet unanticipated coal closures) will emerge and it is therefore prudent to develop and acquire appropriate reserves (for both energy and essential system services) that can minimise future disruptions. These new services must be implemented quickly *before* costly new problems or constraints emerge –the costs of under-procurement are likely to significantly outweigh any costs of over-procurement (particularly given that forecasters inevitably underestimate rates of change).

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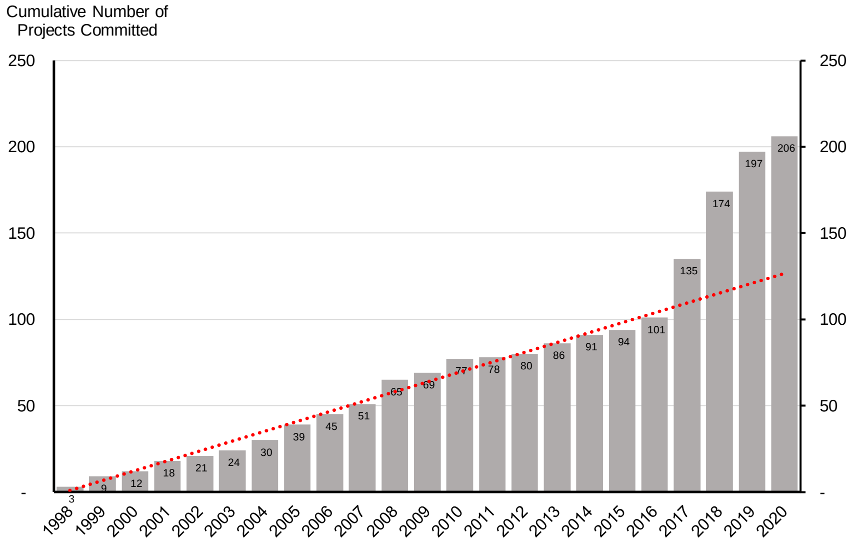
[1] See Simshauser and Gilmore (2020), https://www.researchgate.net/publication/341700642_Is_the_NEM_broken_Policy_discontinuity_and_the_2017-2020_investment_megacycle

Figure 1 Cumulative project commitments (as of May 2020)



Source: Simshauser & Gilmore (2020)1

Finally, it is critical that the AEMC align its interpretation of the 'long-term interests of consumers' with Australia's obligations to reduce emissions in a manner consistent with international efforts to limit anthropogenic climate change to 1.5-2 degrees Celsius above pre-industrial levels. Failure to implement policy that achieves a smooth glide path for reducing emissions to net-zero by mid-century is not in the long-term interests of consumers. Not addressing this aspect of energy policy will create a disorderly transition, as has been the case during the recent 3-4 year investment boom noted above. As such, planning for a system that has a high penetration of zero or very low-emissions generation is in the long-term interests of consumers, and thus a relevant consideration of the AEMC.

1. Infigen - Operating Reserves

QUESTION 8: INFIGEN'S RULE CHANGE REQUEST, *OPERATING RESERVE MARKET*, ISSUES AND PROPOSED SOLUTION.

1. Do stakeholders agree with Infigen that tight capacity conditions and increasing uncertainty in market outcomes are problems that an operating reserve would address?
2. Are there alternative solutions that could be considered to address tight capacity conditions and increasing uncertainty in market outcomes?
3. Do stakeholders consider Infigen's proposal would provide adequate pricing signals to drive efficient use of and investment in operating reserve services now and in the future?
4. How do stakeholders think separate operating reserves arrangements would affect available capacity in the spot, contracts and FCAS markets now and in the future?
5. How do stakeholders think separate operating reserves arrangements would affect prices in the spot, contracts and FCAS markets now and in the future?
6. How could the design of an operating reserve market (e.g. criteria for eligible capacity) best support competitive outcomes both in the operating reserves market but also energy and FCAS markets?
7. What are the factors that should be considered when seeking to set and procure efficient levels of operating reserve?
8. Would Infigen's proposed operating reserve market result in any substantial adverse or unintended consequences in the NEM?
9. What are the costs associated with establishing an operating reserve market in the NEM? If introduced, how should these costs be allocated?
10. What kind of incentive/penalty arrangements would be necessary to be confident the operating reserves procured are available when needed?

QUESTION 15: REQUIREMENT FOR AN EXPLICIT IN-MARKET RESERVE MECHANISM OR MARKET IN THE NEM

1. What do stakeholders see as the key drivers or changes in the NEM that could be addressed by introducing an explicit in-market reserve arrangement?
2. Do stakeholders' think there is a need for an explicit in-market reserve arrangement in the NEM. If yes, do stakeholders consider the need to be permanent or transitional?
3. How would an explicit in-market reserve mechanism or market impact stakeholders? What would be the key benefits and costs? Would it effect stakeholders' operational or investment decisions?
4. Do stakeholders' think there to be an explicit need for a capacity commitment mechanism as proposed by Delta? Do stakeholders' think this as a separate need to an in-market reserve service?

1.1.1 Role of Operating Reserves

Infigen considers that Operating Reserves would provide a valuable near-term service, but can also be an enduring complement to the NEM's highly successful energy only market.

Operating Reserves would address many of the concerns raised by various stakeholders. In particular, they would:

- Allow market participants to continue to hedge efficiently (as they have done to date) without distortionary spot price impact due to perversion of the marginal price dispatch process. That is, participants would still make rational decisions as to whether to commit units, acquire fuel, or reserve battery headroom based on projected needs - the delivery of reserves to hedge against high prices. Operating Reserves would ensure further resources are available to hedge against unanticipated or extreme reliability events - a system services best procured by AEMO through a competitive process.
- In practice, operating reserves would effectively allow for a market based wholesale demand response mechanism (where demand response is effectively priced above the market price cap) and effectively allow customers to choose their own level of reliability at varying price levels above the market price cap (Section 1.1.4).
- Ensure AEMO always has sufficient [2] reserves to deliver a reliable grid when unanticipated events occur. This includes near real-time events (such as the unplanned outages of aging coal units, thermal derating of renewable projects, or higher than expected demand) as well as events on planning timeframes such as unknown system constraints (such as the system strength constraints emerging across the NEM requiring curtailment of capacity or another unanticipated coal closure).
- Provide an market-based alternative to RERT that provides temporally divergent pricing signals. Significantly reduce the need for RERT procurement thereby delivering efficiency of invested capital. In particular, AEMO would be able to call on Operating Reserves when going into a tight supply demand period without the need for any further negotiations, and would have confidence of the volume and nature of the delivered response. Furthermore, AEMO would be able to increase the level of Operating Reserves procured in response to more volatile conditions[3], establishing both a real-time availability signal (and payment) and also an investment signal.
- Reduce the incidence of LOR2/3 events – times of tight supply demand would still lead to high price/MPC events, providing in-market investment signals, but there would be low risk of unserved energy due to the presence of callable reserves.
- Provide Governments with confidence that existing economic signals continue to function, but the physical market will not skate close to delivering unserved energy. Governments could also in principle use the Operating Reserve mechanism to procure (and fund) additional reserves (beyond the Reliability Panel's settings) for

[2] Infigen recommends that level of reserves to be procured be determined by the Reliability Panel based on advice from AEMO
[3] Obviously, new (unregistered) reserves could not enter the market in real-time, but procurement of higher levels of reserves or more frequent procurement would send an investment signal.

their regions, rather than seeking out of market procurement - for example, sufficient reserves could be procured at all times to ensure N-2 reliability (if the Reliability Panel and AEMO determine a lower procurement level).

We note the ESB recently targeted a higher achieved reliability standard, through the procurement of RERT resources to deliver 0.0006% reliability standard, including multi-year contracts that withdraw resources from the market. Previous submission to the AEMC have highlighted the risks of ongoing RERT procurement - particularly through removing demand response from the market as well as the implications of such a high reliability standard on cost to customers.

The ESB recognized that tightening the NEM's standard to 0.0006% would currently (likely) require a higher market price cap. Operating Reserves provide an alternative approach to achieving a higher achieved level of reliability without having a material impact on overall costs; by allow resources to move in and out of the service, it would also not disadvantage investments made in good faith.

1.1.2 Implementing Operating Reserves should be a high priority

Infigen considers that the urgent implementation of an operating reserves framework is essential for future grid reliability, including facilitating a stable investment environment.

Operating Reserves would help ensure that the NEM has sufficient resources to cope with unexpected changes to the grid. Some additional examples are provided below.

Unforecasted coal closures

In our view, the primary risk to NEM system reliability is unexpected and unforecastable coal closures. An appropriate scheme for pricing carbon externalities would provide greater certainty to investors, and allow AEMO to better incorporate closures into its modelling.

Furthermore, any perceived underinvestment in dispatchable capacity can be attributed to a lack of identified investment opportunities, rather than a failure of market signals to drive investment.

For example, despite the closure of ten coal power stations over the past decade, AEMO's Electricity State of Opportunities did not identify any potential closures ahead of time, nor did the market anticipate any closures. Various ESOO scenarios included demand, economic growth, and carbon sensitivities, but have not generally included material closures. The 2016 ESOO included the closure of a generic 1600 MW over four years, but did not consider the possibility of a major closure within 12 months. In short, all ESOO reports appear to be very reactive rather than proactive or anticipative.

We note that even the 2020 ISP's Central Scenario does not consider any coal closures (beyond Liddell) before FY28, despite several Yallourn units reaching their technical life (50 years) by 2023 for Units 1 & 2; in fact, average operating life to date has been 43 years, suggested units are already at elevated risk of closure, and modelling has suggested closure could be as early as 2023[4]. AEMO's Step Change scenario (proposed by Infigen) considers a more aggressive closure trajectory; we consider that AEMO needs to immediately start planning for how to operate this system effectively, building on their Renewable Integration Study but focussing on how higher renewable shares will be enabled rather that suggesting artificial limits.

An Operating Reserves framework would reduce the risk of reliability impacts until either a clearer decarbonisation path is established, or a mechanism to encourage greater transparency and confidence in closure dates (such as Grattan's coal closure model[5]) is implemented.

Table 1 Historical coal closures and reporting in ESOO

	Announcement date	Closure date	AEMO ESOO positions
Swanbank B	26-Mar-2010	27-Mar-2012	2009 ESOO – No projected closure 2010 ESOO – Announced closure included
Playford (mothballing)	Apr-2012 (mothball) 07-Oct-2015 (closure)	08-May-2016	2011 ESOO – No mothballing assumed[6] 2012 ESOO – Announced mothballing included 2015 ESOO – Announced closure included[7]
Collinsville	01-Jun-2012	01-Dec-2012	2012 ESOO – No mention of closure 2013 ESOO – Announced closure included
Munmorah	03-Jul-2012	03-Jul-2012	2010 ESOO – Available until 2014 2011 ESOO – Available until 2014 2012 ESOO – Announced closure included
Morwell	29-Jul-2014	30-Aug-2014	2012 SOO – Downgraded capacity 2014 ESOO – Possibly further capacity downgrade 2015 ESOO – Announced closure included
Wallerawang	01-Nov-2014	01-Nov-2014	2013 ESOO – No closure considered 2014 ESOO – Announced withdrawals included
Redbank	31-Oct-2014	31-Oct-2014	2014 ESOO – No closure considered 2015 ESOO – Announced closure included
Anglesea	12-May-2015	31-Aug-2015	2014 ESOO – No closure considered 2015 ESOO – Announced closure included
Northern	07-Oct-2015	08-May-2016	2012 SOO – Announced winter mothballing 2013,2014 ESOO – No change 2015 ESOO – Announced closure included
Hazelwood	03-Nov-2016	01-Apr-2017	2016 ESOO – 400 MW brown coal closure in FY18 (1600 MW by FY21 in Weak outlook) 2016 ESOO Update – Announced closure included

Short-term reserves

As noted in Infigen's rule change, there are new modes of failure emerging in the NEM. Ordinary variability in supply and demand can be managed effectively through the existing Regulation and Contingency FCAS services, as demonstrated by the recent improvements

[4] https://environmentvictoria.org.au/wp-content/uploads/2019/12/REPUTEX_Victorian-market-readiness-to-support-closure-of-Yallourn-power-station_1219_FINAL.pdf

[5] https://grattan.edu.au/report/power-play/

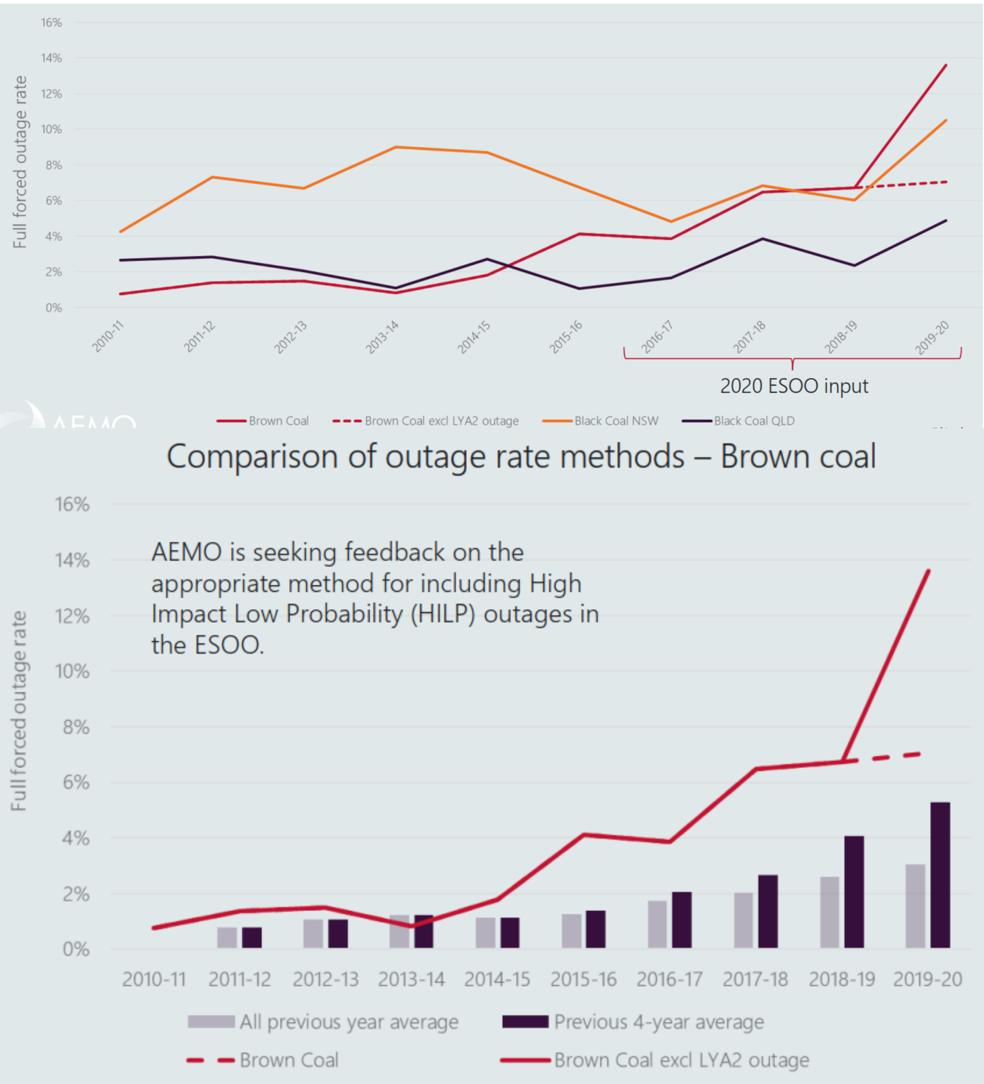
[6] Reduction in available capacity to 200 MW

[7] Despite full re

to frequency performance following (a long-overdue) increase in Regulation FCAS quantities.

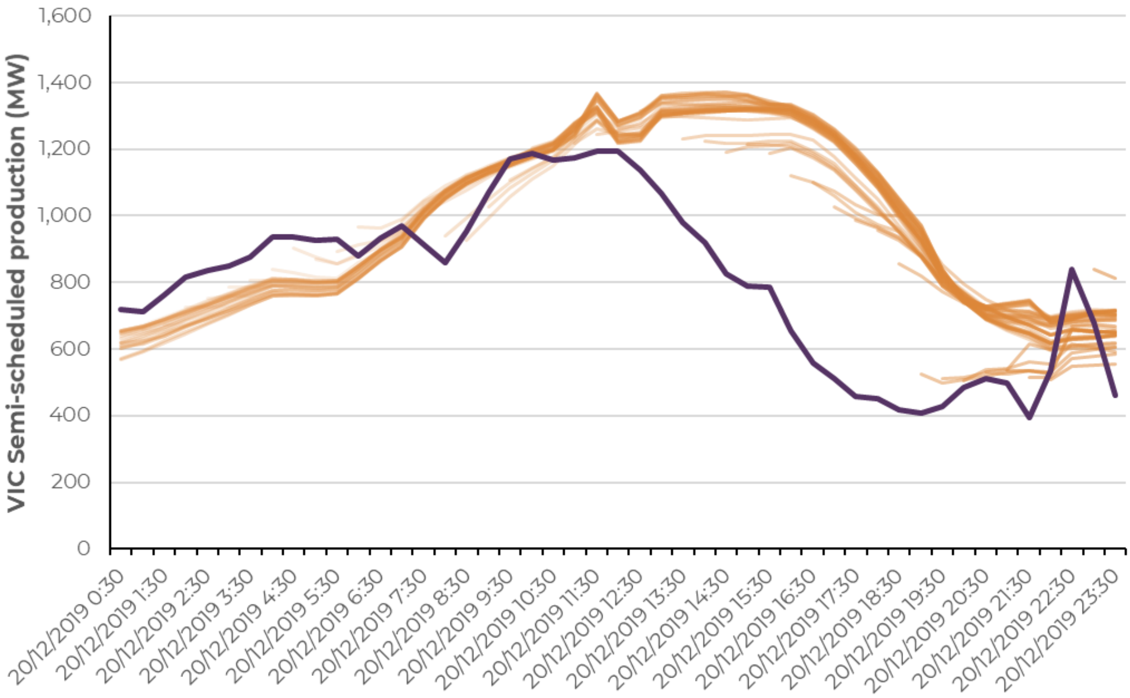
However, significant and protracted outages of aging coal assets may be a material risk to reliability. Figure 2 shows coal forced outage rates are increasingly significantly over time – and in FY20 were materially above the forecasts used in the 2020 ISP. While Contingency FCAS provides a short-term (6s-15min) response to a unit failure, this may not be efficient or sustainable if outages occur during tight supply-demand periods (typically, hot summer afternoons).

Figure 2 Coal forced outage rates (AEMO June 2020 Forecasting Reference Group)



Similarly, extreme weather can result in thermal derating for VRE projects. For example, on 20th December 2019, high temperatures led to significant derating of capacity, with actuals deviating significantly from pre-dispatch. While improved information and forecasting will reduce the frequency of these errors, it is likely that further unexpected deviations are possible, and it would be appropriate to have increased flexible reserves (rather than relying solely on Contingency/Regulation).]

Figure 3 Vic semi-scheduled pre-dispatch for 20th December 2019; forecast (orange) vs actual (purple)



1.1.3 Facilitating a two-sided market

Operating Reserves may also provide a pathway towards a more two-sided market: reserves are paid an availability payment (based on bids), which is attractive to demand side resources. Pre-dispatch would indicate when higher availability payment prices are likely, which could function as a proxy pre-activation payment. Finally, when reserves are activated, they will receive the energy price. A design option would allow for these two payment streams to stack, delivering a *total* payment in excess of the Market Price Cap. For example:

- The Operating Reserves market settles at a nominal $1/MWh: demand response receives an availability payment with very low likelihood of being called – effectively an option premium.
  - Other demand response bids into the Demand Response Mechanism and is not activated.
- In a low reserve period, the Operating Reserves market settles at $1000/MW/hour, but are not activated (no reliability issue): the potential demand response provider still receive the $1000/MW/hour availability payment, which would help cover any pre-activation preparation.
  - Potentially, other demand response resources are bid into the market (dispatchable loads, retailer activated, or Demand Response Mechanism) and receive the pool price (e.g., $14,000/MWh). These resources receive no

availability payment, but have a chance to capture high prices in periods not considered reliability events.

- In an extreme period, reserves settle at $5,000/MW/hour and are activated, being paid the wholesale price of $14,000/MWh for their demand reduction. The demand response effectively receives $19,000/MWh - in excess of the MPC, but still less than the value of customer reliability[8].

1.1.4 Transition and timing

If an Operating Reserve (to, say, N-2) were implemented immediately, there is a risk that it would lead to higher prices to consumers, due to dispatchable capacity being withdrawn from the energy market unless it is balanced by either RERT resources being moved into Operating Reserves or the development of new dispatchable capacity. It may therefore be prudent to have a "slow start" where the volume of reserves to be procured is increased over several years – allowing participants to gain confidence in scheme operation and to contract new demand response and/or develop new capacity.

On this basis, Infigen supports the implementation of Operating Reserves as a priority, which will ensure that a full service can be delivered by 2025.

[8] Note that this is an unlikely scenario – if a reliability event does not occur, resources will not be activated and will not receive the energy price. Many resources (particularly generation) would presumably prefer to remain in the market and capture (or hedge) against the high energy prices. I.e., they may receive higher total annual revenues from more frequent activation, while Operating Reserves may receive higher "per activation" revenues.

2. Delta - Ramping services

QUESTION 9: DELTA'S RULE CHANGE REQUEST, *INTRODUCTION OF RAMPING SERVICES*, ISSUES AND PROPOSED SOLUTION.

1. Do stakeholders agree with Delta that price volatility that occurs when dispatchable generators ramp through their energy bid stacks in response to predictable, daily, high rates of change from solar ramping up and down is a problem that needs addressing?
2. Do stakeholders think that a new raise and lower 30-minute FCAS would address the price volatility at these times? Are there alternatives that could be considered to address this problem?
3. Do stakeholders consider Delta's proposal would provide adequate pricing signals to drive more efficient use of and investment in ramping services than existing price signals and information provided through the PASA and pre-dispatch processes?
4. How do stakeholders think a separate 30 minute ramping product would affect available capacity in the spot, contracts and FCAS markets now and in the future?
5. How do stakeholders think a separate 30 minute ramping product would affect prices in the spot, contracts and FCAS markets, now and in the future?
6. How could the design of a ramping FCAS product (e.g. criteria for eligible capacity) support competitive outcomes both energy and FCAS markets?
7. What are the factors that should be considered when seeking to set and procure efficient levels of ramping services?
8. Would Delta's proposed new 30-minute raise and lower FCAS products result in any substantial adverse or unintended consequences in the NEM?
9. What are the costs associated with establishing new 30-minute raise and lower FCAS products in the NEM? If introduced, how should these costs be allocated?

2.1.1 Pricing impacts

The AEMC has asked, "Do stakeholders agree with Delta that price volatility that occurs when dispatchable generators ramp through their energy bid stacks in response to predictable, daily, high rates of change from solar ramping up and down is a problem that needs addressing?"

While AEMO has noted that evening ramps may increase in the future, we do not find material evidence that ramping is regularly contributing to high prices in the NEM. While ramping might be a problem for many of the current dispatchable generators in the market, new investment in other firming technologies (such as fast-start gas, pumped hydro and battery storage) will ensure that an optimal plant mix is in place to meet emerging ramping requirements.

While ramp rate limitations are a cause of brief high prices in the NEM, this does not currently appear to be a material pricing issue. For example, Figure 4 shows no clear correlation between spot prices in NSW (across FY20) and the ramp in (regional) operational demand net of large-scale wind and solar generation. This is despite ramp rates reaching 1500MW/hour in NSW and 1000MW/hour in Vic. Similarly, Figure 5 compares the difference between minimum afternoon net demand and evening peak net demand (i.e., a proxy for the amount of dispatchable capacity required to ramp across the afternoon) and the average evening price (4pm to 9pm)[9].

Combined, this suggests that even if ramps become larger, there may not be a material pricing impact, or a need to carve out a specific ramping service – particularly given the improved pricing signals of 5 Minute Settlement. That is, participants will continue to self-schedule to meet the credible range of supply and demand scenarios.

Figure 4 Spot price vs hourly net demand ramp in NSW and Vic

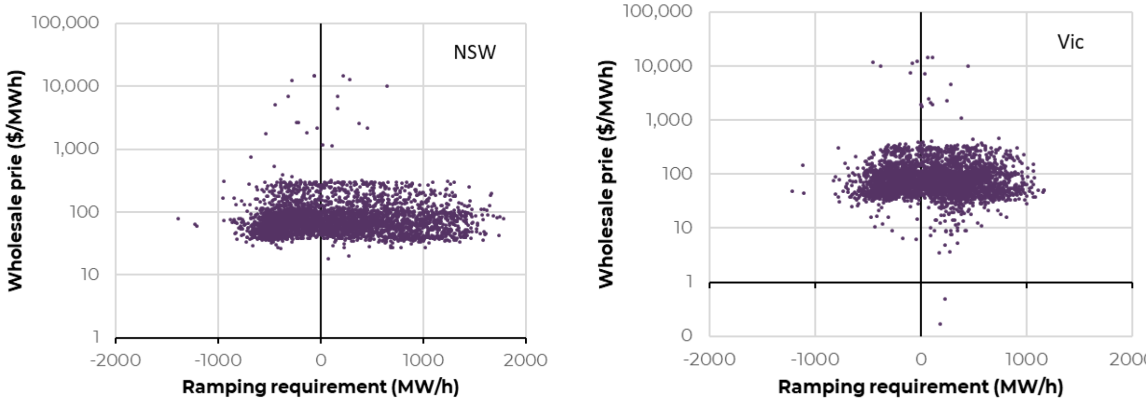
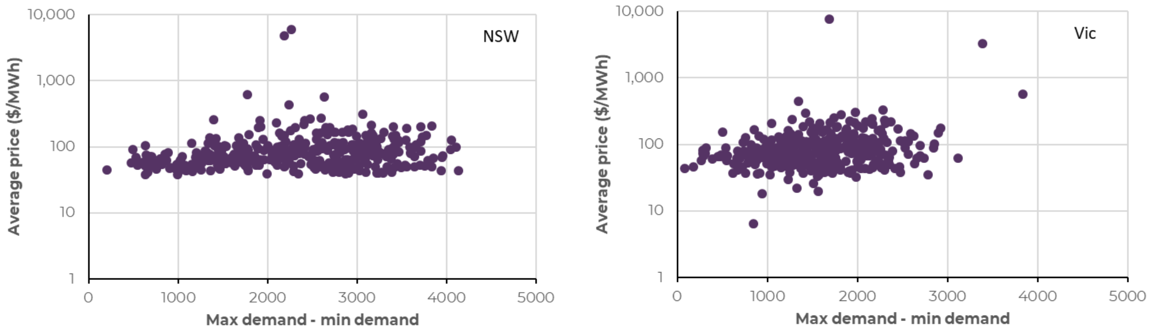


Figure 5 Average evening price (4pm-9pm) vs maximum net demand difference across afternoon/evening



2.1.2 Price signal and unintended consequences

Relatively few details are provided for this proposed service, in particular what obligations would be placed on parties and how this would contribute to improved reliability outcomes. Infigen interprets the proposed service as:

- Defining a minimum ramping requirement;
- Eligible providers of ramping reserve are procured through a competitive real-time market; and

[9] Time ranges are largely arbitrary, but qualitative and quantitative results are robust across possible inputs.

- providers would then be eligible to bid into the energy market as they normally would have (i.e., no obligations to hold back ramping capability, and participants receive all energy payments from their generation)

In our view, for "predictable, daily, high rates of change", there are very strong market signals for flexible capacity to be available. Conversely, there is a risk that Delta's proposal would pay participants for what they would have done regardless, and extra reserves are best procured through a dedicated service.

We consider participants are best placed to manage market risks – particularly those that are well forecast. The alternative is for the central procurer to derisk the delivery of ramping reserves (and other services). However, this effectively requires the central procurer to have identified a risk of a shortfall in ramping capacity *beyond* what a prudent market participant would economically deliver based on the market reliability settings (i.e., the MPC). This is the situation that Infigen's Operating Reserves proposal is designed to address – carving out the reliability risks beyond market settings.

We recognise that there are some services (e.g., faster than normal ramp rates from coal units) that can only be delivered at higher cost and that require activation ahead of time (and potentially before the need is certain). We acknowledge that this may require participants to accept some level of risk, but this is an inherent part of NEM operation (e.g., gas peakers making decisions to start in anticipation of high prices or batteries choosing to withhold energy). Alternatively, this *additional* ramping could be bid into Infigen's Operating Reserve market, where it could be called upon with a ~15 minute call time.

2.1.3 Uniform payment principle

The current NEM (energy market, setting aside FCAS) provides equal payments to all providers of energy, based on actual generation. This ensures that both flexible and inflexible generation receives the same payment in a dispatch interval, reflecting its contribution (in that period) to meeting reliability. Flexible generation will typically receive a higher price, however, if it is able to shape its output to better match load e.g., ramping up quickly in response to price spikes. This provides a strong incentive to make generation available for any tight supply-demand periods.

Delta's proposed framework would appear to discriminate between resources that were already operating at maximum load and resources that are capable of ramping up. This could potentially lead to higher prices before a ramping period, as lower-cost generators may be incentivised to withhold capacity to then offer into the ramping market (but without delivering an increase in ramping capability over the counterfactual).

2.1.4 Costs

In addition to the risks outlined above, we note that AEMO's ISP (outlining a least-cost development plan for the future) develops a significant capacity of highly flexible dispatchable energy storage for firming and reserves. The proposed ramping market would require significant work to develop, and may not be necessary as the NEM continues to transition.

3. Delta - Capacity commitment

QUESTION 10: DELTA'S RULE CHANGE REQUEST, *CAPACITY COMMITMENT MECHANISM FOR SYSTEM SECURITY AND RELIABILITY SERVICE,* ISSUES AND PROPOSED SOLUTION.

1. Do stakeholders agree with Delta that there is an increasing risk that capacity capable of providing reserves or services may not be available at times when the power system may need them to respond to unexpected events because of increasing incentives to de-commit?
2. Do stakeholders think that a mechanism to commit capacity one day ahead of time would deliver the reserves or services needed? Are there alternatives that could be considered to address this problem?
3. Do stakeholders consider Delta's proposal would provide adequate pricing signals to drive more efficient use of and investment in reserves and system services?
4. How do stakeholders think Delta's capacity commitment payment would affect available capacity in the spot, contracts and FCAS markets now and in the future?
5. How do stakeholders think Delta's capacity commitment mechanism would affect prices in the spot, contracts and FCAS markets now and in the future?
6. How would a capacity commitment mechanism and payment affect entry, exit and competition in the NEM over the short and long term?
7. What are the factors that should be considered when deciding how much capacity to commit ahead of time?
8. Would Delta's proposed capacity commitment mechanism result in any substantial adverse or unintended consequences in the NEM?
9. What are the costs associated with establishing a capacity commitment mechanism in the NEM? If introduced, how should these costs be allocated?
10. What kind of incentive/penalty arrangements would be necessary to be confident that the committed capacity would be available throughout the commitment period and/or when called upon?

Delta's proposal creates an ahead market for AEMO to procure system services that are coincident to energy production (Delta includes reserves in this scenario). Delta suggests that an additional top-up payment day-ahead would be required to give generators certainty to commit daytime prices are projected to be low, but could also function as a proxy "system services" market.

Delta has not distinguished between the need for a market for system strength/inertia/etc. (where no revenue stream exists) and operating reserves (where the existing market provides strong signals).

3.1 Delivery of "BAU" reserves

Delta's submission focuses on the delivery of reserves, which we consider under *most* conditions to be effectively delivered and incentivised by the NEM market – and will continue to be appropriately incentivised in the future. This is in contrast to Infigen's Operating Reserves proposal which is aimed at addressing reserve challenges that cannot be forecasted.

For example, on a day-ahead *pre-dispatch* basis, projected wholesale prices and reserve levels are strongly correlated. For example, Figure 6 shows reserve levels and pricing projected for the next day in NSW as of 5pm (indicatively, close of business where participants may need to have made commitment decisions). When reserves were projected to be less than 2,000 MW the lowest *average daily NSW wholesale price* projected was $47/MWh – with actual prices *higher* on the day. This would have been sufficient for a black coal unit to cover its operating costs over the day.

Figure 6 New South Wales day-ahead reserve and price

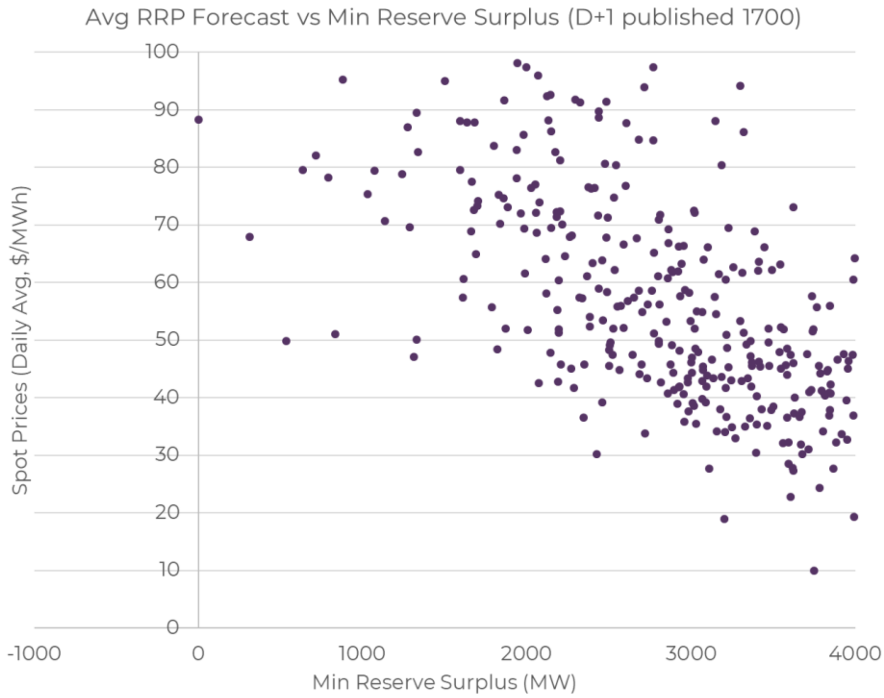
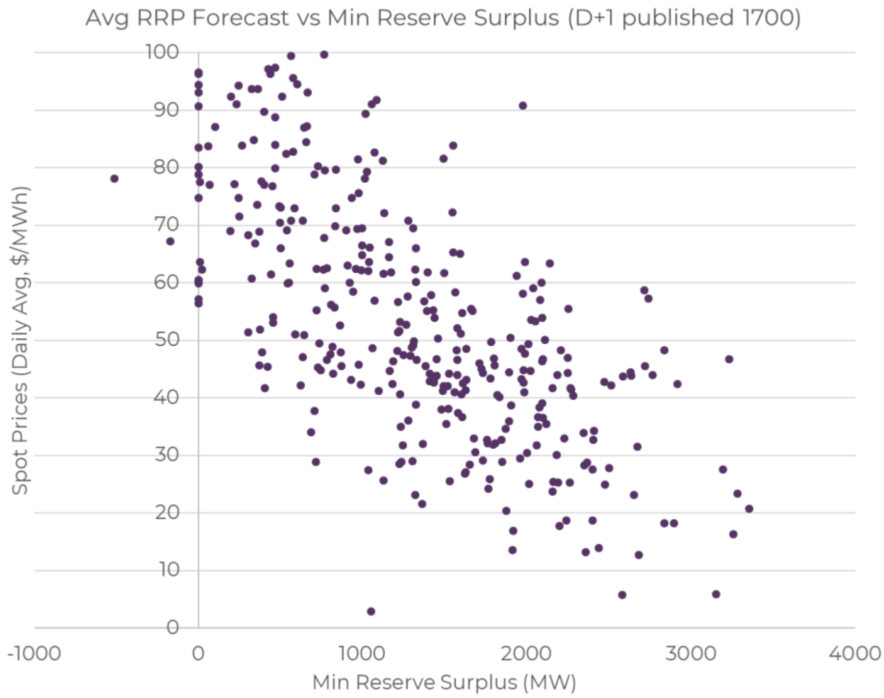


Figure 7 shows a similar but slightly more complex picture for Victoria. Victoria experiences lower prices but still has average daily prices consistently higher than a brown coal SRMC when reserves are low. Two outlier periods deserve closer attention:

- On Sunday April 5th 2020, day-ahead pre-dispatch was projecting prices close to zero with minimum reserves of ~1129 MW – comparatively low relative to the wholesale price. Actual prices were higher ($21/MWh), while reserves met projections (i.e,. no additional resources were available or required). There is no indication of any market failure here – prices were low, driven by significant wind generation across the NEM, and reserves were sufficient even as wind declined across the day.

– Another notable period was the 21st January 2020, where day-ahead prices were -$79/MWh while reserves were projected to be 1622 MW (minimum). Actual reserves were as low as 1304 MW with average prices of ~$20/MWh. Despite very low *forecast* negative daily prices, and relatively low actuals, there was no low reserve conditions.

Figure 7 Victorian day-ahead reserve and price



The corollary is that when reserves are very low, prices are sufficient high to incentivise coal generators to remain online. Therefore, to date, an ahead market for reserves should always have settled at zero – consistent with the delivery to date of sufficient reserves (where such resources existed) to meet all forecast requirements (i.e., there has never been a time where the market operator would have made different decisions to market participants given current standards).

This suggests that despite volatile conditions already occurring in the NEM, there is an effective price signal for reserves, and it is likely there will continue to be into the future even if such periods become more frequent. We consider that for normal, forecastable variability, the existing NEM real-time energy-only market provides very strong signals with several advantages:

– It provides clear signals for flexible generation, including for coal generators to invest in physical capabilities or operator experience for lower minimum operating levels;

- Inflexible generators incur the cost of their inflexibility (being forced to ride through low-priced periods) similar to how renewable generators incur the full cost of their inflexibility when they are unable to choose to generate during high price periods.
- We note that, according to most commentators (including AEMO as part of its expert ISP modelling) all future dispatchable capacity is likely to be highly flexible resources that do not require pre-activation. Real-time signals will be the most critical for delivering reliability in the future.

We note that while NEM coal generators may not have experience with unit commitment decisions, many other generators (including international coal units) have, and manage these costs and risks successfully. Gas generators must make incremental commitments decisions (day-ahead fuel procurement, intra-day fuel procurement, start-up decisions in anticipation of high prices that may not eventuate, etc.) Similarly, batteries and hydro generators must constantly trade-off production during “medium” price periods now against future uncertain “high” price periods. Even a 1% chance of an hour of $14,700/MWh is an expectation value of $147/MWh. Or, alternatively, a 5% chance of $300/MWh for four hours would be equivalent to a $15/MWh uplift in expected revenue over a four hour daytime period. This value would be further supported by any system services markets or contracts.

It is therefore not clear that an ahead market is necessary for the delivery of system services once appropriate price signals are developed. Infigen’s Operating Reserves framwork plus a more formalised directions mechanism would seem more helpful for dealing with *unexpected* conditions that would not be captured by either participants or the Market Operator.

Inflexibility costs should not be socialised

If generators are concerned about exposure to negative prices during the middle of the day, generators can contract with customers/sell swaps/etc. and therefore be guaranteed a price they are happy with. The commitment decisions being considered here are therefore simply about *profit* maximisation – whether the generator can buy from spot cheaper than its sold contract, and this framework may simply extract rent from consumers due to unit inflexibility.

If coal generators are not contracting the bulk of their capacity, this may suggest a greater benefit from the Retailer Reliability Obligation than previously anticipated, but may also highlight uncompetitive generators (and therefore the need for new, more flexible/lower emissions capacity). In contrast, Infigen contracts a high percentage of its highly flexible portfolio directly to customers – delivering both reliability and affordability.

Reserve quantity

We note that Delta’s proposal to value VRE at zero firmness for the purposes of reserve procurement is completely out of touch with both the physics and design of future markets, as well as Australia’s international emission reductions commitments. Renewables are highly forecastable day-ahead, and an appropriate level of firmness has been recognised through the Retailer Reliability Obligation.

3.2 Ahead market for system services

For system strength and inertia, the fundamental problem is the lack of a market/price signal. We consider these are best addressed through the TransGrid proposals (and potentially Hydro Tasmania proposal) discussed below, as well as a future inertia service. Whether an ahead market is necessary to deliver the services is a separate question to how services are procured and value.

Delta's proposal procures reserves through a competitive bidding process for a revenue "top up". This leaves financial risk on participants (i.e., participants must determine how much is required to "top up" revenues in order to commit), and is a form of co-optimisation with the energy market. This design could be considered by the ESB through their post-2025 Essential Services workstream.

However, it would rely on sufficient competition (for bids into this service) to avoid simply paying generators for what they would have done anyway. Strict bidding in good faith rules would be required to minimise distortions and maximise competitive pressures (e.g., if a unit bids a price into the reserves market and is not selected, that unit should not then be allowed to commit anyway, as it has indicated its commitment decision was contingent on this top up payment.)

Alternatively, AEMO has proposed a Unit Commitment Scheme to formalise interventions: based on submitted costs. AEMO would commit and make whole units at the last time to intervene if a shortfall in services were identified and not delivered. This would immunise resources against negative prices, but (if implemented so that resources did not receive a windfall gain if high prices actually eventuated) would preserve signals to self-commit: if not self-committed, resources could not be used to hedge high prices for contracts/a retailer/etc.) The ESB will need to consider these options.

Impact on investment

This scheme would have little benefit for investment in new capacity which will universally come from flexible resources, particularly energy storage as well as synchronous condensors, and which do not require day-ahead commitment.

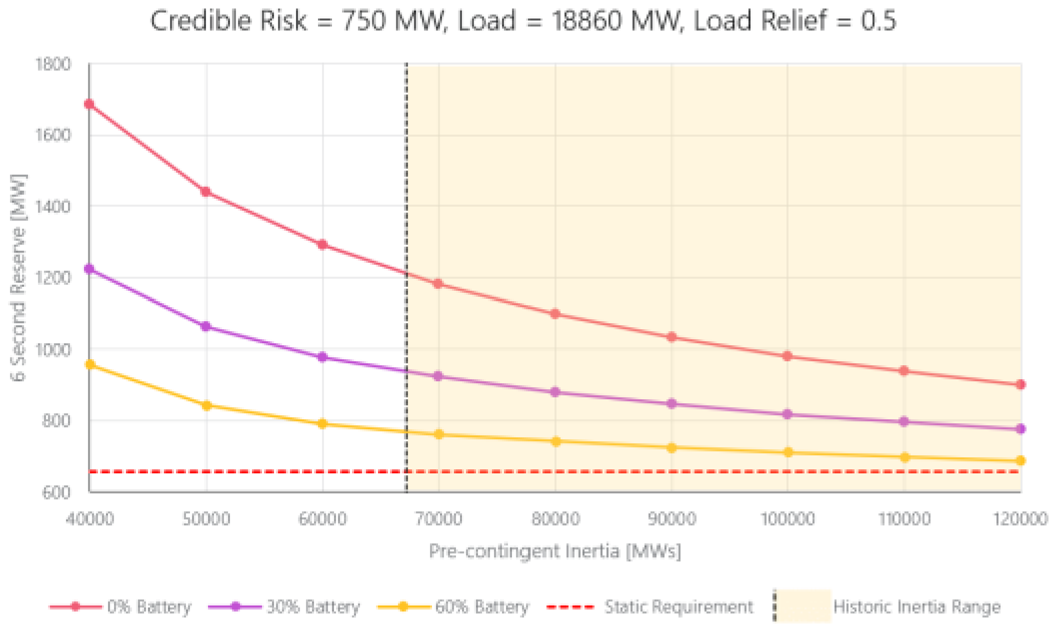
4. Fast Frequency Response

QUESTION 7: INFIGEN'S RULE CHANGE REQUEST, *FAST FREQUENCY RESPONSE MARKET ANCILLARY SERVICE* — ISSUES AND PROPOSED SOLUTION.

1. What are stakeholders' views on the issues raised by the Infigen in its rule change request, *Fast frequency response market ancillary service*?
2. Do stakeholders agree with Infigen's view that a change to the NER is required to encourage efficient provision of FFR services in the NEM following contingency events?
3. What are stakeholders' views on if there are any other issues or concerns that stakeholders have in relation to frequency control in the NEM as levels of synchronous inertia decline?
4. Do stakeholders consider there are alternative solutions that could be considered to improve the frequency control arrangements in the NEM for managing the risk of contingency events as the power system transforms?
5. Do stakeholders consider that 5-minute markets for FFR ancillary services likely to be effective and efficient in the global interconnected NEM and on a regional basis?
6. Do stakeholders consider Infigen's proposal would provide adequate pricing signals to drive efficient investment in FFR capability in the NEM?
7. What are stakeholders' views on, if introduced, how the costs associated with any new FFR market ancillary services should be allocated?
8. What do stakeholders consider to be the likely costs associated with establishing two new ancillary service markets for FFR in the NEM?
9. Would are stakeholders' views on how the proposed solution may result in any substantial adverse or unintended consequences in the NEM?
10. Are there specific issues with FFR that stakeholders think should be addressed in the NER as part of the establishment of markets for FFR services?

In our view, FFR could be implemented through a minimal change to the NEM design, and would deliver immediate benefits to the grid. We note that AEMO has referenced the need for Fast Frequency Response in its analysis of the South Australia separation event. Furthermore, AEMO has noted in its Renewable Integration Study that FFR is critical for efficiently managing the exit of aging synchronous plants and associated inertia.

Figure 13 **Reserve requirement with increasing proportions of faster reserve**



In addition to Infigen's rule change proposal, we note the following in response to the AEMC's questions:

- Infigen's original rule change request did not explicitly consider cost recovery for fast frequency response. Existing contingency FCAS services are primarily to deliver replacement capacity following a contingency event, with the quantity procured primarily determined by the size of the largest contingency. We note that FFR would also assist with managing contingencies, but may also enable more efficient dispatch or network usage (by relaxing other system constraints) and may also protect against non-credible events and as-yet unknown modes of failure.
- We recommend seeking further advice from AEMO and the Reliability Panel on the benefits and hence volume and location of FFR to be procured, including any minimum procurement level and its motivations. While existing Raise contingency services are recovered from generators, depending on the motivation for the procurement quantities, it may be appropriate in this case to recover the costs of FFR Raise from both generators and loads.
- Infigen expects that investment in FFR capable plant will primarily be through "value stacking" - projects developed to deliver multiple services, including energy arbitrage, contingency services, etc. Given that energy and FCAS services are real-time markets (with strengthened signals following 5 Minute Settlement), we consider another real-time service to be most appropriate.
- It is possible that an FFR service could be used a proxy inertia market, valuing the delivery of any initial inertial response that is excluded from the Fast Raise

FCAS service. Synchronous inertia and some virtual inertia services[10] deliver additional value to the grid, and it would seem preferable to establish a separate inertia market/service (e.g., a minimum inertia standard for TNSPs or potentially a spot market for inertia), but the FFR service may be appropriate as an interim measure to reward inertia provision.

5. System strength

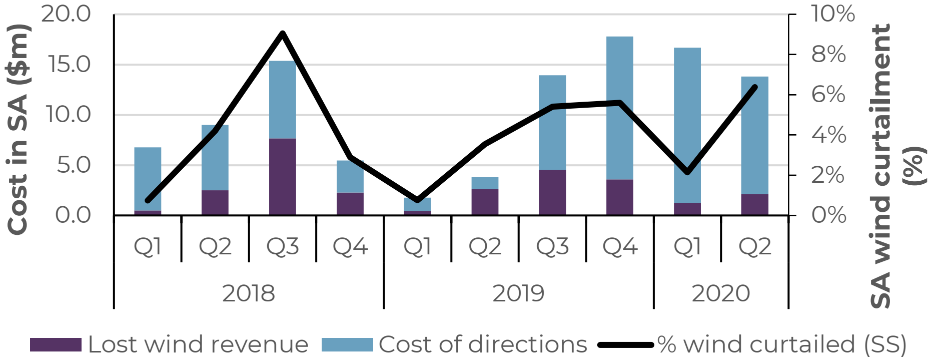
QUESTION 12: TRANSGRID'S RULE CHANGE REQUEST, *EFFICIENT MANAGEMENT OF SYSTEM STRENGTH ON THE POWER SYSTEM, ISSUES AND PROPOSED SOLUTION.*

1. Do stakeholders consider that TransGrid's approach address all issues related to system strength currently experienced in the NEM?
2. Do stakeholders consider that a system strength planning standard met by TNSPs would effectively and pro-actively deliver adequate system strength?
3. Do stakeholders consider TransGrid's proposal will provide useful and timely locational and financial signals to new entrants?
4. Do stakeholders agree that the 'do no harm' obligations should be removed?
   a. If so, do stakeholders consider an alternative mechanism is required to regulate or incentivise the minimisation of a new connecting generator's impact on the local network and proximate plant?
5. What are stakeholder's views regarding generators' being required to make a financial contribution for provision of system strength services?
6. Would stakeholders be supportive of the ownership of existing private system strength assets being transferred to TNSPs, as suggested in TransGrid's rule change request?
7. Would the proposed, TNSP-led solution to system strength result in any adverse or unintended consequences for market participants in the NEM?

Addressing system strength should be a priority project for the AEMC. The “do no harm” framework has failed to deliver effective outcomes, and resulted in significant costs to the energy sector. Currently, in South Australia alone, system strength results in $11m pa of curtailed wind power plus $30m+ in directions, plus the less quantifiable cost of project delays and higher future costs.

[10] Virtual inertia is distinct from Fast Frequency Response, for example: http://www.wattclarity.com.au/articles/2020/04/do-you-know-the-difference-between-virtual-inertia-and-fast-frequency-response/

Figure 8 Cost of system strength in South Australia



Source: Infigen analysis of AEMO data, AEMO QED publications

In our view, system strength is ultimately best described as a network service: it is locational, requires coordination between multiple projects, and requires sophisticated modelling that is not generally available to participants. Like transmission, it is an essential service, and is a fundamental requirement for managing the transition to a clean energy future.

Critically, the costs and benefits of these risks are asymmetric. Insufficient system strength will result in project delays and/or the curtailment of resources, which will ultimately result in higher costs to consumers through both higher project hurdle rates (in the long-run) and use of more expensive resources (in the short-run). These directly affect energy costs, which is the primary driver of consumer bills.

In contrast, over-procurement will increase the cost of that service but also deliver additional value through improved system "resilience".

Infigen therefore supports the basic principles of TransGrid's proposed approach:

- Removal of the generator do no harm regime
- AEMO would be required to set minimum fault level requirements for various "nodes" or "sub-regions" of the NEM based on power system modelling. We suggest that this could expanded to other system strength metrics as AEMO modelling capabilities expand.
- TNSPs would then be required to maintain fault levels sufficiently to meet a standard set by the Reliability Panel.
- TNSPs would invest or contract for system strength with a forward looking investment plan that considers developments in the ISP (or other likely investments). We consider this is appropriate, reflects the similarities between transmission and system strength services, and would address the challenges of timing new developments.
- Drive efficiency of investment in SS by addressing key points in the network and gaining scale benefits from colocation of technology delivering the service.

– Likely better utilisation of services as they are managed centrally and can service more of the network while ensuring risk of interaction between devices is minimised.

Defining nodes

In the AEMO-defined nodes, participants will have confidence that the TNSP will develop and maintain sufficient system strength to enable connection and ongoing operation of the units (based on AEMO's announced minimum levels).

Outside of these nodes, the implication is that generators would be responsible for system strength remediation (i.e., a return to "do no harm"), so as to encourage generators to locate in "strong" areas of the grid.

However, this is somewhat circular logic, given that system strength will be maintained at the nodes in *response* to projected development. It would be prudent to understand whether "existing" system strength is likely to be used up during the transition and, if so, whether there is a difference between the cost of incremental system strength in more remote locations versus more centralised locations. E.g., it may be that if additional syncons are eventually required to reach 100% renewables, it is no more costly to develop them in remote locations (with good renewable resource) than in centralised locations. Similarly, a location may currently have higher system strength, but only because a coal power station has not yet retired but will do so in the near future.

Furthermore, the process by which these nodes will be identified and defined is not clear. There is a risk that AEMO will not define nodes with sufficient resolution to provide sufficient system strength in a timely and efficient fashion for the future grid. There is also a risk that AEMO will effectively "centrally plan" the system by defining specific nodes that, due to the complexity, additional cost, delays, and information asymmetry of remediation, effectively exclude generation development away from these nodes.

Given the significant uncertainties and risk asymmetry, it would be prudent to err on establishing *more* nodes than fewer. This should map to at least the REZ regions in AEMO's ISP, but further sub-nodes may be required to capture the majority of projects. Given the lack of clear signals, it would then be prudent for new nodes to be developed in response to new project developments – thereby ensuring projects can be developed.

Importance of considering all project data

TNSPs should be required to consider both the ISP development pathways (which provide a theoretical view on possible future developments) as well as the locations and status of proposed projects and connection applications known to the TNSP. Infigen expects that TNSPs should approach investment (or contracting) in system strength similar to investment in transmission, with probabilistic/scenario analysis of options.

We note in particular that the ISP REZ modelling is necessarily high level, requiring on one (or sometimes two) wind and solar traces per REZ with a single average capacity factor. In practice, there are likely to be high quality projects in most REZs (i.e., a distribution of project capacity factors) and a lack of renewable development in the ISP should not rule out future development in that REZ (or the establishment of a system strength node).

5.2 Hydro Tasmania – Synchronous Services Markets

QUESTION 11: HYDRO TASMANIA'S RULE CHANGE REQUEST, *SYNCHRONOUS SERVICES MARKETS,* ISSUES AND PROPOSED SOLUTION.

1. Do stakeholders consider this rule change proposal presents a viable model for the provision synchronous services?
   a. Could this proposed model be used to provide the essential levels of system strength (and / or inertia and voltage control) needed to maintain security and the stable operation of non-synchronous generation?
   b. Could this proposed model be used to provide levels of system strength (and / or inertia and voltage control) above the essential level required for security?
2. Do stakeholders consider that the creation of a synchronous services market could have any adverse impacts on other markets in the NEM? If so, what would these impacts be?
3. Would the proposed model set out in the rule change request efficiently price and allocate costs for synchronous services in the NEM ?
4. Do stakeholders consider the model set out in the rule change request would be capable of sending price signals sufficient to encourage new investment in synchronous capacity?
5. Do stakeholders consider the rule change provides an appropriate incentive mechanism for existing synchronous generators to make operational decisions to provide synchronous services ?
6. Do stakeholders consider the rule change provides the appropriate locational signals for the provision of synchronous generators to provide synchronous services ?
7. What do stakeholders see as the primary opportunities / limitations of the mechanism as proposed by Hydro Tasmania?
8. Would the model proposed in the rule change request enable effective competition in the market for the provision of synchronous services?
9. What suggestions do stakeholders have in relation to the first order changes that would be required in NEMDE to facilitate this proposal and any second order changes that may be required as a result of this rule change proposals' implementation?

QUESTION 14: MECHANISMS FOR SYSTEM STRENGTH ABOVE MINIMUM LEVELS NECESSARY FOR SYSTEM SECURITY

In relation to the provision of system strength above minimum levels necessary for system security and the relevant rule change requests:

1. Do stakeholders consider the centrally coordinated model, as proposed by TransGrid, is the preferable option for providing system strength above the essential levels required for secure operation?
2. Do stakeholders consider the decentralised, market-based model proposed by HydroTasmania is the preferable option for providing system strength above the essential levels required for secure operation?
3. Could a hybrid of these models be used to deliver system strength above the minimum?
4. What do stakeholders perceive to be the strengths and weaknesses of each model?
5. Do stakeholders consider there are other, alternative models for delivering system strength above the minimum levels required for secure operation?
6. What do stakeholders perceive to be the biggest benefits and risks to introducing a mechanism to deliver system strength above the minimum levels required for secure operation?

Hydro Tasmania have presented an interesting concept: using constraint equations to deliver commitment instructions. In this approach, a unit capable of providing inertia or system strength can be committed if its commitment cost (as bid) can be traded off against other system constraints to deliver a least-cost outcome.

Infigen does not consider that this approach is suited for driving investment decisions in inertia/system strength resources.

- There remains a high degree of uncertainty over the type, location, volume, and value of system strength resources with significant information asymmetry (investors versus TNSPs/AEMO). Most (or possibly all) participants would not have the capability to model forward looking revenue streams for system strength.
- While spot markets provide clear price signals, investment generally requires some form of longer-term hedging (contracts or vertical integration). However, there are no natural counterparties for system strength investments – these are essentially shared network assets, and it is difficult for a counterparty to capture the value.
- Establishing a new market and incorporating into AEMO's ESOO would take time, and Infigen considers system strength to be an urgent problem.

We therefore consider that an approach similar to TransGrid's proposal is most likely to deliver on the NEO for consumers and drive necessary investment in a timely fashion.

However, Hydro Tasmania's proposal may be a useful service for *scheduling* contracted/TNSPs resources *and* additional capacity (e.g., from synchronous units that are too costly to contract) where it would deliver a more efficient system overall.

There may be some complexities around price formation (particularly around discontinuities in the objective function). Infigen supports further work on this idea.

6. Frequency response

Infigen supports the Commission's focus on how to incentivise narrow-deadband primary frequency response, and we see a need for a replacement framework to be developed well ahead of the sunset period on the Mandatory Primary Frequency Control framework.

We consider that the very first step should be to define an appropriate Frequency Operating Standard. As noted in Infigen's previous submission, the mandatory requirement does not allow for the procurement of any headroom and creates the risk that sufficient Raise or Lower response will not be available as the system transitions. Establishing the "frequency histogram" necessary for both secure system performance *and* efficient costs to consumers is critical for meeting the NEO.

We further note there are several distinct mechanisms that could be used to implement a tight deadband response. These include:

- Establishing a new FCAS market for a narrow-band primary frequency response, similar to the existing Contingency FCAS markets; this seems to be the most clearly defined service, providing AEMO with the certainty that sufficient primary response will be available to maintain frequency close to 50 Hz.
- Modifying the existing FCAS markets to require a faster response from Contingency FCAS providers (effectively, redefining the NOFB) or for Regulation providers to also deliver a primary response
- Modifications to the Causer Pays framework, including strengthening real-time signals for the provision of frequency control (including from participants not procured for an explicit frequency control market)

Infigen looks forward to engaging further with the AEMC on these options. We note that the AEMC must trade off efficiency with complexity, while also recognizing that there is a diversity of technologies that will deliver frequency control in the future.

Conclusion:

We look forward to the opportunity to continue to engage with the AEMC. If you would like to discuss this submission, please contact Dr Joel Gilmore (Regulator Affairs Manager) on joel.gilmore@infigenenergy.com or 0411 267 044.

Yours sincerely

Ross Rolfe
Managing Director